Modelling competitive electricity markets: are consumers paying for a lack of competition? (1)

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Introduction
When, at the beginning of 2005, the European Commission decided to carry out the energy sector inquiry (2), one of its reasons for doing so was the numerous complaints it was receiving about increases in electricity prices, which many felt were due to a lack of competition, and could not be justified by increasing fuel costs (see figure 1).

Figure 1 — Weekly average power exchange prices 2002-2005

In February 2006, when DG Competition released its preliminary report on the sector inquiry, the data gathered clearly pointed to several competition problems in electricity markets, in particular high levels of concentration and a lack of confidence in the prevailing price formation mechanisms. Given these results, it was decided to commission an in-depth study (3) to determine whether there is a systematic difference (mark-up) between price levels recorded on electricity wholesale markets and what they would have been, had the markets been fully competitive.

Given that electricity markets operate on an hourly basis and involve hundreds of production units, such a study requires large amounts of detailed data (4). It was thus necessary to focus the study on specific Member States and a relatively limited time frame. DG Competition chose to “drill down” on the three-year period of 2003 to 2005, for the six Member States for which it had received most complaints early in the sector inquiry, namely (5): Belgium, France, Germany, United Kingdom (in fact, only Great Britain, that is to say, the United Kingdom less Northern Ireland, was included in the sample), the Netherlands, and Spain. With this limited focus, an in-depth investigation was possible.

This article gives a broad overview of the study and its findings. A detailed report is available on the Commission’s thematic Web site on competition policy (6). First we explain the methodology applied. Secondly, we explain some of the practical issues and data assumptions. Thirdly we report on the essential tests that were carried out to verify the robustness of the model. Fourthly we present the main results as regards mark-ups, the relation between concentration and mark-ups and production.

The methodology
As shown in the Final Report of the energy sector inquiry (7), most developed electricity wholesale markets operate in the short-term for the day-ahead trade on an hourly basis (8) in order to be able to follow the changing patterns of demand. In practice, in all markets studied (except Belgium), there is a “power exchange” (9) which matches demand and supply bids in corresponding national territories on an hourly basis on the

(1) The content of this article does not necessarily reflect the official position of the European Communities. Responsibility for the information and views expressed lies entirely with the authors.
(2) See Competition policy newsletters number 1 of 2006 and number 1 of 2007 for a detailed presentation of the sector inquiry. All documents of the sector inquiry and the report of the study are available on the website of DG Competition at: http://ec.europa.eu/competition/sectors/energy/inquiry/index.html.
(3) The full report of the study is available on the website of DG Competition; see footnote 2 for the address.
(4) The study in the end relied on more than a billion data points.
(5) In fact, there were complaints also as regards the Italian wholesale market, but these were already being addressed by the National Competition Authority.
(6) The report of the study is available on the website of DG Competition at: http://ec.europa.eu/competition/sectors/energy/inquiry/index.html.
(7) Final Report on the energy sector inquiry, paragraph 353 and following.
(8) The only exception is the UK, which operates on a half-hourly-basis.
(9) Referring to the Final Report of the sector inquiry it is known that the level of liquidity and volumes of electricity traded differ per power exchanges and further there are additional trade places such as over the counter markets. These have been taken into account in the study.
day before delivery \(^{(10)}\). The exchanges report thus prices of electricity delivered in their territories (in €/MWh) for each hour of each day \(^{(11)}\). In a nutshell, the aim of the study was thus to calculate the difference ("mark-up") between these hourly prices and what prices would have been if markets had been competitive \(^{(12)}\). In the case of Belgium, where there were no market prices during the period studied, such comparison is less meaningful but it was still considered useful to carry out the simulation to assess the impact of external constraints on electricity prices \(^{(13)}\).

Economic theory and practice by electricity operators suggests that the price on short-term perfectly competitive markets is set by the short run marginal cost of the last unit required to meet demand \(^{(14)}\). This is illustrated by the following figure showing the supply curve of a theoretical market (where technologies are ranked in the merit order of their variable costs) and the demand curve (load), which is usually close to a vertical line illustrating that the level of demand is usually rather insensitive to prices. The price (and quantity) of the market is decided by the crossing point between the two curves. This theory is also standard practice in the sector: in their answers to DG Competition questionnaires in the sector inquiry operators confirmed that they use this approach in their operations and in their analysis of markets.

