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Measuring Duopoly Power in the British Electricity Spot Market

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This article presents an empirical study of market power in the British electricity industry. Estimates of price-cost markups are derived using direct measures of marginal cost and several approaches that do not rely on cost data. Since two suppliers facing inelastic demand dominate the industry, most oligopoly models predict prices substantially above marginal costs. All estimates indicate that prices, while higher than marginal costs, are not nearly as high as most theoretical models predict. Regulatory constraints, the threat of entry, and financial contracts between the suppliers and their customers are considered as possible explanations for the observed price levels. (*JEL* L13, L94)

The British government undertook one of the first efforts to develop a fully competitive market for electricity generation when it privatized and restructured its electric power industry in April 1990. A careful analysis of the British electricity spot market provides insight into factors affecting the degree of competition between deregulated power generators. It is increasingly important to understand firm behavior in competitive electricity markets as the United States and other countries begin to implement reforms similar to Britain's.[1]

This article evaluates the applicability of various oligopoly models to the British electricity spot market. I focus on models that have been widely used to analyze outcomes in electricity markets including Cournot (see e.g., Judith B. Cardell et al., 1997; Severin Borenstein and James Bushnell, 1999) and supply function equilibrium (see e.g., Richard J. Green and David M. Newbery, 1992). I find that those models do not describe the spot market very well and that prices have been much lower than they predict.

To evaluate outcomes in the spot market, I consider price-cost markups measured using several approaches. First, I use highly reliable information on costs to measure the difference between prices and marginal costs directly. Production technologies in the electricity industry are straightforward and well understood (see e.g., Joskow and Richard Schmalensee, 1987). Short-run marginal costs are almost entirely composed of the cost of the fuel burned by a plant to generate electricity. A plant's fuel costs, in turn, are a function of the price of the fuel and the efficiency with which the plant converts fuel into electricity. Because the industry was recently in the public domain, I am able to obtain detailed information on plant efficiency levels, information that is now considered competitively sensitive and guarded quite closely.[2]

I also apply two approaches to measuring markups that ignore information on marginal costs. One of the approaches I use is standard in the literature, and I develop a new technique that exploits distortions induced by regulatory intervention in the market.

All of my estimates imply that prices are much closer to marginal costs than even theories of noncollusive supply predict. The

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[1] See the essays in Richard J. Gilbert and Edward P. Kahn (1996) for an overview of electricity restructuring programs around the world and Paul L. Joskow (1997) for a discussion of restructuring in the United States.

[2] Ordinarily, it is virtually impossible for researchers to measure markups directly. True economic profits differ from reported accounting profits for a number of reasons, and accurate cost information is kept confidential.

markups are not zero, however, and I point to instances where the suppliers are clearly manipulating prices. In light of the suppliers' ability to move prices, I consider several explanations for the restrained price levels. I consider the effects of financial contracts between the suppliers and their customers, the threat of entry, and the threat of regulatory intervention in the market. I find little evidence suggesting that contracts are restraining prices, and more support for the effects of potential entry and regulation.

Several other papers have considered the electricity market in Britain. Both Green (1994) and Nils-Henrik von der Fehr and David Harbord (1993) compare the generators' bid prices to their estimated costs on several representative days. While my approach to measuring costs is similar to both Green's and von der Fehr and Harbord's, I measure markups over a much broader period than those papers, compare estimated markups to a number of benchmark economic models, and corroborate the measured markups with other estimates of market power. Frank A. Wolak and Robert H. Patrick (1997) show how the rules governing the spot market provide the generators with an incentive to withhold capacity in certain half-hour periods in order to drive up the pool price (primarily by increasing the capacity fee the pool assigns). The marginal-cost curves I develop account for that type of strategic capacity withholding, and some of the patterns in the markups that I measure are consistent with Wolak and Patrick's description of the generators' strategies. I demonstrate, however, that capacity withholding has not generally resulted in markups as large as those predicted by conventional oligopoly models.

In the next section, I describe the British electricity industry. Section II sets out a framework for the empirical approach I take to assessing market power in the industry and considers the empirical implications of several theoretical models that have been proposed for the electricity spot market in England and Wales. The empirical results are presented in two sections. In Section III, I present the price-cost markups based on measured marginal cost, and Section IV summarizes the results from the analyses that do not use cost information. Section V concludes.

I. The British Electricity Industry

When the British government privatized its electricity sector in April 1990, it made several dramatic changes in the industry structure.[3] Figure 1 provides a diagram of the industry structure before and after privatization.[4] Prior to 1990, a single government organization, the Central Electricity Generating Board (CEGB), owned and operated the generating plants and transmission system. The CEGB's only customers were the 12 government-owned Area Boards, which distributed electricity to the residential, commercial, and industrial end-use customers within their local districts throughout England and Wales.

For the most part, the Area Boards were left unchanged as they were privatized and converted into 12 Regional Electricity Companies (RECs). They are still primarily distribution companies with local monopoly franchises, and distribution charges are subject to a price cap. In contrast, the CEGB is no longer recognizable. First, the vertical integration between generation and transmission activities was dissolved. All of the transmission assets were vested with one company, the National Grid Company (NGC in Figure 1). Also, the CEGB's generating plants were divided among three new companies. One enterprise, Nuclear Electric (NE), took possession of all of the nuclear plants and remained in the public sector for the first six years following privatization. The CEGB's nonnuclear plants were divided between two companies, National Power (NP) and PowerGen (PG).[5] At the time of the restructuring, National Power was given 52 percent of the CEGB's existing capacity (roughly 30 gigawatts), and

[3] See John Vickers and George Yarrow (1991) and Mark Armstrong et al. (1994) for more details on the restructuring.

[4] Most of the Scottish electricity industry was privatized in June 1991. There is a transmission interconnection between Scotland and England, and the Scottish companies are net suppliers to the spot market.

[5] The government's motivation for creating only two nonnuclear companies appears to have been political rather than economic (see Margaret Thatcher, 1993 pp. 680–85). Though some of Prime Minister Thatcher's advisors argued in favor of creating more companies in order to diffuse market power, the head of the CEGB wanted fewer companies. His views held sway, in part because Thatcher was indebted to him for maintaining the electricity supply during the 1984–1985 coal miners' strike.

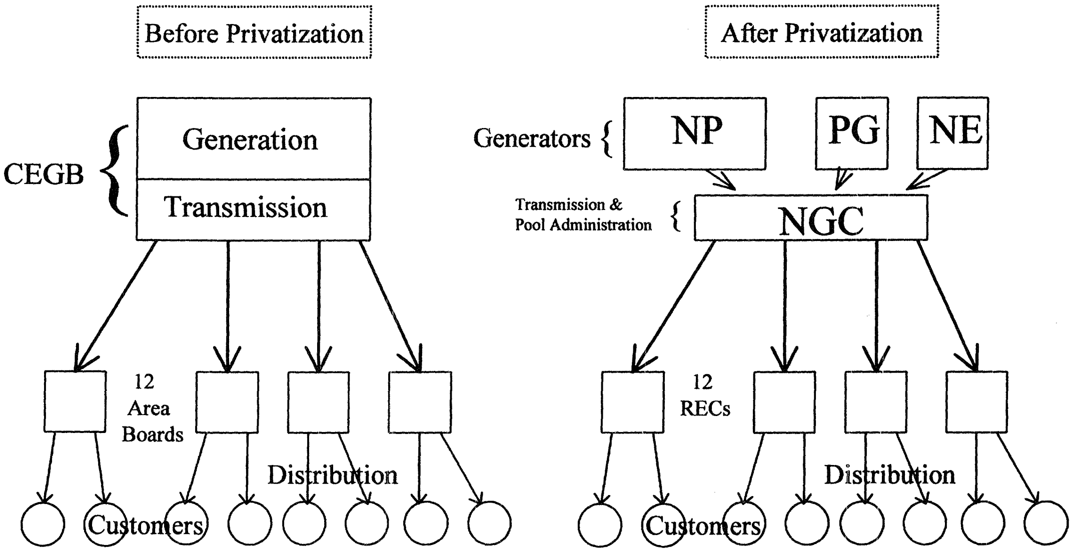

FIGURE 1. INDUSTRY STRUCTURE BEFORE AND AFTER PRIVATIZATION

Note: The "after privatization" side of the figure depicts the industry structure through the end of 1994, the end of the time period considered in this article.

PowerGen was given 33 percent (or approximately 20 gigawatts). Nuclear Electric's 12 stations had total capacity to supply an additional 9 gigawatts. Power supplied through connections with Scotland and France and by two pumped storage facilities owned by the NGC consistently provides several additional gigawatts. Between March 1990 and the end of 1994, approximately 7 gigawatts of new capacity were added, more than half of it owned by suppliers other than National Power and PowerGen.

