ANALYSIS OF ELECTRICITY INDUSTRY LIBERALIZATION IN GREAT BRITAIN: HOW DID THE BIDDING BEHAVIOR OF ELECTRICITY PRODUCERS CHANGE?

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WORKING PAPER SERIES (ISSN 1211-3298)
Electronic Version

415

Working Paper Series 415
(ISSN 1211-3298)

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Prague, September 2010

EVROPSKÝ SOCIÁLNÍ FOND
PRAHA & EU: INVESTUJEME DO VAŠÍ BUDOUCNOSTI

Projekt je financován Evropským sociálním fondem, rozpočtem hl. města Prahy a státním rozpočtem

ISBN 978-80-7343-213-3 (Univerzita Karlova. Centrum pro ekonomický výzkum a doktorské studium)
ISBN 978-80-7344-203-3 (Národohospodářský ústav AV ČR, v.v.i.)

Analysis of Electricity Industry Liberalization in Great Britain: How Did the Bidding Behavior of Electricity Producers Change?*

Sherzod N. Tashpulatov†

WP 415 (updated)

Abstract

Promoting competition among electricity producers is crucial for ensuring allocative efficiency and lower electricity prices. In this paper, I empirically examine the electricity market of England and Wales in order to analyze to what extent the regulatory reforms were successful in promoting competition among electricity producers during 1995–2000.

This research provides further evidence of the effects of the reforms undertaken by the regulatory authority during the liberalization process and could be also of interest to countries that created their wholesale electricity markets similar to the original model of the England and Wales wholesale electricity market.

Abstrakt

Prosazování konkurence mezi výrobci elektřiny je důležité, neboť ve svém důsledku zajišťuje alokační efektivnost a nižší ceny elektřiny. V tomto článku empiricky zkoumám trh elektřiny v Anglii a Walesu, kde analyzuji úspěšnost regulačních reforem při zavádění konkurence mezi výrobci elektřiny během let 1995-2000.

Tento výzkum poskytuje další informace o efektivitě reforem, které regulační orgán provedl v průběhu liberalizace a je proto také vhodným informačním podkladem pro země, které reformovaly své velkoobchodní trhy elektřiny podobně jako tomu bylo v případě velkoobchodního trhu elektřiny v Anglii a Walesu.

Keywords: liberalization, electricity markets, uniform price auction, market power
JEL Classification: D21, D44, L90, L94

*I would like to express my gratitude to Lubomír Lízal, Jan Hanousek, and Jan Kmenta for invaluable comments, suggestions, and guidance. I am thankful to Fabio Michelucci and Peter Katuščák for comments on the earlier drafts. I am also thankful to Richard Stock and Sarah Peck for their help and advice on English language. All remaining errors are mine. This paper was supported by the World Bank Research Fellowship grant and SVV-2010-261 801 grant. E-mail: stashpul@cerge-ei.cz

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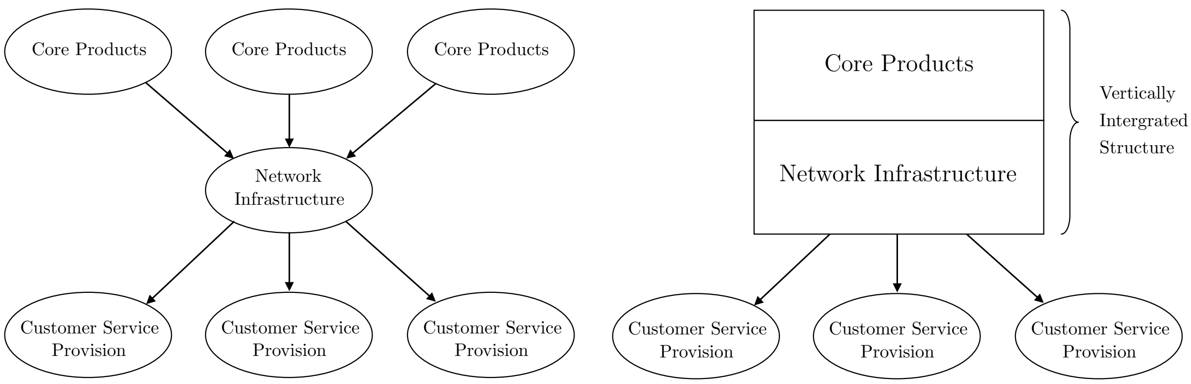
1 General Introduction

Network industries like energy (for example, electricity and natural gas), postal services, telecommunications, and transport (for example, air, maritime, and rail) provide essential services of general economic interest. Promotion of competition at all possible levels of these network industries was the primary goal of the liberalization process started during the 1990s in many European countries (Bergman et al., 1998).

Increased competition is known to result in allocative efficiency by ensuring that least-cost producers are serving the demand at lower prices. In this research, I analyze how, during the liberalization process, the regulatory reforms to increase competition affected the bidding behavior of producers in the wholesale electricity market in England and Wales. The findings of this research would also be of interest to countries that created their wholesale electricity markets similar to the original model of the England and Wales electricity market.

In general, a network industry is an industry in which products are provided to customers via a network infrastructure. As described in Bergman et al. (1998), a network industry is represented by three key components: core products, network infrastructure, and customer service provision. These are schematically presented in Figure 1.1.



(a) Vertically Separated Case (b) Vertically Integrated Case

Source: Bergman et al. (1998).

Figure 1.1: Structure of a Network Industry

As described in Figure 1.1(a), core products are delivered by producers in the upstream production level and customer service provision is delivered by suppliers in the downstream supply level. The upstream production and downstream supply levels are coordinated via the network infrastructure. In the case of the electricity industry, for example, the upstream production level is represented by electricity producers, the network infrastructure by the network operator responsible for electricity transmission over a high-voltage net, and the downstream supply level by retail suppliers responsible for electricity distribution over a low-voltage net. The liberalization in network industries was aimed at introducing competition in the upstream production and downstream supply levels while still allowing for the network infrastructure to remain the only monopoly structure because its replication is not economical.

Until the 1980s the upstream production and network infrastructure levels were mostly vertically integrated and regulated as a single "natural monopoly" structure, which is described in Figure 1.1(b). It was then widely believed that those vertically integrated organizations were better managed as regulated state or private natural monopolies, mainly due to the presence of economies of scale and large fixed costs (Geradin, 2006). Figure 2.1 shows the actual organization of the electricity industry in Great Britain, which contains both structures described in Figure 1.1.

In Great Britain, following the lessons learnt from privatizing the gas industry in 1986, the Chairman of the Central Electricity Generation Board (CEGB) and government consultants demonstrated that splitting the vertically integrated CEGB into production and network infrastructure parts was feasible. The purpose of splitting the vertically integrated utility was to introduce competition at the production level while still allowing for the network infrastructure to remain the only natural monopoly segment. In this respect, Great Britain was the first among the OECD countries to liberalize its Electricity Supply Industry (ESI), where the liberalization therefore included the vertical separation of electricity production and network infrastructure parts, which were previously integrated in the CEGB. At the same time, in the downstream supply level, the Regional Electricity Boards were replaced by 12 Regional Electricity Companies (RECs). These changes were then immediately followed by the creation of a wholesale electricity market in England and Wales, which operated during April 1, 1990 – March 26, 2001.

Paul L. Joskow characterized the privatization, restructuring, market design, and regulatory reforms pursued in the liberalization process of the electricity industry in England and Wales as the international gold standard for energy market liberalization (cited in Glachant and Lévêque, eds, 2009). In this respect, Great Britain, with the longest liberalization experience, can also serve as an important source of lessons.

Competition in the upstream production and downstream supply levels of the ESI in Great Britain was aimed at promoting a decrease of electricity prices for customers and hence, consequently, also an increase in total wealth. However, since the competition among producers and among retail suppliers was introduced gradually, there was an opportunity for electricity producers and retail suppliers to earn high profits. The noncompetitive behavior of producers through an exercise of market power and of retail suppliers through monopoly franchises were facilitating the transfer of the resulting high electricity prices to consumers, who during the 1990s were not allowed to completely freely switch among retail suppliers.

Besides resulting in high wholesale electricity prices, the noncompetitive behavior of electricity producers may also create allocative and productive inefficiencies. On the one hand, if the exercise of market power is present, then the bidding behavior of producers need no longer reflect their costs. This may therefore create allocative inefficiency: a less expensive producer may stop serving the demand because it is replaced by a more expensive producer in the wholesale electricity market, if the former desired a significantly higher price markup. On the other hand, in a less competitive environment producers might not be sufficiently motivated to improve productive efficiency, that is, to drive out high-cost production capacity.

In order to increase competition among electricity producers, several reforms were introduced by the regulatory authority. In this research, I empirically evaluate the influence of the regulatory reforms during the liberalization process of the ESI on the development of competition among electricity producers. The findings and conclusions of this research will provide new evidence about the liberalization process of the electricity industry in Great Britain, which could be also of interest to, for example, Argentina, Australia, Chile, Italy, Spain, and some US states that have adopted trading arrangements similar to those of the wholesale electricity market in England and Wales.

In the following two sections, I present the institutional description of the electricity industry and the research on the development of the bidding behavior of electricity producers in relation to the regulatory reforms during the liberalization process of the electricity industry in Great Britain.

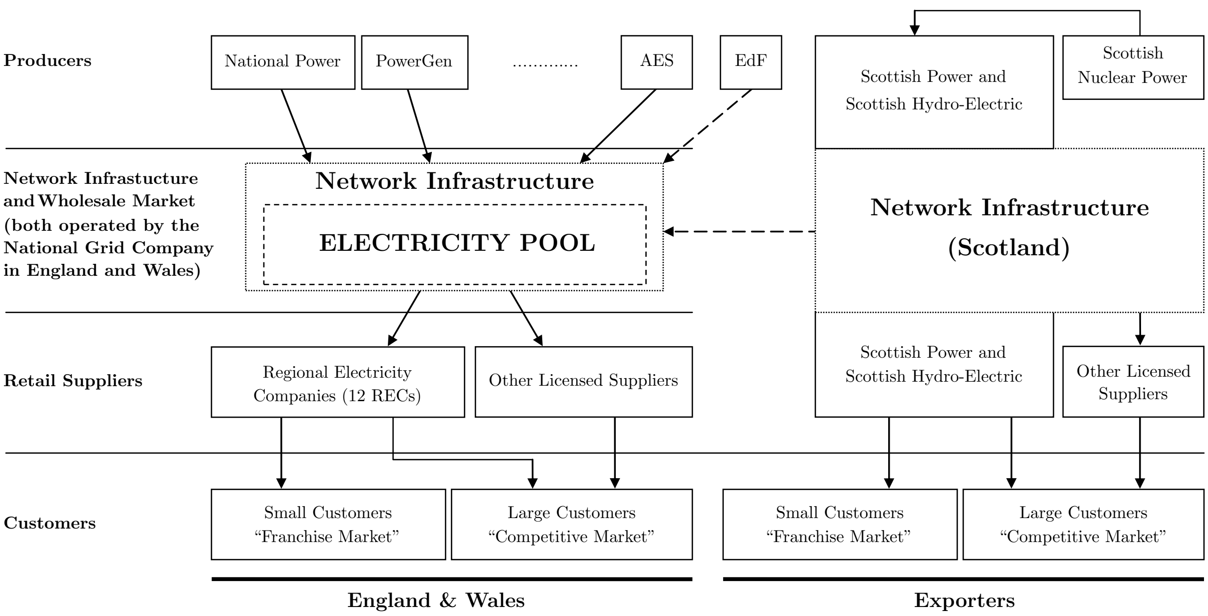
2 *Background* Electricity Supply Industry in Great Britain

2.1 Liberalization of Electricity Supply Industry

According to evaluations provided in Bergman et al. (1998), the liberalization of the Electricity Supply Industry (ESI), which included the opening of the market for competitors, the creation of a level playing field, and measures designed to promote competition, was more extensive in Great Britain as compared to Germany, Italy, Spain, or Sweden.

The liberalization of the ESI in Great Britain, started in 1990, included splitting the vertically integrated utility into production and network infrastructure parts and at the same time the creation of the wholesale electricity market in England and Wales. It is worth mentioning that electricity exchange in the created wholesale electricity market constituted more than 85% of the total electricity exchange in the UK (see, for example, Department of Trade and Industry, 1997–2002; Newbery, 1999).

The ESI as any other network industry encompassed three levels: upstream production represented by electricity producers, network infrastructure represented by a network operator, and the downstream supply and service provision represented by electricity suppliers. Figure 2.1 presents in detail these levels of the ESI for the case of Great Britain.



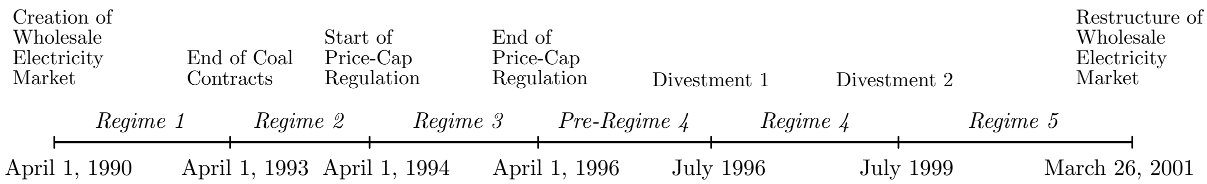
Source: Department of Trade and Industry (1997–2002). Modified for illustration purposes.

Figure 2.1: Description of the Electricity Supply Industry in Great Britain in 1998

The upstream production represented by electricity producers, which sell electricity on the wholesale electricity market, is located on the top level as described in Figure 2.1. The electricity network infrastructure (dotted) and wholesale electricity market (dashed) are both managed by a network operator and are located in the second level. The network infrastructure, which is operated as a regulated natural monopoly, is used for electricity transmission through a high-voltage net. The downstream supply represented by electricity suppliers, which purchase electricity in the wholesale electricity market (often referred to as the "Electricity Pool"), is located in the third level. Retail electricity suppliers then sell electricity to customers, which are located in the bottom level as described in Figure 2.1.

In Scotland, the South of Scotland Electricity Board and the North of Scotland Hydro-Electric Board were replaced by Scottish Power and Scottish Hydro-Electric, which are responsible for production, transmission, and retail supply. As illustrated in Figure 2.1, the production and transmission have been kept vertically integrated and were not unbundled as was done, for example, in England and Wales.

The liberalization process of the ESI during the 1990s included several institutional changes and regulatory reforms. Those changes and reforms both in the upstream production and downstream supply levels shared heavy-handed features of regulation, because specific rules and institutions were established to regulate the ESI in Great Britain. The institutional changes and regulatory reforms that took place in the upstream production level of the ESI in Great Britain during 1990–2001 are summarized in Figure 2.2.



Sources: Department of Trade and Industry (1997–2002), National Grid Company (1994–2001), Newbery (1999), Robinson and Baniak (2002), Wolfram (1999); author's illustration.

Figure 2.2: Institutional Changes and Regulatory Reforms during 1990–2001

In the following paragraphs, I describe the structural breaks and regimes summarized in Figure 2.2. The Director General of Electricity Supply (DGES), Stephen Littlechild, noted the growing discrepancy between rising wholesale electricity prices and falling fuel costs, and specifically the sharp increase in electricity prices in April 1993. In the literature, this is also associated with the expiry of coal and other initial contracts imposed by the government. Hence, April 1, 1993 is considered as the *first structural break*.

The DGES concluded that the market power of electricity producers had enabled them to raise prices above competitive levels. For this reason, the DGES advocated the introduction of a price-cap regulation into the ESI, which would set an explicit ceiling on annual average prices charged for electricity production by the two incumbent electricity producers: National Power (the larger producer) and PowerGen (the smaller producer). Faced with the alternative of a referral to the Monopolies and Mergers Commission (MMC), these electricity producers agreed to a price cap for two financial years: 1994/1995 and 1995/1996 (Wolfram, 1999; Robinson and Baniak, 2002). Therefore, April 1, 1994 and April 1, 1996 are considered as the *second* and *third structural breaks*, respectively.

