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

Part I

Presented to DG Comp 26th February 2007

Prepared by London Economics in association with Global Energy Decisions

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

Part I – Methodology and Results of Belgium and France

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2 Introduction and Background

This report is the final report from London Economics, and our associated partners GED and Professors Fabra, Glachant, and von der Fehr, in the study of the structure and functioning of the EU's major countries' electricity markets for the European Commission DG Competition.

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 optimisation software, despatch modelling, data, and additional electricity market expertise. 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. 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 report is an economic evaluation of the structure and functioning of wholesale electricity generation markets in six selected major EU countries: Belgium, Germany, France, the Netherlands, Spain, and Great Britain. The analysis covers the period 2003-2005.

This report consists of: an executive summary, introduction and background, a methodology report and a data report, country reports with the results for each of BE, DE, ES, FR, NL, and GB, a summary chapter comparing and contrasting the results across countries, and an overall conclusions chapter. Annexes describe the details of the GED models and database used.

2.1 Brief overview and background to the study

The sectoral inquiry into the electricity sector forms the background for the study. In 2005 the EC DG Competition launched a sectoral inquiry into the European electricity and gas markets and the main preliminary findings of the Commission's inquiry are that:

- Market concentration remains unsatisfactorily high in a number of geographical and product markets; primarily national wholesale/generation markets. Concentration in wholesale trading markets is less striking.

    - Further analysis is needed to determine if, as a result, competition is working sufficiently well.
- High degrees of vertical integration exist and are possibly distorting competitive incentives or the functioning of the internal market (vertical foreclosure).
    - Unbundling seems insufficient between supply and transport.
- Market integration between countries is insufficient, due to various reasons-- such as diversity of rules, regulatory regimes but not least insufficient transmission capacity.
- There is a lack of transparency in wholesale markets which undermines confidence in trading.
- Large energy consumers doubt that prices on spot and forward wholesale markets result from fair competition.

A major challenge, but also a major achievement , in the study has been the data. The study involved collection and analysis of often hourly data by generation unit for virtually every large electricity generation unit in the six major electricity markets identified. The Commission collected primary data on, among several variables, electricity system capacities, prices, hourly cost and production data by generation unit from January 1999 to May 2005. Additional data were collected by the project team for the remainder of 2005, data pertaining to carbon dioxide emissions and allowances, and clarifications on data issues needed to complete our study. Data on technical characteristics, location, ownership, constraints were collected by the DG Competition, however, a significant amount of data on technical characteristics was needed to be subsequently collected for precise modelling of the markets[1]. Additional data from public sources was used as necessary, and details of this are given in the annexes of the report.

[1] Dynamic constraints on units can impact on marginal cost significantly.

2.1.1 Objective and key elements of study

The overall objectives and terms of reference for the study were to provide DG Competition with high quality assistance and advice on the structure and functioning of the EU's wholesale electricity markets; the reasons for their (possible) malfunctioning, and, where needed and/or feasible advice on how to improve them.

Along these lines, the first objective was to develop in as much detail as possible structural measures of the large electricity markets in the EU. This meant utilising the unique dataset developed for this study to calculate both traditional market structure measures (e.g., HHI and CR(*n*)) as well as more recent innovative measures of market structure developed specifically for electricity markets, such as the residual supply index (RSI) and the pivotal supplier indicator (PSI). The key objective was to investigate in as much detail as possible the relationship between structural measures and market outcome measures.

To accomplish this, we engaged in a very detailed study and approach. Structural measures such as the RSI were estimated for the largest companies in each of the six markets on and hourly basis for the each of the 3 years. Next, we undertook modelling of the optimal despatch of electricity generating plant in the six major electricity countries markets. Using market price data, we then calculated market outcome measures such as price cost margin and the Lerner index. The approach was then to analyse using regression analysis the relationships between market structure (RSIs and other variables) and market outcomes (PCMs and Lerner indices).

3 Methodology & Literature Review

This chapter presents a brief overview of the existing academic literature and research on the measurement of market power in electricity markets. It highlights a number of approaches previously adopted and the issues encountered in this area. Following this there is a detailed overview of the methodologies and variables applied to calculate the structural indicators and outcome measures for each of the countries addressed as part of this study. The section also serves to highlight the need for detailed modelling of electricity markets when undertaking a market assessment such as those contained in this report. This chapter concludes with a description of the data used within the report, largely the result of the data requests sent by DG Competition as part of the Sector Inquiry into the Energy Market. The quality and quantity of this data is unprecedented for any assessment of the European electricity market and as such allows for the most in-depth assessment of the European electricity market ever undertaken.

3.1 Review of relevant research & academic literature

This sub-section gives a brief overview of existing research and academic literature on the measurement of market power in electricity markets. The difficulties of studying market power have led to a significant body of research on the subject, but broad consensuses have only emerged for small number of questions. The nature of electricity as commodity (non storable, real time balancing) and the complexity of electricity markets precludes a simple test of the exercise of market power. In fact, electricity market participants can display behaviour that can appear similar or even identical, whether they have market power or not. This makes the empirical study of market power in electricity markets an undertaking of crucial importance but one that is beset with difficulties. Other researchers have been tangling with the many problems and nuances of market power measurement in electricity markets.

The long history of the electricity sector as a regulated industry means that research into competition in the sector is a relatively recent development. Furthermore, certain natural features of electricity markets, such as the fact that prices may change in every hour or half hour, real-time balancing requires generators to provide reserves and other 'ancillary' services, which may be complements or substitutes in production, and other factors, it means that conventional approaches to measuring market power cannot readily be applied. The interest in the study of electricity markets has been considerable, however, and a number of studies have to date confronted the problem of measuring market power.

The fundamental concern behind any study of market power (in the electricity or any other sector) is whether one or more suppliers are able to artificially restrict their output and raise[2] prices. In general, in markets for normal goods, this is only possible if the companies engaging in the abuse control a sufficiently large part of the market. As with any market, many studies of electricity market competition start with an analysis of the market structure.

Several approaches have been taken by other researchers in the past. Among them are studies of market concentration using standard concentration indicators (CR(n) and HHI), simulation studies, bidding and also supply analysis.

[2] We should note that there is the possibility of using market power to lower price in the short term to drive out or discipline competitors. At some point in time, though, prices must be raised to make such short term actions profitable in the long term.

Many studies in the early stages of electricity market research used standard or traditional market concentration measures. Studies of market concentration, using straightforward HHI measures often find concentration of a magnitude that raises market power concerns. Schmalensee and Golub (1984) calculated HHIs for 170 regional generation markets in the US, comprising nearly three-quarters of the US population. They found that, depending on cost and demand assumptions, 35-60% of all markets exhibited HHI values above 1,800.[3]

A more recent study by Cardell, Hitt and Hogan (1997) indicates that high concentration has persisted. In their study of 112 regions based on State boundaries and North American Electric Reliability Council (NERC) subregions, they found that about 90% of the markets examined had HHI values above 2,500. However, it should be noted that a number of studies[4] have shown that HHI and concentration measures can be sensitive to the assumptions, and conclude that they are of little use in studying market concentration (market power)[5] in electricity markets.

Other authors[6] have focused on more game-theoretic foundations, arguing that market concentration has little impact on an electric generators ability to raise price (especially in wholesale spot markets)—in general it depends on how pivotal a supplier is.[7]

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[3] 1,800 is the threshold for "high concentration" under the US Federal Trade Commission/ Department of Justice (FTC/DOJ) guidelines. Similar guidelines have been adopted by other competition authorities globally. However, with regards to energy infrastructure markets, an alternative threshold is often considered. For example, in the case of the oil pipeline market in the United States, "The Department of Justice (DOJ) and the Federal Energy Regulatory Commission (FERC) staff have previously advocated an HHI threshold of 2,500 and it would be reasonable for the Commission to consider concentration in the relevant market below this level as sufficient to create a rebuttable presumption that a pipeline does not possess significant market power." See Hogan (1997).

[4] Moss (2005).

[5] See for example Moss (2004), Sheffrin (2001), Williams & Rosen (1999).

[6] We discuss an intuitive model of this with a graphical approach elsewhere in the methodology section.

[7] See for example Stoft (2002).

Thus the link between standard concentration measures and the existence of market power is criticised for two possible flaws: one is the possible sensitivity of HHI to assumptions about interconnection and transmission, while the other is the usefulness of HHI and concentration to indicate the degree of market power *at all.* This raises a subsequent issue for competition authorities who in particular cases may have to determine whether market power is used/abused, as to do so they first have to determine that such market power exists.

The next step is thus to study the link between market power and market structure. It is a generally accepted competition economics tenet that the mere measurement of concentration is not necessarily an indicator of market power existence.

The theoretical and empirical evidence is in fact somewhat mixed on this topic—with some authors finding market power and some others disputing it. In general, though, many studies find that not only are many electricity markets highly concentrated, there is also good international evidence for the exercise of market power. In the United Kingdom and California researchers have found that wholesale electricity prices have been up to 75% above competitive levels during certain periods.

Studies and models in the UK and in California have estimated marginal costs and compared them to pool prices or power exchange prices. Wolfram (1998 and 1999), for example, studied strategic bidding behaviour in the British electricity market, which was one of the first to operate under competitive conditions. Using marginal cost estimates based on units' fuel cost and heat rate data, she found a difference between marginal cost and the Pool's "system marginal price" of between 19% and 25%. This estimate might be biased upwards owing to the fact that variable operating and maintenance costs (O&M) were not included.[8]

[8] However, LE's own experience is that O&M tend to be a small percentage of marginal cost. Further, O&M should not vary with time and demand, while margins in most studies tended to be highest at peak times.

Perhaps due to the difficulties of empirical measurement, many early efforts at measuring market power in electricity markets and relating it to market structure were highly theoretical. Early advances were made using the 'supply function equilibrium' approach[9]; this was applied in the UK. This approach recognised some of the difficulties of relating market structure to market power in electricity markets and recognised that 'electricity was different'. The approach essentially used a game-theoretic approach to give predictions about the degree of market power that exists for a given market structure. The approach assumed that generators bid "supply functions" or a set of pairs of selling prices and quantities according to their generation capacity and technology (unit costs). One of the conclusions of Green and Newbery was that the early structure of the British electricity markets was too concentrated, and that splitting them into five firms would produce 'better' (tolerable levels of mark up) results.

The supply function equilibria approach, however, suffers from a number of drawbacks. For one, it is necessary to assume a functional form for the supply function of generators (it is common to assume quadratic). Secondly, they do not allow their predictions to vary with time; and it is generally agreed that electricity markets display accentuated market power exercise possibilities at peak but lower possibilities off peak, and that conditions change radically hour to hour.

Others, such as Fabra, Von der Fehr and Harbord (2004)[10] have taken a different theoretical approach. Their work uses a multi-unit auction theoretical framework. Qualitatively, they do not conclude that more or fewer firms would produce less market power, nor does the work suggest thresholds for the market structure or number of generators. Their study did come up with interesting conclusions, however, regarding market design, predicting (confirming) that the new electricity trading arrangements (NETA) in the UK would reduce market power and prices. While useful for market design (when data do not exist *ex ante*) the need to apply varying market conditions and relating them to outcome had not been explored using similar techniques.

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[9] Green and Newbery (1992).

[10] Fabra et al. (2004).

The perhaps most common means of measuring market power involves calculating market outcome measures such as price cost margins. This requires observable prices (usually spot prices from an electricity power exchange) and some estimate of marginal cost.

Simulation analysis attempts to identify the marginal cost of production of the marginal generator. This approach requires detailed data on the characteristics of the generators present in the market, which are then used to estimate a supply curve (merit curve) by stacking generators from least expensive to most expensive.

Not only are the data requirements for such a simulation considerable, but in order to have a tractable simulation one needs to make a host of simplifying assumptions, which potentially negate the validity of the exercise. A few assumptions have proved to be particularly problematic, for example assumptions on the treatment of start costs or minimum load effects, as well as ignoring the potential existence of regional sub markets by looking only at markets on the national scale. Most of the assumptions would lead to an underestimate of marginal costs.[11] Looking at national markets one ignores inter-nodal constraints and transmission losses, which would increase Marginal Cost. Simulation models have been harshly criticised for their shortcomings.[12]

Supply or bidding analysis, on the other hand looks at bidding and supply decisions by individual generators to see if they are offering at marginal cost (Wolfram), or equivalently, if they do not offer all electricity they could profitably generate (Joskow and Kahn, 2002).

This is done by comparing generators' actual offer curves to marginal cost estimates. It is clear that this approach makes it sometimes difficult to distinguish between evidence of abuse of market power and simple errors in the estimation of marginal cost.

[11] Guthrie and Videbeck (2003).

[12] Harvey and Hogan (2002).

Perhaps the most recognised study on the existence of market power in deregulated electricity markets comes from Borenstein, Bushnell, and Wolak (2002) in the American Economic Review (AER). [13] This paper is based on a series of papers, starting with Borenstein, Bushnell and Wolak (1999). Through the series, they analyse market power in the Californian electricity market and refine their approach. Their approach is to construct the system marginal cost curve, the merit curve, and then to identify the competitive price in each hour as the intersect of marginal cost curve and total generation. The marginal cost of each unit is estimated using the fuel cost and heat rate of each generating unit as well as the units' variable operating and maintenance (O&M) costs, the cost of NO_x emissions was also included for a number of units. They account for potential complications on the supply side by;

- Excluding must-run units from the cost curve and remove an equivalent quantity from the demand;
- Assuming that hydro units are dispatch so as to minimise cost (i.e. they cannot be used to exercise market power); hydro units are thus also excluded from the cost curve and an equivalent portion of demand is removed;
- Assuming different scenarios on the responsiveness of out-of-state supply to price changes in the Californian market;
- Simulating forced outages based on a probability distribution;
- Ignoring start-up costs;
- Cap marginal cost at the ISO imbalance energy price cap when demand is not met with sufficient available capacity.

Using the method described above, Borenstein *et al* calculate the added cost of power due to prices that exceeded the estimated competitive price (marginal cost). Using a load weighted measure of the difference between the observed and estimated competitive price, the authors found wholesale electricity prices in California to be 17% above the competitive level in the summer of 1998, which represents evidence of significant market power, which cannot be explained by the exclusion of start-up costs.

[13] Borenstein et al. (2002).

In a subsequent study, Wolak (2000) extended the analysis to include the summer of 1999. His revised estimates show that generators potentially received an extra $800 million in payments above competitive levels during the period 1998 to 1999.

In general, by the approach taken through the series of papers, the authors come to qualitatively similar conclusions: that market power existed in California electricity markets and was significant. Interestingly, in the early papers (1998 and 1999), it was questionable whether market power really was a problem in California, as it only seemed to exist in a certain number of hours. However, within a few years, rapid increases in demand, lack of hydro capacity from neighbouring regions, hot weather, nuclear outages, and flawed market design all combined to form a perfect storm for California's new deregulated markets.

Subsequent studies disputed the degree to which market power played in the California crisis, however some authors concluding it played a large role[14]. The California Public Utilities Commission[15] concluded after studying the bidding behaviour and generator data that, "If the state's five largest independent electricity generators had operated all of their available capacity from November 2000 through May 2001 (the height of California's energy crisis), California's citizens could have avoided:

- All 4 days of blackouts in Southern California;
- 65% of the blackout hours in Northern California;
- 81% of service interruption hours in the South, and
- 51% of service interruption hours in the North;

Studies of market power in electricity markets have also been conducted in European markets. Many of these efforts used despatch models to estimate marginal cost. Barquim et al (2004) examined the impact of different economic assumptions on the assessment of the exercise of market power. Models involving similar concepts are also used in Spain (Garcia-Alcade, 2002) and the United Kingdom (Green, 2004).

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[14] See for example Joskow and Kahn (2002).

[15] CPUC Generation Investigative Report (2002), available at Harvard KSG Electricity Policy Group website.

In Germany, Müsgens (2004)[16] was the first to conduct a detailed study that quantifies the extent of market power in the German electricity market by estimating a marginal-cost-based competitive price and comparing it with observed power prices on the German electricity spot market. He finds prices were 50% above estimated costs from September 2001 to June 2003. Following Borenstein's line of reasoning, Müsgens concludes that market power, rather than fundamental factors, such as fuel costs or generation technologies, is the most likely cause of the observed discrepancy.

Schwarz and Lang (2006) also use a simulation approach to analyse the performance of the German wholesale electricity market. They find that, although market power was responsible for high price-cost margins (up to 30%) in 2003, these were subsequently eroded, and overall price rises between 2000 and 2005 broadly reflected changes in marginal costs.

A study conducted by von Hirschhausen et al. on behalf of the association of the German energy industry (VIK) suggests that market power is an important factor in explaining high price-cost margins in the German wholesale electricity market. The authors use a simulation modelling approach to identify marginal costs for the years 2004-2006. They find exchange prices consistently exceed their estimates.

Withholding

It is generally accepted that market power can be exercised either by raising price or by withholding capacity. Capacity withholding is addressed in a paper by Wolak and Patrick (1997). They chose the example of the UK power pool, whose structure meant that firms could reap substantial benefits by withholding generation. Prices paid to generators include a capacity payment determined half-hourly by the pool operator, based on the level of reserves available and the value of lost load. Thus, lower reserve capacity means an increase in capacity payments. Withholding capacity thus meant both higher capacity payments and higher system marginal prices for generators.

[16] Musgens, F. 2004. Market Power in the German Wholesale Electricity Market, EWI Working Paper Nr. 04.03.

Wolak and Patrick find evidence of systematic strategic withholding of capacity by two companies in the early days of UK restructuring. The pieces of evidence they consider are the proportion of capacity declared unavailable during off-peak months, which for the two companies in question was more than double the industry average, and the proportion of available capacity by fuel type, which is also systematically below the industry benchmark. Other studies have also found evidence of behaviour consistent with the systematic use of withholding[17].

It is also noteworthy that 'withholding' as a means of exercising market power can be either an 'error of omission' or an 'error of commission'. For example, the CPUC[18] analysed possible withholding during the California energy crisis of 2000 and 2001. Independent of reported actual forced and planned outages (which the CPUC took at "face value", at least for their initial phases of investigation into the crisis), they found a number of withholding strategies to have existed, including that generators:

- Failed to follow or delayed their responses to ISO requests to produce power;
- Declined the ISO's automated dispatch instructions;
- Failed to take all actions necessary to make plants available as soon as possible after plant outages; and
- Failed to provide adequate fuel and staffing for plants.

However, other authors have disputed the existence of withholding in California's energy markets, even during the crisis. For example, Harvey and Hogan (2002)[19] found, "On balance, to date the publicly available data provides no reason for the Federal Energy Regulatory Commission to change its conclusion that there is no evidence of strategic withholding nor any proof that no strategic withholding has occurred."

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[17] Power Pool of Alberta (2002), "Economic Withholding in the Alberta Power Pool," paper available at Harvard KSG EPG website.

[18] CPUC (2002), *op. cit.*

[19] Notably, their research was sponsored by Mirant, one of the largest generators accused of market power abuse during the crisis.

Still others[20] have disputed that much, if anything, can be said about market power in emerging electricity markets using the current set of techniques. The conclusion of that work was, "that this work on the structure of national electricity market *distracts* from the fundamental objective to introduce competition in the power sector by integrating the national markets into a single electricity market[21]." However, the conclusion that "market structure doesn't matter", would not be taken seriously by most independent energy market economists. Further, studies of whether market integration in the EU across national Member States such as Belgium would have sufficient impact in the short to medium term to improve market structure and reduce market power have concluded that barriers that slow and limit the speed of interconnection will continue in the EU[22].

Relating market structure to market power

To our knowledge, few authors have been able to link market power to market structure in electricity markets. A notable exception has been Sheffrin (2002)[23].

Sheffrin, working for the California ISO proposed the Residual Supply Index (RSI) as an hourly measure of market structure in electricity wholesale markets. The RSI as proposed by Sheffrin is calculated as the difference between total capacity in the market and total capacity of the largest supplier, with this difference divided by total demand. Companies' capacities are adjusted for net contract positions and for capacity reservations contracted with TSOs for system balancing purposes. RSI can be calculated for either the largest individual supplier or the market as a whole. He found that in summer months the RSI was a good explanatory variable for California Power Exchange prices. It is noteworthy that some of the criticisms of simulation modelling using publicly available information (e.g., Harvey and Hogan 2002) was likely avoided here, as CAISO had detailed data on units and contracts.

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[20] Smeers (2004).

[21] Ibid.

[22] See for example London Economics (2004).

[23] Sheffrin (2002).

An econometric approach has also been adopted by Wolak (2003) to directly estimate the cost function[24].

Conclusions to literature review

A great variety of approaches, models and methods have been applied to the study of market structure and market power in electricity markets. Market simulation models (using despatch simulations and price cost margins) and game-theoretic models (using concepts such as the supply function equilibria approach) are the most prevalent. However, little work has been done to relate empirically market structure to market power, however. Some authors have criticised all attempts to measuring market power in electricity markets, but advances have been made. Nonetheless a clear consensus as to the best approach has not been formed to data.

[24] Wolak (2003).

3.2 Overview of the methodological approach

Electricity as a commodity has many special features. 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 whole system within very tight margins in real time. Electricity market interactions are also repeated games, and so dynamic strategies for gaming can be involved. Coupled with this is consumer behaviour, which often sees them purchase at fixed prices in the short term.

3.2.1 Structural measures and their limitations

The standard tools of competition economists and competitions authorities to measure market concentration are Herfindahl-Hirschman Indices (HHI) and concentration ratios (CR(*n*)). The key to using these measures correctly in the context of electricity markets is to make use of detailed data and modelling. This involves adjusting the measures to account for changes in capacity of the system and market shares of players: as despatch changes, as market conditions (e.g., hydrological, fuel prices, etc) change, as units undergo 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 within this report primarily considers the relevant geographic market to be the wholesale generation market within a particular country, with each country considered separately under this approach. Therefore, the role of interconnectors 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. One should however note that role of interconnectors is implicitly contained in much of the modelling, as discussed in more detail below.

Although each market is modelled and analysed separately, one should be aware that in reality it is still possible that transmission constraints could still create submarkets[25]. However, it is not possible to control for such an event in the context of this study but it is also not clear that one would want to.

HHI and CR(*n*) measures have been constructed for a select number of capacity measures (MW), as well as generation output (MWh). In general capacity-based measures of concentration are far less likely to be sensitive[26] to capacity definition, thus not differing substantially between measures whether based on installed capacity or available installed capacity, for example. On this basis one may expect to see a more substantial difference between capacity and output based measures, than between two alternative capacity based measure as variation in output is likely to be less static over time.

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[25] Unlike other industries, the existence of network constraints imply that market boundaries depend on demand and supply conditions. Transmission constraints could create pockets of local market power, where firms could exercise more market power than a concentration index based on aggregate numbers would suggest. Even firms that seem small on aggregate in the market could have a high degree of market power if they are located in congested areas- however, a correct market definition would reflect that these firms are large in the relevant market.

[26] Less sensitive, than despatch modelling, for example. In this case, the cumulative sum of capacity will determine the cost at which demand is met. Small differences in capacity could sum up to the size of several peaking power plants over the whole system, and thus indicate a higher marginal cost.

However, care and caution are required in the use and interpretation of these traditional structural measures with respect to structural phenomenon in electricity markets[27]. These caveats stem mostly from the non-storability of electricity, and the real-time dynamic nature of supply and demand on the grid, thus creating competitive conditions in electricity markets that are very transient – changing hour-by-hour, day-to-day, season-to-season, etc. Therefore, the problem is that an electricity market may be very competitive at certain times of the year/day and potentially very uncompetitive at other times. Traditional concentration measures have generally been found to be unable to reflect this transience in electricity markets, on average. Nevertheless, they do provide a useful provisional assessment of concentration in a context that can be summarily benchmarked against other markets and measures.

Considering the following hypothetical example, one can begin to see the basis for this concern in focussing a competitive analysis of electricity markets on the results of traditional concentration measures. In order to simplify this example, the hypothetical electricity market consists of only two generation companies both with identical portfolios of generation assets and when aggregated represent 500MW of installed capacity each. The market therefore in this case has 1,000MW of installed capacity. It is further assumed that one of the companies, Company B, has slightly higher fuel costs than does company A. The following figure serves to illustrate the market.

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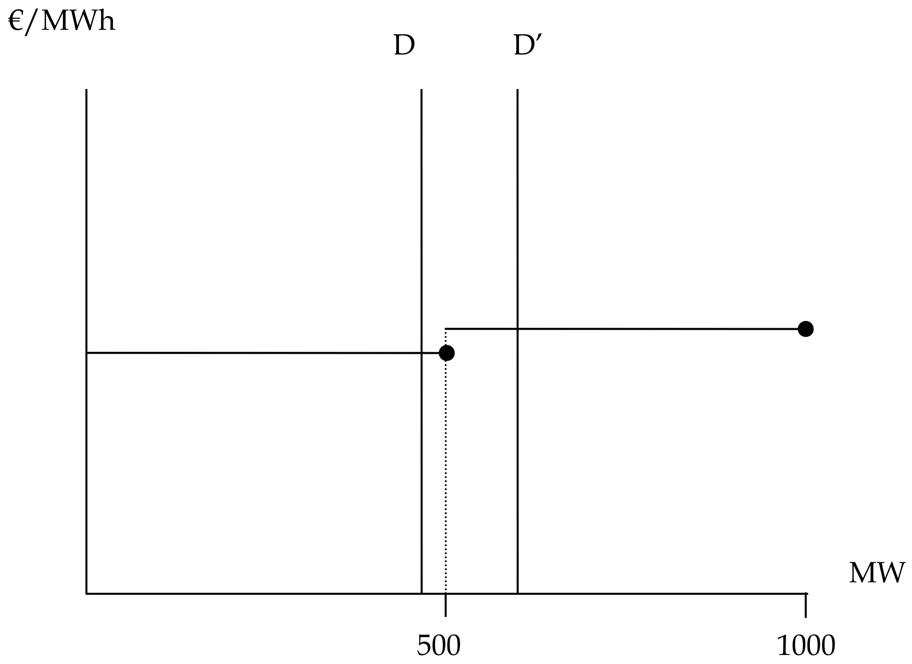
[27] Of course, in some situations, such as when the market is already near monopoly, little care is needed; no matter how many subcategories and divisions in the market definition one tries to make, the HHI will still be indicative of monopoly.

Figure 3.1: Simple stylised electricity market



Source: LE

It is assumed that demand curves D and D' are vertical, indicating that electricity demand cannot respond to prices in the short term[28].

[28] Even with demand-side management or interruptible contracts, the demand curve will only have "kinks", and will have vertical areas along most of its values.

Considering the HHI in this instance once can see that the HHI will be 2500 + 2500 = 5000, indicating a very concentrated market and a likely competition problem. However, notice that at demand level D, if producer 1 (the slightly lower cost producer) tries to raise his price, producer 2 can come in a satisfy all of the demand. The output cannot be stored and the product is homogeneous, so we have a classic Bertrand[29] competition situation when demand is at demand level D.

However, if demand in the market increases to D', demand has increased just a small increment. However, now, if either player holds their output (or raises bid prices[30]), then there would not be enough capacity to meet demand. The electricity system could potentially break down and lead to power outages and costly damage to equipment if both of them are not despatched. In this situation, both suppliers are "pivotal" as they each must generate some output to meet demand. A pivotal supplier has power to increase price significantly.

Interestingly, the HHI will remain unchanged, at least when based on an installed capacity basis, irrespective of the whether one or both of the companies are pivotal and thus capable of exerting market power to influence prices. Notice also that on the "economic capacity" (capacity in merit) basis and the generation basis, HHI actually increases in the arguably more competitive situation, i.e., when demand is low at D.

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[29] In Bertrand competition, price competition is "extreme", and so a competitive (i.e., price = marginal cost) is predicted even if concentration is high. In general, this flows from the assumptions of the model/reality of the electricity market. The key assumptions are that goods are homogeneous, cannot be stored, and suppliers can capture all the residual demand of opponent players who raise price. Indeed, when player capacity constraints are significant, even the theoretical Bertrand model predicts Cournot competition.

[30] The description in terms of price competition may be more intuitive for some. For demand level D, the capacity of a single firm is sufficient to cover the market. The low cost producer does not have the ability to raise prices above the high cost since otherwise, its rival would be willing to supply the whole market. Hence, in equilibrium the low cost producer serves all the demand at a price slightly below its rival's marginal cost. On the contrary, for demand level D' the capacity of both firms is needed to serve demand. We say that both firms are pivotal since they each must generate some output to meet demand. With pivotal firms and completely inelastic demand, either firm could raise prices well above costs (up to the price cap) without any loss in production.

This simple example serves to illustrate the reservations expressed previously in relation to the limited scope of traditional concentration measures to correctly identify issues of concentration and potential market power. In light of this electricity-specific market power indicators, namely the Residual Supply Index (RSI) and the Pivotal Supplier Index (PSI), were developed 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 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 thus necessary to meeting the load. Companies that are pivotal in the market, have market power. Although the PSI addresses the issue as to whether a company is pivotal, it does not provide any indication of the extent to which it is needed to meet demand and as such it's likely degree of market power in a given hour. The answer to this question is provided by the RSI.

The RSI is a generalised form of the PSI. The PSI is based on an absolute calculation of pivotalness and as such returns a binary variable (1,0) to indicate whether the specific company was pivotal in that hour. 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 the load, the basis of the company's market power.

Returning to the simple hypothetical example, the benefit of these measures over the traditional measures can be readily observed. Both the RSI and PSI values are calculated separately for each particular company of interest, generally this is the largest one or two companies in the market. For the purpose of this example the companies are symmetric and therefore it requires discussion of only one case. If one considers the RSI, relative to Company A, one can see that at demand D, Company A will not be considered to be indispensable and as such the resulting market outcome may be the competitive one. This result is based on there being total available installed capacity of the market is 1GW, of which company A owns 500MW, thus leaving 500MW of residual supply. Given demand is strictly less than 500MWh in this one hour, the residual supply is sufficient to cover this demand even in the absence of Company A. However, if one now assumes that the demand in the following hour increases to D', the residual supply is strictly less than the load in this hour, resulting in Company A becoming indispensable in the second hour. Company A is now needed to meet demand and as such can be viewed as having considerable market power, a position the company was not in in the previous hour. Given this result, the market outcome in this hour is not considered to be indicative of a competitive outcome. Similarly, this will be the same for Company B given the symmetric nature of this example.

From this simple example one can see the benefits of these new structural measures of concentration that were designed specifically for the electricity market over the traditional concentration measures. The HHI remained unchanged in the case of the HHI (based on available installed capacity) with changing demand conditions, leading to a conclusion indicating a substantial degree of concentration in the market that is not consistent with competitive markets. The RSI assessment of competitive conditions, under identical circumstances, provided for two different and opposing conclusions as to the degree of market power held by either of the companies in the market, based on different demand conditions. One that can be considered to be likely to bring about a competitive outcome and another that is not likely to bring about a competitive result due to the presence of market power for both companies, indicated by their relative indispensability to meeting demand.

3.2.2 Outcome measures

To assess market outcomes a common approach has been adopted in this study, one that is regularly applied by competition economists and competition authorities generally across markets, and which has previously been applied to electricity markets. Lerner Indices and Price-Cost Mark-ups are 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 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. Unlike many previous studies, the calculation of both measures allows for a direct comparison with results found previously in the literature, which only applied a single methodology to calculating market outcome measures. 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 more standard markets, the LI and PCMU are relatively simple to calculate[31]. However, in electricity markets, things become more problematic. Dynamic constraints and technical characteristics of the system (such as minimum up- and down-times, minimum stable generation) are likely to result in the actual marginal cost not simply being equal to the marginal unit fuel cost obtained from a simple "stacking" (sorting) of the system's units by marginal cost in each hour. It is also the case that units do not necessarily turn on and off through the day in exact merit order. Therefore, due to demand variations, marginal costs are likely to change on an almost hourly basis, however one's ability to correctly represent these changes using a simple stacking model are limited and at best only broadly indicative of the actual outcome in the market.

[31] This is not to say it is normally 'easy' to estimate, as marginal cost information is often difficult to obtain.

In order to address these issues and to arrive at an estimated hourly marginal cost for the system, one that reflects the technical characteristics and dynamic constraints of the system, each of the six electricity markets were separately modelled using Global Energy Decision's MARKETSYM electricity market simulation system using the cost-minimising PROSYM simulation engine. The result of the modelling was to produce, on an hourly basis, an optimal system dispatch and marginal cost for each of the six markets. This marginal cost is used in all of the outcome measures. A more detailed exploration of the approach adopted to estimate the marginal cost is contained in the data description section of this chapter. Analysis of the results returned by the GED simulation exercise for each country, are contained in the country specific chapters of this report.

The price chosen will also be 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 the 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.

3.2.3 Further analysis

The unprecedented quantity and quality of the data collected as part of this inquiry made it possible for further analysis to be undertaken to investigate aspects of the electricity markets in these countries that previously could not have been attempted without a significantly large number of assumptions on key aspects of the data. Therefore, with structural indicators and outcome measures calculated on an 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. Taking the RSI to be the most sophisticated measure of market power in electricity markets, one would expect to see decreases in the RSI value (indicating an increase in indispensability of the relative 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. Although this is largely understood to be the case in markets as a whole, an analysis of this relationship has not previously been undertaken in a European context. Therefore, this study undertakes a regression analysis to assess the suitability of the RSI measure in identifying competitive outcomes, while controlling for many observed and unobservable aspects of the market.

All of the outcome measures calculated as part of this study take the marginal cost estimated by the GED optimal dispatch modelling of each system as the relevant measure of marginal cost. Therefore, the marginal cost in any particular hour resulting from the GED modelling is not necessarily the marginal cost observed in the market in that hour but rather it reflects the marginal cost of the system had an optimal dispatch occurred to produce the most competitive marginal cost and dispatch outcome, given system constraints. However, given the inputs of the GED modelling are largely those provided by the companies in response to the inquiry questionnaires one can expect these two costs to be similar and to converge as increased competition impacts on the system's dispatch. Nevertheless, given the marginal cost used in the calculation of the outcome measures is a modelled representation of the actual marginal cost, an assessment of modelled marginal cost has been undertaken to investigate whether this cost allows for a sufficient contribution to units' fixed and start-up costs.

The results of the GED modelling of each system have also allowed for a detailed assessment of the full cost imposed by the EU ETS since its introduction in 2005. This is done by comparing the results of optimal dispatch modelling simulations that include and exclude the cost of CO_2 in 2005. Importantly, the dispatch will not be the same under both scenarios as all units are not affected equally by the introduction of the EU ETS. In other words, the EU ETS is likely to bring about considerable changes to the merit order of units on the system, relative to the scenario where the cost of CO_2 has been omitted. Therefore, to accurately calculate the cost of carbon, simply looking at the change in the merit curve is not sufficient, one must have recourse to more sophisticated methods in order to calculate the true cost. Under this approach, the amounts calculated within this report reflect the maximum possible impact of the EU ETS if generators were to fully factor in the price of CO_2 certificates in a competitive environment.

The detailed modelling of the system has also allowed one to compare the actual dispatch with the results of the modelled optimal dispatch for each unit. This analysis allows for one to test for the presence and prevalence of behaviour in the market indicative of withholding. This practice involves the systematic withdrawal of capacity that is to the left of the merit curve thus causing it to be replaced by capacity one the right of the curve, more expensive technology. Such behaviour bids up the price of electricity, to the financial benefit of all units dispatching electricity.

3.3 Detailed methodological description

This section formally presents the methodological approach adopted in relation to each of the calculated measure and indices of the report. In general the time subscript (t) is not included in the formulae in order to facilitate ease of reading and comprehension and therefore one should consider the following formulae to relate to a specific hour. This result can subsequently be aggregated over time if so required but a formal exposition of this is not considered to be of assistance to the reader and is thus not included.

3.3.1 Load

The electrical load of a country generally refers to the quantity of electricity consumed at any one particular point in time, throughout the country. Transmission System Operators (TSOs) generally report on the load of their specific country, or area of control, on an hourly basis. The load therefore is equivalent to the demand for electricity and in the case of electricity markets, load must always be met with electrical generation (supply) in order to avoid the suspension of service (blackouts) and potentially costly damage to the network system. As a result, supply and demand in electricity markets, under normal conditions, are equivalent. Therefore, in the case of any one country, one without interconnectors allowing for the import and export of electricity to neighbouring countries, one can see that the supply of electricity from generation units located within the country is equal to the demand for electricity in the market[32]. Given the specified approach of this study is to assess the wholesale electricity markets in each of the six countries separately and not to jointly optimise their operations, then the relevant load for the purposes of modelling and analysis of the markets is the sum of the net electrical output of all units contained in the study, in each hour. The formula for the load used throughout this study is given here.

$$load = \sum_{i=1}^{N} hourly\_generation_i$$

[32] In this simple case one should consider the total generation of units to be net of electrical energy absorbed by the generating auxiliaries and the losses in the main generator transformers, thus the electricity that is available for consumption on the grid.

This approach was adopted in order to obtain the most accurate results from the modelling of the system and the calculation of the various indicators. The data collected by DG Competition through the Sector Inquiry data requests provided hourly output data of all units greater than 25MW for all companies with a portfolio of generation assets of greater than 100MW and are connected to the high voltage grid. For units less than 25MW hourly generation data was also provided, aggregated by technology, by these companies for the full period 2003-2005. Therefore, within each country the sum of generation in each hour is unlikely to be substantially different from the actual load, in fact, comparisons of the loads used in this report and those reported by the TSOs indicate that in many instances these figures are comparatively similar and importantly follow the same load pattern. This comparison also raised a number of potential issues with the data returned by the TSOs particularly in cases where the coverage of the TSOs over the respective high voltage networks did not reflect the entire network. In these cases the sum of generation systematically exceeded the TSO reported load and in such cases the modelling of the system would not reflect an optimal dispatch of the system per se but rather of a sub-section of the system and as such not fulfil the objective of the modelling and subsequent analysis.

Importantly this load includes the hourly generation of a number of units that were not modelled, these include wind unit and run-of-river hydro units. These units were not modelled as it is not appropriate to attempt to re-dispatch their generation, the decision then is whether to include their hourly generation in the modelling or to exclude them from the modelling. The outcome is equivalent irrespective of the option chosen. The load also includes the hourly generation of small units owned by small operators that were identified, based on the technology of the units and an assessment of their generation profile, not to be peaking units[33] and therefore not involved in price setting in the system and thus not modelled. Importantly, the load used for the purpose of the modelling did not include the hourly generation of these units as it is not appropriate to include the demand for this electricity in a model that optimally re-dispatches this supply of electricity across only the units contained in the model.

[33] Units that are specifically used to meet peak demand periods and therefore are capable of setting the system marginal cost.

Although this study has as its objective the separate analysis and modelling of each electricity system, it is important to consider the potential impact of the interconnector links on the approach outlined here for constructing the load and on the subsequent results. Each of the six countries analysed in this report have interconnector links with one or more neighbouring countries and the flows of electricity over these interconnectors will have a bearing on the load in each of the respective countries, as reported by the TSO. In the case of the load being equal to the sum of generation in each country, electricity that is imported cannot be re-dispatched under our approach, as it is generated outside of the system being modelled, and therefore must be taken as given. This is similar to the treatment of run-of-river hydro and wind previously discussed, however, in this case interconnector flows are not included in the load as to do so would also require the inclusion of the relevant capacity from the neighbouring country. A more detailed exposition of this issue is provided in relation to exports.

The export of electricity over interconnectors is implicitly included in the load of each country as the sum of generation, by definition, includes electricity that is generated domestically and subsequently exported. One may view this situation as somewhat of an anomaly as exported electricity is included in the load but imported electricity is not. However, as has previously been discussed the inclusion of imported electricity has no bearing on the subsequent results of the modelling and in the case of exports, if one also takes these as given, then one should be equally indifferent to their inclusion or exclusion from the formulation of the load. In this case, electricity that is exported still represents electricity that is demand on the domestic system. To exclude exports from the load would similarly require that a quantity of capacity is also removed from the available installed capacity of the market in each hour. This adjustment would be required in order to not over-represent the quantity of capacity in a country that was serving the domestic market. If one recalls the simple stylised electricity market presented in Figure 3.1, removing the hourly generation exported would be equivalent to moving the demand (load) from D′ to D, thus artificially reducing the stylised system marginal cost. It is clear from this example that one would equivalently need to remove the capacity in each hour that contributed to the export but first one would need to identify the appropriate capacity to be removed as this also could have a considerable impact on the outcome of the market through the impact it has on the merit curve. Reducing the capacity of Company A, in the hypothetical case, by an equal amount as the reduction in the load would result in a situation with Company B setting the stylised system price (equal to the system marginal cost in a competitive setting). Removing the capacity from Company B would have no effect on the market and Company A would set the stylised system price. As a homogeneous good one is not able to trace the exported electricity back to its source and as a result one would be required to make assumptions similar to those above that are not satisfactory. Therefore, by including in the load the hourly quantity of electricity exported, it holds this quantity as fixed but allows for the modelling of the system to optimally re-dispatch both the electricity generated for the domestic market and that produced to serve the export market, in each hour.

A further issue relating to the potential role of interconnectors is the data, data on the interconnector flows were returned by the TSOs on an aggregated basis, indicating the net imports over all interconnectors in each hour. Therefore, one is unable to distinguish the legitimate quantity of domestically generated electricity that was actually exported in each hour, from any imports that were received as only the difference is observed. In light of this any adjustment to the domestic load to account for the quantity of electricity exported in each hour becomes somewhat arbitrary and subject to further assumptions to those outlined already, whereas the role of imports, as has already been discussed, can be excluded for modelling and analysis purposes as the quantity is taken as given.