A. *The Pool*

All wholesale electricity transactions in England and Wales take place through a central pool. From a financial perspective, the pool operates essentially as a spot market or, more accurately, a "day-ahead" market.[6] Every day is divided into 48 half-hour periods, and a single price covers all purchases and sales in that half hour. Pool prices are based on bid schedules submitted daily by each generator detailing the prices at which they would be willing to supply power from each of the units they own. Using demand forecasts for the following day, the administrator determines a system marginal price (SMP) for each half-hour period based on the bid of the most expensive generating unit used to meet forecast demand. The pool price consists of the SMP plus an additional factor that is designed to compensate the generators for making their capacity available. Estimated prices for the following day are made publicly available by 4:00 P.M.[7]

While the pool works essentially as a physical spot market for electricity, the vast majority of transactions are covered by contracts between the generators and their customers. A one-way contract guarantees that the customer never pays more than the strike price, while a two-way contract provides a hedge for both the

[6] The pool also provides many of the same functions as a control area operator in the United States. It dispatches generation to match supply and demand in real time; maintains the network frequency, voltage, and stability; provides for spinning reserves; manages network constraints; and administers financial settlements between buyers and sellers.

[7] The original published prices are calculated using demand forecasts. After demand is realized, a fee called Uplift is added to the pool price to reflect differences between the actual and forecast demand. Uplift also covers the costs of additional services provided by the generators, for instance, to ensure the stability of the transmission system.

consumer and the supplier. At privatization, the government established initial contracts between the RECs and the generators that ran from one to three years.[8] During the first year of the pool, contracts covered between 85 percent and 90 percent of both National Power and PowerGen's capacities. By fiscal year 1993, the coverage had fallen to just above 70 percent of each company's capacity. At the end of March 1993, all of the contracts put in place by the government expired. The generators and RECs negotiated some replacement contracts, but these only covered about half of the generators' capacities.

B. *Regulatory Oversight of the Pool*

Though pool prices are not directly regulated, the industry regulator[9] possesses a blunt instrument for intervening in the pool because he can refer the generators to the Monopolies and Mergers Commission (MMC), the British antitrust enforcement agency. The MMC, in turn could take radical steps such as breaking up National Power and PowerGen to create new competitors. As a result, the regulator's view of pool prices may influence the generators. Through the end of 1994, OFFER had issued four statements on the pool prices and put out several other reports on various specific pool issues. In the first three pool-price reports, the regulator recommended only minor changes to the institutional structure of the pool, though he expressed concern about price levels and the generators' market power (OFFER, 1991, 1992, 1993). In the fourth report, issued in February 1994, the regulator again expressed concern about high pool prices and high generator profits but agreed not to refer National Power and PowerGen to the MMC if they agreed to sell some of their plant (10–15 percent) to potential competitors and to adhere to a price cap (see OFFER, 1994). The price cap became effective on April 1, 1994.

II. Empirical Framework

In the sections that follow, I present several measures of the generators' markups and discuss the implications they have for the generators' market power. My results can be interpreted with respect to a general model of the pool in which demand is described by

$$D_t = D(P_t, \mathbf{X}_t, \varepsilon_t) \tag{1}$$

where t indexes a particular half-hour period on a particular day, P is the pool price, $\mathbf{X}$ is a vector of observable factors that shift demand and ε represents random noise. In the British electricity industry, it is not self-evident that the pool demand is sensitive to the half-hourly prices. Several large end-users, however, buy directly from the pool, and others have signed contracts with wholesalers that are closely tied to the half-hourly pool prices. Large customers respond to high pool prices in several ways. First, some have backup generators on-site. If the pool price goes above a certain level, they can switch to their backup source. Second, if the pool price is particularly high, certain energy-intensive manufacturers will find it economical to shut down their operations temporarily until the price comes back down. Finally, customers may schedule their usage around the projected pool prices over the course of a day, for instance, performing maintenance on their electricity-intensive machinery during periods when the price is projected to be high.[10]

I assume that the generators have marginal-cost functions of the following form:

$$MC_{it} = MC_i(q_{it}, \mathbf{Z}_{it}, \varepsilon_{sit}) \tag{2}$$

where i indexes the particular generator that

[8] Unfortunately, very little specific information on the terms of the contracts is publicly available. Most of the existing information is from the generators' prospectus (Kleinwort Benson Limited, 1991).

[9] Throughout the time period I study, Steven Littlechild served as the Director General of Electricity Supply and thereby the head of the Office of Electricity Regulation (OFFER).

[10] The last type of customer response implies that demand in a particular half-hour period is also a function of the prices in other periods over the course of the day, or even the week. For ease of notation, I do not reflect that in the demand function. In the empirical sections, I discuss both the extent to which I am able to account for cross-period price effects and any likely biases engendered by *not* fully accounting for them.

supplies q_i, $\mathbf{Z}_i$ is a vector of factors that shift generator i's marginal costs, and ε_{si} is a random noise term. A firm's profit function can be written as

$$\text{(3)} \qquad \Pi_{it} = P(Q_t, \mathbf{X}_t, \varepsilon_t)q_{it} - C(q_{it}, \mathbf{Z}_{it}, \varepsilon_{sit})$$

where $P(\cdot)$ is the inverse of the demand function from equation (1), Q is total industry demand, and $C(\cdot)$ is the function whose derivative with respect to q_{it} is the marginal-cost function of equation (2). The first-order condition to firm i's profit-maximization problem can be written as

$$\text{(4)} \qquad P_t = MC_i(q_{it}, \mathbf{Z}_{it}, \varepsilon_{sit}) - \tilde{\theta}_{it} q_{it} P_Q(Q_t, \mathbf{X}_t, \varepsilon_t)$$

where $P_Q(\cdot)$ is the partial derivative of the inverse demand function with respect to quantity and $\tilde{\theta}_{it}$ characterizes the behavioral paradigm into which firm i fits during period t.[11] For instance, $\tilde{\theta}_{it}$ equals 1 for a firm in a Cournot oligopoly and 0 if the firm behaves competitively and sets price equal to marginal cost.

Information on the quantity supplied by individual generators is not available, so I construct industry-level marginal costs in the following empirical sections. Taking the average of equation (4) over firms, the supply relationship can be rewritten on an industry level as

$$\text{(5)} \qquad P_t = MC(Q_t, \mathbf{Z}_t, \varepsilon_{st}) + \frac{P_t}{\eta_t}\left[\sum_{i=1}^{N} \kappa_{it} \frac{q_{it}}{Q_t} \tilde{\theta}_{it}\right]$$

where $\eta = -D_p P/Q$ is the price elasticity of demand and κ_i is the weight on each firm's marginal cost reflected in the industry marginal cost. To simplify notation, I rewrite equation (5) as

$$\text{(5a)} \qquad P_t = MC(Q_t, \mathbf{Z}_t, \varepsilon_{st}) + \frac{P_t}{\eta_t}\theta_t.$$

Note that if $\kappa_{it} = 1/N$ and $\tilde{\theta}_{it} = \tilde{\theta}_t$, then $\theta_t = \tilde{\theta}_t/N$. Thus, θ_t is equal to 1 if firms are joint profit maximizers, $1/N$ in a Cournot oligopoly, and 0 if there is perfect competition.[12] Because of the Cournot result, $1/\theta_t$ is sometimes interpreted as the "equivalent number of firms" in the industry.

Equation (5a) can be rewritten in terms of θ_t:

$$\text{(6)} \qquad \theta_t = \frac{P_t - MC(\cdot)}{P_t}\eta_t$$

demonstrating that θ_t is essentially an elasticity-adjusted price-cost markup. Note that, for a given price-cost markup, a larger value of θ_t indicates that the deviation from the competitive equilibrium has led to more deadweight loss, because the higher demand elasticity means that the same price increase causes more of a demand reduction. In the following empirical sections, I measure both unadjusted price-cost markups and θ's.

While the framework just described is quite general, several specific theoretical models of noncollusive behavior have been proposed to describe the generators in Britain's electricity pool. Each model has testable implications for measured markups. Von der Fehr and Harbord (1993) characterize the electricity pool as a first-price, sealed-bid, multiunit auction and show that likely equilibria involve prices above marginal costs. In a series of papers, Green and Newbery apply Paul D. Klemperer and Margaret A. Meyer's (1989) supply function equilibrium concept to the pool (see Green and Newbery, 1992; Newbery, 1998; Green, 1999).[13] They simulate potential pool outcomes by deriving supply function equilibria based on

[11] The parameter $\tilde{\theta}_{it}$ is also sometimes written as $(1 + r_{it})$ where $r_{it} = \sum_{j \neq i} dq_{jt}/dq_{it}$ (see Timothy F. Bresnahan, 1989).

[12] There is a fair amount of controversy and confusion over the interpretation of θ when it is *not* equal to 0, 1, or $1/N$ and therefore may not be consistent with a model of a firm's best response to its rivals actions (see Kenneth S. Corts, 1998). I treat θ as a measure of the elasticity-adjusted price-cost markup and develop measures for that parameter.