The price-cap regulation was a temporary measure until the regulatory authority, the Office of Electricity Regulation (OFFER), found an acceptable approach to discipline the bidding behavior of electricity producers in order to ensure the allocative efficiency of production resources and lower electricity prices. Horizontal restructuring through the forced divestment of production capacity was the approach that the OFFER applied to gradually increase competition and mitigate the exercise of market power in the England and Wales electricity market. Under regulatory pressure, the two incumbent electricity producers, National Power and PowerGen, divested (more precisely, leased instead of a planned sale) 6,000 MW of production capacity to Eastern Group (later renamed TXU). In particular, on June 26, 1996, National Power divested the Ironbridge, Rugeley, and West Burton plants, which in total represented 4,000 MW of its 26,000 MW production capacity. Similarly, on July 1, 1996, PowerGen divested the Drakelow and High Marnham plants, which in total represented 2,000 MW of its 20,000 MW production capacity (National Grid Company, 1994–2001). Therefore, I consider April 1, 1996 – June 22, 1996 as an inactive period and July 1, 1996 as the *fourth structural break*.

Eastern Group, one of the largest Regional Electricity Companies (RECs), thereby also became a major electricity producer. As part of the lease, Eastern paid National Power and PowerGen £6/MWh of electricity produced, increasing accordingly Eastern's marginal costs. This arrangement with PowerGen was terminated in March 2000 while the payment to National Power was reduced to £1.5/MWh in summer 2000 and came to an end in January 2001 when Eastern bought the plants from National Power (Bower, 2002). These changes are appropriately accounted for in the approximation of the marginal costs of the divested plants.

The most serious criticism of the performance of the electricity market was the continuing influence of National Power and PowerGen on setting the uniform auction price and the further need for the divestment of production capacity in 1999, despite the earlier divestment of 6,000 MW of production capacity and the increased entry by Independent Power Producers (IPPs). After negotiations and gaining permission to merge with a Regional Electricity Company (REC), PowerGen sold the Ferrybridge (1,956 MW) and Fiddlers Ferry (1,960 MW) plants to Edison and, similarly, National Power sold the Drax plant (3,870 MW) to AES in July 1999. Therefore, I take July 1999 as the *fifth structural break*. All regime periods are described in Figure 2.2.

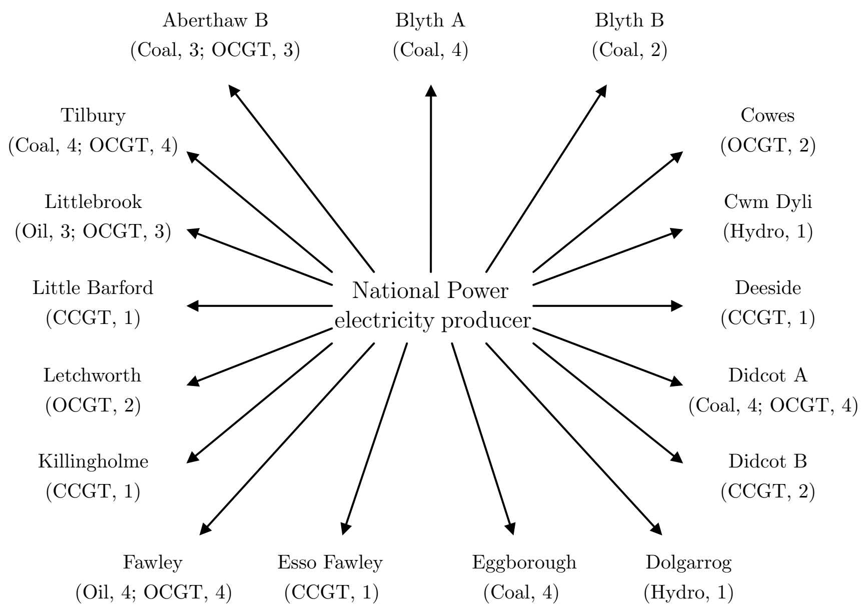
The ultimate goal of the regulatory reforms introduced by the OFFER in the upstream production level was to ensure that prices were set such that markups over marginal costs were sufficient to cover fixed and other common costs. This was crucial because otherwise the exercise of market power expressed in submitting price bids significantly higher than marginal costs could lead to an inefficient allocation of production resources since, as described in Section 2.2, a supply schedule constructed based on submitted bids need no longer guarantee that the least-cost production units are indeed scheduled to produce electricity. This would eventually result in higher prices paid by consumers.

On March 27, 2001, the Electricity Pool was replaced by the New Electricity Trading Arrangements (NETA). The new trading arrangements essentially introduced bilateral trading by dividing the electricity market into the following areas: forward and future markets, where suppliers make agreements with producers based on their estimates of demand; a power exchange, where suppliers buy and sell electricity according to signed contracts; and finally, a balancing market, which is a short-term electricity spot market that allows producers and suppliers to make up any last minute shortfalls in supply caused, for example, by sudden changes in weather conditions. At the present time the available data cover only the operation of the balancing market, where about 5% of all electricity trades in England and Wales take place. No detailed micro data are available on bilateral trading between producers and suppliers. These circumstances limit the scope of the dissertation research to January 1, 1995 – September 30, 2000 period.

2.2 England and Wales Electricity Market

The wholesale electricity market in England and Wales consisted of three participants: producers, the market operator, and retail suppliers. Each of the participants is characterized below.

An electricity producer owns one or several plants that could use single or multiple types of input. Each plant is usually divided into several equally-sized production units. An exception may be plants that are either already too small or using multiple types of input. In Figure 2.3 I present, as an example, the structure of National Power during January 2000. For each plant, I also provide information on the input type and the number of production units.



Source: Data sets described in Section 3.4; author's illustration.

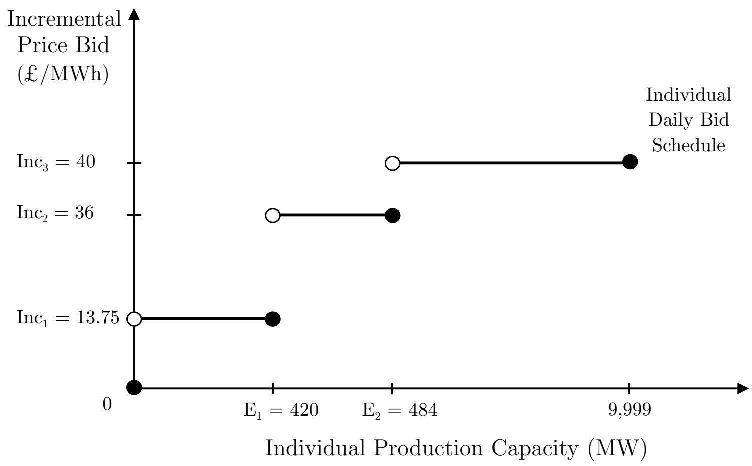
Figure 2.3: Structure of National Power

Electricity producers are located in the upstream production level as described in Figure 2.1. Electricity retail suppliers are responsible for distributing electricity to customers and are located in the downstream supply level as described in Figure 2.1.

The exchange of electricity between producers and retail suppliers took place in the wholesale electricity market, which is also known as the Electricity Pool. This wholesale electricity market was managed by the market operator, the National Grid Company (NGC). This is described in Figure 2.1 in the middle part between upstream production and downstream supply levels.

Trading in the England and Wales wholesale electricity market was conducted every day through a uniform price auction. The trading day started at 5 a.m. and consisted of 48 half-hourly trading periods, which the NGC divided into high- and low-demand trading periods.[1] The NGC invited electricity producers to submit daily and half-hourly bids for each production unit for the following trading day.

The daily bids for each individual production unit included a start-up cost, a no-load cost, (at most) three incremental price bids, and two elbow points. The start-up cost (measured in £) represented the cost to start up a production unit. The no-load cost (measured in £/h) represented the cost to keep a production unit from shutting down. The two elbow points (measured in MW) defined ranges over which the incremental price bids (measured in £/MWh) applied. In Figure 2.4, using data from January 14, 2000, I provide an example of what PowerGen submitted for its coal production unit KINO_02Z, which belonged to the Kingsnorth plant. The submitted bids for the start-up cost and no-load cost for this production unit were £4200 and £5103/h, respectively.



Source: Data set 2 described in Section 3.4; author's illustration.

Figure 2.4: Submission of Daily Bids by PowerGen (January 14, 2000)

Electricity producers were also asked to submit for each individual production unit half-hourly bids on production capacity (measured in MW). Since the duration of a trading period was half an hour, it follows that a production unit with a production capacity of, for example, 40 MW during this time can produce $40\,\mathrm{MW} \cdot \frac{1}{2}\,\mathrm{h} = 20\,\mathrm{MWh}$ of electricity.

[1]For the analysis of the exercise of market power, I consider the bidding behavior of electricity producers during the first five highest-demand trading periods.

All these submitted daily and half-hourly bid data for individual production units were then used to compute the respective half-hourly Combined Bids (CBs) for the next trading day. The computation of CBs measured in £/MWh was common knowledge and was also different for high- and low-demand trading periods.

Before describing the computation of CBs, I would like to stress two important implications following from the market rules. Firstly, since the submission of bids was at the level of individual production units, it follows that the computation of the CB for a certain production unit depended only on daily and half-hourly bids for that production unit. Secondly, since the computation of the CB depended on daily and half-hourly bids, it follows that the computed CB for a production unit would be varying across half hours.

In the following paragraphs, in an intuitive way I try to provide a description of how half-hourly CBs were computed by the market operator (the NGC). The complete description of the algorithm used to transform daily and half-hourly bids into a half-hourly CB for each production unit is common knowledge and is described in Electricity Pool (1990). Here I have decided to use more intuitive names and representations for the different technical concepts and formulas used in Electricity Pool (1990).

Let Inc_1, Inc_2, Inc_3 denote three incremental price bids, E_1 and E_2 denote two elbow points, and k denote production capacity. For high-demand trading periods the Average Bids (ABs) are constructed to compute the CB:

$$\textbf{1)}\ \text{if } k = 0, \text{ then } \begin{cases} AB_1 = \pounds 0/\text{MWh} \\ AB_2 = \pounds 999/\text{MWh} \\ AB_3 = \pounds 999/\text{MWh} \end{cases};$$

$$\textbf{2)}\ \text{if } k \in (0; E_1], \text{ then } \begin{cases} AB_1 = \frac{NoLoad}{k} + Inc_1 \\ AB_2 = 999 \\ AB_3 = 999 \end{cases};$$

$$\textbf{3)}\ \text{if } k \in (E_1; E_2], \text{ then } \begin{cases} AB_1 = \frac{NoLoad}{E_1} + Inc_1 \\ AB_2 = \frac{NoLoad}{k} + \frac{Inc_1 \cdot E_1 + Inc_2 \cdot (k - E_1)}{k} \\ AB_3 = 999 \end{cases};$$

$$\textbf{4)}\ \text{if } k \in (E_2; 9999 \text{ MW}], \text{ then } \begin{cases} AB_1 = \frac{NoLoad}{E_1} + Inc_1 \\ AB_2 = \frac{NoLoad}{E_2} + \frac{Inc_1 \cdot E_1 + Inc_2 \cdot (E_2 - E_1)}{E_2} \\ AB_3 = \frac{NoLoad}{k} + \frac{Inc_1 \cdot E_1 + Inc_2 \cdot (E_2 - E_1) + Inc_3 \cdot (k - E_2)}{k} \end{cases}.$$

This choice of presentation allows interpreting $AB = \frac{NoLoad}{k} + \frac{Inc_1 \cdot E_1 + Inc_2 \cdot (E_2 - E_1) + Inc_3 \cdot (k - E_2)}{k}$, for example, as consisting of two components. The first component uniformly distributes the no-load cost over the production capacity and the second term is essentially a capacity-weighted average of submitted incremental price bids. Similarly, it can be shown that the start-up cost is uniformly distributed over high-demand trading periods during which a production unit is producing electricity and then added to the half-hourly ABs. Depending on the value of production capacity k for each production unit, the minimum among the final AB_1, AB_2, and AB_3 define the half-hourly CBs.
In low-demand trading periods, the CB is set equal to one of the incremental price bids depending on the value of the submitted half-hourly production capacity k:

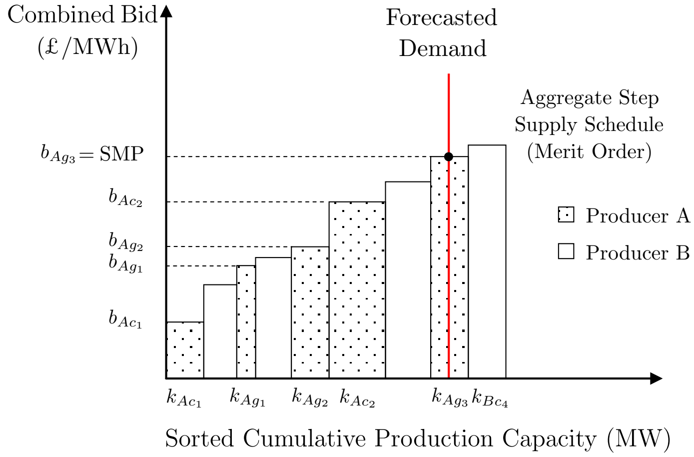
1) if $k = 0$, then $CB = 0$; **2)** if $k \in (0; E_1]$, then $CB = Inc_1$;

3) if $k \in (E_1; E_2]$, then $CB = Inc_2$; **4)** if $k \in (E_2; 9999 \text{ MW}]$, then $CB = Inc_3$.

This algorithm to compute half-hourly CBs is common knowledge among electricity producers and is described in more detail in Electricity Pool (1990).

For each half-hourly trading period, the pairs of the CB and respective production capacity were ordered based on the CB to construct an aggregate supply schedule that would indicate the least expensive way to meet a price-inelastic forecasted demand. The constructed least expensive aggregate supply schedule was also called a merit order. The production unit whose CB in this merit order intersected the price-inelastic forecasted demand was called the marginal production unit. Its respective CB was called the System Marginal Price (SMP). Production units located to the left of the forecasted demand were called infra-marginal production units. Finally, production units located to the right of the forecasted demand were called extra-marginal production units.

Figure 2.5 is a hypothetical example of how the wholesale electricity market would have operated in a given trading period. The vertical line in the graph is the forecasted demand, which is measured in MW, not in MWh. The price-inelastic forecasted demand was prepared by the market operator (i.e., the National Grid Company, NGC), whose forecasting methodology was also common knowledge (see, for example, Wolak, 2000; Wolak and Patrick, 2001).



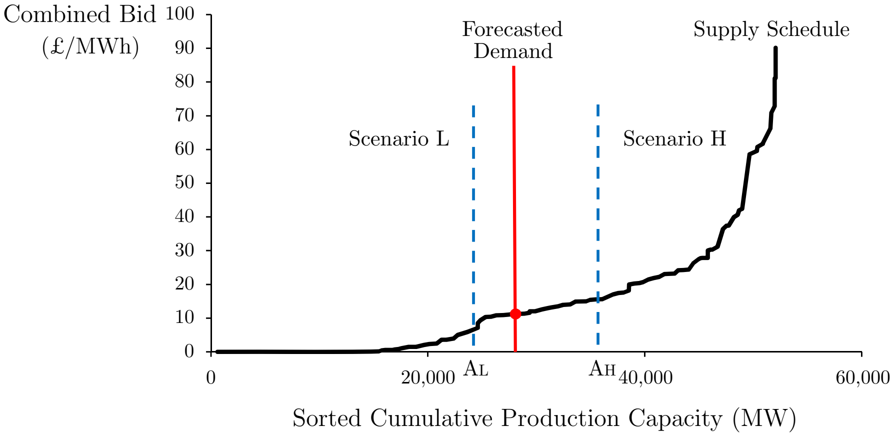
Source: Author's illustration.

Figure 2.5: Determination of the System Marginal Price: A Hypothetical Example

Let b_{Ac_1} denote the CB of electricity producer A's first production unit of type c, whose submitted production capacity is k_{Ac_1} (similarly for b_{Ag_1} and b_{Bc_1}). For illustration purposes, it is assumed that electricity producer A has two coal and three gas production units and electricity producer B has four coal production units. The CBs of all production units belonging to producers A and B are ordered as would have been done by the market operator to create the least expensive aggregate step supply schedule, i.e., the merit order. The intersection of the price-inelastic forecasted demand and the constructed merit order determines the SMP.

In this hypothetical example, in particular, the first four coal and gas production units of electricity producer A are the infra-marginal production units. The third gas production unit of electricity producer A is the marginal production unit that determines the SMP.