Modelling each country separately, electricity produced elsewhere cannot be re-dispatched and, therefore, its input to the modelling procedure is similarly its output and thus the exercise is not affected by its exclusion. The inclusion of exports as part of the load to be served not only reflects the demand for electricity within the system but it also allows for the full inclusion of the available installed capacity of the companies included in the study. Therefore, one can see that the approach adopted within this study accounts for the import and export of electricity through interconnector links with neighbouring countries. Given the exports are explicitly included in the load, represented by the sum of hourly generation, there is the potential that in certain markets that the difference between the TSO load and the constructed load may narrow. However as this load (including exports) represents only the generation produced given the available installed capacity of the units contained in the study, this will not affect the modelled marginal cost on the system. In the event that one may argue that the quantity of electricity exported should not be included in the load but that the installed capacity should remain unchanged, the modelled system marginal cost under the approach adopted in the study will be greater than or at least equal to the marginal cost under this scenario.

3.3.2 Merit curve

A merit curve (supply curve) has been calculated on a monthly basis, for each market, based on the data returned by the generation companies and utilities in response to the DG Competition sector inquiry. The unit cost of generation for each unit (€/MWh) has been found by multiplying the heat rate (GJ/MWh) of each unit by the unit's monthly reported fuel cost (€/GJ). The capacity of each unit is taken to be the average monthly available installed capacity (discussed below) of the unit. The merit curve represents a stacking of average monthly available capacity in ascending order based on the returned costs of the units.

Issues affecting availability of units (outages) can potentially affect the merit curve from month to month and similarly the cost of serving a given level of demand may potentially change. Similarly, given the heat rates of units are regarded as constants for the purpose of this calculation, if the fuel cost of a particular unit changes relative to other units on the curve, that units position on the merit curve is likely to change. Therefore, to summarise one can consider to potential effects that can bring about a shift in the merit curve, firstly a change in the available capacity of units will bring about a left-right shift in the curve through the introduction or removal of capacity from the market. Secondly, the shape of the curve can be altered by changes in the reported fuel costs of units. There is also potential for warm weather deratings to alter the relative position of unit on the merit curve, particularly if the impact of such deratings is greater for certain.

3.3.3 Traditional concentration measures

CR(n) and HHI indicators have been calculated, on an hourly basis, for the companies included in the study. Three different measures of capacity were used to calculate these indicators, as well as a measure of generation output. Each of these are described in turn before a formal description of the traditional concentration measures is presented.

Available Installed Capacity (AIC) – The installed capacity for Company A is equal to the sum of maximum operating capacity reported for each unit in the company's portfolio (taking account of warm weather deration and outages). The impact of warm weather derations on the normal operating capacity was reported by the companies, on a unit by unit basis, in response to Q1-4[34] of DG Competition's Sector Inquiry 2006 data request. Companies were asked to report on outages in their units, both planned and forced, however upon inspection of the responses it was found that the reported outages were of potentially two types, full and partial outage. As the data requested only related to outages and not the particular type of outage, we were forced to make an assumption as to the impact of partial outages in periods where they were identified. A partial outage was identified for a unit where an outage was reported for a particular period and within that period there was a positive level of generation reported. A full outage is recorded where a company reports an outage for a unit and the hourly generation of the unit in that hour is zero. This unit is regarded to be out of operation and therefore not available in that hour. In this case the available capacity figure has been adjusted for the period of the partial outage to reflect the potential reduction in generation capacity. This has been done by revising the available installed capacity figure of the unit to reflect the maximum hourly generation figure reported by the company, for the specific unit, over the period for which a partial outage has been identified. We note that this approach may potentially overstate the availability units on the system, however in light of the presence of partial outages and the data constraint in separately identifying them, the adopted assumption and approach is regarded as the one most likely to be reflective of reality.

The formula for the available installed capacity for Company *i*, is given by;

$$AIC_{is} = \sum_j ICap_{ijs}\Big|_{Outage=o} + \sum_j \max(hourly\_generation_{ij})\Big|_{Outage=partial}$$

[34] It has been assumed that only ambient weather conditions in June, July and August are sufficient, on average, to induce a deration of the normal operating capacity of units. For the remainder of the months the winter heat rate applies.

where; *ICap* = Installed Capacity (maximum operating capacity winter/summer (MW)); *hourly_generation* = reported hourly generation (MWh); for company (*i*), unit (*j*), and season (s). From this equation one can see that in periods where there is no reported outage (Outage=0), the Available Installed Capacity (AIC) is equal to the seasonally adjusted normal maximum operating capacity of the unit.

In relation to three particular types of units, classified by technology, a further adjustment was required to control for a number of factors for which data was not available, more specifically climatological and hydrological factors. For run-of-river and storage[35] hydro units for which detailed hydrological information was not collected for the purpose of this study (i.e., lake/river capacity, inflow, environmental restrictions) a ceiling was applied to the installed capacity (*ICap*) figure reported by the companies in response to the data request. The installed capacity limit on these units is equal to the maximum level of generation reached by these units in each month. Therefore, the installed capacity figure reported for run-of-river and storage hydro units in the study changed monthly to try account for changing climatological and hydrological conditions and as a result of the approach adopted, the installed capacity of these units in any one month never exceeded the actual maximum amount generated by the unit in that month. The adopted approach in relation to Wind units is identical to that outlined above.

Available Capacity (AC) (allowing for Reserve Commitments & Long-Term Contracts) – This measure is based on Available Installed Capacity and adjusts this figure on an hourly basis to reflect the quantity of capacity each company has committed in upward regulation to system reserve requirements (*RES*) and the net position of the company in the long-term contract market (*LTC*)[36]. The net position of each company is defined as quantity of electricity bought *less* the quantity of electricity sold.

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[35] This does not include pumped storage units for which the reported installed capacity figures are taken and subsequently adjusted for outages in both the pumping and generation aspects of the units.

[36] A long-term contract is defined in the DG Competition data requests (2005, 2006) as a contract of duration of three years or more or with no defined end date.

$$AC_{is} = AIC_{is} - RES_i + LTC_i$$

Total Generation – Both the CR(*n*) and HHI indicators have been calculated using the hourly net electrical generation figures reported by the companies for the full three year period 2003-2005 (26,304 hours). The hourly generation of each company (*i*) is equal to the hourly generation of each of that company's units (*j*). Importantly one may notice that the sum of total generation over all companies in the market is equivalent to the load variable used in the study.

$$hourly\_generation_i = \sum_j hourly\_generation_{ij}$$

In Merit/Economic Capacity (*EC*) - CR(*n*) and HHI indicators have been calculated using the concept of in merit/economic capacity. This requires the estimation of an hourly system marginal cost and information on the hourly marginal cost of generation for each of the units in a company's portfolio. If the hourly marginal cost of generation of a particular unit is below, or equal to, the system marginal cost, the available installed capacity (as calculated above (*AIC*)) is included in the company's in merit capacity for that hour. Units which report a marginal cost of generation above that of the system marginal cost are excluded. For the purpose of this calculation, the capacity of each unit was deemed to be "in merit", if the returned cost of the unit (€/MWh fuel cost) was less than the system marginal cost in that hour, resulting from a simple stacking model of actual dispatch based on costs (MC_{system}).

$$EC_i = \sum_j AIC_{ij} \Big|_{MC_{ij} \le MC_{system}}$$

Having formally presented the variables that form the basis of the calculation of the traditional structural measures and further are included in the electricity structural measures (available capacity), these measures are to be discussed in a general form, with the variable "*C*" potentially representative of any of the above measures.

CR(n)

The Concentration Ratio of the *n* largest companies in the market is comprised of the sum of the relevant capacity/output measures (C) of the *n* largest companies in the market, divided by the total sum of capacity in the market.

$$CR(n) = \frac{\sum_{i=1}^{n} C_i}{\sum_{i=1}^{N} C_i} \qquad \text{where } i = 1, 2, 3, \ldots, N; \text{ and } n<N$$

The CR(2) measure represents the market share of the two largest companies in the market in each hour. This measure has been calculated using, Available Installed Capacity, Available Capacity (accounting for reserves and LTCs), Total Generation, and, In Merit/Economic Capacity, for the two largest companies in the market is each hour.

HHI

Formula: $$HHI = \sum_{i=1} \left(\frac{C_i}{\sum_i C_i} \right)^2 \qquad \text{where } i = 1, 2, 3, \ldots, N$$

Explanation: The HHI indicator sums the squares the market shares of all companies in the market, where the market shares of the companies are calculated on an hourly basis using, Available Capacity, Total Generation, and, In Merit/Economic Capacity.

Interconnector

In the absence of company specific information on capacity reservations and flows over the relevant interconnectors in each country, two sensitivity scenarios have been calculated to assess the potential impact of the interconnectors on the CR(*n*) and HHI measures in each market. The hourly availability of interconnector capacity (TSO reported Net Transfer Capacity (NTC)) is applied to the sensitivity case on Available Installed Capacity and interconnector flows reported by the TSOs are used in the case of measures calculated based on total generation. Importantly, the impact of interconnector flows is not to unambiguously increase total generation in a market as it is a net figure that reflects the hourly difference between inflows and outflows (inflows *less* outflows).

The two scenarios that are considered are as follows;

1. Atomistic Competition
2. Largest Company Apportionment

1. Atomistic Competition – Under this scenario the companies' hourly capacity and output figures in the formulae are not affected. The interconnector capacity/flows (*IC*) are included in the denominator of both measures, such that the absolute impact of the interconnector affects the overall market and not any one company. TSO reported NTC values are used in concentration measures based on capacity measures, while net interconnector flows are used in measures based on actual generation.

$$CR(n) = \frac{\sum_{i=1}^{n} C_i}{\sum_{i=1}^{N} C_i + IC}; \quad HHI = \sum_i \left(\frac{C_i}{\sum_i C_i + IC} \right)^2$$

2. Largest Company Apportionment – Under this scenario the hourly interconnector capacity/flows (*IC*) are allotted entirely to the company with the largest market share. The formulae are therefore;

$$CR(n) = \frac{(C_1 + IC) + \sum_{i=2}^{n} C_i}{\sum_{i=1}^{N} C_i + IC}; \quad HHI = \sum_i \left(\frac{C_i + IC_1}{\sum_i C_i + IC} \right)^2$$

With respect to both of these scenarios, it is important to recall that TSO reported NTC values are used in relation to concentration measures based on capacity measures, while net interconnector flows are used in measures based on actual generation.

3.3.4 Electricity specific structural measures

Residual Supplier Index (RSI)

The RSI is calculated for each hour (26,304) in accordance with the following formula;

$$RSI_j = \frac{\left(\sum_{i=1}^{N} AIC_i - AC_j\right)}{\sum_{i=1}^{N} hourly\_generation_i} \qquad \text{where; } i = 1, 2,\ldots,j,\ldots,\text{N}$$

The RSI calculated relative to company (*j*) is equal to the total supply of available capacity in the market *less* the available capacity of company *j* (adjusted for reserves and long-term contracts), divided by the load constructed for the purpose of this study.

The RSI indicator has been calculated for a selection of the largest companies in each market.

A previous study of RSI in California conducted by the CAISO applied a threshold value to the computed hourly indicator. The threshold stated that if the value of the RSI is less than 110% (1.1) for more than 5% of the time, then the underlying market structure was not likely to bring about a competitive outcome. This threshold is not a steadfast rule applied by regulators and competition authorities but should rather be seen as a guiding principle in the determination of potentially problematic market structures with respect to the likelihood of the market producing a competitive outcome.

Interconnector

To account for the potential impact of the interconnectors on the RSI measure two sensitivity cases are calculated;

1. The hourly interconnector capacity (IC_c), aggregated over interconnectors where relevant, is added to the total supply of the market and apportioned in accordance with the companies' market shares (as measured by installed capacity) in the market being assessed. The hourly aggregated interconnector flows (IC_f) are added to the load.
2. The hourly interconnector capacity (IC_c) of each interconnector is added to the total supply of the market and the hourly available capacity of each interconnector is apportioned in accordance with the companies' market shares (as measured by installed capacity) in the markets from which electricity can be imported. The hourly aggregated interconnector flows (IC_f) are added to the load.

Under Scenario 1 the formulae for the RSI is altered accordingly;

$$RSI_j = \frac{\left[\left(\sum_{i=1}^{N} AIC_i + IC_c\right) - \left(AC_j + IC_c\left(\frac{C_j}{\sum_{i=1}^{N} C_i}\right)\right)\right]}{\sum_{i=1}^{N} hourly\_generation_i + IC_f}$$

Under Scenario 2 the formula remains largely the same, the only alteration that is required is to change the basis of the market share calculation such that we consider the market share of the companies in the exporting country, based on installed capacity in that country (*C3*). Therefore, the formulae is re-written as;

$$RSI_j = \frac{\left[\left(\sum_{i=1}^{N} AIC_i + IC_c\right) - \left(AC_j + IC_c\left(\frac{C3_j}{\sum_{i=1}^{N} C3_i}\right)\right)\right]}{\sum_{i=1}^{N} hourly\_generation_i + IC_f}$$

In the event that the company has a presence in two or more of the countries with which the domestic market has interconnector links with, the addition of the company's market share apportionment of interconnector capacity with these further countries would similarly have to be added to the numerator.

Pivotal Supplier Index (PSI)

The PSI is a binary measure indispensability and is calculated for each hour (26,304) in accordance with the following formulae;

$$PSI_j = 0 \;\; if \;\left(\sum_{i=1}^{N} AIC_i - AC_j - \sum_{i=1}^{N} hourly\_generation_i\right) \geq 0$$

$$PSI_j = 1 \;\; if \;\left(\sum_{i=1}^{N} AIC_i - AC_j - \sum_{i=1}^{N} hourly\_generation_i\right) < 0$$

As with the RSI indicator, the PSI is calculated using the total available capacity of the market (supply) given by the sum of the available installed capacity (*AIC*). If the total supply of the market in any one hour, less the load and available capacity of company *j* (adjusted for reserves and LTCs), is less than zero then the PSI value relative to company *j* in that hour is 1. A PSI value of 1 indicates the company is pivotal to meeting demand in that hour.

A threshold for this indicator has been constructed as part of previous studies and market analysis. The FERC apply a threshold of 20% to this measure, if the value of the measure 1 for more than 20% of the time then this is indicative of a pivotal supplier. Once again this threshold should be viewed as a guiding principle to interpreting the results and not as a steadfast rule upon which to base qualified conclusions.

Interconnector

To account for the potential impact of the interconnectors on the PSI measure two sensitivity cases, analogous in approach to those applied to the RSI, are calculated;

1. The hourly interconnector capacity (IC_c), aggregated over interconnectors where relevant, is added to the total supply of the market and apportioned in accordance with the companies' market shares (as measured by installed capacity) in the market being assessed. The hourly aggregated interconnector flows (IC_f) are added to the load.
2. The hourly interconnector capacity (IC_c) of each interconnector is added to the total supply of the market and the hourly available capacity of each interconnector is apportioned in accordance with the companies' market shares (as measured by installed capacity) in the markets from which electricity can be imported. The hourly aggregated interconnector flows (IC_f) are added to the load.

$$PSI_j = 0 \;\; if \;\; \left[\left(\sum_{i=1}^{N} AIC_i + IC_c \right) - \left(AC_j + IC_c \left(\frac{C_j}{\sum_{i=1}^{N} C_i} \right) \right) - \left(\sum_{i=1}^{N} hourly\_generation_i + IC_f \right) \right] \geq 0$$

$$PSI_j = 1 \;\; if \;\; \left[\left(\sum_{i=1}^{N} AIC_i + IC_c \right) - \left(AC_j + IC_c \left(\frac{C_j}{\sum_{i=1}^{N} C_i} \right) \right) - \left(\sum_{i=1}^{N} hourly\_generation_i + IC_f \right) \right] < 0$$

Under Scenario 2 the formula remains largely the same, the only alteration that is required is to change the basis of the market share calculation such that we consider the market share of the companies in the exporting country, based on installed capacity in that country ($C3$). Therefore, the formulae is re-written as;

$$PSI_j = 0 \;\; if \;\; \left[\left(\sum_{i=1}^{N} AIC_i + IC_c \right) - \left(AC_j + IC_c \left(\frac{C3_j}{\sum_{i=1}^{N} C3_i} \right) \right) - \left(\sum_{i=1}^{N} hourly\_generation_i + IC_f \right) \right] \geq 0$$

$$PSI_j = 1 \;\; if \left[\left(\sum_{i=1}^{N} AIC_i + IC_c \right) - \left(AC_j + IC_c \left(\frac{C3_j}{\sum_{i=1}^{N} C3_i} \right) \right) - \left(\sum_{i=1}^{N} hourly\_generation_i + IC_f \right) \right] < 0$$

Once again, for any company with a presence in more than one country with which the domestic country has interconnector links, the relevant apportionment of interconnector capacity should similarly be added to the company's available capacity figure.

3.3.5 Contribution to power exchange prices

The contribution to power exchange prices decomposes the load weighted average power exchange prices into three separate pieces, which collectively sum to the load weighted average price over the relevant period. This analysis presents the Euro value of the load weighted average system marginal cost (€/MWh) resulting from the GED modelling, the load weighted mark-up of prices over costs (€/MWh), and the load weighted average cost of carbon in 2005.

3.3.6 Outcome measures

Lerner Index

The Price-Cost Margin/Lerner Index (LI) has been calculated hourly based on the simulated System Marginal Cost and the publicly available price of electricity for each hour in the period 2003-2005. The formula for the LI is as follows;

$$LI = \frac{P - MC}{P}$$

Price-Cost Mark-Up

As with the Price-Cost Margin/Lerner Index, the Price-Cost Mark-Up (PC Mark-Up) has been calculated hourly based on the System Marginal Cost and the publicly available price of electricity for each hour in the period 2003-2005. The formula is as follows;

$$PC\ Mark-Up = \frac{P - MC}{MC}$$

Having constructed a Lerner Index and Price-Cost Mark-Up for each hour, one may also be interested in calculating these measures on average over the period of the study or for each year. In order to correctly do so, one must calculate the index based on average values and not take the average of the index. Furthermore, reliance on a simple average of the prices and costs of the system will fail to take account of demand conditions in the market may lead one to a conclusion on the outcome measures that may not be accurate and correct[37]. Therefore, to most accurately reflect the functioning of electricity markets, simple averages are replace by load weighted averages of both the price and cost in order to correctly assess the outcomes produced by the underlying market.

Load weighted average prices and costs

The load weighted average price for the three-year period is calculated in accordance with the following formula;

[37] A negative outcome measure in off-peak hours is a very different proposition to that in peak hours as firms may willingly utilise loss making generation capacity in off-peak hours for a number of reasons, including; to avoid turning units off and thus not having to pay large start-up costs, to ensure units are on to meet demand in subsequent hours, or the units may already be on to meet other need such as contract positions, industrial processes or reserve commitments. In peak hours, negative outcome measures are not considered to be a likely outcome and thus merit further attention if they are a systematic occurrence.

$$wP = \sum_{t=1}^{T}\left[\left(\frac{hourly\_generation_t}{\sum_{t=1}^{T} hourly\_generation_t}\right) * P_t\right] \qquad \text{where; } t = 1,2,\ldots..,26,304$$

Similarly the load weighted average marginal cost for the three year period is calculated in accordance with the following formula;

$$wMC = \sum_{t=1}^{T}\left[\left(\frac{hourly\_generation_t}{\sum_{t=1}^{T} hourly\_generation_t}\right) * MC_t\right] \qquad \text{where; } t = 1,2,\ldots..,26,304$$

These weights were similarly calculated on an annual basis, with the denominator in each case equal to the total sum of the load in each of the respective years.

Lerner Index (based on load weighted average prices and costs)

The load weighted average Lerner Index is therefore given by the following formula;

$$wLI = \frac{wP - wMC}{wP}$$

Price-Cost Mark-Up (based on load weighted average prices and costs)

The load weighted average Price-Cost Mark-Up is;

$$wPC\ Mark - Up = \frac{wP - wMC}{wMC}$$

3.3.7 CO_2 Impact

To calculate the potential impact of the introduction of the ETS in 2005, the load weighted average increase in the system marginal cost brought about by the inclusion of the full economic cost of carbon and the resulting possibility for a re-dispatch of the system, due to the non-standard impact of the carbon cost on the costs of units in the system, is calculated.

In order to arrive at this figure it was necessary to model the optimal system dispatch under two scenarios, the base scenario used throughout the report that includes the cost of carbon in 2005, and an alternative scenario that omits this cost. Both modelled simulation runs are identical up to 2005 however after this point the more prevalent mid-merit coal and gas fired capacity is on the merit curve the greater the potential for difference between the two modelled simulations is likely to be.

Importantly, it must once again be noted that the merit order of units is almost certainly going to be altered by the inclusion of the CO_2 cost. In a somewhat extreme but plausible situation one can consider the following hypothetical situation for illustrative purposes of just two particular units on the merit curve, the first a relatively old 300MW coal fired unit and the second a new 400MW CCGT unit. In the absence of the cost of CO_2 in 2005, the coal fired unit has a €/MWh generation cost of €20, while the CCGT unit has a cost of €30/MWh. Clearly in this situation the coal fired unit will be in merit considerably before the CCGT unit. However, if one now includes the full cost of CO_2, the relatively old coal fired unit now incurs a further cost of €18/MWh in generation that is directly attributable to its CO_2 emissions, emissions that are relatively high and owing to the plants age, fuel and technology of the generation process. The new CCGT unit on the other hand is installed with the latest technology and combined with the consumption of the relatively clearer gas, this unit only incurs a cost of €5/MWh under the EU ETS. Now if one considers these two units relative position on the merit curve one can see that the CCGT unit will now be in merit before the coal fired unit and will be capable of serving a further 100MW at this level, thus requiring a further increase in the load before the coal unit is called onto the system. In a situation with only these two units, one can see the cost imposed by the EU ETS is €15/MWh, as the cost of producing that same MWh of electricity has changed from €20/MWh to €35/MWh. Importantly, this takes no account of the unit producing the electricity, just simply the cost of producing a given quantity.

This simple example has very important implications for the calculation of the impact of the EU ETS. Clearly one can see that the merit curve with and without the cost of CO_2 does not present the units in the same order, as the impact of the EU ETS will have a proportionately greater impact on particular units owing to their characteristics. Therefore, attempting to calculate the impact of the ETS based on a dispatch that did not include the cost of CO_2 as a decision variable, will not yield the correct result. To calculate the potential cost of CO_2 one must account for possible changes in the merit curve and compare the system marginal cost in each hour of serving a particular load and not of serving a load with a particular set of units.

Through modelling the optimal dispatch of the system in 2005 both with and without the CO_2 cost included in the generation costs of the units, it has allowed for the calculation of what can be considered to be equivalent to the maximum possible impact of the ETS if generators fully factor in the price of the CO_2 certificates, in a competitive environment.

3.3.8 Contribution to Fixed Cost

An assessment of the modelled marginal cost has been undertaken to investigate whether this cost allows for a sufficient contribution to units' fixed and start-up costs and thus encourage continued investment in the system. To calculate this the €/MWh cost of generation returned on a unit by unit basis by all of the companies in the study, calculated as the product of fuel cost by heat rate of the units (including warm weather derations and the full cost of carbon in 2005) (MC_{it}), is subtracted from the hourly system marginal cost produced by the GED model ($MC_{system,t}$), which is equivalent to the market price in a perfectly competitive market, and then this hourly figure is multiplied by the hourly optimal unit ($m\_generation_{it}$) dispatch specific to each unit (i), again from the GED modeling of the market. The result of this calculation is summed for each company in each year to give the expected outcome in the market, if the market was to operate optimally. The following formula provides the algebraic approach for calculating the contribution to fixed costs (*CFC*) value for a particular unit (i) over the three year period.

$$CFC_i = \sum_{t=1}^{T} \left[\left(MC_{system,t} - MC_{it} \right) * m\_generation_{it} \right] \qquad \text{where; } t = 1,2,\ldots..,26,304$$

3.3.9 Regression analysis

In order to investigate the relationship between the above market outcome/market performance measures and the structural indicators previously discussed, we undertook a detailed regression analysis with the objective of testing this link and in the presence of such a link, uncovering the nature of the relationship. In testing this relationship a number of regression models were estimated but in general the approach applied was to develop and explore simple regression models, and then to progress on to more detailed specifications by including more explanatory factors, all the time ensuring that the classical linear assumptions were not violated.

The Residual Supply Index, as a continuous variable of market structure that was developed specifically for the electricity industry, was used in the regression analysis as a measure of market structure. Previous research has highlighted the problematic nature of using measures such as the HHI as they both exhibit very little variation and have been found to be largely inappropriate for such analysis in the electricity sector. The PSI does present a possible alternative, however given the binary nature of the variable, it being either 1 or 0, its suitability to regression analysis is limited and would represent substantial restrictions on the analysis that are not presented by the RSI. The simple regression model therefore regresses the hourly market outcome measure, either LI or PCM, on the hourly RSI value of any one company.

In order to capture the potential for peak and off-peak periods to have different effects, the peak and off-peak RSI values have been separated into different independent variables to allow for the slope of the estimated regression line to differ during these periods. This will allow for potentially different effects on the outcome measure during peak and off-peak periods. A dummy variable has also been created for peak hours. A dummy variable is a zero-one variable that takes a value of one when a particular statement is true and a value of zero when it is not. In this case, during peak hours the dummy variable will adopt a value of 1 during peak hours and zero otherwise. Just as the peak and off-peak RSI variables allow for the estimated regression to have a different slope in these different periods and thus a different overall effect on the outcome measure, the inclusion of a dummy variable allows for the starting point of the regression itself to differ in these separate periods, thus creating effectively two different regression lines, if the dummy variable is statistically significant. This will be particularly important if there is a difference in how the market effectively operates in peak and off-peak periods.

Further to this an interaction term has been constructed that is the product of the RSIs of two companies contained in the study. This variable will capture the degree to which the ability of a particular company to exercise market power to influence price in the market is constrained or facilitated by the relative position of one of the company's competitors. Importantly a measure of scarcity has also been included in a number of regression equations. This variable will capture the degree to which scarcity impacts on outcome measures and will separate out the potential for the RSI value to simply capture this effect from what is designed to reflect, the impact of a particular companies indispensability on the outcome of the market. The scarcity variable is defined as the difference between available installed capacity and load, as a percentage of load in each hour. One would expect such a variable to have a negative sign on its coefficient.

Variables have been included to capture the impact of potential withholding on the outcome measures. These variables have been constructed relative to the whole market and are not specific to any one company, as such one can consider the likely sign of these variables if there is a systematic manner in which coal fired capacity is being withdrawn and replace by gas fired capacity. In the event of such an occurrence, one would expect to observe a negative sign on the coefficient of the coal variable and a positive sign on the coefficient of the gas variable.

In order to allow for the potential impact of a number of different factors, a number of additional dummy variables have been included to capture the impact of yearly, seasonal, and weekday specific effects.

3.3.10 Withholding

The analysis of the potential presence and prevalence of withholding in the wholesale electricity market of each of the countries in this report, is based on a comparison of the actual dispatch of units in the system with the results of the modelled optimal dispatch for each unit. This result is aggregated by company and then by technology and summary statistics on the average quantity (MW) of this difference is presented. Furthermore, there is a measure for the percentage of time which the modelled outcome is greater than the actual outcome. The results of this measure provides an indication of the possible systematic withholding of relatively cheaper generation capacity and coupled with the average extent of such a difference allows one to identify possible instances of behaviour that may require further investigation.

It is important to note that there are a variety of reasons why the modelled generation pattern may not match the actual. One such reason, for example, could involve the possibility of multiple optima or multiple 'nearly optimal' solutions to the least cost despatch problem. Another reason might involve the treatment of partial outages in our model, which is explained in detail previously in this chapter. Thus, one cannot, with a large degree of certainty, conclude that the measured withholding truly represents evidence of anti competitive behaviour.

3.4 Data description

The data for this study was largely taken from a DG Competition database of responses to questionnaires sent as part of the Sector Inquiry into electricity markets. The database provided, for the purpose of the measures and indicators calculated, all of the unit specific data used for each company included in the study. We acknowledge the efforts and cooperation of the EU generators in the study and the collection of these data and 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[38].

For each unit greater than 25MW this includes all data on characteristics, capacity, costs, output, outages, and ownership. For units less than 25MW it included an aggregated total, by technology, of the capacity, costs and net electrical output of these units. In general, companies with a portfolio of less than 100MW of installed capacity were not included in the study, however certain units, based on their characteristics[39], were included. These were largely units that wee considered to be peaking units and therefore potentially important in the determination of marginal cost and thus price setting on the system. At the company level there is data on the supply portfolio, long-term contracts and reserve commitments of each company.

At the most basic level the data provided in response to the sector inquiry questionnaires include the name, location and owner[40] of each generation unit, for the period January 2003 to December 2005. The start date of each unit is its current state of operation is also provided, as are end dates, as well as any information on whether the unit was mothballed during the period of the study. This allows for any alterations in the units operational status to be taken into account as well as the introduction of new units during the period.

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[38] 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.

[39] If a unit was considered likely to be a peaking unit and therefore potentially a price-setting unit, the unit was included.

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

Data is included on the normal maximum operating capacity (MW) of each unit greater than 25MW. This measure is largely analogous to the concept of installed capacity, however, asked in this way it allowed for companies to provide two measures of capacity for each of their units which allow for derations caused by a decrease in the thermal efficiency of units to be taken into account in warm months. The aggregate installed capacity of units less than 25MW was also provided, classified by technology type.

The output of each listed unit is provided as the hourly net electrical production (MWh) to be transported to the high voltage grid. This data was 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), that 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 technology type. Clearly, for units that were not in operation for the entire period, the number of observations will be strictly less than 26,304 and this is reflected both in the available installed capacity and generation of these units.

In the case of co-owned units, both capacity and output were apportioned on the basis of the ownership share specified by each of the constituent companies in their response to the questionnaire. In some instances this required figures to be adjusted to avoid double counting. Also in instances where the ownership share reported did not reflect the operational reality of the unit, an assumption was made to reflect reality and therefore ignore the reported ownership share. A hypothetical example of this would be if a unit was reported to be 50% owned by both Company A and Company B but on looking at the output profile of the two companies Company A reported 10% and Company B reported 90% of all output, in all hours the units generated. In such a case the 10% - 90% split was applied as it was considered to be the result of an arrangement to which no information had been provided.

The maintenance plans and actual maintenance schedules of each unit was also provided. This allowed for the available capacity of each unit to be adjusted for planned outages. In general, this data provided a start date and time for such outages and an end date and time but in cases where only a date was provided an assumption was made that the planned outage covered the entire day or signalled the day the unit came back into operation. Information on forced outages was also provided on a unit by unit basis in a similar format. The planned maintenance and forced outage periods of co-owned units were amalgamated.

Data on the heat rate (GJ/GWh) of each unit was provided by companies. Two full load heat rate points were requested, summer and winter, to allow for warm weather derations to be taken in to account. From this data standard heat rate curves were derived based on technological profile and reference to GED's world-wide database of plant performance data. Issues of consistency arose in particular responses in relation to the reported units of measurement. In a number of cases the units reported were GJ/MWh, where this was obvious an adjustment was made to GJ/GWh. Similarly where only an efficiency percentage was provided, the percentage was divided into 3,600 to convert to GJ/GWh where appropriate[41].

The average monthly cost of fuel (€/GJ) for each unit was also provided. In cases where units burned more than one fuel information was provided by the companies on the average proportions with which the fuels were used, on a monthly basis, as well as their cost. The data was requested in this manner to allow for different calorific contents of similar fuels to be accounted for. Again, issues over consistency of the data and the units of measurement arose for certain units but these were largely addressed by the companies themselves in clarification notices.

[41] 1 joule/sec = 1 watt; therefore; 1 GWh = 3,600 GJ where (3,600=60*60), as there are 60 seconds in a minute and 60 minutes in an hour.

At the company level, data has also been provided by the companies, in response to the Sector Inquiry questionnaires, on the long-term contracts for both the buying and selling of electricity. A long-term contract is defined as any contract with duration of more than three years, or one with no specified end date. In respect of each of these contracts data has been provided on the parties to the contract, the start date (date of first delivery), end date and the quantity committed to be supplied (GWh/annum). In some cases, information on the delivery characteristics of the electricity is also provided. Also where it occurred that one company bought or sold electricity from a subsidiary of itself, these contracts were not accounted for where the company and subsidiary constituted one company for the purpose of this study.

Data from two sources provided information, on a company by company basis, on the quantity of capacity committed to meet reserve requirements (MW). Companies provided monthly data on the quantity committed to upward and downward regulation of secondary and tertiary reserves. In the case of Great Britain, the only non-UCTE country of the six, this was limited to upward and downward regulation of reserve capacity for system balancing. Similar data was also provided by the countries TSOs in response to a Sector Inquiry questionnaire. Having assessed both sets of data, the information provided by the TSO was favoured as it provided consistent and complete responses on a monthly basis for every company that contributed reserve capacity to system balancing.

The TSOs also provided information on the interconnector links of each system. For each listed interconnector the hourly net transfer capacity (MW) was provided for the full period. Where available the hourly net transfer capacity available on a day-ahead basis was taken as the relevant measure, however in a number of cases this was not available and the capacity available on a week-ahead basis was used as an alternative. The actual flows over the interconnectors were similarly provided hourly but were aggregated over interconnectors to give an hourly net import position for each country. It was not possible to explore company specific involvement over the interconnector, as neither reservations of capacity nor actual flows by company is available as a result of the data requests. Therefore, assumptions have been made in the analysis to allow for the potential impact of interconnectors to be viewed in each market.

As well as data on unit and company specific details of each of the companies included in this study, hourly price level data was also required for the calculation of the outcome measures. This data was 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) day-ahead hourly price series, importantly this data series only begins in July 2004 thus limiting the analysis of price and outcome measures to the final 18 months of the study period.

For some of the price series listed above there were a small number of hours in each market where a price was not reported. No attempt was made to construct a price for these hours due to the stochastic nature of real-time markets and as such these hours were dropped from analysis requiring this price variable. Within the country specific chapters of this report, there is an analysis of the respective price series and how it correlates with the relative scarcity of available installed capacity in the market in each hour.

To compliment the use of these price series in the calculation of outcome measures within the country specific chapters of this report, a second price series has been included that reflects a less volatile market than the hourly market, therefore one that is more likely to be akin to prices set in contractual agreements or tariff structures. Platts Assessment prices of day-ahead over-the-counter (OTC) prices[42] provide a daily peak and base load assessment price (€/MWh) for electricity in each respective market. In the case of Belgium, it only reflects base load electricity. In all markets, apart from Belgium, it has been assumed that base load prices apply during the period 01.00 – 08.00 and that the peak load price is the relevant price for hours 09.00 – 23.00. Therefore either base or peak load prices have been imposed on each of the 24 hours for all days in the period. However, given this data is collected largely as a result of surveys of traders on a daily basis, weekends are largely not included in this series, as a result there is a large number of missing observations for this series. Nevertheless, this price series provides for an interesting scenario to be tested, one that can largely be considered to be closer to tariff and contractual agreements upon which companies largely reply on for revenue.

As has previously been noted one of the primary difficulties in conducting a study on competition in electricity markets is the difficulty surrounding calculating a marginal cost for the system. The hourly marginal cost used throughout this report is the result of a cost minimising commitment and despatch simulation, using GED's MARKETSYM software, to serve the load in each market, in each hour. This approach allows for the returned generators' data and dynamic constraints on the system to be modelled and for a marginal cost to be estimated as a result of the optimal commitment and despatch of the system. However, due to the presence of relatively high fixed costs in the electricity markets, in general, using the system lambda as the marginal cost on the system may lead to the use of an artificially low system marginal cost in the calculation of the market outcome measures, as the system lambda is likely to be insufficient allow for contributions to the relatively high fixed costs. In order to avoid this problem a marginal average cost approach has been adopted.

[42] These are week-ahead OTC prices in the case of Spain.

Under this approach the cost minimising commitment and despatch to serve load is simulated. An associated generation cost is similarly returned for each unit on an hourly basis. Start costs are computed by the model and in hours where they are apparent for units they are removed. Furthermore, a number of units are excluded from setting the marginal average cost based on prior specification and modelling results. Primarily combined heat and power units and stations that are specified to be must-run, thus forcing out-of-merit operation, are excluded from setting the marginal average cost, as are units that are modelled to be running below their specified minimum stable generation but only for the hours for which they do so. For the remaining stations, modelled generation cost (less start costs) of each unit is divided by the non-zero generation of the unit to arrive at the average cost that the generator must cover in that hour. The station(s) with the highest average costs in an hour are identified as marginal; their average costs are the Marginal Average Costs. Finally, in hours in which multiple stations share the same marginal position, duplicates are eliminated to provide a single Marginal Average Cost for use in subsequent analyses.

A detailed description of this marginal cost is included in the Appendices of this report.

Data on the cost impact of the EU ETS in 2005 was similarly returned as a result of the simulation modelling of the electricity market in each country. A cost minimising optimal commitment and despatch model was simulated for 2005 and subsequently a scenario was run excluding the cost impact of the introduction of the EU ETS and CO_2 certificates. The cost difference between these two simulations can be seen as the estimated maximum possible impact of the ETS if generators fully factor in the price of the CO_2 certificates in a competitive environment.

To determine the emission rate for each unit, either a reported emission rate or the combination of actual emissions and plant generation were required. In the case of 2005, actual generation data would be sufficient – as total CO_2 emissions could be identified from the Community Independent Transaction Log (CITL). However, only a very small number of data points (<30) across the integrated zone could be found – either for individual units or stations.

Therefore, GED developed a methodology to assign emissions rates to the vast majority of units based on the rather limited data points available. For each fuel, a basic emission rate (in kg/MWh) was identified for a "reference" unit which burns that fuel and has a known, full load efficiency. Other units were then assigned an emission rate by comparing their full load heat rate with that of the reference unit. Individual units with known emission rates were compared with interpolated emission rates assigned to these units and in each case a very close match was found.

For gas-fired co-generation units, a penalty was applied to their interpolated emission rate to represent CO_2 being produced for heat, rather than power, production. A penalty of 5% was added to units which provide district (or other low-grade heat) and a penalty of 10% to units providing high or intermediate pressure steam. Average monthly CO_2 prices (€/tonne) were taken from EEX and were applied to each of the countries studied within this report.

A further description of the methodology and assumptions surrounding this issue, as well as more general modelling issues, is contained in the Appendices of this report.

4 Belgium

4.1 Introduction to the Belgian Electricity Market

The Belgian electricity market can be classified as a relatively small market in Europe, with medium amounts of interconnection and a mix of technologies including a significant proportion of nuclear capacity. The market structure in Belgium was found to be highly concentrated.

4.1.1 Load Duration Curve

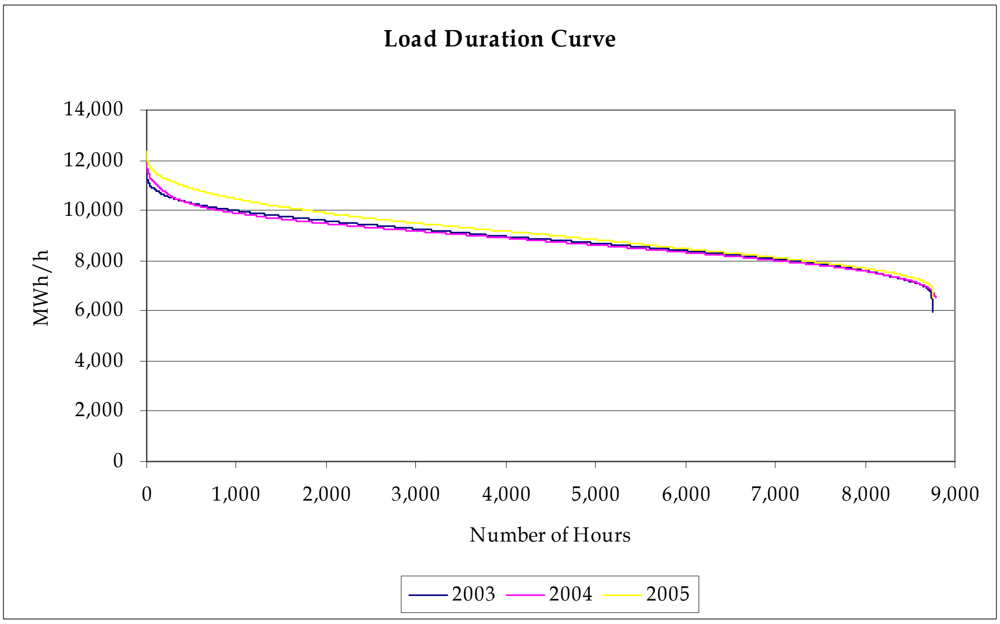
The load duration curve of the Belgian electricity market is an ordered ranking of the electricity demanded in each hour of each year. The load is presented in descending order for each year allowing the reader to quickly determine the amount of hours in each year that demand in Belgium (BE) is above the scale on the vertical axis. Figure 4.1 presents the load duration curve for each of the three years of the study. According to this graph, the distribution of demand between its peak and its minimum remained relatively stable in the first two years, however in 2005 one can see an increase in demand in almost all hours and particularly for the peak demand hours.

Importantly, this load represents the constructed load, described in the methodology chapter of this report as the sum of generation over all units in each hour, and this measure of load is the one used for the purpose of this report[43]. The hourly load included within this report is not that reported by the TSO (ELIA). This approach was adopted so that the results of both the modelling and analysis are accurate and consistently reflect the market for which data is available.

[43] Total generation is equal to demand plus net exports, by the equation that supply must always equal demand: Demand + exports = Supply + imports.

Given the quality and quantity of data collected by DG Competition as part of the Sector Inquiry, it means that only small companies with small non-peaking (price setting) units are not contained in our analysis. However to include the demand for electricity potentially served by these units, contained in the TSO load, and not to include them in the formal modelling and analysis would have created an over utilisation of the capacity in the market, represented by all other companies and units. As previously discussed in the methodology chapter, this approach also accounts for flows over the interconnectors with neighbouring countries.

Figure 4.1: Load Duration Curve- Belgium



Source: LE.

