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The Effect of Falling Market Concentration on Prices, Generator Behaviour and Productive Efficiency in the England and Wales Electricity Market

by

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COMMENTS WELCOME

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1 Introduction

A universal prediction of the various oligopoly models used to predict and explain behaviour in the England and Wales (E&W) electricity wholesale market is that divestiture of plants by the two large incumbent generators and new entry should have led to lower prices and mark-ups. However, even though the market has become significantly less concentrated over the 1990s through both of these mechanisms the regulator (OFGEM, formerly OFFER) has continued to complain about high prices and generator manipulation of prices. This led to OFGEM taking two generators (AES and British Energy) to the Competition Commission in a (failed) attempt to have market abuse conditions inserted in their licences, and has led to the Pool being replaced by a new set of arrangements (NETA) in Spring 2001. These new arrangements are controversial (see Sweeting (2000) for a discussion), and their success is likely to be partly determined by how much market power the generators still have. This paper gathers evidence on what happened to prices and mark-ups during the last five years of the Pool, which have been studied relatively little compared to the first five years, and also seeks to make several more original contributions.

First, I try to identify which generators have been involved in supporting high prices, and to look at whether the owners of divested plants appear to bid in a significantly different manner to the incumbents, National Power (NP) and PowerGen (PG). An important part of this analysis looks at whether the way divestiture was carried out had a significant effect on outcomes. In particular, the first major divestiture of coal plants, to Eastern, was completed via a leasing arrangement under which Eastern paid the former owners of the plants a £6/MWh fee whenever it produced. This would have raised Eastern's marginal cost and the effects of this fee do seem to appear in the data. The second set of divestitures also involved Edison First Mission (EFM) buying two coal stations from PG. EFM already owned E&W's pumped storage plants that frequently set prices in the higher demand periods of each day. Although the data suggests that over time the pumped storage units have been bid at higher prices since 1995, there is no clear additional effect on their bids when EFM purchased its coal stations.

Second, I examine in detail whether there is any evidence that availability is used strategically in the fashion suggested by Patrick and Wolak (1997). They argue that by declaring plant unavailable during the day generators can raise significantly prices above the industry's true marginal cost even though the units may only be bid at cost. I find that inframarginal plant is very rarely declared unavailable during the bidding day, which works against Patrick and Wolak's theory. I also find that overall levels of availability are generally higher – and close to or above the US standard used for comparison by Patrick and Wolak – than their paper suggested. It is true that availability tends to be lower during the summer, but this is consistent with efficient operation as in England and Wales the summer is the low demand period (see Figure 1) and the system as a whole has a significant surplus capacity (in comparison to markets such as California). Of course, this does not mean that availability is never used strategically, but my results suggest that its use is not systematic in the way suggested by Patrick and Wolak.[2]

Third, I try to assess whether developments in the market have led to a decline in productive efficiency. Simple Cournot models suggest that the creation of asymmetric competitors, or some generators bidding competitively as price takers, may decrease productive efficiency. In the context of mergers, this point was analysed in Farrell and Shapiro (1990). The £6/MWh fee may either increase or decrease productive efficiency, acting as an efficiency-enhancing tax on a relatively small generator at peak demand but also inefficiently removing some capacity from the market when demand and prices are low. My initial calculations, using only coal plants and taking plant availability as given, indicate that there has been a decline in productive efficiency following the first round of divestiture in 1996, amounting to around 1% of coal production costs. This is reasonably large in relation to the gains from privatization and restructuring estimated by Newbery and Pollitt (1997) of around 5% of production costs, although it is possible that competition has encouraged other cost savings. Losses of productive efficiency are clearly a concern when divestiture and increased entry have failed to reduce prices.

The main conclusions from the empirical analysis are that divestiture and entry did not reduce prices or mark-ups, even though concentration both in overall generation and in price-setting fell markedly from 1995 to 2000. There is some evidence that the £6/MWh fee may have contributed to higher prices, by increasing Eastern's bids and reducing competition in those low demand periods that have prices below Eastern's inflated marginal costs. The failure of prices to fall could be explained either by prices *already* being close to competitive levels (at least on average) or by generators being able to maintain equilibria above competitive levels even when concentration falls. The former is possible if my measure of marginal cost systematically understates cost, while the latter would be consistent with the level of prices prior to 1995 being determined by factors that were not changed by divestiture. Two possibilities from the existing

[2] OFGEM has claimed to find several cases of capacity decisions taken to affect prices, which include an element of capacity payments. See for example, OFGEM's Second Submission to the Competition Commission (OFGEM (2000), pg. 9ff.). There is also an issue that generators may take inefficient exit decisions, permanently withdrawing capacity from the market to increase prices. I do not try to determine whether this is the case.

literature (see for example Wolfram (1999)) are implicit regulation (prices kept low to deter regulatory intervention) or limit pricing to prevent entry. Given the extent of actual entry and the failure of prices to fall as the capital costs of new CCGT plants have fallen, the former explanation seems to me to be more plausible. Indeed insofar as regulation of many generators may be harder than the regulation of just two, implicit regulation provides a potential explanation for why prices have not fallen since 1995 as fuel costs have declined. If average prices are in fact determined by the level of regulatory pressure, and so do not send efficient signals to customers or potential entrants, there is even more reason to be concerned if divestiture has reduced system efficiency as my results suggest.

This paper may be of interest to those thinking about divestiture in other electricity markets and in regulated markets more generally. Existing empirical studies on divestiture focus primarily on what happens to productive efficiency (for example, Olley and Pakes's (1996) study of the telecommunications equipment industry), or on the consequences of vertical divestiture (for example, Slade's (1998) study of the UK beer industry following the Beer Orders). This study examines a simple case of horizontal divestiture. The results suggest that it is important to think about how divestiture is implemented and to take into account productive efficiency. The fact that prices do not decline when concentration falls, as simple oligopoly models would predict, suggests that we may need to reassess how these models are applied to this kind of market. For example, if there are in fact multiple equilibria, we need to understand far better than we do at the moment what drives the actual choice of equilibrium.

The paper proceeds as follows. Section 2 provides a brief guide to the operation of the market and the history of entry and divestiture. Section 3 presents conclusions from the models that have been used to analyse the Pool, and also estimates a simple parameterized Cournot model to predict the effect of the £6/MWh fee and the divestiture of plant to EFM on prices at the daily peak. Section 4 presents the evidence, based on a large dataset containing generator's bids and availability, as well as prices. Section 5 concludes and discusses implications of my findings.

2 A Brief Guide to the E&W Electricity Wholesale Market

2.1 Operation[3]

The Pool operates as a daily first price multi-unit procurement auction. At 10am each day generators, and a few small demand side bidders (ignored from this point on), present bids for each generating unit (there are 300 units, in around 100 different power plants) to supply power for the next day, along with a schedule which says at what times of the day units are available. Each bid has several components that are combined by the system operator (the SO, NGC) to give a single price for each unit (known as the Table A Bid Price). These are used to rank units by cost into the "merit order". The SO then uses half-hourly demand estimates (price inelastic by the Pool's rules), to find the available marginal unit in a particular half-hour. This unit's Table A Bid Price then determines the System Marginal Price (SMP) for that half-hour. Demand variation leads to SMP rising and falling during the day, even though all bids stay the same. While the Table A Bid Prices determine the merit order for the whole day, in Table B periods, typically those with lower demand, SMP is only based on those elements of bids that reflect incremental costs rather than fixed costs.

The SMP only constitutes one element of Pool prices. The total price received by producers is called the Pool Purchase Price (PPP), and consists of SMP plus a capacity payment, based on the amount of capacity above forecast demand bid into the Pool, translated into the Loss of Load Probability (LOLP). However, it is not the capacity made available for the half hour in question that matters. Instead, LOLP is based on the maximum availability of units over the previous seven days. Hence it is possible for LOLP, and therefore capacity payments, to be low even when the system is relatively short of spare capacity because a lot more capacity was available over the previous week.[4]

The price paid by those buying from the Pool is the Pool Selling Price (PSP) and, during Table A periods, it includes, in addition to the PPP, elements to recover capacity payments to generators available but not producing, ancillary service costs and costs related to meeting differences between actual and forecast demand. In the empirical section I primarily focus on the SMP and the difference between the PSP and SMP as measures of prices. The PSP reflects total payments to generators and includes some amounts in addition to payments for power actually supplied.

[3] Further details of the Pool's operations can be found in a number of papers including Sweeting (2000) and the references therein, as well as The Electricity Pool (1996)

However, its definition has changed over time (particularly with the exclusion of elements relating to transmission constraints in April 1997), whereas the definition of SMP, which is a simpler reflection of the price clearing the electricity auction, has remained the same across the period I look at empirically.

2.2 Market Developments

Table 1 gives capacity shares, by owner and by fuel, for 1995-2000 (the time period covered by my dataset). As noted under the table NP and PG dominated output to a larger extent in 1990/91, and at that time there was no Combined Cycle Gas Turbine (CCGT) generation capacity. Two forces have led to the dramatic shifts in shares away from NP and PG, and away from coal. First, since the early 1990s there has been a large amount of entry by new CCGT plant, much of it operated by independents, frequently financed on the back of long-term contracts with the RECs (the regional electricity supply companies which until 1998 were the sole suppliers to small business and domestic customers in their regions, and were therefore price regulated). CCGT entry had reached 21.7 GW by 2000/01.[5]

CCGT plant is operated almost entirely as baseload, with the effect that coal plants have been pushed further out along the supply curve. Meanwhile NP and PG have closed a number of older, smaller coal, oil and peaking plants, amounting to 15.2 GW of capacity.[6] The possibility of further new entry from 1998 was reduced by the Labour government's implementation of the so-called "Restricted Consents Policy", which limited government approvals for more new generation. Entry by plant with existing approvals continued.

Second, since 1995, there has been a process of divestiture by NP and PG of coal plants and peaking gas turbines partly at the behest of the regulator. The first divestiture involved NP and PG divesting 6,222 MW (3,938 MW, 2,284 MW respectively) to Eastern Group (later bought by TXU) in April 1996. This coincided with the end of a two-year period during which NP and PG had agreed to keep average and demand-weighted average prices below certain levels. The regulator hoped that divestiture would "prevent prices being held above a competitive level" without the need for artificial price restraints.[7] However, the Eastern divestiture was performed as

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[4] For more details, see The Electricity Pool (1996), pg. 106
[5] NGC (2000), pg. 3.11
[6] Figures based on NGC(2000), Table 3.7 "Generating Plants Disconnections", pg. 3.39
[7] OFFER press release, "Generators' Price Undertakings", 12 December 1995

a lease with a peculiar feature: a £6 per MWh generated leasing fee went to the original owners.[8] This, of course, increased Eastern's marginal costs: the effects of this are discussed in more detail below.

The second round of divestiture began in summer 1999, reflecting both OFGEM's continued concerns about Pool price manipulation and the desire of NP and PG to vertically integrate with large electricity supply firms (Midlands Electricity and East Midlands Electricity respectively). EFM bought 3,886 MW of capacity from PG in July 1999, AES bought the 3,870 MW Drax plant from NP in August 1999 (operational in November) and British Energy (BE) bought 1,960 MW of capacity from NP in Nov 1999 (operational in February). No leasing fees were involved. However, these divestitures created two further issues of interest. First, the Edison divestiture gave significant coal capacity to a firm that already controlled E&W's pumped storage capacity (as well as some CCGT plant) having purchased this from NGC in December 1995. Pumped storage plants frequently set prices during higher demand periods each day (as seen in Table 4 (b)). This raised the possibility that Edison's incentives and ability to manipulate prices might be greater than if it was simply an operator of the coal plants. Second, BE is the operator of the UK's more modern nuclear plants, which operate as baseload. The purchase of coal plant made it the country's second largest operator by capacity and output, with potential incentives to operate its small amount of coal capacity strategically.

3 Models of the E&W Wholesale Market

A number of models have been used to explain and predict prices in the Pool. Two predictions are common to these models. First, when the price setting part of the market was under the control of the NP and PG duopoly prices should have been substantially above cost. Second, declining concentration, especially to the levels seen since mid-1999, should have significantly reduced prices and mark-ups. In this section I first review the predicted effects of deconcentration resulting divestiture by incumbents and deconcentration as a consequence of new entry. I then estimate a simple Cournot model designed to capture some particular features of the market, such as the £6/MWh fee, which have not been included in earlier models. I do not consider models of collusion, even though good information about technology and the frequently repeated nature of the electricity auction make it potentially susceptible to collusion. The

[8] Green (1998), pg. 18

literature has not developed formal models of collusion in this market perhaps because prices in the early 1990s were below levels predicted by static models. I also do not consider models of "learning" although learning could well be a feature of this market as there may well be multiple equilibria even in static games.

An important general feature of models of wholesale electricity markets such as England and Wales is the shape of the aggregate marginal cost schedule. Figure 2 shows the estimated marginal cost curve for 15 January and 15 July 1997 based on the units that were available on those days. If availability is restricted strategically then the true curve would be below the one shown. The cost data used to draw the curve is described in Appendix A, and in addition I assume that nuclear plants have zero marginal cost and that the interconnectors bid at cost. It is generally fairly flat for most levels of demand but has a very steep slope where supply is close to total capacity. If demand gets to levels close to the steeply sloped part of the cost curve even competitive prices can be high and, in addition, even reasonably small generators may be able to increase prices by withholding capacity.

3.1 Supply Function Equilibria Models

Green and Newbery (1992) and Green (1996) use the Supply Function Equilibria (SFE) approach of Klemperer and Meyer (1989) to estimate models of the Pool. The SFE approach works around the realization of demand being uncertain so each producer has a {price, quantity} supply schedule rather than offering a fixed price as in Bertrand or fixed quantity as in Cournot. An important feature of the SFE approach is that, when there is an upper limit on the possible realizations of demand, there are multiple equilibria ranging from the competitive (prices equal marginal cost) to one where prices and quantities are Cournot at the highest demand realization.[9] Although there is little demand uncertainty in E&W (especially for SMP which is based on a day-ahead forecast of demand calculated using an algorithm available to generators), they argue that demand variation over a range of volumes during the day over which bids apply is analytically equivalent to demand uncertainty within that range.[10]

[9] The presence of binding capacity constraints eliminates the most competitive equilibria.

[10] For example, the imagine that three different levels of demand will occur during the day (High, Medium and Low) for 8, 16 and 24 half-hour periods respectively. Then, at least with risk-neutral generators, this is equivalent to generators having a prior probability distribution of (1/6, 1/3 and 1/2) over the three outcomes. However the models are only equivalent when firms have to keep the same supply schedule for the entire day. As I discuss below there is scope for generators to vary their availability during the day and therefore change the shape of their supply functions.

Based on parameters chosen to reflect the state of the market at privatization (although using firm symmetry) Green and Newbery find that both divestiture, from duopoly to a five firm oligopoly, and entry, by independent CCGT plant, should have large effects on average prices. Using the highest SFE (Cournot at the daily peak), average prices under a symmetric quintopoly would be £27/MWh, compared £41/MWh under a symmetric duopoly. The price under marginal cost pricing would be £23/MWh. Maximisation of duopoly profits in the face of a free entry threat would reduce prices to £30/MWh with around 8 GW of entry taking place (about the volume which actually did take place by 1994/95).[11] In fact annual average SMP in the early 1990s was between £19 and £24/MWh (and average PSP was around £1 higher) indicating that even if Green and Newbery slightly overestimated costs mark-ups were far lower than they predicted.[12]

Divestiture has an effect similar to that in a Cournot model: a firm with less inframarginal capacity has weaker incentives to raise prices. Independent entry has two effects: the static Cournot effect that entry reduces residual demand for the oligopoly and the additional effect that oligopolists are able to choose a lower static SFE in order to reduce the scope for entry increasing their joint profits.

