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England and Wales - A Competitive Electricity Market?

Richard Green

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University of California Energy Institute
2539 Channing Way
Berkeley, California 94720-5180
www.ucei.berkeley.edu/ucei

England and Wales - A Competitive Electricity Market?

Richard Green*

Department of Applied Economics, University of Cambridge

Department of Applied Economics

Sidgwick Avenue

Cambridge CB3 9DE

+44 1223 335261

rjg10@econ.cam.ac.uk

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The British sometimes exaggerate their own importance. For example, we claim that the electricity market introduced in April 1990 was the first of its kind in the world, neglecting the Chilean reforms of 1978. Another boast is that Britain will be the first country in the world to give all of its domestic electricity consumers a choice of where to buy their power: a boast which many Norwegians know to be wrong. They have been able to switch supplier (for a fee) since 1995, and the switching fee was abolished in 1997. Although some of our claims for priority are exaggerated, there is no denying that the overall package of measures that was introduced in 1990 was substantial, and did go beyond what many people thought would be possible. The existing generation and transmission board was broken up, generators were allowed free entry to the industry, and customers were promised a choice of supplier; if not immediately, then by

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1998. Most of the industry was privatised. The aim was to create a competitive electricity industry. I want to ask if that aim has been realised.

Competition should not be an end in itself, of course, although there are many commentators who seem willing to argue the opposite. The ideological beliefs underlying the restructuring were that private ownership and the profit motive gave far better incentives than the most benevolent kind of state control (let alone the state interference which seemed to be the best that British governments could achieve), and that competitive private industries gave better results than monopolies. This second belief was strengthened by the experience of privatising British Telecommunications (BT) and British Gas as effective monopolies. By the time that Mrs Thatcher asked Cecil Parkinson to plan the privatisation of the electricity industry, in June 1987, BT's quality of service was believed to have declined significantly since privatisation ("believed", because the company had stopped publishing the information), and British Gas was on the brink of being referred to the Monopolies and Mergers Commission. Parkinson decided that he could do better than this, and that when the electricity industry was privatised, it would be restructured to promote competition.

In February 1988, the government published a White Paper (Department of Energy, 1988) which announced this decision. The White Paper had a vision of a competitive electricity industry, in which the transmission grid previously owned by the Central Electricity Generating Board (CEGB) would be owned by the distribution companies, and open to anybody who wished to generate electricity. The CEGB's power stations would be divided between two competing companies, and distributors would be able to buy electricity from them, from France and Scotland, and from new, independent, stations. Some large customers would also be given access to the grid. The decision to create only two incumbent generators was driven by the desire to privatise the CEGB's nuclear power stations: a company with 30 GW of conventional plant might be able to absorb the risks of 10 GW of nuclear plant.[1] The remaining 20 GW of conventional capacity were given to a second company, in the hope that it would act as a counter-balance to "Big G". The government had considered a more competitive structure, with five conventional generators which would jointly own a nuclear company, but decided against this.

[1] Nuclear Electric's capacity in March 1990 was only 8 GW, but some of the company's stations were later uprated, and the total rose to 10 GW by 1995, when the PWR at Sizewell B was commissioned.

One argument was that this complex structure could not be successfully marketed to investors: another (discussed below) is that it could not have been sustained.

The White Paper did not contain much detail, because most of the detail behind the vision had not been worked out. Its authors appear to have thought that competition in generation would be organised around bilateral physical contracts between generators and distributors. In the event, a "spot market", the Pool, became the formal centrepiece of competition, although financial contracts have been used to hedge much of the trading in this market. The nuclear stations had to be withdrawn from the privatisation, when new estimates of their costs and risks proved too much for investors to accept without guarantees that the government was not willing to give. The plans for competition in supply became more ambitious - every customer would be allowed to choose their supplier - but their full realisation was postponed to April 1998, eight years after the reforms were due to commence. Vertical integration would be allowed - generators could sell directly to customers, and distributors could build power stations - but would be limited. Hundreds of special contracts were agreed, aiming to ensure that there would be no unpleasant financial surprises in the first few years of the new system. Everything was just about ready by March 31, 1990, the Vesting Day on which the new structure came into legal being. The twelve distribution boards, now known as Regional Electricity Companies, or RECs, were privatised in December 1990, and the two major conventional generators, National Power and PowerGen, in March 1991. There have been other share sales since: the government kept 40% of the shares in the generators until March 1995, and the RECs divested the National Grid Company in December 1995. Finally, the more modern nuclear stations improved their performance to the point where their owner, British Energy, could be privatised in July 1996.

How was it meant to work?

The Electricity Pool of England and Wales is often presented as the most important, and the most radical, part of the 1990 reforms. It has also proved to be one of the most controversial features, perhaps the least popular with large customers, and possibly the least enduring, for the regulator has suggested that it should be abolished. The many criticisms of the way in which the Pool *has* worked make it hard to assess how it *should have* worked, but that assessment is a crucial part to understanding what the reforms were meant to achieve.

The reformers wanted competition in generation, but they also wished to maintain the merit order system, under which the cheapest generators were dispatched first. While they were still planning to organise the industry around physical contracts, this required a complicated exchange of obligations, so that cheap stations with contracts that had not been called could be used instead of expensive stations with contracts that had been called. This proved impossible to organise in the time available, and the Pool was born. All stations would be dispatched in merit order, for they would all have to bid into a single market, organised one day in advance by NGC, using the same dispatch software that the CEGB had used to schedule its stations. This software would now have to use price bids where it had previously used internal cost data, for the industry was creating a market, and a new module was added to convert those price bids into a System Marginal Price (SMP), based on the bid of the most expensive station in normal operation.