In Figure 2.6, I illustrate an actual example of the determination of the marginal production unit and the SMP. The observed zero values for CBs close to the origin in Figure 2.6 can be explained. Nuclear and combined cycle gas turbine (CCGT) production units had low operating costs and were therefore operating as the base-load and almost constantly. This implied that those types of production unit were often positioned close to the origin of the least expensive aggregate supply schedule and were therefore far from setting the SMP. Moreover, it was not easy to turn those production units on and off (especially nuclear production units). That is why, as an attempt to ensure that those types of production unit were scheduled to produce electricity, producers frequently submitted zero price bids. Such a behavior of electricity producers could therefore be characterized as *free riding* on the SMP, that is, receiving the uniform auction price even without actively bidding in the auction (see, for example, Edwards, 2010).



Source: Data sets described in Section 3.4; author's calculations.
Notes: The trading period during 23:00–23:30 on January 14, 2000. Production units with CBs higher than £100/MWh are not depicted due to the scale problem. Scenario L and Scenario H describe a possible realization of the actual demand.

Figure 2.6: Determination of the System Marginal Price

As depicted in Figure 2.6, the forecasted demand for the trading period under consideration was 34,585 MW. The intersection of the constructed merit order and forecasted demand determined an SMP equal to £15/MWh. It was set by a production unit belonging to the EdF electricity producer.

Below I describe in detail other payments whose computation is dependent on the outcome of the uniform auction price, i.e., the SMP. Although this description is not directly related to the dissertation research, which addresses the development of the bidding behavior of electricity producers in relation to the regulatory reforms, I find it necessary for illustrating how the electricity market in England and Wales operated.

Electricity producers that declared their production units available and were scheduled to produce electricity during high-demand trading periods were in addition to the SMP receiving a Capacity Payment (CP). The CP was an additional payment to stimulate electricity producers to make their production capacity available to the system during high-demand trading periods. The payment was high at times when there was little spare production capacity available. Therefore, from the perspective of producers, this payment could also be interpreted as scarcity rent. The CP was computed based on the Loss of Load Probability (LOLP), the Value of Lost Load (VLL), and the SMP. The LOLP is an estimated probability that demand will exceed the total production capacity (a measure reflecting reliability of electricity supply) and the VLL is the Pool's estimate of customers' maximum willingness to pay for electricity supply. Customers who require high reliability of electricity supply are, for example, airports, hospitals, and farms for which it is very costly to experience power outages.

Thus, electricity producers that declared their production units available and were eventually scheduled to produce electricity during high-demand trading periods received the Pool Purchase Price (PPP), which was equal to the sum of the SMP and CP :

$$\text{PPP} = \text{SMP} + \text{CP} = \text{SMP} + \text{LOLP} \cdot \max\{\, 0,\ \text{VLL} - \text{SMP}\,\}.$$

Otherwise, electricity producers that declared their production units available and were scheduled to produce electricity during low-demand trading periods were receiving only the SMP payment.

As described earlier, the SMP was determined from the intersection of the merit order and forecasted demand. In reality, however, the forecasted demand need not be the same as the actual demand. As described in Figure 2.6, two possible scenarios can arise: Actual Demand < Forecasted Demand (i.e., $A_L < F$) and Actual Demand > Forecasted Demand (i.e., $A_H > F$).

On the one hand, under scenario L, when $A_L < F$, the market rules required that all production units located in $[A_L; F]$ be compensated by SMP less their CBs. On the other hand, under scenario H, when $A_H > F$, the market rules required that all production units located in $[F; A_H]$ be paid their CBs. The compensation scheme for a production unit i under low and high scenarios can therefore be summarized as follows:

$$\begin{cases} \text{Payment}_i = \text{SMP} - \text{CB}_i\,, & \text{if } i \in [A_L; F] \text{ under scenario } L \\ \text{Payment}_i = \text{CB}_i\,, & \text{if } i \in [F; A_H] \text{ under scenario } H\,. \end{cases}$$

Retail suppliers buying electricity from the wholesale market paid the Pool Selling Price (PSP), which only during high-demand trading periods in addition to the PPP included the Transmission Service Price (TSP). The TSP was an additional payment to cover costs imposed by transmission services: PSP = PPP + TSP = SMP + CP + TSP.

The regulatory authority was primarily concerned about the SMP since in the wholesale electricity market it was the equilibrium outcome that depended on the bidding behavior of electricity producers and the forecasted demand. Attempts to increase competition through the regulatory reforms were directed at eventually providing lower prices for customers.

3 Analysis of Electricity Industry Liberalization in Great Britain: How Did the Bidding Behavior of Electricity Producers Change?

3.1 Introduction

At the start of the liberalization of the electricity supply industry in Great Britain, a wholesale market for electricity trading was created in England and Wales. Trading was organized as a uniform price auction, where electricity producers were asked to bid prices at which they were willing to produce electricity. However, there was a belief by the regulatory authority that electricity producers were exercising market power by submitting price bids significantly exceeding their marginal costs; therefore, several reforms were introduced during the liberalization process.

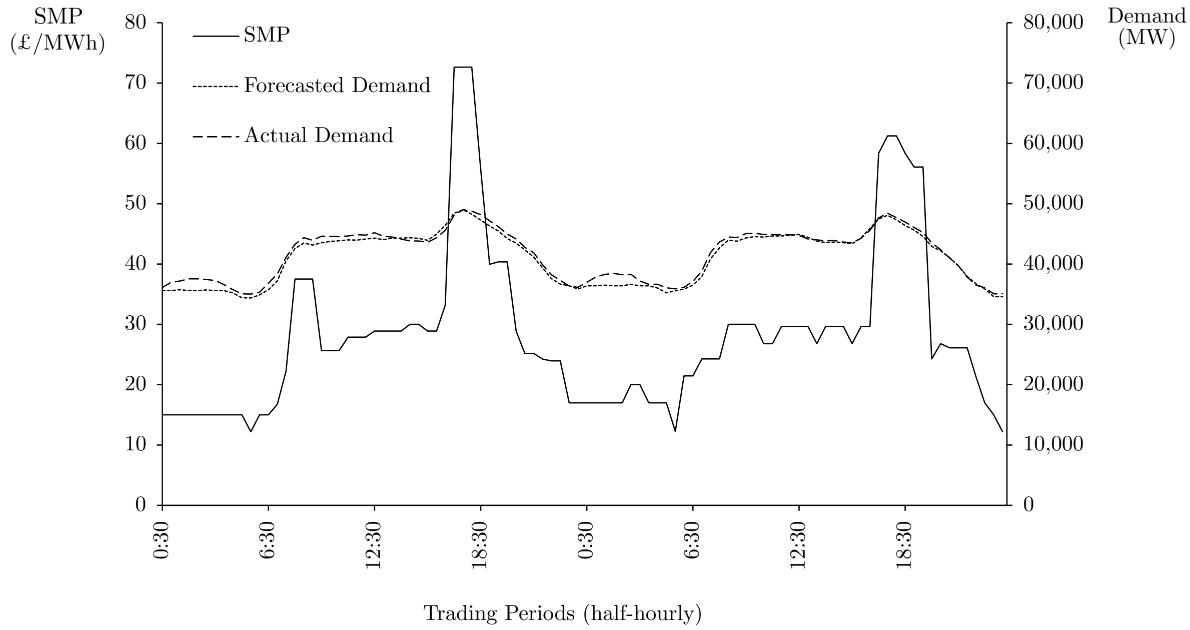
An exercise of market power expressed in electricity producers submitting price bids significantly higher than their marginal costs resulted in higher uniform auction prices (i.e., the System Marginal Price, SMP) and therefore higher revenues. On the other hand, a higher SMP increased payments by retail suppliers, which were in the end reflected in higher prices paid by consumers.

Another consequence of the exercise of market power are the possible losses in the efficient allocation of production resources among electricity producers. In other words, due to possible differences in setting bid markups, there need no longer be any guarantee that based on ordered price bids the least cost production units are indeed scheduled to produce electricity.

These issues of the exercise of market power are also indicated by Bergman et al. (1998) in the analysis of the first form of benefits that electricity market reforms could bring to consumers: lower prices resulting from lower price-cost margins and more cost-efficient production of electricity. The other forms of benefits that electricity market reforms could bring to consumers included a high degree of security of supply and an environmentally friendly electricity supply system, which in the long run would not critically depend on exhaustible natural resources.

Figure 3.1 describes the half-hourly changes of the uniform auction price (i.e., the System Marginal Price, SMP) and demand during January 13, 2000 – January 14, 2000. The computed correlation coefficient between the price and forecasted demand during those two representative consecutive business days is about 0.81. This provides evidence of a high level of comovement between the price and forecasted demand series.

As described in Figure 3.1, the SMP and forecasted demand were changing in the ranges of £10/MWh to £75/MWh and 35,000 MW to 50,000 MW, respectively. However, it is interesting to observe large price changes within the small neighborhood of the highest-demand trading periods, which coincided with the time in the evenings when people usually return home. In particular, on January 13, 2000, the SMP during the highest-demand trading period (when the forecasted demand was 48,975 MW) was about £72.66/MWh, while, for example, just two trading periods earlier (when the forecasted demand was 48,442 MW, which is less by about 1% as compared to 48,975 MW), the respective SMP was £33.2/MWh. A similar event took place the next business day too.



Source: Data set 1 described in Section 3.4; author's calculations.

Figure 3.1: SMP and Demand for Electricity (January 13, 2000 – January 14, 2000)

The regulatory authority, the Office of Electricity Regulation (OFFER), believed that wholesale electricity prices at times were significantly higher than expected. The excessively high prices were attributed to the possible exercise of market power by the two incumbent electricity producers: National Power and PowerGen. Hence, to mitigate the exercise of market power and increase competition among electricity producers, several reforms were introduced. Based on the analysis of the bidding behavior of electricity producers during the highest-demand trading periods, I empirically evaluate to what extent the reforms introduced by the OFFER were successful in mitigating the exercise of market power and in fostering competition among producers during 1995-2000.

3.2 Literature Review

Von der Fehr and Harbord (1993) is the seminal research in modeling electricity auctions. In their research, the authors assumed that N electricity producers serve the British electricity market operated as a uniform price auction. The authors also assumed that marginal costs were common knowledge and differed only across electricity producers. This assumption implied that all production units of a certain electricity producer had the same marginal costs, which could have been partially supported by the fact that during the early 1990s about 70% of production capacity was based on coal (see Figure C.1). However, this is still subject to further criticism because, for example, the thermal efficiency rates of different coal production units belonging to a certain electricity producer need not be the same.

The authors demonstrate that no pure-strategy bidding equilibrium exists when electricity demand falls within a certain range. Their result is explained by an electricity producer's conflicting incentives to bid high to set a high price and bid low to ensure that its production unit is scheduled to produce electricity.

Wolfram (1998) empirically examines the bidding behavior of electricity producers in the wholesale electricity market operated as a uniform price auction. As a benchmark model she analyzes a duopoly case, where the first producer has several production units, while the second producer has one production unit. From the profit maximization problem the author derives an optimality condition, the intuition and conclusions of which are then used in the construction of an empirical regression model.

The main finding of Wolfram (1998) is that electricity producers submit price bids reflecting higher markups for production units that are likely to be scheduled to produce electricity if that producer has large infra-marginal production capacity. The author indicates (using the optimality condition) that the incentive to submit a price bid reflecting a higher markup for a certain production unit is moderated by the presence of the threat that the production unit may be left out of the production schedule. Wolfram (1998) also finds that larger producers submit higher price bids than smaller producers for comparable production units (i.e., production units using the same input to produce electricity and having almost the same marginal costs).

The findings of Wolfram (1998) are in line with the findings of Green and Newbery (1992), which is a seminal study using the framework of supply function equilibrium (SFE) for the England and Wales electricity market. This framework assumes that each producer submits a continuous supply function, which is applicable when producers' production units are small enough or when each producer has a sufficiently large number of production units as was the case, for example, with National Power and PowerGen in England and Wales. Green and Newbery (1992), using the concept of SFE for a duopoly model, show that a larger producer (National Power) tended to submit price bids reflecting higher markups than did a smaller producer (PowerGen). This finding, therefore, also illustrates the case that a producer with larger infra-marginal capacity has more incentive to inflate its price bid.

Crawford et al. (2007) extends the work of Von der Fehr and Harbord (1993) by allowing production units belonging to a particular electricity producer to have different marginal costs. Similar to Von der Fehr and Harbord (1993), Crawford et al. (2007) assume complete information about the marginal production costs of electricity producers because it was possible to approximate them using data on the thermal efficiency rates of production units (they were published just before the liberalization of the electricity supply industry in Great Britain) and input prices (they were published by the Department of Trade and Industry, January 1993 – December 2000).

For some production units, even updated estimates of thermal efficiency rates are available. In general, it is not surprising to expect thermal efficiency rates to change over time because increasing competition among electricity producers stimulated improvement in productive efficiency, which suggested a decrease in marginal costs and driving out expensive and less productive facilities. Using, however, older thermal efficiency rates could at times overestimate the true marginal costs, leading thereby to measurement errors.

Crawford et al. (2007) also assume no demand uncertainty (this assumption is supported by the commonly known forecasting methodology; see the discussion in Section 3.3) and that no electricity producer is able to serve the whole demand (this assumption is supported by the data on market demand and an individual electricity producer's total production capacity). In their research the authors empirically establish the presence of asymmetries in the bidding behavior of marginal and infra-marginal electricity producers in the British electricity market during 1993–1995: during the highest-demand trading periods marginal electricity producers behave strategically by submitting price bids higher than their marginal costs, whereas infra-marginal electricity producers behave competitively by submitting price bids reflecting their marginal costs.

For the following period of 1995-2000, Sweeting (2007) analyzes the development of market power in the same electricity market. The author measures market power as the margin between observed wholesale market prices and estimates of competitive benchmark prices, where the latter is defined as the expected marginal cost of the highest-cost production unit required to meet electricity demand. Sweeting (2007) finds that electricity producers were exercising increased market power during 1995-2000. This finding, as the author indicates, is however in contradiction with oligopoly models, which, given that during this period market concentration was falling, would have predicted a reduction in market power.

As explained in Borenstein et al. (2002), the application of competitive benchmark prices to analyze whether the electricity market as a whole is setting competitive prices has an advantage of being less vulnerable to the arguments of coincidence and bad luck. This approach also allows estimating the scope and severity of departures from competitive bidding over time. However, it does not allow one to analyze in more detail specific manifestations of noncompetitive bidding behavior for different electricity producers. In order to detect the individual attempts of producers to affect prices, I follow the alternative approach applied in Wolfram (1998) and Crawford et al. (2007). More precisely, to analyze the development of the exercise of market power in relation to the reforms introduced by the regulatory authority, I consider the bidding behavior of individual electricity producers during the highest-demand trading periods. The choice of the highest-demand trading periods is also consistent with the finding of Borenstein et al. (2002), where the authors using the example of the wholesale electricity market in California demonstrate that market power is most commonly exercised during high-demand trading periods.

3.3 Methodology

For the empirical analysis of the development in the bidding behavior of electricity producers, I first describe the assumptions and research approach. Then I analyze a duopoly case with an asymmetric technology structure. Based on the conclusions obtained from the optimality condition in a duopoly case and partly on economic intuition, I develop an empirical regression model to analyze the bidding behavior of electricity producers at the level of the types of production unit. This analysis allows to empirically evaluate the success of the reforms introduced by the regulatory authority to foster competition among electricity producers during 1995–2000. A similar specification, named a bid markup equation, is also analyzed in Wolfram (1998) and Crawford et al. (2007). In order to compute bid markups, a knowledge of marginal costs is required. The proposed approach to approximate marginal costs concludes the methodology.

3.3.1 Assumptions and Research Approach

In the analysis of the influence of particular regulatory reforms on the development of the bidding behavior of electricity producers, I assume no uncertainty in the forecasted demand for electricity and that the marginal costs of electricity production can be approximated.

The first assumption is based on the fact that the methodology the market operator (i.e., the National Grid Company) applied to forecast electricity demand for each trading period of the following trading day was common knowledge (see, for example, Wolak, 2000; Wolak and Patrick, 2001). In addition, it is worth mentioning that the forecasting methodology applied by the market operator was very precise. In particular, for example, during January 13, 2000 – January 14, 2000, the computed correlation coefficient between the forecasted and actual demand for electricity was almost unity (see Figure 3.1).

