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Do producers apply a capacity cutting strategy to increase prices? The case of the England and Wales electricity market☆

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ABSTRACT

Promoting competition among electricity producers is primarily targeted at ensuring fair electricity prices for consumers. Producers could, however, withhold part of production facilities (i.e., apply a capacity cutting strategy) and thereby push more expensive production facilities to satisfy demand for electricity. This behavior could lead to a higher price determined through a uniform price auction. Using the case of the England and Wales wholesale electricity market we empirically analyze whether producers indeed did apply a capacity cutting strategy. For this purpose we examine the bidding behavior of producers during high- and low-demand trading periods within a trading day. We find statistical evidence for the presence of capacity cutting by several producers, which is consistent with the regulatory authority's reports.

1. Introduction

Prices of goods and services of general interest play a key role in determining the welfare of a society. Electricity, which usually accounts for a large share of energy consumption, is among those kinds of goods. Nowadays it also has a character of an essential good and understanding the sources and reasons of high electricity price changes therefore becomes an important task. Hence, the key question, given that electricity industry contains a natural monopoly element and is monitored, is whether consumers face fair prices.

In general, there are several means by which producers could exercise market power. The most common is through an exercise of monopoly power, whereby producers charge prices significantly exceeding their marginal production costs. For the case of the England and Wales electricity market, this type of noncompetitive behavior of electricity producers has been thoroughly studied in, for example, Green and Newbery (1992), Von der Fehr and Harbord (1993), Wolfram (1998), Crawford et al. (2007), and Sweeting (2007).

Another means by which producers on a semi-competitive market could set high prices is through the creation of an artificial deficit. Given a sufficiently high level of demand, this strategy could be successful at increasing prices.[1] Late in 2008, the E.ON AG electricity producer was investigated by the European Commission for abusing its dominant position to withhold available production facilities in the German electricity market with a view to raising electricity prices to the detriment of consumers (European Commission, 2009).

Fridolfsson and Tangerås (2009), using the case of the Nordic wholesale electricity market,[2] suggest that producers may have an incentive to withhold base-load nuclear plants to increase output prices without driving a wedge between output prices and marginal production costs. The authors therefore conclude that strategic withholding when demand is relatively high could be another means of increasing prices.

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[1] In general, cases of creating an artificial deficit in order to increase prices have been observed in various contexts. One historical example is burning coffee beans in Brazil, which was successful at increasing Brazilian coffee prices in New York by more than 40% (Time, 1932). Another recent example is the artificial creation of a deficit of diesel fuel by oil companies in Russia, which resulted in excessively high prices. The artificial deficit in this case was created by shutting down plants for maintenance reasons (Avtonovosti — Automobile news, 2011).

[2] Most electricity is produced by means of hydro power plants.

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Exploitation of a capacity cutting strategy undermines the allocative efficiency of production resources. In other words, capacity cutting can introduce distortions to the least-cost production schedules intended to serve demand at lower prices. As a consequence, it may become necessary to operate more expensive production facilities to satisfy demand for electricity at higher prices, whose burden is then eventually transferred to consumers.

Comparing the two means, price bids and capacity bids, Castro-Rodriguez et al. (2009) conclude that because a regulatory authority can relatively easily monitor the submission of price bids in excess of marginal costs, capacity bids could be regarded as an alternative instrument through which producers may affect prices.

In our research on the England and Wales electricity market, we define capacity cutting as a reduction of the amount of declared available capacity of a production unit when demand is forecasted to increase in the half-hourly day-ahead auction (see Fig. 2.2 for a detailed description).[3] We examine producers' bidding behavior between high- and low-demand trading periods (usually evening and afternoon periods). The intra-day analysis of the bidding behavior during different trading days is advantageous for the day-ahead auction, because producers are asked to submit capacity bids in advance for each half-hourly trading period of the next trading day. In contrast, an inter-day analysis may not be conclusive, because capacity could have been reduced during the following day due to maintenance, fuel reload, etc.

In the following sections we first describe the market rules and institutional background. We then review the related literature. In the empirical methodology we describe the regression model, econometric assumptions, and estimation strategy. Finally we quantitatively assess whether the regulatory reforms during the liberalization process were successful at decreasing the extent of applying a capacity cutting strategy.

2. Electricity auction and the market regulation

In this section we first describe the operation of the wholesale electricity market in England and Wales. In particular, using a hypothetical example, we explain the role of producers and the market operator (i.e., the auctioneer). We then proceed to the description of a capacity cutting strategy aimed at increasing the wholesale price. Finally, we describe the reforms introduced by the regulatory authority, the Office of Electricity Regulation (OFFER), which were targeted at improving competition and ensuring lower electricity prices.

At the start of liberalization the power grids were separated from the energy production and a wholesale market for electricity trading was created (Bergman et al., 1998). Trading was organized through a half-hourly uniform price auction, where electricity producers are asked to submit half-hourly capacity bids and daily bids for all production units. Daily bids include incremental price-offer bids, elbow points, start-up and no-load costs. Then half-hourly price bids for every production unit are calculated based on daily bids and half-hourly declared capacity bids. These rules are common knowledge and described in detail in the Electricity Pool (1990), which is a technical summary used by the market operator (the National Grid Company (NGC)). A more intuitive description of trading rules, including the Generator Ordering and Loading (GOAL) algorithm, is also presented in Sweeting (2007).

The market operator orders all production units based on price bids to construct a half-hourly aggregate supply schedule. The market operator also prepares demand forecasts, where the forecasting methodology is common knowledge (Wolak, 2000; Wolak and Patrick, 2001). The forecasting methodology is also independent of producers' bidding behavior (Green, 2006). The production unit whose price bid in the aggregate supply schedule intersects price-inelastic forecasted demand is called the marginal production unit. Its price bid is called the System

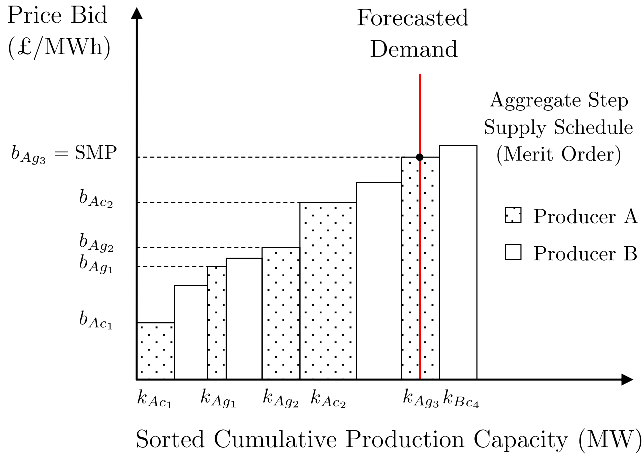

Fig. 2.1. Determination of the SMP during a half-hourly trading period.
Source: Authors' illustration.

Marginal Price (SMP) and represents the wholesale price for electricity production during a given half-hourly trading period. This is the uniform auction price paid the same for producers' production units needed to satisfy demand for electricity.