Figure 2 — Schema of the supply and demand curve in short-term electricity markets

There are of course some theoretical assumptions behind this model. One of them deserves special attention, i.e. the issue of fixed (investment) costs. The generation technologies with the lowest variable costs (e.g. nuclear or lignite-fuelled plants) are usually the ones with the largest fixed (investment) costs, while the generation technologies with the largest variable costs (e.g. oil and gas-fired plants) are usually the technologies with the lowest fixed costs. Thus, the first ones are considered (by academics and operators) to rely on the price set by the higher variable costs of the second ones to amortise their fixed costs. This is shown in the same theoretical example in the figure below \(^{(15)}\).

Figure 3 — Schema of contributions to amortization of fixed costs in short-term electricity markets

\(^{(10)}\) In the case of UKPX, demand and offer can be matched until a few hours before delivery.

\(^{(11)}\) In France, Germany, the Netherlands and Spain, power exchanges determined hourly prices through a single auction mechanism. In Great Britain, the half-hourly price is reported by UKPX based on continuous trade that is carried out on its platform for half-hourly products.

\(^{(12)}\) The study also compares the results of the simulation with average day-ahead prices.

\(^{(13)}\) Untill Belpex, the Belgium power exchange, was launched at the end of 2006, there were no hourly prices in Belgium; there was also little public trade and the main publicly available price was a daily price index (the Belgium Price Index) published by the incumbent (Elektrobel) on weekdays.


\(^{(15)}\) In reality, in a given market there are both new and old plants and the latter do not need contributions to fixed costs if they are fully amortised. Further, the merit curve contains many plants and the steps on the curve are many, which means, given the variation of demand between peak and off-peak, that virtually all plants (except the ones on the far right of the curve), enjoy a price which is set during some hours by a more expensive plant and thus get contributions to fixed costs. Finally, the plants on the far right side of the merit curve called at peak are usually old plants whose fixed costs are fully amortised.
This is an important theoretical concept that, as far as we know, has never been checked against economic reality. One can still simulate the perfectly competitive market as described above but one would need to check that the contributions to fixed costs created by the price of the theoretically competitive market are sufficient. At the request of DG Competition, this study is a first of its kind, which carried out such an analysis.

**Simulating competitive markets in practice**

In order to apply the theory and simulate the competitive outcome (hourly price and volume) one needs to take into account all information about availability of each plant (i.e. information about outages and maintenance) hour by hour during the period as well as information about variable costs of operation of each plant hour by hour during the period. Then the market can be simulated by dispatching all available plants in order to serve the load (consumption) registered in that hour while minimizing generation costs. In the simplest way, it means drawing up a chart equivalent to that in Figure 2: ranking up in each hour all available plants in the order of their costs and selecting the cheapest ones to meet the load.

However, the practical simulation is very complex since there are many (economic, technical and regulatory) constraints on plants affecting the extent to which a plant can be dispatched to serve demand.

For instance, as regards economic constraints, plants have *inter alia* start-up costs, which can be very high (12), as well as technical constraints (so-called minimum-up-times and minimum-down-times) which prevent the plants from being turned on and off repeatedly. Some plants also must produce electricity (they are so called “must-run” plants) during certain periods because of obligations to supply electricity to the Transmission System Operator to solve congestions in the network or because they also have to produce heat (CHP—Combined Heat and Power plants) for other purposes (industrial process, district heating). Also hydro plants can store their “fuel” and thus can arbitrage in time.

Given these and other specificities of electricity production and that supply and demand are matched on an hourly basis (meaning 26,304 hours for the period covered), the simulation required a state-of-the-art software to simulate dynamically electricity markets. This and the need to be advised on the specific conditions of electricity markets led DG Competition to commission the study from an external consultant while asking this consultant to carry out the work on DG Competition premises to protect the full confidentiality of the data. The consultant selected through an open tender process was London Economics, in association with the data and software provider Global Energy Decisions.