4.1.2 Merit Order Curve

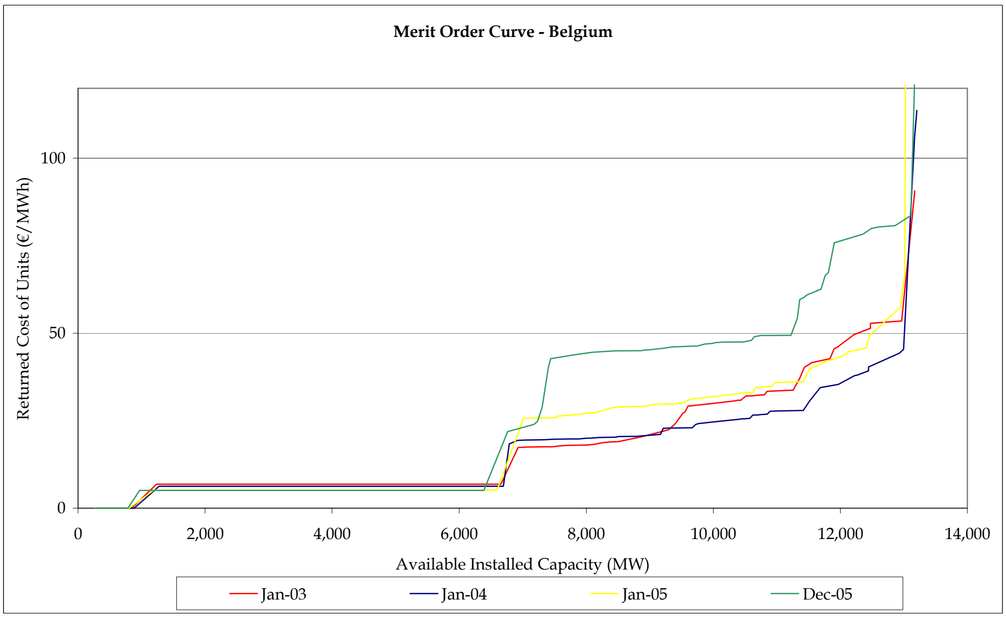
The merit curve is an ascending ordering of the available installed capacity in the system, based on the marginal cost of generation (€/MWh) for each unit on the system. The merit curve can shift based on availability, fuel prices, etc, and thus is specific to a time period or an average. In this instance the merit curve was calculated by taking a monthly average of each unit's available installed capacity and the marginal cost of the unit, calculated using the fuel prices and efficiencies returned by each of the companies for each of their units. These costs are then sorted in ascending order and the corresponding average available capacities aggregated over the market.

The merit order curve for the Belgian electricity market is presented in Figure 4.2. Looking at the merit curve from left to right one can see there is little difference in the installed capacity of units with zero fuel costs over the course of the study, and similarly the available installed capacity, as well as the unit cost of nuclear power generation, remains relatively stable. There is a small difference in the merit curve for December 2005 but this is caused by the change in the availability of technology with zero fuel cost. As one will recall from the discussion in the methodology chapter of this report, the available installed capacity of units of particular technologies, (wind, run-of-river hydro and storage hydro), was limited to the maximum of their generation in each month as an attempt to indirectly account for issues of hydrology and general weather conditions. This approach offers the most satisfactory method of dealing with these issues, the full inclusion of which would far exceed the scope of this current report.

Overall there has been relatively no change in the markets installed capacity, however, the unit cost of electricity generation for units to the right of the nuclear units on the merit curve have experienced a considerable increase in the per unit cost of generation over the period. Global increases in the price of natural gas, and to a lesser extent coal, in 2005 were already being reflected in the merit curve of January in that year, although by the time December came to pass the substantial increase in the price of these commodities had caused a large shift in the merit curve.

Importantly, these merit curves do not capture the impact of the ETS scheme in 2005 and the inclusion of the economic cost of carbon to the generation costs of these units. This issue is addressed subsequently.

Figure 4.2: Merit Order Curve (excl. Carbon) -Belgium

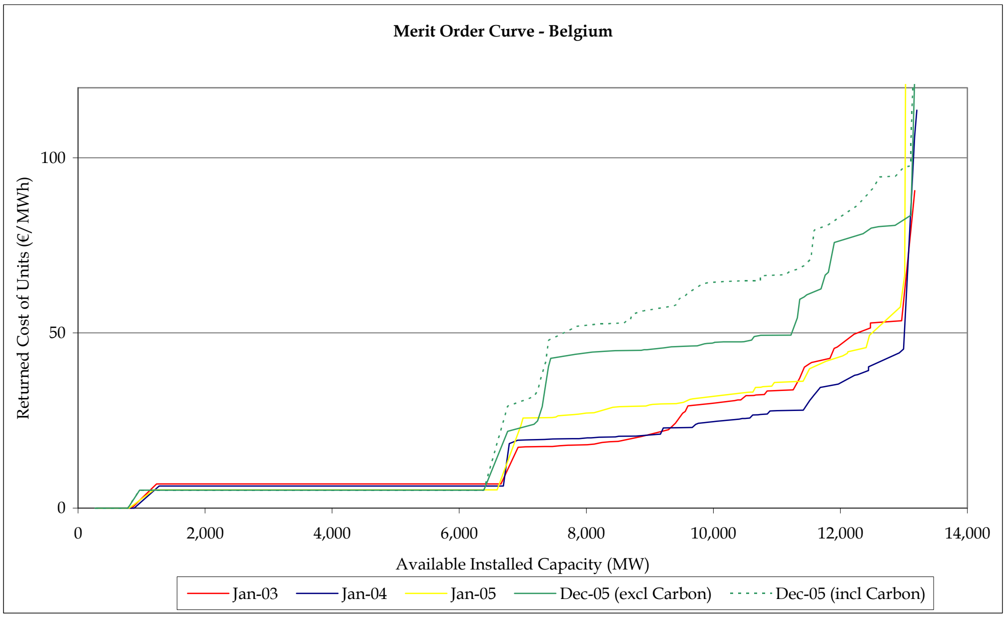


Source: LE.

Merit Order Curve, including the average cost of carbon in December 2005 for all units emitting carbon.

In order to fully assess the impact on the merit order curve of the introduction of the ETS in 2005, the merit order curve for Belgium in December 2005 has been adjusted to include the unit specific €/MWh economic cost of carbon for all generation units liable under this scheme. As one can see (by looking at the lower left of the figure), nuclear capacity in Belgium remains unaffected by the introduction of the ETS as does the generation capacity with zero fuel costs such as wind. However, as one moves to the position on the merit curve where one would expect to see the conventional thermal units located, beginning with coal and moving to gas as one moves further to the right, the impact of the inclusion of the full economic cost of carbon on these units is apparent. It is important for one to note at this point that the inclusion of the full economic cost of carbon has the potential to change the ordering of the units on the merit curve such that one should not consider the difference between the two December 2005 merit curves to represent the full economic cost of carbon for a particular unit but rather for a particular megawatt, not necessarily one located at that point on the merit curve in the absence of the cost of carbon. The implication of this is that one cannot simply estimate the cost of carbon for the system based on the cost of carbon for the marginal unit, as the marginal unit may potentially be different between the carbon and no-carbon case. This is similarly the case for all of the merit curves presented here for different periods, the ordering of the units is potentially different in each period due largely to changes in fuel costs.

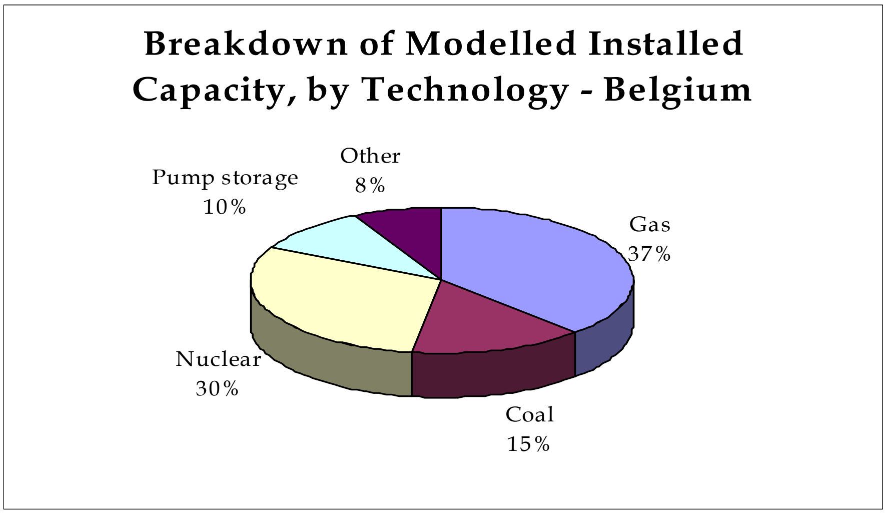
Figure 4.3: Merit Order Curve (incl. Carbon) -Belgium



Source: LE.

As one can see, the effect of carbon is evident in the regions of the merit curve where we observe coal and lo a lesser extent gas fired capacity. Considering this merit curve along with the chart presented in Figure 4.4 will facilitate an understanding of this new merit curve, including carbon, and its impact to the right of the considerable nuclear capacity in Belgium. From the chart, one can observe the breakdown of capacity by technology. The large extent of nuclear, and the significant presence of coal, are evident. However, gas makes up the largest proportion of capacity in Belgium.

Figure 4.4: Breakdown of Installed Capacity, by Technology- Belgium



Source: LE.

4.2 Structural Indicators

Traditional structural indicators have been calculated based on a number of different measures of market share for the Belgian electricity market. These indicators can change with availability and market conditions, so CR(n) and HHI indicators have been calculated, on an hourly basis, for all companies included in the study. Three different measures of market share (capacity) (generation) have been used to calculate these indicators. A brief overview of these measures is presented here but for a more detailed description one should review the relevant section of the methodology chapter.

Available Installed Capacity (AIC) – The Available Installed Capacity of each company is equal to the sum of maximum operating capacity reported for each unit in the company's portfolio (taking account of warm weather deratings and outages). The impact of warm weather derations on the normal operating capacity of units was included as part of DG Competition's data request to companies under the auspices of the Sector Inquiry. Data on outages was similarly returned by the companies and these were seen to take two particular forms: full outages and partial outages. A full outage is recorded where a company reports an outage and the hourly generation in that hour is zero. This unit is regarded to be out of operation and therefore not available in that hour. Companies have also reported partial outages which arise when the period of a reported outage does not correspond with a zero electrical production. In this case we have taken the available capacity to be the maximum hourly generation figure reported by the company, for the specific unit, over the period for which a partial outage has been identified. Further discussion of this as well as a formal exposition of the approach taken is contained in the methodology chapter of this report.

Available Capacity (AC) – Available Capacity is a measure calculated primarily for the purposes of the electricity specific structural indicators, however it is still interesting to assess the results of the traditional measures based on AC both in relation to the other measures of capacity and as an assessment of the HHI approach in general vis-à-vis the more specific measures calculated further on in this chapter. As has previously been stated in the methodology chapter, available capacity is equal to available installed capacity less capacity committed to upward system balancing (reserve) requirements and plus the net purchasing position of companies via long-term contracts.

Total Generation – Both the CR(n) and HHI indicators have been calculated using the hourly net electrical generation figures reported by the companies for the full three year period 2003-2005 (26,304 hours). The hourly generation of each company is simply the arithmetic sum of generation over all units in the company's portfolio in each hour. If one was to aggregate this over each company, it would be equivalent to the load. Therefore, concentration measures based on total generation reflect the market shares of companies over the load of the system.

In Merit/Economic Capacity - CR(n) and HHI indicators have been calculated using the concept of in merit/economic capacity. A station is in merit if its running cost is less than the system marginal cost. This requires the estimation of an hourly system marginal cost and information on the hourly marginal cost of generation for each of the units in a company's portfolio. If the hourly marginal cost of generation of a particular unit is below, or equal to, the system marginal cost, the available generation capacity (as calculated above) is included in the company's available capacity for that hour. Units which report a marginal cost of generation above that of the system marginal cost are excluded. The system marginal cost used for this was the maximum unit cost of any unit reported running on the system in that hour.

CR(n)

The Concentration Ratio (*CR(n)*) of the n largest companies in the market is comprised of the sum of the relevant capacity measures (C) of the n largest companies in the market, divided by the total sum of capacity in the market. This measure has been calculated using, Available Installed Capacity, Available Capacity, Total Generation, and, In Merit/Economic Capacity.

HHI

Formula: $$HHI = \sum_{i=1} \left(\frac{C_i}{\sum_i C_i} \right)^2$$ where i = 1, 2, 3,….,N

The HHI indicator sums the squares the market shares of all companies in the market, where the market shares of the companies are calculated on an hourly basis using, Available Installed Capacity, Available Capacity, Total Generation, and, In Merit/Economic Capacity.

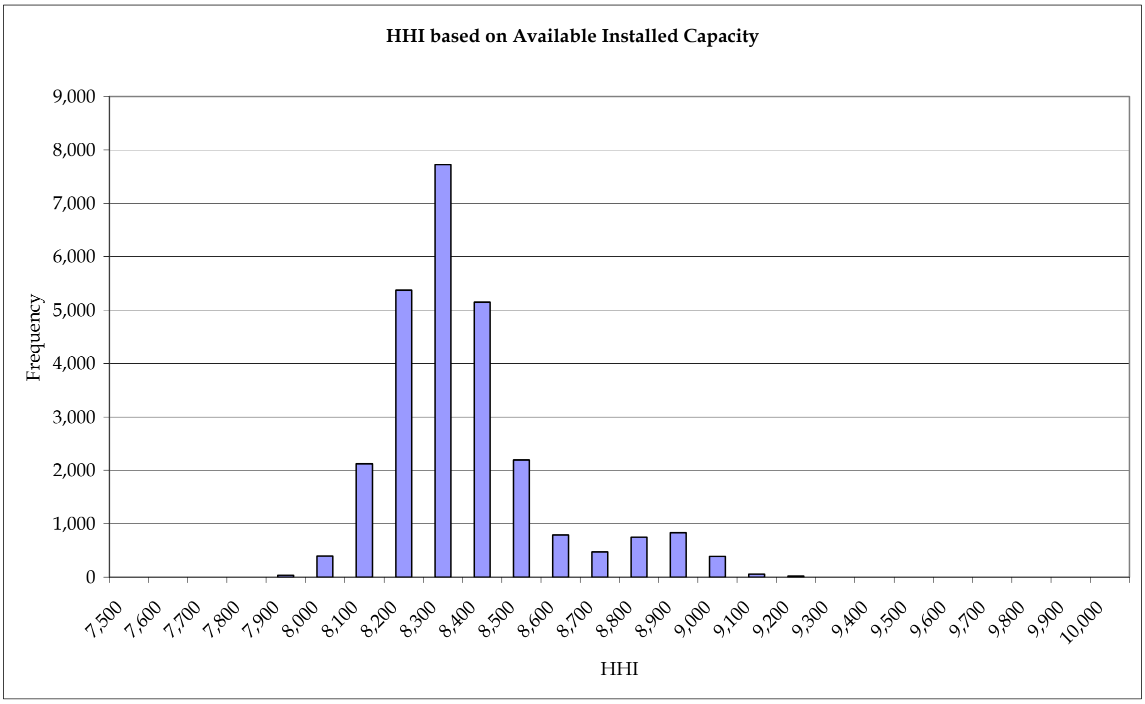
4.2.1 Results

CR(2) & HHI based on available installed capacity

HHI and CR(*n*) measures have been constructed hourly for the full period of the study. An overall representation of the computed HHI values based in hourly available installed capacity is provided in the following histogram.

The histogram shows a considerable degree of concentration in the Belgian market, with HHIs greater than 8,000 for almost the entire period.

Figure 4.5: Histogram of HHI Values based on Available Installed Capacity (2003-2005) - Belgium



Source: LE.

Further summary statistics on HHI based on Available Installed Capacity are presented in Table 4.1. The table shows that a single company, 0513-S-BE, controlled up to 97.5% of Available Installed Capacity in Belgium.

Table 4.1: Summary Statistics of CR(1) & HHI based on Available Installed Capacity - Belgium			
	Available Installed Capacity (MW)	**CR(1)**	**HHI**
Average	12,429	90.7%	8,307
Maximum	14,738	97.5%	9,508
Minimum	9,645	87.2%	7,761
Standard Deviation	786	1.2%	205

Source: LE

As well as the overall representation of the hourly HHI values, a number of pre-selected days have been chosen to assess the existence and prevalence of concentration at different points in weekly and seasonal trends. . Pre-selected days were tested to see if, as a spot check, perhaps concentration problems existed at more precise times in the market. The pre-selected dates are provided in Table 4.2

Table 4.2: Pre-Selected Representative Days[44] - Belgium		
	Weekday	**Weekend**
January (Winter)	2nd & 4th Wednesday	2nd Sunday
April (Spring)	2nd Wednesday	2nd Sunday
August (Summer)	2nd & 4th Wednesday	2nd Sunday
October (Fall)	2nd Wednesday	2nd Sunday

Source: LE

Table 4.3 presents the results of the CR(1) and HHI analysis for available installed capacity for these pre-selected dates. This analysis shows that the leading position enjoyed by the leading Belgian company is virtually constant over the entire period under investigation.

[44] The selection of January and August as Winter and Summer respectively is in accordance with the references to these periods contained in the Horizontal Data Request.

Table 4.3: HHI and CR(1) based on Available Installed Capacity - selected days - Belgium

No.	Date	Average Hourly Demand (MWh/h)	CR(1)	HHI
1	08/01/03 (W-2)	10,129	90.8%	8,326
2	12/01/03 (S-2)	9,487	90.6%	8,296
3	22/01/03 (W-4)	10,081	90.6%	8,289
4	09/04/03 (W-2)	9,208	90.2%	8,228
5	13/04/03 (S-2)	7,244	88.8%	8,012
6	10/08/03 (S-2)	8,484	90.7%	8,313
7	13/08/03 (W-2)	9,055	90.4%	8,263
8	27/08/03 (W-4)	8,630	94.0%	8,866
9	08/10/03 (W-2)	9,694	89.7%	8,141
10	12/10/03 (S-2)	8,200	89.5%	8,099
11	11/01/04 (S-2)	8,769	90.3%	8,241
12	14/01/04 (W-2)	9,753	90.6%	8,292
13	28/01/04 (W-4)	10,094	90.1%	8,197
14	11/04/04 (S-2)	7,485	91.0%	8,363
15	14/04/04 (W-2)	8,863	89.8%	8,169
16	08/08/04 (S-2)	7,757	90.1%	8,209
17	11/08/04 (W-2)	8,849	90.6%	8,290
18	25/08/04 (W-4)	8,293	92.2%	8,550
19	06/10/04 (W-2)	8,761	90.1%	8,201
20	10/10/04 (S-2)	7,709	89.1%	8,048
21	09/01/05 (S-2)	7,802	91.2%	8,390
22	12/01/05 (W-2)	10,014	91.3%	8,411
23	26/01/05 (W-4)	10,899	91.5%	8,444
24	10/04/05 (S-2)	7,771	91.9%	8,511
25	13/04/05 (W-2)	9,589	90.8%	8,331
26	10/08/05 (W-2)	8,384	90.4%	8,263
27	14/08/05 (S-2)	7,444	89.9%	8,186
28	24/08/05 (W-4)	8,812	90.5%	8,282
29	09/10/05 (S-2)	8,294	92.5%	8,616
30	12/10/05 (W-2)	9,296	90.3%	8,249

Source: LE.

As well as looking at these pre-selected dates HHIs have also been calculated over the four peak Summer and Winter days within the three year period of the study, as well as the peak days in Spring and Autumn. This was done to see if seasonality is affecting concentration or market structure in Belgium. The results are presented in Table 4.4. The table shows that the market share of the leading company in terms of available installed capacity is largely unaffected by seasonal variation.

Table 4.4: Concentration measures based on Available Installed Capacity – seasonal peaks - Belgium

	Date	Average Hourly Demand (MWh/h)	CR(1)	HHI
Summer	22/08/2003	9,875	90.6%	8,299
	15/07/2004	9,740	90.5%	8,272
	24/06/2005	10,189	91.1%	8,386
Winter	04/02/2003	10,611	90.5%	8,285
	22/01/2004	11,050	90.2%	8,226
	16/02/2005	11,446	90.9%	8,344
Spring	03/03/2003	9,875	90.1%	8,213
	25/03/2004	9,709	90.6%	8,287
	03/03/2005	10,659	91.0%	8,370
Autumn	17/10/2003	9,806	89.7%	8,137
	25/11/2004	10,094	90.3%	8,240
	23/11/2005	9,926	90.6%	8,300

Source: LE.

Available Capacity (allowing for LTCs and Reserves)

Reserves and long-term contracts can have an important impact on measured concentration in electricity markets. It is therefore important to control for such factors. In order to assess the impact of long-term contracts and reserve commitments on the HHI and CR(1) measures, these measures have been constructed using Available Capacity. Available capacity differs from available installed capacity as it takes account of each company's long-term contract and upward reserve commitment requirements. Available capacity is the basis for the electricity specific structural measures computed in the following section.

Table 4.5 presents a summary comparison of the results of the HHI and CR(1) measures computed hourly over the full period for Available Capacity and Available Installed Capacity (the basis for all of the above analysis).

According to Table 4.5 the concentration measured over Available Capacity is noticeably lower than is the case for Available Installed Capacity. This reflects the fact that company 0513-S-BE commits relatively more of its capacity to reserves and long-term contracts.

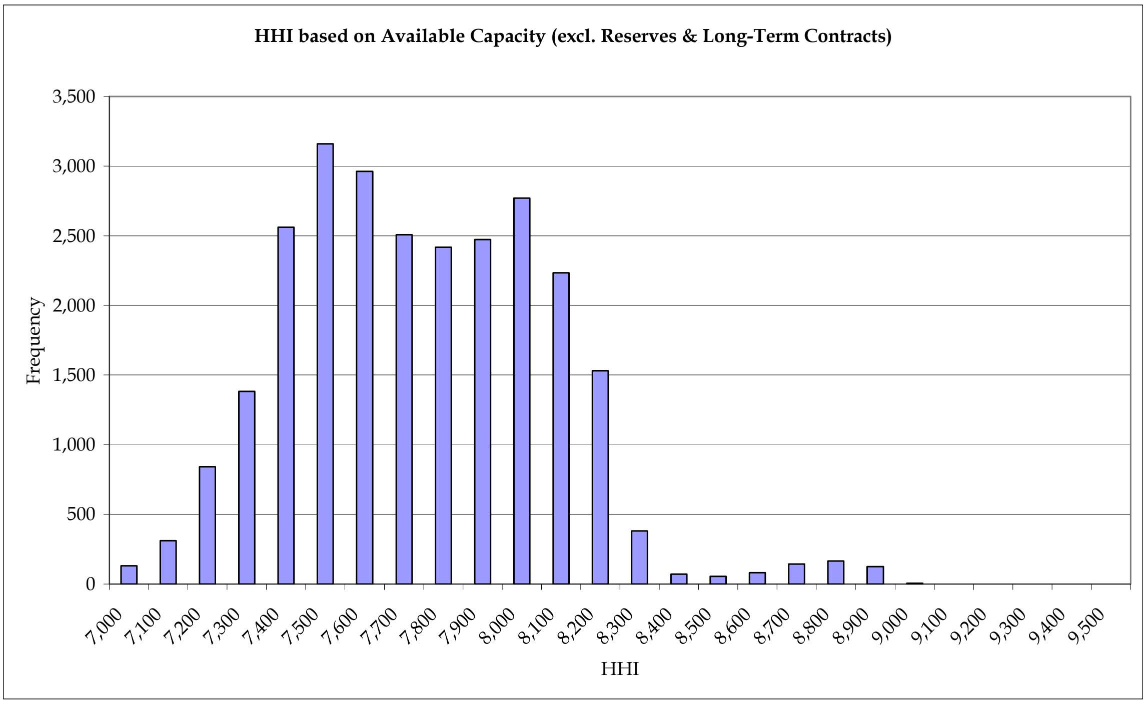
Table 4.5: Summary Statistics of HHI based on Available Capacity and Available Installed Capacity - Belgium

	Available Capacity (MW)		**Available Installed Capacity (MW)**	
	CR(1)	**HHI**	**CR(1)**	**HHI**
Average	86.4%	7,694	90.7%	8,307
Maximum	93.5%	9,079	97.5%	9,508
Minimum	81.0%	6,764	87.2%	7,761
Standard Deviation	2.1%	329	1.2%	205

Source: LE

The histogram presented below provides the frequency of the computed HHI values based on Available Capacity. The histogram shows the central tendency and spread of the distribution of values. It can again be seen that hourly HHIs based on Available Installed Capacity are noticeably lower than those based on just installed capacity, although the qualitative conclusions are the same.

Figure 4.6: Histogram of HHI Values based on Available Capacity (2003-2005) - Belgium



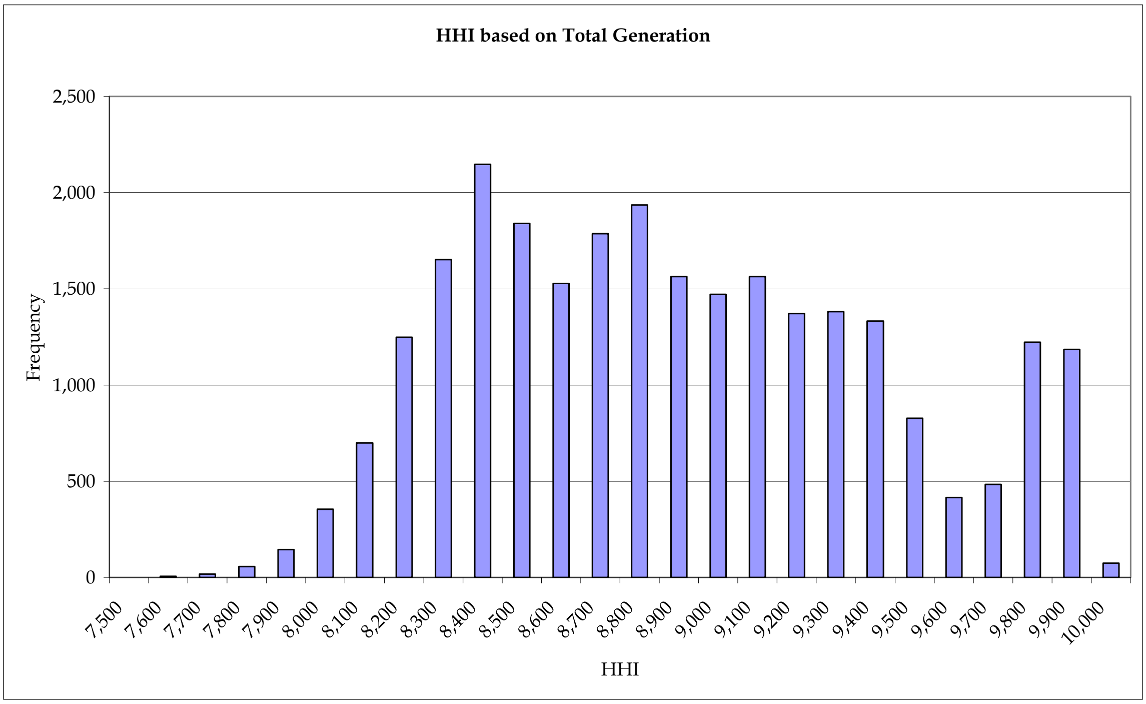
Source: LE

CR(1) & HHI based on Total Generation

An alternative definition often used as a sensitivity in electricity market concentraton is to base market share calculations on total generation. This excludes generation in many hours that are available to meet peak demand, but put greater weight on those generators running baseload, especially in off peak hours. The HHI and CR(1) measures have been re-estimated hourly based on the net electrical production figures returned by the companies. This data similarly is used to construct the load in Belgium.

The Figure below presents a histogram of the frequency of hourly HHI values computed using hourly generation over the period 2003-2005. The histogram is noticeably different from the capacity-based measures. There are more hours to the right of the mean where the frequency of higher HHIs occurs. This is natural as available capacity is a less narrow market definition than total generation. HHIs based on total generation are extremely high. They suggest that company 0513-S-BE held an extremely high share of the Belgian market for a considerable amount of time during the period 2003-2005.

Figure 4.7: Histogram of HHI Values based on Total Generation (2003-2005) - Belgium



Source: LE

This is confirmed by the summary statistics in Table 4.6, which shows that company 0513-S-BE's share of total generation reached a maximum of 99.7%. However, concentration also showed a notable degree of variability, as shown by the histogram above.

Table 4.6: Summary Statistics of CR(1) & HHI based on Total Generation - Belgium			
	Hourly Generation (MWh/h)	**CR(1)**	**HHI**
Average	8,924	93.7%	8,843
Maximum	12,371	99.7%	9,944
Minimum	5,935	85.9%	7,578
Standard Deviation	964	2.9%	517
Source: LE			

Table 4.7 presents the HHI and CR(1) computed for the pre-selected days previously listed in Table 4.2. Although the hourly market share varies by up to 8 percentage points, this does not change the overall impression regarding the market position of company 0513-S-BE.

Table 4.7: Concentration measures based on total generation – selected days - Belgium				
No.	**Date**	**Average Hourly Demand (MWh/h)**	**CR(1)**	**HHI**
1	08/01/03 (W-2)	10,129	93.8%	8,844
2	12/01/03 (S-2)	9,487	95.5%	9,157
3	22/01/03 (W-4)	10,081	90.5%	8,276
4	09/04/03 (W-2)	9,208	97.0%	9,422
5	13/04/03 (S-2)	7,244	98.8%	9,766
6	10/08/03 (S-2)	8,484	89.2%	8,067
7	13/08/03 (W-2)	9,055	93.3%	8,748
8	27/08/03 (W-4)	8,630	96.3%	9,291
9	08/10/03 (W-2)	9,694	94.1%	8,881
10	12/10/03 (S-2)	8,200	94.1%	8,891
11	11/01/04 (S-2)	8,769	94.1%	8,885
12	14/01/04 (W-2)	9,753	96.6%	9,339
13	28/01/04 (W-4)	10,094	91.9%	8,509
14	11/04/04 (S-2)	7,485	96.4%	9,307
15	14/04/04 (W-2)	8,863	90.4%	8,265
16	08/08/04 (S-2)	7,757	90.4%	8,260
17	11/08/04 (W-2)	8,849	94.8%	9,018
18	25/08/04 (W-4)	8,293	97.1%	9,439
19	06/10/04 (W-2)	8,761	96.5%	9,330
20	10/10/04 (S-2)	7,709	95.4%	9,130
21	09/01/05 (S-2)	7,802	94.6%	8,984
22	12/01/05 (W-2)	10,014	91.0%	8,366
23	26/01/05 (W-4)	10,899	91.2%	8,395
24	10/04/05 (S-2)	7,771	94.4%	8,942
25	13/04/05 (W-2)	9,589	91.3%	8,417
26	10/08/05 (W-2)	8,384	94.8%	9,018
27	14/08/05 (S-2)	7,444	96.4%	9,298
28	24/08/05 (W-4)	8,812	91.9%	8,509
29	09/10/05 (S-2)	8,294	95.4%	9,116
30	12/10/05 (W-2)	9,296	91.3%	8,407

Source: LE.

Table 4.8 presents the HHI and CR(1) based on total generation for the selected seasonal peaks in demand. As the constructed load is the sum of hourly generation, this table presents, for peak demand days, the degree of concentration at the seasonal high points of the load duration curve. The conclusion is that seasonality is not a large determinant of concentration using total generation as the basis for the market share calculation.

Table 4.8: HHI based on total generation – seasonal peaks - Belgium

	Date	Average Hourly Demand (MWh/h)	CR(1)	HHI
Summer	22/08/2003	9,875	90.8%	8,334
	15/07/2004	9,740	91.1%	8,375
	24/06/2005	10,189	92.2%	8,564
Winter	04/02/2003	10,611	91.9%	8,511
	22/01/2004	11,050	89.8%	8,162
	16/02/2005	11,446	91.9%	8,518
Spring	03/03/2003	9,875	94.2%	8,903
	25/03/2004	9,709	91.5%	8,441
	03/03/2005	10,659	91.8%	8,492
Autumn	17/10/2003	9,806	91.3%	8,403
	25/11/2004	10,094	92.0%	8,525
	23/11/2005	9,926	92.4%	8,604

Source: LE.

In order to further investigate the degree of concentration at different intervals in the load duration curve, base, shoulder and peak periods have been identified for a selection of the days already presented as part of the analysis of pre-selected days. The definition of base, shoulder and peak used for this analysis is as follows;

- Base is defined as the hours in the year located in the two rightmost quartiles of the load duration curve. The first 50% of hours for which demand is lowest in 2005;

- Shoulder is defined as the hours in the next quartile of the load duration curve, to the left of the base hours;
- Peak is defined as the hours in the first quartile of the load duration curve, which contains the hours for which demand is highest in 2005.

Table 4.9 presents the HHI and CR(1) values during these periods of the selected days, as well as the order of the top two companies in those hours.

Table 4.9: Total Generation – Concentration & Load Duration - Belgium

January 2005		**Company**	**CR(1)**	**HHI**
2nd Wednesday	*Base*	NA	NA	NA
	Shoulder	0513-S-BE	92.8%	8,661
	Peak	0513-S-BE	90.4%	8,266
August 2005				
2nd Wednesday	*Base*	0513-S-BE	95.4%	9,123
	Shoulder	0513-S-BE	93.0%	8,693
	Peak	NA	NA	NA

Source: LE

A number of entries appear as NA in this table due to the fact that hours corresponding to the definition of the categories do not exist on these pre-selected days.

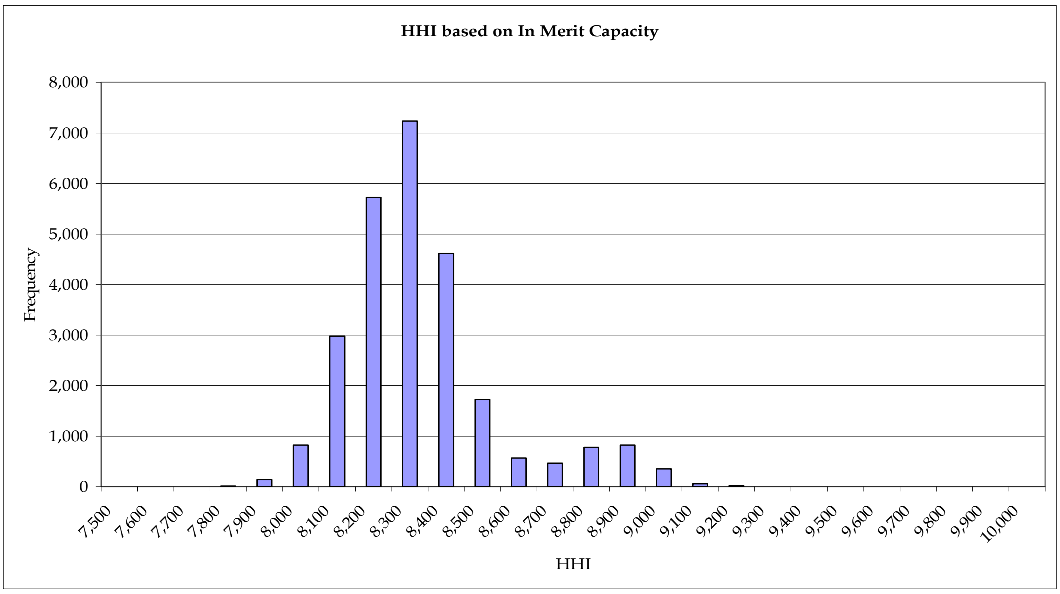
CR(1) & HHI based on In Merit/Economic Capacity

In Merit capacity has been computed based on the realised fuel costs (€/MWh) returned by each company for each of their generation units. Table 4.10 presents summary statistics on the CR(1) and HHI values computed on an hourly basis. The results are not sensitive to this definition of capacity in calculating market shares.

Table 4.10: Summary Statistics CR(1) & HHI based on In Merit Capacity - Belgium			
	In Merit Capacity (MW)	**CR(1)**	**HHI**
Average	12,162	90.5%	8,284
Maximum	14,530	98.0%	9,616
Minimum	9,645	87.2%	7,748
Standard Deviation	807	1.3%	212
Source: LE			

The following histogram represents the frequency of HHI values calculated on the basis of in merit capacity.

Figure 4.8: Histogram of HHI Values based on In-Merit Capacity (2003-2005) - Belgium



Source: LE.

4.2.2 Interconnector

An assessment of the potential impact of interconnection has been carried out using the indicators of concentration previously presented based on Available Installed Capacity and Total Generation. Importantly, it was possible to extract details of ownership of reserved capacity and interconnector flows, by company, from the data collected by DG Competition as part of the Sector Inquiry and as a result a sensitivity analysis is conducted to put upper and lower bounds on the potential impact of interconnection on the traditional measures concentration. Two scenarios have been considered and represent a sensitivity analysis of the figures calculated in the absence of the interconnector;

1. Atomistic Competition
2. Largest Company Apportionment

1. Atomistic Competition – Under this scenario the companies' hourly market share is not affected. The aggregated impact of the interconnector is included in the denominator of both CR(1) and HHI measures, such that the net impact of the interconnectors is only added to the market. Thus, the atomistic competition scenario reduces the measured concentration by the maximum amount possible due to the interconnector.

2. Largest Company Apportionment – Under this alternative scenario the hourly impact of the interconnectors is apportioned entirely to the largest company in the market (as measured by available installed capacity). This scenario thus represents the largest increase in measured concentration possible due to the allocation of the interconnector.

The two allocation procedures thus form the upper and lower bounds of the measured concentration due to the interconnector allocation. It is important to note at this stage that the potential impact of the interconnector is accounted for differently in these scenarios depending on the basis for the calculation. The hourly net transfer capacity of the interconnectors is used in calculations based on the Available Installed Capacity of the companies in the market, while actual hourly interconnector flows are used in calculations based on Total Generation. This is important due to the potential impact of the interconnector flows on the expectations of upper and lower bounds. These bounds are true in the case of Available Installed Capacity but as one may realise, this will only be the case if the country is, on average, a net importer of electricity. In the event that the country is regarded as an exporter, the expected results from these scenarios may be reversed. For a further discussion and formal exposition of how these interconnector scenarios are calculated, one can revert to the methodology chapter of this report.

4.2.3 Results

The following tables represent the sensitivity cases of concentration based on Available Installed Capacity, with hourly available net transfer capacity of the interconnector(s) added to the relevant variables. As implied by the calculation method explained above, concentration figures obtained under the Atomistic scenario are significantly lower than under the standard scenario which ignores the interconnector. The increase in concentration under the scenario that adds the interconnector to the biggest player in the market is comparatively small, which reflects the limited importance of the interconnector given the extent of the lead enjoyed by the biggest player over its rivals. The increases, on average, in the concentration measures under the largest player case only represent a 1.5% increase in the market share of the largest company. On average the HHI changes by approximately 300 points.

Table 4.11: Summary Statistics Concentration measures based on Available Installed Capacity: Impact of the Interconnector - Belgium

	STANDARD (excl. IC based on available installed capacity)		ATOMISTIC		IC ADDED TO BIGGEST PLAYER	
	CR(1)	HHI	CR(1)	HHI	CR(1)	HHI
Average	90.7%	8,307	72.6%	5,332	92.5%	8,617
Max	97.5%	9,508	77.5%	6,030	96.0%	9,236
Min	87.2%	7,761	67.9%	4,678	90.5%	8,266
Standard Deviation	1.2%	205	1.7%	246	0.9%	159

Source: LE.

Assessing the peak seasonal days in the Belgian electricity market one also finds the results to be consistent with those in the previous table. Table 4.12 shows that these results are robust across seasons, with only minute changes occurring between selected dates.

Table 4.12: Concentration measures based on Available Installed Capacity: Impact of the Interconnector - Belgium							
		STANDARD (excl. IC based on available installed capacity)		ATOMISTIC		IC ADDED TO BIGGEST PLAYER	
	Date	**CR(1)**	**HHI**	**CR(1)**	**HHI**	**CR(1)**	**HHI**
Summer	22/08/2003	90.6%	8,299	74.3%	5,573	92.3%	8,581
	15/07/2004	90.5%	8,272	73.1%	5,390	92.4%	8,579
	24/06/2005	91.1%	8,386	74.0%	5,521	92.8%	8,666
Winter	04/02/2003	90.5%	8,285	73.6%	5,475	92.3%	8,580
	22/01/2004	90.2%	8,226	71.7%	5,195	92.2%	8,560
	16/02/2005	90.9%	8,344	72.4%	5,292	92.8%	8,656
Spring	03/03/2003	90.1%	8,213	71.7%	5,207	92.1%	8,546
	25/03/2004	90.6%	8,287	71.1%	5,101	92.6%	8,627
	03/03/2005	91.0%	8,370	72.4%	5,300	92.9%	8,676
Autumn	17/10/2003	89.7%	8,137	72.5%	5,321	91.7%	8,463
	25/11/2004	90.3%	8,240	71.8%	5,211	92.3%	8,572
	23/11/2005	90.6%	8,300	72.9%	5,366	92.5%	8,606

Source: LE.

If one changes the focus of the market definition from available installed capacity to actual generation, wherein interconnector flows are included in the calculation of the sensitivities as opposed to interconnector capacity, this does not limit the impact of the interconnector to be positive but rather it allows for net exports to have a negative impact on the market share of companies and the market as a whole. Summary statistics on the results of the interconnector sensitivity scenarios based on total generation are presented in Table 4.13.

Table 4.13: Summary Statistics Concentration measures based on Total Generation: Impact of the Interconnector - Belgium						
	STANDARD (excl. IC based on total generation)		ATOMISTIC		IC ADDED TO BIGGEST PLAYER	
	CR(1)	HHI	CR(1)	HHI	CR(1)	HHI
Average	93.7%	8,843	85.8%	7,420	94.3%	8,932
Max	99.7%	9,944	97.4%	9,486	99.6%	9,913
Min	85.9%	7,578	75.3%	5,716	88.6%	7,979
Standard Deviation	2.9%	517	4.0%	672	2.5%	455
Source: LE.						