[13] Friedel Bolle (1992) also presents several different models of a spot electricity market designed in part to highlight implications of changing some of Klemperer and Meyer's assumptions.

estimated marginal-cost curves. In the next section, I compare actual pool outcomes to those predicted by Green and Newbery (1992). Green (1999) incorporates the pool contracts into the supply function equilibrium framework and shows that pool prices are decreasing in the amount sold under contract. In the next section, I consider the relationship between markups and contract coverage.

III. Direct Measures of the Generators' Price-Cost Markups

In this section, I present and analyze markups calculated using measures of the generators' marginal costs. I use 25,639 observations on the equilibrium pool prices and quantities from nearly every half-hour period during 18 months in 1992, 1993, and 1994.[14] The Appendix contains a detailed description of the data.

A. *Measuring Marginal Cost*

The short-run marginal cost of a fossil-fuel electricity generating plant is a function of the type of fuel burned, the cost of the fuel, and the efficiency with which the plant converts the fuel to electricity (i.e., the plant's thermal efficiency). For the oil, gas-peaking, and combined-cycle gas turbine (CCGT) plants, I use information on market fuel prices from the sources described in the Appendix.[15] For coal plants, I use the prices embedded in the contracts between British Coal and National Power and PowerGen. The first contracts, which were negotiated at privatization and expired in March 1993, were effectively take-or-pay, providing the generators with more coal than they actually used over that period. To capture the replacement cost of coal burned while the initial contracts were in effect, I assign the price in the contract covering the period from March 1993 to March 1994 (150 pence per gigajoule) to all coal used before the end of March 1994. I use the price in the contract covering the period from March 1994 to March 1995 (137 pence per gigajoule) for coal after March 1994. In addition, I add approximate transportation costs based on the distance between each plant and the coal fields that serve it, both described in Malcolm Rainbow et al. (1993). Those average eight pence per gigajoule, or about 5 percent of the fuel costs.

Before privatization, detailed information on the thermal efficiency levels of all of the coal-, oil-, and gas-fired plants now owned by National Power and PowerGen was published annually in the *CEGB Statistical Yearbook*. Green and Newbery (1992) synthesize information from the 20 years prior to privatization to develop efficiency levels for the plants under optimal operating conditions.[16] To account for any significant upgrades made to the coal plants since privatization, I use efficiency rates from Rainbow et al. (1993) when those numbers are significantly higher than Green and Newbery's. There were no CCGT plants before privatization, so following Green and Newbery, I assume that these plants have thermal efficiencies of 45 percent.

Following Green and Newbery, I assume that the Magnox and newer, advanced gas-cooled reactor nuclear stations run at costs of £13 and £11 per megawatt-hour, respectively. The costs for the nuclear plants are ad hoc and no doubt too high, though even with those costs, the nuclear plants would never have been marginal in any of the periods I consider. Pumped storage capacity is assigned a cost based on the average pool price during periods when energy was being used to accumulate pumped water and the same efficiency rate as in Green and Newbery (1992). Energy from France and Scotland is assigned its bid price.

The final component of the marginal-cost calculations is the quantity supplied by each plant. Because of depreciation and maintenance schedules, the amount of electricity that a plant can generate is not constant over the plant's life or over the course of a typical year. The generators also may face incentives to withhold capacity in order to increase their capacity-related payments (see Wolak and Patrick, 1997). To account for strategic withholding, I assign each

[14] I am missing data for approximately 40 periods.

[15] The units on the fuel prices listed in Table A1, British pounds (£) per metric ton, were converted to British pounds per megawatt-hour using standard conversion rates based on the energy content of the particular fuel.

[16] I am indebted to Richard Green for providing me with his efficiency data.

plant a capacity equal to the mean plus one-half of a standard deviation of its declared daily capacity for a given month.

B. *Markups*

Sample marginal-cost curves and equilibrium price–quantity observations for the months of January and July 1993 are depicted in Figure 2.[17] To calculate markups, I match each observation of the market equilibrium price to the industry marginal cost at the appropriate quantity level.[18] The first column of Table 1 summarizes the average markups (or Lerner indices) by time period and by quantity level.

The numbers in column (ii) of Table 1 are the markups in column (i) multiplied by an approximate demand elasticity, $\eta = -D_p P/Q$ with D_p set equal to -125. I assume that demand is linear and $D_p = -125$ so that the estimates in columns (ii) and (iii) of Table 1 are directly comparable to Green and Newbery's (1992) simulations. Their central case is based on $D_p = -125$ (since they measure demand in gigawatts while I am using megawatts per half hour, the parameter they report is $b = -0.25$) and their low and high cases are based on $D_p = -50$ and $D_p = -250$. At the mean values of PRICE and QUANTITY, $D_p = -125$ implies a price elasticity of 0.17. That value is in the same range as short-run price elasticities for electricity demand found in other work (e.g., Lester D. Taylor, 1975; E. Raphael Branch, 1993).[19] Patrick and Wolak (1997) use data from one of the RECs to estimate price elasticities for customers from various industries that are purchasing electricity on pool-price-related contracts. The maximum price elasticity they find is approximately 0.3 for electricity customers in the water supply industry. That figure is most likely higher than the short-run elasticity the generators face because Patrick and Wolak model the response to transmission charges as well as pool prices and because customers in the water supply industry are particularly price-sensitive.[20]

As is suggested by the high standard deviations reported in Table 1, there is quite a bit of variability in the markups. Given the large number of observations, however, two-sided t-tests reject (at the 1-percent significance level) that the average markups in column (i) are below 0.19 during the latest time period (row 3) and higher than 0.245 in the earliest time period (row 1).[21] The standard deviations reported in columns (i)–(iii) of Table 1 do not account for the fact that the marginal-cost numbers are estimated since all available information about the "true" marginal costs is incorporated in the estimates. In addition, the standard deviations reported in column (ii) do not account for the fact that the demand elasticity is approximated. Given the precision of the markups, adjusting the standard errors to account for those approximations probably would not change the interpretation of the results I report.

C. *Interpreting the Markups*

The first two columns of Table 1 suggest that the price-cost markups in this industry are sizable, yet θ, which summarizes market power under various assumptions, is very small. The numbers in the first column indicate that the pool prices are more than 20 percent higher than the generators' marginal costs, while the estimates of θ suggest that the generators exercise very little of the market power that models discussed in Section II attribute to them. Recall that a value of $\theta = 0.05$ is consistent with a 20-firm symmetric Cournot oligopoly.

Although it may be tempting to fit the pool into a Bertrand framework, in which two producers selling a homogeneous product (such as electricity) would not necessarily be able to

[17] I chose 1993 because it is the midpoint of my data set, and I use January and July as representative winter and summer months. Note that prices are more volatile after March 1993, when the initial contracts expired.

[18] Because I only consider fuel costs to be marginal, the marginal-cost calculations are appropriate for the very short run. So that the prices are comparable, I deduct the component of the pool price designed to compensate the generators for their capacity costs. (In other words, I use only SMP.)

[19] $D_p = -125$ is also roughly consistent with the linear demand equations I estimate in Section IV.

[20] Patrick and Wolak (1997) also estimate cross-price elasticities and find they are much smaller than the own-price elasticities. Generally, they find demand in different periods of the day to be substitutes.

[21] Since there is a fair amount of serial correlation across observations (see Section IV), calculating t-statistics assuming independence may overstate the precision of these estimates slightly.