In Fig. 2.1, we schematically illustrate how the electricity market would have operated in a given half-hourly trading period. All production units are ordered according to half-hourly price bids.

Let b_{Ac_1} denote the price bid of electricity producer A's first coal production unit for which the submitted (declared) production capacity is k_{Ac_1}. For the sake of simplicity, it is assumed that electricity producer A has two coal and three gas types of production units. Price bids of all production units are ordered as would have been done by the market operator to create a half-hourly aggregate supply schedule. The vertical line in the graph is the forecasted demand. The intersection of the constructed aggregate supply schedule and price-inelastic forecasted demand determines the SMP, the wholesale electricity price. In this hypothetical example, it is electricity producer A's third gas production unit whose price bid determines the SMP.

Submitted price and capacity bids for individual production units represent private knowledge for each producer that owns those production units. This is a feature of a sealed-bid uniform price auction, where the bids of one producer are unknown to the other producers.

In the hypothetical example presented in Fig. 2.2 we illustrate how a producer could have applied a capacity cutting strategy in order to increase the wholesale price, which is paid the same to all production units needed to satisfy demand for electricity, and thereby, to enjoy higher profits on their scheduled units.

For illustration purposes, in this example, we assume that producers submit price bids reflecting marginal costs. We also assume that during trading period H producer A had decided to restrict the capacity of its second coal production unit (i.e., $k^H_{Ac_2} < k^L_{Ac_2}$), which led to a higher SMP.[4] If there were no capacity cutting, then we would observe a lower SMP equal to b_{Ag_3}. Producer A's loss and gain associated with applying a capacity cutting strategy are depicted by a shaded area in Fig. 2.2a and Fig. 2.2b, respectively.

From the presented example we see that applying capacity cutting may indeed be profitable and could also serve as a positive externality to competitors. As Dechenaux and Kovenock (2007) find, capacity cutting may even be necessary to sustain tacit collusion. All of this tends to eventually decrease consumers' welfare. Moreover, the difference between gain and loss may be greater, resulting in an even larger SMP, if producers strategically submit price bids in excess of marginal costs, where the latter has been studied in, for example, Green and Newbery

[3] An extreme case of applying a capacity cutting strategy is declaring a production unit as unavailable for electricity production, which may not be inexpensive in terms of the associated start-up costs.

[4] Withholding a whole production unit can be interpreted as a special case of a capacity cutting strategy.

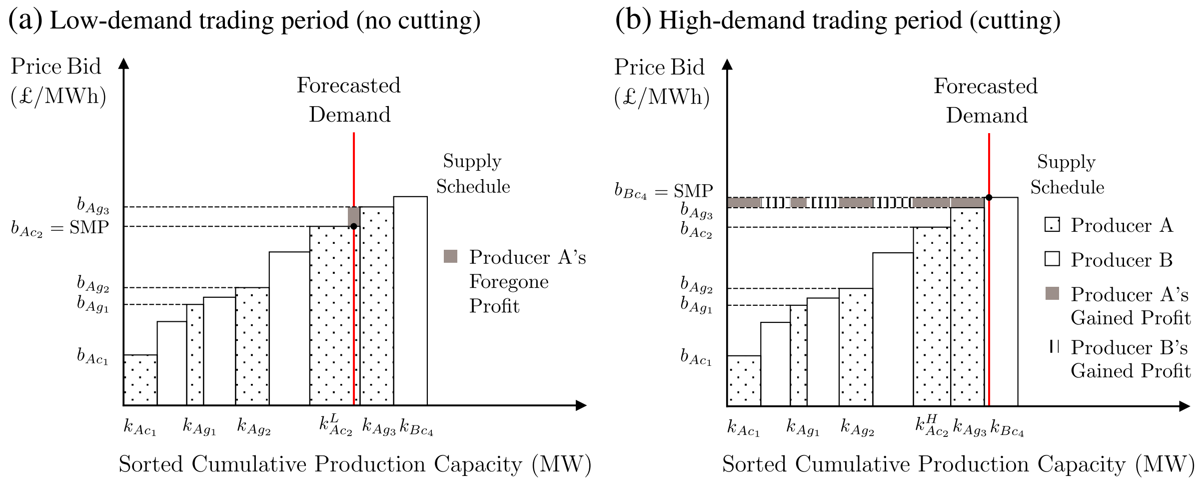

Fig. 2.2. Capacity strategy. *Notes*: In (a) we depict part of production capacity k_{Ac_2}, which could have been withheld for the high-demand period. The shaded area depicts the associated loss if capacity cutting were applied. In (b) we illustrate a change in SMP when part of capacity for k_{Ac_2} is withheld (i.e., $k^H_{Ac_2} < k^L_{Ac_2}$). If there were no capacity cutting, then we would observe a lower SMP equal to b_{Ag_3}. The shaded area depicts, therefore, the gain associated with applying capacity cutting during the high-demand trading period.
Source: Authors' illustration.

(1992), Von der Fehr and Harbord (1993), Wolfram (1998), Crawford et al. (2007), and Sweeting (2007).

As described in Fig. 2.2, in our analysis we focus on strategic capacity bidding which may drive up spot wholesale prices (i.e., the SMP). We do not consider contracts for differences (CfD) that are linked to SMP, because data on financial positions are commercially confidential.[5] Our approach is partly consistent with the methodology in (Cramton et al., 2013) modeling the operation of capacity markets. The authors assume that electricity producers are paid spot prices, even if most output is sold forward. This assumption is motivated by the fact that the prices for forward contracts are linked to expected spot market prices for electricity through intertemporal arbitrage. Moreover, because in the England and Wales electricity market the coverage of sales by CfDs generally decreased (Green, 1999; Herguera, 2000), we can consider that there may have been short-term incentives for producers' strategic capacity bidding.

The regulatory authority, the OFFER, noticed cases of excessively high electricity prices, which were attributed to the possible noncompetitive bidding behavior of the incumbent electricity producers (National Power and PowerGen). In order to decrease the influence of the incumbent producers on the wholesale electricity market, the regulatory authority introduced several reforms in the Electricity Supply Industry (ESI) in Great Britain. The time of the introduced institutional changes and regulatory reforms define different regime periods, which are summarized in Fig. 2.3.

At the time of the creation of the wholesale electricity market, coal and other contracts were introduced by the government, which then expired in 1993. Later, the regulatory authority introduced price-cap regulation and divestment series. The price-cap regulation during 1994–1996 was a temporary measure designed to control the annual average prices set by the incumbent electricity producers. In order to decrease market concentration and improve competition, the incumbent electricity producers were asked to divest part of their production facilities, which took place in 1996 and 1999. In March 2001, the wholesale electricity market was restructured to introduce bilateral trading arrangements.