The second assumption is based on the availability of data describing the technical characteristics (i.e., the thermal efficiency rate and input type) of production units. In particular, the marginal costs of production units using coal, oil, or gas as their inputs are approximated using data on thermal efficiency rates and input prices. The definition of the thermal efficiency rate and data on quarterly input prices are provided by the Department of Trade and Industry (1997–2002, January 1993 – December 2000). These are described in detail in Section 3.3.4.

The approximated marginal costs of production units are then used in the empirical analysis of the bidding behavior of electricity producers during the highest-demand trading periods. The specification of the regression model in the empirical analysis follows from the conclusions of the optimality condition of a profit-maximizing producer and partly from economic intuition.

The idea to selectively focus on a certain trading period or trading day is not a complete novelty. A similar approach was also adopted in Crawford et al. (2007) and Sweeting (2007). Crawford et al. (2007), in particular, focused on the highest-demand trading periods and Sweeting (2007), on the other hand, considered Wednesdays as a representative weekday. The choice of the highest-demand trading periods to analyze the development of the bidding behavior of electricity producers in relation to the introduced regulatory reforms (described in detail in Section 2.1) is also in agreement with the finding of Borenstein et al. (2002), where the authors using the example of the wholesale electricity market in California demonstrated that market power is most commonly exercised during high-demand trading periods.

For the robustness check I also analyze the bidding behavior of electricity producers during the second-fifth highest-demand trading periods.

3.3.2 Analysis of a Duopoly Case with an Asymmetric Technology Structure

General solutions for electricity auction markets to my knowledge have not been analyzed in detail. This is related to the fact that the general setup of trading in electricity auctions would represent a complex game, where the existence and uniqueness of equilibrium bidding strategies of a potentially large number of heterogeneous producers are open questions (see, for example, Von der Fehr and Harbord, 1993). Focusing on the case of symmetric producers might however be of little practical value in the evaluation of reforms since that construction would be far from describing the real market: the bidding strategies of electricity producers using hydro and gas types of input need not be the same.

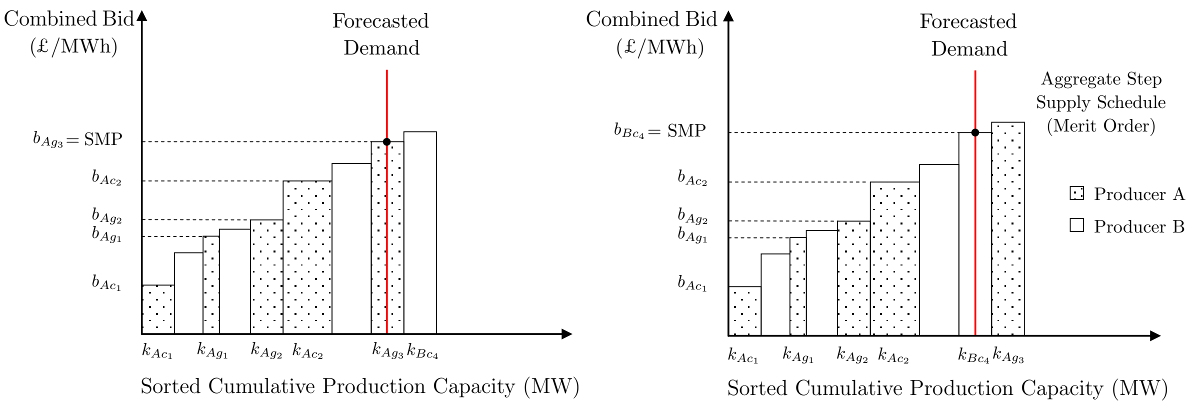
The number of producers is another important issue in modeling electricity markets. Anderson and Xu (2004), for example, model the Australian electricity market as a two-player game. The authors mention that this is the main limitation of their research. They also state that the situation with three or more electricity producers becomes much harder to analyze.

The heterogeneity and number of producers are further complicated by two key properties of electricity, which make the analysis of electricity markets special. First of all, electricity is a perfectly homogeneous product, which means that neither retail suppliers nor consumers can tell by which producer or by which input type the electricity was produced. Secondly, electricity is a nonstorable product, which creates a necessity to coordinate supply and demand on a continuous basis with the highest precision possible. For the case of England and Wales, to account for this feature, half-hourly trading periods were organized. As described in detail in Section 2.2, the market operator was responsible for managing the exchange of electricity between producers and retail suppliers through a uniform price auction by preparing the forecasted demand and determining day-ahead half-hourly prices.

Similar to Wolfram (1998) and Crawford et al. (2007), to circumvent these issues I consider a duopoly case with two electricity producers with the main distinction that I analyze at the level of the type of production unit. This modeling approach allows to analyze the behavior of individual electricity producers with respect to marginal or extra-marginal production units of different types that are identified using the forecasted demand. This is needed for the ex-post evaluation of the impact of the reforms introduced by the regulatory authority to mitigate the exercise of market power and foster competition among electricity producers. Namely marginal or extra-marginal production units of different input types located at or close to the forecasted demand could likely be used for strategic bidding because of being potential candidates to use to set the uniform auction price.

Let us assume the presence of two risk-neutral electricity producers A and B. Assume that electricity producer A has several types of production unit (e.g., National Power uses coal, oil, gas, and hydro types of production unit as described in Table B.5), while electricity producer B has just one type of production unit. The assumption about electricity producer B having just one type of production unit is, for example, supported partly by the structure of British Energy. As summarized in Table B.5, this producer has ten nuclear (operated usually as the base-load) and four coal production units. The coal type of production unit could indeed set the uniform auction price in line, for example, with National Power.

For the explanation of the model I refer to the example in Figure 3.2, which is similar to the hypothetical example presented in Section 2.2. More general cases demand complex notations, which may complicate the illustration of derivation results important for the construction of the empirical regression model described in Section 3.3.3.



(a) Producer A sets the uniform price

(b) Producer B sets the uniform price

Source: Author's illustration.

Figure 3.2: Determination of the System Marginal Price: A Hypothetical Example

Let $k_{A\tau}$ denote the production capacity of type τ belonging to producer A that is declared available to produce electricity. More precisely, $k_{A\tau}$ is the overall production capacity of production units of type τ from the supply schedule constructed by the market operator (i.e., the auctioneer). For the example described in Figure 3.2, it follows that $k_{Ac} = k_{Ac_1} + k_{Ac_2}$, $k_{Ag} = k_{Ag_1} + k_{Ag_2} + k_{Ag_3}$, $k_{Bc} = k_{Bc_1} + k_{Bc_2} + k_{Bc_3} + k_{Bc_4}$.

Let $c_{A\tau}$ denote the approximated marginal cost of producer A's highest-cost production unit of type τ. For the hypothetical example this would mean that $c_{Ac} = c_{Ac_2}$, $c_{Ag} = c_{Ag_3}$, and $c_{Bc} = c_{Bc_4}$. Setting the marginal costs of all production units of type τ by the marginal costs of the most expensive production unit in the calculation of expected profits is partly similar to the concept of competitive benchmark prices used in Sweeting (2007). The marginal costs of production units are approximated based on the methodology described in Section 3.3.4.

Let b_B denote the combined bid submitted for the highest-cost production unit belonging to producer B. Since producer B is assumed to have only one type of production unit the subscript for the type is omitted. Assume that the probability distribution of b_B is defined according to a cumulative distribution function $F(b_B)$ and the respective probability density function $f(b_B)$ with support on the compact interval $[\,\underline{b},\, \overline{b}\,]$, where $\underline{b},\, \overline{b} \in \mathbb{R}^+$ and $\overline{b} > \underline{b}$. This is assumed to be common knowledge.

Similarly, let $b_{A\tau}$ denote the combined bid submitted for the highest-cost production unit of type τ belonging to producer A. For a simplified example described in Figure 3.2, it is the combined bid of the third gas production unit that could be used for strategic manipulation by producer A. In other words, $b_{Ag} \in [\,\underline{b},\, \overline{b}\,]$ is producer A's strategic choice variable.

The payoff of a producer is represented by an expected profit, which is dependent on the outcome of the uniform price auction (i.e., who sets the uniform auction price), the amount of electricity a producer sells at the market, and production costs. More precisely, given the bid b_B of producer B, let us define the expected profit maximization problem of producer A:

$$E[\pi_A(b_{Ag}, b_B)] \;=\; E[\pi_A \,|\, \underbrace{b_B > b_{Ag}}_{\text{A sets}}] \;+\; E[\pi_A \,|\, \underbrace{b_B \le b_{Ag}}_{\text{B sets}}] \;=$$

$$= \int_{b_{Ag}}^{\overline{b}} \left[(b_{Ag} - c_{Ac}) \cdot \frac{1}{2}\, k_{Ac} + (b_{Ag} - c_{Ag}) \cdot \frac{1}{2}\, k_{Ag}\right] \cdot f(b_B)\, db_B \,+$$

$$+ \int_{\underline{b}}^{b_{Ag}} \left[(b_B - c_{Ac}) \cdot \frac{1}{2}\, k_{Ac} + (b_B - c_{Ag}) \cdot \frac{1}{2}\, \alpha_{Ag}\, k_{Ag}\right] \cdot f(b_B)\, db_B \;.$$

In the calculation of the expected profit, producer A considers two possible scenarios depending on who sets the uniform auction price as is described in Figure 3.2. If producer A sets the price, the uniform auction price is b_{Ag}. However, if producer B sets the price, the uniform auction price is b_B and only α_{Ag} part of the submitted gas production capacity belonging to producer A will be scheduled to produce electricity.

It is important to differentiate the meanings of MW and MWh measurement units used throughout. As described in Section 2.2, MW is used to measure the amount of production capacity and MWh is used to measure the amount of electricity. In the expected profit maximization problem, I use a factor of $\frac{1}{2}$ to convert MW to MWh. This follows from the fact that the duration of a trading period is 30 minutes. A production capacity of, for example, 40 MW multiplied by this time gives the amount of electricity produced by a production unit during a half-hour period: $40\,\mathrm{MW} \cdot \frac{1}{2}\,\mathrm{h} = 20\,\mathrm{MWh}$.

Taking the first order condition with respect to b_{Ag} and rearranging leads to

$$\log\left(b_{Ag} - c_{Ag}\right) = \log(k_{Ac} + k_{Ag}) \; - \; \log(1 - \alpha_{Ag})k_{Ag} \; + \; \log\left(1 - F\big(b_{Ag}\big)\right) \; - \; \log\left(f(b_{Ag})\right) \; .$$

In the optimality condition, $b_{Ag} - c_{Ag}$ denotes the markup defined as the price bid minus the approximated marginal cost of the production unit of type g that belongs to producer A. The methodology to approximate the marginal cost of production units is reviewed in Section 3.3.4.

$k_{Ac} + k_{Ag}$ denotes the total capacity of production units located up to price bid b_{Ag} in the supply schedule constructed by the market operator (i.e., the auctioneer). The optimality condition suggests that larger total production capacity creates an incentive to submit a higher price bid, which is a reasonable argument because when that price bid sets the uniform auction price it is applied to producer A's total production capacity. Similar intuition was also provided in Mount (2001), where the author additionally stated that the increasing difference between the price bid and marginal costs observed when the number of units for sale is increasing was an example of how market power can be used to increase the final price.

However, the incentive to inflate a price bid is moderated by the presence of risk that a production unit at stake may not eventually be scheduled to produce electricity. The next term in the optimality condition, $(1 - \alpha_{Ag})k_{Ag}$, denotes precisely a part of the production capacity of type g belonging to producer A that might not be scheduled to produce electricity due to a significantly high price bid. A negative sign in the optimality condition exactly reflects the presence of a trade-off when inflating the price bid, which is incarnated in potential losses caused by the production unit at stake not being scheduled to produce electricity.

$f(b_{Ag})$ denotes the likelihood that a production unit of type g that belongs to producer A becomes marginal. As the optimality condition suggests, a higher price bid decreases the likelihood of setting the uniform auction price, which therefore negatively affects the producer's incentive to submit an excessively high price bid. $1 - F\big(b_{Ag}\big)$ represents the probability that b_{Ag} sets the price. This probability is predicted to positively affect producer A's bid markup.

For the ex-ante analysis, it is necessary to accurately estimate these probability values. The accurate estimation of these time-variant probability values is, however, a difficult task in the case of several producers. Besides the fact that these probability values are generally different across producers, they are also expected to vary across the types of input an individual producer can use for electricity production. However, for the assessment of the regulatory reforms, an ex-post analysis could have been more applicable. Given the market outcomes, I evaluate the success of the undertaken regulatory reforms directed at fostering competition among electricity producers.

The presented theoretical model suggests considering a log-linear functional relationship in the specification of a regression model to evaluate the success of the regulatory reforms targeted at improving competition in the wholesale electricity market in England and Wales.

3.3.3 Empirical Specification of Regression Model

Based on the conclusions discussed in the analysis of a duopoly case at the level of the type of production unit and partly on economic intuition, we can formulate the following regression model to empirically analyze the bidding behavior of electricity producers:

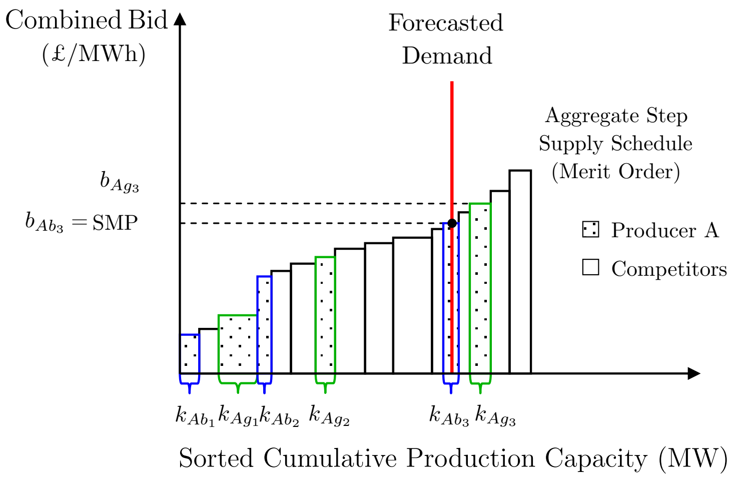
$$\log\big(Markup_{\,ijt}\big) = \beta_{0i} + \beta_{1i} \cdot \log\big(Production\ \ Units\ \ below\ \ Bid\ \ b_{\,ijt}\big) + \beta_{2ij} \cdot \log\big(Production\ \ Unit\ \ at\ \ Bid\ \ b_{\,ijt}\big) + \\ + \sum_{l=1}^{5} \gamma_l \cdot Day_{\,lt} + \sum_{l=1}^{3} \theta_l \cdot Season_{\,lt} + \varepsilon_{ijt}\,.$$

In this regression model, subscript i stands for an electricity producer. Subscript j stands for a marginal or extra-marginal production unit of type j. This means that producers' production units located at or above the forecasted demand are considered. If a producer has several production units of the same input type located at or above the forecasted demand, then only a production unit closest to the forecasted demand is considered. Finally, subscript t stands for a half-hourly trading period. Trading periods were ordered according to the forecasted demand (from the highest to the lowest). This is done with a view to analyze and understand the strategic bidding behavior of producers during different high-demand trading periods. That is, I first analyze the bidding behavior of producers during only the highest-demand trading period. Then, for a robustness check, I similarly consider the next four highest-demand trading periods.

The dependent variable, $Markup_{ijt}$, denotes the price bid minus the marginal cost of a production unit of type j (could be a marginal or extra-marginal production unit of type j) belonging to producer i during trading period t.

The two key explanatory variables in the regression model are *Production Units below Bid* b_{ijt} and *Production Unit at Bid* b_{ijt}. *Production Units below Bid* b_{ijt} denotes the total capacity of production units that belong to producer i and have price bids lower than b_{ijt}. *Production Unit at Bid* b_{ijt} denotes the capacity of a marginal or extra-marginal production unit of type j for which producer i submitted price bid b_{ijt}.

In Figure 3.3, using an example of producer A with two types of production unit, I schematically illustrate the key explanatory variables used in the regression model.



Source: Author's illustration.