Assessing the peak seasonal days in the Belgian electricity market one also finds the results to be consistent with those in the previous table. Table 4.14 shows that these results are robust across seasons, with very small changes occurring between selected dates.

Table 4.14: Concentration measures based on Total Generation: Impact of the Interconnector - Belgium

		STANDARD (excl. IC based on total generation)		ATOMISTIC		IC ADDED TO BIGGEST PLAYER	
	Date	CR(1)	HHI	CR(1)	HHI	CR(1)	HHI
Summer	22/08/2003	90.8%	8,334	88.6%	7,930	91.0%	8,370
	15/07/2004	91.1%	8,375	89.6%	8,108	91.2%	8,399
	24/06/2005	92.2%	8,564	89.1%	8,002	92.5%	8,609
Winter	04/02/2003	91.9%	8,511	84.5%	7,190	92.6%	8,622
	22/01/2004	89.8%	8,162	82.6%	6,916	90.6%	8,293
	16/02/2005	91.9%	8,518	89.5%	8,081	92.2%	8,554
Spring	03/03/2003	94.2%	8,903	89.7%	8,083	94.5%	8,952
	25/03/2004	91.5%	8,441	83.0%	6,944	92.3%	8,574
	03/03/2005	91.8%	8,492	84.4%	7,184	92.4%	8,603
Autumn	17/10/2003	91.3%	8,403	84.2%	7,148	91.9%	8,516
	25/11/2004	92.0%	8,525	82.6%	6,877	92.8%	8,663
	23/11/2005	92.4%	8,604	79.4%	6,352	93.5%	8,785

Source: LE.

The results from the tables above show that measured concentration in the Belgian market does not seem particularly sensitive to the interconnector allocation procedure, regardless of the basis of the market share calculation. HHIs and CR(*n*)s stay in the highly concentrated range, with HHIs greater than 8,000 for most days and hours, seasons, etc, while CR2 is in the 90% range generally.

4.3 Electricity Specific Structural Measure

As discussed previously, electricity markets display many unique characteristics that indicate limits to the usefulness of tradition measures of market structure. We therefore have endeavoured to estimate electricity-specific structural indicators. Both the Residual Supply Index (RSI) and Pivotal Supplier Index (PSI) are calculated using the aggregated Available Capacities of the units in each companies portfolio, unlike the previous available capacity measure, this measure is complimented by adjusting the hourly available capacity figures (as discussed above) for the long-term contract position of the companies and their commitment to provide reserves for upward regulation. The long-term contract position of the companies has been adjusted to reflect any change in the net position of the companies that occurred over the period 2003-2005. This is also true for the quantity of generation committed to meet reserve requirements; this data has been taken from the TSO response to the 2005 Data Request and not from the generators' responses.

4.3.1 RSI

Since much of our further results are based on the RSI, we repeat the formula for RSI used in the methodology section. It is noteworthy that the RSI is in general specific to a chosen company. The RSI is calculated for each hour (26,304) in accordance with the following formula;

$$RSI_j = \frac{\left(\sum_{i=1}^{N} ac_i - AC_j\right)}{\sum_{i=1}^{N} hourly\_generation_i} \qquad \text{where; } i = 1, 2, \ldots, j, \ldots, N$$

The companies' total available capacity and generation in each hour is indexed by i. The RSI indicator usually should have the system load as the denominator in this equation, however for the purposes of this study (for reasons outlined elsewhere) the system load has been constructed as the sum of the net hourly electrical production figures reported by all companies. This indicator has been calculated for both the four largest companies in the market in Belgium, rather than the top two as in other countries, because the four largest companies were all of a similar size and market position. The calculation of the capacity of the largest company or chosen company is indicated by Company *j*.

Previous studies that have used this measure have attempted to apply a threshold value to the computed hourly indicator. The threshold states that if the value of the RSI is less than 110% (1.1) for more than 5% of the time, then this is indicative of a market structure that is likely to be open to non competitive behaviour. This threshold test and the threshold itself was developed by the CAISO and as applied indicates potentially troublesome periods as those where the residual supply is less than 110% of the market demand for electricity and whether or not this systematically occurs in more than 5% of the time. The threshold itself is not the result of in-depth economic analysis but rather based on knowledge of market functioning but as such one may consider tailoring the threshold for each country. This was not done as part of this report as it was considered that the 110% threshold would be appropriate to achieving the objectives of this study and would further allow for a consistent comparison across countries.

4.3.2 PSI

The PSI is calculated for each hour (26,304) in accordance with the formulae presented in the methodology section. The PSI is a zero-one indicator of when a company is needed to meet demand.

As with the RSI indicator, the PSI is traditionally calculated using the system load, however for the purposes of this study the system load is replaced by the sum of the hourly generation of the companies included in the study.

A threshold for this indicator has been constructed as part of previous studies and market analysis. The FERC apply a threshold of 20% to this measure, if the value of the measure 1 for more than 20% of the time then this is indicative of a pivotal supplier. As with the threshold applied in relation to the RSI, this threshold is not the result of rigorous economic analysis and as such should be considered to be an indicator of potential market power issues rather than a steadfast rule in relation to overall conclusions that can be drawn from the results.

4.3.3 Results

RSI Results

Table 4.15 presents the results of the threshold test for the RSI calculated on an hourly basis for both the full period and individually for each year. With the threshold set at 110%, the test requires that the value of the RSI be greater than 110% (1.1) for more than 95% of the time for the largest market participant, in order for the market outcome to be deemed competitive. This table presents the results of the threshold test for all of the large generation companies in Belgium. If the percentage of hours, for which the RSI measure is less than 110%, is greater than 5% for any of the companies, then the market outcome cannot be considered to be a competitive one.

The table demonstrates that the threshold level of 110% is never reached by company 0513-S-BE in any hour throughout 2003, 2004 or 2005. This result indicates that the company is indispensable to meeting demand in all hours. On average over the three year period company 1469-S-BE can be seen to be marginal with respect to the 5% threshold. The indispensability of this company increases over time and as one is already aware from the merit curve, this coincides with the increase in the demand for electricity witnessed over time in this market.

Table 4.15: RSI Threshold Analysis - Belgium

RSI Result	0513-S-BE	1469-S-BE
2003-05	26,304	1,303
% hrs< 110%	*100.0%*	*5.0%*
2003	8,760	91
% hrs< 110%	*100.0%*	*1.0%*
2004	8,784	466
% hrs< 110%	*100.0%*	*5.3%*
2005	8,760	746
% hrs< 110%	*100.0%*	*8.5%*

Source: LE.

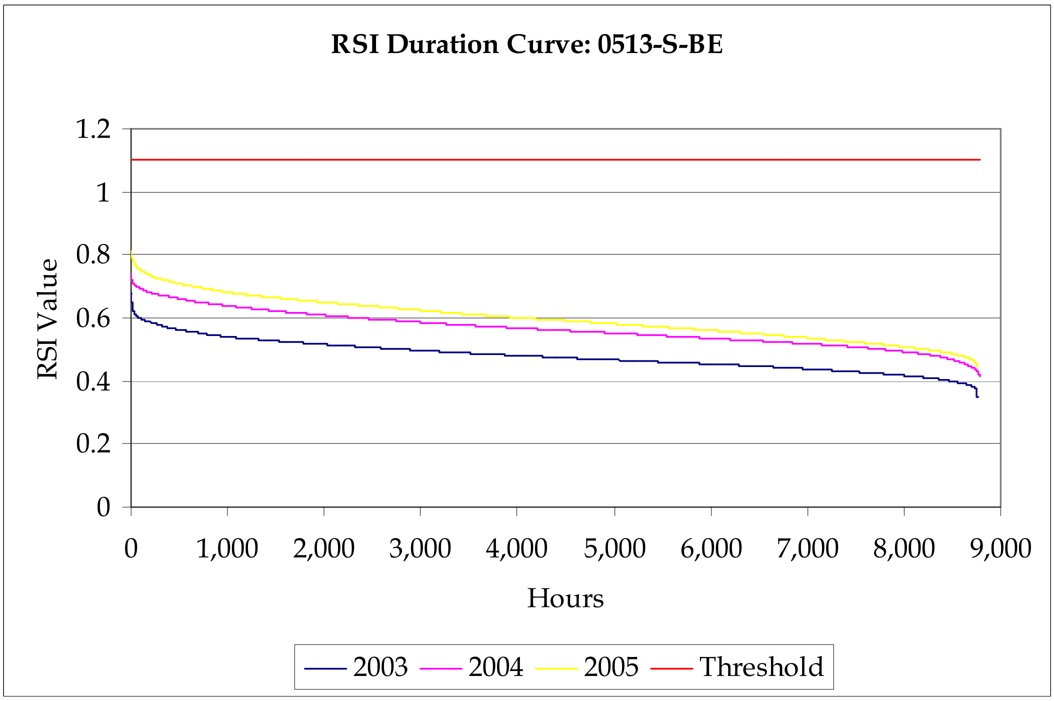
Table 4.16 presents summary statistics on the RSI.

Table 4.16: Summary Statistics on RSI - Belgium								
	0513-S-BE				**1469-S-BE**			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.55	0.48	0.57	0.60	1.26	1.28	1.27	1.24
Max	0.81	0.68	0.74	0.81	1.75	1.75	1.72	1.68
Min	0.35	0.35	0.41	0.44	0.97	1.04	0.97	0.99

Source: LE.

Since the RSI is a continuous measure and calculated hourly, we can also consider an RSI duration curve (a mirror of the cumulative distribution) to show the number or % of hours that RSI is above a certain value. The following graphic represents the duration curve for the RSI in Belgium, accounting for the markets largest company. This gives an idea of the distribution as well as the mean of the measure over time. The figure shows the RSI of company 0513-S-BE to be below the threshold value of 110% at all times.

Figure 4.9: RSI Duration Curve for Company 0513-S-BE



Source: LE.

Alternative RSI Scenarios

The existence of long term contracts and reserve commitments can impact the RSI and PSI similarly as they can the traditional measures of concentration. It is therefore necessary to check these sensitivities. As a sensitivity test on the RSI values presented above, the RSI is re-estimated under two alternative scenarios. Firstly, by excluding the long-term contract positions of the companies from the calculation of available capacity, and secondly, by excluding the companies' upward reserve commitments from the same calculation.

Table 4.17 presents the results of the threshold test when long-term contracts have been excluded from the calculation of available capacity. The picture remains virtually unchanged for company 0513-S-BE, however company 1469-S-BE can no longer be viewed as pivotal in a critical number of hours thus indicating that company 0469-S-BE relies partly on contracted capacity in certain hours when it is regarded to be indispensable. Nonetheless this does nothing to diminish concerns about competition in the Belgian electricity market.

Table 4.17: RSI Threshold Analysis - Scenario 1 (accounts for Reserves only) - Belgium

RSI Result	0513-S-BE	1469-S-BE
2003-05	26,304	448
% hrs< 110%	*100.0%*	*1.7%*
2003	8,760	91
% hrs< 110%	*100.0%*	*1.0%*
2004	8,784	168
% hrs< 110%	*100.0%*	*1.9%*
2005	8,760	189
% hrs< 110%	*100.0%*	*2.2%*

Source: LE.

Table 4.18 presents the RSI values for the two largest companies in Belgium. It reconfirms the indispensable position of company 0513-S-BE.

Table 4.18: Summary Statistics of RSI Results - Scenario 1 (accounts for Reserves only) - Belgium

	0513-S-BE				1469-S-BE			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.17	0.14	0.20	0.17	1.29	1.28	1.30	1.28
Max	0.28	0.19	0.28	0.25	1.77	1.75	1.77	1.73
Min	0.07	0.07	0.11	0.10	1.00	1.04	1.00	1.02

Source: LE.

Similarly, the RSI results for company 0513-S-BE are not sensitive to the inclusion of long-term contracts only in the calculation of available capacity. Table 4.19 and Table 4.20 show the results of this analysis. As before, the threshold level of 110% is exceeded by company 0513-S-BE in all hours. The tables show that the RSI is indicating a concentration problem in Belgium markets is in general not sensitive to the impact of reserves and long term contracts. The results for company 1469-S-BE support the previous finding that the company relied on contracted capacity to supplement its market involvement. This result also indicates the company contributes capacity to meet system balancing requirements, although this is significantly less than the quantity contracted from other sources.

Table 4.19: RSI Threshold Analysis - Scenario 2 (accounts for LTC only) - Belgium		
RSI Result	**0513-S-BE**	**1469-S-BE**
2003-05	26,304	1,789
% hrs< 110%	*100.0%*	*6.8%*
2003	8,760	91
% hrs< 110%	*100.0%*	*1.0%*
2004	8,784	657
% hrs< 110%	*100.0%*	*7.5%*
2005	8,760	1,041
% hrs< 110%	*100.0%*	*11.9%*
Source: LE.		

Table 4.20: Summary Statistics of RSI Results - Scenario 2 (accounts for LTC only) - Belgium								
	0513-S-BE				**1469-S-BE**			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.51	0.48	0.50	0.54	1.25	1.28	1.25	1.22
Max	0.74	0.68	0.66	0.74	1.75	1.75	1.70	1.66
Min	0.35	0.35	0.37	0.41	0.95	1.04	0.95	0.98
Source: LE								

4.3.4 PSI Results

The results of the PSI analysis for the large generation companies in Belgium are presented in Table 4.21. As discussed above the PSI is a (0,1) variable, equal to 1 if the company is deemed to be pivotal to supply in a given hour and zero if not. An established threshold test for this measure is one applied by FERC which considers a market participant to be pivotal, and thus the market outcome not to be competitive, if the PSI for any company is equal to one for more than twenty percent of the time. The results show company 0513-S-BE to be pivotal 100% of the time. However, unlike the result of the RSI, company 1469-S-BE is not deemed to be pivotal based on these results in a sufficient number of hours to be deemed pivotal. This result is brought about by the different formulations of the threshold tests, by definition the PSI is triggered when the residual supply is less than 100% of the load while the RSI threshold test comes into effect when this the residual supply is less than 110% of the load. To compensate for this difference, the number of hours these thresholds are not met differs for the two measures with the PSI finding companies to be pivotal more frequently through the lower threshold but requiring them to be pivotal in more hours.

Table 4.21: PSI Threshold Analysis - Belgium

PSI Result	**0513-S-BE**	**1469-S-BE**	**2030-S-BE**
2003-05	26,304	10	0
% hrs =1	*100.0%*	*0.0%*	*0.0%*
2003	8,760	0	0
% hrs =1	*100.0%*	*0.0%*	*0.0%*
2004	8,784	6	0
% hrs =1	*100.0%*	*0.1%*	*0.0%*
2005	8,760	4	0
% hrs =1	*100.0%*	*0.0%*	*0.0%*

Source: LE

Alternative PSI Scenarios

As with the RSI analysis above, the PSI analysis has been re-estimated under the same alternative scenarios to test for sensitivity. Table 4.22 presents the results of the PSI threshold test having only included long-term contracts in the formulation of available capacity.

Table 4.22: PSI Results - Scenario 1 (accounts for Reserves only) - Belgium

PSI Result	0513-S-BE	1469-S-BE	2030-S-BE
2003-05	26,304	0	0
% hrs =1	*100.0%*	*0.0%*	*0.0%*
2003	8,760	0	0
% hrs =1	*100.0%*	*0.0%*	*0.0%*
2004	8,784	0	0
% hrs =1	*100.0%*	*0.0%*	*0.0%*
2005	8,760	0	0
% hrs =1	*100.0%*	*0.0%*	*0.0%*

Source: LE

Table 4.23 presents the results of the PSI threshold test under Alternative Scenario 2, whereby upward reserve commitments have been excluded from the calculation of available capacity.

Table 4.23: PSI Results - Scenario 2 (accounts for LTC only) - Belgium			
PSI Result	**0513-S-BE**	**1469-S-BE**	**2030-S-BE**
2003-05	26,304	23	0
% hrs =1	*100.0%*	*0.1%*	*0.0%*
2003	8,760	0	0
% hrs =1	*100.0%*	*0.0%*	*0.0%*
2004	8,784	13	0
% hrs =1	*100.0%*	*0.1%*	*0.0%*
2005	8,760	10	0
% hrs =1	*100.0%*	*0.1%*	*0.0%*
Source: LE			

As was the case in the section on RSIs, it turns out that the PSI results are not sensitive to the inclusion or exclusion of long-term contracts and reserves.

4.3.5 Interconnector

To account for the potential impact of the interconnectors on the RSI and PSI measures, two sensitivity cases are calculated within this section to address this issue. Given interconnector capacity reservations and flows are not available at the company level it has been necessary to consider two hypothetical situations in order to assess the impact. The two scenarios are briefly described here;

1. The hourly interconnector capacity (IC_c), aggregated over the interconnectors, is added to the total supply of the market and apportioned in accordance with the companies' market shares (as measured by installed capacity) in the market being assessed. The hourly aggregated interconnector flows (IC_f) are added to the load.

2. The hourly interconnector capacity (IC_c) of each interconnector is added to the total supply of the market and the hourly available capacity of each interconnector is apportioned in accordance with the companies' market shares (as measured by installed capacity) in the markets from which electricity can be imported. The hourly aggregated interconnector flows (IC_f) are added to the load.

It is important to note that in all hours the interconnector flows are not necessarily positive values, they will be negative in hours where the market exports more electricity than it imports, therefore necessarily increasing the residual supply relative to the load, holding other factors equal.

The following sections contain the RSI and PSI analysis under the different interconnector scenarios. The results are consistent with those found in the absence of the interconnector effect. Overall these results confirm that company 0513-S-BE continues to be indispensable to the Belgian market, regardless of how the interconnector is accounted for.

4.3.6 Results – (Interconnector allocated according to domestic market share)

RSI Results

Table 4.24 presents the results of the threshold test for the RSI calculated on an hourly basis for both the full period and individually for each year. The presence of the interconnector does not change the number of times the RSI is below the threshold for company 0513-S-BE; overall, the RSI results are not sensitive to the interconnector.

Table 4.24: RSI Threshold Analysis (+ IC domestic) - Belgium

RSI Result	0513-S-BE	1469-S-BE
2003-05	26,304	11
% hrs< 110%	*100.0%*	*0.0%*
2003	8,760	1
% hrs< 110%	*100.0%*	*0.0%*
2004	8,784	9
% hrs< 110%	*100.0%*	*0.1%*
2005	8,760	1
% hrs< 110%	*100.0%*	*0.0%*

Source: LE

Table 4.25: Summary Statistics on RSI (+ IC domestic) – Belgium

	0513-S-BE				1469-S-BE			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.53	0.47	0.54	0.58	1.44	1.45	1.44	1.44
Max	0.82	0.65	0.75	0.82	2.07	2.07	1.97	2.00
Min	0.33	0.33	0.40	0.42	1.06	1.07	1.06	1.08

Source: LE

Alternative RSI Scenarios

We tested the sensitivity of the results to the exclusion of reserves from the calculation of available capacity, therefore capturing only the impact of long-term contracts. The results are shown in Table 4.26 and Table 4.27. In fact further analysis shows that including long-term contracts or reserves separately does not change the conclusions regarding the RSI. The values reported below indicate a lack of substantial competition in almost all hours.

Table 4.26: RSI Threshold Analysis (+ IC domestic) - Scenario 2 (accounts for LTC only) - Belgium

RSI Result	0513-S-BE	1469-S-BE
2003-05	26,304	13
% hrs< 110%	*100.0%*	*0.0%*
2003	8,760	1
% hrs< 110%	*100.0%*	*0.0%*
2004	8,784	11
% hrs< 110%	*100.0%*	*0.1%*
2005	8,760	1
% hrs< 110%	*100.0%*	*0.0%*

Source: LE

Table 4.27: Summary statistics on RSI (+ IC domestic) - Scenario 2 (accounts for LTC only) - Belgium

	0513-S-BE				**1469-S-BE**			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.50	0.47	0.48	0.53	1.44	1.45	1.43	1.43
Max	0.76	0.65	0.66	0.76	2.07	2.07	1.95	1.99
Min	0.33	0.33	0.35	0.38	1.05	1.07	1.05	1.07

Source: LE

PSI Results

The results of the PSI sensitivity case under the domestic apportionment of interconnector capacity, for the largest generation companies in Belgium are presented in Table 4.28. As discussed above the PSI is a (0,1) variable, equal to 1 if the company is deemed to be pivotal to supply in a given hour and zero if not. A threshold test applied in previous studies which considers a market participant to be pivotal, and thus the market outcome not to be competitive, if the PSI for any company is equal to one for more than twenty percent of the time, is applied here as a means of elucidating the results of the measure.

The following tables present the PSI threshold analysis with the interconnector allocated according to domestic market share. This approach has no impact on the pivotal status of company 0513-S-BE, which is still shown to be pivotal in all hours.

Table 4.28: PSI Threshold Analysis (+IC domestic) - Belgium

PSI Result	0513-S-BE	1469-S-BE
2003-05	26,304	0
% hrs =1	*100.0%*	*0.0%*
2003	8,760	0
% hrs =1	*100.0%*	*0.0%*
2004	8,784	0
% hrs =1	*100.0%*	*0.0%*
2005	8,760	0
% hrs =1	*100.0%*	*0.0%*

Source: LE

Alternative PSI Scenarios

Table 4.29: PSI Threshold Analysis (+IC domestic) –Scenario 2 (accounts for LTC only) - Belgium

PSI Result	0513-S-BE	1469-S-BE
2003-05	26,304	0
% hrs =1	*100.0%*	*0.0%*
2003	8,760	0
% hrs =1	*100.0%*	*0.0%*
2004	8,784	0
% hrs =1	*100.0%*	*0.0%*
2005	8,760	0
% hrs =1	*100.0%*	*0.0%*

Source: London Economics

4.3.7 Results (Interconnector allocated according to foreign market share)

RSI Results

This section repeats the analysis described above, this time allocating the interconnector according to companies' market share in other countries. This approach leads to slightly lower values of the RSI. However, as the drop in the number of hours in which the threshold value of 110% is not exceeded is very small, the overall conclusions are not affected.

Table 4.30: RSI Threshold Analysis (+ IC foreign) - Belgium

RSI Result	0513-S-BE	1469-S-BE
2003-05	26,267	2
% hrs< 110%	*99.9%*	*0.0%*
2003	8,760	0
% hrs< 110%	*100.0%*	*0.0%*
2004	8,782	2
% hrs< 110%	*100.0%*	*0.0%*
2005	8,725	0
% hrs< 110%	*99.6%*	*0.0%*

Source: LE

Table 4.31: Summary Statistics on RSI (+IC foreign) - Belgium

	0513-S-BE				1469-S-BE			
	2003-2005	2003	2004	2005	2003-2005	2003	2004	2005
Mean	0.79	0.72	0.80	0.84	1.47	1.48	1.47	1.46
Max	1.16	1.01	1.12	1.16	2.11	2.11	2.01	2.04
Min	0.53	0.53	0.59	0.62	1.08	1.11	1.08	1.10

Source: LE

Alternative RSI Scenarios

That allocation of the interconnector according to foreign market share does not affect the results in any significant manner is shown by the sensitivity analysis provided below. The inclusion of long-term contracts only again leads to a situation where company 0513-S-BE violates the RSI threshold in all hours.

Table 4.32: RSI Threshold Analysis (+IC foreign) - Scenario 2 (accounts for LTC only) – Belgium

RSI Result	0513-S-BE	1469-S-BE
2003-05	26,304	4
% hrs< 110%	*100.0%*	*0.0%*
2003	8,760	0
% hrs< 110%	*100.0%*	*0.0%*
2004	8,784	3
% hrs< 110%	*100.0%*	*0.0%*
2005	8,760	1
% hrs< 110%	*100.0%*	*0.0%*

Source: LE

Table 4.33: RSI Threshold Analysis (+ IC foreign) - Scenario 2 (accounts for LTC only) - Belgium

	0513-S-BE				**1469-S-BE**			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.75	0.72	0.74	0.79	1.46	1.48	1.45	1.45
Max	1.10	1.01	1.03	1.10	2.11	2.11	1.99	2.03
Min	0.53	0.53	0.53	0.58	1.07	1.11	1.07	1.09

Source: LE

PSI Results

The PSI results are also changed slightly by changing the way the interconnector is accounted for. Allocation of the interconnector according to companies' foreign market shares leads to slightly lower PSI values. As the following tables show, this means that company 0513-S-BE is no longer pivotal 100% of the time. However, the fall in the number of hours where the company is pivotal is small, so that the overall conclusion reached in the preceding analysis, namely that company 0513-S-BE is the crucial operator in the Belgian market appears insensitive to changes in assumptions.

Table 4.34: PSI Threshold Analysis (+IC foreign) - Belgium

PSI Result	**0513-S-BE**	**1469-S-BE**
2003-05	25,555	0
% hrs =1	*97.2%*	*0.0%*
2003	8,758	0
% hrs =1	*100.0%*	*0.0%*
2004	8,635	0
% hrs =1	*98.3%*	*0.0%*
2005	8,162	0
% hrs =1	*93.2%*	*0.0%*

Source: LE

Alternative PSI Scenario

Table 4.35: PSI Threshold Analysis (+IC foreign) – Scenario 2 (accounts for LTC only) - Belgium

PSI Result	0513-S-BE	1469-S-BE
2003-05	26,110	0
% hrs =1	*99.3%*	*0.0%*
2003	8,758	0
% hrs =1	*100.0%*	*0.0%*
2004	8,768	0
% hrs =1	*99.8%*	*0.0%*
2005	8,584	0
% hrs =1	*98.0%*	*0.0%*

Source: LE

Overall conclusions

Broadly speaking, the Belgian electricity market is very highly concentrated. This conclusion is robust to choice of concentration measure, electricity specific market structure measure, and choice of market definition. Interconnectors similarly fail to alter the overall conclusion.

4.4 Contribution to BE Electrabel Index Prices

This analysis assesses the contribution of three factors, (the GED system modelled marginal cost, the estimated costs of carbon and the estimated mark-up) to the load weighted average BE Electrabel Index price. It is important to note at the outset that the BE Electrabel Index is not an exchange price; no exchange price existed for Belgium over the sample period[45]. (We discuss this more in the following section on margins). Leaving aside for now the issues with the lack of a day-ahead spot price, since our goal is to show the relative magnitudes of cost and carbon, Table 4.36 presents the annual contribution of these three factors to the load weighted average daily BE Electrabel Index price.

One can see that there has been a substantial increase in the load weighted average system modelled marginal cost over the period of the study. However, perhaps most noticeable is the change in the load weighted average mark-up in each year, resulting in a large negative 2005, the value of which largely off-sets the increase in cost caused by the introduction of the ETS in the same year. Nevertheless there was a substantial decrease in the mark-up between 2003 and 2004, in the absence of the ETS. One very important caveat must be mentioned in relation to these results in relation to the price of electricity used for this assessments and subsequently used in the outcome measures in the following section, the BE Electrabel Index price is not a hourly price index but a daily index of agreed exchange prices between Electrabel and counterparties. It has therefore been necessary to make an assumption on the price of electricity in order to construct an hourly series. It was therefore assumed that the daily Electrabel Index price was the price in all hours of the day. A further exposition of this is provided in the following section relating to the outcome measures.

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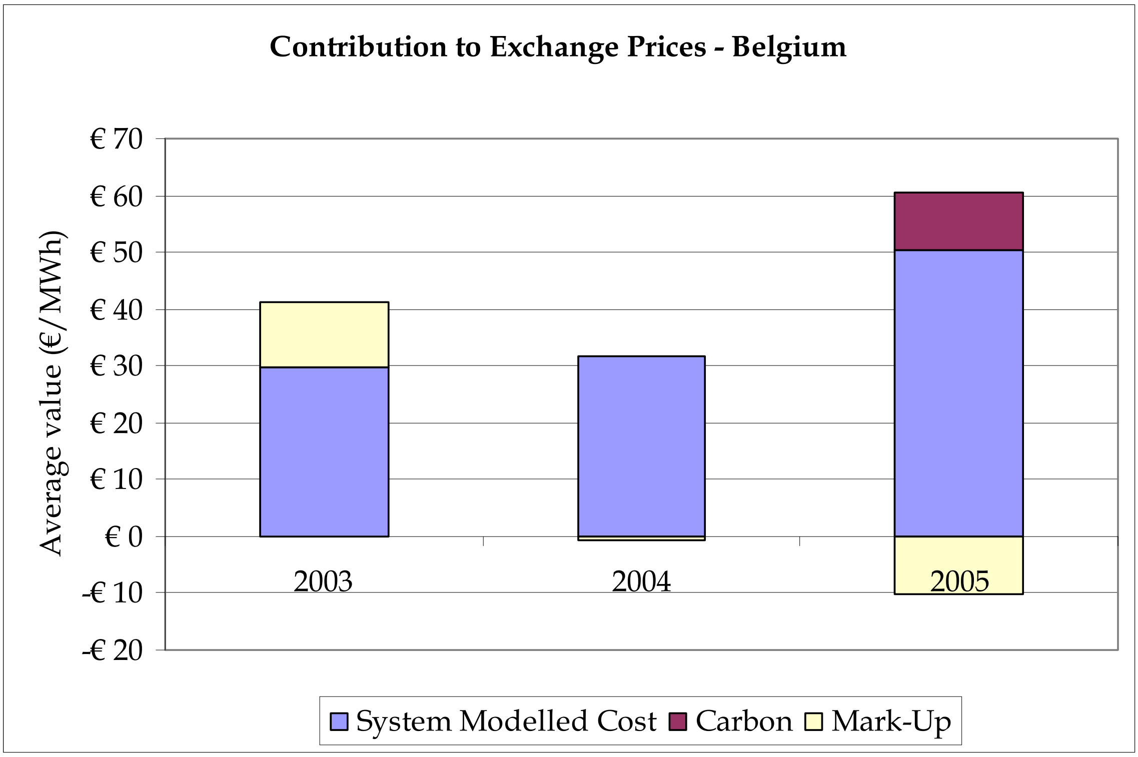
[45] The Belgian power Exchange had just begun trading at the end of 2006.

Table 4.36: Contribution of Cost, Carbon and Mark-up to BE Electrabel Index Prices			
	2003	**2004**	**2005**
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

Note: Based on load weighted average prices and costs
Source: LE

Figure 4.10 provides a graphical representation of the above table. Within each year one can see the load weighted average contributions of each of the three factors to the overall load weighted average BE Electrabel Index price.

Figure 4.10: Contribution to Exchange Prices – Belgium (2003-2005)



Source: LE

4.5 Outcome Measures

4.5.1 Price-Cost Margin (Lerner Index)

The Price-Cost Margin/Lerner Index (LI) has been calculated hourly based on the System Marginal Cost and the publicly available price of electricity for each hour in the period 2003-2005. The formula for the LI is as follows;

$$LI = \frac{P - MC}{P}$$

However, the use of a simple average has been rejected in favour of a load-weighted-average approach. Therefore, a more accurate description of the above equation is to consider each of the variables to be load weighted averages of the relevant period. A more formal exposition of this approach is presented in the methodology chapter of this report.

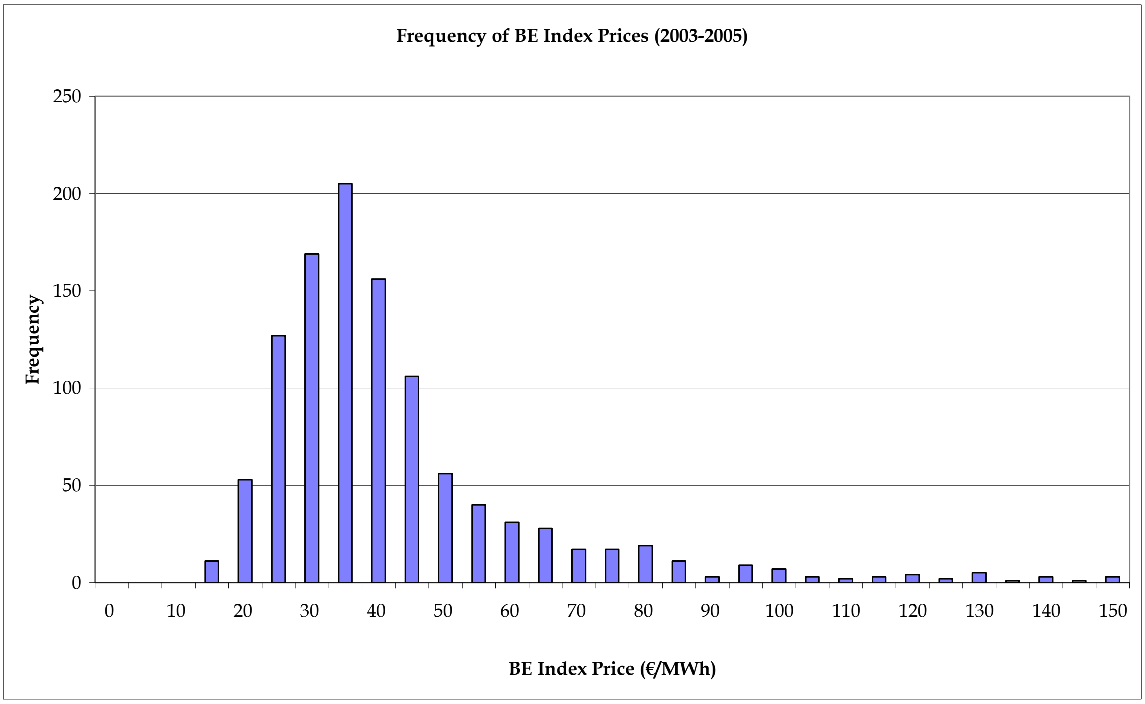
Two different sets of prices are used for this analysis;

1. Day ahead base and peak prices published by Electrabel (BE INDEX).
2. Platts Assessments Prices – this data set provides a daily base and peak price for the majority of weekdays in the period and a base price for electricity at weekends.

At this stage, it is important to consider the appropriateness of either the Electrabel Belgian price index and the Platts assessment prices. In terms of the general applicability of either price, we would desire that the prices be reflective of supply and demand conditions in every hour, in comparison to our marginal cost estimates. A first shortcoming is that neither of these indices is hourly. A question is then how useful or how much can be learned from margins using these price indices.

A frequency distribution will show the range of prices over the sample period. The frequency of the daily aggregate day-ahead prices (€/MWh) on the BE Electrabel Index price over the period of the study is presented in the following histogram. The figure does not show anything in particular[46], other than the fact that in a small number of hours, very high prices are possible.

Figure 4.11: Frequency of BE Index Prices (2003-2005)



Source: LE

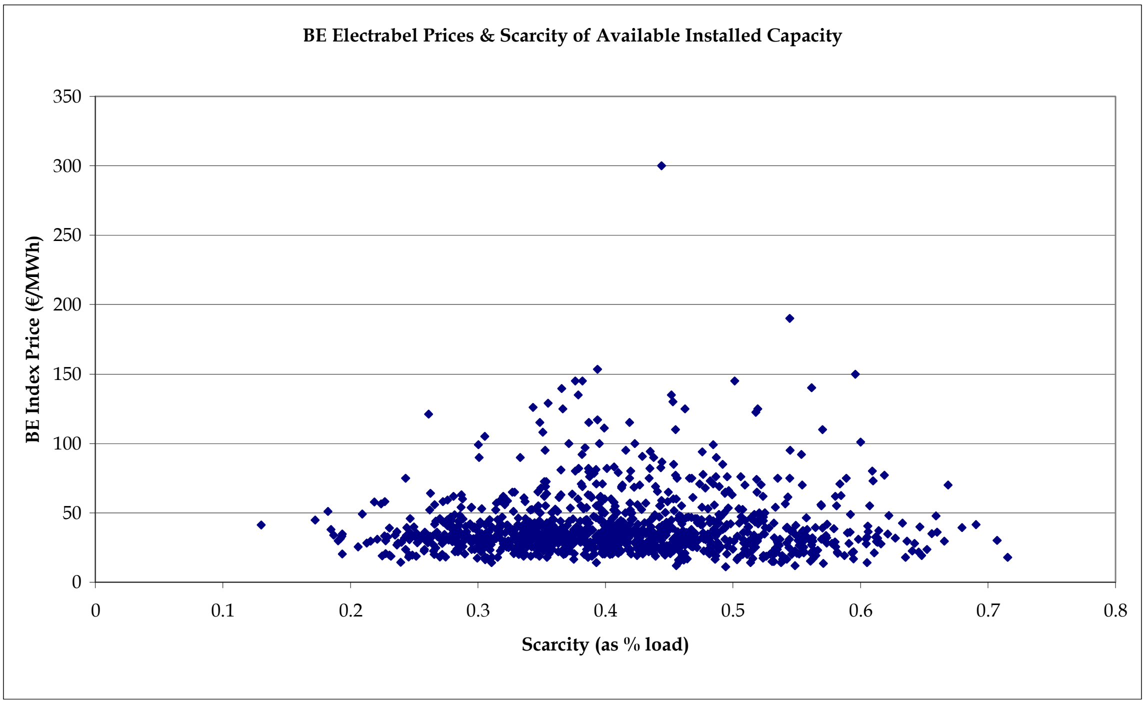
[46] It has an approximate log-normal shape—i.e., skewed to the right with a single peak.. The log-normal distribution is common to model strictly positive time series such as exchange prices.

In general, it is useful to consider the appropriateness of a candidate price for our margin analysis in every hour. For the Electrabel Index price to be considered a relevant price for electricity in Belgium it should be seen to reflect changing market dynamics within the Belgian electricity market. In general, to the extent that marginal cost in electricity naturally would rise as demand reaches peaks due to the trade-off between thermal efficiency and capital cost in electricity generation technology, the price of electricity on the Electrabel Index price should reflect the scarcity of available generation capacity in any one hour on the system. In other words, the price should rise with scarcity and peakiness of the system based on the slope of the merit curve. Unfortunately given the absence of an hourly price from the Electrabel Index, it is not likely that there will be a significant relationship between the prices posted on the Electrabel Index and the hourly variation in scarcity, computed using the following formula.

$$Scarcity_i = \frac{(ac_i - hourly\_generation_i)}{hourly\_generation_i}$$

This subsequent graph represents the relationship between the hourly price of electricity on the Electrabel Index price, one of two price points per day price stretched over each relevant hour, and the scarcity of available generation capacity, expressed as a percentage of the load (sum of generation) in that hour.

Figure 4.12: Belgium (Electrabel Index Price) & Scarcity of Available Generation Capacity



Source: LE

The absence of a discernable correlation between the price variable and scarcity may lead one to question the applicability of this price stream to further analysis in this market. Other issues lead one to question it further.

The most important element of understanding the value of the BE price index is to recognise its relationship to the concentration in the market and how it is defined. Effectively, Electrabel sets a price and a quantity that is sold in the market daily. The quantity and price are thus effectively set by an operator with approximately 90% of the market share. Further, the quantity is well less than anywhere near the total quantity sold daily in the market. Thus, when one observed the outcomes, the price does not represent any kind of normal interaction between supply and demand (i.e., where if price rises more supply comes in and (demand falls); and if price falls, less supply comes in (and demand rises[47]). It is precisely the supply and demand interactions, when they set price, that makes a market price such an important benchmark, because the price contains information about the economic cost/value of supply and demand.

However, given the manner in which the series is constructed it will provide a reasonable proxy for the majority of the electricity sold in the Belgian market under tariff and contract agreements, at least for our current purposes. The series will therefore be used for the purpose of constructing the outcome measures but it will impose limitations on further work such as any regression analysis. We have not estimated regression models for Belgium using the BPI.

In addition to the Electrabel Index price the Platts assessment price of electricity in Belgium shall also be used in calculations of the LI and mark ups. This price series provides a base and peak price for electricity on a daily basis on weekdays and a base price for electricity on weekends. As this price is constant for all hours of base and peak in the relevant days, this price may be a more appropriate representation of the price of electricity contracted forward (over periods greater than a day) in Belgium, a quantity considerably greater than that traded on a day-ahead basis. Alternatively, the Platts price is not reflective of hourly fluctuations in scarcity. Finally, forward prices may contain forward premia for risk, or merely the risk free rate of interest which are natural and not indicative of market power use (and thus would show up in margins). The Belgian margins based on the Platts prices therefore should be interpreted with caution. We nonetheless include the Platts price analysis as an alternative price measure.

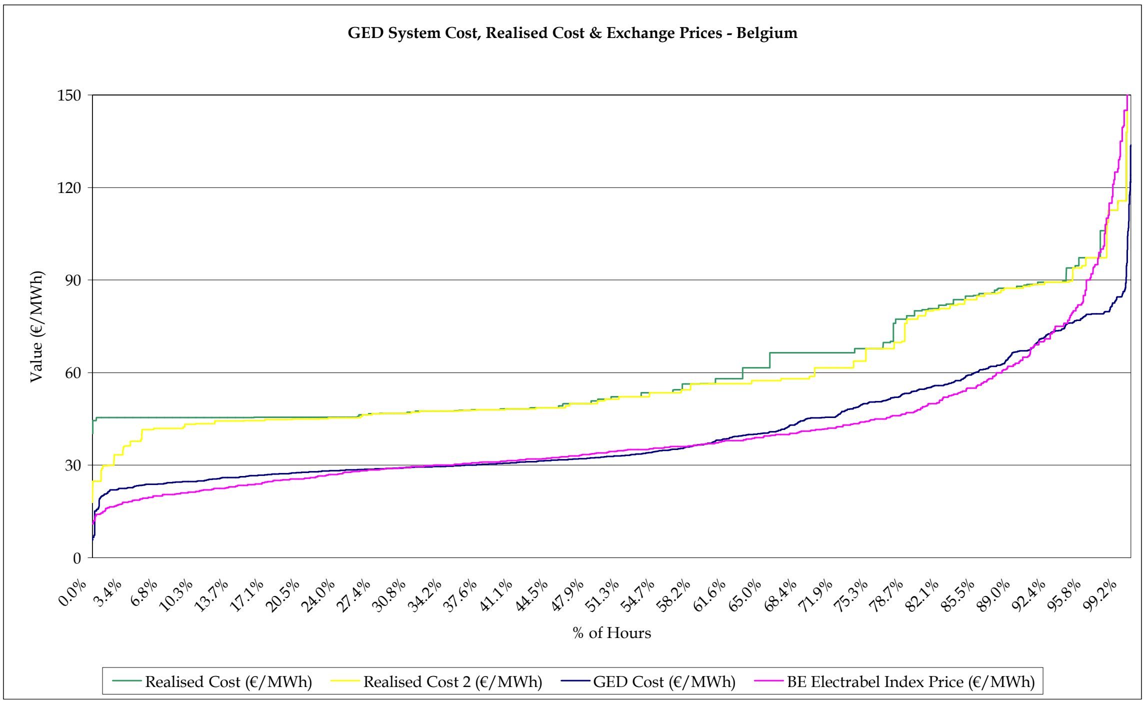
[47] There is likely some degree of demand response even in electricity markets; some contracts have demand response clauses; some pumped storage might not pump up if the price is high at night; exports might be reduced as well.