When defining regime periods we consider the exact dates when the reforms were introduced. This approach better reflects the nature of the divestment series introduced by the regulatory authority. For example, the introduction of the first series of divestments for PowerGen led to the transfer of all medium coal production facilities to Eastern Group, which was later renamed TXU (National Grid Company, 1994–2001).[6] Hence, we assume that the structural breaks are exogenously given by the dates when the reforms were introduced. It is also worth mentioning that the structural changes introduced through the two divestment series differ, because the first series of divestments included the lease and the second series of divestments included the sale of production facilities (National Grid Company, 1994–2001). Hence, the impact of the two divestment series on the bidding behavior of electricity producers is likely to be different.

Table 2.1 describes the distribution of shares of production capacity and price setting among electricity producers between the financial years 1995/1996 and 1999/2000. To the original table reproduced from Bishop and McSorley (2001) we add a measure of the Herfindahl–Hirschmann Index (HHI) computed as a sum of squared shares. The calculations show that thanks to the divestment series and new entry the concentration measure decreased by almost twofold.

Similar to Borenstein et al. (2002), we restrict our analysis to electricity producers located in Great Britain. In particular, we exclude the EDF exporter, which was not suspected of abusing market power. We also observe that the incidence of capacity cutting by this producer was very low and its capacity bidding was generally consistent with competitive bidding behavior.

The measures designed to promote competition during the liberalization were more extensive in Great Britain compared to Germany, France, Italy, or Sweden (Bergman et al., 1998). In particular, Joskow (2009) characterizes 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. In this respect, Great Britain, with the longest experience of a liberalization process, can also serve as an important source of lessons.

5 This is also a limitation of research by (Robinson and Baniak, 2002), where the authors state that producers could have been deliberately increasing price volatility in order to enjoy higher risk premia in the contract market. This statement, however, has not been empirically verified.

6 A separate analysis of the bidding behavior of PowerGen with respect to medium coal production facilities several days or weeks before the actual divestment took place may not be statistically reliable due to a small number of observations. For Eastern Group, it would not be possible because Eastern Group did not have coal production facilities before and therefore could not participate in the auction by submitting bids for coal production units.

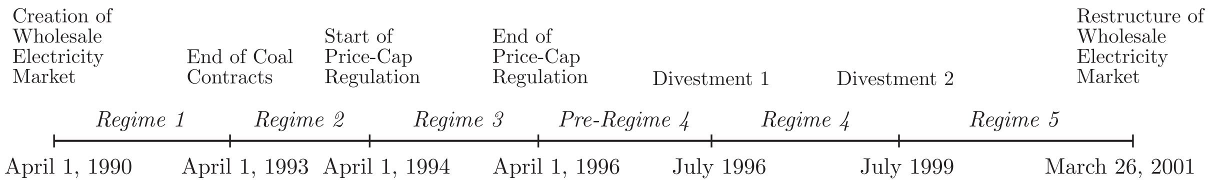

Fig. 2.3. Institutional changes and regulatory reforms in the ESI in Great Britain during 1990–2001.
Sources: Department of Trade and Industry (1997–2002), National Grid Company (1994–2001), Newbery (1999), Robinson and Baniak (2002), Wolfram (1999); authors' illustration.

3. Evidence on uniform price auction and incentives for capacity cutting in the literature

Le Coq (2002) and Crampes and Creti (2005) theoretically analyze a two-stage duopoly game, where producers first decide on capacity bids and then compete in a uniform price auction. The authors find that a uniform price auction creates an incentive for strategic capacity cutting when demand is known. This result is generalized for the case of stochastic demand in Sanin (2006).

Joskow and Kahn (2002) study the California spot electricity market during the California electricity crisis that cost $40 billion in added energy costs (Weare, 2003) and find that even after accounting for low levels of imports, high demand for electricity, and high prices of NO_x emissions permits, there are still large deviations of wholesale market prices from the competitive benchmark prices, i.e., the marginal cost of supplying additional electricity at the associated market clearing quantities. The authors find that capacity cutting, which is observed from substantial gaps between maximal and submitted capacity bids at peak hours, could explain the remaining deviations from the competitive benchmark prices. Their observation of gaps between maximal and submitted capacity bids during peak hours has been important for the development of our regression analysis, where we compare capacity bids during low- and peak-demand trading periods within a trading day over time for the case of the electricity market in England and Wales.

The application of competitive benchmark prices to analyze whether an 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 (Borenstein et al., 2002).

Sweeting (2007) similarly applies the methodology of competitive benchmark prices to analyze the development of market power in the England and Wales electricity market. The author finds that electricity producers were exercising increased market power in the late 1990s. 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.

Sweeting (2007) also finds that from the beginning of 1997 the National Power and PowerGen incumbent electricity producers could have increased their profits by submitting lower price bids and increasing output. From the short-term perspective, these findings are explained as tacit collusion. The latter finding on output could also be related to capacity cutting, which we empirically analyze in this research. This conjecture is consistent with findings in Dechenaux and Kovenock (2007), where the authors consider a symmetric oligopoly market structure with firms having equal sharing of profits. The authors show that in this market structure, operated as a uniform price auction, capacity withholding may even be necessary to sustain collusion.

Earlier, capacity bidding in the same electricity market was empirically studied in Wolak and Patrick (2001) and Green (2011). Wolak and Patrick (2001) show that capacity bids are a more "high-powered" instrument than price bids for strategic bidding. In particular, by analyzing the pattern of submitted half-hourly capacity bids, the authors conclude that the incumbent producers were strategically withholding capacity to increase wholesale prices. However these conclusions are mainly drawn from time series observations and probability distributions.

In contrast, in our research we use a regression model and consider the period during the late 1990s. This period also includes several new entrants like the TXU and AES producers. Our approach to consider demand increases within different trading days as producers' possible incentive for strategic capacity bidding is, in general, consistent with observations in Wolak and Patrick (2001) and Joskow and Kahn (2002).

On the other hand, withholding capacity may lead to an increase in the probability that demand will exceed supply, which will ultimately increase capacity payments.[7] Historically, PowerGen successfully applied this strategy during the summer and early fall of 1991. The producer had to stop this practice in response to criticism by the regulatory authority.

Almost a decade later, in June 2000, Edison similarly withdrew a large coal production unit of 480 MW capacity from the Fiddlers Ferry plant, which was again investigated by the regulatory authority. The withdrawn production capacity presents approximately 1% of total production capacity operated during peak-demand periods in England and Wales (National Grid Company, 1994–2001). In July, the producer agreed to return the plant to the system and the regulatory authority did not take any action (Ofgem, 2000a). The strategic withholding was calculated to cause a 10% increase in wholesale prices, which during June–July approximately amounted to a total increase in revenues by £100 million (Ofgem, 2000b).

In the analysis of the England and Wales electricity market, Green (2011) distinguishes two incentives for withholding capacity: 1) increasing capacity payments; 2) increasing wholesale prices.[8] Firstly,

Table 2.1
Structural impact of National Power and PowerGen divestments.
Source: Reproduced from Bishop and McSorley (2001).