SMP was intended to reflect the short-run marginal cost of electricity, but the price of electricity has to rise above its short-run marginal cost from time to time, or peaking capacity would never cover its fixed costs. There are several ways of doing this. In the past, the CEGB had simply charged the Area Boards a fixed amount (about £16/kWh in 1988/89) for each unit of electricity that they took in the three peak half-hours of the year.[2] At one stage, the industry considered requiring suppliers to back all of their energy demand with "capacity tickets". This could lead to problems with "free riding", however, if suppliers failed to buy enough tickets, or generators sold tickets without providing reliable capacity. We would have needed a clearing system to match demand to tickets, and tickets to capacity, and on the rare occasions when demand threatened to exceed capacity, this would have given generators more market power than the buyers were willing to countenance. In a very competitive market, we might expect that prices would equal marginal cost as long as there is any spare capacity at all, but that they would rise, almost without limit, at the rare times when there is no spare capacity.[3]

[2] The rate was expressed in £/kW of average demand during the three half-hours. The CEGB had also charged the Area Boards a further £20/kW for their average demand during the next 250 highest half-hours, on the grounds that the stations which were marginal at these times had higher fixed costs than the peaking stations - this was about 16p/kWh.

[3] If enough customers can react to prices in real time, then they could reduce their demand as prices start to rise, and the equilibrium price would be just sufficient to keep demand down to the level of capacity. If customers cannot react in this way, and "random" power cuts are needed, then there is no limit to the price that the generators could

In the end, the industry decided to smooth the cost of capacity, charging for it on the expected cost of power cuts, rather than on the actual cost. A computer program calculated the Loss of Load Probability (LOLP) and the government set the Value of Lost Load (VOLL). The capacity payment was set equal to LOLP $\times$ (VOLL - SMP): the probability of a power cut multiplied by its expected cost.[4] Power Stations which were available would receive the capacity payment, whether or not they generated. If they generated, they would receive SMP as well.

The Pool was the centrepiece of the new market, in that almost all generation had to be sold to the Pool, at the Pool Purchase Price (PPP) of (1 - LOLP) $\times$ SMP + LOLP $\times$ VOLL. Various other costs were recovered in an Uplift charge, and this was added to PPP to give the Pool Selling Price which had to be paid by almost all demand. It is impossible for either generators or suppliers to free-ride, since generators are only paid if they are available, and all demand pays its share of the cost of capacity. Since all parties have the option of trading at Pool prices, we would expect any other prices at which trading takes place to converge to their level. In that sense, the Pool is the centre of the wholesale market.

In practice, however, most participants want to trade at prices which are less volatile than the Pool's half-hourly prices. Contracts for Differences (CfDs) allow them to do this, and between 80% and 90% of electricity trades have been hedged with CfDs. With a two-way CfD, the parties agree a strike price for a fixed quantity of electricity, and whenever the Pool price is below the strike price, the buyer will pay the seller the difference between the two. When the Pool price is higher, the seller refunds the difference. If a generator produces the amount of electricity covered by its CfD, then its revenues are fixed by the strike price. With this type of CfD, however, the Pool price still determines the generator's incentives at the margin. If the Pool price is below the station's marginal cost, the generator will make more by simply collecting difference payments, and not trying to run. Submitting bids equal to the station's costs should ensure that the station only runs when the Pool price is above its costs. CfDs can therefore hedge a station's revenues while still giving it an incentive to operate efficiently.

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set, if they were allowed to do so after the shortage has appeared. In Australia, a (very high) administered price is used in these circumstances.

[4] The expected cost is the economic value of the load which cannot be met (deemed to be VOLL), less the short-run marginal cost of meeting it, believed to equal SMP.

The capacity payments mechanism can also be combined with appropriate CfDs to promote efficient decisions about plant closures. For at least twenty years, the level of capacity in England and Wales has been "fine-tuned", not by new investment, but by bringing forward or delaying the closure of old stations. CfDs exist which make payments with reference to the capacity payment alone, and the strike price should be based on the expected value of capacity payments over the year. If there is a lot of spare capacity, this expected value should be low, and less than the cost of keeping at least some of this capacity open. That can be seen as a market signal that closures would be appropriate, remembering that the capacity payment is intended to reflect the expected value of the energy that would be lost through capacity shortages. When there is less spare capacity, the expected capacity payment will be higher, raising the value of the CfD, and signalling that stations should be kept open. While the CfD can "lock in" revenues for a station that is kept available throughout the year, the station is still free to make day-to-day decisions about its availability on the basis of the capacity payment expected for the following day. It should be efficient to make the station available whenever the expected capacity payment exceeds the cost of doing so, but not when the expected capacity payment is lower. This efficient course of action should also be privately profitable, for the owner of a single station.

That caveat is critical. For most purposes, we can treat the owner of a single station as a price-taker, who should respond in an efficient manner to the signals provided by the Pool. Most of the capacity in England and Wales, however, has been owned by larger companies with many stations each. These companies are not price-takers, and if they withdraw some of their capacity from the market, the capacity payments received by the remainder will rise (Newbery, 1995). The larger generators will maximise their profits by keeping the industry's capacity at less than the efficient level, unless the smaller companies are able to provide enough capacity to offset any withdrawals. Similarly, the larger companies maximise their profits by bidding some of their stations above their marginal costs: the stations which raise their bids may be displaced in the merit order, sacrificing market share, but the infra-marginal stations earn more from the higher level of SMP (Green and Newbery, 1992).