The analysis also considers three different cost estimates for the system;

1. The System Cost estimated as part of GED's optimal despatch run.
2. A simple stacking of the returned realised cost of generation (fuel cost) provided for each unit, with the highest cost unit generating in any one hour setting the system marginal cost. This cost only considers the fuel cost of generation. (Realised Cost)
3. Same as 2, with all units with capacity less than 25 MW, or designated must-run or CHP removed from the analysis. (Realised Cost 2)

The relationship between these two series can be seen in Figure 4.13.

Figure 4.13: Comparison of GED System Modelled Cost, Realised Cost and Exchange Prices – Belgium (2003-2005)



Source: LE

As one can see from this graph, the maximum system realised cost of generation returned by the companies is greater than the system marginal cost estimated by GED's optimal despatch simulation. There are a number of potential reasons for this. Simple stacking models are unable to reflect many market conditions in electricity markets. Unit-specific characteristics may require units to run but not set the price, "must-run" units or units that are run to provide system balancing or reserves may have a cost greater than the system marginal cost but as these units are not being despatched they do not affect the price. The fact that must run, CHP, and other such units "should" not set the price is common to electricity market marginal cost estimation. This may similarly be the case for some CHP units whose primary function is to provide heat and for whom electricity production is a by-product. These units are not seen as economically relevant price setters because in general they are not representative of capable of providing the next megawatt of energy on the system. Further, in the case of many units, energy is a joint product with other products, and the true marginal cost of energy is economically only the additional cost of production of energy, after the primary product has been produced. Nevertheless, both costs are represented within this analysis.

The Realised Cost 2 curve, also precludes units with capacities of less than 25MW from setting the system marginal cost. These units have been aggregated by companies in their responses' to DG Competition's data request as part of the Sector Inquiry. Both costs and generation output have been aggregated by technology and there is no indication as to whether any of the constituent units are must run. The costs returned by companies are also potentially inclusive of a number of other costs not included in the calculation of the €/MWh fuel cost undertaken on a monthly basis for all other units (those greater than 25MW). Therefore these units have been removed from possibly setting the system cost in the simple stacking model for Realised Cost 2 as it was not possible to determine if only fuel costs were reported and more importantly whether these units were must-run or CHP units, the reason for excluding the other units as part of Realised Cost 2.

One may also notice that there are a number of hours where the GED modelled system cost is greater than the BE Electrabel Index price, thus indicating that there are a number of hours where companies' cost of generation in a competitive environment is in excess of the observed power exchange prices. This result is partly explained by the limitations of the price data available for Belgium. However, part of this can also be explained by recourse to reasons similar to those discussed previously in relation to the divergence between the GED modelled cost and the realised costs of units. Power exchange prices can be representative of the residual values of energy on the system and since in reality, electricity that is placed on the grid can often be produced as a joint product with electricity committed to long-term supply contracts, ancillary services, electricity and heat for on-site industrial processes, and general heat production. Additionally, generators might rationally be willing to pay to avoid shutting down and incurring stop and start costs, thus resulting in them effectively dumping electricity on the system. Furthermore, there are technical and operational reasons power plant operators may wish to avoid shutting down and starting on a daily/frequent basis, such as wear and tear on the machine and the increased probability of a forced outage. This result has similarly been found previously in studies of electricity markets in Europe and the US.

Summary statistics on the both the GED System Cost and the Realised Cost are provided in Table 5.37.

Table 4.37: Comparison of GED System Cost & Realised Cost - Belgium					
		Average	**Minimum**	**Maximum**	**St Dev**
2003-2005	*GED System Cost*	€ 40.32	€ 5.70	€ 133.81	€ 16.99
	Realised Cost	€ 60.84	€ 40.34	€ 276.33	€ 20.22
	Realised Cost 2	€ 58.76	€ 17.94	€ 276.33	€ 20.68
2003	*GED System Cost*	€ 29.42	€ 7.10	€ 70.72	€ 5.71
	Realised Cost	€ 49.81	€ 40.34	€ 114.18	€ 6.56
	Realised Cost 2	€ 47.55	€ 17.94	€ 114.18	€ 7.16
2004	*GED System Cost*	€ 31.42	€ 6.54	€ 105.99	€ 6.07
	Realised Cost	€ 50.65	€ 44.42	€ 177.99	€ 12.80
	Realised Cost 2	€ 48.62	€ 24.86	€ 177.99	€ 11.35
2005	*GED System Cost*	€ 60.15	€ 5.70	€ 133.81	€ 14.36
	Realised Cost	€ 82.09	€ 66.50	€ 276.33	€ 18.52
	Realised Cost 2	€ 80.15	€ 50.98	€ 276.33	€ 20.42

Source: LE

In general, the realised cost 2 is on average about €18 higher than the system marginal cost over the period 2003-2005, while the absolute realised cost is slightly higher still. Also, it can be seen that marginal costs have risen substantially from 2003 to 2005, regardless of the measure. This is in general due to rising fuel prices.

4.5.2 Results

GED Modelled System Cost and BE INDEX Prices

Table 5.40 presents the average of the Lerner Index values estimated for Belgium based on the load weighted average system marginal cost returned by the GED optimal despatch simulation and the BE Index price[48].

Table 4.38: Average LI based on GED System Marginal Cost & BE Electrabel Index Prices (including carbon)

	2003-2005	2003	2004	2005
Lerner Index	0.1%	27.5%	-2.3%	-20.4%

Note: Based on load weighted average prices and costs
Source: LE

Table 4.39: Average LI based on GED System Marginal Cost & BE Electrabel Index Prices (excluding carbon)

	2003-2005	2003	2004	2005
Lerner Index	8.5%	27.5%	-2.3%	0.2%

Note: Based on load weighted average prices and costs
Source: LE

The tables above indicate a sharp drop in margins from 2003 to 2004, followed by an equally large drop in 2005 when carbon costs are taken into account.

GED Modelled System Marginal Cost and Platts Assessment Prices

Table 5.42 presents the load weighted average LI calculated using Platts Assessment prices. This series of prices only begins in 2004. The load weighted average LI based on Platts Assessment prices similarly shows a large drop in margins in 2005.

[48] Recalling the difficulties with price.

Table 4.40: Average Lerner Index based on GED System Marginal Cost & Platts Assessment Prices (Day-Ahead) - Belgium				
	2004-2005	**2003**	**2004**	**2005**
Lerner Index	-11.8%	-	0.0%	-18.8%

Note: Based on load weighted average prices and costs
Source: LE

4.5.3 Price Cost Mark-Up

An alternative measure of margin is the price cost mark up. As with the Price-Cost Margin/Lerner Index, the Price-Cost Mark-Up (PCMU) has been calculated based on the GED System Cost and the publicly available price of electricity for each hour in the period 2003-2005. The formula for the PCMU is as follows;

$$PCMU = \frac{P - MC}{MC}$$

As with the Lerner Index, the use of a simple average is rejected in favour of a load weighted average approach. Therefore, a more accurate description of the above equation is to consider each of the variables to be load weighted averages of the relevant period. A more formal exposition of this approach is presented in the methodology chapter of this report.

4.5.4 Results

Price-Cost Mark-Up based on GED Modelled System Marginal Cost and BE INDEX Prices

Table 5.43 presents the Price Cost Mark-Up (PCMU) values estimated for Belgium based on the load weighted average system marginal cost returned by the GED optimal despatch simulation and the BE INDEX price. The following table returns this excluding the impact of carbon in 2005.

Table 4.41: Average PCMU based on GED System Marginal Cost & BE Electrabel Index Prices (including carbon)

	2003-2005	2003	2004	2005
Price-Cost Mark-Up	0.1%	38.0%	-2.2%	-16.9%

Note: Based on load weighted average prices and costs
Source: LE

If one excludes the economic cost of carbon from the calculation of the mark-up in 2005, one can see that the figure drops from -16.9% to -0.2%, relative to the carbon case. The results of the calculation of the PCMU, excluding the cost of carbon in 2005 is presented in Table 4.42.

Table 4.42: Average PCMU based on GED System Marginal Cost & BE Electrabel Index Prices (excluding carbon)

	2003-2005	2003	2004	2005
Price-Cost Mark-Up	9.3%	38.0%	-2.2%	-0.2%

Note: Based on load weighted average prices and costs
Source: LE

Price-Cost Mark-Up based on GED Modelled System Marginal Cost and Platts Assessment Prices

Table 5.45 presents the PCMU calculated using the load weighted average Platts Assessment prices and GED system marginal cost.

Table 4.43: Average PCMU based on GED System Marginal Cost & Platts Assessment Prices (Day-Ahead) (including carbon) - Belgium

	2004-2005	2003	2004	2005
Price-Cost Mark-Up	-10.5%	-	0.0%	-15.8%

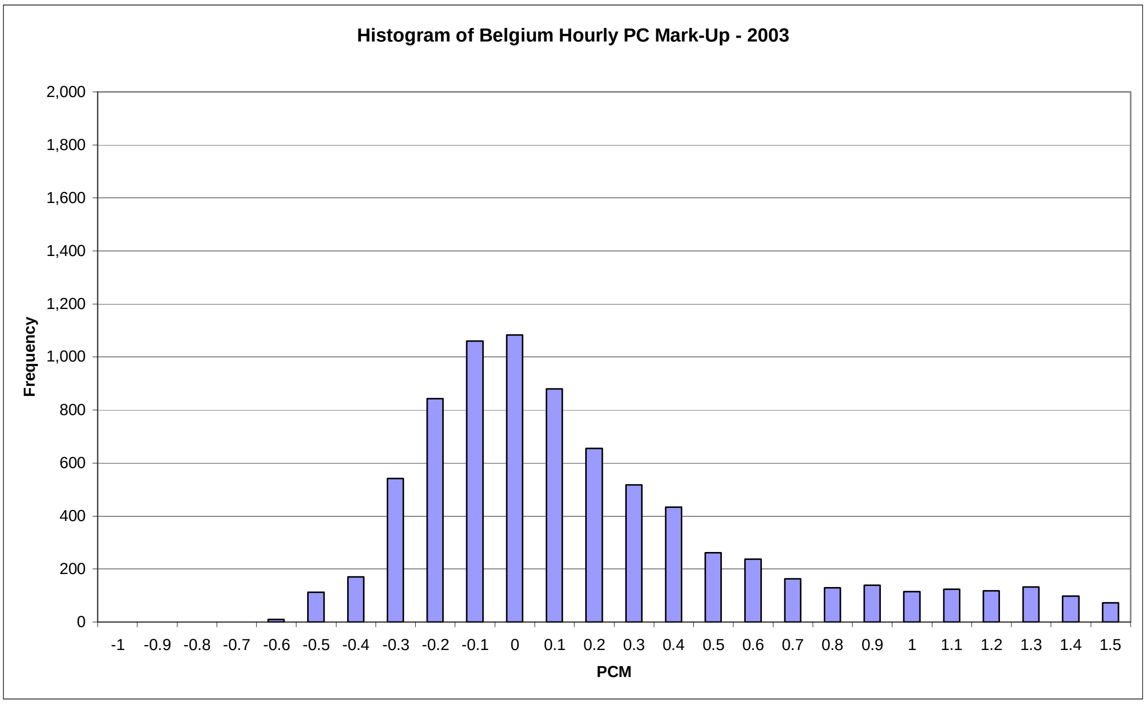
Note: Based on load weighted average prices and costs
Source: LE

Qualitatively, the price cost mark ups are similar to the LIs. There appears to have been steep decline in margins in 2005, and as one might expect carbon appears to have reduced margins. This may be due to it not being priced in fully by companies, however one cannot draw solid conclusions on the basis of these results due to the previously mentioned caveat on the BE Electrabel Index price series and its inability to reflect the hourly variation in market conditions.

4.5.5 Hourly PCM Histograms

The following figures present the histograms of the hourly PCM value in each year. In Belgium, as we do not have hourly price figures, these are created using the daily index prices applied to the hourly marginal cost estimates. The effect of this will be to smooth out price spikes during a few peak hours during the day. Thus we would expect the true distribution to show more spread. These figures are based on the actual values returned in each hour and are not weighted by the load in that hour. Given these figures are also based on the BE Electrabel Index, it is once again subject to caution in interpreting the results.

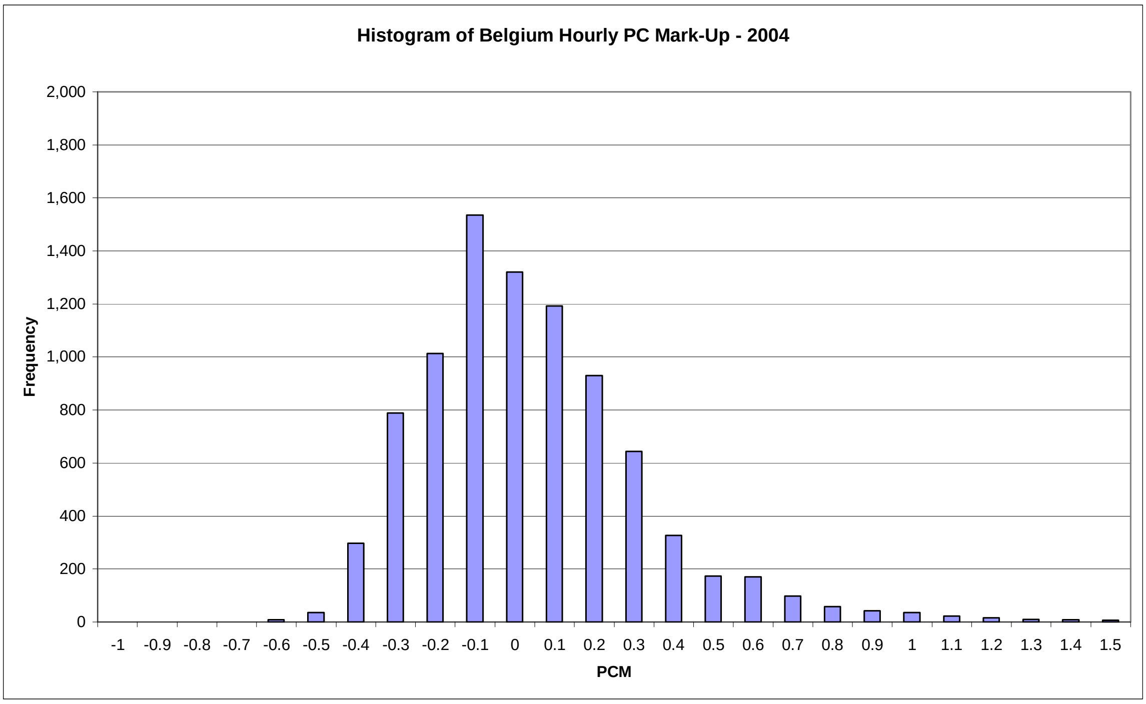
Figure 4.14: Histogram of Belgium Hourly Price- Cost Mark-up - 2003



Note: N=7,898

Source: LE

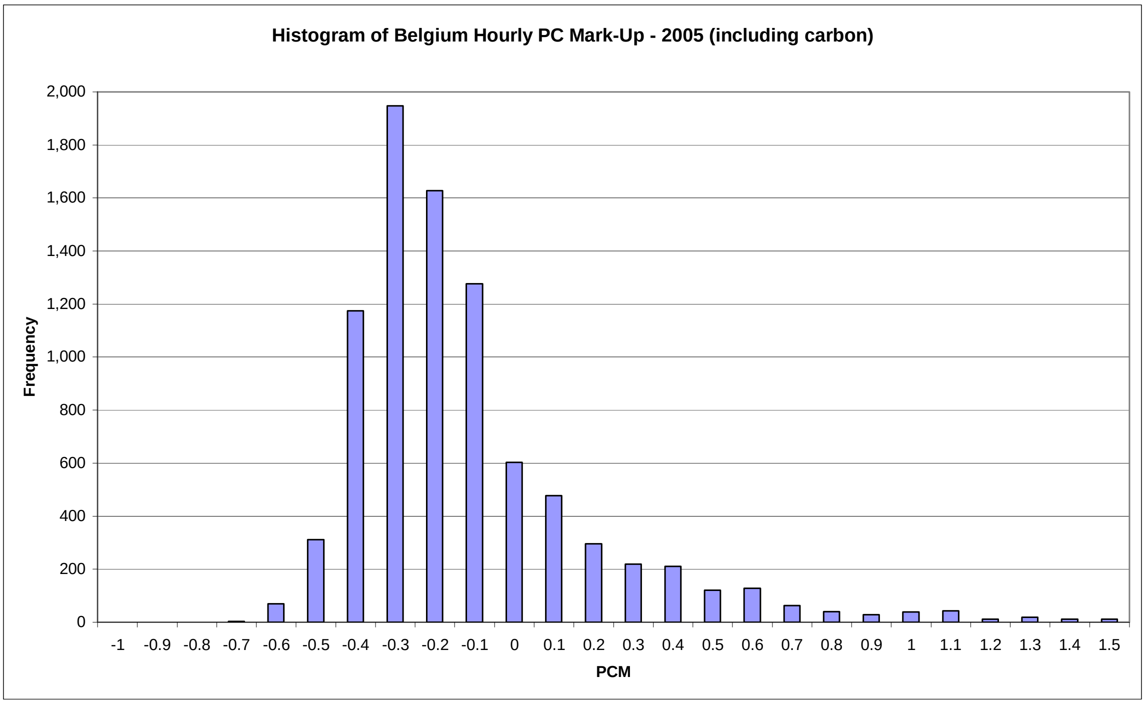
Figure 4.15: Histogram of Belgium Hourly Price- Cost Mark-up - 2004



Note: N=8,737

Source: LE

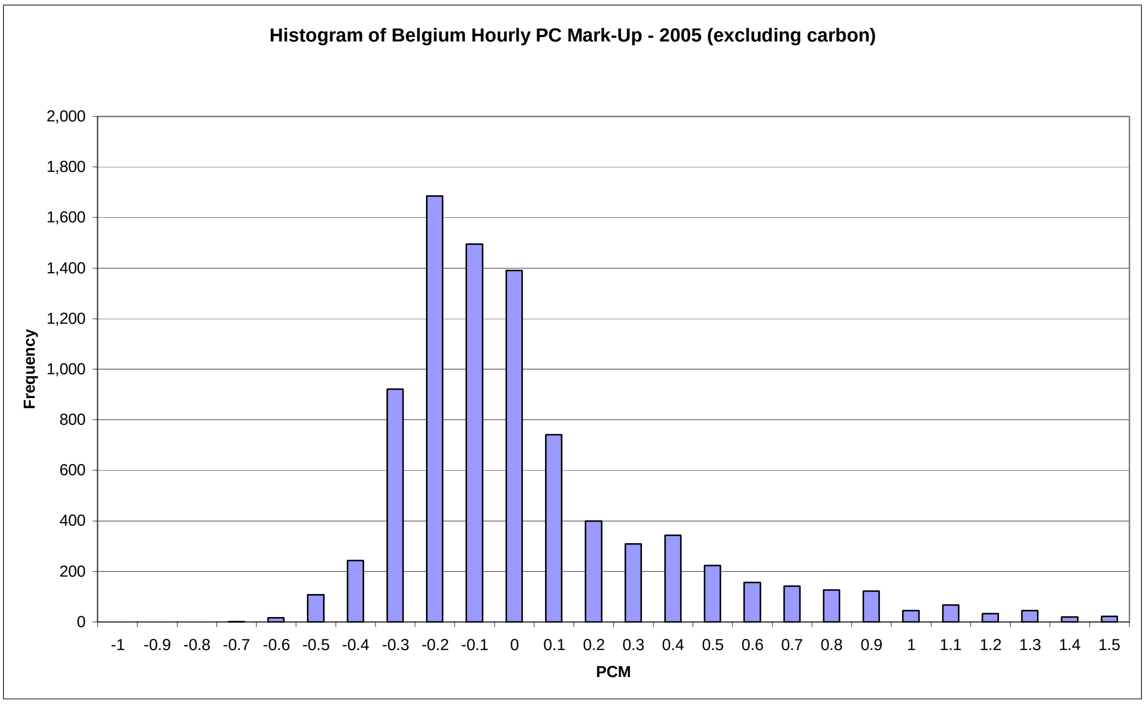
Figure 4.16: Histogram of Belgium Hourly Price- Cost Mark-up – 2005 (incl. Carbon)



Note: N=8,726

Source: LE

Figure 4.17: Histogram of Belgium Hourly Price- Cost Mark-up – 2005 (excl. Carbon)



Note: N=8,654

Source: LE

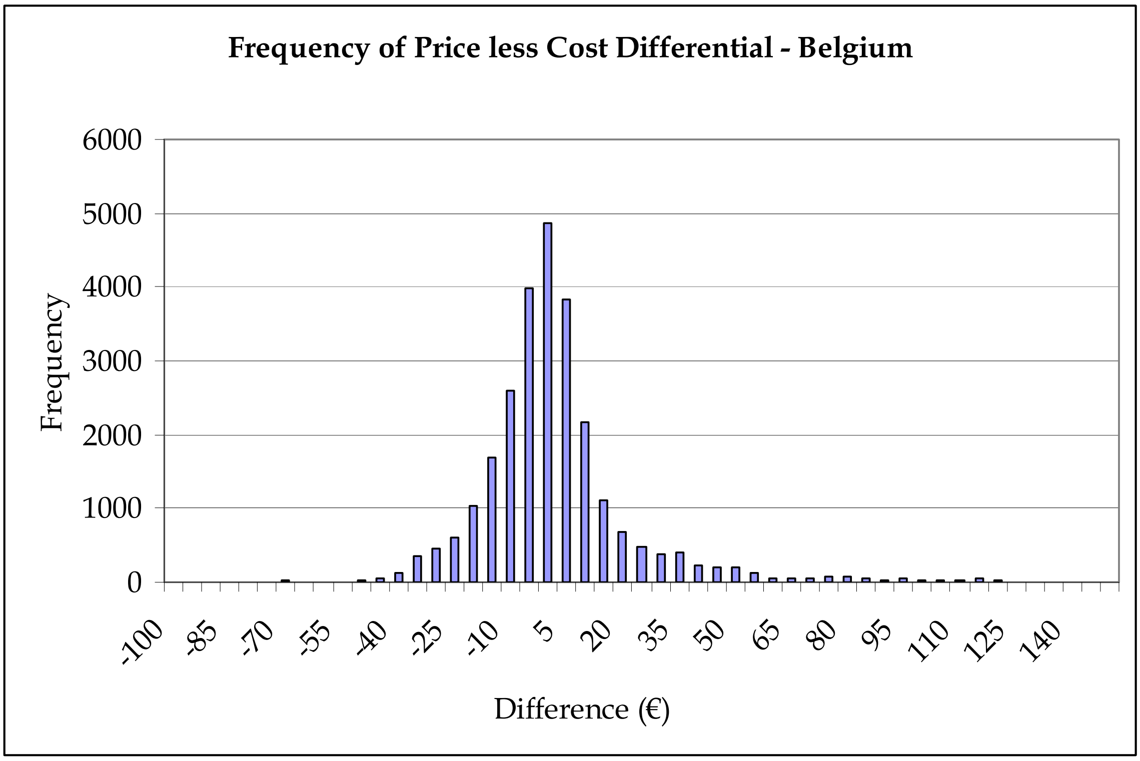
The histograms show the distribution of mark-ups across hours in the year. A few points deserve mention. First, the number of hours is somewhat less than 8760 in some cases due to missing values, mainly on price. Second, the distributions exhibit an expected amount of right skewness (large values to the right of the mean possible). This is common as price spikes are possible but prices themselves are bounded below by zero (although hourly spikes are not possible with the BE price data).

The mark-up measures themselves can be below zero, and in a significant number of hours this is the case. This is not too surprising for a number of reasons. First, a number of previous studies have found a similar finding. Second, it is likely that, given that a unit is running, it is rational to be willing to pay a premium (run at unit cost rather than purchasing at market) to avoid shutting down. This is due to many factors, including the fact of start costs and uncertainty of being redespatched. There also may be engineering or other reasons to avoid shutting the plant and restarting it frequently, such as risk of forced outage. Therefore, running at cost above the market price in certain hours is not surprising.

4.6 Price Cost Differential

Underlying both the LI and PCMU analysis is the basic relationship between Price and Cost. The following graph represents the frequency, over the three year period, of the difference between the bi-daily BE Electrabel Index Price, stretched over the relevant hours of each day, and the System Marginal Cost estimated by GED as a result of their optimal despatch simulation.

Figure 4.18: Frequency of Price *less* Cost Differential - Belgium



Source: LE

From the distribution, again it appears to be skewed right, indicating some probability of very high mark ups. At the same time, the vast majority of mark ups are between about -10 and 10 €/MWh, with the most frequent occurrences being between about -5 and 5 €/MWh. The mean, median and mode of the distribution is apparently greater than zero.

Regression analysis was not carried out for Belgium, as it was our opinion that the available price variables did not adequately capture variations in the supply and demand for electricity and market conditions. This combined with the fact that the structural evidence is unequivocal in terms of the concentration of the market led us to conclude that the regression analysis was not appropriate for Belgium.

4.7 Carbon Impact in 2005

As is apparent from the previous analysis, the cost of carbon is included in the GED optimal despatch model for 2005 in order to take account of the introduction of the ETS in that year. In order to quantify the impact of the introduction of this scheme, the GED optimal despatch model of 2005 has been compared with a scenario model of that year, within which the cost of carbon is reduced to zero. Not only will this affect the unit costs of emitting stations but it will also alter the optimal system dispatch. Table 4.44 presents, for selected months, the modelled difference between the load weighted average system marginal cost in the model that includes the full economic cost of carbon and the alternative scenario where the cost of carbon has been reduced to zero.

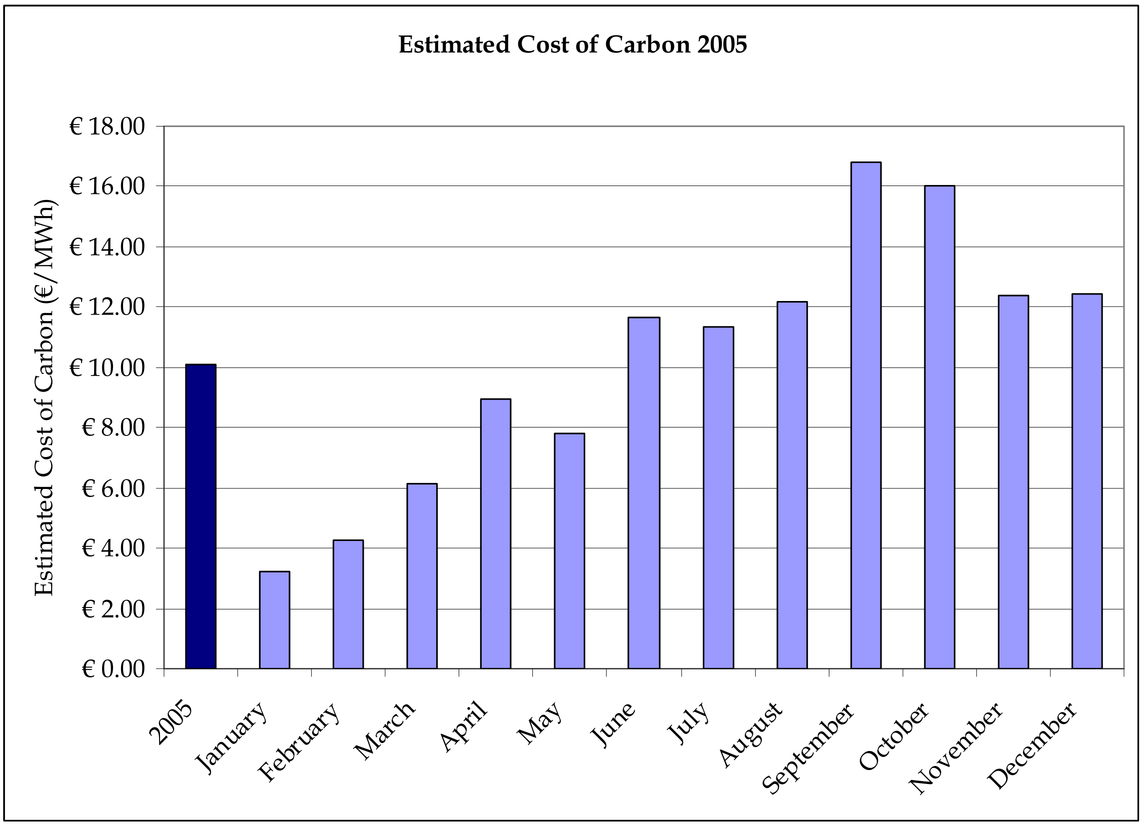
Table 4.44: Summary Statistics on the Modelled Impact of Carbon in 2005 - Belgium

	2005	January	April	August	October
Average	€ 10.11	€ 3.24	€ 8.97	€ 12.19	€ 16.02

Note: Based on load weighted average prices and costs
Source: LE

Figure 4.19 presents the evolution of this differential over the year. As one can see the overall cost of carbon is estimated to have increased in almost every month from the introduction of the scheme in January through to September at which point, over €16/MWh, it began to moderate through the remaining 3 months to still a considerable level of just over €12/MWh.

Figure 4.19: Estimated Monthly Cost of Carbon 2005 - Belgium



Source: LE

It is important for one recall at this point the discussion presented in relation to the merit curve both with and without carbon in the introductory section of this chapter. This discussion highlighted the point that one cannot simply estimate the cost of carbon for the system based on the cost of carbon for the marginal unit as the marginal unit may potentially be different between the carbon and no-carbon merit curves as units are not monotonically affected by the ETS and the cost of carbon and in reality the ordering of units on the merit curve is likely to change as a result of including the specific €/MWh cost of carbon, for each unit.

Furthermore, the estimated impact of the introduction of the EU ETS will depend on how much of the value of CO_2 is factored in by operators, however, it has not been possible to discern this information from the data returned by the companies. Therefore, the amounts reported in this study correspond to the maximum possible impact of the ETS, if generators fully factor in the price of the CO_2 certificate in a competitive environment.

4.8 Withholding

Withholding is a strategy that may be entered into by companies in an attempt to manipulate the price of electricity on the market. Conceptually such a strategy would involve a company withholding generation capacity generally located to the left of the merit curve, but in any event it must be in merit, thus causing capacity further to the right of the merit curve, that previously was not required to meet the specific load level, to turn on an therefore set the market price at a higher level. Importantly, the capacity that is forced to come online does not have to belong to the company exercising the withholding strategy as everyone will get the same market price for electricity irrespective of who owns the unit setting the market price.

The GED model of optimal system despatch can provide the modelled hourly generation data for each specific unit. This can be compared with the actual hourly generation patterns of the units in an attempt to identify potential systematic withholding of generation assets. We note that there are a variety of reasons why the modelled generation pattern may not match the actual. One such reason, for example, could involve the possibility of multiple optima or multiple 'nearly optimal' solutions to the least cost despatch problem. Thus we cannot distinguish with too much certainty whether the measured withholding truly represents evidence of anti competitive behaviour.

Table 4.45 shows total installed capacity in Belgium broken-down by generation technology.

Table 4.45: Total Installed Capacity, by Technology - Belgium

Gas	Coal	Nuclear	Pump storage	Other	Total
4,962	1,931	3,953	1,300	999	13,145

Source: LE

Table 5.48 presents the number of hours and the percentage of time that modelled generation exceeded actual generation, on an hourly basis. On average over the period of the study the modelled generation of both the nuclear and coal fired technologies of company 0513-S-BE exceeded the actual reported generation, more than 50% of the time. For the more expensive gas fired technologies one can see that for this company the actual exceeded the modelled in almost 75% of the hours over the three years. Qualitatively this pattern is repeated is repeated for the first two years of the study, 2003 and 2004. However, in 2005 the quantity of gas fired generation actually produced was less than that modelled in 64.4% of the time and for coal fired generation actual generation exceeded the modelled quantity over 90% of the time. During 2005 the pattern in relation to nuclear power generation remained relatively stable.

Table 4.46: Potential Withholding, by Technology, for 0513-S-BE, (Number of hours where modelled is greater than actual generation)

	Gas	Coal	Nuclear	Pump Storage	Other
2003-05	6,655	15,563	19,955	1,299	12,208
% hrs<0	25.3%	59.2%	75.9%	4.9%	46.4%
2003	122	8,449	7,238	423	7,180
% hrs<0	1.4%	96.4%	82.6%	4.8%	82.0%
2004	893	6,375	6,511	431	4,374
% hrs<0	10.2%	72.6%	74.1%	4.9%	49.8%
2005	5,640	739	6,206	445	654
% hrs<0	64.4%	8.4%	70.8%	5.1%	7.5%

Source: LE

Considering the number of hours modelled generation exceeded actual generation is somewhat unjustified without placing the results in a context that allows one to not only see that a difference exists but also to assess the size of the difference before concluding that there is potentially a problem in relation to the observed pattern of generation reported by the company. With a view to addressing this issue Table 5.49 presents the average difference between actual and modelled generation, by technology, for Company 0513-S-BE.

Table 4.47: Potential Withholding (MW), by Technology, for 0513-S-BE

	Gas	Coal	Nuclear	Pump storage	Other	Total
2003-05	415	7	-135	96	4	387
2003	817	-350	-190	89	-75	291
2004	571	-159	-107	98	-6	396
2005	-145	529	-108	103	93	472

Source: LE

Combining the results of the two tables one can begin to assess the extent to which this company may over or under utilised its capacity, categorised by technology, relative to the optimal despatch scenario modelled using GED software. Firstly, one notices the quantity by which the actual generation reported for gas fired capacity by company 0513-S-BE is in excess of the modelled quantity. This figure represents 415MW, on average, in every hour of the threes years for which we know the actual exceeded the modelled in approximately 75% of hours. On average the quantity of difference represents approximately 8.4% of the installed gags fired capacity in Belgium. It is not an insignificant amount. The nuclear powered capacity in Belgium consistently reported both a similar frequency and quantity, on average, that the quantity modelled generation exceeded the actual generation. This is not discussed further in this section due to a number of problems encountered in the modelling process in relation to nuclear capacity. From the data available it does not appear to be sufficient to account for all of the technical and operational limitations on nuclear capacity. Nevertheless, this does not say there is not a problem here just that it cannot be specifically identified.

Finally if one considers the results in relation to the coal fired technology and the average quantity of withholding, one can see that on average over the period the difference is insignificant however this average masks the unusual annual pattern that is similarly observed in relation to gas fired technology in 2005. The results of 2003 indicate that on average 350MW of coal fired generation that was modelled to have been optimal to generate, was not generated. This figure represents approximately 18% of the installed coal fired capacity in Belgium.

The results in relation to the gas and coal fired generation profiles of company 0513-S-BE in 2003 and 2004 may warrant further investigation in relation to uncovering the reasons for such a result as that found in here. There are a number of operational and technical reasons both in relation to the units and the modelling of the system that may lead one to such a conclusion. Such an investigation to rule out possible price manipulation is not the focus of this study and thus this issue is left for a more thorough investigation of the facts if such an investigation is deemed warranted.

In relation to company 1449-S-BE, Table 5.50 presents the number of hours and the percentage of time that modelled generation exceeded actual generation. The table shows that the company's gas units generated below their modelled optimal output for most of the period under investigation.

Table 4.48: Potential Withholding, by Technology, for 1469-S-BE, (Number of hours where modelled is greater than actual generation)

	Gas	Coal	Nuclear	Pump Storage	Other
2003-05	22,035	-	-	-	8,885
% hrs<0	83.8%	-	-	-	33.8%
2003	6,007	-	-	-	975
% hrs<0	68.6%	-	-	-	11.1%
2004	7,427	-	-	-	730
% hrs<0	84.6%	-	-	-	8.3%
2005	8,601	-	-	-	7,180
% hrs<0	98.2%	-	-	-	82.0%

Source: LE

The average hourly amount of potential withholding for Company 1469-S-BE is shown in Table 5.51. The results presented both here and in the previous table indicate that company 1449-S-BE is consistently under-utilising its generation portfolio. Once again the precise reason for this result cannot be determined at this stage and there is a reasonable caveat to be taken into account in relation to the modelling of the system based on the data returned. Nevertheless, this result may also warrant further investigation in order to explain such a result in a market wherein this company is trying to compete with a far larger rival.

Table 4.49: Potential Withholding (MW), by Technology, for 1469-S-BE						
	Gas	**Coal**	**Nuclear**	**Pump storage**	**Other**	**Total**
2003-05	-243	-	-	-	-13	-256
2003	-164	-	-	-	4	-161
2004	-267	-	-	-	3	-264
2005	-296	-	-	-	-46	-342
Source: LE						

4.9 Conclusions

We keep our conclusions on Belgium brief. Belgium is the smallest of the markets we studied, with capacity of only just over 13,000MW. Belgium is one of the most concentrated markets studied, with CR(*n*) and HHI both near their maximum values of 90% and 10,000. There is no sensitivity of these results to the assumptions about interconnection and contracts.

Margins in Belgium must be interpreted with caution, as no exchange price was available on an hourly basis. Nonetheless in some hours very large margins were found. Further, substantial margins on average were found in 2003, but in 2004 and 2005 near zero margins to slightly negative margins were found on a weighted average basis. It is not clear whether this is due to carbon or fuels or both, but according to our calculations breaking down the prices, the increase in the price due to carbon was largely offset by a reduction in margins. On a cashflow basis, this may be due to the receipt of carbon allowances for free. Additional measures were used to study the market structure in more detail. The RSI and PSI showed the largest operator to be pivotal in 100% of hours. Regression analysis and contribution to fixed costs were not done because of the lack of hourly data on price, and the fact that the market structure was already so concentrated.

5 France

5.1 Introduction to the French Electricity Market

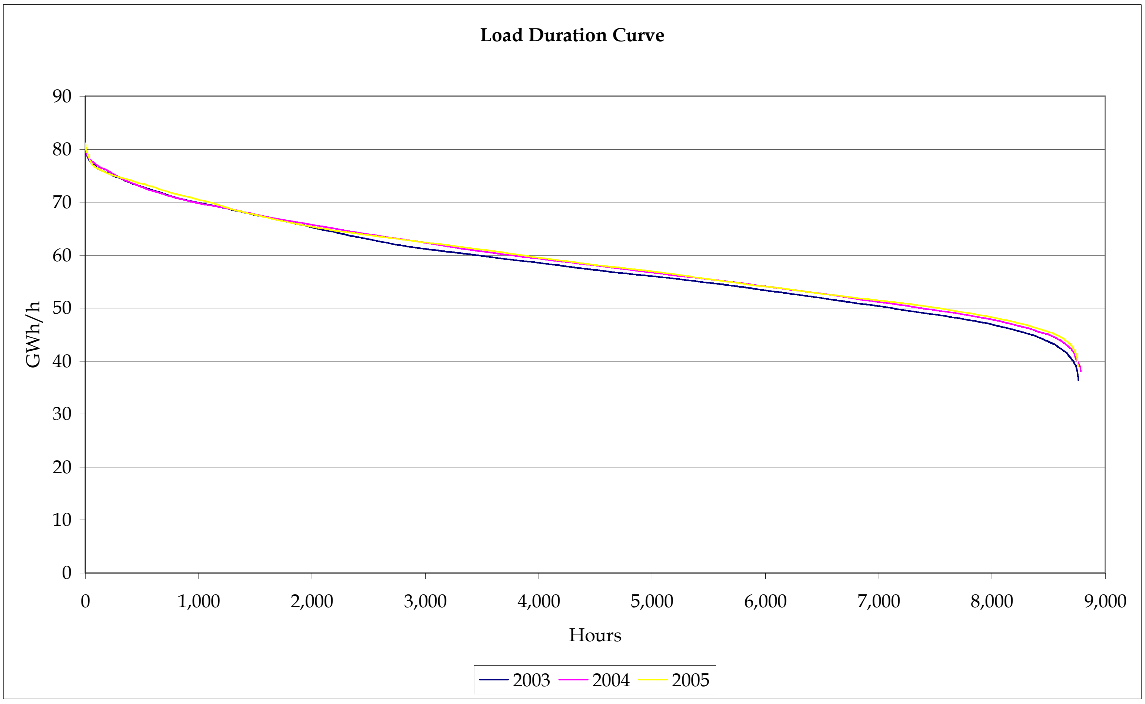
France's electricity market was the largest market we studied on an installed capacity basis. Indeed, France is one of the largest interconnected centrally despatched systems in the world. France's electricity market and technology profile are also quite unique. France has the highest percentages of nuclear capacity in the EU, and also a high percentage of storage and pumped storage hydro. In terms of market structure, France was the most concentrated market we studied.

5.1.1 Load Duration Curve

The load duration curve of the French electricity market is an ordered ranking of the electricity demanded in each hour of each year. The load is presented in descending order for each year allowing the reader to quickly determine the amount of hours in each year that demand in France (FR) is above the scale on the vertical axis. Figure 5.1 presents the load duration curve for each of the three years of the study. According to this graph, the distribution of demand between its peak and its minimum remained relatively stable since 2003.