Producer	Share of capacity		Share of price setting	
	1995/1996	1999/2000	1995/1996	1999/2000
National Power	33.7	13.0	44.8	14.6
PowerGen	28.1	16.5	31.8	16.8
BNFL Magnox	5.8	5.4	0.0	0.0
EDF	3.3	3.3	0.7	10.7
Scottish Interconnector	2.3	2.2	1.7	0.4
TXU	1.6	9.2	7.3	11.8
Edison	3.8	8.9	13.2	21.1
British Energy	12.0	14.8	0.0	4.9
AES	0.5	7.6	0.0	19.3
Combined cycle gas turbines	7.8	17.2	0.5	0.4
Others	1.3	2.0	0.0	0.0
HHI	0.22	0.12	0.33	0.16

Note: HHI stands for Herfindahl–Hirschmann Index (sum of squared shares: monopoly = 1).

[7] Capacity payments are computed as $CP = LOLP \cdot (VLL - SMP)$, where LOLP stands for Loss of Load Probability (an estimated probability that demand will exceed supply), VLL for Value of Lost Load (the Pool's estimate of customers' maximum willingness to pay for electricity supply), and SMP for System Marginal Price (a wholesale price).

[8] Generally, high capacity payments or wholesale prices during peak-demand periods besides decreasing the economic welfare of consumers may also lead to wrong investment or new entry decisions and increased price volatility.

using Monte Carlo simulations, the author finds that during November–February in 1997–2001 low availability rates are not responsible for raising capacity payments above competitive levels computed based on US availability rates. Secondly, the author finds that the industry's annual truly excess outputs are lower after privatization, which suggests that after privatization producers' output was closer to the optimal pattern and, hence, matching of demand and supply improved.

Because from the long-term perspective neither of the two incentives for withholding capacity is found significant, Green (2011) concludes that the evidence for large-scale capacity withholding is weak. However, this conclusion is not completely in line with findings in Wolak and Patrick (2001) and the regulatory authority's investigation reports.

In our research, by analyzing producers' bidding behavior during peak- and low-demand trading periods within a trading day over time, we intend to add new evidence on whether producers apply capacity cutting to increase prices as described in the hypothetical example in Fig. 2.2.

4. Binding theory and empirics

4.1. Data and its use

We use two data sets covering 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 forecasted demand and wholesale prices (the System Marginal Price (SMP)).

In Figs. A.1 and A.2 we present the distribution of peak-demand half-hours across regime periods and across seasons, respectively.

A sample summary of the market data with the associated measurement units is provided in Table 4.1.

Using data on the forecasted demand, we compute demand increases as a relative change in the forecasted demand during the peak-demand trading period compared to the same day preceding low-demand trading period. More precisely, we consider the following:

$$\text{growth in demand}_t = \frac{\text{forecasted demand}_{t,(\text{peak-demand period})}}{\text{forecasted demand}_{t,(\text{peak-demand period}-\text{five hours})}} - 1 \quad (1)$$

where t denotes trading day.

Similarly, we compute relative changes in the wholesale price (i.e., SMP):

$$\text{growth in SMP}_t = \frac{\text{SMP}_{t,(\text{peak-demand period})}}{\text{SMP}_{t,(\text{peak-demand period}-\text{five hours})}} - 1, \quad (2)$$

where t denotes trading day.

In our research we consider five-hour differences between the peak- and low-demand periods within a trading day. Qualitatively the results are similar to alternative choices of a low-demand period. But considering namely peak-demand periods is crucial because generally it has been documented in the literature that noncompetitive bidding behavior occurs most frequently during peak-demand periods (Joskow and Kahn, 2002).

Table 4.1
Sample of descriptive statistics for market data (January 1, 2000–January 31, 2000).
Source: Authors' calculations.

	Forecasted demand (MW)	SMP (£/MWh)
Mean	38,464.60	24.39
Min	25,001.00	8.00
Max	49,945.00	77.89
Std. Dev.	5247.83	12.54
Frequency	30 min	30 min
Obs.	1488	1488

Table 4.2
Relative changes in market demand (MW) and SMP (£/MWh) during January 6, 2000.
Source: Authors' calculations.

$\text{Demand}_{t,(\tau-5\text{hrs})}$	$\text{Demand}_{t\tau}$	Growth in demand_t	$\text{SMP}_{t,(\tau-5\text{hrs})}$	$\text{SMP}_{t\tau}$	Growth in SMP_t
42,825	48,215	0.126	55.56	77.89	0.402

Notes: Subscript t is trading day (January 6, 2000) and τ is peak-demand trading period (17:30).

Table 4.3
Sample of descriptive statistics for capacity bidding data (January 1, 2000–January 31, 2000).
Source: Authors' calculations.

	Capacity bids (MW)
Mean	175.41
Min	0.00
Max	989.00
Std. Dev.	248.12
Frequency	30 min
Obs.	450,336

The application of Eqs. (1)–(2) for market data of a trading day on January 6, 2000 is presented in Table 4.2.

The second data set contains data on half-hourly capacity bids (i.e., declared availability) for each trading period, which also includes the identity of an electricity producer, plant, production unit, and capacity (input) type. A sample summary of capacity bidding data is presented in Table 4.3.

In order to exclude the ambiguity that some production capacity is not made available to the market due to, for example, maintenance and other technical reasons, we consider declared capacity bids on a daily basis. More precisely, for each trading day we compute a relative change in submitted capacity during the peak-demand trading period in comparison to the same day preceding low-demand trading period. This relative change in submitted capacity at producer and capacity type level is considered as the dependent (explained) variable in the regression analysis.[9]

Algebraically, the definition of a relative change of capacity between periods can be summarized in the following way:

$$\Delta k_{ijt} = \frac{\sum_{l\in j} k_{ilt,(\text{peak-demand period})}}{\sum_{l\in j} k_{ilt,(\text{peak-demand period}-\text{five hours})}} - 1, \quad (3)$$

where subscripts i, j, l, t denote producer, capacity type, production unit, trading day, respectively and $\sum_{l\in j} k_{ilt,(\text{peak-demand period})}$ denotes producer i's capacity of type j during the peak-demand period of trading day t.

The application of Eq. (3) for submitted (declared) capacity bids on January 6, 2000 is presented in Table 4.4.

In Table 4.5, based on the comparison between the peak- and low-demand trading periods within a day, we present the incidence of noncompetitive and competitive capacity bidding behaviors.

The first block in Table 4.5 contains a summary of the incidence of noncompetitive bidding behavior manifested through an application of capacity cutting when demand is forecasted to increase. The distribution of the incidence of noncompetitive bidding across regime periods is presented in Table B.1.

Cases when producers either do not change or increase declared available capacity when an increase in demand is forecasted are defined

[9] The unexpected technical failures in real-time supply of energy do not affect our identification strategy as they can occur only after the day-ahead bidding is made.

Table 4.4
Application of Eq. (3) for capacity bids during January 6, 2000.
Source: Authors' calculations.