Green (1996) uses the linear SFE (between the Cournot and Bertrand cases) to study the effects of different divestiture options (for the 1996 divestiture) on prices and welfare. Under the assumption of linear marginal costs a linear SFE exists, and in fact it is the only SFE when demand uncertainty is unbounded. Green chooses parameters to fit the market prior to divestiture. Based on divestiture of 20% of NP's and PG's plants to two parties, mark-ups above marginal cost are predicted to fall by around 50%. Divestiture into five equal size firms would result in mark-ups falling a further 50%.[13]

The effects on prices are not affected that much by whether new owners bid competitively (at marginal cost) or use supply functions above marginal cost like NP and PG. However, as Green notes, competitive bidding tends to have a negative effect on productive efficiency, as competitive bidders will use less efficient plant at the margin than strategic bidders. This effect also appears for smaller bidders in a Cournot model, as I discuss below. Green's modeling does not consider the issue of the £6/MWh fee or the influence of the fact that owners of divested plant

[11] Green and Newbery (1992), Table A and Table B
[12] For average prices, see Table 3.
[13] Green (1996), Figures 1, 2 and 3, pg. 212-3

own pre-existing capacities.[14] Entry does not change the slope of the supply functions but by reducing the size of oligopoly's (residual) demand does reduce prices.

An important feature of the market is that a large proportion of output is covered by hedging Contracts for Differences (CfDs), which reduce the exposure of both generators and Pool customers to variations in the Pool price. A typical two-way CfD specifies a volume and a price. The generator pays the customer (for example, a REC) the difference between the Pool Price (either the SMP or PSP, depending on the contract) and the contract price, multiplied by the volume in the contract whenever the Pool price is above the contract price. In a two-stage model, signing contracts in the first stage reduces the effective infra-marginal capacity in the second stage spot market. This reduces generator's incentives to restrict output and bid up prices. Green (1999) examines this in a SFE framework, although when generators have Cournot conjectures in the contract market the equilibrium is that they sign no contracts. However, given that they do sign contracts, we can see that the effects of divestiture will tend to reduce prices both via the contract market (more contracts will be sold, hence reducing inframarginal capacity in the spot market) and via the standard SFE effects on the spot market. The possibility of entry by new baseload plant may also encourage generators to sign contracts in order to commit to aggressive pricing. In this case we might expect the government's restricted consents policy to reduce contract volumes (unfortunately not observed) and to have increased prices. Prior to the policy, the decrease in CCGT entry costs (OFGEM (2000), Figure 2.5 estimates that capital costs per KW have halved over the 1990s) should have forced prices downwards if generators have been engaging in pricing to limit the amount of CCGT entry.[15]

3.2 Auction-based approaches

The main alternative approach to modeling the E&W market is to use the logic of multi-unit auctions, in the manner of von der Fehr and Harbord (1993). This approach is attractive because it takes into accounts the facts that the units which generators bid into the market are discrete (so the same bid has to apply for a particular volume of electricity) and that the demand forecast used to set the price is inelastic (no SFE or Cournot equilibrium exists in this case). However, no account is made of the fact that bids apply to 48 different demand realizations (so bids are not based on a complicated optimizations across these periods) and the model has only been

[14] In fact the £6/MWh fee would tend to create a discontinuity in the other firms' residual demand curves and hence would eliminate the linear SFE.

[15] OFGEM (2000), pg. 7

implemented for cases of constant marginal cost. In this case, when generators know that demand is sufficiently low that none of them can be guaranteed to supply, prices will be competitive. If all generators know that they are necessary for supply, prices could be unbounded, and von der Fehr and Harbord invoke a maximum price, perhaps created by implicit regulation. In between there are mixed strategy equilibria, as well as pure strategy equilibria. In fact, if uncertainty about the level of demand is high (in particular if it is greater than any firm's capacity) then no pure strategy equilibria exist.[16]

Despite the lack of clear solutions, the (unsurprising) effects of divestiture and entry are clear and potentially very strong. Divestiture of capacity makes it more likely that demand will fall in the range where no generator can be guaranteed to supply, and hence should increase the proportion of the time that prices are set competitively. Entry, by reducing the residual demand has the same effect. Similarly divestiture and entry make it less likely that levels of demand are such that *all* generators know that they are required will be reached.

3.3 Availability Strategies

SFE and auction models have focused on the question of how generators bid a given amount of capacity. However, Newbery (1995) and Patrick and Wolak (1997) note that it is not necessarily correct to take available capacities as given: instead these could also be subject to strategic manipulation. Newbery (1995) presents a very simple model, under which larger generators have incentives to restrict availability in order to raise capacity payments (part of PPP) on their available and uncontracted plant. Divestiture, by decreasing inframarginal capacity and increasing contracting should reduce the incentives for this kind of manipulation, leading to an increase in availability over time. On the other hand, entry by more efficient plant would tend to lead to a decline in the observed availability of less efficient existing plants.

As outlined above, manipulation of capacity payments requires capacity to have reduced availability for at least seven days. Patrick and Wolak (1997) also informally suggest a strategy through which generators might use within day availability variation in order to influence prices. One of the limitations on generators' bidding is that their bids have to be kept the same for the whole day. However, availability can be varied during the day, and varying availability allows the slope of the bid function to be changed during the day even when bids cannot. By giving generators additional freedom it expands the scope to raise prices, and it also suggests that an

[16] von der Fehr and Harbord (1993), Propositions 2-4, pgs. 533-536

SFE approach, which assumes that generators have to maintain the same supply schedules throughout the day, may not capture an important feature of the market. However, generators can only use within-day availability strategically when the plant declared unavailable is infra-marginal. When it is extra-marginal it will have no effect on the SMP or, as it is only within-day variation, on capacity payments. These distinctions are not made by Patrick and Wolak. Although there is no formal model of generators using availability behaviour the usual consequence of divestiture - less inframarginal capacity reducing incentives for strategic behaviour - would seem to apply.

3.4 A Simple Cournot Model

In order to get some sense of the likely effects of adding two features of divestiture, the £6/MWh Eastern fee and EFM's ownership of pumped storage plant, I estimated several versions of a simple Cournot model with asymmetric cost functions and capacity constraints. The actual amount of entry happening in the market is also taken into account. If the parameters are taken as applying around the daily peak in demand, then the results are those which would apply for the peak period under the highest SFE. As prices for the rest of the day would be lower, average prices would be significantly less than those estimated by the model.

For each estimation, the demand side is kept the same in order to focus on the effect on changes in the supply side. This is also reasonable given that the demand side is very stable over the period - average demand increases about 5% over the whole 6 years. I assume linear demand, with a demand curve of Q=56,000 - 250 P (quantity measured in MWhs).[17] The value of 250 is chosen to correspond to the central case of Green and Newbery (1992).[18] Based on this demand curve, I estimate the model for parameters corresponding to a "1995" model, two "1997" models (Eastern divestiture without the £6/MWh fee, and with the fee) and three "1999" models (adding the EFM and AES divestitures to the two cases above, and also calculating the case where EFM

[17] The output volumes correspond roughly to those for the peak of a typical winter's day (NGC (2000)). As indicated by the load demand curves in Figure 1, in E&W peak demand occurs in the winter, reflecting the greater importance of heating and lighting and lower importance of air-conditioning than many places in the United States.

[18] The use of a linear demand model is a convenient device in modeling electricity markets with few generators because even when the slope parameter is small, the demand curve becomes elastic for high enough prices. This guarantees the existence of a Cournot equilibrium. However, the estimate of demand used to set SMP in England and Wales is completely price inelastic. In this case, a Cournot model (and by implication the highest equilibrium of an SFE model) would predict infinite prices. As noted above, infinite prices also result in an auction model with inelastic demand when generators know that they are required to produce.

does not also own pumped storage capacity but including the fee). I do not consider the BE divestiture, in order to avoid dealing with constraints that nuclear plants cannot be used strategically. I also do not consider the effect of contracts.

For each model, I specify the capacities for each fuel type owned by each operator in the market for each different year. This is done by finding the maximum capacity bid by a unit in the year in question (using my availability data described in Appendix 1) and by allocating units to the relevant generators. I make an assumption that 90% of this capacity is available on the day in question for all fuel types. This is an ad-hoc assumption to reflect the fact that even during the winter some plant is unavailable due to maintenance. It is not supposed to capture strategic availability decisions. I then aggregate capacities of the nuclear plants, the interconnectors and independent CCGT plant (which includes operators such as EFM and AES before they purchase coal plants) and deduct these capacities from the intercept of the demand curve, i.e. I assume that they operate. This will be true if these suppliers act as a competitive fringe at the prices predicted by the model as they have estimated marginal costs that are lower than the predicted prices.[19]

The next step is to specify the marginal cost curves roughly approximating to my cost data. I specify a linear industry marginal cost curve for CCGT, between a marginal cost of £8/MWh and £11/MWh for the volume of CCGT capacity in the market (which expands over time). I also specify a combined marginal cost curve for coal, oil and gas plant. This curve is

$$11+0.0004*Q_{COAL} \qquad 0<Q_{COAL}<20{,}000 \text{ MW}$$

$$11+0.0004*Q_{COAL} + 0.000001(Q_{COAL} - 20000)^2 \qquad Q_{COAL}>20{,}000 \text{ MW}$$

The linear section of the marginal cost curve takes marginal cost up to £19/MWh. Where appropriate £6/MWh is added to Eastern's marginal fuel costs. Firms share the CCGT and coal supply curves in proportion to their CCGT and coal capacities. For example, if firm A has 2 GW (2.22 GW before the 90% availability adjustment) of available CCGT capacity then the function for the relevant part of its cost function, is

$$8+\left[\frac{3}{2000}\right]*q^{A}_{CCGT}$$

[19] Nuclear operators and the interconnectors (operated by EdF and the Scottish generators) are large enough not to act competitively. In the case on nuclear plants this possibility is removed by operational and safety constraints (and in fact they never set marginal prices in the six years of the sample). The interconnectors may well bid strategically but I have no information on their costs. If I assumed that the interconnectors did bid strategically this would increase the predicted prices.

These capacities are also estimated from the availability data, and hence reflect the asymmetries in the market. Asymmetric capacities create asymmetric cost functions, although no attempt is made to capture the fact that we know which generators own particular units (for example, that AES's coal capacity is at Drax which is more efficient than most coal plants). I do not include changes in fuel costs over time, in order to focus on the structure of the supply side. Taking into account the fall in fuel prices over the period would reduce the price estimates for later years. Pumped storage is assumed to have an (exogenous) marginal cost of £16/MWh (reflecting a premium over average nighttime prices). For the "1999" models a flat section at £16/MWh is included as a flat segment in EFM's marginal cost curve.

The model is then estimated taking into account the relevant capacity constraints. As well as prices and volumes, I also estimate the cost of production by the oligopoly and the productively efficient cost of producing the same output. The results are shown in Table 2. It is clear that divestiture is expected to have a large effect on price in line with the models discussed above. The marginal cost of efficient production for all the scenarios is between £16 and £17/MWh implying the mark-ups halve between "1995" and "1999" although they remain substantial (the industry Lerner Index for 1999 is around 0.5). The size of mark-ups reflect the Cournot modeling assumption, the small number of producers and the low elasticity of demand at prices close to the competitive level. Prices are increased, but not by much, through the two provisions of interest. The £6/MWh fee and giving coal plants to the pumped storage generator each increase price by around £1/MWh. Of course, we would expect the fee to have a larger impact in off-peak hours. For example, during low demand periods prices often fall to around £10-12/MWh, around the marginal fuel cost of even the most efficient coal plants. With a premium of £6/MWh the Eastern plants would be removed from the market entirely at these prices. In this case, at those hours the market would remain a duopoly and marginal cost schedules will have been steepened by the removal of some efficient coal plants from the market, so standard oligopoly logic would predict that divestiture should increase prices. Of course, as bids apply to all hours the actual equilibrium in the market should be more complicated. However it is clear that a model focusing on the peak may underestimate the increase in prices caused by the premium.[20]

In my model, both features actually improve productive efficiency (though the creation of smaller generators by divestiture works in the other direction), even though they increase prices. This

[20] The Cournot model developed above does not capture this situation very well unless the slope parameter in the demand is increased dramatically. This is because the model only predicts prices close to cost at very low demand levels or where demand is very elastic.

comes from the standard feature of Cournot models that one would like to redistribute output from small firms to large firms who have lower marginal costs at equilibrium levels of output. When Eastern is taxed NP and PG, which have plants with lower marginal costs on the margin, increase their output. When EFM owns pumped storage plants (always inframarginal in equilibrium) it reduces the inefficiently high output from its coal plants. Divestiture itself has two effects on productive efficiency. First, it makes NP and PG more symmetric improving efficiency (in 1999, it makes NP and PG more symmetric with Eastern). This effect is small as by 1995 the NP and PG were fairly similar is size, partly because PG owns more CCGT capacity. Second, it creates small firms who tend to use their capacity less inefficiently, even though this acts to reduce prices. Of course, in an off-peak model where Eastern's plant is removed from the market productive inefficiency would be increased, not reduced, by the premium.

In summary, this simple model would lead us to expect to see prices falling and productive efficiency decreasing with the first divestiture, and prices falling further in 1999. However, it is also noticeable that mark-ups remain high even with divestiture, reflecting the low demand elasticity at lower mark-ups.[21] This raises the issue of how we should interpret the results of a model concerning price **changes** when the model does not necessarily predict the initial level of prices with accuracy.[22] If something else has limited prices, for example the threat of regulatory intervention, then the relevant questions to ask are whether falling concentration has reduced unconstrained prices to below the regulator-constrained levels and what effects it may have on the regulator’s ability to influence generators. If unconstrained prices remain above the constrained levels (reflecting low demand elasticity or tacit collusion) and divestiture make the regulator’s job harder (as it becomes more difficult to intervene a second time without admitting that the initial policies failed to work), then falling concentration could increase mark-ups rather than reducing them.

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[21] However, if prices are supposed to represent prices at the daily peak, the model predicts prices which are roughly similar in magnitude to those seen in the market (mean prices for the periods with the highest four SMPs each day are between £35 and £55 for nearly every quarter 1995-2000). As I discuss in the next section it is quite possible that basing a marginal cost estimate on efficient-operation fuel costs is not appropriate at the peak. This could explain why we observe prices which are higher than are predicted by the Cournot model.

[22] Most models have therefore been interpreted as giving predictions about relative prices under alternative market structures rather than as giving absolute price predictions.

4 Prices, bidding behaviour and efficiency 1995-2000

The predictions concerning the effects of divestiture, the £6/MWh fee and entry are compared with the evidence from 1995-2000. Section 4.1 examines what happened to prices and mark-ups, while Section 4.2 focuses on the identity of the price-setter. Section 4.3 looks at bidding behaviour, while Section 4.4 examines availability in the light of the suggestions of Patrick and Wolak (1997) that this may be used strategically. Section 4.5 implements a simple method for calculating the productive efficiency of coal fired generation. The data used in the analysis is described in Appendix 1.

4.1 Prices and Mark-ups

Figures 3(a) and (b) show the 30-day moving average of SMP and the difference between PSP and SMP, which is composed of capacity payments and some charges to recover ancillary service costs and the costs of having to provide additional power to meet higher than expected demand. The very low values of SMP in early 1995 have been identified in earlier studies and is associated with a particular period of regulatory pressure.[23] Comparing the post-April 1996 period, i.e. following both the first divestiture and the end of the price-cap, with the prior period suggests that there was no marked decrease in average SMP. Following the second divestiture average SMP was lower and seasonality was less marked over winter 1999/00. However, from Figure 3(b) it is clear that, after the second divestiture, the average difference between PSP and SMP (including capacity payments) increased. This meant that the overall level of prices paid from those purchasing from the Pool did not decline. The figure also indicates that entry or the threat of entry combined with falling entry costs did not drive prices downwards. There is also no obvious break following the introduction of the “restricted consents” policy at the start of 1998.