There are two ways in which this market power can be restrained. One is through the contract market, for a generator which has covered most of its output with CfDs is practically indifferent to the Pool price in the short term (Green, 1998). In the medium term, however, the generator is likely to be aware that contract prices depend on expected Pool prices, and that raising Pool prices, even though it is not immediately profitable, will raise the company's future revenues. The second route is through entry. Unless there are barriers to entry, the incumbents must keep prices just below the level at which entry is profitable, or lose market share to new stations. The industry rapidly developed a package of linked contracts - a CfD for electricity, a long-term gas purchase contract, and project finance for building the station - that removed most of the risks from entry, and made the market for very long-term contracts contestable.[5] At the time of the restructuring, when a large number of three-year contracts were signed, the government was relying on these two mechanisms to produce an acceptable outcome in the generation market (Hunt, 1992).

Competition in electricity supply was a new concept in 1990. Before then, the physical distribution of electricity was not distinguished from its supply - the activity of dealing with the consumer and collecting payment. The regulatory licences issued in 1990 separated the two businesses, however, and required the RECs to keep separate accounts for each business. More importantly, each REC had to publish a tariff at which any licensed supplier could use its distribution system to supply customers in its area, and had to ensure that this tariff applied to its own supply business as well. The level of the tariff was regulated with the kind of "RPI-X" price cap which was fast becoming traditional in British utility privatisations. This "common carriage" provision made competition in electricity supply a reality, and contrasted with the initial situation in the gas industry, where British Gas was expected to use its control of the distribution system to block any attempts at supply competition.[6]

The prices which the RECs' supply businesses charged final customers in their own areas (so-called "first tier" customers) were also regulated. At first, this covered not only the customers with maximum demands of less than 1 MW, who could not choose their supplier, but also many of the customers in the competitive market. This implied that a price reduction to a customer in the competitive market could be balanced, within the control, by an increase to a captive customer, and so a separate control prevented their prices from rising in real terms for the first three years. When the supply price controls were reset, from 1993, they were limited to

[5] Generation itself is not a contestable activity, for a station remains a sunk investment. The contract market is contestable, however, for it costs relatively little to arrange the package of contracts, and once they are signed, the new entrant is protected from most price risks.

customers within the RECs' franchise. The controls contained an "RPI-X" component for the supply business' own costs and profits, and passed through the regulated costs of transmission and distribution. Generation costs were also subject to a pass-through, although a yardstick control, linking allowable costs to the average incurred by the industry, would have given the RECs more incentive to keep their costs down. Instead, there was an "economic purchasing condition", to be enforced by the regulator, requiring the RECs to buy electricity "at the best effective price reasonably obtainable having regard to the sources available".

The government realised that existing electricity companies moving into new activities might be the most important source of new competition, but was worried about the potential for "sweetheart deals". Vertical integration was therefore allowed, but limited. National Power and PowerGen's direct sales (second tier supply) were initially limited to a total of 15% of the demand in each REC's area. Each REC was given a limit (in MW) for its equity investment in generation capacity, again representing around 15% of the peak demand in its area.[7]

The final piece in the jigsaw was the fossil fuel levy, which was intended to raise about £82 billion (in 1990 prices) towards the costs of decommissioning nuclear power stations and reprocessing their fuel. This was linked to the difference between the amount that the nuclear industry was expected to spend, and the amount that it was expected to earn in the market. Preparations for the privatisation had revealed that these costs were much higher than the CEGB had anticipated, and the levy appeared (to the government) to be the best way of building up the necessary funds. The levy was applied to all the electricity produced from fossil-fuelled stations, or those which received payments from it, initially at a rate of 10.6% of the final price. A small part of the proceeds would be used to support renewable generation - wind power, waste burning, and the like - with developers bidding for contracts, awarded by the government, in biennial tender rounds. The levy was originally intended to last until 1998, but will now continue for the foreseeable future to pay for renewables, albeit at a much lower rate (presently 0.9%).

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[6] I have not heard that British Gas actually did block any such attempts: the obstacles to potential suppliers appeared so overwhelming that none of them bothered to try.

[7] The average demand is about two-thirds of the peak demand, and only half of this is taken by customers with demands below 100 kW, who would remain in the RECs' legal franchise until 1998. A REC which used all of its allowable investment could have met half of these customers' demand, and more if it had equity partners that did not take any electricity.

How well has it worked?