Producer	Type	$\sum_{l\in j} k_{ilt,(\tau-5\ \text{hrs})}$ (MW)	$\sum_{l\in j} k_{ilt,\tau}$ (MW)	Δk_{ijt}	Case consistent with strategy
NP	Large coal	4845	4350	−0.102	Noncompetitive
	Medium coal	1306	1306	0	Competitive
	Oil	1180	1180	0	Competitive
	CCGT	3265	3295	0.009	Competitive
	OCGT	412	412	0	Competitive
PG	Large coal	4346	4346	0	Competitive
	Oil	1350	1350	0	Competitive
	CCGT	2991	3032	0.014	Competitive
	OCGT	191	191	0	Competitive
BNFL	Nuclear	2449	2449	0	Competitive
SI	Export	1514	1514	0	Competitive
	CCGT	2843	2843	0	Competitive
TXU	Large coal	3792	3792	0	Competitive
	Medium coal	1774	1774	0	Competitive
	CCGT	595	595	0	Competitive
	OCGT	90	90	0	Competitive
Ed	Large coal	2946	2946	0	Competitive
	OCGT	68	68	0	Competitive
	PSB	2088	1998	−0.043	Noncompetitive
BE	Nuclear	5461	5483.4	0.004	Competitive
AES	Large coal	3225	3225	0	Competitive
	CCGT	250	250	0	Competitive
	OCGT	215	215	0	Competitive

Notes: k denotes capacity and Δk_{ijt} denotes a relative change in capacity, which is computed using Eq. (3). Subscript i is producer, j is capacity type, l is production unit, t is trading day (January 6, 2000), τ is peak-demand trading period (17:30). Capacity cutting (i.e., noncompetitive capacity bidding) is defined as a reduction of capacity during the peak-demand period compared to the same day preceding low-demand period.

to be consistent with competitive bidding behavior. Their incidence results are presented in the last two blocks in Table 4.5. The incidence results can be explained as producers applying a mixed strategy approach between bidding noncompetitively and competitively.

Explanation of capacity cutting during peak-demand periods based on scheduled maintenance reasons is not economically justifiable. If a producer needs to run brief maintenance, then it is most probably done during the low-demand period of a day when prices are usually low. In this case a producer incurs minimal losses associated with not making the capacity available for electricity production.

Table 4.5 suggests that among major power producers Edison has relatively least withheld the PSB type of capacity. However, a more detailed analysis is required with respect to Edison's large coal production capacity, which the producer received during the second series of divestments. As mentioned in Ofgem (2000b), it was the reduction of the large coal capacity type, which lead to an increase of wholesale prices.

4.2. Empirical methodology

When demand is forecasted to increase producers may bid capacity either noncompetitively (by applying a capacity cutting strategy) or

Table 4.5
Incidence of noncompetitive and competitive capacity bidding during January 1, 1995–September 30, 2000.
Source: Authors' calculations.

Case		Producer	Large coal	Medium coal	Small coal	Oil	Nuclear	CCGT	OCGT	PSB	Export
Competitive bidding consistent	No (cutting)	NP	186	112	17	29	–	885	143	–	–
		PG	346	16	–	18	–	1015	67	–	–
		BNFL	–	–	–	–	198	–	–	–	–
		SI	–	–	–	–		113	–	–	80
		TXU	214	89	–	–	–	173	22	–	–
		Ed	28	–	–	–	–	–	–	41	–
		BE	5	–	–	–	122	–	–	–	–
		AES	11	–	–	–	–	25	15	–	–
	Yes (no change)	NP	1437	1705	1380	1935	–	509	1597	–	–
		PG	1174	302	–	1528	–	371	1897	–	–
		BNFL	–	–	–	–	1588	–	–	–	–
		SI	–	–	–	–		1662	–	–	1570
		TXU	601	670	–	–	–	1510	1478	–	–
		Ed	332	–	–	–	–	–	–	905	–
		BE	139	–	–	–	1138	–	–	–	–
		AES	428	–	–	–	–	694	1312	–	–
	Yes (expanding)	NP	406	180	79	64	–	633	289	–	–
		PG	509	51	–	195	–	643	65	–	–
		BNFL	–	–	–	–	243	–	–	–	–
		SI	–	–	–	–		252	–	–	374
		TXU	705	501	–	–	–	290	48	–	–
		Ed	77	–	–	–	–	–	–	1072	–
		BE	85	–	–	–	377	–	–	–	–
		AES	11	–	–	–	–	19	13	–	–

Note: Capacity cutting (i.e., noncompetitive capacity bidding) is defined as a reduction of capacity during the peak-demand period compared to the same day preceding low-demand period.

competitively (by increasing or at least not changing declared available capacity). The incidence of noncompetitive and competitive capacity bidding is summarized in Table 4.5. We use a regression analysis to examine the noncompetitive capacity bidding. Specifically, we consider the following regression model:

$$\Delta k_{ijt} = \alpha + \beta_{ij} \cdot \text{growth in demand}_t + \varepsilon_{ijt}, \quad (4)$$

where subscripts i, j, t denote producer, capacity type, trading day, respectively. The dependent variable is defined as a relative change in submitted (declared) capacity during the peak-demand trading period compared to the same day preceding low-demand trading period. This is defined in Eq. (3). We consider negative values of the dependent variable, which reflect the extent of capacity cutting by producers across various capacity types. The explanatory variable, growth in demand, is defined as a relative increase in forecasted demand during the peak-demand trading period compared to the same day preceding low-demand trading period.

We consider five-hour differences between the peak- and low-demand trading periods. The results are generally similar to those which are based on alternative choices of a low-demand trading period as a comparison benchmark. More importantly, because noncompetitive bidding behavior could be observed mainly during high-demand trading periods, similar to Joskow and Kahn (2002) and Crawford et al. (2007), we analyze the bidding behavior of electricity producers in relation to the peak-demand trading periods.[10]

The disturbance term in the regression model is assumed orthogonal to the explanatory variable. The exogeneity assumption of the explanatory variable is in line with the fact that the forecasting methodology the market operator applies is, firstly, common knowledge (Wolak, 2000; Wolak and Patrick, 2001) and, secondly, independent of producers' bidding behavior (Green, 2006).

The slope parameter is assumed to be producer and capacity type specific.[11] It measures the extent of cutting capacity when demand increases by 1%. The intuition that an increase in demand explains the extent of capacity cutting is testable. In particular, if the capacity cutting hypothesis holds, then we should obtain statistical evidence that an increase in demand explains a decrease in capacity made available for electricity production.

However, estimating regression Eq. (4) is expected to be subject to sample selection bias. The sample selection problem arises in our research because we have selected the noncompetitive sample based on the negative values of the dependent variable. In order to correct for the sample selection problem, we use Heckman's two-step procedure developed in Heckman (1979).

In the first step we estimate the selection equation using the probit model on the full sample. We assume that demand and wholesale price (i.e., the SMP) increases explain a producer's decision to submit capacity bids noncompetitively or competitively during the peak-demand trading period. Even if growth in SMP is not sufficient, we still can rely on growth in demand thanks to the nonlinearity of the probit model in correcting for the selection bias.[12]

The fitted values from the probit model are used to calculate λ_{ijt}, the inverse Mill's ratio, which is a decreasing function of the probability that an observation is selected into the sample. The calculated $\hat{\lambda}_{ijt}$ is then used in the second step as an additional explanatory variable to estimate the amount equation for the selected sample.