Given that a price-cap was in operation from April 1994-1996 it is also interesting to compare prices with years before 1994 for which I do not have data. Table 3 uses data from Patrick and Wolak's Tables 1and 2 to provide a comparison for SMP and the ratio of SMP to PSP. The average SMP column suggests that SMP levels are fairly similar to those prior to the price cap, with (as we would expect) lower prices in the summer. The second column indicates that prior to the price cap SMP/PSP was generally between the extremes we see in the later period. Taken

[23] For example, Green (1999) comments that "Following a strongly-worded statement from the regulator, National Power and PowerGen kept their bids very low for the remaining two months of the financial year".

together with the combination of low inflation and declining fuel prices, these numbers suggest that neither entry nor divestiture have had the expected effect on outcome prices.

The last two columns divides periods into Table A and Table B periods. Table B (about one-fifth of all periods) are those periods each day which are considered to be off-peak, and have fewer elements of bids included in the price. The prices generally move together, but the Table B prices tend to increase slightly relative to Table A prices, as well as increasing absolutely. This would be consistent with the £6 premium decreasing competition and increasing costs in low demand periods, even if divestiture has some effect in restraining prices at higher demand periods. Of course, if it is the fear of regulatory intervention that caps prices in higher demand periods, then the effect of the premium and divestiture might be to make consumers unambiguously worse off.[24]

While the pattern of prices is of some interest because it avoids the need to make estimates of marginal cost, mark-ups are the informative statistic for an assessment of the extent of market power. I follow Wolfram (1998) and (1999) in forming a direct estimate of marginal fuel cost for each plant using data on plant efficiencies and fuel prices (see Appendix 1). Unlike Wolfram I know the identity of the marginal plant so I can calculate the mark-up (SMP less cost estimate) of the unit setting the marginal price and divide through by SMP to set the Lerner Index for the period.[25] Figure 4(a) shows the moving average of the Lerner Index based on SMP. The upward drift is *greater* than that seen in prices for two reasons. First, fuel prices, and in particular coal prices, have fallen since 1995. For example, the price in contracts with successors of British Coal fell from 137p/GJ for the period from 1995 to 122p/GJ in March 1998, and there was a similar trend in world coal prices. Second, the displacement of the most efficient coal plants from providing baseload and the closure of old plants has tended to make the marginal plant more efficient. The average Lerner Index following the second divestiture is above the level during the price cap, even when the very low prices at the start of 1995 are excluded.

Of course, calculating the Lerner Index in this way is likely subject to various types of bias, even if my estimates of plant efficiencies and fuel costs are accurate. First, other elements of cost (for example, the elements of labour cost that are marginal) may be increasing over the period,

[24] Wolfram (1999) argues that the 1994-96 price cap should have led to the generator's reducing off-peak prices to maintain prices at higher levels of demand. This would also explain these results. However, Wolfram's argument is premised on the average price element of the cap being more biding that the demand weighted element.

[25] Wolfram (1999) used an estimate of the supply curve to calculate an estimate of marginal cost for the quantity of electricity generated.

leading my direct method to overestimate mark-ups by an increasing amount over time. Second, using efficient operation heat rates is likely to understate the true marginal cost of plants that operate only at the daily peak. For example, coal plants which have fluctuating output during the day will operate less efficiently and so have higher marginal costs. In addition, they may also need to recover some fixed costs of operation via the marginal price in the few periods in which they operate, although in E&W this point is limited in its importance by the fact that generators can receive additional payments from the System Operator if they are estimated not to have recovered their submitted Start-Up costs. Hence the daily supply curve is likely to be above the "efficient operation" estimated supply curve even when both are based on the same unit availability. In addition, the daily curve could be significantly steeper than the efficient operation curve at the peak. The possibility that the daily supply curve is higher and steeper than the efficient operation curve is consistent with the evidence on prices shown in Figure 2. Here for January 1997 and July 1997 I plot prices (SMP) at the daily minimum and peak of daily demand, along with the supply curves for 15 January 1997 and 15 July 1997 respectively. The minimum demand can be met by plant which can operate as baseload for the rest of the day and so can run continuously. The marginal costs of these plants should be around the efficient operation marginal costs estimated above. Consistent with a competitive outcome minimum prices are at or even below the estimated marginal cost curve. In contrast, maximum prices are significantly above the curve. The question of how bad an approximation the efficient operation curve is to the within-day curve has not been addressed in the literature. However, this clearly means that the interpretation of estimated mark-ups have to be treated with extreme caution, especially as the identity of plants that have varying output has changed over time reflecting new entry. In spite of these reservations I interpret the mark-up results as indicating that mark-ups have not fallen markedly in the way that existing models or my Cournot model predicted. The caveat is that it is hard to distinguish whether prior to deconcentration prices were close to competitive levels, or whether they have remained substantially above competitive levels. Notably however, prices show considerable variation at the daily peak even for similar levels of demand and times of days, as illustrated by Figure 4. This fact would tend to support the claim that sometimes prices are significantly above cost. However, there is no simple reason why so much more market power should be exercised on some days rather than others. The role of multiple equilibria and learning are two possibilities I intend to investigate in future work.

4.2 Ownership of the Price-setting Unit

As I know the identity of the marginal plant, I am also able to examine who sets prices, at what levels and at what times of the day. This is particularly interesting as it allows a partial assessment of which generators are driving high prices and, in particular, whether divested owners tend to set prices less often or at lower levels. It also allows an examination of the hypothesis that the £6/MWh fee should lead to Eastern setting prices less frequently off-peak. Table 4(a) shows shares of price setting and the average SMP set for Table A and Table B periods for each six month period by coal plants (which, as Table 4(b) illustrates, set SMP the majority of the time). Two features immediately emerge, which suggest that the fee may have an effect. Eastern sets prices far more rarely in Table B periods than in Table A periods, and during Table A periods it sets higher prices than other operators of coal plants. Formally, t-tests reject the hypothesis that Eastern sets similar prices to other operators, although such tests also reject that other operators set similar prices for most periods reflecting the large number of observations. The other divested coal plant owners seem to set prices at similar levels to NP and PG. During Table B periods the prices Eastern sets are similar to those of the other generators.

One explanation of these results would be that the fee has little effect, but that Eastern simply owns plants with higher costs. My cost data suggests that the Eastern stations are fairly similar in efficiency to those of NP, even if they are less efficient than the plants that remain with PG following divestiture. Combining the coal price data with the efficiencies also indicates that even a difference in efficiency of 8 percentage points would only give a cost difference of £2/MWh, smaller than the observed difference and the size of the fee.[26] I also compared with the prices set by the same units in 1995, prior to divestiture. As would be suggested by the efficiency figures, the NP plants that went to Eastern set prices significantly lower than the NP average in 1995, whereas the prices set by the PG plants were above the PG average. Hence a cost explanation is not implausible, but an explanation based on the fee is also entirely consistent with the evidence.

For Table A periods I also examined the level of prices set by pumped storage plants (which rarely set prices in Table B periods). EFM's ownership brings no immediate change in price set, and the upward shift occurs before EFM's ownership of coal plants (although EFM was developing its CCGT ownership prior to 1999). In part this upward trend could be caused by the increase in off-peak electricity prices seen above, as off-peak electricity is the primary input to pumped storage plants.

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[26] My cost data suggests that the most efficient coal plants have efficiencies of around 38%.

4.3 Bidding Behaviour

The data allows an analysis of generators' bidding behaviour. In this sub-section I look both at stations average bids and employ the methodology of Wolfram (1998) to analyse whether generators bid "strategically".

Table 5 shows the average bids of coal stations and pumped stations for each six month period in the sample. I focus on coal plants as they are the most likely to set the clearing price and are also the ones divested. I use the formulae given in Appendix 1 to create the daily bids for each unit and then average across all units in the station for the half-year in question, treating those days when a unit is unavailable as missing values. During this period coal costs were generally falling. The first point to note is that for many stations bids are fairly volatile, which does not reflect any observable evidence on underlying fuel costs. Also some generators seem to increase their bids absolutely relative to other generators: for example, NP bids higher relative to other generators in October 1997-March 1998 than in other periods. The very low prices in early 1995 reflect the regulatory pressure described above.

5 of the 6 stations leased by Eastern increased their bids immediately after divestiture. The sixth, West Burton, had lower average bids partly because of a number of very low (<£2/MWh bids) which would certainly have been below cost.[27] At the same time most other stations showed bid decreases or small increases. This would support the notion that the £6/MWh premium had an effect on bidding behaviour, although the Cournot analysis would not lead one to expect that it should dominate the competitive effect of divestiture. From late 1996 onwards however, the bids of Eastern do not differ obviously from those of other generators, and, consistent with the price evidence, there is no obvious decline in bids. The other divestitures were associated with an immediate small decline in the bid levels of the divested stations. The standard deviation of bids from these plants also falls which is consistent with more competitive bidding given that underlying costs are fairly stable.[28]

[27] Out of 945 coal bids of less than £2/MWh submitted during the whole sample, 721 one of them were by Eastern between April 1996 and September 1999. This could potentially reflect technical constraints on some units although the behaviour applied to a number of units, including some not at West Burton, and, in addition, did not apply to the same units prior to April 1996. Hence it would seem to be more a feature of Eastern's bidding behaviour.

[28] As noted below in the context of Wolfram (1998)'s model, strategic bidding should be sensitive to the availability of plant (both of the same generator and other generators) as well as to other circumstances which make price increasing behaviour profitable or wise (eg., regulatory scrutiny), in addition to costs.

Another feature of the average bids is that some efficient plants such as Drax and Ratcliffe that bid low and with low variance early in the period tend to bid at higher and more varying prices from 1997 onwards. This reflects the more efficient coal capacity becoming increasingly marginal at both the firm and industry level. At the industry level, new entry increases the number of periods when only a few coal units operate, especially in the summer. At the firm level, divestiture may mean that efficient plants becoming more marginal for any owner. If efficient plants are used to try to inflate the price and in consequence sometimes do not run this could undermine the productive efficiency of the merit order. I examine this issue in more detail in Section 4.5.

The pumped storage stations have increased bids and variance of bids from Winter 1997/98 onwards. There is no further increase associated with EFM's purchase of coal plants, which represented an approximate doubling of its capacity. However, the fact that EFM is submitting pumped stations at higher bids than it did earlier is one reason why prices do not decline (as Table 4(b) shows pumped plants set prices a significant amount of the time). A higher variance in bidding is, as already noted, consistent with plants being used strategically.[29]

Wolfram (1998) combined bidding data with cost data, and used regression analysis to estimate whether generators bid strategically in the Pool from 1992-94. The basic idea is simple. Generators are uncertain about the bids of their rivals and hence set their bids for each unit by trading off the loss from bidding too high (causing the unit not to run) and the potential gain from increasing prices (for the unit and for all inframarginal units) when the unit is marginal. A generator is defined to bid "strategically" when it bids more for a given unit when it has greater inframarginal capacity, smaller capacity for the unit in question (this lowers the cost to being placed out of merit when price is above marginal cost) and when the units of rivals that usually compete most closely with this unit are not available. Wolfram claims to find some evidence of strategic bidding in the E&W market using data from 1992-94. I repeated Wolfram's analysis for my data and Table 6 contains the results from the analogue of her instrumental variables specification, using only coal plants.[30]

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[29] Of course, pumped storage stations have costs which are dependent on the future price of electricity. They can therefore be rather unstable over time. An increase in off-peak prices, caused for example by the Eastern fee, would also increase pumped stations costs and its bids by more than one pound for every pound increase. This may be once source of the bid increase.

[30] I use coal plants as these are the fossil fuel plants most likely to set prices, and hence likely to bid strategically. For her study, Wolfram did not have access to the identity of the price setting plant, so used all fossil fuel plants. One further difference from Wolfram's study is that I use quarters rather than months

In order to examine the effects of divestiture I include interactions with three time periods (Period 0: pre-April 1996, Period 1: April 1996-September 1999, Period 2:September 1999-September 2000). The variable definitions and the construction of the instruments are described in Appendix 1. The results in column 3 suggest that strategic bidding by NP and PG has persisted over time, at least based on the *LOG(AVAILABILITY)* variable and, to a lesser extent, the *LOG(CAPACITY)* coefficients. The small size and non-significance of Bid Impact is robust to different samples. In fact the availability coefficient suggests that NP and PG may bid more, rather than less, strategically in Periods 1 and 2 than in Period 0. This would be consistent with the end of the price cap or the fact that NP and PG must act more strategically to maintain prices at the level just acceptable to the regulator in a divested market than before. In period 2 an F-test cannot reject the hypothesis that NP and PG bid their plants similarly to the divested plant owners.[31]

The magnitude of the coefficients would suggest that when a generator has 10% more inframarginal capacity available, bids increase by around 65 pence (based on the column 1 coefficient), which is about three times larger than the effect found by Wolfram.[32] On the other hand, it seems as if Eastern (the only non-NP/PG owner in period 1) does bid less strategically. If Eastern would still have bid less strategically without the fee (a strong assumption) this would further suggest that the fee did serve to increase prices. A potential drawback of the approach is that if marginal costs are higher when plant is more marginal, as discussed above, then the results will be biased towards a finding of strategic bidding. However, even in this case it is of interest that Eastern seems to bid *relatively* less strategically then NP and PG.

Overall the pattern of bidding behaviour is consistent with the evidence from prices and mark-ups in the sense that falling concentration has no clear effect on bids or outcomes, and that there is substantial variation over time which cannot be explained by (apparent) cost or demand factors. Variation in the level and variance of bids is suggestive of non-competitive bidding, especially when the bids of all operators tend to move together without an obvious cost explanation.[33] There is some evidence that the premium does affect the behaviour of Eastern, which would be consistent with the evidence from price-setting.

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to form my variables. This is possible because I have a continuous set of months whereas she had a selection of months for each year.

[31] F(1,98678)=0.70, P(F>0.70 under H_0 that the coefficient on availability is the same)=0.4042

[32] The difference could however be attributed to my use of quarters rather than months, as quarters provide more variation. Using months gives coefficients closer to Wolfram levels.

[33] When all bids move together it is harder to attribute the increase in bids to a particular plant simply becoming more marginal.

4.4 Availability

One potential problem with the Wolfram methodology is that availability may be used strategically (Wolfram (1998), pg. 721-22), as has been suggested by Patrick and Wolak (1997).[34] As well as arguing from the size of capacity payments, they contend that the availability performance of NP and PG was poor relative to both that of independents in E&W and international standards, as summarised by NERC figures from the US. Their measure of availability is based on comparing actual availability over the course of the year to maximum possible availability based on unit nameplate capacities at the end of the year (1995). No distinction is made between infra-marginal and extra-marginal availability or between within-day and between day variation. This is in spite of the fact that, as indicated above, parts of their argument rely on variation in the availability of infra-marginal capacity within days. Tables 7-9 give various statistics on availability for my data, and I try to make these distinctions.

In Table 7 the NERC figures from Patrick and Wolak are given underneath the fuel type, and the relevant Patrick and Wolak estimates underneath the owner's name. I calculate availability in a slightly different way to Patrick and Wolak. Instead of using the nameplate capacity in the denominator, I use the maximum availability of the unit during the six months in question. One reason that this is likely to be a preferred measure is that it may be less biased by entry and exit. Plant which is entering the market (in particular CCGT plant) may be connected to the grid and have positive nameplate capacity but not be operational. Exiting plant (especially gas and small coal plant) may still be connected but also not really be operational. It seems inappropriate to class this plant's availability as being used to strategically manipulate capacity payments or affect SMP, at least in the short-run.[35] In addition, nameplate capacity may simply become an inaccurate measure of actual capacity over time due to ageing, modifications or environmental restrictions.