Notes:

Production Units below Bid b_{Ab_3} :	$k_{Ab_1} + k_{Ag_1} + k_{Ab_2} + k_{Ag_2}$
Production Unit at Bid b_{Ab_3} :	k_{Ab_3}
$Markup_{Ab_3}$:	$b_{Ab_3} - c_{Ab_3}$
Production Units below Bid b_{Ag_3} :	$k_{Ab_1} + k_{Ag_1} + k_{Ab_2} + k_{Ag_2} + k_{Ab_3}$
Production Unit at Bid b_{Ag_3} :	k_{Ag_3}
$Markup_{Ag_3}$:	$b_{Ag_3} - c_{Ag_3}$

Figure 3.3: Explanation of Two Key Explanatory Variables

The effect of the first key explanatory variable measuring the total capacity of production units below the submitted price bid is generally assumed to be different across producers. Moreover, the producer-specific slope parameter β_1 is expected to be positive because, as the theoretical predictions suggest, larger total production capacity would create an incentive to submit a price bid reflecting a higher bid markup: when this price bid sets a uniform auction price, it is applied to a producer's entire scheduled production capacity. This intuition was also analyzed by Mount (2001), where the author additionally stated that the increasing difference between the price bid and marginal costs observed when the number of units for sale is increasing was an example of how market power can be used to increase the final price.

The effect of the second key explanatory variable measuring the capacity of a production unit at the submitted price bid is assumed to vary across not only producers but also input types. Moreover, the producer- and type-specific slope parameter β_2 is expected to be negative because, as the theoretical predictions suggest, a significantly large production unit at stake moderates a producer's willingness to inflate its bid markup. Thus, a producer faces the trade-off between bidding high to set a high price and bidding low to ensure that the production unit at stake is scheduled to produce electricity.

To take into account multiple seasonality effects, the regression model is enriched to include Day_{lt} and $Season_{lt}$ variables. Day_{lt} are dummy variables that capture day-of-the-week effects. Non-working days represented by Saturdays, Sundays, and official public/bank holidays in England and Wales are taken as the base. $Season_{lt}$ are dummy variables that capture annual seasonal effects. Finally, it is assumed that a disturbance term, ε_{ijt}, is orthogonal to the included explanatory variables.

Estimation of this regression model over different regime periods allows to analyze the development in the bidding behavior of electricity producers and to evaluate the success of the reforms introduced by the regulatory authority to mitigate the exercise of market power and foster competition among electricity producers.

3.3.4 Approximation of Marginal Costs

The marginal costs of production units are approximated based on the definition of the thermal efficiency rate and data on quarterly input prices provided by the Department of Trade and Industry (1997–2002, January 1993 – December 2000). Before describing the methodology of approximating marginal costs, I first define the needed concepts used in energy economics.

Definition: The thermal efficiency rate is the efficiency rate with which heat energy contained in fuel is converted into electrical energy (Department of Trade and Industry, 1997–2002).
This definition allows us to formally express the thermal efficiency rate of production unit X using input Y to produce 1 MWh of electricity denoted by $\kappa(X, Y)$ in the following way:

$$\kappa(X, Y) = \frac{\big(1 \text{ MWh of electricity}\big) \cdot \text{factor } E}{\text{input } Y \cdot \text{factor } Y},$$

where the additional terms denoted by factor E and factor Y are multipliers used to convert 1 MWh of electricity and input Y necessary to produce 1 MWh of electricity into the commonly used energy measurement unit, for example, gigajoules (GJ). In particular, since 41.868 GJ = 11.63 MWh, it follows that factor $E = 3.6$ GJ/MWh.

The formula for $\kappa(X, Y)$ suggests that the marginal costs of production unit X using input Y to produce 1 MWh of electricity can be approximated by

$$\begin{aligned} MC(X, Y) &= \big(\text{price of input } Y\big) \cdot \text{input } Y = \\ &= \big(\text{price of input } Y\big) \cdot \frac{\big(1 \text{ MWh of electricity}\big) \cdot \text{factor } E}{\kappa(X, Y) \cdot \text{factor } Y}. \end{aligned}$$

If input prices are given in £/MWh, then the above formula simplifies to

$$MC(X, Y) = \big(\text{price of input } Y\big) \cdot \frac{\big(1 \text{ MWh of electricity}\big)}{\kappa(X, Y)}.$$

As summarized in Table B.5, there are seven types of production unit: coal, oil, nuclear, CCGT, OCGT, PSB, and hydro. Nuclear and hydro types of production unit were far from influencing the outcome of the uniform auction price since they mainly operated as the base-load and were located in the beginning of the supply schedule constructed by the market operator (i.e., the auctioneer). This excludes the necessity to approximate their marginal costs. Combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) production units are based on different technologies that use gas. The production units of pumped storage business (PSB) have turbines that pump water up to a hill-top reservoir during off-peak periods, which then allows the production of electricity during peak periods or during unexpected shortfalls in system supply. The marginal costs of these pumped facilities are approximated by the minimal price bid.

3.4 Data

The data consist of three data sets and cover the period January 1, 1995 – September 30, 2000. The first data set contains half-hourly market data for each trading period and includes observations on the System Marginal Price (SMP), the Pool Purchase Price (PPP), the Pool Selling Price (PSP), and the forecasted and actual demand for electricity. A summary of these data with the associated measurement units is provided in Table B.1. This data set also includes information about the production unit that set the System Marginal Price (SMP): the name of the production unit, its input type, and the name of the corresponding plant and electricity producer.

The second data set contains daily bid data for each trading day on the submitted start-up cost, no-load cost, three incremental price bids, and elbow points. This data set also includes information about the electricity producer, plant, and production unit for which the daily bids are submitted. A summary of these data with the associated measurement units is provided in Table B.2.

The third data set contains half-hourly bid data for each trading period on submitted production capacities and on computed combined bids (i.e., price bids measured in £/MWh). This data set also includes information about the electricity producer, plant, and production unit for which the half-hourly bids are submitted and computed. A summary of these data with the associated measurement units is provided in Table B.3.

Detailed information and my acknowledgments to people and organizations I was in contact with in the process of collecting data and materials will be listed at a later stage of the dissertation research.

Table B.4 describes the distribution of shares of production capacity and price setting among electricity producers during the financial years of 1995/1996 and 1999/2000. To the original table reproduced from Bishop and McSorley (2001) I have added a measure of the Herfindahl-Hirschmann index computed as a sum of squared shares. The calculations show that the concentration measure decreased by almost twofold.

Figure C.1 describes in percentages the distribution of input types used for electricity production. In order to illustrate the compositional changes, I consider only the years 1990, 1995, and 2001. The necessary data for this figure are taken from the annual publications of the Department of Trade and Industry (1997–2002).

Figure C.2 describes the quarterly average input costs (measured in £/MWh) of electricity producers. The necessary data for this figure are taken from the monthly publications of the Department of Trade and Industry (January 1993 – December 2000).

These average quarterly data on input costs are used in approximating the marginal costs of production units to analyze the development of the bidding behavior of electricity producers in relation to the introduced reforms during the liberalization process of electricity supply industry in Great Britain.

3.5 Estimation Results

In Section 3.3.3, the specification of the regression model to evaluate the success of the regulatory reforms was introduced. The choice of the log-linear functional form of the regression model was based on the first-order condition from the expected profit maximization problem in a duopoly case as discussed in Section 3.3.2. Generally, log-linear regression models are used quite often in empirical research. One of the advantages of a log-linear regression model is that the estimated slope coefficients in this specification can be directly interpreted as elasticities.

Based on economic intuition, the baseline regression model was enriched to include trading day effects and annual seasonal effects. For the evaluation of the reforms introduced by the regulatory authority, I include regime dummy variables. Figure 2.2 describes the creation of regime periods based on the dates when institutional changes and regulatory reforms took place. Data availability allows analyzing the development of the bidding behavior of electricity producers during 1995-2000. This therefore suggests analyzing the period January 1, 1995 – March 31, 1996 as the base or reference period.

For statistical inference I apply heteroscedasticity and autocorrelation robust standard errors. This is justified since the null hypothesis about the equality of variances of residuals from the same model estimated, for example, during January 1, 1995 – March 31, 1996 and April 1, 1996 – June 22, 1996, is rejected at the 5% significance level and the Durbin-Watson test for the presence of autocorrelation is inconclusive.

The analysis includes National Power (NP), PowerGen (PG), TXU, Edison (Ed), British Energy (BE), and AES electricity producing companies, which are listed in Table B.4. Three electricity producers are excluded from the analysis: BNFL Magnox, EdF, and Scottish Interconnector. BNFL Magnox is excluded from the analysis because production units belonging to this producer were always infra-marginal and therefore far from influencing the market outcomes. EdF and Scottish Interconnector are producers that exported electricity into the England and Wales wholesale electricity market (see Figure 2.1). No data describing their technological characteristics are available, which does not allow approximating their marginal costs of producing electricity. Moreover, these exporters were not suspected of abusing market power. These circumstances limit the research on the analysis of electricity producers located in England and Wales. This is similar to Borenstein et al. (2002), who also restricted their research to measuring market inefficiencies in California's restructured wholesale electricity market by analyzing only electricity producers located in California.

An extract of the estimation results based on the period January 1, 1995 – September 30, 2000 is presented in the table below. These results provide a gradual analysis of the effect of the regulatory reforms on the bidding behavior of the incumbent producers.

$$\log\left(Markup_{\,ijt}\right) = \beta_{0i} + \beta_{1i}\cdot\log\left(Production\ \ Units\ below\ Bid\ b_{\,ijt}\right) + \beta_{2ij}\cdot\log\left(Production\ \ Unit\ at\ Bid\ b_{\,ijt}\right) + \\ + \sum_{l=1}^{5}\gamma_l\cdot Day_{\,lt} + \sum_{l=1}^{3}\theta_l\cdot Season_{\,lt} + \varepsilon_{ijt}$$

Variable			Jan 95 - Mar 96 Coef.	Jan 95 - Mar 96 Std. Err.	Pre-Regime 4 Coef.	Pre-Regime 4 Std. Err.	Regime 4 Coef.	Regime 4 Std. Err.	Regime 5 Coef.	Regime 5 Std. Err.
Producers		NP	8.206 ***	2.135	-25.084 ***	2.758	-9.762 ***	2.661	-5.399 **	2.158
Producers		PG	-0.287	1.796	4.986	3.502	-0.224	1.868	0.806	1.820
log(Production Units Below)		NP	-0.338	0.235	2.485 ***	0.300	0.798 ***	0.289	0.886 ***	0.235
log(Production Units Below)		PG	0.277 *	0.144	0.170	0.234	0.504 ***	0.149	0.202	0.149
log(Production Unit at Risk)	NP	Coal	-0.595 ***	0.134	0.830 ***	0.158	0.673 ***	0.145	-0.166	0.147
log(Production Unit at Risk)	NP	Oil	-0.353 ***	0.121	0.647 ***	0.143	0.565 ***	0.129	-0.237 *	0.133
log(Production Unit at Risk)	NP	OCGT	-0.166	0.196	0.765 ***	0.231	0.716 ***	0.208	-0.739 ***	0.227
log(Production Unit at Risk)	PG	Coal	0.089	0.192	-1.181 ***	0.361	-0.666 ***	0.208	-0.375 *	0.194
log(Production Unit at Risk)	PG	Oil	0.193	0.167	-0.976 ***	0.310	-0.612 ***	0.183	-0.309 *	0.169
log(Production Unit at Risk)	PG	OCGT	0.697 **	0.279	-1.876 ***	0.512	-1.203 ***	0.306	-0.708 **	0.282
Business Days		Mo	0.050 ***	0.017						
Business Days		Tu	0.045 ***	0.016						
Business Days		We	0.041 **	0.016						
Business Days		Th	0.041 **	0.016						
Business Days		Fr	0.038 **	0.015						
Seasons		Spring	0.001	0.018						
Seasons		Summer	0.007	0.017						
Seasons		Autumn	0.071 ***	0.015						
		Obs.	16,606							
		Adj. R^2	0.802							

Source: Author's calculations.

Notes: Markup is measured as the price bid minus approximated marginal costs. In some cases the difference was negative. In order to account for the possibility of measurement error resulting from the approximation of marginal costs, I add £5, as was done in Wolfram (1998). *, **, and *** stand for 10%, 5%, and 1% significance levels, respectively.

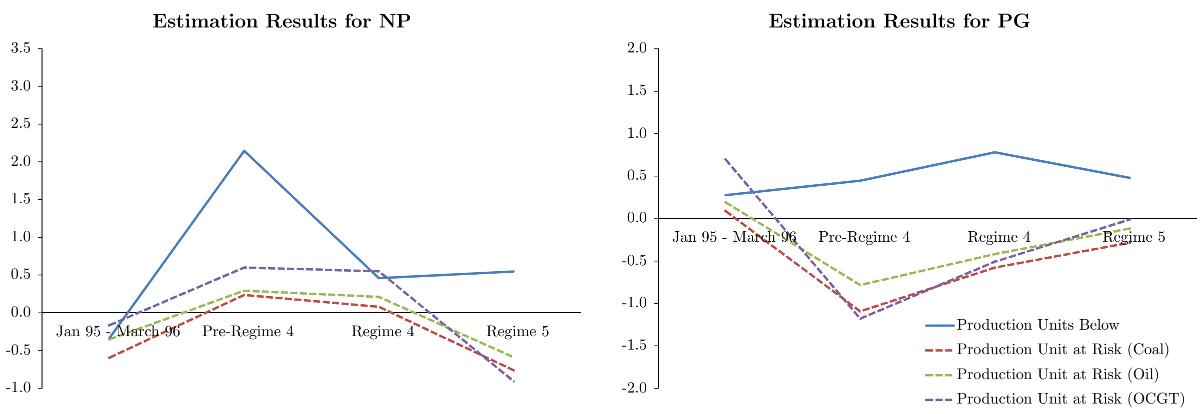
January 1, 1995 – March 31, 1996 represents the base period. For the later periods I assume that the intercept term and slope parameters in front of the key explanatory variables can vary. The validity of this assumption is verifiable by the formal testing. For example, a test for the equality of the intercept term for the larger incumbent producer during Jan 95 – Mar 96 and Pre-Regime 4 can be represented as testing the following null hypothesis:

$$\mathrm{H}_0 : \ \beta_{0,\mathrm{NP}}^{\text{Pre-Regime 4}} - \beta_{0,\mathrm{NP}}^{\text{Jan 95 – Mar 96}} = \delta_{0,\mathrm{NP}}^{\text{Pre-Regime 4}} = 0.$$

The value of $t_{stat} \approx -9.095$ suggests rejecting H_0 at the 1% significance level.

The estimation results will allow us to draw conclusions related to the analysis of the theoretical predictions and of the success of the regulatory reforms. Only for illustration, I graphically present the estimated model parameters based on the highest-demand trading periods during different regimes. These graphs are, of course, not meant to substitute the detailed estimation results presented in Appendix D.

The theoretical predictions indicate that when a larger number of production units is available, there is an incentive to inflate a markup, that is, exercise market power. As described in Figure 3.4, the incumbents' incentive to submit price bids in excess of marginal costs when a larger number of production units is below (the solid line) was greater during the subsequent regime periods than during the reference period, January 1, 1995 – March 31, 1996.

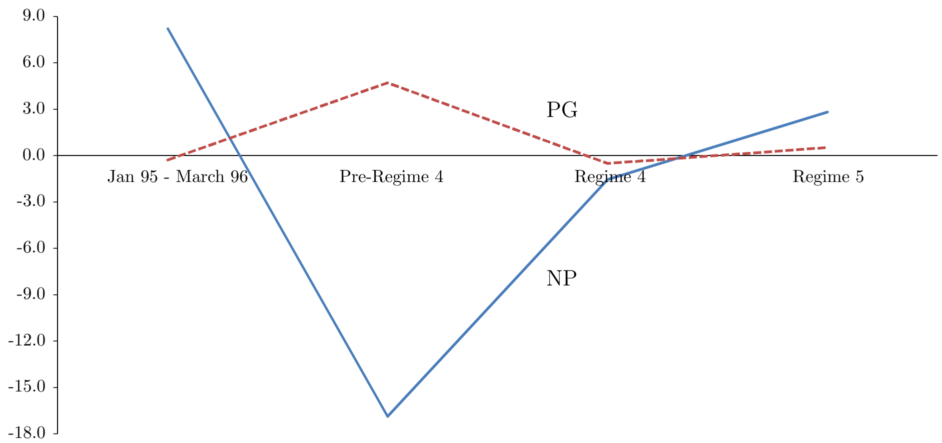


Source: Author's calculations.