The new system has been a technical success - the lights have stayed on. Large customers have adapted to competition in supply, and more than two fifths of them now buy from a second tier supplier. Prices for many customers have fallen by 30% in real terms since 1990, but the industry's profits are also high. This obviously implies that there have been some dramatic reductions in the industry's costs, but does not necessarily mean that costs and prices have been minimised. While parts of the industry are clearly now competitive, others are not, and there is a wealth of evidence that competition is better at promoting economic efficiency than privatisation. Figure 1 shows the prices paid by the three main customer classes, reflated to 1990 levels using the GDP deflator. The data cover the UK as a whole, but England and Wales account for nearly nine-tenths of the electricity consumed in the UK, and will therefore dominate the figures. All three averages fell slightly in the run-up to privatisation, but then diverged. The average price for industrial customers fell in 1990, for many of them stopped contributing to the high cost of British coal. In the competitive part of the market, there was no mechanism for passing through the cost of the effective subsidy which the coal industry received, and industrial sales are

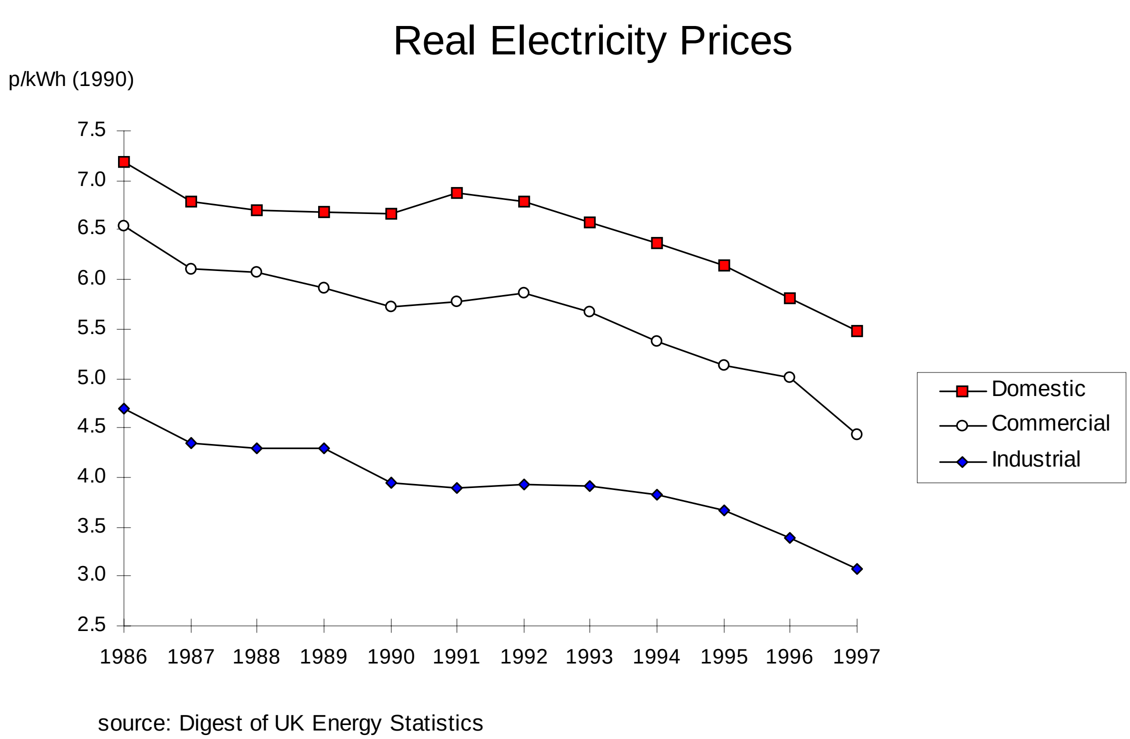

figure 1

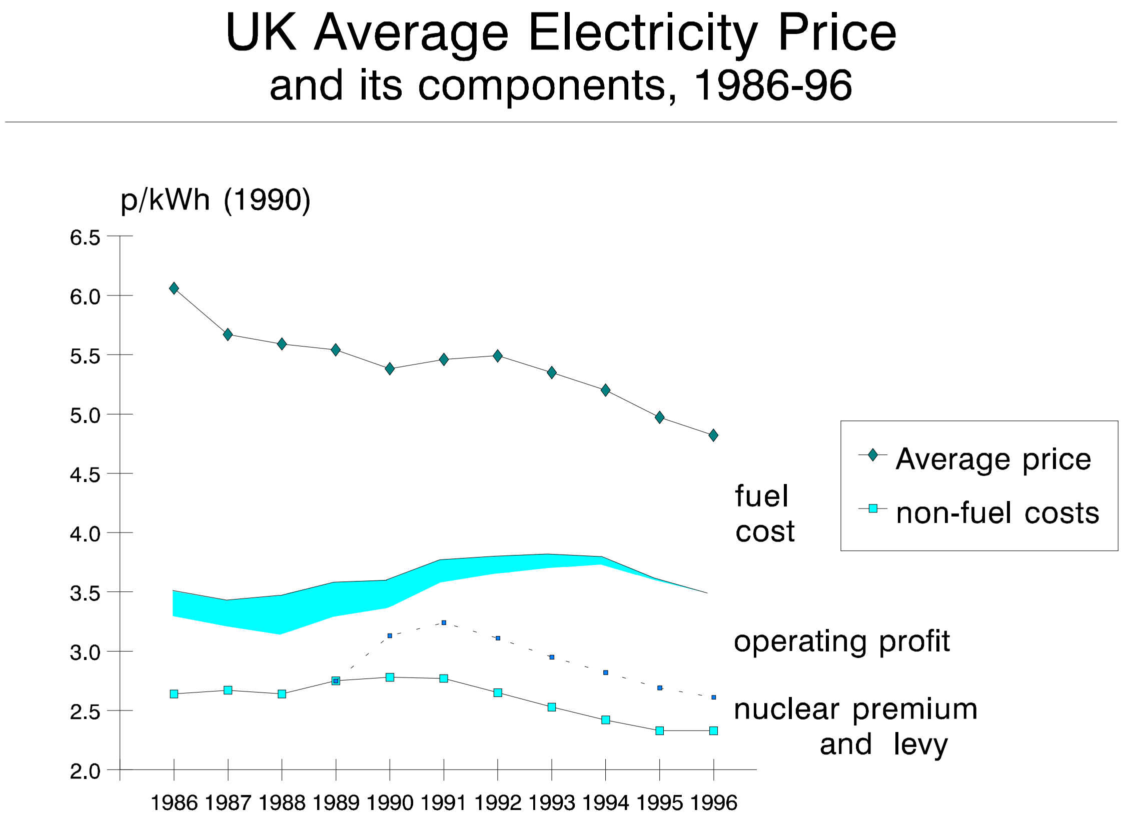

figure 2

dominated by large users who gained by no longer having to contribute to British Coal. The very largest users lost out from the introduction of competition, however, because they had effectively received a subsidy before the restructuring. Their representatives have been among the industry's fiercest critics ever since. Smaller customers' prices went up slightly at the time of privatisation (which increased the value of the companies to be sold), but have since fallen. Many commercial customers saw significant reductions in 1994, when they in turn entered the competitive market and stopped contributing to the British coal subsidy (which has declined throughout the period). In the last few years, lower prices have come from reductions in the regulated charges for distribution and transmission, and in the fossil fuel levy, which has now fallen from 11% (in 1991/2) to 0.9% (in 1998/9).

Figure 2 shows that most of these price reductions have come from savings in fuel costs, rather than in the electricity industry's value added. The top line shows the average price across all consumers, and the next line down deducts fuel costs. The line is based on the current cost of nuclear fuel, now that a deal for reprocessing services has been agreed; the shaded area shows the higher figures that had previously been allowed by the nuclear companies. The industry's revenue net of fuel costs actually peaked in 1993, and has since declined by about 10%.