The bottom figure in each box in Table 7 is for availability during the entire season, and is the figure most comparable to the Patrick and Wolak figures. It is given by dividing the sum of actual availability over the six months, by maximum availability (the highest observed availability multiplied by the number of half-hours in the six months). The top figure in each box

[34] In the Wolfram analysis strategic availability decisions would lead to the instrument being correlated with the error, i.e. an endogeneity problem.

[35] This does not mean that entry and exit decisions are necessarily efficient. In particular, exit decisions may be made partly to influence prices in the future, although equally it may well be efficient for older plant to leave the market or be mothballed given the extent of excess capacity in the market. However, this is different to the primarily short-term market manipulation discussed by Patrick and Wolak.

gives the average of a statistic reflecting within-day availability. For every day actual availability is divided by maximum availability that same day multiplied by 48 (the number of periods). Units never available are given missing values. This is averaged across all unit-days belonging to a particular owner-fuel type group. Thus a figure of 1 might appear even if a generator does not have full availability, as long as on those days when plant is available it is available throughout the day at the same capacity.

Several points emerge from Table 7. I start with the seasonal availability figures. First, my figures differ from those of Patrick and Wolak even for 1995, in a way that works against their conclusion that availability is manipulated, especially for coal and gas. This most probably reflects my numbers being less affected by plants that close. Second, coal plant is consistently less available in the summer than in the winter, and in the winter attains availability close to or above NERC levels. Given that E&W has excess capacity, especially in the summer, this pattern is consistent with efficient operation: we would expect some surplus coal plant not be available in the summer. Third, seasonal availability is lower for NP and PG's CCGT plants than those of independents, but tends not to be that different from the NERC figures for most periods. It is also noticeable that Eastern's CCGT availability performance declines once it owns coal plants, although this is not true for AES or EFM. PG's oil plant performance is very poor but these units also submit high bids, and this could well be explained by plant specific factors, as well as the increase in oil prices relative to coal (for my sample, oil plant has higher estimated marginal costs than any of the coal plants). The seasonal evidence therefore provides only weak support for the Patrick and Wolak's theory.

The within-day figures are even worse for the theory that availability id used strategically. For NP availability varies less than 5% from the maximum possible for almost all periods for all fuel types. PG has slightly lower performance for its coal plants, while the oil plant performance is poor (again suggesting plant specific factors). One problem in assessing these figures is the lack of an appropriate benchmark for expected variations in ex-ante within day availability, but it is noticeable that in general NP and PG have similar performance to independents where these comparisons can be made (CCGT plants). Notably, Eastern again appears as an outlier with systematically lower within-day availability performance for its coal plants. To examine this further, I examined whether coal plants became unavailable within-day when they are infra-marginal or extra-marginal. As within day variation cannot affect capacity payments, strategic withdrawal can only occur when the unit is inframarginal, as otherwise SMP is not affected. I take maximum availability during the whole day as the benchmark for capacity and calculate actual availability for a unit as a proportion of the maximum possible for hours when its bid makes the unit infra-marginal, and for those hours when it is extra-marginal.[36]

Table 8 shows that NP and PG's plants have very high within-day availability for plants which are inframarginal. Most availability variation is not of the sort that supports Patrick and Wolak's theory. On other hand, a lot of Eastern's variation comes from times when plant is infra-marginal. There is no obvious theoretical reason why the £6/MWh fee should cause this: as long as bids are above Eastern's marginal cost whenever the plant is infra-marginal Eastern should want to operate. However, remember that Eastern sometimes bids very low, below its marginal cost. An alternative to bidding at the marginal cost inflated by the premium is to bid less, but simply not operate when the price is expected to be low. Speculatively, this may be caused by Eastern worrying about the intertemporal optimization in NGC's algorithm to schedule plant. In order to guarantee that it does run when it wants to run, Eastern may do better by using a low bid-limited availability strategy for some plant than by using bidding alone. Such strategies may have important consequences for system efficiency, but in the case of Eastern there seems likely to be a different rationale to that proposed by Patrick and Wolak.

As spells of unavailability for more than seven days affect the calculation of capacity payments I also examined the frequency of such spells. Ideally, one would like to estimate an equation (similar in spirit to the Wolfram equation) to test whether the duration of spells is a function of the level of capacity payments and their sensitivity to availability decisions (payments are complicated and highly non-linear function of the reserve margin). Of course the level of capacity payments is partly endogenous to the availability decision and no good instruments suggest themselves. Specifications involving demand, and the availability of nuclear and independent plant were tried but the results were highly unstable. This in part reflects the fact that the availability decisions of all generators will partly be driven by expectations of capacity payments (so a generator is more likely to conduct maintenance on plant at the same time that some other generators are doing so). This is true even when generators are not acting strategically. Hence Table 9 just shows the number of spells when coal plants are unavailable for more than seven days. These spells are more frequent in the summer and increase in number over time. Both are consistent with extra-marginal plant being temporarily retired (new entry pushing

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[36] For example, imagine that a unit is available at 200MW for the first 20 periods, available at 100 MW for the next 20 and is unavailable for the last eight. Its bid makes it inframarginal for the first 24. The total-within day figure calculated used in Table 8 is calculated as (200*20 + 100*20)/(200*48)=0.625. Inframarginal within day availability is (200*20 + 100*4)/(200*24)=0.92. Extramarginal availability is (100*16)/(200*24)=0.33

coal plants out along the supply curve) and so are consistent with coal plant not being used strategically. Of course, the increase in capacity payments in since the summer of 1999 raises the possibility that withdrawal is not efficient, but excessive.

4.5 Productive Efficiency

Finally I analyse productive efficiency. The Cournot model and the likely effect of the £6/MWh fee on Eastern's off-peak bids suggested that productive efficiency might decline after the first round of divestiture. I therefore performed a simple productive efficiency analysis for coal plants. I do not have unit output figures, but I do know the merit order and the identity of the marginal plant, and my cost data gives a cost per MWh for each unit.

I only use those periods when a coal plant is marginal. For these periods I add up the available volume of all units in the merit order up to and including the unit which sets the SMP. This gives me the volume required from coal plants. Adding the cost of these units gives me the (estimated) actual cost of production. I then re-order the plants based on cost and work out the ideal cost of producing the same volume assuming that unit availability is the same as it actually was. Repeating for every period during six months, gives me a total actual cost and a total ideal cost. The ratio of the total actual cost to the total ideal cost gives my efficiency statistic, with a higher number indicating greater inefficiency.

Taking availability as given will, if availability is in fact inefficient, bias my statistic downwards as the ideal cost will be greater than it could be. For example if Eastern's units are inefficiently unavailable off-peak I will not pick that up in my estimates. The failure to include start-up costs could have a similar effect, especially given Eastern's on-off availability strategy. On the other hand, mismeasurement of unit costs would tend to bias the statistic upwards.[37] From my perspective the main concern is that these biases should not drive the statistic upwards over time. If anything, the considerations concerning Eastern would seem likely to drive the bias the other way.

The results are shown in Table 10. There is some evidence of an increase in inefficiency over time, amounting to around 1% of system costs. Further analysis at the owner level (not reported) suggests that this inefficiency comes largely from variation between generators and less efficient use of plant by Eastern.

1% of cost may seem like a small number, but it should be seen in its proper context, i.e. relative to the lack of apparent price decreases from the first divestiture and relative to the estimated benefits of privatization/restructuring. Newbery and Pollitt (1997), using far broader sources for efficiency gains than I use, estimate that privatizing and restructuring the CEGB brought benefits of around 5% of production costs. My simple calculations suggest that at least on the cost side divestiture in the way it took place may have eroded up to 20% of those gains. Of course, these losses could be offset by other efficiency improvements resulting from competitive pressure such as more efficient purchasing or better use of labour. Loss of economies of scope across plants would however work the other way. It is also important to remember that technical inefficiency creates absolute deadweight loss whereas, in a market with inelastic demand, high prices largely result in transfers from consumers to producers and hence little welfare loss when welfare is measured as the sum of producer and consumer surplus.

5 Conclusion and Implications

This paper has examined what happened in the E&W electricity market from 1995-2000, focusing primarily on the effects of divestiture and to a lesser extent entry. Contrary to the predictions of the standard models used in this market, prices and mark-ups appear not to have fallen since the early 1990s. The £6/MWh fee involved in the Eastern divestiture may have played a role in this outcome, with a particularly negative effect on prices and efficiency in off-peak hours. The lack of a significant price effect presents a puzzle which it is worth considering in more detail.

A number of features of the market were not really captured in the Cournot model or the empirical analysis which could plausibly affect outcomes in a significant way. Three obvious examples are the role of contracts, vertical integration by the major generators and changes in the structure of retail markets (which were fully opened up to competition in 1999). As discussed in Section 3, increased competition in the market for contracts could generally be expected to reinforce the effects of divestiture. Unfortunately information on generators' contract cover is not publicly available, but OFGEM has explained particular instances of high prices by generators having temporarily lower levels of contract cover.[38] However, the level of contract cover is

[37] Imagine that the system is in fact fully efficient but that I mis-measure some plant costs (in particular I mis-order efficiencies, as fuel costs are assumed common across coal plants so cancel out of both the numerator and the denominator). Then I will find that the system is not efficient even when it is

[38] For example, OFGEM (2000) pg. 17, claims that high Pool prices in July 1999 were due to NP and PG having increased incentives to manipulate prices due to temporarily low contract cover.

endogenous and most CfD contracts are annual so this is unlikely to explain much of the observed volatility in prices and mark-ups within days and within months. The effects of vertical integration need to be considered in the context of increasing competition in the supply market. Manipulation of Pool prices could provide a mechanism by which generators attempt to disadvantage non-integrated supply companies, either directly by raising prices or by increasing the degree of market risk. Of course, with reasonably low concentration in the generation market supply companies should be able to hedge much of this risk by signing contracts with non-integrated generators. Alternatively, vertical integration may create a barrier to entry into the generation market as suggested by Green (1998). However, vertical integration only occurred in1999 as did full liberalization of the supply market, so these features cannot explain the lack of a price effect prior to 1999. It is worth noting that in the longer term, changes in the structure of the supply market which could help to reduce prices by increasing the effective elasticity of demand.

If these features cannot explain the results, then there are two possible interpretations of the evidence presented in Section 4. It could be the case that, if marginal costs were measured properly, then prices would be found to have been fairly close to competitive levels both prior to and after 1995. In this case, falling concentration could not have reduced prices because there was little scope for them to fall. In this case, we need to identify why it is that prices are low when our standard models of oligopoly suggest that they should not be. The observed volatility of prices and bids suggests that this it is probably not the case that the market always acts competitively.

The second interpretation is that, for some reason, market power has been largely unaffected by the change in market concentration. If this is true we need to understand what actually does drive market power, not least because this could have implications for other electricity markets with similar characteristics. Price volatility suggests that generators may be using mixed strategies or moving between multiple equilibria. The use of mixed strategies would be consistent with the model of von der Fehr and Harbord (1993). However, given that generators do not change their bids every day, even though they could do so, theory would suggest that individual generators are more likely to have pure strategies as strictly best responses.[39] If decisions can only be taken on a weekly basis then mixed strategies might be consistent with the evidence. Yet mixed strategies on their own would not explain why prices have not fallen because, as in the von der Fehr and

Harbord model, falling concentration would still lead us to predict lover prices on average. This is also a problem for a theory involving multiple equilibria, as falling concentration should have made more competitive equilibria feasible. Trying to develop models which explain the dynamics of the market (for example, by seeing how generators respond to shocks such as baseload capacity becoming unavailable) seems to be the logical next step in explaining why static models lack predictive power.

The other possible explanation for what has happened if there is market power, is that the market should have been understood in terms of a game between the generators and the regulator, and that the regulator's ability to restrain prices has become weaker. Two possible reasons for this are that it is hard for a regulator to intervene repeatedly or (conversely) that, because history has shown that the regulator cannot be deterred, the incentives of the generators to try to restrain prices have been reduced. For example, once it became clear that the Pool was going to be replaced (the first review started in 1998) the incentive of the generators to limit price to prevent change could well have been diminished. If the regulator has played a key role in determining the level of prices then this suggests that simply changing the structure of the mechanisms that govern the market, as is being attempted under NETA, will not solve the regulator's problems.

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[39] In my sample, over 60% of coal units (on average) submitted exactly the same bids and availability as they submitted the same before and a further 10% only changed their Table A Bid by less than £1/MWh.

Appendix 1: Data Appendix

The analysis uses data purchased from ESIS Ltd. on market clearing prices and volumes for each half-hour, generator's bids and their availability declarations. I also used a number of sources to produce estimates of generators' marginal costs. This Appendix gives details of variable construction. Table A1 gives summary statistics for bids and some of the constructed variables.

A1.1 Price Data

For each half-hour period I use the "Ex-post" SMP and PSP figures. These occasionally differ from the SMP set day ahead due to recalculations, and are the prices used to pay generators and settle Pool transactions. The demand figure used is the forecast demand to be met by centrally dispatched units (known as QO). The data also identifies the unit setting the marginal price. Ownership was identified using a number of published sources, including NGC (2000) and the "Producer identifier" included in the bidding data.

The sequence of prices covers every half-hour from 1 January 1995-30 September 2000.

A1.2 Bid and Availability Data

There are several elements of each bid (start-up, no-load and three incremental energy prices along with elbow points specifying where the elbow points apply). I combine them to form a single bid price, equivalent to the "Table A Bid Price" used by NGC, using the formulae below from Appendix E of NGC(2000).

$$Bid = \frac{No\ Load + Inc1 * Elbow1 + Inc2 * (Elbow2 - Elbow1) + Inc3 * (Avail - Elbow2)}{Avail}$$
$$if\ \ Avail > Elbow2$$

$$Bid = \frac{No\ Load + Inc1 * Elbow1 + Inc2 * (Avail - Elbow1)}{Avail}$$
$$if\ \ Elbow2 > Avail > Elbow1$$

$$Bid = \frac{No\ Load + Inc1 * Avail}{Avail}$$
$$if\ \ Elbow1 > Avail$$

Availability is measured by the maximum MW declared available at the time of making the bid available during any period during the day to which the bid applies (running from 10am to 10am the next day). In the terminology of the Pool this quantity is known as XA_i. Of course, availability may turn out to be different from this (due to outages etc.) but the day-ahead measure is the appropriate measure for determining the SMP. This measure of availability is used to calculate bids and to measure availability.

I have data on the bids of all generating units, including the nuclear units and interconnectors from 1 January 1995-30 September 2000, with only a few missing observations (at the start of 1997 for a few coal plants owned by Eastern).

A1.3 Marginal Cost Data

I calculate the marginal fuel cost per MWh for each coal station using information on heat rates and fuel prices. I do not attempt to estimate other elements of marginal cost, for example labour costs or transport costs.[40]

Heat rates for coal plants come from two main sources: Richard Green, who kindly provided me with the data used in Green and Newbery (1992), and McCloskey's *UK Coal Power Stations* report. These correspond to the main sources used by Wolfram (1998) and (1999). Of course, these are more out of date by the late 1990s than they are for her studies of the E&W market in the early 1990s. This should be less of an issue for established coal plants, unless there is major refitting going on (anecdotally only two coal plants are fitted with FGD technology). As a check I also examined information from OXERA's *UtilityView Generation* database and the environmental reports (which give fuel inputs and electricity outputs for each station) drawn up by the major generators. These suggested that actual efficiency rates are slightly below the Green/McCloskey heat rates, by two or three percentage points. Of course, the environmental numbers reflect how the plants are operated and would be reduced by strategic operation. In preference, I therefore use the numbers from Green, and from McCloskey for any missing values (McCloskey numbers are very similar to those of Green).