Figure 3.4: Do Estimation Results Conform to Theoretical Predictions? Analysis of $\hat{\beta}_1$ and $\hat{\beta}_{2j}$ for the Incumbent Producers

The incentive to submit a price bid reflecting a high markup is however moderated by the presence of the risk that the production unit at stake may not be scheduled to produce electricity. This effect also generally need not be the same across producers. Moreover, if a single producer has several types of production unit, then this disincentive may additionally vary across types of production unit. The detailed modeling of the second level of asymmetry produced significantly better estimation results in contrast to the case when symmetry was assumed. The asymmetry at the producer and input-type levels is usually referred to as inter- and intra-firm differences.

Estimation results summarized in Figure 3.4 indicate that during the reference period, January 1995 – March 1996, the attitude towards the risk of losing a production unit when a high price bid is submitted (the dashed lines) are confirmed only for NP (the larger incumbent producer), whereas estimation results contradictory to the theoretical predictions are obtained for PG (the smaller incumbent producer). This counter-intuitive attitude towards the risk observed during the base period could resemble the aggressive bidding behavior possibly caused by the small overall influence of the second incumbent producer to inflate markups (small intercept term for PG illustrated in Figure 3.5).



Source: Author's calculations.

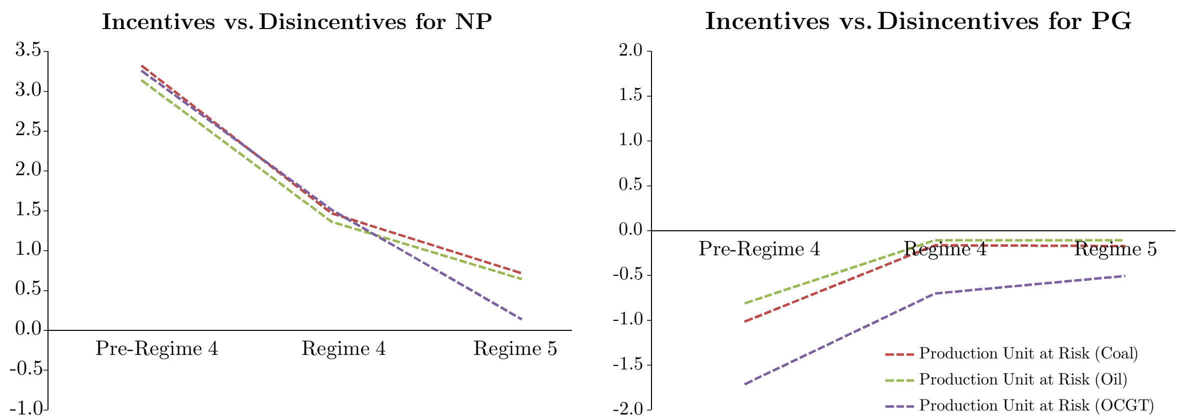
Figure 3.5: Is NP or PG More Influential? Analysis of $\hat{\beta}_0$ for the Incumbent Producers

A very interesting observation for NP described in Figure 3.4 and Figure 3.5 is related to the Pre-Regime 4 and Regime 4 periods. The large decrease in NP's overall influence to inflate markups described in Figure 3.5 (the significantly decreased intercept term for NP during the Pre-Regime 4 and Regime 4 periods as compared to the reference period) possibly caused a change in the attitude towards the risk described in Figure 3.4. Namely during the Pre-Regime 4 and Regime 4 periods, NP manifested aggressive bidding behavior similar to PG during the reference period. The issue of aggressive bidding in the wholesale electricity market in England and Wales was also mentioned in Bergman et al. (1999). Conversely, during the subsequent regime periods, PG became risk-averse about losing a production unit at stake (see Figure 3.4).

As described in Figure 3.4, during the last regime period all theoretical predictions describing the incentives and disincentives of NP and PG to exercise market power are completely confirmed by the empirical results. This can partly be attributed to the success of the regulatory reforms in disciplining the bidding behavior of electricity producers.

Since the intercept term for NP described in Figure 3.5 significantly decreased, we can infer that the overall influence of NP to inflate markups (i.e., exercise market power) reduced during the subsequent regime periods. Moreover, as described in Figure 3.6, during the last two regime periods, the net incentives to inflate a markup uniformly decreased, thereby shedding light on the successes of the regulatory reforms in disciplining the bidding behavior of the larger incumbent producer.

The analysis of the influence of the regulatory reforms on the incentives and disincentives to inflate a markup is also not straightforward for PG. In particular, as shown in Figure 3.4, the incentives and disincentives to inflate a markup for PG were larger during the subsequent regime periods as compared to the reference period. However, as summarized in Figure 3.6, since during the subsequent regime periods disincentives to inflate a markup always uniformly dominated (negative net incentives), we can conclude that the reforms were successful. Hence, PG in general also became less optimistic about inflating markups, that is, exercising market power.



Source: Author's calculations.

Figure 3.6: Net Incentive Analysis for the Incumbent Producers. Analysis of $\hat{\delta}_1 + \hat{\delta}_{2j}$

Dummy variables reflecting day-of-the-week effects also confirmed economic intuition that the extent of inflation in the markups during different trading days need not be the same. In particular, the largest and the smallest estimated coefficients correspond to Monday and Friday trading days, respectively. Overall, the estimated model is able to explain about 80% of the variations in the dependent variable by the variations in the key explanatory variables augmented by the trading day and annual seasonal effects.

For the robustness check, I consider the second–fifth highest-demand trading periods with nominal and real price markups. Complete estimation results are presented in Appendix D. Compared to the estimation results for the first highest-demand trading periods, in some instances there were sign reversals in the estimated parameters but they were statistically insignificant. In general, qualitative conclusions regarding the analysis of the theoretical predictions and the evaluation of the regulatory reforms are similar to those for the first highest-demand trading periods. The results are therefore generally robust.

3.6 Conclusions

In this paper I analyzed the bidding behavior of electricity producers to evaluate the success of the regulatory reforms introduced during the liberalization process of the electricity supply industry in Great Britain. New results were obtained that indicate the success of regulatory reforms in mitigating the exercise of market power of the incumbent electricity producers.

In particular, as the findings indicate, the overall influence of National Power to inflate markups (i.e., to exercise market power) was decreased to a large extent, which however brought about aggressive bidding behavior with respect to the production unit at risk. This counter-intuitive observation finally disappeared and all theoretical predictions were confirmed during the last regime period. Moreover, net incentives to inflate a markup uniformly decreased in later regime periods.

During the later regime periods all theoretical predictions reflecting incentives and disincentives of PowerGen to inflate a markup (i.e., to exercise market power) were confirmed by the empirical results. An interesting finding is that the disincentive to inflate the markup always uniformly dominated over the incentive to inflate the markup during the subsequent regime periods.

In addition to the analysis of the bidding behavior of electricity producers during the highest-demand trading periods (as was done, for example, in Crawford et al., 2007), I also analyze the bidding behavior of electricity producers during the next four highest-demand trading periods with nominal and real price markups. The results generally conform to those of the first highest-demand trading periods but with infrequent sign reversals for the variables which are statistically insignificant.

The findings and conclusions of this research could be of interest to countries that formed or are about to form the operation of their electricity supply industry based on the model of the original England and Wales wholesale electricity market.

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Appendices

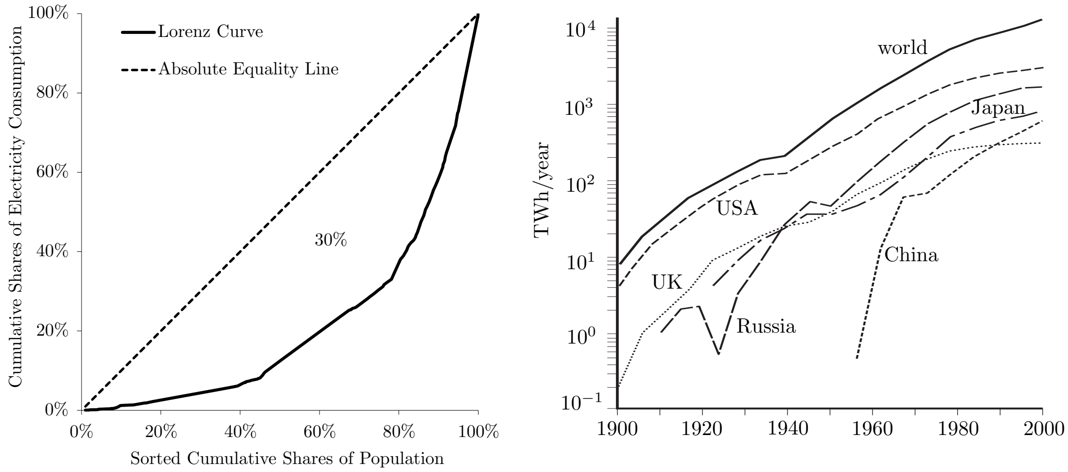
A Global Outlook of Energy

Energy forms the lifeblood of a growing and healthy economy. In this respect, there are three goals for energy use: cheapness, cleanliness, and security. These goals however share conflicting priorities whose optimal resolution becomes significant not only for economic welfare but also for environmental and even political aspects. For example, coal, on the one hand, may seem to be cheap and secure, but it is certainly not clean. Nuclear energy, on the other hand, is certainly not cheap and also raises concerns about cleanliness and especially security (Griffin, 2009). Nevertheless, the development of nuclear energy is very important in the face of the fact that with world energy consumption increasing at a rate of about 5% p.a., reserves of all fossil fuels are expected to run out in one or two centuries. In particular, the success of nuclear fusion research experiments is expected to provide electricity production for human use for over 100 million years, which is crucial given that electricity consumption accounts for the lion's share of energy use in different areas of the economy (Zemin, 2008).

In Figure A.1, I present a global view of electricity consumption and production. In particular, in Figure A.1(a), I construct the Lorenz curve for the year 2006 based on a sample of 136 countries. Data on population and electricity consumption (which was defined as gross production + imports − exports − transmission/distribution losses) were taken from Intenational Energy Agency (2008). For the construction of the Lorenz curve I used the ranking based on GDP per capita as of January 2007.

The Lorenz curve in Figure A.1(a) depicts the relationship between the sorted cumulative shares of population and the respective cumulative shares of electricity consumption. The analysis indicates that in the year 2006, 38% of total electricity consumption was shared by 80% of the total population considered in the sample. Numerical integration yielded the Gini coefficient approximately equal to 0.3. These findings suggest the presence of significant disparities in electricity consumption among the selected countries of the world.

Figure A.1(b) depicts electricity production in China, Japan, Russia, the UK, the USA, and the world during 1900–2000 (Smil, 2006). This figure in particular illustrates the presence of structural breaks in the growth rates of electricity production, which were possibly caused by the world wars and economic depression.



(a) Electricity Consumption in 2006

(b) Electricity Production

Sources: Intenational Energy Agency (2008); Smil (2006).

Figure A.1: Electricity Consumption & Generation: Global Outlook

B Tables

Table B.1: Market Data (January 2000)

	SMP	PPP	PSP	Forecasted Demand	Actual Demand
	£/MWh	£/MWh	£/MWh	MW	MW
Mean	24.39	30.96	32.10	38,464.60	38,615.42
Min	8.00	8.00	8.00	25,001.00	22,988.70
Max	77.89	320.35	359.01	49,945.00	49,617.08
Std. Dev.	12.54	37.24	41.91	5,247.83	5,559.35
Frequency	30 min				
Obs.	1,488				

Source: Data set 1 described in Section 3.4; author's calculations.

Table B.2: Daily Bid Data at the Level of Production Unit (January 2000)

	Start-Up	No-Load	Inc 1	Inc 2	Inc 3	Elb 1	Elb 2
	£	£/h	£/MWh	£/MWh	£/MWh	MW	MW
Mean	13,100.45	1,938.69	164.09	171.46	172.06	7,978.40	9,757.51
Min	0.00	0.00	0.00	0.00	0.00	55.00	181.00
Max	99,999.00	9,999.99	999.99	999.99	999.99	9,999.00	9,999.00
Std. Dev.	28,419.23	3,081.44	328.42	325.45	325.24	3,917.77	1,496.45
Frequency	Daily						
Obs.	8,587						

Source: Data set 2 described in Section 3.4; author's calculations.

Table B.3: Half-Hourly Bid Data at the Level of Production Unit (January 2000)

	Production Capacity	Combined Bid
	MW	£/MWh
Mean	87.70	39.54
Min	0.00	0.00
Max	494.50	37,865.50
Std. Dev.	124.06	106.68
Frequency	30 min	
Obs.	450,336	

Source: Data set 3 described in Section 3.4; author's calculations.

Table B.4: Structural Impact of National Power and PowerGen Divestments

		Share of Capacity		Share of Price Setting	
		1995/1996	1999/2000	1995/1996	1999/2000
1	National Power	33.7	13.0	44.8	14.6
2	PowerGen	28.1	16.5	31.8	16.8
3	BNFL Magnox	5.8	5.4	0.0	0.0
4	EdF	3.3	3.3	0.7	10.7
5	Scottish Interconnector	2.3	2.2	1.7	0.4
6	TXU	1.6	9.2	7.3	11.8
7	Edison	3.8	8.9	13.2	21.1
8	British Energy	12.0	14.8	0.0	4.9
9	AES	0.5	7.6	0.0	19.3
10	Combined cycle gas turbines	7.8	17.2	0.5	0.4
11	Others	1.3	2.0	0.0	0.0
	HHI	0.22	0.12	0.33	0.16

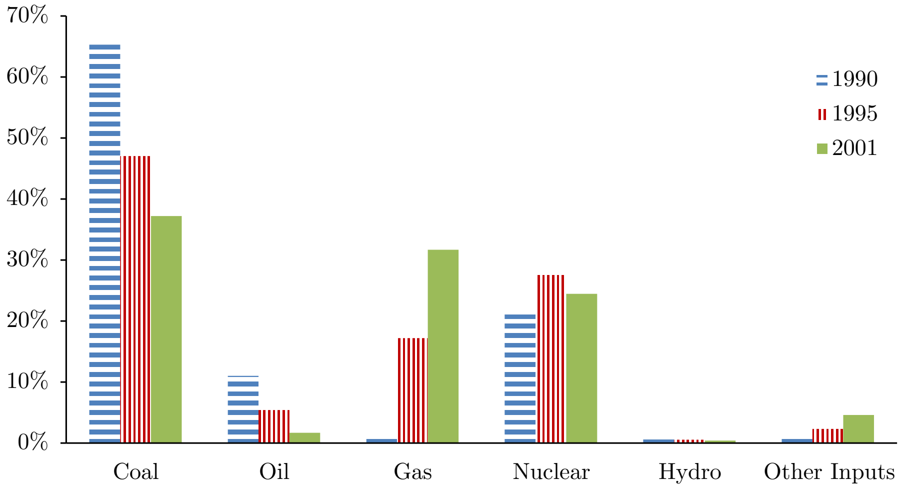
Source: Reproduced from Bishop and McSorley (2001).
Note: HHI = Herfindahl-Hirschmann Index (sum of squared shares: monopoly = 1).