Importantly, this load represents the constructed load, described in the methodology chapter of this report as the sum of generation over all units in each hour, and this measure of load is the one used for the purpose of this report. The hourly load included within this report is not that reported by the TSO (RTE). This approach was adopted so that the results of both the modelling and analysis are accurate and consistently reflect the market for which data is available. Given the quality and quantity of data collected by DG Competition as part of the Sector Inquiry, it means that only small companies with small non-peaking (price setting) units are not contained in our analysis. However to include the demand for electricity potentially served by these units, contained in the TSO load, and not to include them in the formal modelling and analysis would have created an over utilisation of the capacity in the market, represented by all other companies and units. As previously discussed in the methodology chapter, this approach also accounts for flows over the interconnectors with neighbouring countries.

Figure 5.1: Load Duration Curve - France



Source: LE

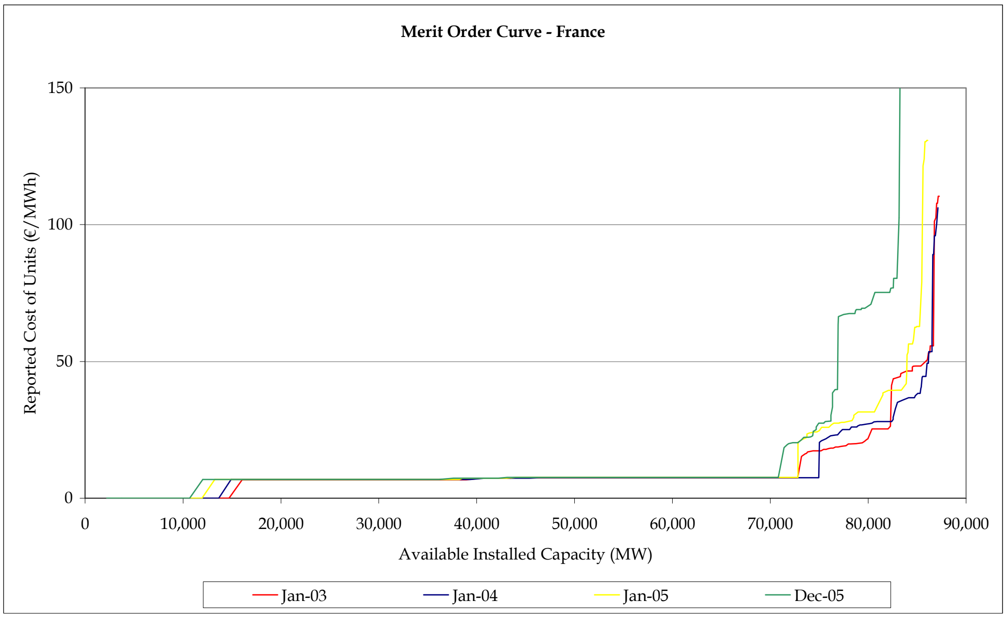
5.1.2 Merit Order Curve

The merit curve is an ascending ordering of the available installed capacity in the system, based on the marginal cost of generation (€/MWh) for each unit on the system. The merit curve can shift based on availability, fuel prices, etc, and thus is specific to a time period or an average. In this instance the merit curve was calculated by taking a monthly average of each unit's available installed capacity and the marginal cost of the unit, calculated using the fuel prices and efficiencies returned by each of the companies for each of their units. These costs are then sorted in ascending order and the corresponding average available capacities aggregated over the market.

The merit order curve for the French electricity market is presented in Figure 5.2 below. The shape of the curve is evidence of the important role played by low-cost nuclear power generation in the French market as it dominates the merit curve providing almost 70GW of available installed capacity (flat part of curve from left above zero). This shape is unique among the countries studied. The change in the shape of the merit curve in December 2005 is due to both the introduction of new gas fired capacity earlier in the year and a reduction in the availability of hydro capacity in that month. As one will recall from the discussion in the methodology chapter of this report, the available installed capacity of units of particular technologies, (wind, run-of-river hydro and storage hydro), was limited to the maximum of their generation in each month as an attempt to indirectly account for issues of hydrology and general weather conditions. This approach offers the most satisfactory method of dealing with these issues, the full inclusion of which would far exceed the scope of this current report.

Importantly, these merit curves do not capture the impact of the ETS scheme in 2005 and the inclusion of the economic cost of carbon to the generation costs of these units. This issue is addressed subsequently.

Figure 5.2: Merit Order Curve (excl. Carbon) - France

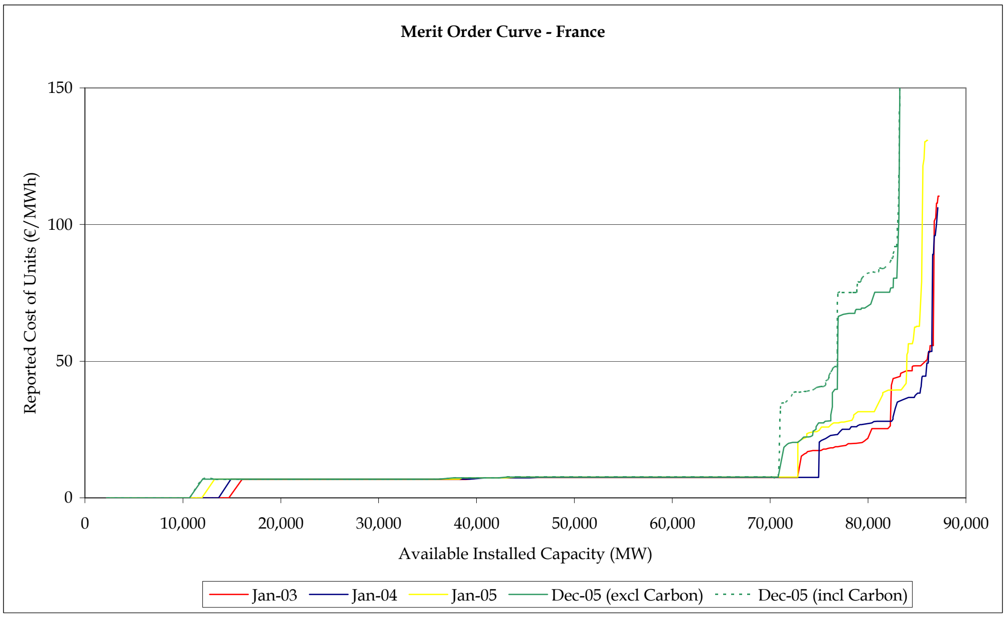


Source: LE

Merit Order Curve, including the average cost of carbon in December 2005 for all units emitting carbon.

In order to fully assess the impact on the merit order curve of the introduction of the ETS in 2005, the merit order curve for France in December 2005 has been adjusted to include the unit specific €/MWh economic cost of carbon for all generation units liable under this scheme. As one can see the initial difference persists to the left of the merit curve, due to the differing availability of units with zero marginal cost of generation (Wind, Storage and Run-of-River Hydro). The large quantity of nuclear capacity in France remains unaffected but as one moves to the position on the merit curve where one would expect to see the conventional thermal units located, beginning with coal and moving to gas as one moves further to the right, the impact of the inclusion of the full economic cost of carbon on these units is apparent. It is important for one to note at this point that the inclusion of the full economic cost of carbon has the potential to change the ordering of the units on the merit curve such that one should not consider the difference between the two December 2005 merit curves to represent the full economic cost of carbon for a particular unit but rather for a particular megawatt, not necessarily one located at that point on the merit curve in the absence of the cost of carbon. The implication of this is that one cannot simply estimate the cost of carbon for the system based on the cost of carbon for the marginal unit as the marginal unit may potentially be different between the carbon and no-carbon case. This is similarly the case for all of the merit curves presented here for different periods, the ordering of the units is potentially different in each period due largely to changes in fuel costs.

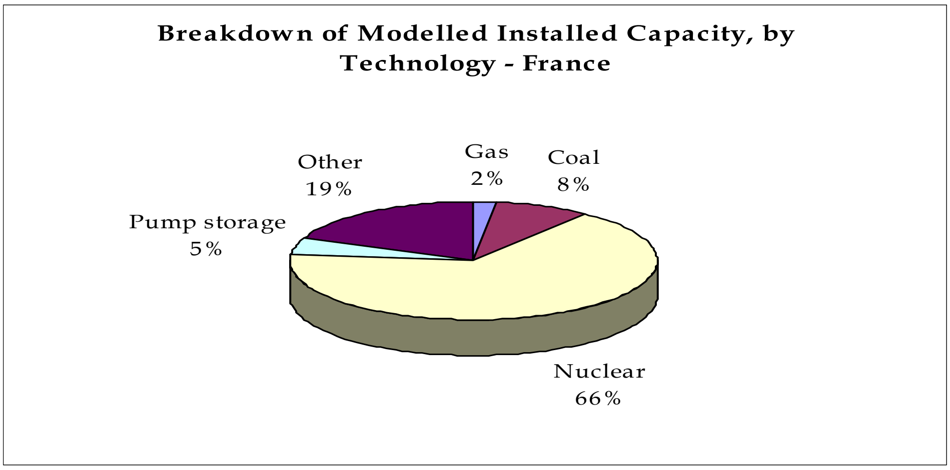
Figure 5.3: Merit Order Curve (incl. Carbon) - France



Source: LE.

As one can see, the effect of carbon is not applicable for the majority of the installed capacity in France, given its dependence on renewable and nuclear technology. There is however a discernable impact once one moves to the right of the nuclear capacity on the merit curve. The following figure on the portfolio of installed capacity in the France market works to provide an underpinning for the effects observed in the merit curve and the impact of carbon.

Figure 5.4: Breakdown of Installed Capacity (by technology) – France (2003-2005)



Source: LE.

5.2 Structural Indicators

Traditional structural indicators have been calculated based on a number of different measures of market share for the French electricity market. These indicators can change with availability and market conditions, so CR(n) and HHI indicators have been calculated, on an hourly basis, for all companies included in the study. Three different measures of market share (capacity) (generation) have been used to calculate these indicators. A brief overview of these measures is presented here but for a more detailed description one should review the relevant section of the methodology chapter.

Available Installed Capacity (AIC) – The Available Installed Capacity of each company is equal to the sum of maximum operating capacity reported for each unit in the company's portfolio (taking account of warm weather deratings and outages). The impact of warm weather derations on the normal operating capacity of units was included as part of DG Competition's data request to companies under the auspices of the Sector Inquiry. Data on outages was similarly returned by the companies and these were seen to take two particular forms: full outages and partial outages. A full outage is recorded where a company reports an outage and the hourly generation in that hour is zero. This unit is regarded to be out of operation and therefore not available in that hour. Companies have also reported partial outages which arise when the period of a reported outage does not correspond with a zero electrical production. In this case we have taken the available capacity to be the maximum hourly generation figure reported by the company, for the specific unit, over the period for which a partial outage has been identified. Further discussion of this as well as a formal exposition of the approach taken is contained in the methodology chapter of this report.

Available Capacity (AC) – Available Capacity is a measure calculated primarily for the purposes of the electricity specific structural indicators, however it is still interesting to assess the results of the traditional measures based on AC both in relation to the other measures of capacity and as an assessment of the HHI approach in general vis-à-vis the more specific measures calculated further on in this chapter. As has previously been stated in the methodology chapter, available capacity is equal to available installed capacity less capacity committed to upward system balancing (reserve) requirements and plus the net purchasing position of companies via long-term contracts.

Total Generation – Both the CR(n) and HHI indicators have been calculated using the hourly net electrical generation figures reported by the companies for the full three year period 2003-2005 (26304 hours). The hourly generation of each company is simply the arithmetic sum of generation over all units in the company's portfolio in each hour. If one was to aggregate this over each company, it would be equivalent to the load. Therefore, concentration measures based on total generation reflect the market shares of companies over the load of the system.

In Merit/Economic Capacity - CR(n) and HHI indicators have been calculated using the concept of in merit/economic capacity. A station is in merit if its running cost is less than the system marginal cost. This requires the estimation of an hourly system marginal cost and information on the hourly marginal cost of generation for each of the units in a company's portfolio. If the hourly marginal cost of generation of a particular unit is below, or equal to, the system marginal cost, the available generation capacity (as calculated above) is included in the company's available capacity for that hour. Units which report a marginal cost of generation above that of the system marginal cost are excluded. The system marginal cost used for this was the maximum unit cost of any unit reported running on the system in that hour.

CR(n)

The Concentration Ratio (*CR(n)*) of the n largest companies in the market is comprised of the sum of the relevant capacity measures (C) of the n largest companies in the market, divided by the total sum of capacity in the market. This measure has been calculated using, Available Installed Capacity, Available Capacity, Total Generation, and, In Merit/Economic Capacity.

HHI

Formula: $$HHI = \sum_{i=1} \left(\frac{C_i}{\sum_i C_i} \right)^2$$ where $i = 1, 2, 3,\ldots,N$

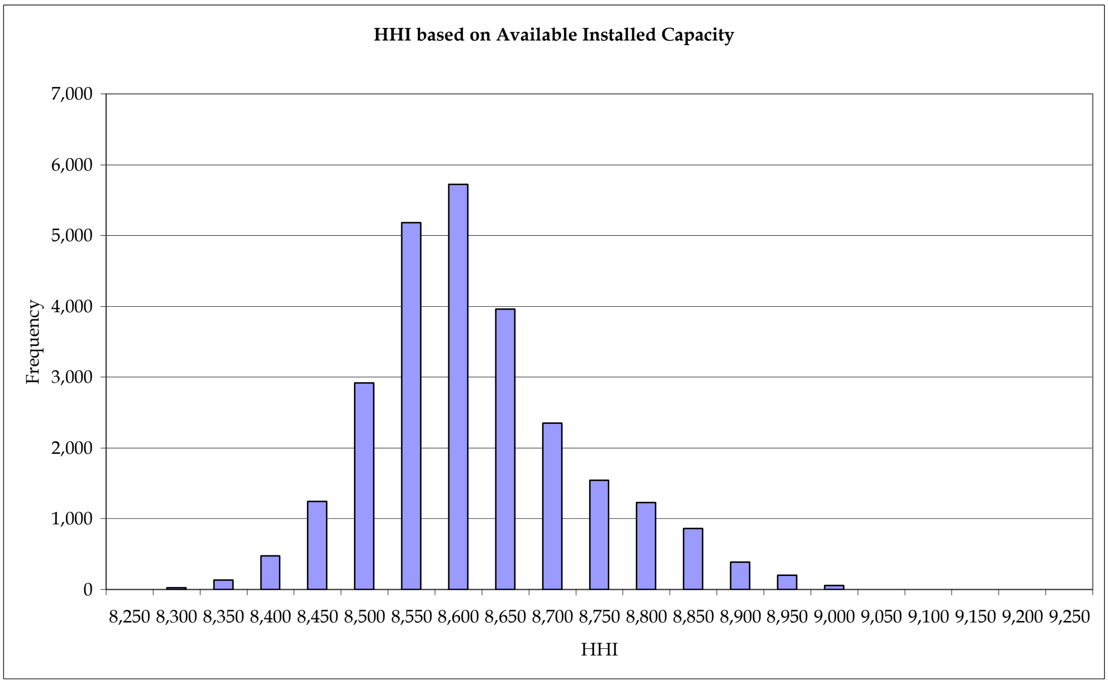
The HHI indicator sums the squares the market shares of all companies in the market, where the market shares of the companies are calculated on an hourly basis using, Available Installed Capacity, Available Capacity, Total Generation, and, In Merit/Economic Capacity.

5.2.1 Results

CR(1) & HHI based on available installed capacity

HHI and CR(*n*) measures have been constructed hourly for the full period of the study, 2003-2005. An overall representation of the computed HHI values based in hourly available installed capacity is provided in Figure 5.5. The HHI values shown in the histogram are high[49] throughout the period 2002-2005, evidence that ownership of available capacity is very highly concentrated.

Figure 5.5: Histogram of HHI values based on Available Installed Capacity (2003-2005) - France



Source: LE.

[49] HHI values greater than 1,800 are considered to indicate high market concentration. Although this threshold is not based on rigorous economic analysis, it is a generally accepted threshold used by competition economist and competition authorities in analysing market concentration.

The high degree of market concentration in France is similarly reflected in the summary statistics on CR(1) and HHI measures based on Available Installed Capacity presented in Table 5.1. According to these figures, a single company controlled more than 90% of all available installed capacity in the market in all hours over the period 2003-2005.

Table 5.1: Summary Statistics of CR(1) & HHI based on Available Installed Capacity (2003-2005) - France

	Available Installed Capacity (MW)	CR(1)	HHI
Average	76,801	92.6%	8,592
Maximum	92,675	94.8%	8,987
Minimum	57,011	90.9%	8,289
Standard Deviation	7,100	0.6%	112

Source: LE

As well as the overall representation of the hourly HHI values, a number of pre-selected days have been chosen to assess the existence and prevalence of concentration at different points in weekly and seasonal trends. Pre-selected days were tested to see if, as a spot check, perhaps concentration problems existed at more precise times in the market. The pre-selected dates are provided in Table 5.2.

Table 5.2: Pre-Selected Representative Days50 - France

	Weekday	Weekend
January (Winter)	2nd & 4th Wednesday	2nd Sunday
April (Spring)	2nd Wednesday	2nd Sunday
August (Summer)	2nd & 4th Wednesday	2nd Sunday
October (Fall)	2nd Wednesday	2nd Sunday

Source: LE

50 The selection of January and August as Winter and Summer respectively is in accordance with the references to these periods contained in the Horizontal Data Request.

Table 5.3 presents the results of the CR(1) and HHI analysis for available installed capacity for these pre-selected dates. The variation in concentration in terms of Available Installed Capacity between the selected days is minute, which is further evidence of the strong position of the largest company in the French market.

Table 5.3: Concentration measures based on available installed capacity - selected days, (2003-2005) - France

No.	Date	Average Hourly Demand (MWh/h)	CR(1)	HHI
1	08/01/03 (W-2)	74,983	92.8%	8,632
2	12/01/03 (S-2)	70,449	92.7%	8,604
3	22/01/03 (W-4)	69,352	92.9%	8,642
4	09/04/03 (W-2)	65,669	93.1%	8,674
5	13/04/03 (S-2)	54,342	92.7%	8,608
6	10/08/03 (S-2)	45,367	93.6%	8,769
7	13/08/03 (W-2)	49,546	92.9%	8,652
8	27/08/03 (W-4)	51,988	93.9%	8,828
9	08/10/03 (W-2)	57,200	91.8%	8,448
10	12/10/03 (S-2)	47,795	91.9%	8,460
11	11/01/04 (S-2)	59,925	92.7%	8,617
12	14/01/04 (W-2)	70,495	93.0%	8,668
13	28/01/04 (W-4)	73,581	92.3%	8,542
14	11/04/04 (S-2)	53,757	93.5%	8,747
15	14/04/04 (W-2)	61,644	93.2%	8,692
16	08/08/04 (S-2)	44,364	93.9%	8,841
17	11/08/04 (W-2)	49,260	93.5%	8,756
18	25/08/04 (W-4)	51,661	93.1%	8,676
19	06/10/04 (W-2)	57,590	92.0%	8,481
20	10/10/04 (S-2)	51,274	92.5%	8,569
21	09/01/05 (S-2)	58,933	92.3%	8,529
22	12/01/05 (W-2)	68,234	92.5%	8,569
23	26/01/05 (W-4)	75,570	92.8%	8,620
24	10/04/05 (S-2)	54,753	91.6%	8,419
25	13/04/05 (W-2)	60,104	91.8%	8,455
26	10/08/05 (W-2)	50,566	92.5%	8,573
27	14/08/05 (S-2)	44,204	92.7%	8,616
28	24/08/05 (W-4)	54,875	92.8%	8,620
29	09/10/05 (S-2)	47,774	91.9%	8,461
30	12/10/05 (W-2)	57,133	92.3%	8,543

Source: LE.

As well as looking at these pre-selected dates HHI and CR(1) measures have also been calculated over the four peak Summer and Winter days within the three year period of the study, as well as the peak days in Spring and Autumn. This was done to see if seasonality is affecting concentration or market structure in France. The results are presented in Table 5.4, which shows that seasonal variation in the French market structure is minimal.

Table 5.4: Concentration measures based on Available Installed Capacity– seasonal peaks, (2003-2005) - France

	Date	Average Hourly Demand (MWh/h)	CR(1)	HHI
Summer	02/07/2003	56,964	94.1%	8,874
	09/06/2004	56,736	92.0%	8,491
	15/06/2005	58,414	92.4%	8,553
Winter	10/01/2003	75,989	92.8%	8,628
	15/12/2004	74,053	92.5%	8,574
	26/01/2005	75,570	92.8%	8,620
Spring	09/04/2003	65,669	93.1%	8,674
	02/03/2004	68,641	92.1%	8,493
	01/03/2005	72,666	92.9%	8,638
Autumn	28/11/2003	68,385	92.1%	8,503
	25/11/2004	69,023	92.4%	8,563
	30/11/2005	71,736	92.8%	8,620

Note: peak days are selected on the basis of total demand over a 24-hour period.
Source: LE.

Available Capacity (allowing for LTCs and Reserves)

Reserves and long-term contracts can have an important impact on measured concentration in electricity markets. It is therefore important to control for such factors. In order to assess the impact of long-term contracts and reserve commitments on the HHI and CR(1) measures, these measures have been constructed using Available Capacity. Available capacity differs from available installed capacity as it takes account of each company's long-term contract and upward reserve commitment requirements. Available capacity is the basis for the electricity specific structural measures computed in the following section.

Table 5.5 presents a summary comparison of the results of the HHI and CR(1) measures computed hourly over the full period for Available Capacity and Available Installed Capacity (the basis for all of the above analysis). The table shows that Available Capacity, i.e. capacity not taken up by long-term contracts or committed as reserves is even more concentrated in the hands of the larges company, which implies that pre-commitments play a greater role in the sales portfolio of the smaller competitors.

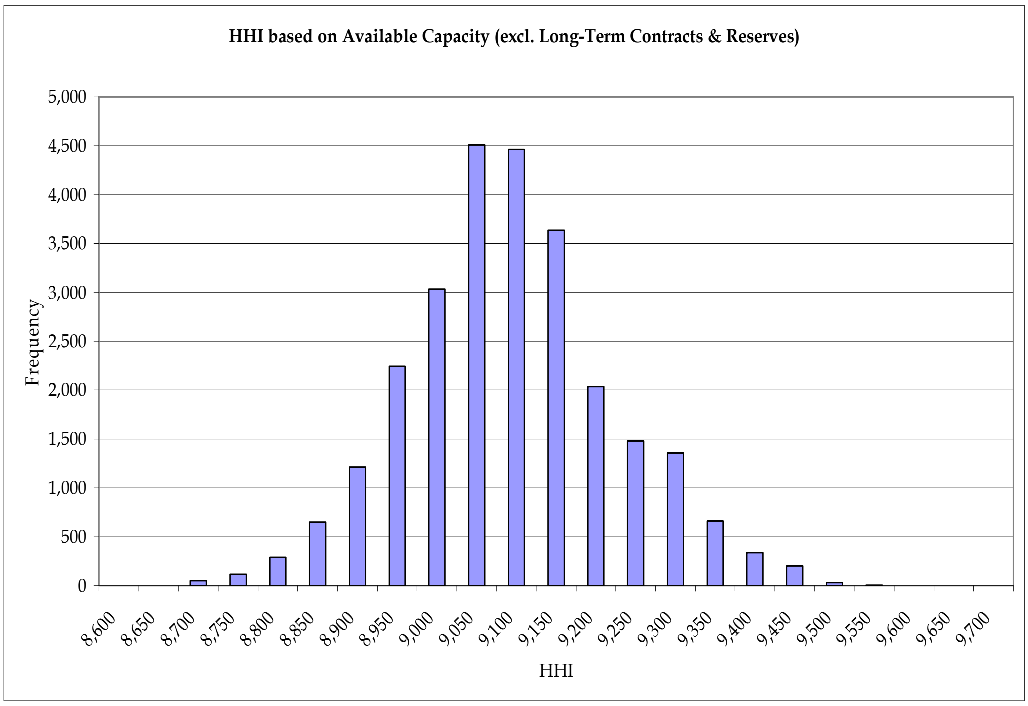
Table 5.5: Comparison of Available Capacity & Available Installed Capacity, (2003-2005) - France

	Available Capacity (MW)		Available Installed Capacity (MW)	
	CR(1)	**HHI**	**CR(1)**	**HHI**
Mean	95.2%	9,067	92.6%	8,592
Max	97.5%	9,508	94.8%	8,987
Min	93.0%	8,661	90.9%	8,289
Standard deviation	0.7%	129	0.6%	112

Source: LE

The histogram presented below provides the frequency of the computed HHI values based on Available Capacity. The histogram shows the central tendency and spread of the distribution of values. As with the summary statistics in Table 4, the histograms of both available capacity and available installed capacity are broadly similar, with slightly higher values for the HHIs based on Available Capacity.

Figure 5.6: Histogram of HHI values based on Available Capacity (2003-2005) - France



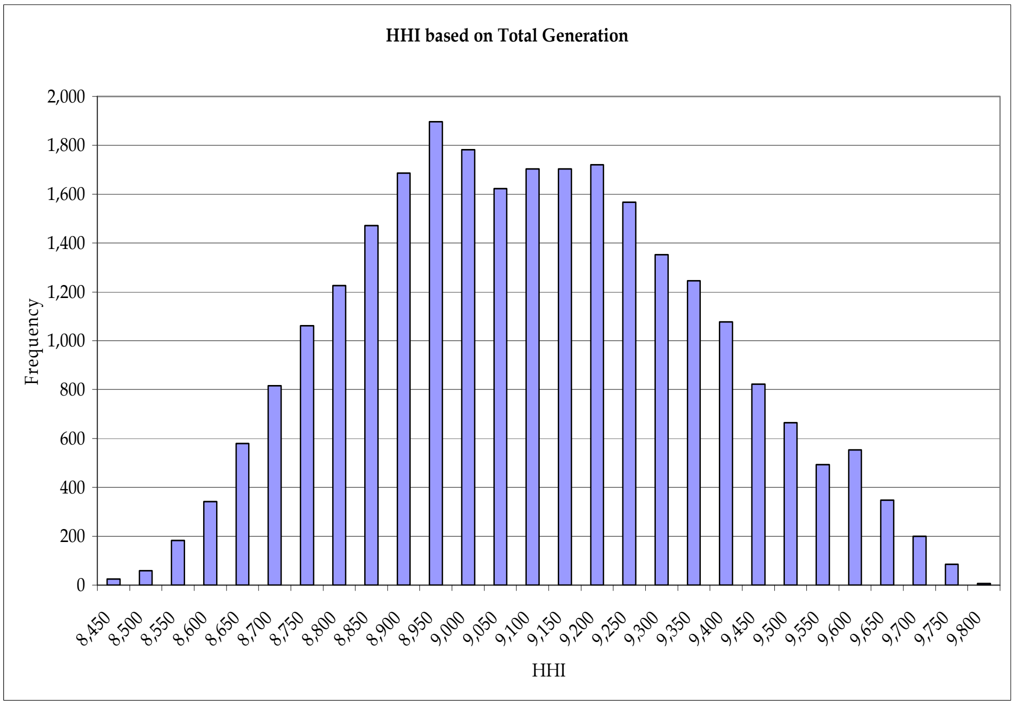
Source: LE.

CR(1) & HHI based on Total Generation

An alternative definition often used as a sensitivity in electricity market concentration is to base market share calculations on total generation. This excludes generation in many hours that are available to meet peak demand, but put greater weight on those generators running baseload, especially in off peak hours. The HHI and CR(1) measures have been re-estimated hourly based on the net electrical production figures returned by the companies. This data is also used to construct the load in France.

The Figure below presents a histogram of the frequency of hourly HHI values computed using hourly generation over the period 2003-2005.

Figure 5.7: Histogram of HHI values based on Total Generation (2003-2005) - France



Source: LE.

Summary statistics on CR(1) and HHI based on Total Generation are presented in Table 5.6. The extent to which electricity generation in France is provided by the largest company (0472-S-FR) is again evident in the extremely high concentration figures.

Table 5.6: Summary Statistics of CR(1) & HHI based on Total Generation, (2003-2005) - France

	Hourly Generation (MWh/h)	CR(1)	HHI
Average	58,704	95.2%	9,072
Maximum	81,107	98.8%	9,764
Minimum	36,346	90.9%	8,298
Standard Deviation	8,418	1.4%	264

Source: LE

Table 5.7 presents the HHI and CR(1) measures computed for the pre-selected days previously listed in Table 5.2. The table shows that concentration is virtually unaffected by demand conditions on individual days.

Table 5.7: Concentration measures based on total generation - selected days, (2003-2005) - France				
No.	**Date**	**Average Hourly Demand (MWh/h)**	**CR(1)**	**HHI**
1	08/01/03 (W-2)	74,983	96.0%	9,218
2	12/01/03 (S-2)	70,449	96.1%	9,247
3	22/01/03 (W-4)	69,352	95.7%	9,170
4	09/04/03 (W-2)	65,669	97.5%	9,516
5	13/04/03 (S-2)	54,342	97.3%	9,477
6	10/08/03 (S-2)	45,367	95.9%	9,199
7	13/08/03 (W-2)	49,546	94.4%	8,934
8	27/08/03 (W-4)	51,988	96.3%	9,280
9	08/10/03 (W-2)	57,200	93.3%	8,734
10	12/10/03 (S-2)	47,795	96.0%	9,233
11	11/01/04 (S-2)	59,925	95.3%	9,095
12	14/01/04 (W-2)	70,495	94.3%	8,913
13	28/01/04 (W-4)	73,581	92.8%	8,628
14	11/04/04 (S-2)	53,757	95.1%	9,046
15	14/04/04 (W-2)	61,644	94.6%	8,953
16	08/08/04 (S-2)	44,364	97.8%	9,572
17	11/08/04 (W-2)	49,260	95.5%	9,139
18	25/08/04 (W-4)	51,661	94.4%	8,924
19	06/10/04 (W-2)	57,590	95.7%	9,161
20	10/10/04 (S-2)	51,274	97.8%	9,564
21	09/01/05 (S-2)	58,933	95.8%	9,193
22	12/01/05 (W-2)	68,234	94.6%	8,957
23	26/01/05 (W-4)	75,570	93.6%	8,767
24	10/04/05 (S-2)	54,753	94.8%	9,001
25	13/04/05 (W-2)	60,104	93.0%	8,670
26	10/08/05 (W-2)	50,566	98.0%	9,607
27	14/08/05 (S-2)	44,204	98.4%	9,687
28	24/08/05 (W-4)	54,875	95.4%	9,120
29	09/10/05 (S-2)	47,774	97.7%	9,546
30	12/10/05 (W-2)	57,133	95.0%	9,043

Source: LE.

Table 5.8 presents the CR(1) and HHI measures based on total generation for the selected seasonal peaks in demand. As the constructed load is the sum of hourly generation, this table presents, for peak demand days, the degree of concentration at the seasonal high points of the load duration curve.

Concentration on peak demand days is predictably high and shows no discernable difference to concentration on the other selected days. The conclusion is that seasonality is not a large determinant of concentration using total generation as the basis for the market share calculation.

Table 5.8: Concentration measures based on total generation – seasonal peaks, (2003-2005) - France

	Date	Average Hourly Demand (MWh/h)	CR(1)	HHI
Summer	02/07/2003	56,964	95.9%	9,200
	09/06/2004	56,736	94.3%	8,904
	15/06/2005	58,414	95.0%	9,031
Winter	10/01/2003	75,989	96.2%	9,263
	15/12/2004	74,053	94.8%	8,994
	26/01/2005	75,570	93.6%	8,767
Spring	09/04/2003	65,669	97.5%	9,516
	02/03/2004	68,641	93.3%	8,728
	01/03/2005	72,666	93.8%	8,805
Autumn	28/11/2003	68,385	93.0%	8,665
	25/11/2004	69,023	94.8%	8,995
	30/11/2005	71,736	93.7%	8,799

Source: LE.

In order to further investigate the degree of concentration at different intervals in the load duration curve, base, shoulder and peak periods have been identified for a selection of the days already presented as part of the analysis of pre-selected days. The definition of base, shoulder and peak used for this analysis is as follows;

- Base is defined as the hours in the year located in the two rightmost quartiles of the load duration curve. The first 50% of hours for which demand is lowest in 2005;

- Shoulder is defined as the hours in the next quartile of the load duration curve, to the left of the base hours;
- Peak is defined as the hours in the first quartile of the load duration curve, which contains the hours for which demand is highest in 2005.

Table 5.9 presents the HHI and CR(1)values during these periods of the selected days, as well as the order of the top two companies in those hours.

Table 5.9: Concentration & Load Duration – 2005 - France

January 2005		**Company**	**CR(1)**	**HHI**
2nd Wednesday	*Base*	NA	NA	NA
	Shoulder	0472-S-FR	95.9%	9,197
	Peak	0472-S-FR	94.1%	8,856
August 2005				
2nd Wednesday	*Base*	0472-S-FR	98.0%	9,607
	Shoulder	NA	NA	NA
	Peak	NA	NA	NA

Source: LE

A number of entries appear as NA in this table due to the fact that hours corresponding to the definition of the categories do not exist on these pre-selected days.

CR(1) & HHI based on In Merit/Economic Capacity

In Merit capacity has been computed based on the realised fuel costs (€/MWh) returned by each company for each of their generation units. Table 5.10 presents summary statistics on the CR(1) and HHI values computed on an hourly basis. The results are not sensitive to this definition of capacity in calculating market shares.

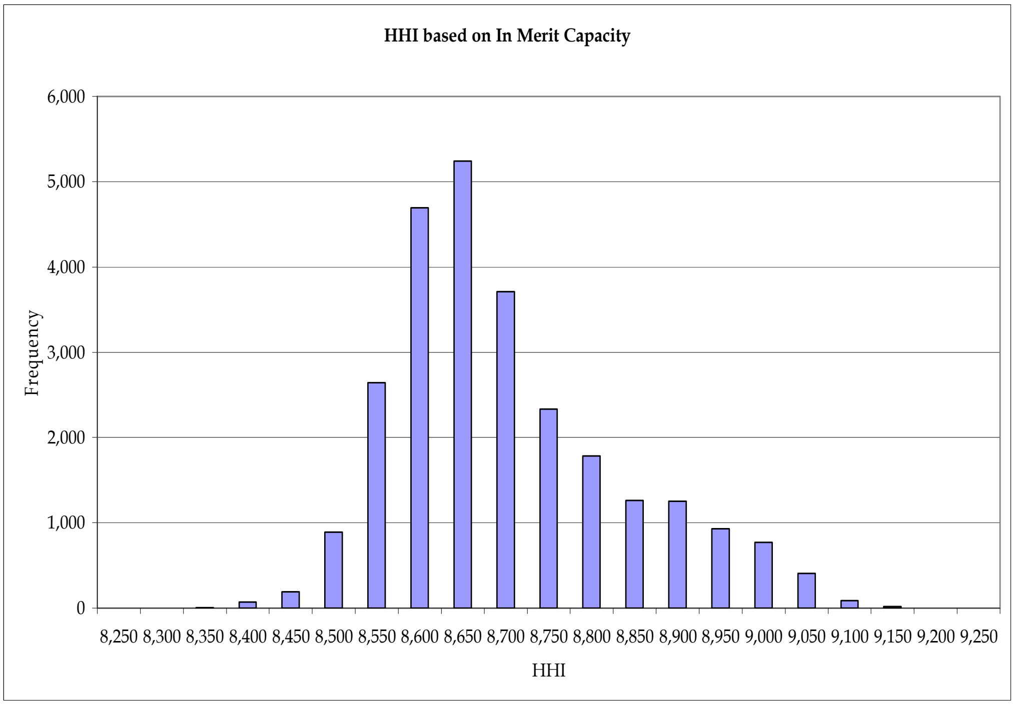
Table 5.10: Summary Statistics of CR(1) & HHI based on In Merit Capacity, (2003-2005) - France

	In Merit Capacity (MW)	CR(1)	HHI
Average	75,089	93.1%	8,675
Maximum	91,251	96.3%	9,289
Minimum	53,905	91.2%	8,347
Standard Deviation	7,401	0.7%	133

Source: LE

The following histogram represents the frequency of HHI values calculated on the basis of in merit capacity.

Figure 5.8: Histogram of HHI values based on In-Merit Capacity (2003-2005) - France



Source: LE.

5.2.2 Interconnector

An assessment of the potential impact of interconnection has been carried out using the indicators of concentration previously presented based on Available Installed Capacity and Total Generation. Importantly, it was possible to extract details of ownership of reserved capacity and interconnector flows, by company, from the data collected by DG Competition as part of the Sector Inquiry and as a result a sensitivity analysis is conducted to put upper and lower bounds on the potential impact of interconnection on the traditional measures concentration. Two scenarios have been considered and represent a sensitivity analysis of the figures calculated in the absence of the interconnector;

1. Atomistic Competition
2. Largest Company Apportionment

1. Atomistic Competition – Under this scenario the companies' hourly market share is not affected. The aggregated impact of the interconnector is included in the denominator of both CR(1) and HHI measures, such that the net impact of the interconnectors is only added to the market. Thus, the atomistic competition scenario reduces the measured concentration by the maximum amount possible due to the interconnector.

2. Largest Company Apportionment – Under this alternative scenario the hourly impact of the interconnectors is apportioned entirely to the largest company in the market (as measured by available installed capacity). This scenario thus represents the largest increase in measured concentration possible due to the allocation of the interconnector.

The two allocation procedures thus form the upper and lower bounds of the measured concentration due to the interconnector allocation. It is important to note at this stage that the potential impact of the interconnector is accounted for differently in these scenarios depending on the basis for the calculation. The hourly net transfer capacity of the interconnectors is used in calculations based on the Available Installed Capacity of the companies in the market, while actual hourly interconnector flows are used in calculations based on Total Generation. This is important due to the potential impact of the interconnector flows on the expectations of upper and lower bounds. These bounds are true in the case of Available Installed Capacity but as one may realise, this will only be the case if the country is, on average, a net importer of electricity. In the event that the country is regarded as an exporter, as is the case in France, the expected results from these scenarios may be reversed. For a further discussion and formal exposition of how these interconnector scenarios are calculated, one can revert to the methodology chapter of this report.

5.2.3 Results

The following tables represent the sensitivity cases of concentration based on Available Installed Capacity, with hourly available net transfer capacity of the interconnector(s) added to the relevant variables. As implied by the calculation method explained above, concentration figures obtained under the Atomistic scenario are significantly lower than under the standard scenario which ignores the interconnector. The increase in concentration under the scenario that adds the interconnector to the biggest player in the market is comparatively small, which reflects the limited importance of the interconnector given the extent of the lead enjoyed by the biggest player over its rivals.

Figure 5.5 presents summary statistics on the results of the interconnector scenarios when applied to the concentration measures based on available installed capacity. As one may expect, although the interconnector has the expected impact on the CR(1) and HHI values, the market remains highly concentrated. The atomistic scenario can be seen to have a substantially larger impact on the measures of concentration than does the largest player case. The increases, on average, in the concentration measures under the largest player case only represent a 1% increase in the market share of the largest company. On average the HHI changes by less than 200 points.

Table 5.11: Summary Statistics Concentration measures based on Available Installed Capacity: Impact of the Interconnector, (2003-2005) - France

	STANDARD (excl. IC based on available installed capacity)		**ATOMISTIC**		**IC ADDED TO BIGGEST PLAYER**	
	CR(1)	**HHI**	**CR(1)**	**HHI**	**CR(1)**	**HHI**
Average	92.6%	8,592	80.6%	6,505	93.6%	8,767
Max	94.8%	8,987	86.2%	7,437	95.6%	9,139
Min	90.9%	8,289	75.5%	5,717	92.0%	8,477
Standard Deviation	0.6%	112	1.4%	227	0.6%	102

Source: LE.

Assessing the peak seasonal days in the French electricity market one also finds the results to be consistent with those in the previous table. Table 5.12 presents the results of the CR(1) and HHI measures under both interconnector scenarios.

Table 5.12: Results of HHI & CR(1) Analysis of the Impact of the Interconnector, based on hourly Available Installed Capacity, (2003-2005) - France

		STANDARD (excl. IC based on available gen capacity)		ATOMISTIC		IC ADDED TO BIGGEST PLAYER	
	Date	**CR(1)**	**HHI**	**CR(1)**	**HHI**	**CR(1)**	**HHI**
Summer	02/07/2003	94.1%	8,874	81.9%	6,719	94.9%	9,015
	09/06/2004	92.0%	8,491	78.6%	6,187	93.2%	8,702
	15/06/2005	92.4%	8,553	79.5%	6,336	93.5%	8,746
Winter	10/01/2003	92.8%	8,628	82.5%	6,825	93.6%	8,773
	15/12/2004	92.5%	8,574	82.9%	6,877	93.3%	8,716
	26/01/2005	92.8%	8,620	83.8%	7,039	93.5%	8,747
Spring	09/04/2003	93.1%	8,674	80.8%	6,544	94.0%	8,841
	02/03/2004	92.1%	8,493	80.8%	6,538	93.0%	8,669
	01/03/2005	92.9%	8,638	83.7%	7,012	93.6%	8,768
Autumn	28/11/2003	92.1%	8,503	80.8%	6,534	93.1%	8,679
	25/11/2004	92.4%	8,563	81.3%	6,630	93.4%	8,727
	30/11/2005	92.8%	8,620	81.1%	6,581	93.7%	8,787

Source: LE.

If one changes the focus of the market definition from available installed capacity to actual generation, wherein interconnector flows are included in the calculation of the sensitivities as opposed to interconnector capacity, this does not limit the impact of the interconnector to be positive but rather it allows for net exports to have a negative impact on the market share of companies and the market as a whole. Summary statistics on the results of the interconnector sensitivity scenarios based on total generation are presented in Table 5.13.