The bottom line shows the electricity industry's non-fuel operating costs. Some of the increase in the late 1980s may have been due to a better recognition of nuclear costs, rather than a real increase in cost levels. From 1991, however, the industry's costs have been falling at around 3% a year. If we deduct uncontrollable costs, such as depreciation, the figure is closer to 5%: a significant fall, if not quite as dramatic as some of the "headline" cuts in employment.[8] The industry's profits are given by the gap between its revenues, net of fuel costs, and its other operating costs. (The area below the dotted line shows the portion of the industry's profts which was due to the fossil fuel levy and a similar premium paid to Scottish Nuclear). Profits were quite low (measured as a return on assets) in the 1980s, and some increase could be justified on grounds of allocative efficiency. In the event, current cost operating profits nearly doubled in the early 1990s, and have not been much reduced since. This increase had not been foreshadowed in the companies' sale prices, however, and shareholders made large gains. The high level of profits in the industry has angered many of its critics.

There are two ways of keeping profits down, competition and regulation. I will discuss competition in the next sections. For the first few years after privatisation, the regulator insisted that he should not respond to rising profits by bringing forward his scheduled price control reviews, as this would destroy the incentive to cut costs in the future. Figure 3 shows what he did when the reviews fell due. Transmission initially contributed about 0.2 p/kWh (in 1990 prices) to an under-100 kW customer's bill, the supply business' own costs about 0.4 p/kWh, and distribution about 1.9 p/kWh. At first, distribution prices were allowed to rise, while the other price controls were constant in real terms. The regulator's first reviews, of transmission and supply prices, imposed small values of "X", implying that these prices had to fall by 3% and 2% a year, respectively. By the time of the distribution price control review, however, it was clear that the companies could afford much larger price reductions, and the regulator decided on a set of one-off cuts of between 11% and 17%. This was widely seen as far too lenient, and the control had to be re-opened the following year, causing large falls in the share prices of all electricity companies. Since this happened just after the government had completed the major

[8] Some companies have halved employment over this period, with the generators (including the then-publicly owned Nuclear Electric) leading the (privately-owned) RECs.