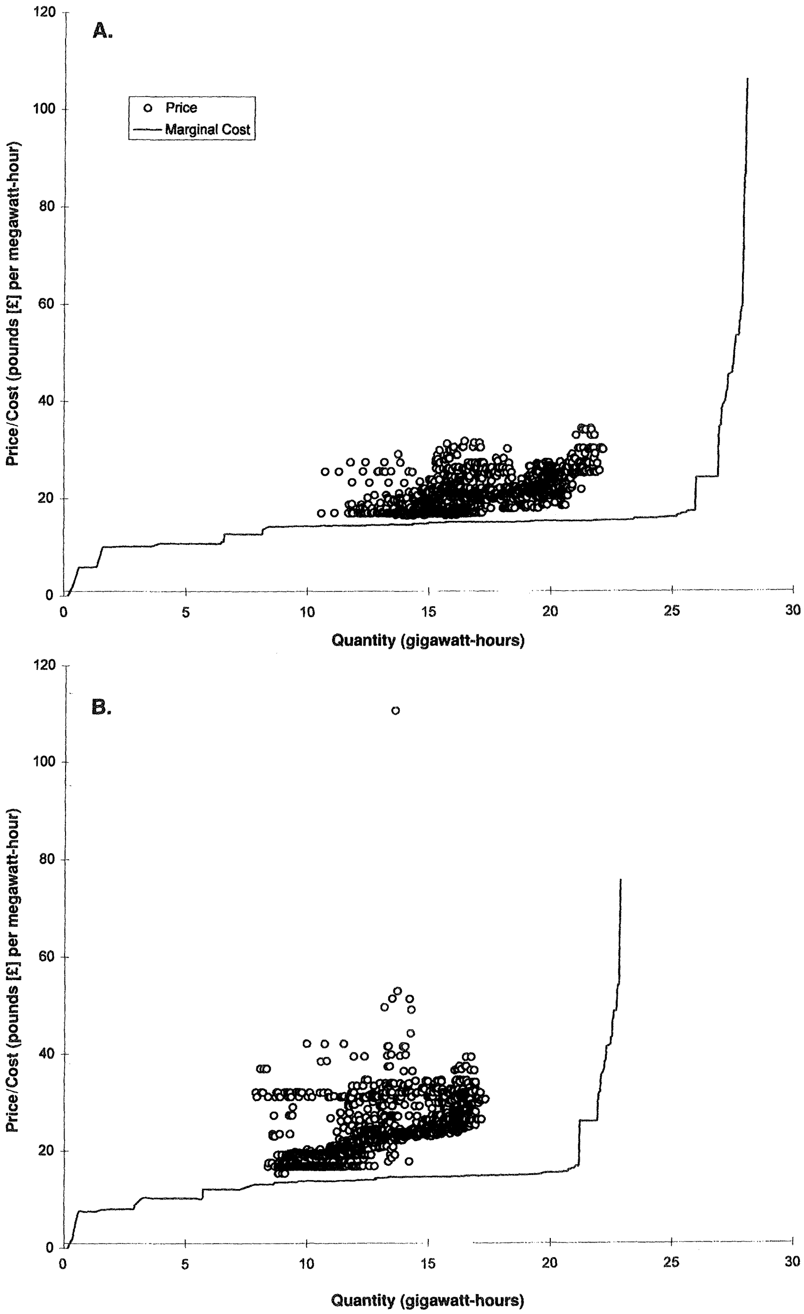

FIGURE 2. POOL PRICES AND MARGINAL COSTS: (A) JANUARY 1993; (B) JULY 1993

sustain a price above marginal cost (implying $\theta = 0$), a number of attributes of the spot market suggest that the two dominant suppliers could collude to maximize their joint profits. For instance, National Power and PowerGen's daily bids to supply power on the following day are

TABLE 1—PRICE-COST MARKUPS CALCULATED USING ACTUAL MARGINAL COSTS

Time period	(i) $\frac{(P - MC)}{P}$	(ii) $\theta = \frac{(P - MC)}{P} \eta$	(iii) θ, based on highest SFE	(iv) Number of observations
January 1992–March 1993	0.241	0.043	0.28	12,704
	(0.129)	(0.030)	(0.06)	
April 1993–March 1994	0.259	0.057	0.29	8,637
	(0.228)	(0.055)	(0.06)	
After March 1994	0.208	0.067	0.33	4,298
	(0.416)	(0.086)	(0.07)	
Four weeks before a regulatory decision	0.329	0.071		3,216
	(0.150)	(0.051)		
Four weeks after a regulatory decision	0.156	0.028		2,671
	(0.213)	(0.040)		
By Quantity Level:				
January 1992–March 1993				
Above median	0.279	0.046	0.31	6,764
	(0.124)	(0.027)	(0.05)	
Below median	0.198	0.039	0.23	5,940
	(0.121)	(0.033)	(0.02)	
April 1993–March 1994				
Above median	0.299	0.056	0.33	4,530
	(0.184)	(0.044)	(0.05)	
Below median	0.214	0.058	0.24	4,107
	(0.261)	(0.065)	(0.02)	
After March 1994				
Above median	0.554	0.138	0.37	1,526
	(0.122)	(0.057)	(0.09)	
Below median	0.018	0.027	0.26	2,772
	(0.398)	(0.073)	(0.02)	

Notes: Standard deviations are reported in parentheses. The θ calculations assume $D_p = -125$, where $\eta = -D_p P/Q$. SFE stands for supply function equilibria.

essentially moves in an infinitely repeated game. Also, the fact that the two companies were previously under common ownership would suggest that they have good information about the costs of one another's plants and that the lines of communication between them are open. While the values of θ in column (ii) suggest that the generators are not perfectly colluding to maximize joint, unconstrained profits, they are significantly greater than zero and reject the Bertrand model.

I also sought to ascertain how closely the markups correspond to other models thought to describe the pool. The third column of Table 1 lists the values of θ implied by the highest possible supply function equilibrium (SFE). Following Green and Newbery (1992), the calculations assume that the industry is supplied by a symmetric duopoly. Klemperer and Meyer (1989) show that potential SFEs solve a differential equation, and I calculate the highest SFE as the solution that passes through the point on the right-most demand curve where two symmetric duopolists would be if they behaved as Cournot competitors.[22] The θ's in column (iii) represent the product of the price-cost margin implied by the highest SFE and the demand elasticity assuming $D_p = -125$.[23] Those values

[22] For the right-most demand curve, I use the line with slope equal to -125 that passes through the monopoly price when quantity equals 30 gigawatts. Maximum demand during the period that I study was 24 gigawatts, so 30 is conservative (the highest possible SFE will be slightly lower for a higher right-most demand curve).

[23] Values of θ based on the highest possible SFE are reported in Table 1 so that the numbers are directly comparable to those of Green and Newbery (1992). Given the parameter values in this industry, particularly the sharply

imply that the producers have exercised considerably less market power than the supply-function-equilibrium concept implies they could have. Hence, the high average pool prices in Green and Newbery's (1992) simulations have not been realized.

There are several notable patterns to the markups. The bottom of Table 1 suggests that markups are higher for higher quantities, especially after March 1994. This behavior is consistent with several theoretical models.[24] In addition, after March 1994, the price cap imposed by the industry regulator gave the generators an incentive to increase prices at high quantities. In light of the pattern, one might be more interested in the *quantity-weighted* average markups than the time-weighted averages reported in Table 1, because they reveal more about the total consumer surplus that is transferred to producers.[25] Averages of the markups weighted by quantity supplied during each half-hour period are not substantively different from the markups reported in Table 1 for the first two periods. Before March 1993 the quantity-weighted average was 0.248 (standard deviation = 0.150) and between April 1993 and March 1994 it was 0.264 (0.237). The quantity-weighted average is considerably higher than the unweighted average after March 1994: 0.262 (0.431) compared to 0.208 (0.416) (see Table 1).[26]

D. *Other Factors Potentially Influencing Pricing*

I consider evidence on three possible explanations for the low observed measures of market power: the contracts between the generators and their customers; the threat of regulatory intervention; and the threat of entry.

Comparing the figures in the first two rows of Table 1, one sees a slight increase in both the unadjusted and elasticity-adjusted markups between the time period when the initial contracts were in effect and the year following those contracts' expiration. The increase suggests that the initial contracts restrained the generators' pricing behavior, though the effect is small. Recall that the initial contracts covered approximately 75 percent of the generators' output while the replacement contracts covered approximately one-half of their output. The numbers in the first two rows of Table 1 imply that the more than 20-percentage-point reduction in the amount of output under contract resulted in less than a 2-percentage-point increase in the markups. While the contracts may suppress prices slightly, their presence does little to explain why oligopoly models provide poor predictions for this market.

The fourth and fifth rows of Table 1 present the average markups in the four weeks before and the four weeks after OFFER released pool-price statements expressing dissatisfaction with the high pool prices. Those parameters suggest that the generators change their prices in reaction to regulatory actions: prices are higher than average in the four weeks before the regulator's statements and lower than average in the four weeks following statements.[27] Though this behavior is not necessarily consistent with standard models of regulator–firm interactions, it does suggest that pool prices react to the regulator's actions. The generators know when the regulator is preparing a statement. The regulator

increasing marginal-cost curve, markups implied by the *lowest* possible SFE are very similar to those reported.

[24] For instance, if demand is less elastic or if cross-price effects are larger when the quantity demanded is higher, theories of multiproduct firms suggest that markups should be larger. Fluctuations in demand are predictable in this industry, so Edward J. Green and Robert H. Porter's (1984) prediction that collusion will break down when demand is low is not applicable, though John Haltiwanger and Joseph E. Harrington's (1991) analysis of collusion given known demand movements may be.

[25] Note, however, that deadweight loss as a proportion of consumer expenditures is proportional to θ (assuming marginal costs are nearly constant), so unweighted averages reflect average efficiency losses.

[26] Note that the variation in markups by quantity explains less than 5 percent of the standard deviations in the markups. Wolak and Patrick (1997) document the patterns in price volatility in more detail. The volatility in the markups is primarily driven by price changes, as the marginal cost assigned to each plant is constant over at least a month and the costs of marginal plants are quite similar (see Figure 2).