DG Competition then proceeded to collect all relevant data from generators: technical characteristics of plants, prices of fuels, efficiency of the plants, effective output for all hours etc. This data (17) was checked for consistency and to the extent necessary generators were asked to correct the data provided. The simulation was to be based on all generators with more than 250MW of installed generation capacity (18) in the six markets. This meant that data was collected from more than a hundred companies relating to more than a thousand power plants.

Once data from generators was collected and checked a number of issues raised by the practical simulation were addressed. The most important are:

First, what value should be used for the load? Previous studies (19) usually rely on measurements of consumption made by Transmission System Operators on their networks. DG Competition had indeed separately collected data about the total consumption recorded by the operators of the transmission networks on their networks on an hourly basis during the period. However, this consumption was smaller (and in some cases very much so) than the sum of the generation reported by all generators which had provided data. This was due to the fact that some power plants are connected to lower-voltage distribution networks. It was thus necessary to take as a load for the simu-

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(12) Start-up costs can be more than ten times more expensive than the price of fuel for production during a whole day.

(17) All data from the generators was processed and analysed in the premises of 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.

(18) The threshold of 250MW was decided to cover in practice almost all power plants which contribute to the determination of electricity prices, since the plants of smaller operators are usually not selling their output on public markets.

lation the sum of generation of all plants included in the study to obtain a more complete picture of the market.

The second question that arose was how to model the interconnections between markets? It was difficult to model all of them, since data included only a selection of the European markets. However, because the load used for the simulation is equal to total generation in each market, this load takes into account the imports and exports that actually occurred during the period \(^{(20)}\). Simulating on that basis thus takes into account the current importing and exporting nature of the market (and the downward or upward consequences on prices).

Thirdly, electricity markets require some reserves to balance supply and demand at all times \(^{(21)}\). The simulation thus ensured that such reserves would be met \(^{(22)}\), the simulation also addressed the specifics of certain power plants, such as minimum and maximum up-time, must-run nature, etc. \(^{(23)}\).

Fourthly, there is always an issue with simulations done ex-post: they are inevitably distorted by the fact that they are made with the benefit of hindsight — and thus simulate a market without uncertainty about future availability of production assets and future demand. However, this distortion has been minimised to the extent that it does not affect the reliability of the results. This is first of all due to the fact that the level of the load in electricity markets is in fact very much predictable in the short-term: the hypothesis of perfect foresight on the part of the generators is thus not far from reality. In the simulation, decisions depending on the load have thus been made with information equivalent to what was available to generators in reality\(^ {24}\). Further, the simulation was designed so as to avoid exaggerating the impact of arbitrage in time on the operation of hydro-power facilities. In the electricity sector, arbitrage in time is very much limited by the fact that electricity cannot be stored; however, there is one exception: hydro power. In order to take a conservative approach, the simulation therefore never ran the hydro power plants more than they did in reality each week. In other words, the simulation did not try to create more arbitrage on the long-run, it only maximised arbitrage between peak and off-peak periods within each week.

Finally, there was one specific issue for the year 2005, when the European Trading Scheme (ETS) for CO\(_{2}\) allowances came into force. Modelling this issue is not straightforward because the generators have been given a large part (e.g. in Spain and in the UK) or all (e.g. in Germany) of the CO\(_{2}\) allowances they need in the first period for free. Nobody doubts that allowances purchased by generators are a cost that they factor into the price of electricity. In principle, the opportunity cost of not selling valuable allowances, even if they were obtained for free, would be factored in as well by operators in a competitive market. However, there may be constraints on the opportunity to sell the allowances: for instance, in an ongoing antitrust procedure\(^ {25}\), the Bundeskartellamt finds that certain German operators could not pass the full CO\(_{2}\) opportunity costs onto their customers if they were in a competitive market. Thus, it is not clear whether the modelling of a competitive market, should be based on the factoring of the full value of CO\(_{2}\) allowances into the price of the electricity they offer when they obtained these allowances for free\(^ {26}\). Therefore, for 2005 two scenarios were calculated. First a simulation was executed on where the cost of CO\(_{2}\) allowances was fully factored in as a cost even if enough allowances were allocated for free (scenario "with carbon"). Then a second simulation was carried out based on the assumption that the CO\(_{2}\) Emission Trading Scheme had

\(^{(20)}\) The equation of an electricity market is: consumption + exports + generation + imports.