Below we formally summarize the estimation procedure:

$$\text{P}(\text{Decision} = 1|\text{x}) = \Phi\left(a + b_{ij} \cdot \text{growth in demand}_t + c_{ij} \cdot \text{growth in SMP}_{\mathbf{t}}\right) \quad (5)$$

$$\Delta k_{ijt} = \alpha + \beta_{ij} \cdot \text{growth in demand}_t + \gamma \cdot \hat{\lambda}_{ijt} + \varepsilon_{ijt}, \quad (6)$$

where in Eq. (5) we use Decision = 1 to code the cutting case. The term $\hat{\lambda}_{ijt}$ is calculated as a ratio of $\hat{\phi}(\cdot)$ and $\hat{\Phi}(\cdot)$. Then Eq. (6), the amount equation (also called the second stage equation), is estimated only for the noncompetitive sample with Mill's inverse ratio included as a correction term.

This Heckman's two-step procedure is also described in Kmenta (2004). This procedure allows estimating the regression equation free of sample selection bias.

Our methodology is generally consistent with the game-theoretic point of view. In particular, we consider that a firm first decides which bidding strategy to adopt: noncompetitive or competitive. If, for example, in the first stage a firm has decided to bid noncompetitively, then in the second stage it decides on the amount (extent) of capacity cutting.

Therefore, regression Eq. (4) describing capacity cutting behavior is modified according to Eq. (6). If $\hat{\gamma}$ is found statistically significant, then we can conclude that there would have been a sample selection bias had we not included $\hat{\lambda}_{ijt}$ in the amount equation (i.e., control for the probability of selecting a particularly observed strategy) and hence distorting the coefficient of interest β_{ij}.

For the regulation analysis, we assume that producer and capacity type specific slope parameter β_{ij} may vary during different regime periods described in Fig. 2.3. This approach allows us to draw conclusions regarding the effectiveness of regulatory reforms in mitigating the noncompetitive capacity bidding. In particular, using our estimation results, we would be able to draw conclusions if the changes during later regime periods are economically and statistically significant.

5. Results and discussion

The discussion of estimation results is divided into two parts. First, we discuss the results of the probit selection equation. Decision = 1 corresponds to noncompetitive capacity bidding and Decision = 0 corresponds to competitive capacity bidding. The incidence of these strategic decisions is summarized in Table 4.5. The estimation of this selection equation is necessary to calculate $\hat{\lambda}_{ijt}$ for the amount equation. We then proceed to the discussion of results for the amount equation describing noncompetitive capacity bidding of producers.

5.1. Selection equation

The analysis includes cases of noncompetitive and competitive capacity bidding. They represent 3970 and 35,043 observations, respectively. Decision = 1 corresponds to noncompetitive capacity bidding when a producer applies a capacity cutting strategy. In Table 5.1 we present our estimation results for the probit selection equation.

The estimation results suggest that the increase of demand and wholesale price (i.e., the SMP) has an asymmetric effect across producers and capacity types. This finding sheds light on producers' differing attitudes in the decision to apply capacity cutting across various types of production capacity and, therefore, supports our assumption that the model parameters may be producer and capacity type specific. In particular, we find that the effect of an increase in demand is the

[10] This is the period when the SMP is usually determined at a steeper part of the aggregate supply schedule. In this case, even a small decrease in declared available capacity may have a large effect on the SMP.

[11] A producer can, in general, use different inputs (e.g., coal, gas, etc.) to produce electricity. Therefore we distinguish production capacities that use different inputs. Moreover, coal input can be used in large-, medium-, and small-sized plants. Because the efficiency rate of production capacity in these plants is different, we also distinguish large coal, medium coal, and small coal types of production capacity. These types of production capacity are usually located in different parts of the aggregate supply schedule. For this reason, we consider not only producer but also capacity type specific parameters.

[12] Our method is robust even when a producer just uses a randomization strategy. The probit model estimates the probability of a particular bidding decision (noncompetitive or competitive capacity bidding). Moreover, our identification strategy is not dependent on random failures, because we analyze bidding on a day-ahead auction.

Table 5.1
Probit selection equation. P(Decision = 1|x) = $\Phi(a + b_{ij} \cdot \text{growth in demand}_t + c_{ij} \cdot \text{growth in SMP}_t)$.

Dependent variable: Decision		Growth in demand ($\hat{b}_{ij}$)		Growth in SMP ($\hat{c}_{ij}$)	
Producer	Type	Coef.	Std. Err.	Coef.	Std. Err.
NP	Large coal	0.788***	0.237	0.031	0.025
	Medium coal	0.506*	0.305	−0.074*	0.042
	Small coal	−1.062	0.801	−0.341***	0.110
	Oil	−2.808***	0.453	−0.010	0.031
	CCGT	6.884***	0.283	−0.020	0.015
	OCGT	1.050***	0.338	−0.002	0.029
PG	Large coal	3.191***	0.275	−0.045**	0.020
	Medium coal	−1.978	1.688	0.103	0.103
	Oil	−4.100***	1.012	−0.066	0.115
	CCGT	7.520***	0.367	0.017	0.053
	OCGT	−0.184	0.534	−0.092	0.078
BNFL	Nuclear	1.929 ***	0.276	−0.067	0.046
SI	Export	−0.241	0.537	−0.052	0.059
	CCGT	−0.331	0.235	0.030	0.027
TXU	Large coal	0.233	0.328	0.079*	0.047
	Medium coal	−0.800	0.725	0.071	0.059
	CCGT	0.948***	0.272	−0.001	0.020
	OCGT	−0.754	0.633	−0.385***	0.127
Ed	Large coal	−0.107	0.493	0.003	0.103
	PSB	−3.893***	0.453	0.012	0.038
BE	Large coal	−1.533	1.788	−0.071	0.195
	Nuclear	0.974***	0.352	−0.074*	0.040
AES	Large coal	0.755	0.850	−0.445***	0.165
	CCGT	1.631**	0.785	−0.383*	0.231
	OCGT	−0.515	0.605	−0.395***	0.062
	Intercept	−1.541***	0.059		

Notes: Producer–capacity type–day clustered robust standard errors are used for statistical inferences.*, **, and *** stand for the 10%, 5%, and 1% significance levels, respectively. Obs = 39,013.

largest for the CCGT type (less profitable and more flexible) belonging to the incumbent producers.

We also find that sometimes the effect of an increase in demand and wholesale price is opposite, indicating the presence of a trade-off in deciding towards capacity cutting.

For statistical inference we apply producer–capacity type–day clustered robust standard errors. This approach allows one to take into account heteroscedasticity and weekly seasonality features. Volatility and seasonality of electricity prices in the given market are studied in Robinson and Baniak (2002) and Tashpulatov (2013).