[27] Two-sided t-tests conclusively reject that the markups around the regulatory action are equal to markups at other times. The differences in the markups persist when one controls for factors that affect the quantity demanded (see the variables included in Table A2 in the Appendix).

usually analyzes pool prices from previous months and is not able to incorporate contemporaneous activities as he prepares his statement, so the generators may deliberately raise prices during that time period.[28] In the four weeks after the statements, the generators may restrain prices in an effort to demonstrate that prices are not too high while the regulator's and the public's attention are focused on the pool.

Several pieces of evidence speak to the effect of the threat of entry on pool prices. First, back-of-the-envelope calculations suggest that the pool price is just below a potential entrant's long-run average costs. Assuming, following Green and Newbery (1992), that capital and nonfuel operating costs for a new, CCGT plant were roughly £85 per kilowatt and that the plant will run approximately 90–95 percent of a year, an entrant's plant would have nonfuel costs between £11 and £10 per megawatt-hour. Adding fuel costs of roughly £16 per megawatt-hour implies an average cost of £26–27 per megawatt-hour. During fiscal years 1993 and 1994, pool prices averaged £23.6 per megawatt-hour. Second, pool prices are positively correlated with the price of natural gas, even at high levels of demand (i.e., when the existing CCGT plants are not marginal). In a regression of the pool price on all of the demand instruments in Appendix Table A2 and the price of natural gas interacted with a dummy equal to 1 in periods when demand is greater than 15 gigawatts, the coefficient on the price of natural gas is positive and significant.[29]

If the generators are keeping prices low to deter entry, this industry provides a rare empirical example of limit pricing (see also Vrinda Kadiyali, 1996).[30] The success of the strategy is difficult to evaluate. There has been some entry since the pool began; however, it is impossible to identify whether there would have been more had the generators allowed pool prices to increase. There are reasons to believe that decisions about entry are influenced by factors other than pool prices. All independent power plants added since vesting are at least partially owned by one or more of the RECs, and there are suspicions that the RECs were selling power from these plants to themselves at prices unrelated to pool prices because they could pass those costs directly to franchise customers.

E. *Sensitivity of the Direct Markup Measures*

In order to assess the sensitivity of the markups presented in Table 1 to the accuracy of the information used to derive them, I recalculated them under a variety of different assumptions. The results are reported in Table 2. The first column of Table 1 is reproduced as the base case. Columns (ii) and (iii) of Table 2 report markups based on high and low assumptions about fuel costs. High-fuel-cost (low-markup) calculations assume that: (a) coal is priced at 180 pence per gigajoule through March 1993 (the price reflected in the take-or-pay contracts through that date); (b) oil and gas prices are everywhere 20 percent higher; and (c) the costs of advanced gas-cooled reactor and Magnox nuclear stations are both increased by £1 per megawatt-hour. Similarly, for the low-fuel-cost (high-markup) calculations: (a) coal is priced at 120 pence per gigajoule through March 1994 and 110 pence per gigajoule thereafter (based on the world coal price, see the Appendix for the data source);[31] (b) oil and gas prices are everywhere 20 percent lower; and (c) the costs of advanced gas-cooled reactor and Magnox nuclear stations are both reduced by £1 per megawatt-hour.

[28] Amihai Glazer and Henry McMillan (1993) develop a model in which the threat of regulation induces a monopolist to charge a price lower than the monopoly price, though the monopolist raises its price as the probability of future regulation increases.

[29] The magnitude of the coefficient is 0.024 (standard error = 0.008), implying that a 10-percent increase in the price of natural gas leads to less than a 1-percent increase in the pool price. If the entry-deterring strategy the generators follow involves keeping the average pool price just below the entrant's average costs, the size of the coefficient should imply nearly a one-to-one relationship between gas and pool prices. It is possible that the generators are following a more complex strategy or that the measured coefficient is biased downward because NATURAL GAS PRICE measures the gas price faced by a potential entrant with error.

[30] Game-theoretic models of limit pricing rely on some asymmetric information between the incumbent and entrant. For many of the same reasons that I am able to measure marginal costs, it is unlikely that this industry is characterized by much asymmetric information on costs. It is conceivable, however, that entrants have poor information on the extent of the regulatory constraints on prices.

[31] Note that world coal prices do not reflect the quality and delivery assurances that British Coal provides the generators (see e.g., Rainbow et al., 1993). Hence, the world coal price is most likely too low.

TABLE 2—PRICE-COST MARKUPS UNDER VARIOUS ASSUMPTIONS

Sensitivity to:		Fuel prices		Plant capacity				
	(i) Benchmark[a]	(ii) High fuel costs	(iii) Low fuel costs	(iv) Low availability	(v) High availability	(vi) Daily capacity declarations	(vii) Pool selling price	Number of observations
January 1992–March 1993	0.241	0.097	0.384	0.231	0.250	0.231	0.278	12,704
	(0.129)	(0.154)	(0.105)	(0.130)	(0.127)	(0.130)	(0.147)	
April 1993–March 1994	0.259	0.119	0.399	0.246	0.268	0.245	0.314	8,637
	(0.228)	(0.269)	(0.184)	(0.231)	(0.226)	(0.233)	(0.233)	
After March 1994	0.208	0.179	0.338	0.196	0.215	0.195	0.270	4,298
	(0.416)	(0.432)	(0.352)	(0.421)	(0.415)	(0.422)	(0.417)	

Notes: Standard deviations are reported in parentheses. See text for a description of the assumptions used to derive markups in columns (ii)–(vii).

[a] From column (i) of Table 1.

Columns (iv) and (v) of Table 2 report markups based on low and high assumptions about plant availability. The low-availability (low-markup) calculations were made assuming plants' output levels over a month are equal to the mean of their declared daily capacity for that month. The high-availability calculations reflect an increase in each plant's output level over a month to the mean plus a full standard deviation of its declared daily capacity. With the base calculation of availability (mean plus half a standard deviation), plants are assigned a capacity that is on average 85 percent of the maximum capacity they have declared for the year, and weighting by plant size, the average increases to 100 percent. For the high-availability calculations (mean plus a full standard deviation) the unweighted average ratio rises to 92 percent, above the average capacity factor for a very reliable baseload plant.[32] For comparison purposes, column (vi) reports markups based on the actual declared daily capacity.

The markups are quite sensitive to the fuel-cost information, varying by slightly more than 50 percent in each direction. They are much less sensitive to assumptions about availability. A separate calculation revealed that 90 percent of the difference between the baseline markups and those calculated using high and low fuel-cost assumptions is driven by the assumptions made about coal costs. Figure 2 depicts exactly why those patterns hold. At most demand levels, the system marginal-cost curve tracks the costs of the coal plants: it has a very slight upward slope reflecting the progression from the cheaper (newer and bigger) coal plants to the more expensive (older and smaller) plants.[33] Changing assumptions about the coal costs moves the coal segment of the line up or down (affecting the markups for nearly all of the observations), while changing assumptions about availability shortens or lengthens the line.

The final column of Table 2 presents markups measured as the difference between the pool selling price (the price that reflects the capacity fee plus Uplift [see footnote 7]) and the baseline calculated marginal costs. The markups are 15–30 percent higher, as the extra charges account for approximately 5–10 percent of the pool price during the time period I consider.

I also evaluate the calculated markups by

[32] For instance, the North American Electric Reliability Council (NERC) collects statistics on plant availability levels in the United States. Between 1991 and 1995, the average availability factor for all fossil-fuel plants was between 80 percent and 90 percent (see NERC, 1996).

[33] Beginning in November 1995, the National Grid Company began publicizing the identity of the unit setting SMP. In the 12 months ending in March 1997, coal plants set SMP in 82 percent of the periods, pumped storage plants in 14 percent, CCGT plants in 2 percent, and all other plants in the remaining 2 percent. Although the portfolio of plants in those 12 months is slightly different from the time period I consider, the figures provide additional insight into why the markups I calculate are primarily sensitive to assumptions about coal prices.

comparing the implications they have for the firms' profits to information from other sources. Because I have cost information on all of the generating plants, I can trace out both National Power and PowerGen's marginal-cost curves and then calculate the producer surplus they earn at the equilibrium prices. I find that the producer surplus is on average 25 percent of the revenue the companies receive from sales at SMP. The demand-weighted average SMP is just over 90 percent of the demand-weighted average total pool price (see e.g., OFFER, 1994). Further, National Power reports that its total pool revenues are approximately 70 percent of its total revenues. (The generator's main source of additional revenue is contract payments made by the RECs. PowerGen did not decompose its revenues.)[34] Therefore, my estimates imply that fuel costs are 47 percent of the companies' total revenues ($0.75 \times 0.9 \times 0.7$). That number is well in line with figures reported in the annual reports. In 1994, PowerGen's reported fuel costs were 40 percent of its total revenues, and National Power's fuel costs were 45 percent of its total revenues. Since my calculations show that National Power's producer surplus is in fact slightly lower than PowerGen's, the companies' accounting costs accord well with my cost estimates.