In the mark-up calculation in Section 4 I use the average contract prices reported in the press for power stations purchasing UK coal. These contracts were renegotiated in March 1998, with the reported price falling from 137p/GJ to 122p/GJ. I also did all the calculations using prices for Australian coal delivered to Europe from *International Financial Statistics* which goers up to the end of 1999. Use of these prices give higher mark-ups for coal plants, but as I am primarily

[40] In the Wolfram IV regression equations I also included a measure of the number of miles from coal plants to their primary coalfield when the stations were operated by the CEGB using information from

interested in differences between coal plants, and use the same fuel prices for all coal plants whichever prices I use, this does not affect the pattern of the results. One point about the efficiency data should be noted: it is at the station rather than the unit level (there are on average about four units in each coal plants). Assuming that all units were installed in coal plants at the same time this may not be an excessive simplification.

To calculate the moving average mark-ups I also need to calculate mark-ups on other plant types. For pumped plants I assume that their fuel cost is the average PSP of electricity the following evening (11pm-5am), and I assume an efficiency of 66%, which is similar to that implied by the costs assumed in Green and Newbery (1992). Oil station efficiencies are given in the Green data, and fuel prices are the Heavy Fuel Oil 3.5% (CIF for NW Europe) weekly prices from Datastream.[41] EdF and Scottish producers supplying via the interconnectors are assumed to bid at cost (zero markup). The same assumption is made for the few occasions when prices are set by Demand Side Bidders.[42] Peaking gas plants are assumed to have an efficiency of 20% (Green and Newbery use a band of 18-25%) and their input fuel costs are given by the Gas Oil (CIF for the EEC) weekly prices taken from Datastream. CCGT efficiencies are taken from the OXERA database where available, with gaps filled in by taking the average of efficiencies reported for plants opening in the same year. Natural gas prices are the International Petroleum Exchange (London) One Month Ahead weekly prices from 1997, and prior to this I use the Natural Gas for Electricity Generation quarterly series from *Energy Prices and Taxes* (IEA).

A1.4 Definition of Variables used in Wolfram IV regression equations

The basic specification used is:

$$Log(MarkUp_{ijt}+10) = \beta_1 * Log(Availability\ Below)_{ijt} + \beta_2 * Log(Capacity)_{ijt} + \beta_3 * Bid\ I_{ijt} + $$
$$+\beta_4 * Log(Demand)_t + unit-time\ dummies + \varepsilon_{ijt}$$

McCloskey (1993). This figure turned out to be insignificant. One explanation for this is that, by the late 1990s, plants more distant from the few remaining UK coalfields were more likely to use imported coal.

[41] Dual coal/oil plants are treated as coal plants as, using my data, coal production is cheaper than oil production. The environmental reports suggest that it is coal that is mainly used during this period at those stations.

[42] The Demand Side Bidding Scheme was a very limited scheme under which about 30 large customers are allowed to bid to reduce their demand based on prices. From the point of view of setting prices they are treated like generators.

with interactions included for the first three variables (which are those of primary interest) by period and, in a second specification, by owner. The variable definitions are as follows.

Mark-Up: the unit's bid price calculated as above minus the estimated marginal fuel cost, calculated from the heat rates and fuel prices (the results reported actually use the Australian coal prices). Following Wolfram I add 10 to the bids in order to reduce the number of observations lost due to bids being just below marginal costs. This primarily affects the very low bids in early 1995.

Availability Below: the amount of capacity (MW) a generator owns that has bids below that of the unit in question (i.e., the amount of inframarginal capacity). As high bids will increase the unit's position in the merit order, there is simple mechanical (positive) relationship between a high bid and this variable, creating an endogeniety problem. For this reason an instrument is used: **Availability Below IV**. Instead of being ordered on its actual bid, units are ordered by all their bids on weekdays (weekends) in the quarter. I then calculate availability below based on this measure, and this number forms the instruments. As unit-quarter-weekday (-end) dummies are also included, identification comes simply from variation in the availability of other units during weekdays and weekends in the quarter, and not via the availability or bids of the unit itself. As long as the availability of other units is not correlated with the error in the unit in question's bid (possible if availability decisions are made strategically) then the endogeneity problem should be overcome.

Capacity: the maximum capacity declared available by the unit on the day in question. The unit-quarter-weekday dummies implies that identification of this variables comes from deviation in capacity relative to the quarter-weekday/end average.

Bid Impact: measured by taking the quarter-weekday (weekend) ranking used to construct the instrumental variable and finding the nearest unit above the unit in question which is owned by another operator. If this unit is available on the day Bid Impact is 1, otherwise it is zero. This variable is intending to proxy the degree of competition facing the unit to be included in the merit order.

Net Demand: Total forecast of demand required from centrally dispatched units (Q0) less the supply of nuclear plants, interconnectors and independent CCGT. Using demand alone produces similar results. This variable is included as a control.

Unit-quarter-weekday (weekend) dummies: the inclusion of these dummies also limits the extent to which mis-measurement of costs should play a role in the results, assuming that costs remain fairly similar over a quarter.

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FIGURE 1: LOAD DURATION CURVES JANUARY – JULY 1997

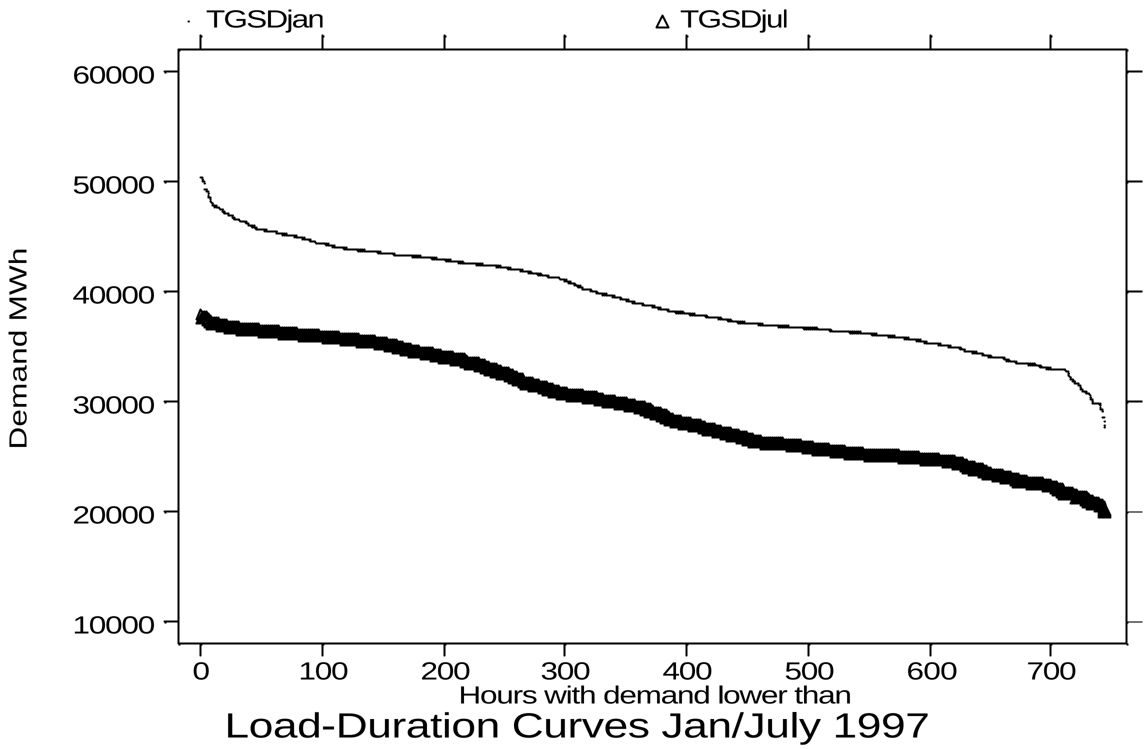
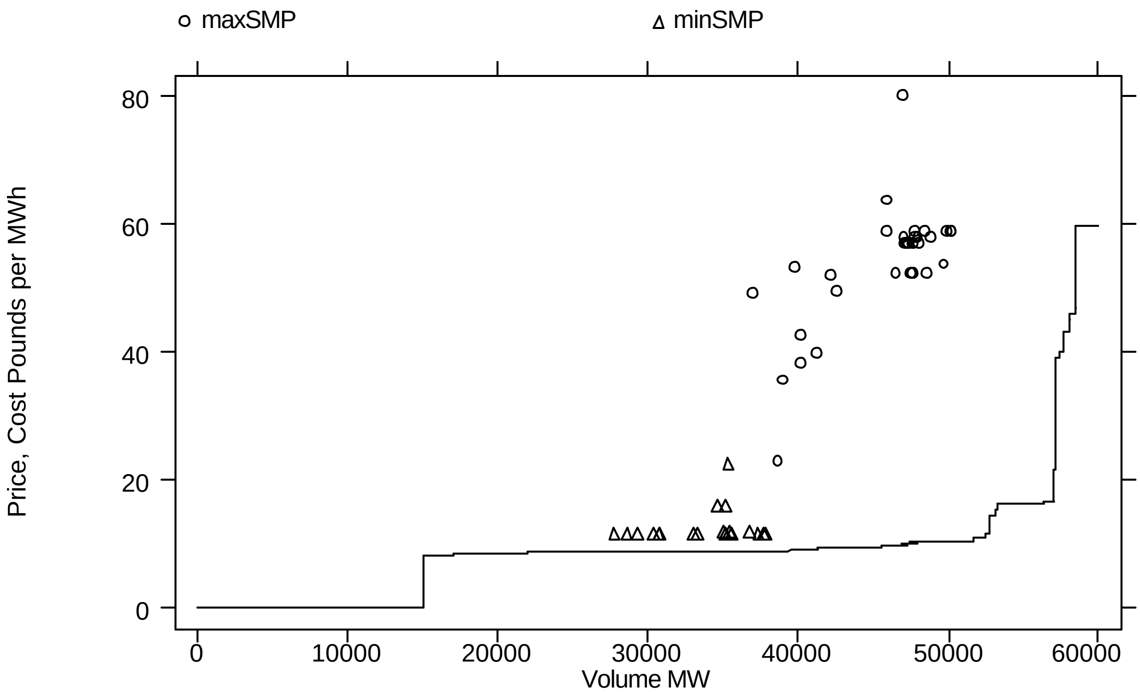
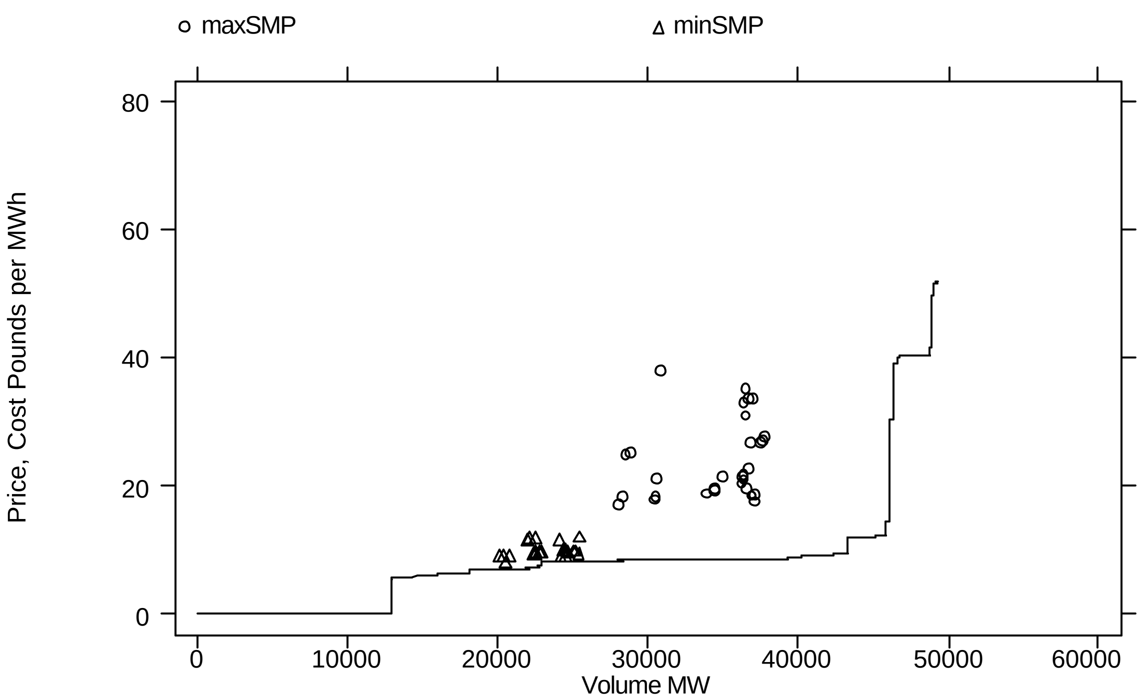


FIGURE 2: Estimated Marginal Fuel Cost Supply Curves for 15 January and 15 July 1997 and Daily Maximum and Minimum SMPs for January and July 1997



January 1997



July 1997

FIGURE 3 (a) : 30-Day Moving Average of SMP (£/ MWh) 1995-2000

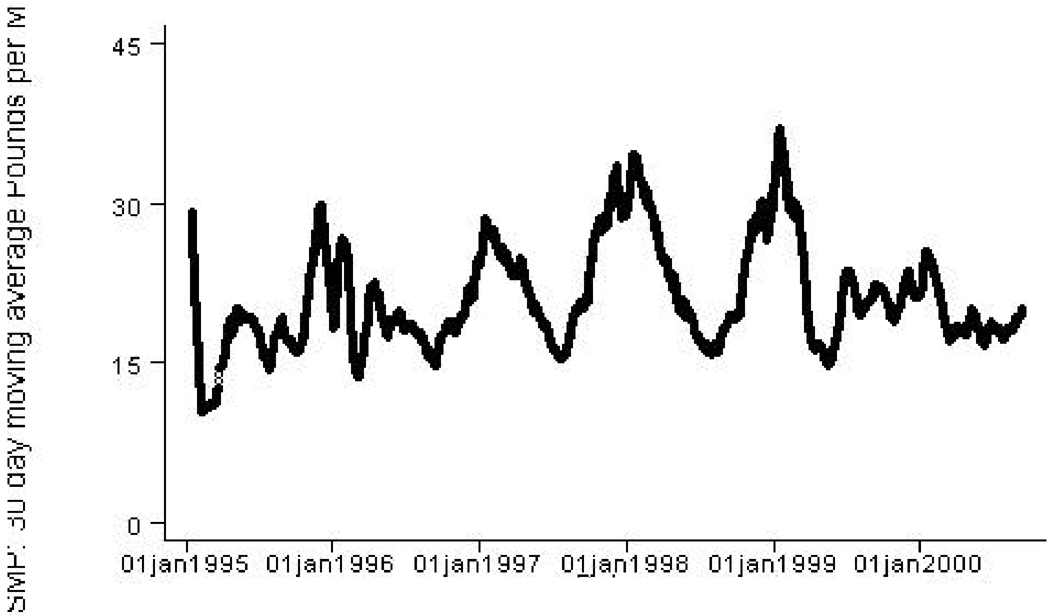


FIGURE 3(b) : 30-Day Moving Average of the Difference between PSP and SMP (£/MWh) 1995-2000