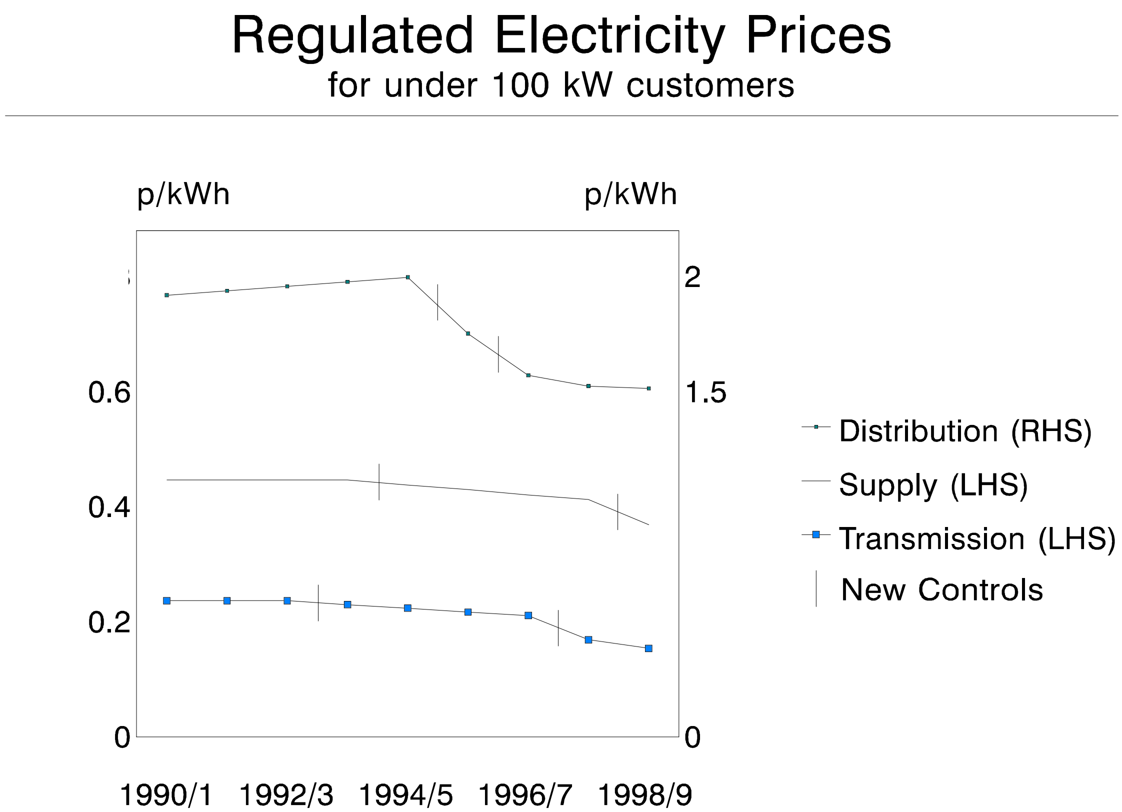

figure 3

generators' privatisation, selling £4 billion of shares in National Power and PowerGen, the timing was somewhat unfortunate.[9] The regulator found a justification for cutting another 10% from distribution prices, but even this was less than had been expected, and was seen as the trigger for a wave of take-overs. In fact, it was probably the end of regulatory uncertainty (at least for some time) that caused the take-overs, and not the prices chosen by the regulator. The bidders could have gone ahead with their take-overs if the regulator had set lower prices, compensating by offering less for the target companies. They were presumably bidding because they thought they could make *more* money than the companies were making at the time, which is a slightly different matter from whether the companies were making *too much* money.

Transmission and supply prices have now been reviewed a second time, and one-off cuts have again been imposed. These sudden adjustments may give the companies fewer incentives to cut costs (particularly in the run-up to a review) than more gradual price changes, but it was

[9] Strictly speaking, distribution prices were nothing to do with the generators, but their shares fell anyway.

clear that their profits were too high at the times the cuts were made. Overall, regulation has gradually cut prices to customers, but it has taken time, and the companies have earned high profits before the regulator cut prices. This may be inevitable, since the main reason for improving performance is believed to be the prospect of higher profits. Competition offers the prospect of greater speed and flexibility in passing improved performance to consumers, but the electricity industry's record on this has at best been mixed.

Has there been enough competition in generation?

The government had hoped that the generation market would be competitive, but one legacy of the failed attempt to privatise the nuclear stations was the duopoly of National Power and PowerGen. These companies started their lives with three-year contracts for coal and electricity, arranged to meet a number of objectives. The coal contracts required the generators to buy almost all of their fuel requirements from British Coal, and to pay much more than the world market price. The excess cost of this was passed on to the RECs' captive franchise customers in the electricity contracts. Customers in the competitive market could not be made to share in this cost, since they would have the option of buying electricity from a supplier paying Pool prices, and those were expected to reflect the world price of coal, not the British price. Pool prices were also expected to reflect the generators' inherited excess capacity, and the contracts included a "capacity allowance" to raise the generators' revenues until they had brought the market into equilibrium by closing plant (Henney, 1994).

In a competitive market with excess capacity, prices would be kept low, and might only cover the industry's variable costs. If the industry has deep pockets, it can wait until demand rises, but otherwise it must either reduce the amount of capacity, or collude to raise prices above short-run costs. Hunt (1992), who was an advisor during the privatisation process, doubts that the industry would have been able to close plants in an orderly manner if they had been divided among a larger number of companies. She therefore suggests that the conventional duopoly was not just a side effect of the failed nuclear privatisation, but the only way of dealing with the overhang of excess capacity. National Power and PowerGen had the ability to raise Pool prices, but their ability to raise contract prices was limited by the threat of entry, and most electricity is sold through contracts, not the Pool.

The problem is that the one-off overhang expected in 1990 has turned into an almost continuous excess of capacity, because of the amount of entry. The RECs had been given the opportunity to make some unregulated profits by investing in new power stations, and eleven of them took it. The contract structure developed for these stations, and the fact that their regulation allowed them to pass their purchase costs straight through to their captive customers, meant that these investments appeared almost riskless. The regulator agreed that the stations met the RECs' economic purchasing condition, given the unattractive nature of the generators' initial offers for renewed contracts.[10] The RECs might have been less enthusiastic if yardstick regulation had been used for their purchase costs, rather than a pass-through, although the desire to reduce their dependence on the major generators was another justification for the new stations.

Following this first "dash for gas" in the early 1990s, a second wave of stations has been built, with outside investors playing a larger role. The major generators have also built gas-fired stations, in part to reduce their sulphur emissions by switching away from coal-fired generation. They have also closed or mothballed 19 GW of capacity, almost matching the 20 GW that has been added since 1990. If the incumbents had not been willing to reduce their capacity in this way, and to keep prices at about the level of entrants' costs, much of the new capacity would have been unprofitable. Figure 4 shows the way in which the entrants (and increased nuclear output) have displaced output from National Power and PowerGen.