An alternative way to summarize the data presented in Table 1 is to estimate the following version of equation (5a):

$$P_t = \omega MC(\cdot) + \varepsilon_t \tag{7}$$

by regressing price on the measured marginal cost numbers. Here $\omega = \eta/(\eta - \theta)$. While the markups summarized in Table 1 are calculated allowing the relationship between prices and marginal costs to vary freely for each observation, equation (7) imposes a linear relationship between them. It allows me, however, to use standard procedures to account for measurement-error bias in marginal cost. Estimated on all the data, $\hat{\omega} = 1.92$ (robust standard error = 0.75), implying $\theta = 0.081$, for a demand elasticity of 0.17. Given the standard errors, that estimate is within the range of the values of θ reported in Table 1. Since $\hat{\omega}$ may be biased downward due to measurement error, I also estimated versions of equation (7) using instruments for marginal costs.[35] The parameter estimate was slightly, though not significantly (either economically or statistically) higher than the reported $\hat{\omega}$.[36]

I also considered the sensitivity of the calculations reported in Table 1 to several other assumptions. As discussed above, the θ values reported in columns (ii) and (iii) reflect the assumption that demand is linear with $D_p = -125$, implying a demand elasticity of 0.17 at the mean values of the pool price and demand. If I instead assume a constant elasticity of demand equal to 0.17, the θ values change very little. For the three time periods covered in the first three rows of Table 1, the values are, respectively, 0.041 (standard deviation = 0.022), 0.044 (0.039), and 0.035 (0.071).[37]

Not only do the numbers in columns (ii) and (iii) of Table 1 reflect assumptions on the functional form of the demand curve, they are also based on a short-run demand elasticity. The sensitivity of the actual values of θ [reported in column (ii)] to the level of demand elasticity can be assessed by inspection because the numbers in each row of column (ii) are the values in column (i) times the demand

[34] I rely most heavily on information in the companies' 1994 annual reports. Fiscal year 1994, which ended in March 1994, fell in the middle of the time period for which I have data.

[35] I use the components of $\mathbf{X}_t$ described in Section IV as instruments. If the error in measured marginal costs varies systematically by quantity level, these may not be exogenous to the measurement error. Similar results were obtained using the variable NUCLEAR AVAILABILITY as an instrument, but because of data limitations (described more fully in Section V) I could not use it for the whole time period.

[36] Edward E. Leamer (1978) demonstrates that the instrumental-variables estimate, $\hat{\omega}_{IV}$, is the maximum-likelihood estimate for ω if it lies between and has the same sign as the ordinary least-squares (OLS) and reverse least-square estimates. The reverse least-square estimate for ω is 62.5, no doubt so high since price varies every half hour, and marginal cost estimates are basically constant for a given month.

[37] For the linear demand specification, the relationship between elasticity and quantity is nonmonotonic (recall that markups are generally increasing in quantity). With a concave demand curve parametrized so that the elasticity is equal to 0.17 at the mean values of price and quantity, the θ values for the three time periods are 0.043 (standard deviation = 0.036), 0.060 (0.065), and 0.077 (0.010).

elasticity. Therefore, θ would only be 1 (implying that the generators are colluding to maximize joint profits) if demand elasticity were approximately 4 (1/0.25), and θ would only be 0.52 (implying that the two asymmetric generators behave as Cournot competitors) if demand elasticity were 2.1 (0.52/0.25). Even studies of long-run electricity demand rarely find elasticities greater than 1.5 (see e.g., Taylor, 1975). (The long run is defined as the time it takes consumers to make decisions about capital investments, for instance, in more energy-efficient machinery.)

The reported θ values also reflect the assumption that the demand elasticity did not change over the entire time period I study. That assumption may be unrealistic for several reasons. First, the number of customers eligible to buy directly from the pool expanded in April 1994. Second, though presumably much less important, the pool began a pilot program in which 12 large customers were allowed to submit demand-side bids in December 1993. As depicted above, however, the relative size of θ before and after April 1994 depends considerably on the assumed functional form of the demand equation. Even absent real changes in demand conditions it is difficult to come to firm conclusions about the relative values of θ before and after April 1994.

The sensitivity of θ based on the highest SFE to the demand elasticity cannot be assessed directly from the numbers in Table 1 because the possible equilibria are functions of the demand elasticity. Separate calculations revealed that demand elasticity must be higher than approximately 3 before the actual θ (analogous to those values reported in column (iii) of Table 1) equals θ based on the highest SFE.

IV. Alternative Approaches to Measuring Markups

In this section, I present and discuss results from two approaches to measuring markups that do not rely on information about marginal costs. The first technique is new and exploits a distortion in the generators' pricing behavior induced by the price cap that was imposed in March 1994. With the second technique, I attempt to identify θ by analyzing the generators' responses to changes in demand. This is the approach used by Richard E. Just and Wen S. Chern (1980), Kathryn Graddy (1995), and David Genesove and Wallace P. Mullin (1998) and described in section 3.1 of Bresnahan (1989).

A. *Estimates of Markups Based on Changes in the Regulatory Environment*

In February 1994, OFFER decided not to refer the generators to the MMC if they agreed to adhere to a cap on pool prices. The price cap became effective on April 1, 1994. The regulator established one cap based on a simple average of pool prices over the fiscal year and a higher cap based on the average of pool prices weighted by demand levels. The unweighted price cap apparently was binding because, while it was in place, the generators reduced pool prices when demand was low and increased them when demand was high, as demonstrated in the last two rows of Table 1. In other words, the cap on the unweighted average caused the industry supply curve to rotate counterclockwise.

I take advantage of the change in the generators' pricing behavior induced by the price cap to measure the extent to which they can push prices above their marginal costs. Figure 3 presents a graphical representation of my calculations. First, I separate the observations in my data set into 25 groups based on the level of demand observed during each period. (For instance, all periods in which the demand was greater than or equal to 16 gigawatt-hours and less than 16.5 gigawatt-hours are grouped together.) I then determine whether the average price for each group was higher after the price cap than before. The dashed vertical line in Figure 3 is drawn at the rotation axis, or the lowest quantity level where prices after the cap were higher than before. In my data set, 11 of the groups fall to the left of the rotation axis and 14 to the right.[38] I calculate $(P_H - P_L)/P_H$ for each group to the right of the rotation axis (to the right of the dashed line), so that P_H is the average price for the group after the price cap

[38] The results presented are not sensitive to the fact that I use 25 quantity groups.

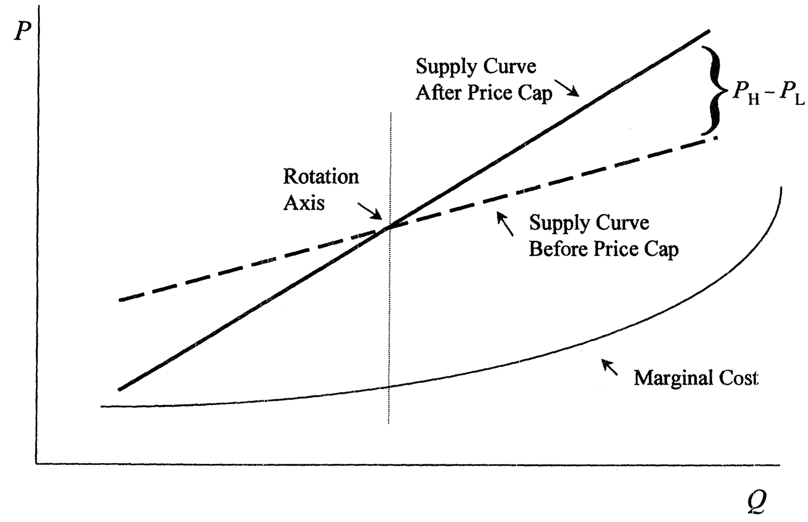

FIGURE 3. STYLIZED SUPPLY-CURVE ROTATION

Note: The difference $P_H - P_L$ is only taken to the right of the rotation axis.

and P_L is the average price before the price cap.[39]

The average of $(P_H - P_L)/P_H$ over the 14 quantity groups to the right of the rotation axis is 0.277 (standard deviation = 0.145).[40] If the generators were pricing at marginal cost for high quantity levels before the price cap was imposed, this figure would be roughly the same as the average Lerner index for quantities above the median for the period "after March 1994" in Table 1. (It would be exactly the same if the rotation axis were directly at the median quantity level.) More likely, the generators were pricing slightly above marginal cost at all quantity levels before the price cap was imposed and then lowered prices at low quantities and raised them for high quantities (see Figure 3). In this case, P_L is an upper bound on marginal costs, and the ratio is a lower bound on the Lerner index. Comparing the 0.277 figure to the average Lerner index in the last row of Table 1 suggests that the calculation of $(P_H - P_L)/P_H$ understates the true markups by about 50 percent.