\(^{(21)}\) Day-ahead markets cannot foresee perfectly demand, thus it is necessary for network operators to contract in advance capacity to be made available to them and that they can call upon to generate electricity (or diminish electricity production) to meet last minute imbalances between offer and demand.

\(^{(22)}\) In practice, in order to simplify the data input, the simulation adopted a requirement of 5% of total demand, which was larger than what occurred in reality. In markets where there were larger requirements in reality (Germany), the simulation was also done with a 10% requirement: this did not change substantially price outcomes.

\(^{(23)}\) As explained above, the simulation took into account the technical regulatory and other constraints on plants. The simulation also defined the profile of production of storage and pump-storage hydro plant as peak-shaving: they sold in the simulation at peak time within the limits of their reported weekly production; in addition, pump storage plants stored water during off-peak hours.

\(^{(24)}\) In particular, all decisions about whether to turn on or off a plant, with due regards to its start-up costs, have been made essentially on the basis of the shape of the actual load the day after: this is in most cases the shape that could be predicted by the operator.

\(^{(25)}\) Cf. press release of 20 December 2006: Bundeskartellamt issues warning to electricity provider on account of excessive electricity prices within the context of CO\(_{2}\) emission allowance trading.

\(^{(26)}\) In its procedure against one German generator, the German competition authority (the Bundeskartellamt) finds that there are constraints on the opportunity to sell and thus that the pricing-in of CO\(_{2}\) allowances is not fully justified. The purpose of the study was not to analyse whether or not generators are allowed to factor in CO\(_{2}\) certificates.
not been introduced (scenario “without carbon”). In the scenario “with carbon”, the cost of a given plant thus includes the value of CO₂ allowances for that plant (27) whereas in the scenario “without carbon”, the cost of the plant does not include the value of CO₂ allowances. Each scenario (“with carbon” and “without carbon”) led to a marginal cost of the system in each hour where a different unit may set the price in each scenario. It follows that the impact of ETS is equal to the difference between the two marginal costs estimated (28).

Checking fixed costs

As explained in the section on methodology, there could be a concern that the contributions to fixed costs generated in the model applied are not sufficient to amortize fixed costs. The simulation showed however that, for all markets but one, the contributions to fixed costs are sufficiently large for each operator to invest in new plants. In practice, the study estimated that the contribution to fixed costs necessary for a generic 400MW gas-fired CCGT plant would be about 68,000€/MW/year and for a generic 1000MW coal-fired CCGT plant would be about 61,900€/MW/year. In Germany, the UK and the Netherlands, the contributions to fixed costs per MW of installed capacity for all operators in the market were above these references. In Spain, the average contribution was lower (about 50,000€/MW/year), but given that this calculation is based on the assumption that all plants in the market would be new whereas some of them are already amortised, it was concluded that the contribution to fixed costs would be sufficient there as well.

There is one country where this verification could not be carried out, namely France. The merit curve of that market is very flat: it essentially consists of some hydro and many nuclear power plants. The prices of competitive markets under the simulation are thus — during many hours — set by nuclear plants given that there are enough such plants to meet both domestic demand and existing exports in most hours. In such circumstances, operators in the theoretically competitive market could not recover their fixed costs by simply offering their power at marginal costs (no more expensive plant is setting the price for most hours). The applied theoretical model does not yield reliable results and the data on France is thus not included in this article (29).

The results

Significant mark-ups in all markets

Table 1 presents for each market and for every year the price (30) that could have been expected in a perfectly competitive market (in the table referred to as “cost”), the actual price of the power exchange in that market and the difference between the two (the “mark-up”). In 2005, there is also a “Carbon” value, which is the maximum potential impact of the ETS as defined above, and, for that year, the mark-up is presented as the difference between the actual price of the exchange and the sum of the “cost” and “carbon” components. For a proper interpretation of this table one should keep in mind that an increase of one €/MWh of the wholesale electricity price will mean an increase of one €/MWh plus taxes for all customers. An average industrial user consumes 24,000MWh per year (31).