Combined cycle gas turbines are clearly the cheapest form of new generation, and building CCGTs will often be a cheaper way to reduce sulphur emissions than retro-fitting existing stations with flue gas desulphurisation equipment.[11] The problem in England and Wales was that the CCGTs were built while the industry had excess capacity, and before sulphur emissions became a binding constraint. It is hard to avoid the conclusion that they raised the industry's costs.

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[10] It is possible that the generators planned to make better offers at a later stage in the contract negotiations, but the RECs built their own stations instead.

[11] The comparison depends on fuel prices and on the remaining life of the coal station, over which the investment has to be amortised.

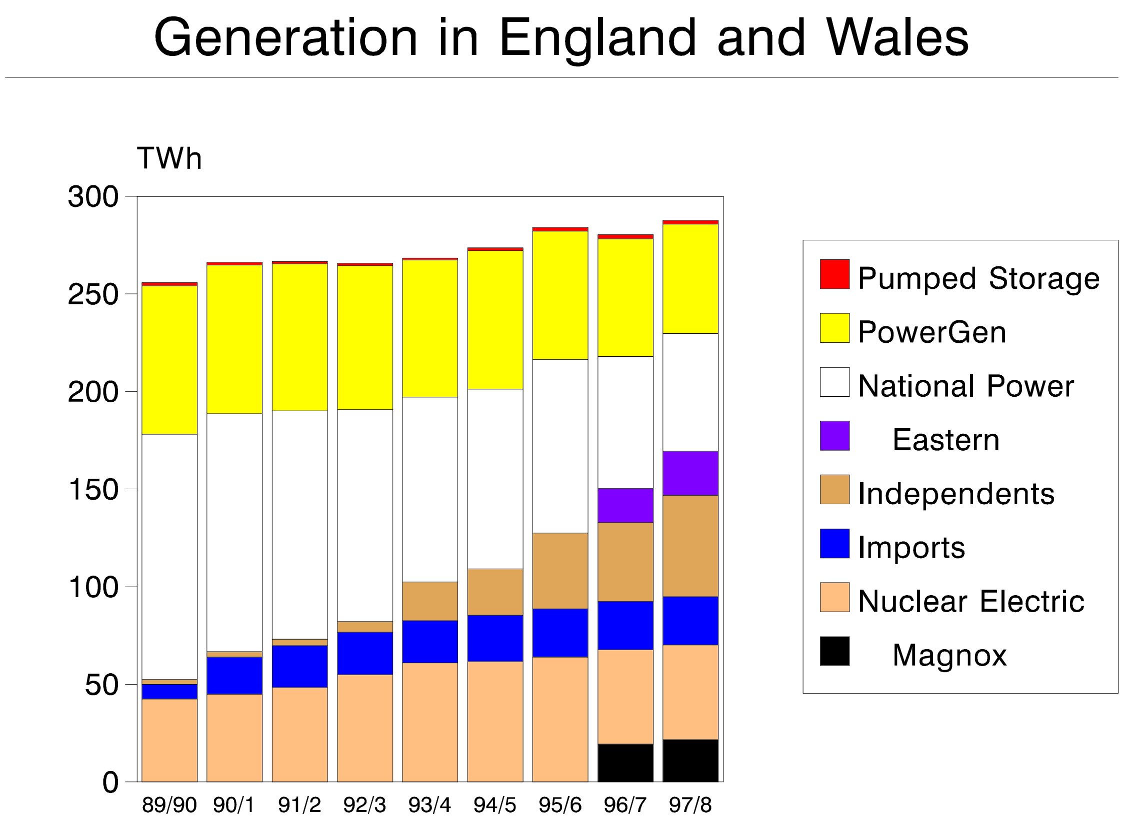

figure 4

The switch to gas-fired generation also had a large impact on the coal industry. The UK's coal output fell by one-third between 1982 and 1992, from 125 to 85 million tonnes, but British Coal's employment fell by nearly four-fifths, as the corporation concentrated its output on its more productive mines. In 1982, British Coal employed around a quarter of a million workers, but this had fallen to roughly 50,000 by 1992. During that year, it became clear that the generators wanted to reduce their purchases from 70 million tonnes (in 1991/2) to 30 million tonnes a year (from 1994/5 onwards), and that this would result in the loss of another 30,000 jobs. This sparked a political crisis, resolved with promises of government assistance, but the stations which were crowding coal out of the industry's fuel mix already had contracts. The government was not willing to tear up these contracts, and was unable to increase the amount of coal burned. It was able to persuade the electricity industry to agree to another set of linked coal and electricity contracts, passing on the excess cost of British coal to the RECs' franchise consumers. The coal price was falling, however, reducing the premium in the electricity contracts. These had to expire in 1998, when the franchise was due to end, in case competition made it impossible to pass on further premia.

In the Autumn of 1997, it became clear that the generators' demand for coal would fall further. By that time, however, Britain had a Labour government, with historical ties to the miners, and a slightly more interventionist mindset than the Conservatives. Existing contracts remained sacrosanct, but the government announced a temporary moratorium on new power stations.[12] This would not affect the amount of coal burned in the next two years (since it only affects stations not yet under construction) but had symbolic importance as a statement of support for the coal industry.