Generally, the calculations I report provide a lower bound on the extent to which the generators can move their prices above marginal costs when regulatory pressures make it advantageous to do so. The approach to measuring market power developed in this section is analogous to the one used by Porter (1983) because it compares outcomes across different pricing regimes. The difference is that in the present application the regimes are induced by exogenous regulatory intervention rather than by firm conduct.[41] The generators' response to the price cap also provides evidence of the distorting effects of price caps, something that has been considered theoretically but of which there is little empirical evidence.

[39] In principle, I could also use changes in pricing to the left of the rotation axis to estimate markups. I chose not to because it is possible that, under the price cap, the generators priced below their marginal costs at very low quantity levels so that they could raise prices at high quantity levels and still stay beneath the unweighted cap. At quantity levels to the left of the rotation axis, therefore, I could be overestimating markups.

[40] The average is weighted by the number of periods in each of the 14 groups after March 1994.

[41] My approach is also similar to papers that measure market power using regulatory interventions that induce exogenous changes in marginal costs. For example, Orley Ashenfelter and Daniel Sullivan (1987) consider changes in the excise tax for cigarettes.

B. *Estimates of the Elasticity-Adjusted Markup Using Comparative Statics in Demand*

To identify θ using changes in demand, I first estimate a linear version of demand equation (1):

$$(8)\quad Q_t = \mathbf{X}_t'\boldsymbol{\alpha} - P_t(\text{WINTER WEEKDAY})_t\beta_w - P_t(\text{SUMMER \& WEEKEND})_t\beta_s + \varepsilon_{dt}$$

where P_t and Q_t represent the price and quantity in period t, $\mathbf{X}_t$ is the vector of demand instruments, and ε_{dt} is the error term.[42] WINTER WEEKDAY is a dummy variable equal to 1 for periods between 9:00 A.M. and 5:00 P.M. on weekdays during January, February, and March, and SUMMER & WEEKEND is a dummy variable equal to 1 in all other periods. I let the coefficients on price vary between winter weekdays and summer and weekend days because the pool demand forecasters told me that the most substantial variations in demand elasticities occurred between those two periods.

If marginal costs are also linear, then the supply relationship [equation (5a) from Section II] can be estimated as

$$(9)\quad P_t = \mathbf{Z}_t'\gamma + Q_t\delta + \left(\frac{a_t}{b_t}\right)\frac{\theta}{1+\theta} + \varepsilon_{st}$$

where $\mathbf{Z}_t$ is the vector of variables that shift marginal costs and ε_{st} is the error term,[43] and where $a_t/b_t = h_t$ is the ratio of the constant in the demand equation ($\mathbf{X}_{t'}\hat{\alpha}$) over $-D_{\text{p}}$ (estimated as $\hat{\beta}$). The parameters that are estimated in equation (8) are used to generate the variable h_t.[44] The distribution of observations on a_t/b_t is driven by the difference in b between winter weekdays and other days and by differences in a, which vary with different observations on the components of $\mathbf{X}_t$. The coefficient on h_t yields an estimate of θ. The estimated values of γ and δ reflect the corresponding parameters of the marginal-cost function divided by $(1 + \theta)$.

I apply two-stage least squares to estimate equation (8) using the variable NUCLEAR AVAILABILITY as an instrument for price. Nuclear plants have very low marginal costs and generate electricity continuously, except during routine maintenance and refueling outages or if some mishap forces a shutdown. If one or more nuclear plants are out of service for either reason, more expensive plants must be run at every level of demand, effectively shifting the marginal-cost curve up. Maintenance and refueling outages are scheduled to occur when demand is low, such as during the summer. Outages of the second type are random and exogenous to pool demand. NUCLEAR AVAILABILITY is designed to capture changes in the availability of nuclear plants due to unplanned outages. It represents the megawatt-hours of nuclear capacity available on a given day. Plants are treated as available during planned outages, unless an unexpected event was documented that caused the outage to be extended. In that case, I categorized the unanticipated extension as an unplanned outage. The detailed information necessary to construct the instrumental variable was only available from Nuclear Electric for fiscal year 1994 (April 1993–March 1994). As a result, I am only able to estimate equation (8) for a subset of my data.

An estimate of demand equation (8) is pre-

[42] Because I am omitting prices in periods other than period t, the coefficient on P_t will be biased downward (in absolute value) to the extent that prices in a given day are positively correlated and the cross-price effects are positive (elasticities negative). That bias is at least partially offset, however, because neglecting to account for negative cross-period price elasticities overstates the marginal revenue. Identifying θ based on changes in the exaggerated marginal revenue most likely biases the estimate of θ downward. Empirically, within-day cross-price effects appear to be small because the coefficients on prices do not change by much when the demand equation is estimated using daily averages. Also, Patrick and Wolak (1997) find small cross-price elasticities.

[43] Results very similar to those in Table 3 were obtained estimating the supply function in the form

$$P_t = \mathbf{Z}_t'g + Q_td + \left(\frac{Q_t}{b_t}\right)\theta + \varepsilon_t.$$

[44] The standard errors in Table 3 account for the fact that this variable is generated using the adjustment proposed by Whitney K. Newey (1984).

sented at the top of Table 3. The coefficients on the price variables are small yet indicate that demand is almost twice as sensitive to price on winter weekdays.[45] The standard errors in the second column do not account for the presence of serial correlation. The standard errors in the third column are based on the estimator of the covariance matrix proposed by Newey and Kenneth D. West (1987) and therefore account for serial correlation as well as heteroskedasticity. Without the serial-correlation correction, an F test of the hypothesis that the two coefficients are equal is rejected at the 15-percent level. However, with the serial-correlation correction, one cannot reject the hypothesis that the price coefficients are equal, nor that both of them are positive. It is likely, however, that the noisy relationship between NUCLEAR AVAILABILITY and PRICE inflates the standard errors, and there are several reasons for accepting the point estimates as reasonable.[46] At the mean price and quantity, the price coefficients imply demand elasticities of approximately 0.1, a value that is generally consistent with past findings of short-run price elasticities for electricity (see e.g., Taylor, 1975; Branch, 1993). Also, the relative size of the coefficients on WINTER WEEKDAY PRICE (WWP) and SUMMER & WEEKEND PRICE (S&WP) are consistent with the conventional industry wisdom about the sensitivity of demand to price across the two periods. The presence of serial correlation does not appear to affect the size of the coefficients on the PRICE variables, as estimates on daily averages yielded broadly similar results: $\beta_{\text{WWP}} = 101$ (SE = 125) and $\beta_{\text{S\&WP}} = 62$ (86). The coefficients on the demand shifters in Table 3 are reasonable and very precisely estimated.

Equation (9) is estimated using the values of α and β from the demand equation, and the results are reported at the bottom of Table 3. As discussed above, more NUCLEAR AVAILABILITY shifts the marginal-cost curve down. In addition, costs are lower during the winter for a given level of demand, most likely reflecting the fact that the generators take plants out of service for maintenance during the summer. With less capacity available, more expensive plants are used at any given quantity level.[47] The positive and significant coefficient on QUANTITY is consistent with a priori beliefs that marginal costs are increasing in quantity in this industry. The estimate of θ is essentially zero. Based on the standard errors corrected for serial correlation and the presence of a generated variable, one cannot reject that the parameter estimated here is equal to 0.057, the actual value of θ for fiscal year 1994 from Table 1. General conclusions about the markup levels based on the value of θ estimated here are similar to those based on the measured value reported in Table 1.[48]

V. Conclusions

This article has presented a number of estimates of markups in the British electricity spot market. The figures presented in Table 1 imply that, though the generators are charging prices significantly higher than their observed marginal costs, they have not taken full advantage of the inelastic demand to raise their prices to levels predicted by standard oligopoly models. The incumbent generators may be restraining prices in order either to deter new entrants or to stave off substantial regulatory action. Consistent with the last hypothesis, the generators appear to alter their pricing behavior in response to actions taken by the regulator. The correlation between pool prices and natural gas prices, as well as the fact that average pool prices are just below estimates of a potential entrant's long-run average cost, provide evidence of entry deterrence. By contrast, I find little support for the idea that the contracts between the

[45] Estimates of a version of equation (8) using the logarithm of prices and quantities yielded similar results.

[46] The first-stage estimates of the price equations are available from the author on request.

[47] Versions of equation (9) that also included the fuel price variables listed in Appendix Table A1 yielded similar results to those reported in Table 3. The fuel price variables did not affect the fit of the estimated supply relationship, no doubt because fuel price variables in my data vary infrequently.

[48] An earlier version of this paper considered the sensitivity of estimates of θ to assumptions about the functional form of the demand and supply curves; θ estimates appear particularly sensitive to the specification of the demand curve. In particular, if variables that shift demand are excluded, elasticity estimates can be biased. Estimates of θ are then likely to be biased, since they are identified based on changes in the demand elasticity. That sensitivity could be present in other studies which attempt to derive estimates of θ using the approach considered in this section.