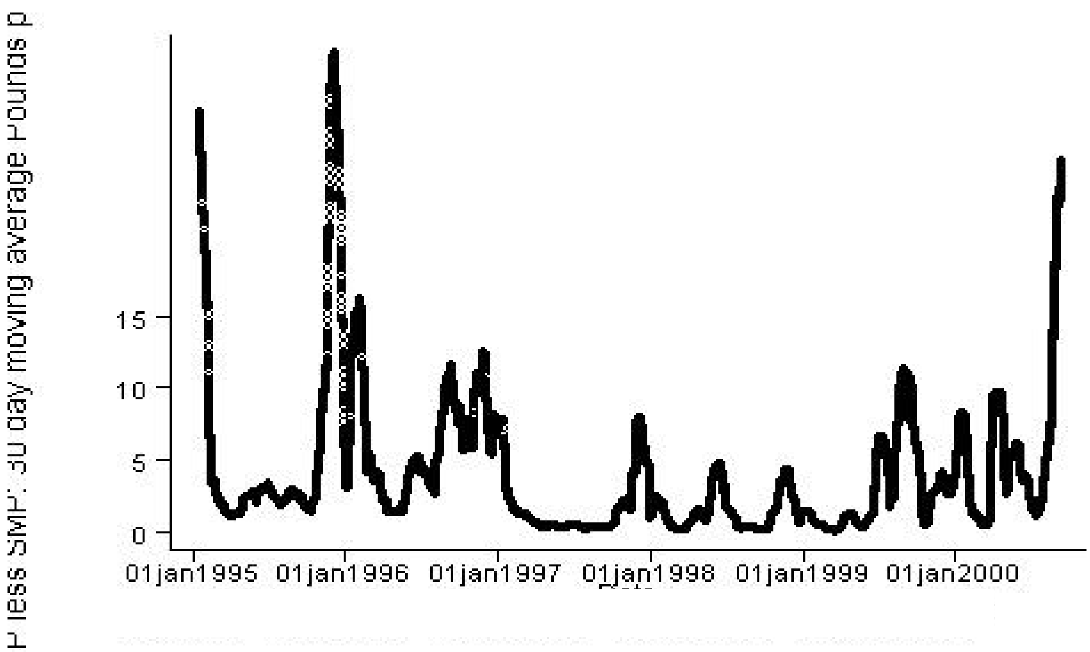


FIGURE 4 (a) SMP Lerner Index 1995 –2000

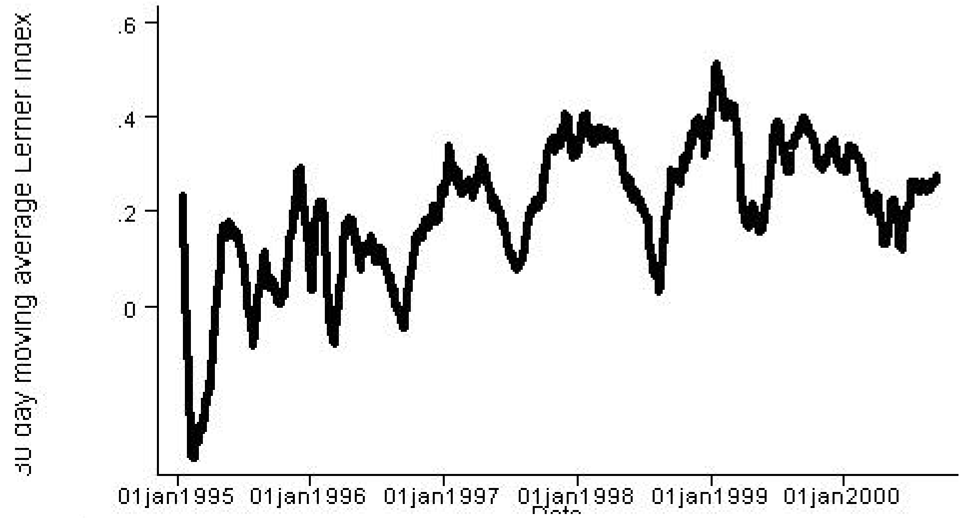


FIGURE 4 (b) PSP Lerner Index 1995-2000

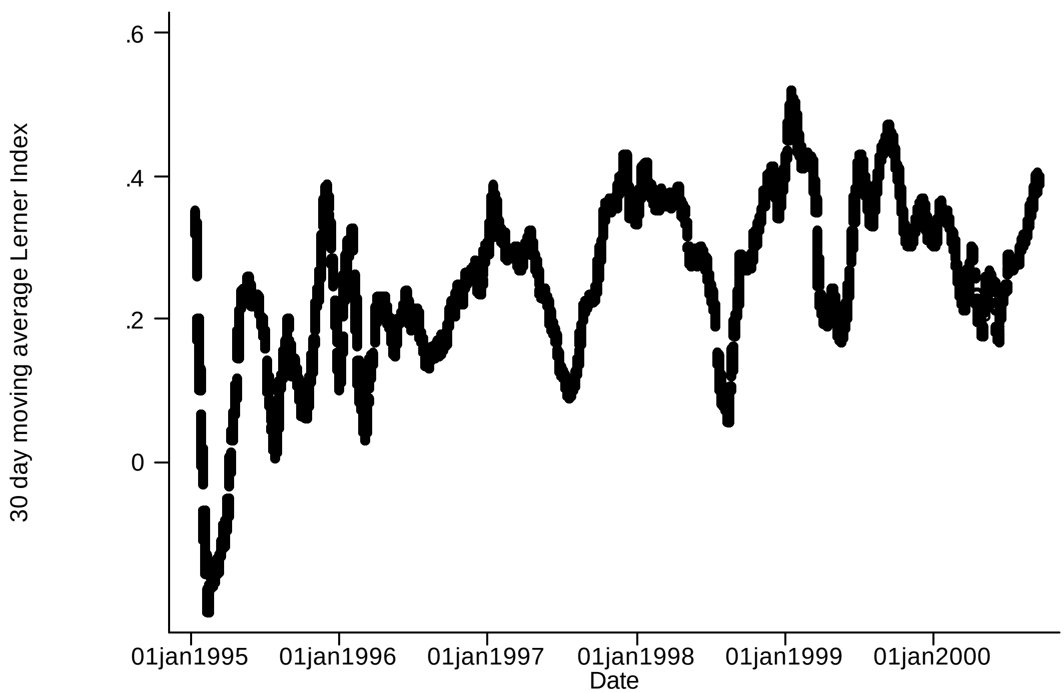


TABLE 1: CAPACITY SHARES

(a) Ownership Shares of Capacity % (based on capacity bid, excluding Interconnectors)												
	Jan-Mar '95	Apr-Sept '95	Oct '95-Mar '96	Apr– Sept '96	Oct '96 – Mar '97	Apr–Sept '97	Oct '97 – Mar '98	Apr-Sept '98	Oct '98 – Mar '99	Apr-Sept '99	Oct '99 – Mar '00	Apr–Sept '00
NP	40.9	37.0	37.8	31.5	27.0	26.7	29.6	27.7	27.7	24.7	21.3	12.7
PG	30.2	28.5	29.2	27.6	26.7	25.7	24.2	21.9	22.1	21.8	17.9	18.9
Eastern	0.7	0.8	0.8	5.7	11.1	9.8	12.1	11.2	10.9	10.4	11.1	8.9
BE	-	-	-	13.6	11.8	13.7	11.8	13.6	12.5	16.4	11.0	16.4
BNFL/NE	15.6	19.4	17.3	5.7	6.0	6.0	6.0	6.0	5.9	5.5	4.9	3.6
AES	-	-	-	0.0	0.0	0.6	0.3	0.8	0.7	0.8	4.7	9.0
EFM	0.4	0.5	2.9	4.8	4.5	4.7	4.6	6.3	4.4	6.3	11.1	10.6
NGC	4.4	4.4	1.8	-	-	-	-	-	-	-	-	-
Other	7.6	9.2	10.8	10.9	11.9	12.7	11.4	13.9	15.7	17.9	17.9	19.9
(b) Fuel Shares of Capacity Bid % (excluding Interconnectors)												
Coal	55.0	52.1	52.3	49.0	47.9	44.3	47.8	43.9	43.7	39.1	42.0	39.3
CCGT	13.7	14.9	16.5	19.1	20.1	22.5	21.8	23.9	26.4	29.6	29.9	31.3
Oil	8.9	6.7	6.7	5.3	5.5	5.2	4.9	4.3	4.1	5.3	4.8	4.2
Gas	2.4	2.2	2.8	2.9	3.4	3.8	3.4	3.8	3.3	3.7	3.3	3.4
Nuclear	15.6	19.4	17.4	19.3	18.8	19.9	17.8	19.7	18.5	17.9	15.6	17.0
Pumped	4.4	4.4	4.3	4.3	4.0	4.2	4.1	4.3	4.0	4.2	4.1	4.4

Comparison with 1990/91:
Based on output shares, excluding imports, from Green (1998), Figure 4, pg. 15
NP: 50%, PG 32%, Nuclear Electric 16%

TABLE 2 : RESULTS OF COURNOT MODEL OF E&W ELECTRICITY MARKET

	Scenario 1: 1995, NP and PG duopoly, NGC owns PS	Scenario 2: 1997, Eastern Divestiture, ₤6/MWh premium	Scenario 3: 1997, Eastern Divestiture, no premium	Scenario 4: 1999, Eastern, EFM, AES Divestiture, ₤6/MWh premium, EFM owns pumped	Scenario 5: 1999, Eastern, EFM, AES Divestiture, no premium, EFM owns pumped	Scenario 6: 1999, Eastern, EFM, AES Divestiture, ₤6/MWh premium, NGC owns pumped
Price (₤/MWh)	**48.7**	**41.6**	**40.4**	**33.5**	**32.5**	**32.5**
Quantities (MWh):						
Independent* (assm)	**26100**	**26870**	**26870**	**27900**	**27900**	**27900**
NP	**8115.4**	**6330.8**	**6099.6**	**4708.9**	**4542.7**	**4532.7**
PG	**7729.2**	**6259.7**	**6034.5**	**4817.3**	**4658.5**	**4648.3**
Eastern	**-**	**4057.2**	**4803.8**	**2893.0**	**3710.3**	**3036.0**
EFM	**-**	**2085.3**	**2085.3**	**4021.4**	**3893.9**	**2733.4**
AES	**-**	**-**	**-**	**3290.0**	**3157.8**	**3149.38**
NGC	**1879.2**	**-**	**-**	**-**	**-**	**1879.2**
Oligopoly	**17724**	**18733**	**19023**	**19730**	**19963**	**19979**
Productive Inefficiency (costs/ideal costs)	**1.003**	**1.032**	**1.043**	**1.020**	**1.021**	**1.030**

* independents include EFM, AES and Eastern prior to them becoming coal owners

TABLE 3 : SMP and PSP/SMP ratios 1991-2000

Period	SMP ₤	SMP/PSP	SMP Table A ₤	SMP Table B ₤
Patrick and Wolak (1997)				
Apr 91-Mar 92	19.52 (4.10)	0.92 (0.11)	-	-
Apr 92 – Mar 93	22.64 (4.24)	0.94 (0.05)	-	-
Apr 93 – Mar 94	24.16 (6.71)	0.92 (0.06)	-	-
Apr 94 – Mar 95	20.78 (12.28)	0.90 (0.12)	-	-
Current Sample				
Jan – Mar 95	17.0 (14.2)	0.87 (0.20)	21.0 (16.1)	9.4 (2.3)
Apr – Sept 95	17.7 (17.8)	0.90 (0.08)	20.2 (19.5)	9.1 (1.2)
Oct 95 – Mar 96	21.1 (12.3)	0.88 (0.17)	24.5 (12.0)	9.5 (1.6)
Apr – Sept 96	18.3 (9.7)	0.87 (0.16)	20.7 (9.5)	8.9 (0.5)
Oct 96 – Mar 97	22.7 (12.3)	0.91 (0.13)	25.8 (12.2)	11.6 (1.5)
Apr – Sept 97	19.4 (9.0)	0.99 (0.02)	20.8 (8.9)	10.6 (1.0)
Oct 97 – Mar 98	29.5 (16.8)	0.98 (0.07)	32.9 (16.5)	13.2 (3.7)
Apr – Sept 98	19.2 (11.0)	0.98 (0.09)	20.9 (11.3)	10.7 (2.8)
Oct 98 – Mar 99	28.0 (18.1)	0.98 (0.06)	31.3 (17.9)	10.3 (2.6)
Apr – Sept 99	19.1 (8.2)	0.93 (0.16)	21.0 (11.3)	11.2 (1.9)
Oct 99 – Mar 00	21.1 (9.9)	0.97 (0.10)	24.0 (9.8)	12.3 (1.8)
Apr – Sept 00	18.4 (8.5)	0.88 (0.22)	20.7 (8.4)	10.7 (1.3)

TABLE 4(a) : SHARES AND AVERAGE SMP SET BY COAL PLANTS AND PUMPED ST0RAGE PLANTS, BY TABLE PERIOD 1995-2000

(i) Shares of Price Setting (%) and Average SMP set by coal plants and Average SMP for pumped storage plants in Table A periods

	Jan-Mar '95	Apr-Sept '95	Oct '95-Mar '96	Apr– Sept '96	Oct '96 – Mar '97	Apr–Sept '97	Oct '97 – Mar '98	Apr-Sept '98	Oct '98 – Mar '99	Apr-Sept '99	Oct '99 – Mar '00	Apr–Sept '00
COAL PLANTS												
NP	85.0% 16.7 (9.8)	70.2% 17.0 (25.2)	75.9% 21.6 (9.5)	59.1% 18.8 (7.2)	43.7% 23.1 (9.3)	43.7% 18.3 (5.5)	46.3% 29.7 (11.8)	35.4% 16.5 (6.1)	29.2% 29.0 (15.0)	44.4% 20.4 (5.3)	31.5% 21.1 (6.3)	12.5% 16.3 (4.1)
PG	15.0% 33.8 (11.4)	29.8% 18.6 (5.8)	25.0% 25.5 (11.9)	34.3% 17.1 (4.9)	26.2% 22.4 (8.6)	34.6% 17.9 (5.2)	28.5% 29.7 (11.3)	35.0% 16.7 (5.1)	26.1% 28.1 (13.6)	28.0% 22.0 (7.1)	14.8% 21.8 (6.6)	18.3% 19.7 (5.3)
Eastern	-	-	-	6.6% 19.1 (6.9)	30.0% 27.1 (12.9)	21.7% 25.0 (9.5)	25.2% 32.9 (22.4)	29.6% 27.5 (16.4)	44.7% 31.6 (18.6)	22.0% 23.8 (6.1)	30.2% 26.9 (9.6)	17.0% 25.3 (10.0)
EFM	-	-	-	-	-	-	-	-	-	5.6% 19.2 (7.9)	16.2% 20.2 (5.5)	17.0% 19.5 (5.6)
AES	-	-	-	-	-	-	-	-	-	-	6.7% 17.4 (4.2)	23.7% 17.4 (3.9)
BE	-	-	-	-	-	-	-	-	-	-	0.6% 18.5 (5.6)	11.5% 20.1 (6.4)
PUMPED STORAGE PLANTS												
NGC	32.7 (10.3)	31.0 (7.8)	35.0 (10.7)	-	-	-	-	-	-	-	-	-
EFM	-	-	33.8 (11.8)	31.3 (10.2)	37.3 (13.8)	33.8 (10.8)	47.2 (17.3)	30.6 (9.3)	43.8 (17.2)	36.5 (10.5)	42.3 (11.5)	34.8 (9.1)

(ii) Shares of Price Setting (%) and Average SMP Mark-Ups set by coal plants in Table B periods