The fitted values of the probit selection equation are used in calculating the inverse Mill's ratio, which is included as an additional explanatory variable in amount Eq. (6) describing the noncompetitive bidding behavior at the level of individual producers' capacity types.

5.2. Effect of a regulatory regime change

In estimating amount Eq. (6) we assume that the producer and capacity type specific slope parameter β_{ij} may additionally vary during different regime periods described in Fig. 2.3. We present our estimation results in Table 5.2. This amount equation is estimated using observations corresponding to capacity cutting with sample selection correction for producers' capacity bidding as discussed in the previous section.

Our results indicate that the null hypothesis stating no sample selection problem is rejected. This finding justifies the validity of our assumption that firms first decide on their bidding strategy.

The extent of how much to cut when demand is forecasted to increase is reflected by the producer and capacity type specific slope parameter β_{ij} in amount Eq. (6). In Table 5.2 we present our estimation results for the slope parameter in front of the growth of demand in two blocks. In the first block we present coefficient estimates for the growth in demand during a reference period. In the second block we present coefficient estimates for the interaction terms between regime dummy variables and growth in demand. The second block in the estimation table allows one to observe changes for β_{ij} during later regime periods in the extent of capacity cutting associated with demand increases. The estimation results indicate that there are differences in the bidding behavior across not only producers but also capacity types. This generally supports our assumption of the producer and type specific parameter β_{ij}.

In the following sections we first discuss estimation results for the incumbent electricity producers. Next we review the results for the state-owned British Nuclear Fuels Limited (BNFL) and exporting Scottish Interconnector (SI) producers. We then discuss in detail the findings for TXU and Edison, which received plants during the divestment series. We conclude our discussion with the British Energy and AES producers.

5.2.1. Incumbent producers: National Power and PowerGen

Our estimation results presented in the first block of Table 5.2 indicate statistical evidence for the presence of capacity cutting by the incumbent electricity producers (NP and PG) in peak-demand trading periods during price-cap regulation. Wolfram (1999) identifies that price-cap regulation led the industry supply curve to rotate counterclockwise. The author explains the change in the industry supply curve as the consequence of reducing prices when demand is low and increasing them when demand is high in order to satisfy the price cap. Our result on capacity cutting during peak-demand periods may therefore provide a possible alternative explanation of how the bidding behavior of producers during price-cap regulation led the industry supply curve to rotate counterclockwise.

Based on the estimation results presented in the second block of Table 5.2, we find that for NP (the larger incumbent producer) the extent of applying capacity cutting during peak-demand periods has generally decreased in the pre-regime 4 period (i.e., after price-cap regulation and before divestment series). The only exception is the oil type for which the extent of capacity cutting has increased. For the small coal type during pre-regime 4 we do not observe capacity cutting at all.

Table 5.2
Amount equation: $\Delta k_{ijt} = \alpha + \beta_{ij} \cdot \text{growth in demand}_t + \gamma \cdot \hat{\lambda}_{ijt} + \varepsilon_{ijt}$.

Dependent variable: Δk_{ijt}			Regime 3 (Jan 95–Mar 96) Price-cap		Pre-regime 4 (Apr 96–Jul 96)		Regime 4 (Jul 96–Jul 99) divestment 1		Regime 5 (Jul 99–Sept 00) divestment 2	
	Pr	Type	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
Block 1: growth in demand ($\hat{\beta}_{ij}$)	NP	Large coal	0.068***	0.025						
Estimation during a reference period		Medium coal	−0.484***	0.089						
		Small coal	−0.121	0.163						
		Oil	−0.164	0.135						
		CCGT	−0.410***	0.077						
		OCGT	−0.037	0.024						
	PG	Large coal	−0.058	0.037						
		Medium coal	−0.379	0.250						
		Oil	−0.020	0.184						
		CCGT	−0.383***	0.080						
		OCGT	0.090	0.064						
	BNFL	Nuclear	0.024	0.020						
	SI	Export	−0.509*	0.287						
		CCGT	−1.304***	0.274						
	TXU	Large coal					0.180*	0.108		
		Medium coal					−0.665***	0.105		
		CCGT	−0.213	0.278						
		OCGT					−0.466***	0.140		
	Ed	Large coal							−0.355***	0.056
		PSB	0.096	0.123						
	BE	Large coal							−0.770***	0.256
		Nuclear			0.166***	0.027				
	AES	Large coal							−0.299***	0.052
		CCGT							0.140***	0.033
		OCGT							−0.186	0.135
Block 2: regime × growth in demand ($\hat{\delta}_{ij}$)	NP	Large coal			0.056***	0.019	−0.095***	0.019	−0.658***	0.120
Change in comparison to a reference period		Medium coal			0.070	0.072	0.092	0.074	−0.463*	0.267
		Small coal			NA		−0.205***	0.055		
		Oil			−0.553***	0.191	−0.784***	0.192	−0.195	0.711
		CCGT			0.132***	0.023	0.079**	0.031	0.075***	0.027
		OCGT			0.034	0.024	−0.006	0.018	−0.101	0.065
	PG	Large coal			0.013	0.018	−0.030**	0.013	−0.167**	0.069
		Oil			0.372**	0.160	−1.257**	0.624		
		CCGT			−0.062***	0.022	−0.008	0.015	0.000	0.007
		OCGT			−0.050	0.092	−0.084	0.078	−0.483***	0.042
	BNFL	Nuclear			0.086***	0.027	0.003	0.030	0.021**	0.009
	SI	Export			0.423	0.308	0.270	0.289	0.136	0.342
		CCGT			1.123***	0.362	0.918***	0.259	1.471***	0.263
	TXU	Large coal							−0.663***	0.117
		Medium coal							0.185	0.138
		CCGT			0.249	0.322	0.037	0.293	−0.654***	0.183
		OCGT							0.185	0.152
	Ed	PSB			NA		0.042	0.180	0.498***	0.100
	BE	Nuclear					−0.136***	0.016	−0.260***	0.028
		$\hat{\gamma}$	−0.112***	0.019						
		Intercept	0.141***	0.032						

Notes: The first block contains coefficient estimates for a reference period and the second block for the interaction terms with regime dummy variables. Producer–capacity type–day clustered robust standard errors are used for statistical inferences. *, **, and *** stand for the 10%, 5%, and 1% significance levels, respectively. Obs = 3970 and $R^2 = 0.376$.

But after the divestment series, the extent of capacity cutting compared to the price-cap regulation period (i.e., regime 3) has increased for almost all types. That is, we find that in absolute terms $\hat{\beta}_{ij}^{\text{Regime 4}}$ and $\hat{\beta}_{ij}^{\text{Regime 5}}$ are greater than $\hat{\beta}_{ij}^{\text{Regime 3}}$ for $i = \text{NP}$ and $j \in$ {Large Coal, Small Coal, Oil, OCGT}.[13] An exception is related to the medium coal (during regime 4) and CCGT (during all later regimes) types for which the extent of capacity cutting has decreased. Generally, after the second series of divestments the extent of capacity cutting by NP has increased with the only exception for the CCGT type.