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(27) The value of CO₂ allowances for a given plant (per MWh) is estimated by multiplying the emissions of that plant (tonne/MWh) by the value of a tonne of carbon (€/t), as provided by the market for CO₂ allowances. In its procedure, the Bundeskartellamt finds that the generator involved could not have factored the value of CO₂ allowances into the price of electricity for more than 25% of the allowances.

(28) In this respect it is important to note that this estimation is the maximum possible impact of ETS as the scenario “with carbon” relies on the assumption that all companies fully price in the value of all CO₂ allowances that they use.

(29) In practice, operators of nuclear plants in the competitive French market would include some add-on to the price at which they offer to cover their fixed costs. This depends on the age of the plants in the portfolio. In addition, given the lower price obtained in the French market compared to other markets, there would be more exports than what occurred in reality and prices would be driven up further. A test case was done in that latter respect.

(30) More precisely, all prices in the table are weighted averages of the prices registered for all hours: the price of each hour in the period is weighted by the load experienced in that hour. The same applies for the “Carbon” value.

(31) The wholesale price of electricity is the “energy component” of the end-user’s bill; the end-user’s bill also includes the fees for networks as well as taxes; these latter two elements together represent at a minimum a bit less than the energy component in the case of the large industrial users, and at a maximum twice as much as the “energy component” of the end-user’s bill in the case of households. The end-user’s bill also includes a much smaller component (which is equal to a few percentage points of the total price at maximum): the margin of the retailer.
Table 1 — Contribution to Power Price (€/MWh)

<table>
<thead>
<tr>
<th>Country</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
</tr>
</thead>
<tbody>
<tr>
<td>BE Belgium</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost</td>
<td>29.75</td>
<td>31.70</td>
<td>50.40</td>
</tr>
<tr>
<td>Carbon</td>
<td>0.00</td>
<td>0.00</td>
<td>10.11</td>
</tr>
<tr>
<td>DE Germany</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost</td>
<td>19.46</td>
<td>24.27</td>
<td>28.17</td>
</tr>
<tr>
<td>Carbon</td>
<td>0.00</td>
<td>0.00</td>
<td>3.86</td>
</tr>
<tr>
<td>Mark-Up</td>
<td>11.42</td>
<td>5.36</td>
<td>6.39</td>
</tr>
<tr>
<td>Total</td>
<td>30.88</td>
<td>29.63</td>
<td>48.42</td>
</tr>
<tr>
<td>EEX Price</td>
<td>30.88</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ES Spain</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost</td>
<td>23.95</td>
<td>27.51</td>
<td>33.65</td>
</tr>
<tr>
<td>Carbon</td>
<td>0.00</td>
<td>0.00</td>
<td>9.52</td>
</tr>
<tr>
<td>Mark-Up</td>
<td>6.29</td>
<td>1.39</td>
<td>12.20</td>
</tr>
<tr>
<td>Total</td>
<td>30.24</td>
<td>28.89</td>
<td>55.97</td>
</tr>
<tr>
<td>OMEL Price</td>
<td>30.24</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NL Netherlands</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost</td>
<td>36.26</td>
<td>34.64</td>
<td>50.50</td>
</tr>
<tr>
<td>Carbon</td>
<td>0.00</td>
<td>0.00</td>
<td>9.52</td>
</tr>
<tr>
<td>Mark-Up</td>
<td>11.99</td>
<td>-0.63</td>
<td>-3.09</td>
</tr>
<tr>
<td>Total</td>
<td>48.24</td>
<td>34.01</td>
<td>56.93</td>
</tr>
<tr>
<td>APX Price</td>
<td>48.24</td>
<td></td>
<td></td>
</tr>
<tr>
<td>GB/Great Britain (32)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost</td>
<td>—</td>
<td>33.33</td>
<td>39.06</td>
</tr>
<tr>
<td>Carbon</td>
<td>—</td>
<td>0.00</td>
<td>10.00</td>
</tr>
<tr>
<td>Mark-Up</td>
<td>—</td>
<td>1.25</td>
<td>6.35</td>
</tr>
<tr>
<td>Total</td>
<td>—</td>
<td>34.58</td>
<td>55.41</td>
</tr>
<tr>
<td>UKPX Price</td>
<td>—</td>
<td>34.58</td>
<td>55.41</td>
</tr>
</tbody>
</table>

Note: all values in this table are load weighted average values. “Cost” is the price of the simulated competitive market.