	Jan-Mar '95	Apr-Sept '95	Oct '95-Mar '96	Apr– Sept '96	Oct '96 – Mar '97	Apr–Sept '97	Oct '97 – Mar '98	Apr-Sept '98	Oct '98 – Mar '99	Apr-Sept '99	Oct '99 – Mar '00	Apr–Sept '00
COAL PLANTS												
NP	70.7% 8.9 (1.6)	59.0% 9.1 (1.0)	37.8% 9.2 (0.9)	66.3% 9.0 (0.3)	41.6% 11.6 (2.0)	58.9% 10.8 (0.9)	74.6% 13.4 (4.0)	61.4% 11.0 (2.5)	66.1% 10.3 (2.3)	57.7% 11.3 (1.2)	39.9% 12.1 (0.6)	24.9% 11.1 (0.5)
PG	29.3% 9.2 (1.6)	41.0% 9.0 (0.9)	62.2% 9.4 (1.2)	33.6% 9.0 (0.3)	39.8% 11.4 (0.8)	33.4% 10.8 (0.8)	16.0% 12.7 (2.8)	38.1% 11.0 (2.4)	33.0% 10.0 (1.7)	32.2% 11.7 (1.66)	14.2% 11.9 (0.7)	18.1% 11.3 (0.4)
Eastern	-	-	-	0.1% 12.1 (3.7)	18.6% 11.8 (0.3)	7.6% 11.2 (1.0)	9.3% 11.7 (1.9)	0.5% 16.0 (0.3)	0.9% 16.6 (14.6)	6.8% 13.0 (1.0)	5.6% 12.5 (0.8)	2.1% 11.1 (0.8)
EFM	-	-	-	-	-	-	-	-	-	3.3% 12.9 (1.8)	19.4% 12.1 (0.8)	15.4% 10.4 (0.7)
AES	-	-	-	-	-	-	-	-	-	-	20.8% 11.6 (0.8)	39.0% 11.2 (0.5)
BE	-	-	-	-	-	-	-	-	-	-	0.1% 11.1 (0.1)	0.5% 11.7 (0.5)

TABLE 4(b) : SHARES OF THE SMP-SETTING UNIT 1995-2000

(i) Ownership Shares of Price Setting Unit % (Other category mainly composed of Demand Side Bidders, - if never set price) – ALL FUEL TYPES												
	Jan-Mar '95	Apr-Sept '95	Oct '95-Mar '96	Apr– Sept '96	Oct '96 – Mar '97	Apr–Sept '97	Oct '97 – Mar '98	Apr-Sept '98	Oct '98 – Mar '99	Apr-Sept '99	Oct '99 – Mar '00	Apr–Sept '00
NP	62.0	50.4	49.1	45.8	35.5	36.1	42.1	30.5	28.7	33.6	26.8	11.4
PG	17.5	32.1	33.7	31.5	25.8	34.5	27.6	34.1	27.9	28.2	15.0	18.9
Eastern	0.0	0.0	-	5.0	23.9	15.4	18.2	20.7	31.5	14.5	19.4	9.7
BE	-	-	-	-	-	-	-	-	-	-	0.0	6.3
BNFL	-	-	-	-	-	-	-	-	-	-	-	-
AES	-	-	-	-	-	-	0.0	0.0	1.7	0.4	8.5	23.3
EFM	-	-	5.9	16.0	11.1	9.8	11.0	11.6	3.5	7.1	18.8	19.6
NGC	10.0	16.3	6.6	-	-	-	-	-	-	-	-	-
Interc	10.3	0.9	4.6	1.6	3.5	4.0	0.0	2.7	4.6	15.6	11.0	9.6
Other	0.0	0.0	0.1	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(ii) Fuel Shares of Price Setting Unit% (Other category mainly composed of Demand Side Bidders, - if never set price) - ALL FUEL TYPES												
Coal	72.9	81.6	81.3	80.5	83.5	85.2	87.6	81.6	87.4	79.0	83.0	78.0
CCGT	5.9	1.7	0.3	1.8	1.8	1.0	0.3	3.6	-	1.4	0.2	4.4
Oil	6.0	1.0	1.5	-	0.0	-	-		-	-	-	-
Gas	-	-	-	-	-	0	0.4	0.2	1.6	0.6	0.5	0.4
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-
Pumped	7.6	14.8	11.8	16.0	11.1	9.8	11.0	11.6	3.5	3.4	5.2	7.6
Interc	10.3	0.9	4.6	1.6	3.5	4.0	0.0	2.7	4.6	15.6	11.0	9.6
Other	0.0	0.0	0.1	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Interc=Interconnector

Comparison 1991/92: HHI in price setting was 7,000 (cf. 4,350 in Jan-Mar 1995) (OFGEM, 1999, Figure 14.4).

TABLE 5 : AVERAGE BIDS OF COAL PLANTS AND PUMPED STATIONS 1995-2000

	Jan-Mar 95	Apr-Sept 95	Oct 95-Mar 96	Apr-Sept 96	Oct 96 - Mar 97	Apr-Sept 97	Oct 97 - Mar 98	Apr-Sept 98	Oct 98-Mar 99	Apr-Sept 99	Oct 99-Mar 00	Apr-Sept 00
NP stations												
Aberthaw A	34.3	13.9	14.0	8.3	26.3	13.8	26.9	22.5	32.9	26.3	20.9	15.1
	(39.8)	(2.8)	(5.7)	(3.7)	(77.1)	(4.2)	(7.8)	(7.8)	(12.5)	(10.0)	(7.5)	(3.8)
Aberthaw B	8.5	13.7	14.9	14.1	12.1	16.4	27.6	24.1	35.7	32.6	20.7	13.3
	(9.1)	(3.2)	(6.5)	(3.0)	(5.0)	(4.0)	(7.8)	(7.0)	(11.0)	(10.9)	(7.8)	(1.8)
Blyth A	12.5	16.8	18.3	18.7	25.4	25.6	36.6	23.6	43.6	-	-	-
	(7.9)	(6.0)	(6.6)	(7.8)	(9.5)	(8.6)	(7.8)	(6.9)	(11.1)	-	-	-
Blyth B	9.3	14.5	13.9	15.31	23.2	20.3	30.1	19.6	34.3	68.7	80.1	-
	(2.4)	(17.2)	(3.3)	(3.3)	(7.8)	(5.1)	(8.1)	(6.1)	(14.2)	(10.40	(8.3)	-
Didcot A	13.8	22.2	23.9	21.7	26.2	12.5	30.5	21.9	33.5	27.0	23.0	14.4
	(9.1)	(6.3)	(7.1)	(12.5)	(30.1)	(7.0)	(7.3)	(7.2)	(13.2)	(9.7)	(6.6)	(3.4)
Tilbury	10.4	15.7	20.6	20.9	27.0	19.2	29.3	16.5	23.8	20.9	22.1	13.0
	(9.0)	(4.4)	(6.8)	(9.5)	(43.9)	(6.2)	(7.4)	(3.1)	(12.3)	(6.5)	(7.1)	(1.6)
Willington B	13.2	16.9	22.3	32.4	28.6	20.8	37.0	20.8	30.4	-	-	-
	(9.4)	(4.4)	(7.1)	(29.6)	(8.0)	(4.1)	(6.7)	(6.7)	(11.0)	-	-	-
PG stations												
Cottam	4.7	7.9	6.9	12.0	18.3	16.1	21.6	14.7	25.1	20.3	19.5	19.7
	(0.4)	(4.4)	(4.3)	(6.5)	(8.6)	(6.0)	(9.1)	(5.3)	(13.1)	(7.0)	(8.5)	(5.8)
Ince	4.3	5.2	2.5	3.1	0.7	-	-	-	-	-	-	-
	(0.3)	(0.8)	(1.2)	(1.6)	(1.2)	-	-	-	-	-	-	-
Kingsnorth	10.3	20.4	19.1	12.8	20.1	18.4	23.9	16.3	21.0	20.5	19.8	17.9
	(11.3)	(8.2)	(9.9)	(5.7)	(100.9)	(4.7)	(7.8)	(7.4)	(11.1)	(6.2)	(7.0)	(4.7)
Ratcliffe	4.6	8.3	6.9	11.4	18.9	16.8	22.7	14.3	24.5	19.4	19.0	19.0
	(0.8)	(4.7)	(4.0)	(5.6)	(8.9)	(6.0)	(9.5)	(5.6)	(12.8)	(6.5)	(6.4)	(5.4)
NP stations divested to Eastern April 1996												
Ironbridge B	10.3	14.4	19.7	30.0	19.8	15.0	14.3	16.6	21.9	20.3	22.2	22.6
	(9.6)	(2.1)	(6.5)	(8.8)	(11.9)	(7.2)	(9.0)	(8.4)	(14.1)	(5.6)	(5.5)	(3.4)
Rugeley B	7.7	9.2	7.7	18.2	14.6	14.7	8.7	15.2	8.6	15.2	17.9	19.7
	(7.8)	(2.3)	(1.4)	(10.8)	(43.3)	(9.0)	(9.9)	(9.4)	(7.1)	(5.8)	(3.2)	(4.4)
West Burton	4.2	12.5	12.4	11.4	12.3	13.5	10.7	13.8	13.9	17.1	18.6	18.5
	(2.7)	(3.0)	(5.6)	(9.1)	(39.2)	(6.2)	(9.5)	(8.1)	(8.8)	(4.4)	(3.5)	(3.9)
PG stations divested to Eastern April 1996												
Drakelow C	13.6	25.6	23.9	36.9	14.9	14.1	10.9	20.6	13.5	17.2	21.0	14.4
	(11.9)	(6.9)	(9.1)	(11.6)	(11.9)	(10.2)	(7.7)	(12.0)	(10.3)	(6.8)	(7.9)	(2.6)
High Marnham	11.9	27.6	24.6	37.1	15.1	15.1	14.6	15.6	19.6	21.9	25.9	12.7
	(10.5)	(11.8)	(10.2)	(15.4)	(9.2)	(9.6)	(11.3)	(11.6)	(12.7)	(5.6)	(5.5)	(1.9)
PG stations divested to EFM July 1999												
Ferrybridge	4.1	7.5	6.5	12.5	19.6	20.3	19.8	15.4	23.7	19.2	12.6	16.5
	(1.0)	(4.4)	(4.9)	(12.8)	(10.9)	(15.1)	(7.8)	(5.8)	(12.2)	(8.4)	(2.7)	(5.3)
Fiddler's Ferry	4.6	14.5	13.4	9.8	17.3	19.8	24.6	19.1	27.5	19.9	15.5	16.3
	(3.1)	(6.5)	(8.9)	(4.9)	(10.6)	(8.8)	(9.1)	(18.0)	(17.6)	(8.4)	(5.0)	(5.3)
NP station divested to AES November 1999												
Drax	4.0	8.1	7.7	6.2	7.8	10.5	17.1	10.4	16.6	16.2	14.1	13.8
	(2.7)	(1.8)	(2.1)	(2.3)	(2.9)	(4.8)	(4.6)	(4.3)	(9.4)	(3.9)	(2.4)	(1.7)
NP station divested to BE February 2000												
Eggborough	4.1	10.4	7.3	11.5	19.8	18.2	25.7	14.9	28.5	20.0	16.4	16.0
	(2.6)	(24.4)	(1.8)	(4.4)	(6.2)	(6.6)	(9.5)	(4.4)	(11.3)	(5.6)	(4.2)	(3.3)
Pumped stations bought by EFM from NGC December 1995												
Dinorwig	31.1	30.1	32.7	31.1	33.6	34.5	43.4	33.5	43.1	39.7	40.3	42.6
	(10.0)	(10.5)	(10.1)	(10.9)	(11.9)	(12.3)	(19.9)	(11.2)	(23.8)	(21.3)	(17.3)	(16.8)
Ffestiniog	37.4	38.8	41.2	36.8	39.6	43.4	54.2	38.4	55.1	42.5	46.5	47.7
	(7.6)	(12.2)	(11.3)	(8.9)	(8.3)	(7.1)	(16.4)	(9.7)	(23.5)	(23.3)	(20.4)	(20.7)

Definitions: Average bid (£/MWh) of all units in station on days when some capacity is available. Standard deviations in parentheses. Double lines mark start of season before divestiture

TABLE 6: RESULTS FROM WOLFRAM (1998)-STYLE STRATEGIC BIDDING REGRESSIONS

Method: IV using Log(Availability Below IV) as an instrument. Standard errors corrected with heteroskedasticity across generating units and autocorrelation within units. All regressions contain a set of generating unit-quarter-weekday/-end dummies as well as weekday dummies. Dependent variable is Log(Mark-Up+10). Variable definitions in Appendix 1.

Time Interactions only		**Time-Owner Interactions**	
	(1) Coal units		**(2) Coal units**
Log(Availability)	0.198 (0.083) **	Log(Availability)	0.201 (0.082)**
Log(Availability)*Time 1	0.115 (0.121)	Log(Availability) * Time 1 * NP/PG	0.344 (0.094)***
Log(Availability)*Time 2	-0.019 (0.077)	Log (Availability) * Time 2 * NP/PG	-0.005 (0.080)
Log(Capacity)	-0.417 (0.117) ***	Log (Availability) * non-NP/PG	*No coal units*
Log(Capacity)*Time 1	0.370 (0.180) **	Log (Availability) * Time 1 * non-NP/PG	-0.188 (0.175)
Log(Capacity)*Time 2	0.222 (0.140)	Log (Availability) * Time 2 * non-NP/PG	-0.036 (0.074)
Bid Impact	-0.002 (0.004)	Log (Capacity)	-0.417 (0.117)***
Bid Impact * Time 1	0.004 (0.002)	Log (Capacity) * Time 1 * NP/PG	0.204 (0.140)
Bid Impact * Time 2	0.0009 (0.002)	Log (Capacity) * Time 2 * NP/PG	0.145 (0.140)
Log (Net Demand)	0.060 (0.019) ***	Log (Capacity) * non-NP/PG	*No coal units*
		Log (Capacity) * Time 1 * non-NP/PG	0.825 (0.236) ***
Constant	0.009 (0.003) ***	Log (Capacity) * Time 2 * non-NP/PG	0.309 (0.186) *
# of observations	101,915	Bid Impact	-0.002 (0.004)
		Bid Impact * Time 1 * NP/PG	0.003 (0.002)
		Bid Impact * Time 2 * NP/PG	0.002 (0.002)
		Bid Impact * non-NP/PG	-0.002 (0.004)
		Bid Impact * Time 1 * non-NP/PG	0.003 (0.002)
		Bid Impact * Time 2 * non-NP/PG	-0.0004 (0.002)
		Log (Net Demand)	0.055 (0.025) **
		Constant	0.009 (0.002) ***
		# of observations	101,915

*** indicates significance at 1% level, ** 5% level, * 10% level

TABLE 7: AVAILABILITY (Within Day, (Standard Deviation), Availability in Season)