Qualitatively, the estimation results related to the noncompetitive bidding behavior of PG (the smaller incumbent producer) are similar to NP. However, there are differences in the magnitudes of the estimation results. Therefore, the regulatory actions, generally, did not have the same effect on the incumbents' bidding behavior. We explain the observed quantitative differences as the consequence of an unequal horizontal restructuring introduced through divestment series, which affected differently individual incumbent producers' mix of capacity types.

Our estimation results indicating an increase in the extent of capacity cutting by the incumbent producers after the divestment series is partly consistent with Sweeting (2007), where the author finds that the incumbent producers could have increased their profits by lowering price bids and increasing output. This behavior is interpreted as an indication of possible tacit collusion. Dechenaux and Kovenock (2007) also finds that capacity cutting in a uniform price auction could be even necessary to sustain tacit collusion.

[13] We use the following notation:

$$\hat{\beta}_{ij}^{\text{Pre-Regime 4}} = \hat{\beta}_{ij}^{\text{Regime 3}} + \hat{\delta}_{ij}^{\text{Pre-Regime 4}},$$

$$\hat{\beta}_{ij}^{\text{Regime 4}} = \hat{\beta}_{ij}^{\text{Regime 3}} + \hat{\delta}_{ij}^{\text{Regime 4}},$$

$$\hat{\beta}_{ij}^{\text{Regime 5}} = \hat{\beta}_{ij}^{\text{Regime 3}} + \hat{\delta}_{ij}^{\text{Regime 5}},$$

where $\hat{\delta}_{ij}^{\text{Pre-Regime 4}}, \hat{\delta}_{ij}^{\text{Regime 4}}, \hat{\delta}_{ij}^{\text{Regime 5}}$ are the estimates of a change presented in the second block of Table 5.2.

5.2.2. State-owned and exporter producers: BNFL and SI

British Nuclear Fuels Limited (BNFL) was a state-owned company using Magnox nuclear reactors for electricity production. We do not find any statistical evidence for this producer's capacity cutting when demand is forecasted to increase.

Scottish Interconnector (SI) was an exporter of electricity to the wholesale market. There is statistical evidence for this producer's non-competitive bidding behavior in exporting electricity although to a smaller extent during later regime periods. A reduction in export could have however been related to the increased demand for electricity in Scotland. This producer also had CCGT production facilities located in England and Wales. We find that the extent of cutting for the CCGT type of capacity compared to the reference period has largely decreased during later regime periods.

5.2.3. Divestment recipients: TXU and Edison

TXU is the producer which received plants during the first series of divestments. We find statistical evidence that this producer's bidding behavior is consistent with applying capacity cutting when demand is forecasted to increase (except for the large coal type during regime 4).

During the second series of divestments, the plants were transferred to Edison. There is statistical evidence for this producer's withholding of the large coal capacity type. This is indicated in the first block of Table 5.2 by a statistically significant negative slope coefficient during regime 5. Our finding is consistent with the Ofgem's investigation report into the withdrawal of a large coal production unit by this producer discussed in Section 3 (Ofgem, 2000a). However, we do not find statistical evidence for applying capacity cutting for the PSB type when demand is forecasted to increase.

5.2.4. Code of conduct: British Energy and AES

In the following paragraphs we analyze the estimation results for producers that did not wish to join the market abuse license condition (MALC).[14]

Similar to the BNFL producer, there is weak evidence that BE applied capacity cutting for the nuclear capacity type during pre-regime 4 and regime 4 periods. However, because $\hat{\beta}_{ij}^{\text{Regime}\ 5} = \hat{\beta}_{ij}^{\text{Pre}-\text{Regime}\ 4} + \hat{\delta}_{ij}^{\text{Regime}\ 5}$ is negative for $i = \text{BE}$ and $j = \text{Nuclear}$, we can state that during the last regime period there is statistical evidence for cutting nuclear capacity during peak-demand periods. Our finding from the short-term perspective is partly consistent with the suggestion in Fridolfsson and Tangerås (2009) that producers may restrict base-load nuclear capacity to increase electricity prices.

The estimation results presented in the first block of Table 5.2 indicate noncompetitive bidding behavior of BE with respect to the large coal capacity (a negative estimate for the slope parameter). However, as the incidence of cutting is relatively very low (see Table 4.5), we can conclude that the evidence of capacity cutting for the large coal capacity is generally weak.

The second producer which did not sign the MALC was AES. Our estimation results presented in the first block of Table 5.2, indicate weak evidence for capacity cutting with respect to CCGT and OCGT production facilities. However, we find statistical evidence consistent with capacity cutting for the large coal capacity type when demand is forecasted to increase. We also observe that the incidence of cutting and expanding patterns summarized in Table 4.5 is the same for this producer's large coal capacity.

[14] The regulatory authority proposed a license condition targeted at tackling market abuse in 2000. Because two major electricity producers, British Energy and AES, refused to accept the MALC, the regulatory authority referred the matter to the Competition Commission (CC). The CC subsequently did not approve the introduction of the MALC, although it acknowledged the possibility that British Energy could profit from capacity cutting (Ofgem, 2000b).

6. Conclusions

Using the case of the England and Wales electricity market, we analyze whether producers apply a capacity cutting strategy to increase prices at a uniform price auction. The capacity cutting strategy may allow producers to artificially create deficit and drive up wholesale electricity prices and hence revenues and profits of all producers on the market.

Our results suggest that the extent of applying capacity cutting by the incumbent electricity producers has increased after the divestment series (with two exceptions for the NP producer). This result is partly consistent with the simulation study of Sweeting (2007), who finds that during the late 1990s the incumbent producers could have increased profits by lowering price bids and increasing output. Based on the findings in Dechenaux and Kovenock (2007), we suggest that restricting capacity could have been necessary to sustain tacit collusion, which is also consistent with the findings of possible tacit collusion discussed in Sweeting (2007).

Quantitatively, however, the estimation results differ for the incumbent producers. We explain this as the consequence of an unequal horizontal restructuring, which affected differently the capacity mix of the individual incumbent producers. Our results also suggest that divestment series were successful at reducing the extent of applying capacity cutting for the CCGT type of production capacity belonging to the NP producer.

Generally, statistical evidence for capacity cutting by BNFL during peak-demand periods is weak. This finding is partly consistent with the simulation study of Green (2011), who also finds weak evidence for large-scale capacity withholding.

We find statistical evidence indicating capacity cutting by Edison with respect to the large coal type of capacity. This finding is in line with Ofgem's official investigation of capacity withdrawal by this producer (Ofgem, 2000a,b). Making less base-load or infra-marginal capacity available may force the market operator to use more expensive and sometimes less efficient production facilities, which in the end could lead to higher electricity prices to the detriment of consumers' welfare.

There is also statistical evidence that the BE and AES producers, which did not sign the market abuse license condition (MALC), restricted their nuclear and large coal capacity during peak-demand periods. This can be an interesting evidence in reasoning why the BE and AES producers did not wish to join the MALC code of conduct.

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Appendix A. Supplementary data

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