Table 5.13: Summary Statistics Concentration measures based on Total Generation: Impact of the Interconnector, (2003-2005) - France

	STANDARD (excl. IC based on Total Generation)		ATOMISTIC		IC ADDED TO BIGGEST PLAYER	
	CR(1)	**HHI**	**CR(1)**	**HHI**	**CR(1)**	**HHI**
Average	95.2%	9,072	106.3%	11,331	94.6%	8,974
Max	98.8%	9,764	124.1%	15,398	98.6%	9,720
Min	90.9%	8,298	91.5%	8,381	89.5%	8,055
Standard Deviation	1.4%	264	5.1%	11,331	1.5%	278

Source: LE.

The results of these sensitivity cases do not mirror those of the previous scenario based on available installed capacity. This is due to the nature of the flows over the French interconnectors. France is a considerable net exporter of electricity and as such the inclusion of interconnector flows in the atomistic case has the result of reducing the overall market size in the denominator of the calculation of both HHI and CR(1). Therefore, the market share of the largest company in the market increases and breaches the 100% market share ceiling due to the reduction in the size of the market. Similarly the resulting HHI value is in excess of 10,000. One can see the impact of positive net exports, on average, from the French market in the largest player case also. Under this scenario there is a reduction, on average, in the market share of the largest company due to the inclusion of a negative interconnector effect.

Assessing the impact of these scenarios on the peak seasonal demand days in the French electricity market one also finds the results to be largely consistent with those in the previous table. Table 5.14 presents the results of the CR(1) and HHI measures under both interconnector scenarios.

Table 5.14: Results of HHI & CR(1) Analysis of the Impact of the Interconnector, based on hourly Total Generation, (2003-2005) - France							
		STANDARD (excl. IC based on total generation)		ATOMISTIC		IC ADDED TO BIGGEST PLAYER	
	Date	CR(1)	HHI	CR(1)	HHI	CR(1)	HHI
Summer	02/07/2003	95.9%	9,200	109.7%	12,052	95.3%	9,091
	09/06/2004	94.3%	8,904	108.6%	11,816	93.4%	8,747
	15/06/2005	95.0%	9,031	110.1%	12,140	94.2%	8,883
Winter	10/01/2003	96.2%	9,263	104.6%	10,965	95.9%	9,200
	15/12/2004	94.8%	8,994	102.2%	10,457	94.4%	8,918
	26/01/2005	93.6%	8,767	98.5%	9,726	93.2%	8,704
Spring	09/04/2003	97.5%	9,516	108.0%	11,674	97.3%	9,465
	02/03/2004	93.3%	8,728	95.9%	9,213	93.2%	8,694
	01/03/2005	93.8%	8,805	94.9%	9,020	93.7%	8,792
Autumn	28/11/2003	93.0%	8,665	102.3%	10,484	92.3%	8,539
	25/11/2004	94.8%	8,995	104.0%	10,823	94.3%	8,902
	30/11/2005	93.7%	8,799	99.4%	9,894	93.4%	8,730
Source: LE.							

Overall, the traditional measures of concentration indicate that the French electricity market is very concentrated. This conclusion is consistent across a number of different measurements of available capacity and actual output, as well as when the potential role of interconnection is taken into account. Following on from these traditional measures of concentration, the results of electricity specific structural measures are presented in the following section. These measures are designed to take account of the dynamic nature of electricity markets, a feature traditional measures are not particularly adept in capturing.

5.3 Electricity Specific Structural Measures

As discussed previously, electricity markets display many unique characteristics that indicate limits to the usefulness of tradition measures of market structure. We therefore have endeavoured to estimate electricity-specific structural indicators. Both the Residual Supply Index (RSI) and Pivotal Supplier Index (PSI) are calculated using the aggregated Available Capacities of the units in each companies portfolio, unlike the previous available capacity measure, this measure is complimented by adjusting the hourly available capacity figures (as discussed above) for the long-term contract position of the companies and their commitment to provide reserves for upward regulation. The long-term contract position of the companies has been adjusted to reflect any change in the net position of the companies that occurred over the period 2003-2005. This is also true for the quantity of generation committed to meet reserve requirements; this data has been taken from the TSO response to the 2005 Data Request and not from the generators' responses.

5.3.1 RSI

Since much of our further results are based on the RSI, we repeat the formula for RSI used in the methodology section. It is noteworthy that the RSI is in general specific to a chosen company. The RSI is calculated for each hour (26,304) in accordance with the following formula;

$$RSI_j = \frac{\left(\sum_{i=1}^{N} ac_i - AC_j\right)}{\sum_{i=1}^{N} hourly\_generation_i} \qquad \text{where; } i = 1, 2, \ldots, j, \ldots, N$$

The companies' total available capacity and generation in each hour is indexed by i. The RSI indicator usually should have the system load as the denominator in this equation, however for the purposes of this study (for reasons outlined elsewhere) the system load has been constructed as the sum of the net hourly electrical production figures reported by all companies. This indicator has been calculated for both the four largest companies in the market in France, rather than the top two as in other countries, because the four largest companies were all of a similar size and market position. The calculation of the capacity of the largest company or chosen company is indicated by Company *j*.

Previous studies that have used this measure have attempted to apply a threshold value to the computed hourly indicator. The threshold states that if the value of the RSI is less than 110% (1.1) for more than 5% of the time, then this is indicative of a market structure that is likely to be open to non competitive behaviour. This threshold test and the threshold itself was developed by the CAISO and as applied indicates potentially troublesome periods as those where the residual supply is less than 110% of the market demand for electricity and whether or not this systematically occurs in more than 5% of the time. The threshold itself is not the result of in-depth economic analysis but rather based on knowledge of market functioning but as such one may consider tailoring the threshold for each country. This was not done as part of this report as it was considered that the 110% threshold would be appropriate to achieving the objectives of this study and would further allow for a consistent comparison across countries.

5.3.2 PSI

The PSI is calculated for each hour (26,304) in accordance with the formulae presented in the methodology section. The PSI is a zero-one indicator of when a company is needed to meet demand.

As with the RSI indicator, the PSI is traditionally calculated using the system load, however for the purposes of this study the system load is replaced by the sum of the hourly generation of the companies included in the study.

A threshold for this indicator has been constructed as part of previous studies and market analysis. The FERC apply a threshold of 20% to this measure, if the value of the measure 1 for more than 20% of the time then this is indicative of a pivotal supplier. As with the threshold applied in relation to the RSI, this threshold is not the result of rigorous economic analysis and as such should be considered to be an indicator of potential market power issues rather than a steadfast rule in relation to overall conclusions that can be drawn from the results.

5.3.3 Results

RSI Results

Table 5.15 presents the results of the threshold test for the RSI calculated on an hourly basis for both the full period and individually for each year. With the threshold set at 110%, the test requires that the value of the RSI be greater than 110% (1.1) for more than 95% of the time for the largest market participant, in order for the market outcome to be deemed competitive. This table presents the results of the threshold test for all of the large generation companies in France. If the percentage of hours the RSI measure is less than 110% is greater than 5% for any of the companies, then the market outcome cannot be considered to be a competitive one.

The results shown in Table 5.15 and Figure 5.9 reconfirm the previous finding of a high degree of market concentration in the France, with company 0472-S-FR both holding a large market share and being pivotal to meeting demand in the French electricity market 100% of the time. At no point in time during the period 2003-2005 did the RSI computed for company 0472-S-FR exceed the threshold level of 110%. The RSI threshold analysis therefore offers a strong indication that the outcomes of the French electricity are not indicative of competitive outcomes.

Table 5.15: RSI Threshold Analysis - France

RSI Result	0340-S-FR	0472-S-FR	1449-S-FR
2003-05	136	26,304	8
% hrs< 110%	*0.5%*	*100.0%*	*0.0%*
2003	11	8,760	0
% hrs< 110%	*0.1%*	*100.0%*	*0.0%*
2004	47	8,784	0
% hrs< 110%	*0.5%*	*100.0%*	*0.0%*
2005	78	8,760	8
% hrs< 110%	*0.9%*	*100.0%*	*0.1%*

Source: LE

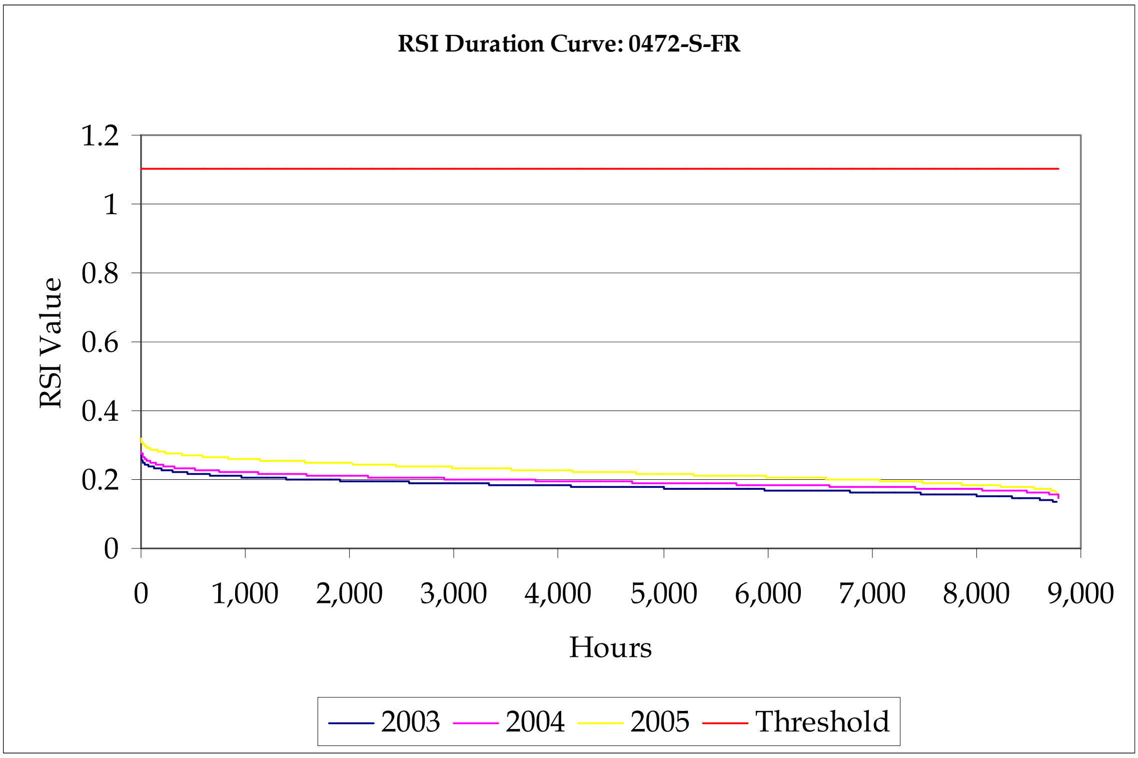
Table 5.16 presents summary statistics on the RSI. The gap between company 0472-S-FR and its closest competitor, company 0340-S-FR, is again evident in these figures.

Table 5.16: Summary Statistics on RSI - France								
	0472-S-FR				**1449-S-FR**			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.20	0.18	0.20	0.22	1.32	1.33	1.31	1.32
Max	0.32	0.27	0.28	0.32	1.89	1.89	1.79	1.74
Min	0.13	0.13	0.15	0.16	1.09	1.11	1.10	1.09
Source: LE								

RSI Duration Curves for 0472-S-FR

Since the RSI is a continuous measure and calculated hourly, we can also consider an RSI duration curve (a mirror of the cumulative distribution) to show the number or % of hours that RSI is above a certain value. This gives an idea of the distribution as well as the mean of the measure over time. We present below a duration curve on RSI for company 042-S-FR. The figures demonstrate that as well as the table evidence that the RSI below the threshold of 110% in all hours.

Figure 5.9: RSI Duration Curve for Company 0472-S-FR (2003-2005) - France



Source: LE.

Alternative RSI Scenarios

The existence of long term contracts and reserve commitments can impact the RSI and PSI similarly as they can the traditional measures of concentration. It is therefore necessary to check these sensitivities. As a sensitivity test on the RSI values presented above, the RSI is re-estimated under two alternative scenarios. Firstly, by excluding the long-term contract positions of the companies from the calculation of available capacity, and secondly, by excluding the companies' upward reserve commitments from the same calculation. The following tables show that the RSI results presented in the previous section are highly robust.

Table 5.17 presents the results of the threshold test when long-term contracts have been excluded from the calculation of available capacity. While the overall picture remains unchanged, the slightly higher figures for company 1449-S-FR reflect the company's limited involvement in the provision of reserves.

Table 5.17: RSI Threshold Analysis - Scenario 1 (accounts for Reserves only) - France

RSI Result	0340-S-FR	0472-S-FR	1449-S-FR
2003-05	150	26,304	97
% hrs< 110%	*0.6%*	*100.0%*	*0.4%*
2003	11	8,760	7
% hrs< 110%	*0.1%*	*100.0%*	*0.1%*
2004	48	8,784	22
% hrs< 110%	*0.5%*	*100.0%*	*0.3%*
2005	91	8,760	68
% hrs< 110%	*1.0%*	*100.0%*	*0.8%*

Source: LE

Table 5.18 presents summary statistics on the RSI values calculated under this alternative scenario for the two largest thermal companies in France (based on market share of total installed capacity).

Table 5.18: Summary Statistics of RSI Results - Scenario 1 (accounts for Reserves only) - France

	0472-S-FR				1449-S-FR			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.11	0.10	0.11	0.11	1.29	1.30	1.28	1.29
Max	0.17	0.17	0.15	0.16	1.84	1.84	1.75	1.69

Source: LE

Table 5.19 presents the results of the threshold test when reserves have been excluded from the calculation of available capacity. The table shows that long-term contracts do no affect the relative position of the three companies in terms of RSI.

Table 5.19: RSI Threshold Analysis - Scenario 2 (accounts for LTC only) - France			
RSI Result	**0340-S-FR**	**0472-S-FR**	**1449-S-FR**
2003-05	136	26,304	8
% hrs< 110%	*0.5%*	*100.0%*	*0.0%*
2003	11	8,760	0
% hrs< 110%	*0.1%*	*100.0%*	*0.0%*
2004	47	8,784	0
% hrs< 110%	*0.5%*	*100.0%*	*0.0%*
2005	78	8,760	8
% hrs< 110%	*0.9%*	*100.0%*	*0.1%*
Source: LE			

Table 5.20 presents summary statistics on the RSI values calculated under this alternative scenario for the two largest thermal companies in France (based on market share of total installed capacity).

Table 5.20: Summary Statistics on RSI - Scenario 2 (accounts for LTC only) - France								
	0472-S-FR				**1449-S-FR**			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.19	0.17	0.19	0.21	1.32	1.33	1.31	1.32
Max	0.31	0.26	0.27	0.31	1.89	1.89	1.79	1.74
Min	0.13	0.13	0.14	0.15	1.09	1.11	1.10	1.09
Source: LE								

5.3.4 PSI Results

The results of the PSI analysis for the large generation companies in France are presented in Table 5.21. As discussed above the PSI is a (0,1) variable, equal to 1 if the company is deemed to be pivotal to supply in a given hour and zero if not. An established threshold test for this measure is one applied by FERC which considers a market participant to be pivotal, and thus the market outcome not to be competitive, if the PSI for any company is equal to one for more than twenty percent of the time.

According to Table 5.21 company 0472-S-FR was the pivotal supplier of electricity in the French market for the entire period 2003-2005.

Table 5.21: PSI Threshold Analysis - France

PSI Result	0340-S-FR	0472-S-FR	1449-S-FR
2003-05	0	26,304	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*
2003	0	8,760	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*
2004	0	8,784	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*
2005	0	8,760	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*

Source: LE

Alternative PSI Scenarios

As with the RSI analysis above, the PSI analysis has been re-estimated under the same alternative scenarios. Table 5.22 presents the results of the PSI threshold test having excluded long-term contracts from the analysis.

Table 5.22: PSI Threshold Analysis - Scenario 1 (accounts for Reserves only) - France

PSI Result	0340-S-FR	0472-S-FR	1449-S-FR
2003-05	0	26,304	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*
2003	0	8,760	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*
2004	0	8,784	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*
2005	0	8,760	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*

Source: LE

Table 5.23 presents the results of the PSI threshold test under Alternative Scenario 2, whereby upward reserve commitments have been excluded from the calculation of available capacity. The results obtained under the alternative scenarios do not differ from the original results reported above. In every case company 0472-S-FR is pivotal all of the time.

Table 5.23: PSI Threshold Analysis - Scenario 2 (accounts for LTC only) - France

PSI Result	0340-S-FR	0472-S-FR	1449-S-FR
2003-05	0	26,304	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*
2003	0	8,760	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*
2004	0	8,784	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*
2005	0	8,760	0
% hrs =1	*0.0%*	*100.0%*	*0.0%*

Source: LE

5.3.5 Interconnector

To account for the potential impact of the interconnectors on the RSI and PSI measures, two sensitivity cases are calculated within this section to address this issue. Given interconnector capacity reservations and flows are not available at the company level it has been necessary to consider two hypothetical situations in order to assess the impact. The two scenarios are briefly described here;

1. The hourly interconnector capacity (IC_c), aggregated over the interconnectors, is added to the total supply of the market and apportioned in accordance with the companies' market shares (as measured by installed capacity) in the market being assessed. The hourly aggregated interconnector flows (IC_f) are added to the load.

2. The hourly interconnector capacity (IC_c) of each interconnector is added to the total supply of the market and the hourly available capacity of each interconnector is apportioned in accordance with the companies' market shares (as measured by installed capacity) in the markets from which electricity can be imported. The hourly aggregated interconnector flows (IC_f) are added to the load.

It is important to note that in all hours the interconnector flows are not necessarily positive values, they will be negative in hours where the market exports more electricity than it imports, therefore necessarily increasing the residual supply relative to the load, holding other factors equal. Given France is, on average, a considerable net exporter of electricity, one can expect to see this situation in effect in the following results.

The following sections contain the RSI and PSI analysis under the different interconnector scenarios. The results we report do not lead to conclusions different from those recounted before. Instead, they reconfirm that company 0472-S-FR has the highest market share by far, regardless of how the interconnector is accounted for.

5.3.6 Results (Interconnector allocated according to domestic market share)

RSI Results

Table 5.24 presents the results of the threshold test for the RSI calculated on an hourly basis for both the full period and individually for each year. The RSI results are not sensitive to the interconnector. One can see that company 0472-S-FR is once again indispensable to meeting the load in all hours with no other company in the market indispensable in even one hour out of 26,304.

Table 5.24: RSI Threshold Analysis (+IC domestic) - France			
RSI Result	**0340-S-FR**	**0472-S-FR**	**1449-S-FR**
2003-05	0	26,304	0
% hrs< 110%	0.0%	100.0%	0.0%
2003	0	8,760	0
% hrs< 110%	0.0%	100.0%	0.0%
2004	0	8,784	0
% hrs< 110%	0.0%	100.0%	0.0%
2005	0	8,760	0
% hrs< 110%	0.0%	100.0%	0.0%
Source: LE			

Table 5.25 presents summary statistics on the RSI measure for the country's two largest companies (measured by installed thermal capacity). Considered in the indicative threshold of 1.1 (110%), one can immediately assess the extent of the markets dependence on company 0472-S-FR, even with the interconnector taken into account in this scenario, one can see that on average over the period of the study only 24% of the demand in the market would have been met if company 0472-S-FR was not present.

Table 5.25: Summary Statistics on RSI (+IC domestic) - France								
	0472-S-FR				1449-S-FR			
	2003-2005	2003	2004	2005	2003-2005	2003	2004	2005
Mean	0.24	0.22	0.23	0.27	1.69	1.71	1.67	1.70
Max	0.42	0.33	0.35	0.42	2.54	2.54	2.36	2.47
Min	0.15	0.15	0.16	0.18	1.24	1.30	1.24	1.24
Source: LE								

Alternative RSI Scenario

Table 5.24 presents the results of the threshold test when only long-term contracts have been included in the calculation of available capacity.

Table 5.26: RSI Threshold Analysis (+ IC domestic) - Scenario 2 (accounts for LTC only) - France			
RSI Result	**0340-S-FR**	**0472-S-FR**	**1449-S-FR**
2003-05	0	26,304	0
% hrs< 110%	0.0%	100.0%	0.0%
2003	0	8,760	0
% hrs< 110%	0.0%	100.0%	0.0%
2004	0	8,784	0
% hrs< 110%	0.0%	100.0%	0.0%
2005	0	8,760	0
% hrs< 110%	0.0%	100.0%	0.0%
Source: LE			

Table 5.27 presents summary statistics on the RSI values calculated under this alternative scenario for the two largest companies in France (based on market share of total installed capacity of thermal technology).

Table 5.27: Summary Statistics on RSI (+ IC domestic) - Scenario 2 (accounts for LTC only) - France								
	0472-S-FR				1449-S-FR			
	2003-2005	2003	2004	2005	2003-2005	2003	2004	2005
Mean	0.23	0.21	0.22	0.26	1.69	1.71	1.67	1.70
Max	0.40	0.31	0.33	0.40	2.53	2.53	2.35	2.47
Min	0.15	0.15	0.15	0.17	1.24	1.30	1.24	1.24
Source: LE								

In general, the results from different allocation procedures for the interconnector flows are largely similar. There is little variation across companies too. We therefore conclude that there is little sensitivity of the measures to interconnector allocation procedure.

PSI Results

The results of the PSI analysis for the large generation companies in France are presented in Table 5.21. As discussed above the PSI is a (0,1) variable, equal to 1 if the company is deemed to be pivotal to supply in a given hour and zero if not. An established threshold test for this measure is one applied by FERC which considers a market participant to be pivotal, and thus the market outcome not to be competitive, if the PSI for any company is equal to one for more than twenty percent of the time.

Table 5.28: PSI Threshold Analysis (+IC Domestic) - France

PSI Result	0340-S-FR	0472-S-FR	1449-S-FR
2003-05	0	26,304	0
% hrs =1	0.0%	100.0%	0.0%
2003	0	8,760	0
% hrs =1	0.0%	100.0%	0.0%
2004	0	8,784	0
% hrs =1	0.0%	100.0%	0.0%
2005	0	8,760	0
% hrs =1	0.0%	100.0%	0.0%

Source: LE

Alternative PSI Scenarios

As with the RSI analysis above, the PSI analysis has been re-estimated under the same alternative scenario. Table 5.29 presents the results of the PSI threshold test having included only long-term contracts in the calculation of available capacity.

Table 5.29: PSI Threshold Analysis (+IC Domestic) - Scenario 2 (accounts for LTC only) - France			
PSI Result	**0340-S-FR**	**0472-S-FR**	**1449-S-FR**
2003-05	0	26,304	0
% hrs =1	0.0%	100.0%	0.0%
2003	0	8,760	0
% hrs =1	0.0%	100.0%	0.0%
2004	0	8,784	0
% hrs =1	0.0%	100.0%	0.0%
2005	0	8,760	0
% hrs =1	0.0%	100.0%	0.0%

As with the RSI results, the PSI results are not sensitive to the way the interconnector is allocated.

5.3.7 Results (Interconnector allocated according to foreign market share)

RSI Results

Table 5.30 presents the results of the threshold test for the RSI calculated on an hourly basis for both the full period and individually for each year.

Table 5.30: RSI Threshold Analysis (+IC foreign) - France			
RSI Result	**0340-S-FR**	**0472-S-FR**	**1449-S-FR**
2003-05	0	26,304	0
% hrs< 110%	0.0%	100.0%	0.0%
2003	0	8,760	0
% hrs< 110%	0.0%	100.0%	0.0%
2004	0	8,784	0
% hrs< 110%	0.0%	100.0%	0.0%
2005	0	8,760	0
% hrs< 110%	0.0%	100.0%	0.0%
Source: LE			

Table 5.16 presents summary statistics on the RSI.

Table 5.31: Summary Statistics on RSI (+IC foreign) - France								
	0472-S-FR				**1449-S-FR**			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.45	0.43	0.43	0.48	1.68	1.70	1.66	1.69
Max	0.75	0.71	0.66	0.75	2.52	2.52	2.34	2.45
Min	0.26	0.26	0.29	0.29	1.23	1.29	1.23	1.23
Source: LE								

Alternative RSI Scenario

Table 5.32 presents the results of the threshold test when reserves have been excluded from the calculation of available capacity.

Table 5.32: RSI Threshold Analysis (+IC foreign) - Scenario 2 (accounts for LTC only) - France

RSI Result	0340-S-FR	0472-S-FR	1449-S-FR
2003-05	0	26,304	0
% hrs< 110%	0.0%	100.0%	0.0%
2003	0	8,760	0
% hrs< 110%	0.0%	100.0%	0.0%
2004	0	8,784	0
% hrs< 110%	0.0%	100.0%	0.0%
2005	0	8,760	0
% hrs< 110%	0.0%	100.0%	0.0%

Source: LE

Table 5.33 presents summary statistics on the RSI values calculated under this alternative scenario for the two largest thermal companies in France (based on market share of total installed capacity).

Table 5.33: Summary Statistics on RSI (+IC foreign) - Scenario 2 (accounts for LTC only) - France

	0472-S-FR				1449-S-FR			
	2003-2005	**2003**	**2004**	**2005**	**2003-2005**	**2003**	**2004**	**2005**
Mean	0.44	0.42	0.42	0.47	1.68	1.70	1.66	1.69
Max	0.73	0.69	0.64	0.73	2.52	2.52	2.34	2.45
Min	0.26	0.26	0.28	0.28	1.23	1.29	1.23	1.23

Source: LE

PSI Results

The results of the PSI analysis for the large generation companies in France are presented in Table 5.34. As discussed above the PSI is a (0,1) variable, equal to 1 if the company is deemed to be pivotal to supply in a given hour and zero if not. An established threshold test for this measure is one applied by FERC which considers a market participant to be pivotal, and thus the market outcome not to be competitive, if the PSI for any company is equal to one for more than twenty percent of the time.

Table 5.34: PSI Threshold Analysis (+IC foreign) - France

PSI Result	0340-S-FR	0472-S-FR	1449-S-FR
2003-05	0	26,304	0
% hrs =1	0.0%	100.0%	0.0%
2003	0	8,760	0
% hrs =1	0.0%	100.0%	0.0%
2004	0	8,784	0
% hrs =1	0.0%	100.0%	0.0%
2005	0	8,760	0
% hrs =1	0.0%	100.0%	0.0%

Source: LE

Alternative PSI Scenario

As with the RSI analysis above, the PSI analysis has been re-estimated under the same alternative scenario. Table 5.35 presents the results of the PSI threshold test having excluded reserves from the calculation of available capacity.

Table 5.35: PSI Threshold Analysis (+IC foreign) - Scenario 2 (accounts for LTC only) – France			
PSI Result	**0340-S-FR**	**0472-S-FR**	**1449-S-FR**
2003-05	0	26,304	0
% hrs =1	0.0%	100.0%	0.0%
2003	0	8,760	0
% hrs =1	0.0%	100.0%	0.0%
2004	0	8,784	0
% hrs =1	0.0%	100.0%	0.0%
2005	0	8,760	0
% hrs =1	0.0%	100.0%	0.0%
Source: LE			

The PSI results accounting for long term contracts with and without are broadly similar to the results with and without interconnector under different allocation procedures. In addition, there is little change across company or over time. Thus we conclude that the PSI is not sensitive to the allocation of interconnectors or the inclusion of long-term contracts.

Overall conclusion

Broadly speaking, the French electricity market is very highly concentrated. This conclusion is robust to choice of concentration measure, electricity specific market structure measure, and choice of market definition. Interconnectors similarly fail to alter the overall conclusion.

5.4 Contribution to POWERNEXT Prices

We next calculated the breakdown of the exchange prices into its component parts. This analysis assesses the contribution of three factors, (the GED system modelled marginal cost, the estimated costs of carbon and the estimated mark-up) to the annual load weighted average POWERNEXT price. Table 5.36 presents the load-weighted-average contribution of these three factors, to the load weighted average POWERNEXT price. As evidenced from the table, the mark-up is the biggest factor in the price, contributing markedly more than the system marginal cost, and carbon. At this point, it is important to recall some data issues with France and the French merit curve.

From the merit curve presented previously, the extent of nuclear capacity is an obvious and important feature in France, much more so than in other countries. In addition, this is coupled with pumped storage hydro, and a significant amount of normal storage hydro. The result of this is that in France the marginal cost as per our modelling is very often set by nuclear capacity (the pumped storage does not set the price, but shaves load). In fact, though, when comparing our optimal despatch results to the actual results, it was apparent that nuclear plant were running significantly less in actuality than in the model. We checked all countries, and while this was present in other countries with nuclear capacity, it was not nearly so widespread as in France. Additional checks did not yield a particular pattern (that we could discern by plant—some plants ran closer to capacity than others).

A potentially important element contributing to this general result is the quality of the data returned by the companies in relation to outages, particularly partial outages. As has previously been discussed in the methodology chapter of this report, we were forced to make an assumption on the potential impact of partial outages on the availability of units during periods where an outage was reported by a company but that same unit continued to generate electricity. Incidentally it was therefore not possible to account for situations where a partial outage occurred but was not reported as the unit continued to generate, albeit at a reduced capacity. Therefore, if nuclear plant were running less than full capacity, and had not reported a partial outage, then the model would despatch these plants at full capacity. Similarly, if nuclear capacity was withdrawn from the system for reasons other than reported outages, these units would remain available in these hours and would be called by the model in hours where they were needed to meet demand.

Time and financial constraints on the study did not allow further deeper investigation with the operators. Nonetheless, with limited time, our opinion was that we would proceed with the French modelling as is, but caveat the results. As a result of the difficulties with nuclear data, our opinion is that the high margins estimated for France are less reliable than estimates in other countries. However, we present them here as broadly indicative figures. These figures also enable us to breakdown the costs of carbon and fuel price rises, which are not subject to the same caveats. We did not, further, compare France on the same footing as other countries with respect to margins, nor did we carry out regressions or contribution to fixed costs for France.

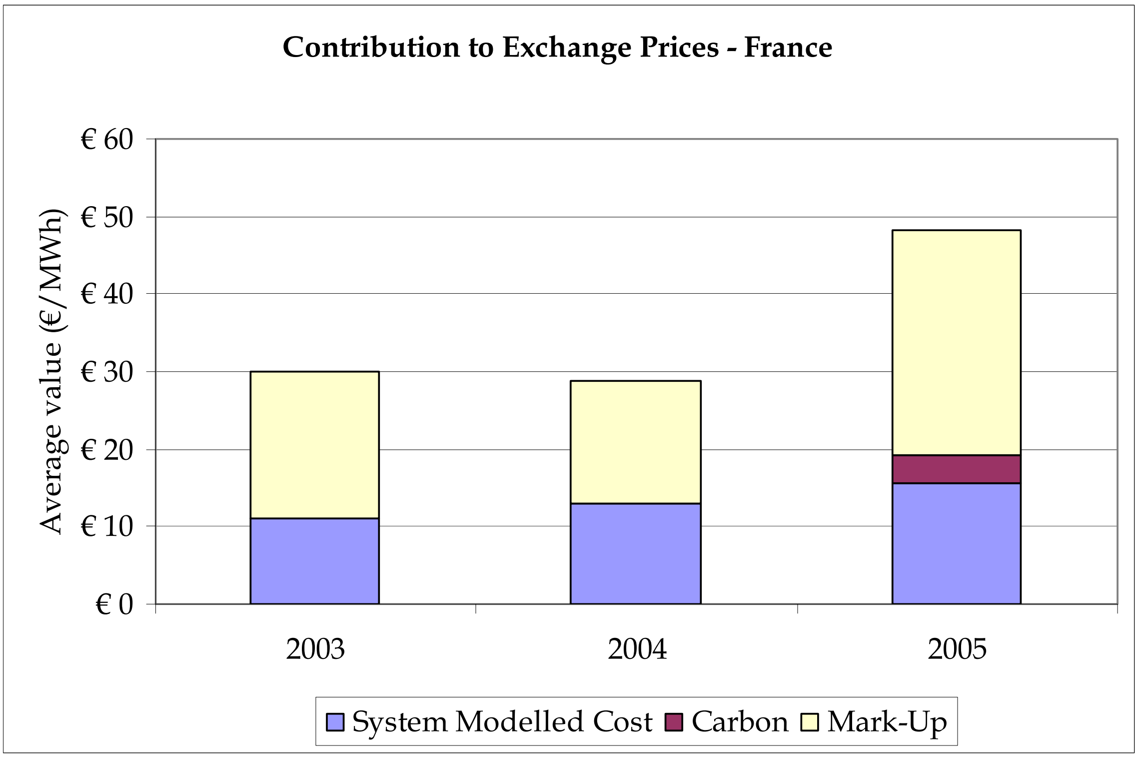
Table 5.36: Contribution of Cost, Carbon and Mark-up to POWERNEXT Prices - France

	2003	2004	2005
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

Note: Based on load weighted average prices and costs
Source: LE

Figure 5.10 provides a graphical representation of the above table. Within each year one can see the load weighted average contributions of each of the three factors to the overall load weighted average POWERNEXT price.

Figure 5.10: Contribution to POWERNEXT Prices, (2003-2005) - France



Source: LE

5.5 Outcome Measures

5.5.1 Price-Cost Margin (Lerner Index)

In spite of the aforementioned issues with the returned data (with nuclear plant inexplicably running less than reported capacity) and the impact of this on the simulated marginal costs in France, the results of the market outcome analysis for France is presented in this subsection, with a similar caveat as before.

The Price-Cost Margin/Lerner Index (LI) has been calculated hourly based on the System Marginal Cost and the publicly available price of electricity for each hour in the period 2003-2005. The formula for the LI is as follows;

$$LI = \frac{P - MC}{P}$$

However, the use of a simple average has been rejected in favour of a load weighted average approach. Therefore, a more accurate description of the above equation is to consider each of the variables to be load weighted averages of the relevant period. A more formal exposition of this approach is presented in the methodology chapter of this report.

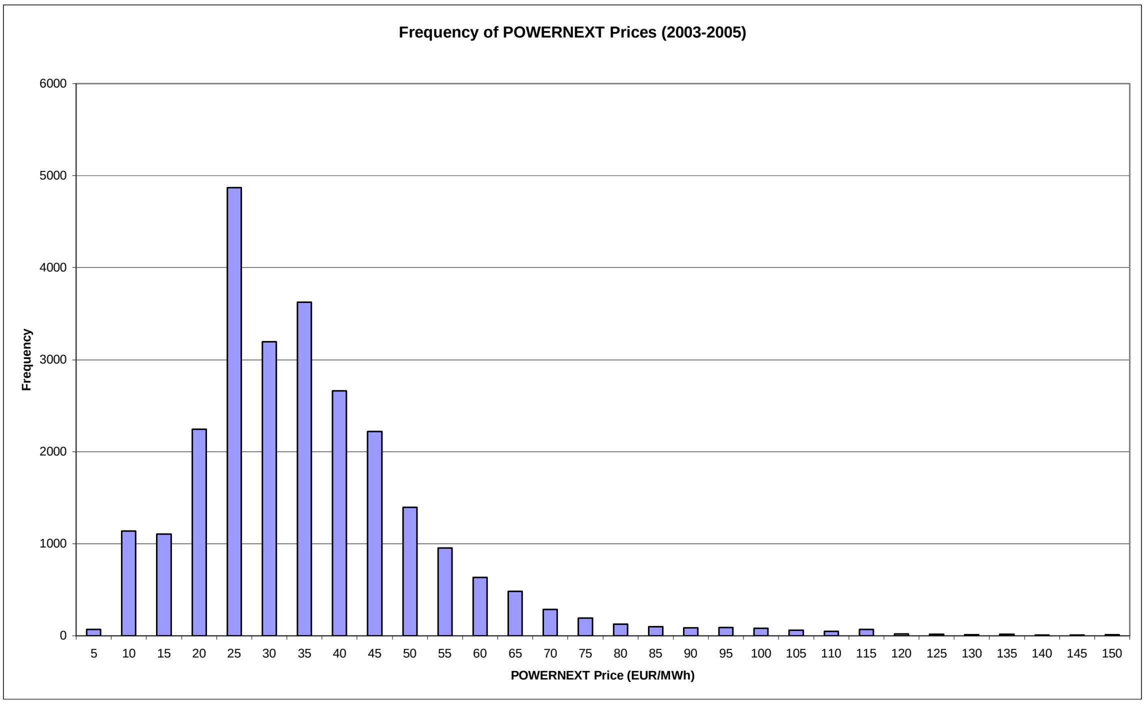
Two different sets of prices are used for this analysis;

1. The hourly day ahead prices published by the French Power Exchange, POWERNEXT[51].
2. Platts Assessments Prices – this data set provides a daily base and peak price for the majority of weekdays in the period and a base price for electricity at weekends.

The frequency of hourly prices (€/MWh) on POWERNEXT over the period of the study is presented in the histogram in Figure 5.11. It suggests the mean of the distribution for wholesale electricity prices in France is approximately 25 to 35 €/MWh. POWERNEXT prices are not available for 14 days during the period of the study. In addition, the price exceeded €150 in 137 hours in 2003-2005, with a maximum price of €1,000.

[51] Obtained from Platts European Power database.

Figure 5.11: Frequency of POWERNEXT Prices (2003-2005) - France

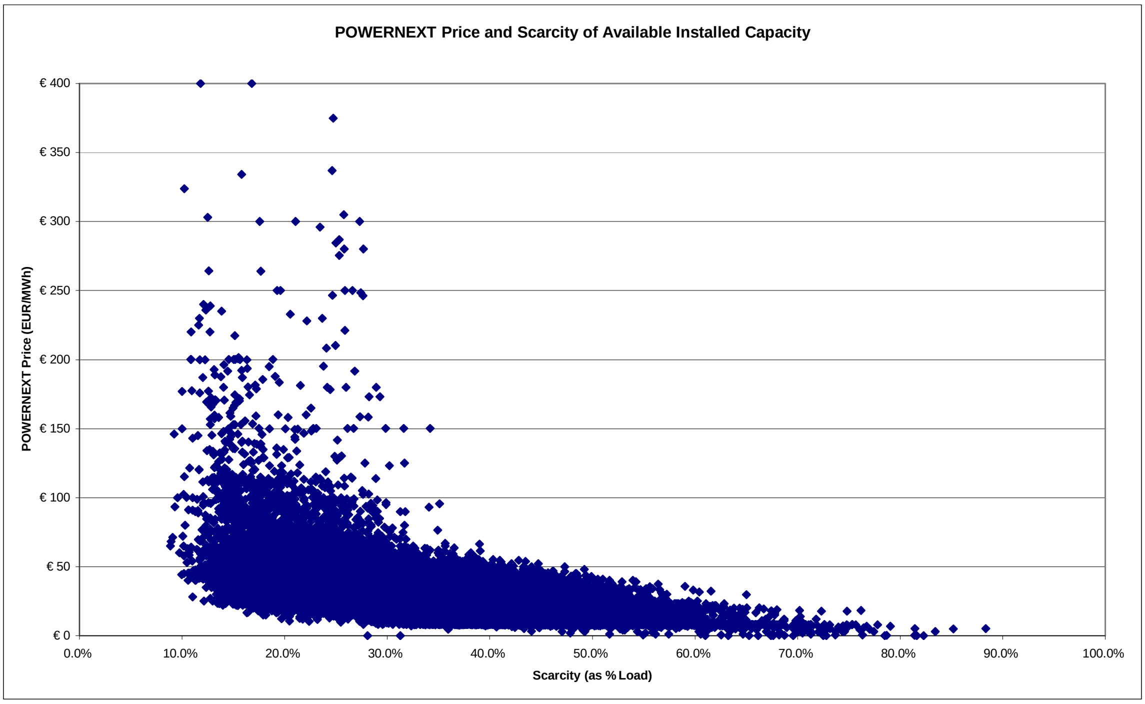


Source: LE

In general, it is useful to consider the appropriateness of a candidate price for our margin analysis in every hour. For the POWERNEXT price to be considered a relevant price for electricity in France it should be seen to reflect changing market dynamics within the French electricity market. In general, to the extent that marginal cost in electricity naturally would rise as demand reaches peaks due to the trade-off between thermal efficiency and capital cost in electricity generation technology, the POWERNEXT price should reflect the scarcity of available generation capacity in any one hour on the system. In other words, the price should rise with scarcity and peakiness of the system based on the slope of the merit curve. The following graph represents the relationship between the hourly POWERNEXT price and the scarcity of available generation capacity, expressed as a percentage of the load (sum of generation) in that hour.

The scarcity of available generation capacity in any one hour is computed using the following formula.

Figure 5.12: Scatter-plot of Scarcity and POWERNEXT Prices (2003-2005) - France



Source.: LE

One can see from this graphic that high POWERNEXT prices correspond to times of relative scarcity of generation capacity, which is what one would expect given the natural convexity of the merit curve.