Fuel (NERC)	Owner (P&W)	Jan-Mar 95	Apr-Sept 95	Oct 95-Mar 96	Apr-Sept 96	Oct 96–Mar 97	Apr-Sept 97	Oct 97 -Mar 98	Apr-Sept 98	Oct 98-Mar 99	Apr-Sept 99	Oct 99-Mar 00	Apr-Sept 00
CCGT 0.802	**AES** -	-	-	-	-	-	-	-	0.9808 (0.0949) 0.6596	0.9998 (0.0024) 0.9876	1.0000 (0.0000) 0.9457	1.0000 (0.0000) 0.9938	0.9929 (0.0265) 0.8866
CCGT 0.802	**EFM** -	0.9920 (0.0556) 0.8928	0.9956 (0.0420) 0.9575	0.9951 (0.0475) 0.9516	0.9968 (0.0413) 0.9042	0.9934 (0.0528) 0.9006	0.9970 (0.0398) 0.9647	0.9964 (0.0328) 0.9411	0.9956 (0.0439) 0.8868	0.9960 (0.0326) 0.9684	0.9979 (0.0275) 0.9652	0.9952 (0.0404) 0.9680	0.9988 (0.0165) 0.9606
CCGT 0.802	**Eastern** -	0.9503 (0.0632) 0.8635	0.9868 (0.0806) 0.9090	0.9590 (0.0679) 0.9010	0.9803 (0.0951) 0.6670	0.9662 (0.0837) 0.7143	0.9699 (0.0515) 0.7019	0.9821 (0.0502) 0.9166	0.9788 (0.0449) 0.8673	0.9644 (0.0687) 0.8632	0.9900 (0.0780) 0.6851	0.9947 (0.0484) 0.7887	0.9731 (0.0546) 0.7484
CCGT 0.802	**Indep** -	0.9518 (0.1229) 0.7082	0.9645 (0.1063) 0.7426	0.9832 (0.0749) 0.9408	0.9925 (0.0423) 0.8702	0.9851 (0.0738) 0.8862	0.9932 (0.0476) 0.8698	0.9930 (0.0388) 0.9291	0.9925 (0.0549) 0.7766	0.9942 (0.0321) 0.8486	0.9931 (0.0517) 0.8311	0.9969 (0.0223) 0.9535	0.9913 (0.0424) 0.7933
CCGT 0.802	**NP** -	0.9841 (0.0639) 0.5721	0.9802 (0.0768) 0.9430	0.9668 (0.1127) 0.7346	0.9512 (0.1421) 0.5960	0.9605 (0.1215) 0.5735	0.9457 (0.1266) 0.6611	0.9652 (0.1054) 0.8114	0.9650 (0.0872) 0.7146	0.9795 (0.0769) 0.8631	0.9750 (0.0580) 0.7518	0.9844 (0.0503) 0.8778	0.9773 (0.0320) 0.7377
CCGT 0.802	**PG** -	0.9924 (0.0250) 0.9152	0.9655 (0.0971) 0.7778	0.9884 (0.0553) 0.7592	0.9612 (0.1216) 0.6867	0.9724 (0.0930) 0.9109	0.9614 (0.0995) 0.8242	0.9789 (0.0637) 0.9325	0.9706 (0.0823) 0.6471	0.9751 (0.0868) 0.8038	0.9534 (0.1080) 0.7720	0.9765 (0.0805) 0.8846	0.9666 (0.0902) 0.7512
Coal 0.892	**AES** -	-	-	-	-	-	-	-	-	-	-	0.9951 (0.0500) 0.8231	0.9812 (0.1082) 0.8057
Coal 0.892	**EFM** -	-	-	-	-	-	-	-	-	-	0.8779 (0.1611) 0.4051	0.9240 (0.1631) 0.7625	0.9770 (0.1187) 0.5756
Coal 0.892	**Eastern** -	-	-	-	0.7727 (0.2145) 0.5486	0.8653 (0.2192) 0.7511	0.7616 (0.2351) 0.5198	0.8772 (0.2111) 0.8293	0.6083 (0.2568) 0.4609	0.8530 (0.2245) 0.7173	0.7597 (0.2019) 0.5293	0.9233 (0.1509) 0.7731	0.8439 (0.1811) 0.4505
Coal 0.892	**BE** -	-	-	-	-	-	-	-	-	-	-	0.9880 (0.0560) 0.8481	0.8375 (0.1516) 0.5293
Coal 0.892	**NP** 0.715	0.9600 (0.1444) 0.9007	0.9849 (0.0755) 0.7796	0.9901 (0.0613) 0.8969	0.9860 (0.0746) 0.7408	0.9852 (0.0829) 0.8410	0.9854 (0.0759) 0.6927	0.9899 (0.0738) 0.9094	0.9859 (0.0714) 0.7535	0.9900 (0.0689) 0.9032	0.9712 (0.1229) 0.6522	0.9153 (0.2031) 0.7491	0.9633 (0.1083) 0.5812
Coal 0.892	**PG** 0.700	0.9130 (0.1461) 0.8646	0.9103 (0.1410) 0.7544	0.9170 (0.1362) 0.8695	0.9415 (0.1198) 0.7399	0.9399 (0.1273) 0.8705	0.9495 (0.1119) 0.7345	0.9554 (0.1068) 0.8471	0.9532 (0.1115) 0.6621	0.9421 (0.1173) 0.7737	0.9481 (0.1154) 0.6450	0.9264 (0.1207) 0.7456	0.9010 (0.1397) 0.6291

Definitions: Within Day = Sum of Actual Actual Availability during Day /(48 Daily Periods * Maximum Availability). Seasonal Availability = Sum of Actual Availability for all units during season / Sum of (Maximum Availability * 48 Daily Periods * # of days in Season) for all units in season. Standard Deviations in parentheses for Within Day figure. Figures in first two columns are NERC availability figures and Patrick and Wolak's estimates for E&W availability in 1995, taken from Patrick and Wolak (1997), Table 4, pg. 58. Independent CCGT figure is weighted average of figures reported in Patrick and Wolak.

TABLE 7 cont. :AVAILABILITY (Within Day, (Standard Deviation), Availability in Season)

Fuel	Owner	Jan-Mar 95	Apr-Sept 95	Oct 95- Mar 96	Apr-Sept 96	Oct 96– Mar 97	Apr-Sept 97	Oct 97 -Mar 98	Apr-Sept 98	Oct 98- Mar 99	Apr-Sept 99	Oct 99- Mar 00	Apr-Sept 00
Dual coal oil -	**PG** -	0.8745 (0.1598) 0.7675	0.8186 (0.2195) 0.5833	0.8753 (0.1759) 0.7677	0.9859 (0.0633) 0.6463	0.9849 (0.0754) 0.5893	0.9617 (0.0938) 0.8387	0.9863 (0.0683) 0.8838	0.9933 (0.0441) 0.8317	0.9913 (0.0590) 0.9282	0.9903 (0.0535) 0.7490	0.9723 (0.0840) 0.7367	0.9781 (0.0758) 0.7561
Gas 0.845	**AES** -	-	-	-	-	1.0000 (0.0000) 0.9778	1.0000 (0.0000) 0.9398	0.9888 (0.1039) 0.9298	1.0000 (0.0000) 0.9503	0.9994 (0.0067) 0.9494	0.9979 (0.0274) 0.9020	0.9950 (0.0496) 0.9713	0.9876 (0.0926) 0.9334
Gas 0.845	**EFM** -	-	-	-	-	-	-	-	-	-	0.9981 (0.0320) 0.9946	0.9983 (0.0273) 0.9928	0.9954 (0.0567) 0.9736
Gas 0.845	**Eastern** -	-	-	-	1.0000 (0.0000) 0.9339	0.9958 (0.0563) 0.9229	0.9968 (0.0348) 0.9682	1.0000 (0.0000) 0.9889	0.9976 (0.0452) 0.9797	0.9709 (0.1489) 0.9365	0.8329 (0.3545) 0.7802	0.9939 (0.0734) 0.9441	0.9979 (0.0405) 0.8487
Gas 0.845	**Indep** -	-	0.9736 (0.1027) 0.1572	0.9804 (0.0769) 0.6799	0.9952 (0.0291) 0.4053	0.9101 (0.1960) 0.8605	0.9997 (0.0038) 0.9495	1.0000 (0.0003) 0.8971	0.9987 (0.0119) 0.9162	0.9948 (0.0610) 0.9780	0.9981 (0.0256) 0.9382	1.0000 (0.0000) 0.8880	0.9990 (0.0137) 0.7204
Gas 0.845	**NP** 0.534	0.9902 (0.0743) 0.9567	0.9895 (0.0789) 0.9503	0.9882 (0.0821) 0.9673	0.9910 (0.0733) 0.9141	0.9899 (0.0759) 0.9675	0.9918 (0.0630) 0.9357	0.9876 (0.0827) 0.9670	0.9855 (0.0891) 0.9252	0.9921 (0.0663) 0.9382	0.9911 (0.0714) 0.9533	0.9918 (0.0632) 0.9432	0.9923 (0.0670) 0.8148
Gas 0.845	**PG** 0.739	0.9954 (0.0622) 0.9726	0.9948 (0.0600) 0.9058	0.9973 (0.0404) 0.9555	0.9934 (0.0679) 0.9596	0.9922 (0.0666) 0.9316	0.9959 (0.0541) 0.8570	0.9977 (0.0423) 0.9856	0.9992 (0.0232) 0.9264	0.9964 (0.0483) 0.9768	0.9941 (0.0670) 0.9026	0.9966 (0.0520) 0.9447	0.9993 (0.0199) 0.9465
Oil 0.784	**NP** 0.289	0.8847 (0.2206) 0.8046	0.9836 (0.1077) 0.9180	0.9921 (0.0692) 0.9833	0.9835 (0.1006) 0.9120	0.9836 (0.0971) 0.5862	0.9855 (0.0947) 0.9544	0.9943 (0.0531) 0.9702	0.9866 (0.0986) 0.8337	0.9964 (0.0443) 0.9911	0.9989 (0.0150) 0.9958	0.9902 (0.0735) 0.9530	0.9724 (0.1317) 0.7129
Oil 0.784	**PG** 0.292	0.6856 (0.1928) 0.4198	0.6393 (0.1288) 0.3248	0.7173 (0.1971) 0.4256	0.5696 (0.0629) 0.3164	0.6643 (0.0456) 0.4574	0.6726 (0.0602) 0.3873	0.6867 (0.0241) 0.4662	0.7739 (0.1850) 0.5018	0.8137 (0.1976) 0.5816	0.9735 (0.0921) 0.8197	0.9910 (0.0464) 0.9342	0.9831 (0.0657) 0.6671
Pumped -	**NGC** -	0.8051 (0.1604) 0.7857	0.8065 (0.1772) 0.6934	-	-	-	-	-	-	-	-	-	
Pumped -	**EFM** -	-	-	0.7867 (0.1842) 0.7537	0.8000 (0.1763) 0.6863	0.8280 (0.1708) 0.7933	0.7398 (0.1534) 0.6328	0.7929 (0.1396) 0.7702	0.7145 (0.1345) 0.6482	0.6898 (0.1743) 0.6734	0.6833 (0.1729) 0.6081	0.7009 (0.1964) 0.6897	0.7148 (0.1671) 0.6343

TABLE 8 : WITHIN DAY AVAILABILITY VARIATION FOR COAL PLANTS: INFRAMARGINAL vs. EXTRAMARGINAL
(Average Availability Within Day, Within Day when Unit is Inframarginal, Within Day when Unit is Extramarginal)

Fuel	Owner	Jan-Mar 95	Apr-Sept 95	Oct 95-Mar 96	Apr-Sept 96	Oct 96–Mar 97	Apr-Sept 97	Oct 97-Mar 98	Apr-Sept 98	Oct 98-Mar 99	Apr-Sept 99	Oct 99-Mar 00	Apr-Sept 00
Coal	AES	-	-	-	-	-	-	-	-	-	-	0.9951 0.996(0.029) 0.950(0.181)	0.9812 0.986(0.074) 0.910(0.247)
Coal	EFM	-	-	-	-	-	-	-	-	-	0.8779 0.862(0.297) 0.826(0.297)	0.9240 0.946(0.121) 0.830(0.315)	0.9770 0.984(0.082) 0.950(0.163)
Coal	Eastern	-	-	-	0.7727 0.784(0.190) 0.786(0.254)	0.8653 0.915(0.141) 0.822(0.251)	0.7616 0.724(0.262) 0.821(0.168)	0.8772 0.920(0.104) 0.767(0.288)	0.6083 0.696(0.231) 0.601(0.251)	0.8530 0.903(0.164) 0.748(0.278)	0.7597 0.798(0.224) 0.660(0.279)	0.9233 0.940(0.147) 0.845(0.241)	0.8439 0.858(0.165) 0.716(0.339)
Coal	BE	-	-	-	-	-	-	-	-	-	-	0.9880 0.986(0.060) 0.964(0.131)	0.8375 0.861(0.148) 0.704(0.356)
Coal	NP	0.9600 0.980(0.088) 0.873(0.269)	0.9849 0.991(0.054) 0.937(0.189)	0.9901 0.991(0.051) 0.944(0.185)	0.9860 0.989(0.058) 0.930(0.206)	0.9852 0.988(0.061) 0.954(0.166)	0.9854 0.983(0.082) 0.948(0.175)	0.9899 0.992(0.053) 0.961(0.147)	0.9859 0.987(0.062) 0.951(0.164)	0.9900 0.991(0.053) 0.966(0.141)	0.9712 0.976(0.109) 0.905(0.232)	0.9153 0.964(0.137) 0.806(0.284)	0.9633 0.963(0.100) 0.857(0.278)
Coal	PG	0.9130 0.947(0.109) 0.793(0.289)	0.9103 0.984(0.061) 0.760(0.226)	0.9170 0.966(0.096) 0.764(0.201)	0.9415 0.975(0.089) 0.860(0.200)	0.9399 0.971(0.109) 0.893(0.170)	0.9495 0.973(0.105) 0.887(0.197)	0.9554 0.981(0.077) 0.903(0.184)	0.9532 0.970(0.098) 0.883(0.217)	0.9421 0.970(0.097) 0.892(0.183)	0.9481 0.956(0.124) 0.891(0.212)	0.9264 0.955(0.110) 0.860(0.199)	0.9010 0.935(0.134) 0.838(0.209)

Definition: Within Day = Sum of Actual Actual Availability during Day /(48 Daily Periods * Maximum Availability). Infra-marginal = Sum of Actual Actual Availability during Day when Bid Makes Unit Infra-marginal/(# of Periods when Unit is Inframarginal * Maximum Availability). Extra-marginal defined similarly for hours when unit is made extra-marginal by its bid. Standard Deviations in parentheses.

TABLE 9 : NUMBER OF SPELLS WITH UNITS NOT AVAILABLE FOR MORE THAN SEVEN DAYS

Fuel	Owner	Jan-Mar 95	Apr-Sept 95	Oct 95-Mar 96	Apr-Sept 96	Oct 96–Mar 97	Apr-Sept 97	Oct 97-Mar 98	Apr-Sept 98	Oct 98-Mar 99	Apr-Sept 99	Oct 99-Mar 00	Apr-Sept 00
Coal	AES	-	-	-	-	-	-	-	-	-	-	1	2
Coal	EFM	-	-	-	-	-	-	-	-	--	5	5	10
Coal	Eastern	-	-	-	5	5	14	4	11	7	15	12	11
Coal	BE	-	-	-	-	-	-	-	--	-	-	0	3
Coal	NP	5	36	12	27	13	21	8	21	9	25	6	12
Coal	PG	3	2	10	15	4	15	4	13	8	9	8	7
TOTAL		8	38	22	47	21	40	16	43	24	54	26	45

TABLE 10 : PRODUCTIVE EFFICIENCY FOR COAL PLANTS

	Jan-Mar 95	Apr-Sept 95	Oct 95-Mar 96	Apr-Sept 96	Oct 96 - Mar 97	Apr-Sept 97	Oct 97 - Mar 98	Apr-Sept 98	Oct 98-Mar 99	Apr-Sept 99	Oct 99-Mar 00	Apr-Sept 00
System Efficiency	1.013	1.016	1.014	1.021	1.024	1.026	1.025	1.028	1.031	1.026	1.024	1.029

Efficiency=(Actual cost)/(Ideal costs) based on efficient running of plants that are available at the point of time in question. Double lines represent the timing of the first divestiture of coal plants and the start of the second period of divestiture.