The table shows first that prices of competitive markets should have remained rather stable at around 30€/MWh between 2003 and 2004 (cf. rows on costs) in most markets reflecting the moderate growth in demand and the stable fuel prices. However in 2005 a substantial increase of electricity prices in 2005 can be observed, which can at least partly be explained by higher fuel costs in certain markets. Indeed, in Belgium and the Netherlands fuel price increased significantly explaining the 50% increase of the competitive price. These two markets rely substantially on gas to meet electricity demand (33). The contribution from rising fuel prices to electricity price increases in Spain and UK is lower: about 20% of the competitive price of 2004. In Spain and the UK gas is only indispensable to meet demand at peak hours whereas coal-fired plants are sufficient to meet demand at many off-peak hours. The impact of fuel price rises is even lower in Germany (more or less 16% of the competitive price of the year before), where coal-fired capacity is even larger. The difference (in €/MWh) is more than fourfold between the extreme cases and underlines the impact of the different fuel strategies pursued by the member states.

As regards CO2, the maximum ETS impact depends on the emitting nature of the plants: coal-fired plants emit more than gas-fired plants and nuclear and hydropower plants do not emit CO2 at all. The results show thus that the maximum effect of the ETS is largest (roughly 14€/MWh) in Germany, which has the largest fleet of coal-fired plants. The effect is roughly equal to 10€/MWh in most other markets (34). Again, the national choice of fuel mixes has different impacts for users.

The table reveals further that electricity prices have been roughly 10€/MWh above the competitive price in 2003 for all markets where the comparison can be made: this meant for that year roughly 240,000€ were paid too much by an average industrial user for its electricity. The mark-up has narrowed down significantly for all markets in 2004 but increased again for Germany, Spain and the UK (35) in 2005. If one adds the carbon effects, 2005 was a very profitable year for the electricity generators.

In terms of percentages, the actual price of the market has been on average over the period 27% (51% if one excludes CO2 from the cost basis) over the competitive benchmark in Germany, 21% (35% if one excludes CO2 from the cost basis) in Spain, and much less in the Netherlands and the UK.

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

(33) Gas-fired plants represent about 60 percent of the installed generation in the Netherlands and 40% in Belgium. In both cases, gas «sets the price» in many hours.

(34) As explained above, the model could also compute the carbon effect in France: as expected it is much lower (4€/MWh) due to the large proportion of nuclear generation.

(35) In the case of the UK, the price of the competitive market is underestimated in 2005 due to the fact that the simulation could not take into account the impact of exceptionally high gas prices in that market in the second half of 2005 and the unique liquidity of the UK gas market, which gave the opportunity to generators to sell back their gas instead of generating electricity.
although one must note for the Netherlands (16) that the price cost margin reached a high level of 33% in 2003. This is shown in the table below:

Table 2 — The mark-up as a percentage of the “cost”

<table>
<thead>
<tr>
<th>Country</th>
<th>2003 (CO\textsubscript{2} added to the “cost”)</th>
<th>2004 (CO\textsubscript{2} excluded from the “cost”)</th>
<th>2005 (CO\textsubscript{2} added to the “cost”)</th>
<th>2005 (CO\textsubscript{2} excluded from the “cost”)</th>
<th>2003/2005 (CO\textsubscript{2} added)</th>
<th>2003/2005 (CO\textsubscript{2} excluded)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany</td>
<td>59%</td>
<td>22%</td>
<td>15%</td>
<td>72%</td>
<td>27%</td>
<td>51%</td>
</tr>
<tr>
<td>Spain</td>
<td>26%</td>
<td>5%</td>
<td>28%</td>
<td>66%</td>
<td>21%</td>
<td>35%</td>
</tr>
<tr>
<td>Netherlands</td>
<td>33%</td>
<td>–2%</td>
<td>–5%</td>
<td>13%</td>
<td>6%</td>
<td>14%</td>
</tr>
<tr>
<td>Great Britain</td>
<td>—</td>
<td>4%</td>
<td>13%</td>
<td>42%</td>
<td>11%</td>
<td>31%</td>
</tr>
</tbody>
</table>