Table B.5: Distribution of Types of Production Unit

	Producer	Types of Production Unit							
		Coal	Oil	Nuclear	CCGT	OCGT	PSB	Hydro	Subtotal
1	National Power	58	11	0	6	48	0	4	127
2	PowerGen	28	9	0	9	17	0	4	67
3	BNFL Magnox	0	0	40	0	0	0	1	41
6	TXU	16	0	0	2	8	0	0	26
7	Edison	8	0	0	0	4	10	0	22
8	British Energy	4	0	10	0	0	0	0	14
9	AES	9	0	0	1	4	0	0	14
	Subtotal	123	20	50	18	81	10	9	311

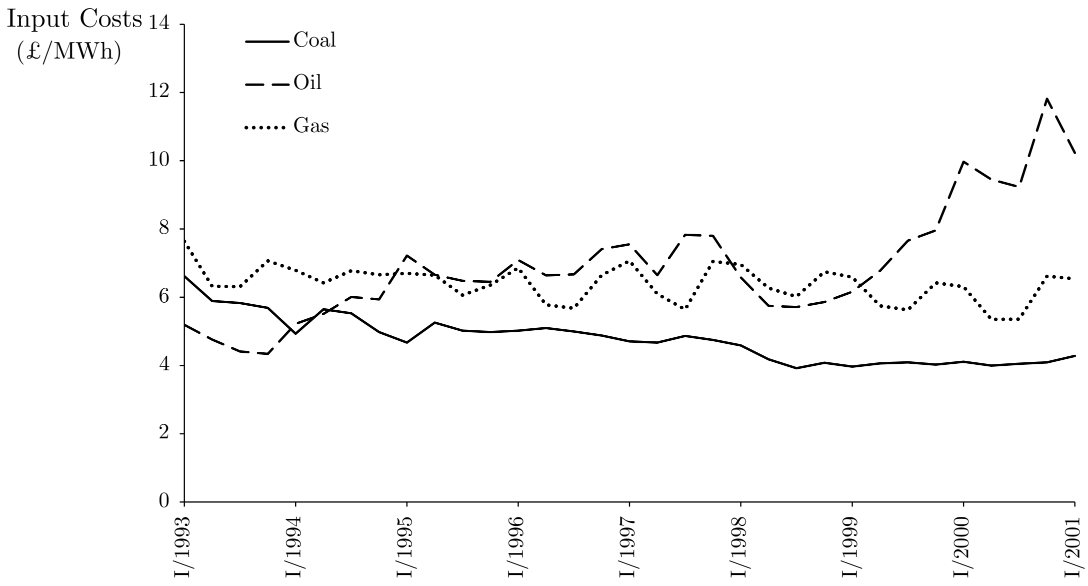
Source: National Grid Company (1994–2001) publications for various years; author's calculations.

C Figures



Source: Department of Trade and Industry (1997–2002); author's calculations.

Figure C.1: Distribution of Input Types for Electricity Production



Source: Department of Trade and Industry (January 1993 – December 2000); author's calculations.

Figure C.2: Quarterly Average Input Costs of Electricity Producers in the UK

D Estimation Tables

Table D.1: Estimation Results Based on the First Highest-Demand Trading Period

Dependent Variable: log(Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	8.206 ***	2.135	-25.084 ***	2.758	-9.762 ***	2.661	-5.399 **	2.158
		PG	-0.287	1.796	4.986	3.502	-0.224	1.868	0.806	1.820
		TXU	2.261 ***	0.275					0.073 ***	0.025
		Ed	2.365 ***	0.184	-0.752 **	0.324	-0.314	0.251	-4.764 ***	0.631
		BE	1.081	1.783						
		AES	5.531 ***	0.096					0.241 ***	0.065
log(Production Units Below)		NP	-0.338	0.235	2.485 ***	0.300	0.798 ***	0.289	0.886 ***	0.235
		PG	0.277 *	0.144	0.170	0.234	0.504 ***	0.149	0.202	0.149
		TXU	0.075 ***	0.011						
		Ed	0.114 ***	0.002	-0.002	0.004	0.013 ***	0.003	0.221 **	0.098
		BE	0.412 **	0.193						
		AES	0.107 ***	0.004						
log(Production Unit at Risk)	NP	Coal	-0.595 ***	0.134	0.830 ***	0.158	0.673 ***	0.145	-0.166	0.147
		Oil	-0.353 ***	0.121	0.647 ***	0.143	0.565 ***	0.129	-0.237 *	0.133
		CCGT	0.281 **	0.109						
		OCGT	-0.166	0.196	0.765 ***	0.231	0.716 ***	0.208	-0.739 ***	0.227
	PG	Coal	0.089	0.192	-1.181 ***	0.361	-0.666 ***	0.208	-0.375 *	0.194
		Oil	0.193	0.167	-0.976 ***	0.310	-0.612 ***	0.183	-0.309 *	0.169
		OCGT	0.697 **	0.279	-1.876 ***	0.512	-1.203 ***	0.306	-0.708 **	0.282
	TXU	Coal	-0.118 **	0.048						
		CCGT	-0.040	0.061						
		OCGT	0.436 ***	0.103						
	Ed	Coal	0.513 ***	0.027						
		OCGT	2.055 ***	0.098						
		PSB	0.032	0.038	0.155 **	0.068	0.083	0.052	0.621 ***	0.052
	BE	Coal	-0.335 ***	0.089						
	AES	Coal	-0.709 ***	0.014						
		CCGT	-0.758 ***	0.056						
		OCGT	-0.722 ***	0.022						
Business Days		Mo	0.050 ***	0.017						
		Tu	0.045 ***	0.016						
		We	0.041 **	0.016						
		Th	0.041 **	0.016						
		Fr	0.038 **	0.015						
Seasons		Spring	0.001	0.018						
		Summer	0.007	0.017						
		Autumn	0.071 ***	0.015						
		Obs.	16,606							
		Adj. R^2	0.802							
		AIC	1.152							
		D-W stat.	1.719							

Table D.2: Estimation Results Based on the First Highest-Demand Trading Period

Dependent Variable: log(Real Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	9.143 ***	2.176	-25.904 ***	2.790	-10.390 ***	2.634	-5.322 **	2.201
		PG	0.345	1.810	4.406	3.449	0.014	1.888	1.020	1.841
		TXU	2.415 ***	0.277					0.114 ***	0.025
		Ed	2.429 ***	0.177	-0.666 **	0.325	-0.245	0.248	-4.288 ***	0.549
		BE	3.174 *	1.896						
		AES	5.775 ***	0.101					0.256 ***	0.068
log(Production Units Below)		NP	-0.440 *	0.240	2.590 ***	0.302	0.878 ***	0.286	0.906 ***	0.239
		PG	0.221	0.145	0.229	0.232	0.486 ***	0.150	0.180	0.150
		TXU	0.077 ***	0.011						
		Ed	0.115 ***	0.002	-0.005	0.004	0.009 ***	0.003	0.175 **	0.085
		BE	0.264	0.202						
		AES	0.108 ***	0.004						
log(Production Unit at Risk)	NP	Coal	-0.592 ***	0.136	0.823 ***	0.160	0.677 ***	0.147	-0.206	0.149
		Oil	-0.348 ***	0.123	0.638 ***	0.144	0.566 ***	0.130	-0.272 **	0.135
		CCGT	0.279 ***	0.105						
		OCGT	-0.155	0.199	0.748 ***	0.233	0.715 ***	0.211	-0.804 ***	0.231
	PG	Coal	0.073	0.193	-1.158 ***	0.358	-0.669 ***	0.210	-0.364 *	0.195
		Oil	0.177	0.168	-0.955 ***	0.307	-0.611 ***	0.185	-0.296 *	0.170
		OCGT	0.672 **	0.280	-1.842 ***	0.507	-1.201 ***	0.309	-0.684 **	0.285
	TXU	Coal	-0.121 **	0.049						
		CCGT	-0.056	0.062						
		OCGT	0.427 ***	0.104						
	Ed	Coal	0.506 ***	0.026						
		OCGT	2.050 ***	0.091						
		PSB	0.029	0.036	0.149 **	0.068	0.090 *	0.051	0.615 ***	0.050
	BE	Coal	-0.461 ***	0.096						
	AES	Coal	-0.722 ***	0.015						
		CCGT	-0.785 ***	0.059						
		OCGT	-0.740 ***	0.023						
Business Days		Mo	0.055 ***	0.017						
		Tu	0.055 ***	0.017						
		We	0.050 ***	0.017						
		Th	0.050 ***	0.016						
		Fr	0.045 ***	0.016						
Seasons		Spring	-0.059 ***	0.018						
		Summer	0.027	0.018						
		Autumn	0.138 ***	0.015						
		Obs.	16,606							
		Adj. R^2	0.797							
		AIC	1.180							
		D-W stat.	1.677							

Table D.3: Estimation Results Based on the Second Highest-Demand Trading Period

Dependent Variable: log(Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	4.435 *	2.326	-20.235 ***	3.046	-5.800 **	2.783	-1.693	2.344
		PG	0.131	1.620	3.552	3.614	-1.920	1.644	-1.437	1.667
		TXU	2.578 ***	0.314					0.087 ***	0.025
		Ed	2.119 ***	0.215	-0.557	0.420	-0.019	0.271	-3.591 ***	0.418
		BE	0.843	1.898						
		AES	5.574 ***	0.078					0.259 ***	0.063
log(Production Units Below)		NP	0.011	0.257	1.986 ***	0.344	0.448	0.305	0.509 **	0.257
		PG	0.210	0.140	0.276	0.240	0.542 ***	0.145	0.286 **	0.145
		TXU	0.098 ***	0.012						
		Ed	0.113 ***	0.002	-0.005	0.004	0.012 ***	0.002	0.059	0.058
		BE	0.433 **	0.192						
		AES	0.105 ***	0.004						
log(Production Unit at Risk)	NP	Coal	-0.452 ***	0.109	0.715 ***	0.153	0.490 ***	0.121	-0.269 **	0.123
		Oil	-0.243 **	0.099	0.579 ***	0.141	0.422 ***	0.107	-0.300 ***	0.113
		CCGT	0.251 **	0.116						
		OCGT	0.009	0.161	0.666 ***	0.229	0.488 ***	0.173	-0.818 ***	0.194
	PG	Coal	0.111	0.161	-1.068 ***	0.369	-0.416 **	0.162	-0.093	0.171
		Oil	0.220	0.140	-0.886 ***	0.317	-0.377 ***	0.141	-0.045	0.151
		OCGT	0.742 ***	0.235	-1.729 ***	0.523	-0.815 ***	0.237	-0.273	0.253
	TXU	Coal	-0.221 ***	0.054						
		CCGT	-0.069	0.067						
		OCGT	0.227 *	0.116						
	Ed	Coal	0.537 ***	0.025						
		OCGT	2.200 ***	0.079						
		PSB	0.080 *	0.044	0.112	0.087	0.023	0.055	0.618 ***	0.054
	BE	Coal	-0.327 ***	0.126						
	AES	Coal	-0.725 ***	0.011						
		CCGT	-0.744 ***	0.046						
		OCGT	-0.736 ***	0.017						
Business Days		Mo	0.059 ***	0.016						
		Tu	0.051 ***	0.016						
		We	0.050 ***	0.016						
		Th	0.043 ***	0.016						
		Fr	0.037 **	0.015						
Seasons		Spring	0.013	0.018						
		Summer	0.010	0.017						
		Autumn	0.070 ***	0.015						
		Obs.	16,934							
		Adj. R^2	0.802							
		AIC	1.181							
		D-W stat.	1.724							

Table D.4: Estimation Results Based on the Second Highest-Demand Trading Period

Dependent Variable: log(Real Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	5.271 **	2.376	-20.955 ***	3.062	-6.318 **	2.770	-1.527	2.395
		PG	0.717	1.632	3.015	3.551	-1.689	1.661	-1.332	1.688
		TXU	2.725 ***	0.308					0.127 ***	0.026
		Ed	2.162 ***	0.209	-0.458	0.426	0.069	0.269	-3.247 ***	0.380
		BE	3.015	1.994						
		AES	5.818 ***	0.086					0.273 ***	0.066
log(Production Units Below)		NP	-0.082	0.263	2.081 ***	0.345	0.518 *	0.304	0.522 **	0.263
		PG	0.156	0.141	0.334	0.237	0.520 ***	0.146	0.263 *	0.146
		TXU	0.101 ***	0.012						
		Ed	0.115 ***	0.002	-0.008 *	0.004	0.008 ***	0.003	0.037	0.050
		BE	0.284	0.199						
		AES	0.107 ***	0.004						
log(Production Unit at Risk)	NP	Coal	-0.446 ***	0.110	0.704 ***	0.154	0.491 ***	0.121	-0.313 **	0.124
		Oil	-0.235 **	0.100	0.567 ***	0.142	0.421 ***	0.108	-0.339 ***	0.114
		CCGT	0.249 **	0.111						
		OCGT	0.025	0.161	0.644 ***	0.231	0.483 ***	0.174	-0.889 ***	0.196
	PG	Coal	0.099	0.162	-1.051 ***	0.365	-0.412 **	0.163	-0.063	0.173
		Oil	0.209	0.141	-0.871 ***	0.314	-0.370 ***	0.142	-0.013	0.153
		OCGT	0.724 ***	0.236	-1.704 ***	0.517	-0.802 ***	0.238	-0.219	0.256
	TXU	Coal	-0.222 ***	0.053						
		CCGT	-0.083	0.065						
		OCGT	0.223 *	0.114						
	Ed	Coal	0.528 ***	0.025						
		OCGT	2.183 ***	0.075						
		PSB	0.082 *	0.042	0.104	0.088	0.027	0.055	0.604 ***	0.052
	BE	Coal	-0.469 ***	0.132						
	AES	Coal	-0.738 ***	0.012						
		CCGT	-0.772 ***	0.049						
		OCGT	-0.754 ***	0.020						
Business Days		Mo	0.064 ***	0.017						
		Tu	0.061 ***	0.016						
		We	0.059 ***	0.017						
		Th	0.052 ***	0.017						
		Fr	0.043 ***	0.016						
Seasons		Spring	-0.047 ***	0.018						
		Summer	0.029	0.018						
		Autumn	0.138 ***	0.015						
		Obs.	16,934							
		Adj. R^2	0.796							
		AIC	1.209							
		D-W stat.	1.683							

Table D.5: Estimation Results Based on the Third Highest-Demand Trading Period

Dependent Variable: log(Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	5.255 **	2.254	-19.338 ***	3.359	-6.433 **	2.578	-2.087	2.277
		PG	-1.527	1.696	9.943 ***	1.840	2.096	1.788	1.214	1.733
		TXU	2.728 ***	0.200					0.028	0.023
		Ed	1.832 ***	0.206	-0.326	0.385	0.270	0.259	-1.658 **	0.646
		BE	0.993	1.693					0.661 ***	0.071
		AES	4.016 ***	0.564						
log(Production Units Below)		NP	-0.164	0.242	2.006 ***	0.362	0.559 **	0.276	0.491 **	0.243
		PG	0.325 **	0.143	-0.136	0.160	0.323 **	0.147	0.054	0.146
		TXU	0.076 ***	0.012						
		Ed	0.113 ***	0.002	-0.007	0.005	0.013 ***	0.003	-0.034 ***	0.008
		BE	0.490 ***	0.178						
		AES	0.081 ***	0.005						
log(Production Unit at Risk)	NP	Coal	-0.322 **	0.128	0.502 ***	0.195	0.420 ***	0.136	-0.221	0.153
		Oil	-0.121	0.114	0.399 **	0.176	0.364 ***	0.121	-0.245 *	0.140
		CCGT	0.390 ***	0.123						
		OCGT	0.220	0.185	0.366	0.288	0.378 *	0.196	-0.641 ***	0.239
	PG	Coal	0.222	0.163	-1.626 ***	0.185	-0.808 ***	0.191	-0.228	0.170
		Oil	0.324 **	0.141	-1.366 ***	0.159	-0.743 ***	0.170	-0.159	0.149
		OCGT	0.927 ***	0.238	-2.530 ***	0.268	-1.422 ***	0.284	-0.473 *	0.251
	TXU	Coal	-0.219 ***	0.033						
		CCGT	-0.143 ***	0.047						
		OCGT	0.243 ***	0.070						
	Ed	Coal	0.347 ***	0.110						
		OCGT	1.763 ***	0.282						
		PSB	0.139 ***	0.042	0.067	0.081	-0.033	0.053	0.336 **	0.143
	BE	Coal	-0.438 ***	0.115						
	AES	Coal	-0.492 ***	0.096						
		CCGT	-0.504 ***	0.127						
		OCGT	-0.410 ***	0.134						
Business Days		Mo	0.078 ***	0.015						
		Tu	0.063 ***	0.015						
		We	0.057 ***	0.015						
		Th	0.070 ***	0.015						
		Fr	0.064 ***	0.015						
Seasons		Spring	0.024	0.017						
		Summer	-0.030 *	0.017						
		Autumn	0.050 ***	0.014						
		Obs.	17,320							
		Adj. R^2	0.805							
		AIC	1.188							
		D-W stat.	1.713							