TABLE 3—ESTIMATES OF MARKET POWER USING COMPARATIVE STATICS IN DEMAND

Independent variable	Coefficient	Standard error	Corrected standard error
Demand Equation:			
WINTER WEEKDAY PRICE	−71.4	24.9	108.2
SUMMER & WEEKEND PRICE	−45.1	20.8	78.4
TEMPERATURE	−331	15	57
$(\text{TEMPERATURE})^2$	9.86	0.54	1.66
COOLING POWER	5.38	1.46	4.32
CLOUDS	49.8	5.4	12.5
DUSK	518	74	223
NIGHT	1,816	177	674
Supply Relationship:			
Constant	11.0	2.2	5.13
NUCLEAR AVAILABILITY	−0.001	0.0005	0.0007
WINTER	−8.20	0.20	0.84
QUANTITY	0.001	0.0004	0.0007
θ	0.012	0.002	0.044

Notes: Coefficients were estimated using two-stage least squares; $N = 7{,}523$. The column to the far right reports standard errors corrected for serial correlation (see Newey and West, 1987) and, in the supply equation, for the presence of a generated variable (see Newey, 1984). The demand equation also includes winter-weekday, month, time-of-day × weekday and time-of-day × weekend fixed effects.

generators and their customers have affected pool prices.

It is unclear to what extent one can draw implications from the experience in the British pool for electricity industry restructurings elsewhere. On the one hand, if the threat of further entry is the primary mechanism restraining the generators' pricing, it would be reasonably straightforward to assess whether economic conditions would similarly stimulate entry in other settings. On the other hand, if the generators are reacting to the possibility of further regulation, it may be difficult to characterize the set of political, historical, and cultural conditions that inspire this deference in Britain.

APPENDIX: DATA SOURCES AND SUMMARY STATISTICS

Tables A1 and A2 provide summary statistics for the data used in Sections III and IV, respectively. All information on the pool-related variables was obtained from the National Grid Company, the pool administrator. The data consist of observations from nearly every half-hour period of every day in six months (January, February, March, April, July, and November) from each of the three calendar years between 1992 and 1994.[49] The pool information was merged with fuel price information obtained from a number of secondary sources and with hourly weather information obtained from the British Meteorological Office.

Table A1 summarizes the two price variables used to develop the numbers reported in Tables 1 and 2: system marginal price (SMP) and pool selling price (PSP). QUANTITY reflects the number of megawatt-hours metered in a given half-hour period. It includes transmission losses, the energy that dissipates as electricity is transmitted between the generating station and the final customer.

Table A1 also summarizes the prices for the different types of fuel burned at National Power and PowerGen's plants. One of the simulations in Table 2 is based on the variable COAL PRICE which is the price in pounds (£) per metric ton for Australian coal as reported on a monthly basis in the International Monetary Fund publication *International Financial Statistics*. (For comparison purposes, the contract coal price for coal from British Coal in 1994/

[49] Some variables were not available from the National Grid Company for years prior to 1992, so the analysis does not cover the earliest years of the pool.

TABLE A1—SUMMARY STATISTICS: JANUARY, FEBRUARY, MARCH, APRIL, JULY, AND NOVEMBER 1992, 1993, AND 1994

Variable	Mean	Standard deviation	Number of observations
Market Variables:			
SMP (pounds [£]/megawatt-hour)	22.26	7.10	25,639
PSP (pounds [£]/megawatt-hour)	24.40	10.17	25,639
QUANTITY DEMANDED (megawatt-hours)	16,211	2,839	25,639
Fuel Prices:			
COAL PRICE (monthly; pounds [£]/metric ton)	25.18	1.60	18
HEAVY-FUEL-OIL PRICE (monthly; pounds [£]/metric ton)	43.84	8.23	18
LIGHT-FUEL-OIL PRICE (monthly; pounds [£]/metric ton)	99.66	9.83	18
NATURAL-GAS PRICE (monthly; pounds [£]/kilowatt-hour)	0.662	0.035	18

TABLE A2—FISCAL-YEAR 1994 SUMMARY STATISTICS: APRIL, JULY, AND NOVEMBER 1993 AND JANUARY, FEBRUARY, AND MARCH 1994

Variable	Mean	Standard deviation	Number of observations
Dependent Variables:			
WINTER WEEKDAY PRICE (pounds [£]/megawatt-hour)	23.0	9.4	986
SUMMER & WEEKEND PRICE (pounds [£]/megawatt-hour)	23.3	8.6	6,537
WINTER WEEKDAY QUANTITY (megawatt-hours)	19,911	1,189	986
SUMMER & WEEKEND QUANTITY (megawatt-hours)	15,777	2,756	6,537
Demand Instruments:			
TEMPERATURE (°C)	8.63	4.83	7,523
$(\text{TEMPERATURE})^2$	101	100	7,523
COOLING POWER[a]	25.1	13.6	7,523
CLOUDS[b]	5.75	2.06	7,523
DUSK[c]	0.104	0.299	7,523
NIGHT[d]	0.505	0.498	7,523
Supply Instruments:			
WINTER WEEKDAY NUCLEAR AVAILABILITY (megawatt-hours)	4,273	172	986
SUMMER & WEEKEND NUCLEAR AVAILABILITY (megawatt-hours)	4,251	182	6,537

[a] Defined as $(\text{wind velocity [in knots]})^{0.5} \times (18.3 - \text{TEMPERATURE})$.
[b] Eighths of sky covered.
[c] One hour before or after sunrise or sunset (dummy variable).
[d] From one hour after sunset to one hour before sunrise (dummy variable).

1995 was approximately £31.50 per metric ton.) Both of the generators also have several base-load plants that burn heavy fuel oil and a large number of small peaking plants that burn light fuel oil. HEAVY-FUEL-OIL PRICE and LIGHT-FUEL-OIL PRICE are monthly average spot prices expressed in pounds (£) per metric ton as reported in *Platt's Oil Price Handbook and Oilmanac* (various years). HEAVY-FUEL-OIL PRICE is the free-on-board price for heavy fuel from Northwest Europe with a sulfur content not exceeding 3.5 percent. Similarly, LIGHT-FUEL-OIL PRICE is the free-on-board price for gas oil from Northwest Europe with a sulfur content not exceeding 0.2 percent. NATURAL-GAS PRICE is the monthly price expressed in pounds (£) per kilowatt-hour for "power station fuel" as reported in *World Gas Intelligence* (various years).

Table A2 summarizes the information used to estimate the supply and demand system described in Section IV. The PRICE variable in Table A2 is the pool purchase price (PPP) expressed in pounds (£) per megawatt-hour. I use this price for the analyses in Section IV, as opposed to the pool selling price, because the pool purchase price is published ahead of time and monitored by customers who are deciding how much electricity to consume. The analysis presented in Table 3 assumes that the generators take customers' reactions to the PPP into account in submitting their bids.[50] QUANTITY is based on the same data as those summarized for the whole time period in Table A1.

The next seven variables listed in Table A2 are the demand instruments represented by $\mathbf{X}_t$ in equation (1). The first four are the weather-related variables found to be accurate predictors of electricity demand in England and Wales by the pool's demand forecasters.[51] Following the practices of the pool's forecasters, all four of the weather variables reflect weighted averages of the weather conditions near London, Bristol, and Manchester. London is given twice the weight of the other two cities. Because the weather information that I obtained is hourly, observations on the weather variables for the two periods in an hour are the same. TEMPERATURE reflects the average of the mean temperature over the past four hours and the mean temperature over the same four-hour period on the previous day. The variable (TEMPERATURE)^2 reflects the average of the squares of the hourly temperatures. COOLING POWER is a function of the square root of the wind speed, measured in knots, and the temperature. It is designed to capture the cooling power of the wind, which is also a function of the ambient temperature. CLOUDS is an integer that ranges from 0 to eight and reflects the eighths of the sky covered by clouds. DUSK is a weighted average of two dummy variables. The first one is equal to 1 in the hour before and the hour after sunset and sunrise in Manchester, and the other is equal to 1 in the hour before and the hour after sunset and sunrise in London. (London is approximately 150 miles south of Manchester.) Similarly, NIGHT is a weighted average of dummies for the period between sunrise and sunset in Manchester and London. CLOUDS, DUSK, and NIGHT affect the level of electricity demand because they influence lighting and heating needs.

[50] In addition, the results reported in Section IV are very similar to results obtained using final PSP.

[51] Both econometricians and economists interested in energy policy issues have devoted considerable attention to econometric models of electricity demand. For the purpose of choosing variables to include in the demand equation estimates in this study, I relied heavily on the modeling work of the pool's demand forecasters. I also experimented with other specifications, and none improved on the reported specifications.

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