Of course, given the sensitivity of such an exercise, it is not possible to reason that the mark-up in the market was exactly equal to the values presented above. However, the magnitude of the mark-ups allows us to conclude that electricity prices have been too high.

Correlation between mark-ups and concentration established

Given these results, it is interesting to find out an explanation for them. The study first tried to establish a statistical explanation. Indeed, the sector inquiry report and many experts in the sector argue that concentration is the main reason why prices are too high in the sector. The study has thus measured concentration in the six markets. It did so with traditional indices (CR\textsubscript{n}, HHI) as well as with electricity specific indices. One of the specific indices is the so called “Residual Supply Index” (RSI): it measures how much indispensable an operator is to meet demand. The RSI of an operator in a given hour is equal to the sum of available capacity of all other operators (taking into account outages) divided by demand in that hour: if RSI is below 1, the operator is indispensable to meet demand.

The study calculated the RSI for the main operators in each market in each hour and, through regression analysis, tried to establish if there is a linear relationship between the mark-ups and the RSI of one or several of the main operators as single or multiple explanatory variables. The following graph shows the results for the Spanish market and one of the main operators. It shows that the more indispensable this operator was during the period, the higher the mark-ups were.

The regression analysis showed in fact that, in all markets, there is a statistically relevant correlation between the RSI of the main generators and the mark-ups in each hour. In other words, the more the main generators are needed to supply demand, the higher the mark-ups in the market become. The regression analysis corrected for other possible factors that could contribute to explaining high(er) mark-ups, such as the lack of electricity generating capacity of the whole market (scarcity), peak moments and seasonal variations in demand. However, the correlation between mark-ups and the indispensability of certain operators was significantly in all these tests and hence for the first time empirically tested and confirmed in this study. It can thus be concluded that concentration contributes to explaining the level of mark-ups.
The issue of “withholding”

The study further compared what operators produced in reality to what they would have produced in the perfectly competitive market. This is important to explain if prices have been too high simply because operators sold at higher prices or because operators have actually practised a strategy called “withholding”. Withholding takes place when an operator does not produce (or produces less) with a power plant that would be economic to run with a view to forcing recourse (along the merit curve) to more expensive plants to meet demand. This is possible due to the specifics of the sector: the lack of storability of the product, a steep merit curve, little flexibility on the demand side, demand predictability, the single auction price mechanism of short-term markets, etc. It will be profitable if the revenues foregone from not producing are compensated by the higher revenues earned with the other plants through the higher market price. Large operators with sufficiently large portfolios of base-load plants (e.g. nuclear plants) are deemed to have adequate portfolios to carry out such strategies.

The results of the study show that differences between operators are significant, and that some operators seem to have not made full use of their generation capacity. This is one of the allegations made in 2006 by some users in the German market and was one of the subject of inspections carried out at the premises of German generators in December 2006 (37).

Conclusion

The scope and detail of the study make it the first of its kind with substantial new insights into the performance of electricity markets, including a reliable estimation of what wholesale electricity prices would have been if the markets had been competitive. The results show that prices are significantly above relevant (fuel) generation costs in most markets in 2003 and in some of them in 2005, indicating significant mark-ups due to a lack of competition in almost all markets studied. The results also show that the mark-ups are systematically greater when concentration on the supply side of generation rises in each market. In addition, the results show that a number of operators have apparently not fully used their relatively cheap available capacity: they may have thus withdrawn capacity to raise prices. These results confirm the findings of the sector inquiry and the need to further promote competition in the sector both by reinforcing the regulatory framework and by carrying out competition investigations in specific cases.