Table D.6: Estimation Results Based on the Third Highest-Demand Trading Period

Dependent Variable: log(Real Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	6.136 ***	2.263	-20.199 ***	3.324	-7.052 ***	2.540	-2.341	2.288
		PG	-0.942	1.705	9.370 ***	1.872	2.457	1.807	1.133	1.749
		TXU	2.863 ***	0.195					0.069 ***	0.023
		Ed	1.871 ***	0.201	-0.263	0.389	0.352	0.256	-1.408 **	0.635
		BE	3.354 *	1.749						
		AES	4.223 ***	0.587					0.678 ***	0.073
log(Production Units Below)		NP	-0.260	0.245	2.110 ***	0.359	0.639 **	0.274	0.533 **	0.246
		PG	0.273 *	0.144	-0.076	0.163	0.293 **	0.148	0.045	0.148
		TXU	0.078 ***	0.012						
		Ed	0.114 ***	0.002	-0.009 *	0.005	0.010 ***	0.003	-0.039 ***	0.007
		BE	0.320 *	0.179						
		AES	0.082 ***	0.005						
log(Production Unit at Risk)	NP	Coal	-0.320 **	0.127	0.505 ***	0.194	0.422 ***	0.135	-0.230	0.153
		Oil	-0.116	0.114	0.398 **	0.176	0.364 ***	0.121	-0.252 *	0.139
		CCGT	0.380 ***	0.116						
		OCGT	0.231	0.185	0.362	0.288	0.375 *	0.196	-0.651 ***	0.239
	PG	Coal	0.208	0.163	-1.603 ***	0.186	-0.816 ***	0.193	-0.184	0.171
		Oil	0.311 **	0.142	-1.346 ***	0.160	-0.746 ***	0.172	-0.114	0.150
		OCGT	0.907 ***	0.238	-2.497 ***	0.268	-1.427 ***	0.287	-0.397	0.252
	TXU	Coal	-0.218 ***	0.032						
		CCGT	-0.154 ***	0.047						
		OCGT	0.243 ***	0.068						
	Ed	Coal	0.337 ***	0.109						
		OCGT	1.733 ***	0.278						
		PSB	0.143 ***	0.041	0.066	0.081	-0.030	0.053	0.316 **	0.140
	BE	Coal	-0.582 ***	0.120						
	AES	Coal	-0.498 ***	0.100						
		CCGT	-0.525 ***	0.133						
		OCGT	-0.420 ***	0.140						
Business Days		Mo	0.084 ***	0.016						
		Tu	0.072 ***	0.016						
		We	0.065 ***	0.016						
		Th	0.077 ***	0.016						
		Fr	0.070 ***	0.015						
Seasons		Spring	-0.037 **	0.018						
		Summer	-0.014	0.018						
		Autumn	0.116 ***	0.015						
		Obs.	17,320							
		Adj. R^2	0.800							
		AIC	1.215							
		D-W stat.	1.676							

Table D.7: Estimation Results Based on the Fourth Highest-Demand Trading Period

Dependent Variable: log(Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	4.952 **	2.091	-19.405 ***	2.969	-5.525 **	2.589	-0.765	2.091
		PG	-0.530	1.542	7.293 ***	2.025	0.779	1.636	0.365	1.565
		TXU	2.722 ***	0.216					0.064 ***	0.023
		Ed	1.569 ***	0.200	0.011	0.411	-0.231	0.273	-1.327 **	0.531
		BE	1.969	1.572						
		AES	5.484 ***	0.086					0.599 ***	0.067
log(Production Units Below)		NP	-0.161	0.237	2.014 ***	0.342	0.534 *	0.283	0.328	0.237
		PG	0.234 *	0.127	0.036	0.163	0.380 ***	0.132	0.160	0.130
		TXU	0.094 ***	0.010						
		Ed	0.113 ***	0.002	-0.009 **	0.004	0.011 ***	0.003	-0.049 ***	0.006
		BE	0.308 *	0.166						
		AES	0.083 ***	0.005						
log(Production Unit at Risk)	NP	Coal	-0.295 ***	0.114	0.511 ***	0.153	0.304 *	0.159	-0.228 **	0.115
		Oil	-0.087	0.104	0.408 ***	0.139	0.256 *	0.143	-0.240 **	0.106
		CCGT	0.138	0.164						
		OCGT	0.293 *	0.170	0.365	0.229	0.184	0.234	-0.625 ***	0.173
	PG	Coal	0.166	0.153	-1.385 ***	0.204	-0.649 ***	0.176	-0.221	0.158
		Oil	0.285 **	0.133	-1.164 ***	0.178	-0.602 ***	0.157	-0.169	0.138
		OCGT	0.866 ***	0.224	-2.201 ***	0.297	-1.189 ***	0.262	-0.493 **	0.231
	TXU	Coal	-0.255 ***	0.036						
		CCGT	-0.110 **	0.047						
		OCGT	0.174 **	0.078						
	Ed	Coal	0.349 ***	0.090						
		OCGT	1.779 ***	0.230						
		PSB	0.188 ***	0.041	-0.004	0.086	0.072	0.056	0.285 **	0.119
	BE	Coal	-0.356 ***	0.092						
	AES	Coal	-0.743 ***	0.014						
		CCGT	-0.841 ***	0.046						
		OCGT	-0.759 ***	0.021						
Business Days		Mo	0.091 ***	0.015						
		Tu	0.087 ***	0.015						
		We	0.080 ***	0.015						
		Th	0.063 ***	0.015						
		Fr	0.062 ***	0.014						
Seasons		Spring	0.036 **	0.017						
		Summer	-0.013	0.016						
		Autumn	0.056 ***	0.014						
		Obs.	17,878							
		Adj. R^2	0.809							
		AIC	1.192							
		D-W stat.	1.693							

Table D.8: Estimation Results Based on the Fourth Highest-Demand Trading Period

Dependent Variable: log(Real Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	5.743 ***	2.123	-20.171 ***	2.946	-6.010 **	2.560	-0.953	2.125
		PG	0.044	1.553	6.670 ***	2.034	1.107	1.656	0.379	1.578
		TXU	2.847 ***	0.212					0.105 ***	0.024
		Ed	1.618 ***	0.201	0.091	0.421	-0.167	0.276	-1.117 **	0.518
		BE	4.156 **	1.693					0.617 ***	0.069
		AES	5.794 ***	0.094						
log(Production Units Below)		NP	-0.247	0.241	2.111 ***	0.339	0.602 **	0.280	0.367	0.241
		PG	0.180	0.129	0.102	0.165	0.360 ***	0.134	0.154	0.132
		TXU	0.097 ***	0.010						
		Ed	0.114 ***	0.002	-0.011 **	0.004	0.007 ***	0.003	-0.054 ***	0.005
		BE	0.157	0.176						
		AES	0.084 ***	0.005						
log(Production Unit at Risk)	NP	Coal	-0.291 **	0.114	0.507 ***	0.153	0.299 *	0.158	-0.241 **	0.115
		Oil	-0.081	0.105	0.401 ***	0.139	0.250 *	0.143	-0.251 **	0.106
		CCGT	0.124	0.162						
		OCGT	0.305 *	0.171	0.350	0.229	0.171	0.234	-0.643 ***	0.174
	PG	Coal	0.155	0.153	-1.363 ***	0.204	-0.665 ***	0.178	-0.198	0.157
		Oil	0.276 **	0.133	-1.145 ***	0.178	-0.613 ***	0.159	-0.144	0.137
		OCGT	0.852 ***	0.224	-2.170 ***	0.296	-1.208 ***	0.266	-0.450 *	0.231
	TXU	Coal	-0.254 ***	0.036						
		CCGT	-0.118 **	0.046						
		OCGT	0.175 **	0.077						
	Ed	Coal	0.343 ***	0.087						
		OCGT	1.763 ***	0.224						
		PSB	0.190 ***	0.041	-0.009	0.088	0.078	0.057	0.273 **	0.116
	BE	Coal	-0.498 ***	0.098						
	AES	Coal	-0.768 ***	0.015						
		CCGT	-0.887 ***	0.048						
		OCGT	-0.793 ***	0.023						
Business Days		Mo	0.095 ***	0.016						
		Tu	0.094 ***	0.016						
		We	0.086 ***	0.016						
		Th	0.069 ***	0.016						
		Fr	0.066 ***	0.015						
Seasons		Spring	-0.024	0.017						
		Summer	0.005	0.018						
		Autumn	0.124 ***	0.014						
		Obs.	17,878							
		Adj. R^2	0.806							
		AIC	1.221							
		D-W stat.	1.650							

Table D.9: Estimation Results Based on the Fifth Highest-Demand Trading Period

Dependent Variable: log(Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	7.470 ***	1.967	-22.960 ***	2.954	-8.371 ***	2.282	-2.976	1.968
		PG	-2.708	1.691	10.793 ***	1.894	1.733	1.745	3.372 *	1.729
		TXU	1.664 ***	0.234					0.078 ***	0.023
		Ed	1.400 ***	0.210	0.428	0.378	0.444	0.304	-1.461 ***	0.567
		BE	2.980 *	1.521						
		AES	5.098 ***	0.333					0.668 ***	0.075
log(Production Units Below)		NP	-0.200	0.203	2.095 ***	0.297	0.560 **	0.237	0.315	0.204
		PG	0.421 ***	0.145	-0.208	0.173	0.157	0.149	-0.096	0.148
		TXU	0.063 ***	0.013						
		Ed	0.111 ***	0.002	-0.014 ***	0.005	0.012 ***	0.002	-0.042 ***	0.007
		BE	0.238	0.164						
		AES	0.078 ***	0.005						
log(Production Unit at Risk)	NP	Coal	-0.727 ***	0.120	1.065 ***	0.184	0.812 ***	0.131	0.213 *	0.122
		Oil	-0.469 ***	0.109	0.901 ***	0.163	0.710 ***	0.118	0.159	0.111
		CCGT	0.342 ***	0.103						
		OCGT	-0.322 *	0.171	1.161 ***	0.262	0.918 ***	0.186	0.024	0.175
	PG	Coal	0.262 *	0.158	-1.650 ***	0.184	-0.475 ***	0.169	-0.379 **	0.166
		Oil	0.373 ***	0.136	-1.400 ***	0.158	-0.430 ***	0.148	-0.306 **	0.145
		OCGT	1.018 ***	0.229	-2.594 ***	0.267	-0.910 ***	0.249	-0.723 ***	0.244
	TXU	Coal	-0.017	0.038						
		CCGT	0.041	0.057						
		OCGT	0.692 ***	0.082						
	Ed	Coal	0.398 ***	0.093						
		OCGT	1.898 ***	0.237						
		PSB	0.219 ***	0.044	-0.093	0.081	-0.066	0.063	0.309 **	0.124
	BE	Coal	-0.441 ***	0.098						
	AES	Coal	-0.682 ***	0.056						
		CCGT	-0.719 ***	0.078						
		OCGT	-0.680 ***	0.080						
Business Days		Mo	0.109 ***	0.015						
		Tu	0.102 ***	0.015						
		We	0.097 ***	0.015						
		Th	0.091 ***	0.015						
		Fr	0.078 ***	0.014						
Seasons		Spring	0.037 **	0.016						
		Summer	-0.015	0.016						
		Autumn	0.057 ***	0.014						
		Obs.	17,862							
		Adj. R^2	0.812							
		AIC	1.200							
		D-W stat.	1.719							

Table D.10: Estimation Results Based on the Fifth Highest-Demand Trading Period

Dependent Variable: log(Real Markup)					Pre-Regime 4		Regime 4		Regime 5	
Variable			Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Producers		NP	8.254 ***	2.008	-23.720 ***	2.931	-8.870 ***	2.276	-3.155	2.011
		PG	-2.147	1.705	10.104 ***	1.943	1.971	1.767	3.384 *	1.754
		TXU	1.759 ***	0.233					0.121 ***	0.023
		Ed	1.481 ***	0.210	0.468	0.379	0.471	0.303	-1.296 **	0.547
		BE	5.262 ***	1.638						
		AES	5.367 ***	0.358					0.688 ***	0.077
log(Production Units Below)		NP	-0.282	0.207	2.189 ***	0.295	0.630 ***	0.236	0.349 *	0.208
		PG	0.372 **	0.146	-0.139	0.179	0.135	0.151	-0.106	0.150
		TXU	0.067 ***	0.013						
		Ed	0.112 ***	0.002	-0.016 ***	0.005	0.009 ***	0.003	-0.047 ***	0.007
		BE	0.087	0.171						
		AES	0.078 ***	0.006						
log(Production Unit at Risk)	NP	Coal	-0.727 ***	0.122	1.066 ***	0.183	0.809 ***	0.132	0.205 *	0.123
		Oil	-0.466 ***	0.110	0.899 ***	0.162	0.705 ***	0.119	0.154	0.112
		CCGT	0.326 ***	0.097						
		OCGT	-0.316 *	0.173	1.154 ***	0.262	0.908 ***	0.187	0.015	0.177
	PG	Coal	0.247	0.158	-1.619 ***	0.184	-0.474 ***	0.171	-0.348 **	0.169
		Oil	0.359 ***	0.136	-1.374 ***	0.159	-0.425 ***	0.150	-0.273 *	0.148
		OCGT	0.997 ***	0.230	-2.551 ***	0.267	-0.901 ***	0.252	-0.668 ***	0.248
	TXU	Coal	-0.011	0.038						
		CCGT	0.039	0.057						
		OCGT	0.702 ***	0.082						
	Ed	Coal	0.395 ***	0.090						
		OCGT	1.888 ***	0.228						
		PSB	0.214 ***	0.043	-0.089	0.081	-0.053	0.063	0.307 **	0.120
	BE	Coal	-0.600 ***	0.107						
	AES	Coal	-0.699 ***	0.061						
		CCGT	-0.752 ***	0.083						
		OCGT	-0.705 ***	0.085						
Business Days		Mo	0.112 ***	0.015						
		Tu	0.108 ***	0.015						
		We	0.103 ***	0.015						
		Th	0.096 ***	0.016						
		Fr	0.082 ***	0.015						
Seasons		Spring	-0.023	0.017						
		Summer	0.002	0.018						
		Autumn	0.126 ***	0.014						
		Obs.	17,862							
		Adj. R^2	0.809							
		AIC	1.231							
		D-W stat.	1.674							

E Abbreviations

CB	Combined Bid (price bid measured in £/MWh)
CCGT	Combined Cycle Gas Turbine
CEGB	Central Electricity Generation Board
CP	Capacity Payment
DGES	Director General of Electricity Supply
ESI	Electricity Supply Industry
IPP	Independent Power Producer
LOLP	Loss of Load Probability
MMC	Monopolies and Mergers Commission
NETA	New Electricity Trading Arrangements
NGC	National Grid Company
NP	National Power
OCGT	Open Cycle Gas Turbine
OFFER	Office of Electricity Regulation
PG	PowerGen
PPP	Pool Purchase Price
PSB	Pumped Storage Business
PSP	Pool Selling Price
REC	Regional Electricity Company
SFE	Supply Function Equilibrium
SMP	System Marginal Price
TSP	Transmission Service Price
VLL	Value of Lost Load

Working Paper Series
ISSN 1211-3298
Registration No. (Ministry of Culture): E 19443

Individual researchers, as well as the on-line and printed versions of the CERGE-EI Working Papers (including their dissemination) were supported from the European Structural Fund (within the Operational Programme Prague Adaptability), the budget of the City of Prague, the Czech Republic's state budget and the following institutional grants:

- Center of Advanced Political Economy Research [Centrum pro pokročilá politicko-ekonomická studia], No. LC542, (2005-2010);
- Economic Aspects of EU and EMU Entry [Ekonomické aspekty vstupu do Evropské unie a Evropské měnové unie], No. AVOZ70850503, (2005-2010);
- Economic Impact of European Integration on the Czech Republic [Ekonomické dopady evropské integrace na ČR], No. MSM0021620846, (2005-2011);

Specific research support and/or other grants the researchers/publications benefited from are acknowledged at the beginning of the Paper.

Published by
Charles University in Prague, Center for Economic Research and Graduate Education (CERGE)
and
Economics Institute ASCR, v. v. i. (EI)
CERGE-EI, Politických vězňů 7, 111 21 Prague 1, tel.: +420 224 005 153, Czech Republic.
Printed by CERGE-EI, Prague
Subscription: CERGE-EI homepage: http://www.cerge-ei.cz

Phone: + 420 224 005 153
Email: office@cerge-ei.cz
Web: http://www.cerge-ei.cz

The paper is available online at http://www.cerge-ei.cz/publications/working_papers/.

ISBN 978-80-7343-213-3 (Univerzita Karlova. Centrum pro ekonomický výzkum a doktorské studium)
ISBN 978-80-7344-203-3 (Národohospodářský ústav AV ČR, v. v. i.)

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