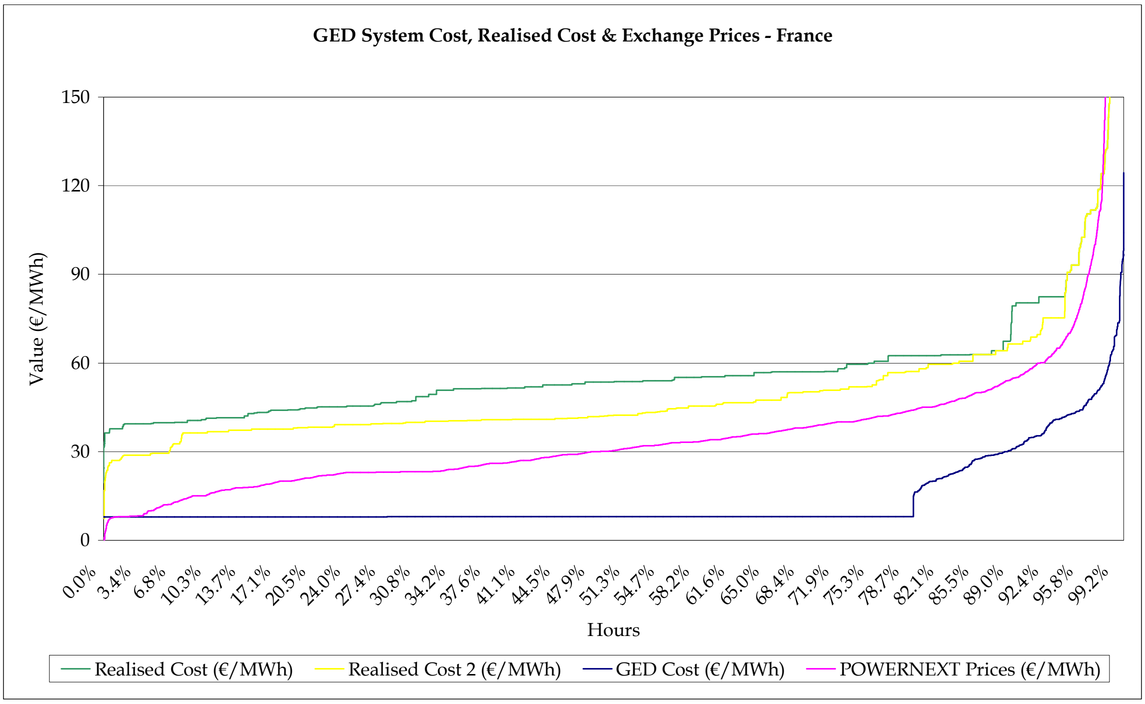
However as indicated above, the Platts assessment price of electricity in France shall also be used in calculations of the LI and mark ups. This price series provides a base and peak price for electricity on a daily basis on weekdays and a base price for electricity on weekends. As this price is constant for all hours of base and peak in the relevant days, this price may be a more appropriate representation of the price of electricity contracted forward (over periods greater than a day) in France, a quantity considerably greater than that traded on a day-ahead basis. Alternatively, the Platts price is not reflective of hourly fluctuations in scarcity. Finally, forward prices may contain forward premia for risk, or merely the risk free rate of interest which are natural and not indicative of market power use. We nonetheless include the Platts price analysis as an alternative price measure.

The analysis also considers three different cost estimates for the system;

1. The System Cost estimated as part of GED's optimal despatch run. (GED Cost)
2. A simple stacking of the returned realised cost of generation (fuel cost) provided for each unit, with the highest cost unit generating in any one hour setting the system cost. This cost only considers the fuel cost of generation. (Realised Cost)
3. Same as 2, with all units with capacity less than 25 MW, or designated must-run or CHP removed from the analysis. (Realised Cost 2)

The relationship between these two series can be seen in the following graphic.

Figure 5.13: Comparison of GED System Modelled Cost, Realised Cost, Realised Cost 2 & POWERNEXT Prices (2003-2005) - France



Source: LE

As one can see from this graph, the maximum system realised cost of generation returned by the companies is always significantly greater than the system marginal cost estimated by GED's optimal despatch simulation. There are a number of potential reasons for this. Firstly, the data issue in relation to the apparent limited availability of some nuclear capacity for which outages are not reported. Secondly, simple stacking models are unable to reflect many market conditions in electricity markets. Unit-specific characteristics may require units to run but not set the price, "must-run" units or units that are run to provide system balancing or reserves may have a cost greater than the system marginal cost but as these units are not being despatched they do not affect the price. The fact that must-run, CHP, and other such units "should" not set the price is common to electricity market marginal cost estimation. This may similarly be the case for some CHP units whose primary function is to provide heat and for whom electricity production is a by-product. These units are not seen as economically relevant price setters because in general they are not representative of capable of providing the next megawatt of energy on the system. Finally, in the case of many units, energy is a joint product with other products, and the true marginal cost of energy is economically only the additional cost of production of energy, after the primary product has been produced. Nevertheless, both costs are represented within this analysis. The Realised Cost 2 curve, which takes account of some of the problems by excluding CHP and must-run units, as well as units with capacities up to 25 MW, is also shown in the graph above.

The units with capacities of less than 25MW have been aggregated by companies in their responses' to DG Competition's data request as part of the Sector Inquiry. Both costs and generation output have been aggregated by technology and there is no indication as to whether any of the constituent units are must run. The costs returned by companies are also potentially inclusive of a number of other costs not included in the calculation of the €/MWh fuel cost undertaken on a monthly basis for all other units (those greater than 25MW). Therefore these units have been removed from possibly setting the system cost in the simple stacking model for Realised Cost 2 as it was not possible to determine if only fuel costs were reported and more importantly whether these units were must-run or CHP units, the reason for excluding the other units as part of Realised Cost 2.

One may also notice that there are a number of hours, although small in France, where the GED modelled system cost is greater than the POWERNEXT price, thus indicating that there are a number of hours where companies' cost of generation in a competitive environment is in excess of the observed power exchange prices. Part of this can be explained by recourse to reasons similar to those discussed previously in relation to the divergence between the GED modelled cost and the realised costs of units. Power exchange prices can be representative of the residual values of energy on the system and since in reality, electricity that is placed on the grid can often be produced as a joint product with electricity committed to long-term supply contracts, ancillary services, electricity and heat for on-site industrial processes, and general heat production. Additionally, generators might rationally be willing to pay to avoid shutting down and incurring stop and start costs, thus resulting in them effectively dumping electricity on the system. Furthermore, there are technical and operational reasons power plant operators may wish to avoid shutting down and starting on a daily/frequent basis, such as wear and tear on the machine and the increased probability of a forced outage. This result has similarly been found previously in studies of electricity markets in Europe and the US.

Summary statistics on the both the GED System Cost and the Realised Cost are provided in Table 5.37.

Table 5.37: Comparison of GED System Cost & Realised Cost - France					
		Average	**Minimum**	**Maximum**	**St Dev**
2003-2005	*GED System Cost*	€ 13.69	€ 7.92	€ 124.31	€ 13.04
	Realised Cost	€ 57.34	€ 19.50	€ 193.30	€ 20.89
	Realised Cost 2	€ 49.84	€ 7.40	€ 193.30	€ 22.63
2003	*GED System Cost*	€ 10.65	€ 7.92	€ 96.08	€ 7.53
	Realised Cost	€ 53.15	€ 37.80	€ 122.30	€ 14.07
	Realised Cost 2	€ 44.78	€ 7.40	€ 122.30	€ 16.94
2004	*GED System Cost*	€ 12.31	€ 8.01	€ 65.95	€ 9.94
	Realised Cost	€ 50.80	€ 33.90	€ 143.70	€ 15.59
	Realised Cost 2	€ 42.98	€ 7.50	€ 143.70	€ 16.21
2005	*GED System Cost*	€ 18.12	€ 8.07	€ 124.31	€ 18.00
	Realised Cost	€ 68.08	€ 19.50	€ 193.30	€ 26.32
	Realised Cost 2	€ 61.78	€ 19.50	€ 193.30	€ 27.80
Source: LE					

In general, the realised cost 2 is about €36 higher than the GED system cost. Also, it can be seen that costs have risen substantially from 2003 to 2005, regardless of the measure. This is in general due to rising fuel prices

5.5.2 Sensitivity of the French marginal cost estimates to interconnection

An additional piece of analysis we carried out for France was a sensitivity case with additional interconnection. In spite of the fact that, by modelling total generation as load, we thus include net exports[52] in our estimate of load we wanted to consider the possibility of more exports in the perfectly competitive case. The reason for this is that, given our estimates of the marginal cost in France, if we were to model all markets together, it is likely that France would have exported more than they currently do (assuming their price is lower than neighbouring markets). In addition, one would expect the marginal cost estimate in France to rise significantly.

Table 5.38: Average excess capacity added to the load in each period

	2003-2005	2003	2004	2005
Average	5,551	5,303	5,303	6,050

Source: LE

Thus, to include this sensitivity case, we added to the modelled load (total generation), the total spare capacity available in every hour on the interconnectors. The average amount added in each period is presented in Table 5.38. We then re-ran the GED model to re-estimate the marginal cost. We then, however, capped the new French marginal cost (competitive price) estimates with the marginal cost estimates (competitive prices) obtained in the neighbouring markets. This is because additional exports would only be expected to flow to neighbours to the extent that the French competitive price stayed below the estimated neighbours estimated competitive prices. The results are shown, as load-weighted annual averages, below in Table 5.39.

[52] Since demand + exports = supply + imports, and supply=total generation, then total generation must equal demand (load) plus net exports.

Table 5.39: French interconnector sensitivity case: weighted average MC €/MWh - France			
Year	**Model Result**	**With maximum exports**	**% change**
2003	€ 11.13	€ 23.37	+110%
2004	€ 13.06	€ 28.42	+118%
2005	€ 19.85	€ 44.39	+124%

Source: LE (GED modelling)

The table shows a number of things. First, weighted average marginal costs in France were estimated to be quite low, but would have been almost doubled from maximum interconnection. Note that the original case also included net exports implicitly, but the second case is an estimate of the maximum impact of potential exports. Interestingly, the prices estimated with maximum exports are not extremely large, and show that additional exports would indeed have increased the estimated French costs significantly.

5.5.3 Results

GED Modelled System Cost and POWERNEXT Prices

Table 5.40 presents the results of the load weighted average Lerner Index values calculated for France based on the system cost returned by the GED optimal despatch simulation and the POWERNEXT price. Table 5.41 presents the results of a similar calculation with the full economic cost of carbon removed for 2005.

Table 5.40: Average LI based on GED System Cost & POWERNEXT Prices (including carbon) - France

	2003-2005	2003	2004	2005
Lerner Index	59.6%	63.1%	55.3%	59.9%

Note: Based on load weighted average prices and costs
Source: LE

Table 5.41: Average LI based on GED System Cost & POWERNEXT Prices (excluding carbon) - France

	2003-2005	2003	2004	2005
Lerner Index	62.8%	63.1%	55.3%	67.3%

Note: Based on load weighted average prices and costs
Source: LE

The tables indicate very high margins in France for the period in focus as part of this study, excluding the cost of carbon the overall average margin calculated under this approach is 62.8%. However, one should be aware of an important caveat in relation to these results and those following in subsequent sections. Substantial difficulties were encountered when modelling the French electricity system brought about by the large quantity of nuclear capacity within the country and the apparent disparity between reported capacity and actual running. In many hours, this created what potentially is a downward biased marginal cost for the system, which is further reflected in the results of these measures.

GED Modelled System Cost and Platts Assessment Prices

Table 5.42 presents the average load weighted LI values calculated using Platts Assessment prices. Once again these figures are subject to the previous caveat.

Table 5.42: Average Lerner Index based on GED System Cost & Platts Assessment Prices (Day-Ahead) - France

	2003-2004	2003	2004	2005
Lerner Index	67.0%	71.3%	61.9%	66.6%

Note: Based on load weighted average prices and costs
Source: LE

If one considers the results of these calculation one can see that the Platts assessment prices show an apparent increase in margins in 2005. While the Platts margins appear slightly higher than the POWERNEXT calculated margins, some of this may be due to premia in forward sales, contract type, which may or may not have any basis in a market power related explanation.

5.5.4 Price Cost Mark-Up

An alternative measure of margin is the price cost mark up. As with the Price-Cost Margin/Lerner Index, the Price-Cost Mark-Up (PCMU) has been calculated based on the GED System Cost and the publicly available price of electricity for each hour in the period 2003-2005. The formula for the PCMU is as follows;

$$PCMU = \frac{P - MC}{MC}$$

As with the Lerner Index, the use of a simple average is rejected in favour of a load weighted average approach. Therefore, a more accurate description of the above equation is to consider each of the variables to be load weighted averages of the relevant period. A more formal exposition of this approach is presented in the methodology chapter of this report.

5.5.5 Results

Price-Cost Mark-Up based on GED Modelled System Cost and POWERNEXT Prices

Table 5.43 presents the average load weighted PCMU values estimated for France based on the system cost returned by the GED optimal despatch simulation and the POWERNEXT price. Once again one must be wary of the caveat on the estimated marginal costs of the system when assessing the outcomes.

Table 5.43: Average PCMU based on GED System Cost & POWERNEXT Prices (including carbon) - France

	2003-2005	2003	2004	2005
Price-Cost Mark-Up	147.2%	170.9%	123.7%	149.6%

Note: Based on load weighted average prices and costs
Source: LE

One can immediately see that the results of the PCMU calculation indicate mark-ups in excess of the cost of generation in the French electricity market over the period 2003-2005. Based on the average load weighted values of price and cost the calculated PCMU, in the case where the full cost of carbon is included in the cost of generation in 2005, is 147.2%. From Table 5.44 one can see that this figure increases to 168.8% when the cost of carbon in 2005 is excluded form the calculation.

Table 5.44: Average PCMU based on GED System Cost & POWERNEXT Prices (excluding carbon) - France

	2003-2005	2003	2004	2005
Price-Cost Mark-Up	168.8%	170.9%	123.7%	205.5%

Note: Based on load weighted average prices and costs
Source: LE

Price-Cost Mark-Up based on GED Modelled System Cost and Platts Assessment Prices

Table 5.45 presents the average of the hourly PCMU calculated using Platts Assessment prices. These figures are substantially higher than those calculated with respect to the POWERNEXT price, however, once again some of this may be due to premia in forward sales, contract type, which may or may not have any basis in a market power related explanation.

Table 5.45: Average PCMU based on GED System Cost & Platts Assessment Prices (Day-Ahead) - France

	2004-2005	2003	2004	2005
Price-Cost Mark-Up	203.1%	248.0%	162.7%	199.7%

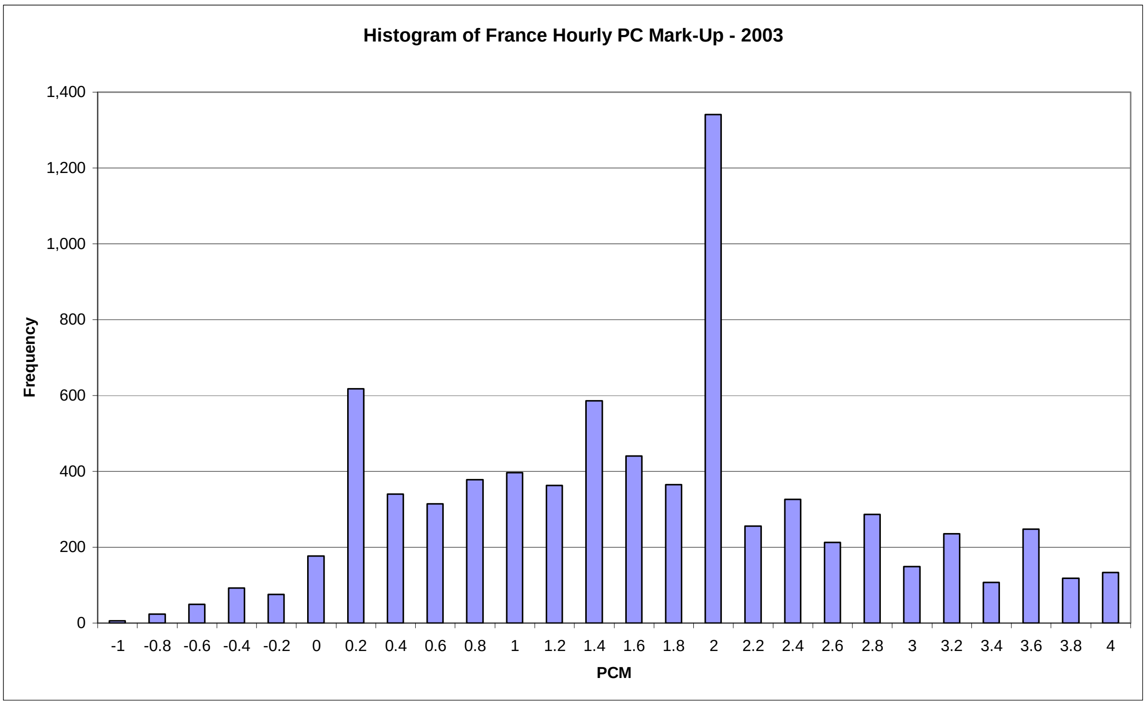
Note: Based on load weighted average prices and costs
Source: LE

Qualitatively, the price cost mark ups are similar to the LIs. There appears to have been an increase in margins from 2004 to 2005, carbon seems to have reduced margins, and the margins based on the Platts prices appear higher. Note that quantitatively, the price cost mark-ups will be higher by construction since price is in general above cost.

5.5.6 Hourly PCM Histograms

The following figures present the histograms of the hourly PCM value in each year. These figures are based on the actual values returned in each hour and are not weighted by the load in that hour. As one can see the vast majority of the returned values are positive and the distribution, save for one spike in each year, is relatively flat indicating that the results above are brought about by consistent outcomes during the course of the year and are not due to exceptional periods within any one year.

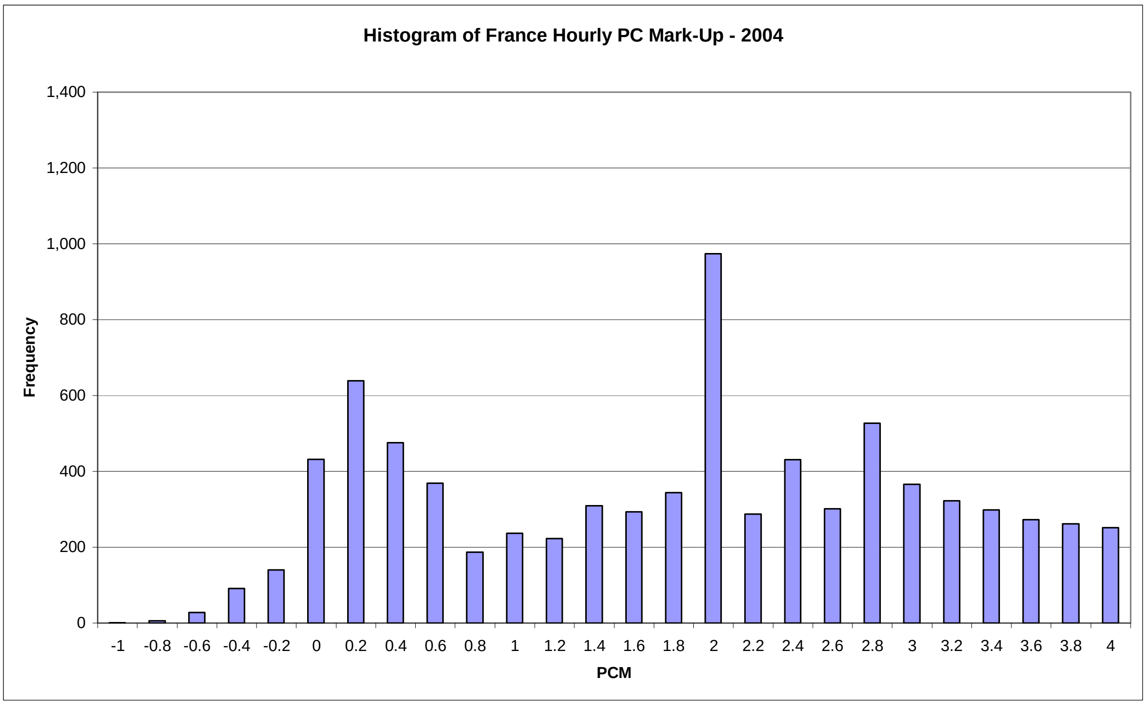
Figure 5.14: Histogram of the hourly Price-Cost Mark-Up – 2003 - France



Note: =7,642

Source: LE

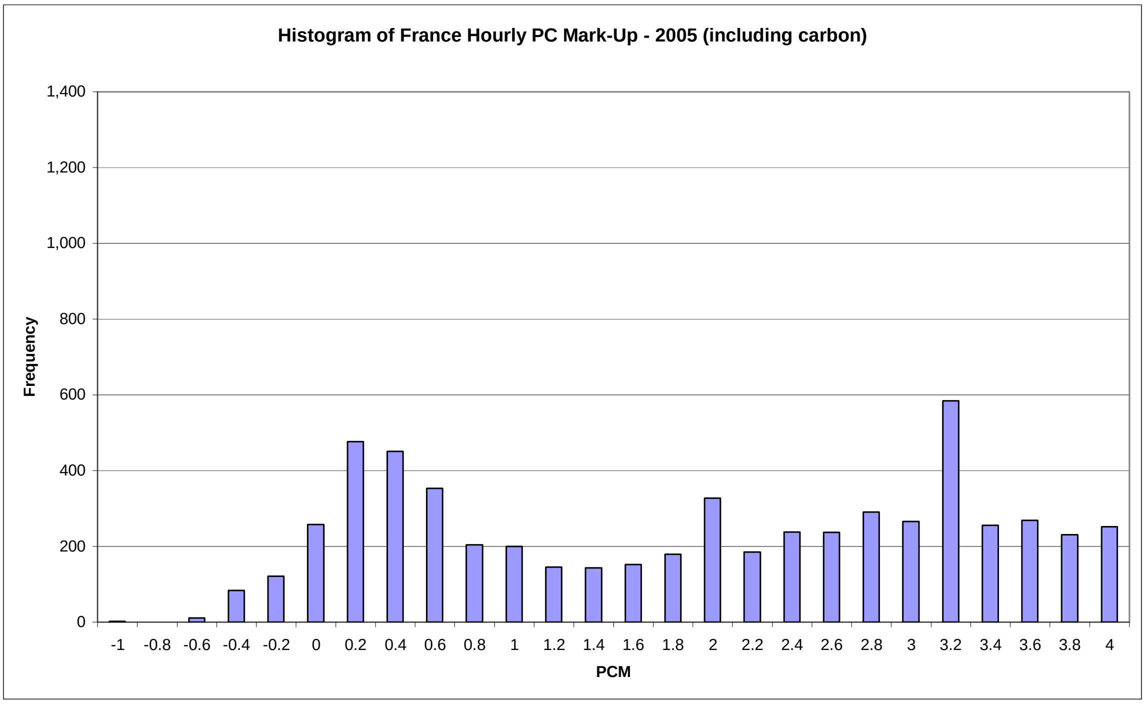
Figure 5.15: Histogram of the hourly Price-Cost Mark-Up – 2004 - France



Note:N=8,072

Source: LE

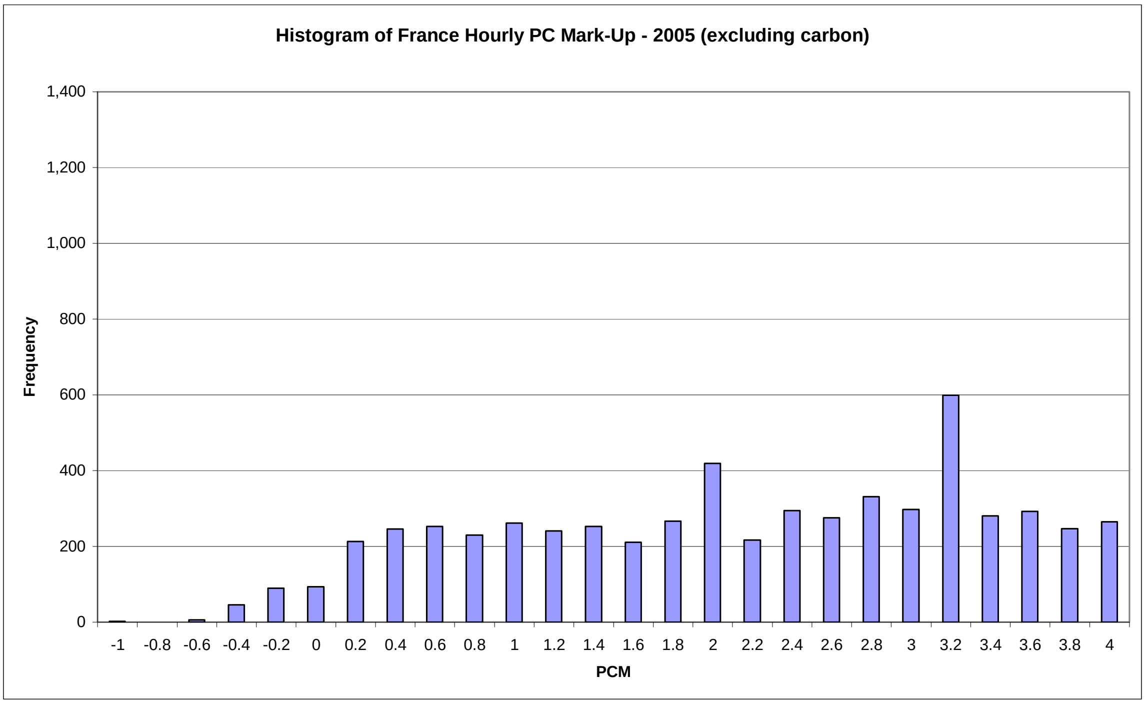
Figure 5.16: Histogram of the hourly Price-Cost Mark-Up – 2005 (incl. Carbon)



Note: N=5,916

Source: LE

Figure 5.17: Histogram of the hourly Price-Cost Mark-Up – 2005 (excl. Carbon) - France



Note: N=5,935

Source: LE

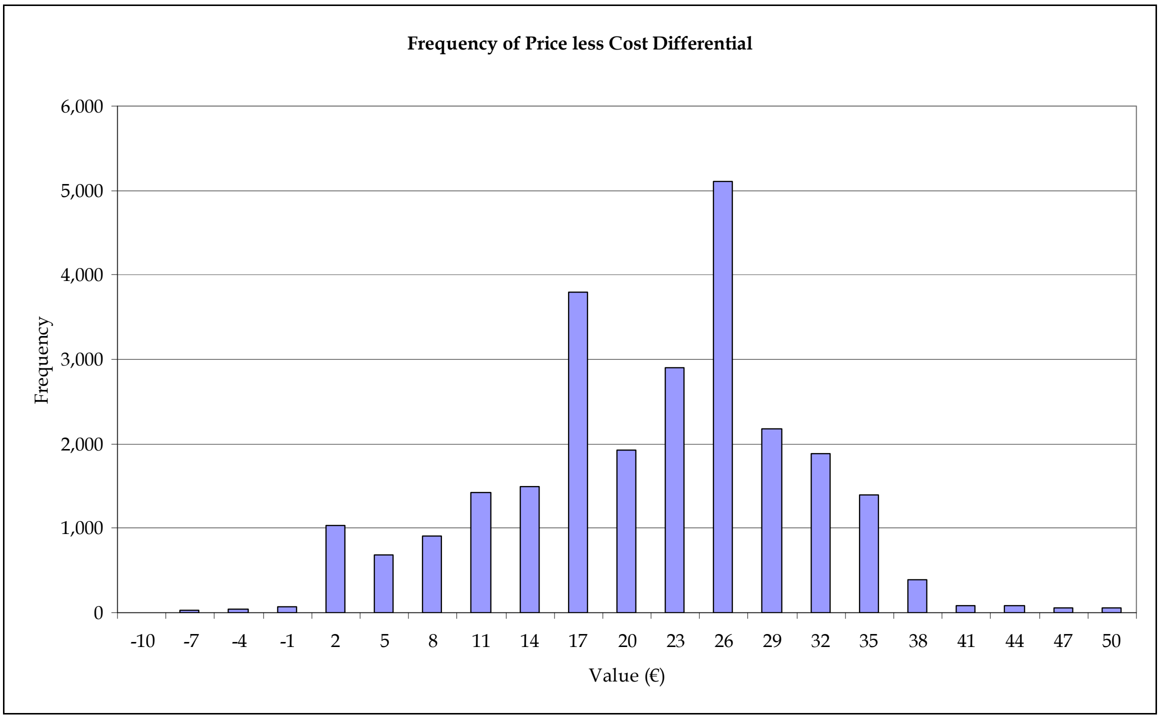
The histograms show the distribution of markups across hours in the year. A few points deserve mention. First, the number of hours is somewhat less than 8760 due to missing value mainly on price. Second, the frequencies of different mark-ups are surprisingly similar and the mean of the distributions is not clearly visible. However, the histograms show marked spikes, which recur with remarkable regularity during the period 2003-2005.

The markup measures themselves can be below zero, and in a limited number of hours this is the case. This is not surprising, as it is likely that, given that a unit is running, it is rational to be willing to pay a premium (run at unit cost rather than purchasing at market) to avoid shutting down. This is due to many factors, including the fact of start costs and uncertainty of being redespatched. There also may be engineering or other reasons to avoid shutting the plant and restarting it frequently, such as risk of forced outage.

5.6 Price Cost Differential

Underlying both the LI and PCMU analysis is the basic relationship between Price and Cost. Both of the outcome measures presented previously are unitless measures and in this section a more tangible indicator of the potential mark-up is presented. The following graph represents the frequency, over the three-year period, of the difference between the hourly POWERNEXT Price and the System Cost estimated by GED as a result of their optimal despatch simulation. Once again however, one should apply the caveat in relation to the estimated marginal cost brought about by difficulties fully accounting for changes in the availability of nuclear capacity, even when a reasonable assumption on the impact of partial outages is implemented, when considering this result.

Figure 5.18: Frequency of the Price *less* Cost Differential (2003-2005) - France



Source: LE

The price-cost mark-ups are absolute Euro/MWh figures, whereas the PCMU and LI are alternatively unitless figures. The usefulness of this measure is to put actual euro figures on the mark-ups. The vast majority of mark-ups are between about -11 and 35 €/MWh, with the highest frequencies occurring between 17 and 26 €/MWh. The mean, median and mode of the distribution is greater than zero.

Regression analysis was not carried out for France because it was our opinion that the system marginal cost modelling did not adequately capture variations in the marginal cost of electricity, due to the data problems in relation to the reporting the true capacity of the French nuclear plants. This was due to an apparent mismatch between the reported and actual availability of nuclear units unaccounted for by the outages reported for the units. Essentially, model results were showing an extremely low achievable marginal system cost in most hours—given that the model despatched nuclear plants to full capacity and in a number of hours where this was not sufficient to meet demand, pumped storage capacity was utilised to shave the load such that nuclear units were once again marginal. This combined with the fact that the structural evidence is unequivocal in terms of the concentration of the market led us to conclude that the regression analysis was not appropriate for France.

5.7 Carbon Impact in 2005

As is apparent from the previous analysis, the cost of carbon is included in the GED optimal despatch model for 2005 in order to take account of the introduction of the ETS in that year. In order to quantify the impact of the introduction of this scheme, the GED optimal despatch model of 2005 has been compared with a scenario model of that year, within which the cost of carbon is reduced to zero. Not only will this affect the unit costs of emitting stations but it will also alter the optimal system despatch. Table 5.46 presents, for selected months, the modelled difference between the system cost in the model that includes the cost of carbon and the alternative scenario where the cost of carbon has been reduced to zero.

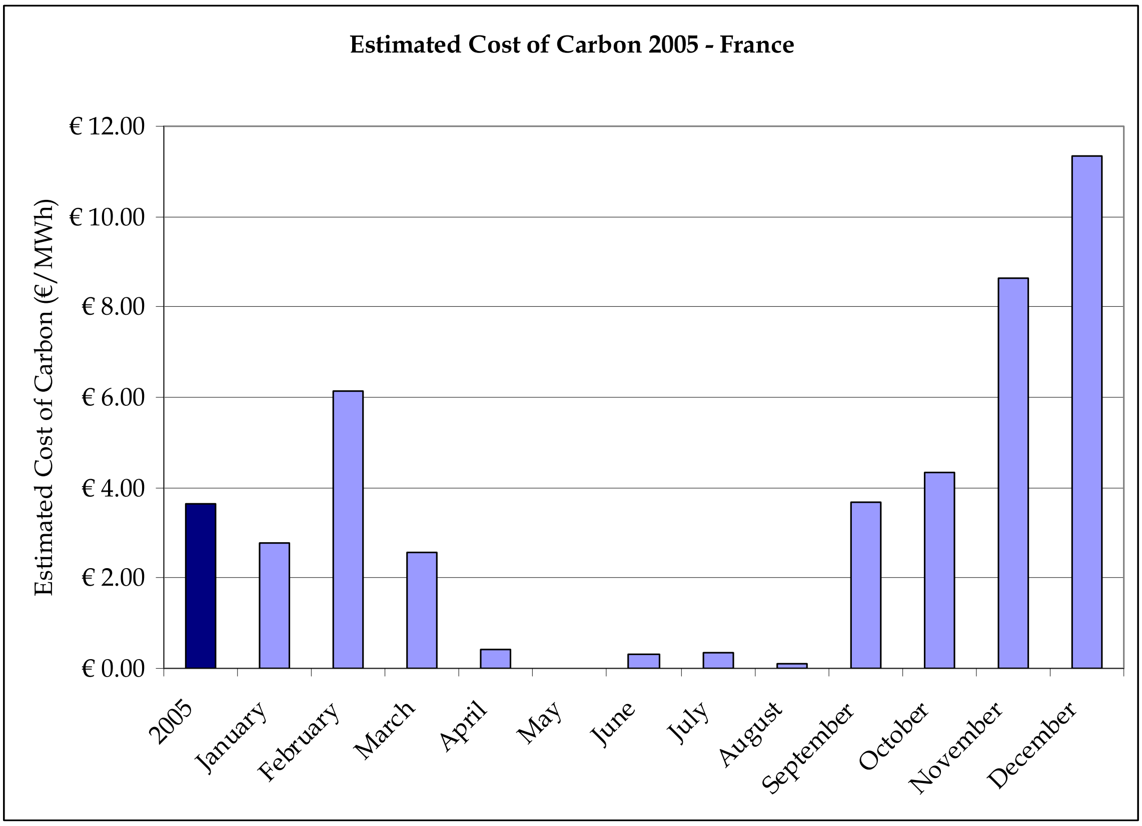
Table 5.46: Summary Statistics on the Modelled Impact of Carbon in 2005 - France

	2005	January	April	August	October
Average	€ 3.65	€ 2.76	€ 0.42	€ 0.12	€ 4.33

Note: Based on load weighted average prices and costs
Source: LE

Figure 5.19 presents the evolution of this differential over the year. One can clearly notice a seasonal pattern in the cost of carbon from this graph, however it is unlikely that one can decompose this effect from the difficulties encountered in relation to the French electricity market. Nonetheless if one expects conventional thermal capacity to play a greater role in the French market in practice then one would also expect to see higher carbon contributions to the hourly cost in 2005.

Figure 5.19: Average Monthly Cost of Carbon – 2005 - France



Source: LE

It is important for one recall at this point the discussion presented in relation to the merit curve both with and without carbon in the introductory section of this chapter. This discussion highlighted the point that one cannot simply estimate the cost of carbon for the system based on the cost of carbon for the marginal unit as the marginal unit may potentially be different between the carbon and no-carbon merit curves as units are not monotonically affected by the ETS and the cost of carbon and in reality the ordering of units on the merit curve is likely to change as a result of including the specific €/MWh cost of carbon, for each unit.

Furthermore, the estimated impact of the introduction of the EU ETS will depend on how much of the value of CO_2 is factored in by operators, however, it has not been possible to discern this information from the data returned by the companies. Therefore, the amounts reported in this study correspond to the maximum possible impact of the ETS, if generators fully factor in the price of the CO_2 certificate in a competitive environment.

5.8 Withholding

Withholding is a strategy that may be entered into by companies in an attempt to manipulate the price of electricity on the market. Conceptually such a strategy would involve a company withholding generation capacity generally located to the left of the merit curve, but in any event it must be in merit, thus causing capacity further to the right of the merit curve, that previously was not required to meet the specific load level, to turn on an therefore set the market price at a higher level. Importantly, the capacity that is forced to come online does not have to belong to the company exercising the withholding strategy as everyone will get the same market price for electricity irrespective of who owns the unit setting the market price.

The GED model of optimal system despatch can provide the modelled hourly generation data for each specific unit. This can be compared with the actual hourly generation patterns of the units in an attempt to identify potential systematic withholding of generation assets. We note that there are a variety of reasons why the modelled generation pattern may not match the actual, and not all of these may be correlated with market power use. One such reason, for example, could involve the possibility of multiple optima or multiple 'nearly optimal' solutions to the least cost despatch problem. Thus we cannot distinguish with too much certainty that the measured withholding truly represents evidence of anti-competitive behaviour.

In relation to France one is once again limited in the interpretation of these results by the difficulties encountered in relation to the data provided on the French market. The failure of both the reported data and the assumption adopted in relation to partial outages to account for the considerable difference between the modelled available capacity and actual generation record of nuclear units in France leads one to consider other potential reasons for the apparent withdrawal of nuclear capacity availability from the market over the period of the study. A number of technical and operational aspects of these units were potentially unable to be accounted for with the data provided and as a result these units are utilised more in the optimal scenario than appears to be possible in reality. However, in considering a range of potential explanations one must also consider the possibility that companies in France engaged in a systematic withdrawal of nuclear capacity from the system.

Nevertheless, the results of this section do indeed go some way to explaining the cause of some of the outcome measures calculated within this chapter, but more investigation is needed. On average this section points to the apparent over utilisation of coal and under utilisation of nuclear powered capacity.

Table 5.47 presents the total generation capacity installed in France split by generation technology.

Table 5.47: Total Installed Capacity of modelled Units, by Technology - France

Gas	Coal	Nuclear	Pump storage	Other	Total
1,873	8,003	63,620	4,464	17,964	95,924

Source: LE

The following tables present the number of hours and the percentage of time that modelled generation exceeded actual generation, on an hourly basis, as well as the absolute difference between modelled and reported generation. Our analysis indicates that there has been potential withholding of nuclear generation by company 0472-S-FR during the period 2003-2005.

Table 5.48: Potential Withholding, by Technology, for 0472-S-FR, (Number of hours where modelled is greater than actual generation) - France

	Gas	Coal	Nuclear	Pump Storage	Other
2003-05	439	922	25,432	7,885	8,801
% hrs<0	1.7%	3.5%	96.7%	30.0%	33.5%
2003	0	290	8,384	2,399	3,122
% hrs<0	0.0%	3.3%	95.7%	27.4%	35.6%
2004	438	359	8,537	2,491	3,161
% hrs<0	5.0%	4.1%	97.2%	28.4%	36.0%
2005	1	273	8,511	2,995	2,518
% hrs<0	0.0%	3.1%	97.2%	34.2%	28.7%

Source: LE

Table 5.49 presents evidence of potential withholding for Company 0472-S-FR. As one can see, on average, in each hour of the period covered by the study (2003 – 2005), an excess of 2.48GW of available installed nuclear capacity was utilised by the model over that utilised in reality. Over time this difference displays substantial variation and at times is far in excess of the reported average value. Interestingly, the relative under-utilisation of nuclear capacity vis-à-vis the modelled outcome, based on the data returned by the company with which we accounted for their reported outages, occurs simultaneously with an apparent over-utilisation of coal fired generation capacity in the market. Although there is potentially a wide range of explanations for this result, and a caveat on the analysis has already been stated, one must consider the possibility that this company has engaged in behaviour consistent with a systematic withdrawal of nuclear capacity in this market.

Table 5.49: Potential Withholding, by Technology, for 0472-S-FR						
	Gas	**Coal**	**Nuclear**	**Pump storage**	**Other**	**Total**
2003-05	157	1,292	-2,481	52	276	-704
2003	182	1,373	-2,494	109	229	-602
2004	168	1,151	-2,309	87	215	-688
2005	120	1,354	-2,640	-41	383	-824

Source: LE

Table 5.50 presents the number of hours and the percentage of time that modelled generation exceeded actual generation, on an hourly basis, for company 1449-S-FR.

Table 5.50: Potential Withholding, by Technology, for 1449-S-FR, (Number of hours where modelled is greater than actual generation)					
	Gas	**Coal**	**Nuclear**	**Pump Storage**	**Other**
2003-05	-	1,926	-	-	-
% hrs<0	-	7.3%	-	-	-
2003	-	196	-	-	-
% hrs<0	-	2.2%	-	-	-
2004	-	628	-	-	-
% hrs<0	-	7.1%	-	-	-
2005	-	1,102	-	-	-
% hrs<0	-	12.6%	-	-	-

Source: LE

Table 5.51 presents evidence of potential withholding for Company 1449-S-FR.

Table 5.51: Potential Withholding, by Technology, for 1449-S-FR						
	Gas	**Coal**	**Nuclear**	**Pump storage**	**Other**	**Total**
2003-05	-	610	-	-	-	610
2003	-	623	-	-	-	623
2004	-	686	-	-	-	686
2005	-	521	-	-	-	521

Source: LE

5.9 Conclusions

The case of France is unique among the markets studied for a variety of reasons. France is the biggest market studied, and also one of the most concentrated. France is a concentrated market by any measure. The range of HHI and CR(*n*) did not come anywhere close to figures that would be considered unconcentrated. While new electricity-specific market structure measures confirmed the market structure (i.e., the largest operator was pivotal 100% of the time, extensive analysis merely confirmed with precision what was known in advance. There is no chance that added interconnection or other such sensitivities will change the qualitative conclusions about France.

France's reliance on nuclear capacity coupled with hydro give it a very low estimated marginal cost in many hours. Study of the apparent differences between the modelled output of nuclear and its actual output led us to be cautious about the results due to what appears to be an over-estimation of the availability of nuclear capacity in France. We believe this to be likely a data issue on the reported capacity of nuclear plant versus their actual running. We cannot tell with any great certainty whether this difference is due to some kind of exercise of market power or rather some rationale that is benign and a function of how French nuclear plants are operated. Nevertheless even if one could correct for this, the load profile in the French market indicates that Nuclear capacity would remain setting the price in a large number of hours in the market. This leads one to further consider the ability of firms to amortise fixed costs in a market where infra-marginal rents are not apparent due to the flat nature of the merit curve. Although a calculation of the contribution to fixed cost was not undertaken, due to potentially difficulties in interpretation as a result of the absence of data about how much the fixed costs of French nuclear units represent and how much of these costs are really amortised, this issue means that similarly no real conclusions can be reached in relation to the market outcome measures. A caveat applies in relation to these figures, not because they are not correct but because given the current data one cannot discern whether market characteristics or market behaviour are determining the results. With these cautions in mind, however, France had some of the highest margins of any country studied.

In addition, smaller impacts from carbon and fuel cost rises are observed in France, as would be expected given their dependence on nuclear and hydro capacity. We did not perform further analysis on France using regression analysis, given the caveats on the calculated outcome measures.