The industry's regulator, however, "was concerned about the consequences of the proposed policy of restricting new entry both for competition and for prices to customers." Allowing himself a degree of criticism unusual for a civil servant, he advised the government that "[t]he distortions in the market ... would not seem to justify [the] policy," and that "it would be helpful if ... an early opportunity could be taken to relax and then remove it" (Offer, 1998b). His concerns stem from his belief that the generation market is still insufficiently competitive, and that removing the threat of entry will allow the incumbents to raise prices.

The regulator has issued ten reports on competition in generation since 1991, and all of them have reflected his concern at National Power and PowerGen's dominance of the Pool. At first, Pool prices were below the companies' avoidable costs (most of their sales were hedged by contracts at much higher prices) and the regulator did not object to increases, but by 1993, he found that prices were higher than they would have been in a competitive market. In 1994, the companies agreed to sell 6 GW of their capacity (about 15%), and to restrain prices in the Pool, and for new contracts, rather than face a reference to the Monopolies and Mergers Commission for investigation and possible action. Ironically, many of the duopolists' sales were already covered by their five-year coal-related contracts with the RECs, and the reduction in short-term prices probably had a bigger impact on Nuclear Electric than on the companies which agreed the deal!

The Undertaking to keep prices down was promptly followed by a winter of record prices, caused by plant failures which reduced the amount of spare capacity, and raised capacity

[12] Section 36 of the Electricity Act 1989 requires new stations to obtain a consent from the government, but this had not previously been a significant barrier.

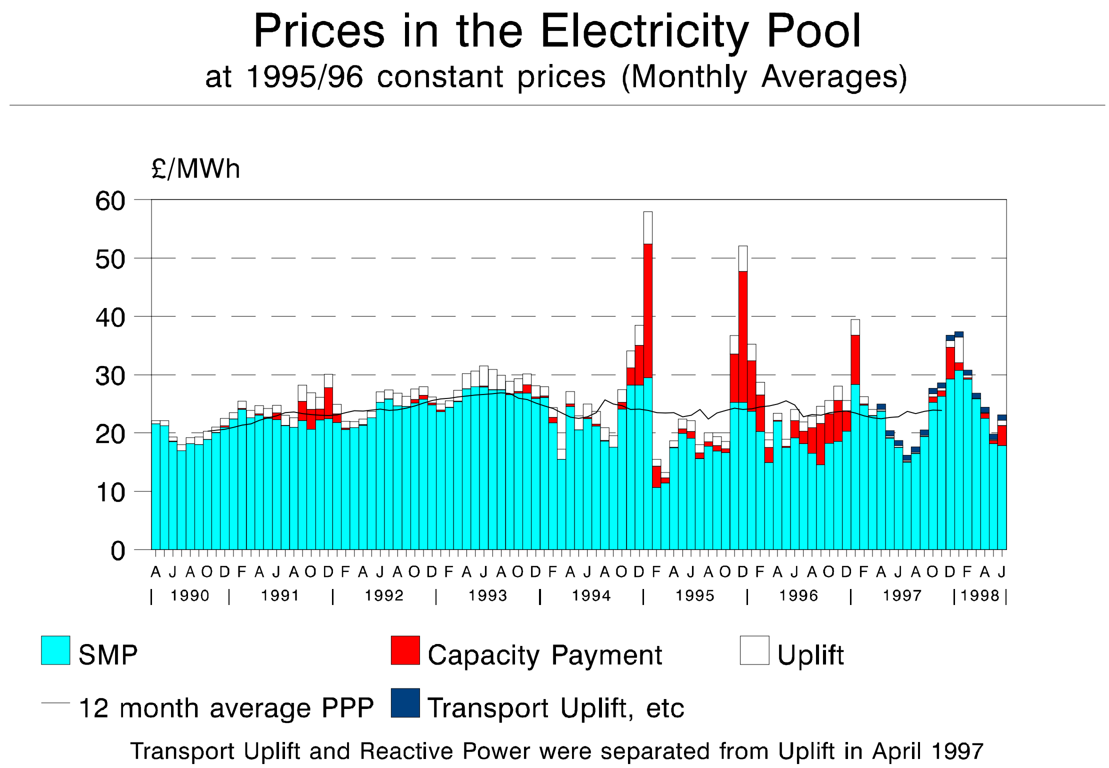

Figure 5

payments (figure 5). The regulator accepted that these plant failures were unusual, and that the high prices did not breach the companies' Undertakings, but warned them to avoid a repetition. Capacity payments were even higher the following year, but the companies kept the annual average price down to the level they had agreed with the regulator. The regulator made no attempt to extend the restraint on prices, which was only ever intended as a temporary relief, and had significant effects on companies which were not parties to it. His long-term hopes for the deal agreed in 1994 depended on the generators selling part of their capacity to increase competition in the "mid-merit" part of the market.

By the mid-1990s, a large number of CCGT stations were competing for continuous, baseload, running alongside Nuclear Electric, imported electricity, and the duopolists. This part of the market was probably adequately competitive, but most Pool prices were set by mid-merit stations which only generated for part of the time: by definition, SMP is a *marginal* price. Most of the time, this price was set by one of the stations owned by National Power or PowerGen, and they clearly had enough infra-marginal capacity to benefit from price increases. Furthermore, the threat of baseload entry would not prevent them from changing the balance of peak and off-peak prices, deterring entry by keeping the time-weighted average low, but raising their own revenues. Forcing the companies to sell some of their price-setting plant should reduce both their ability and their incentive to raise prices - a company which raised its bids would face a greater risk of losing market share to one of its larger number of rivals. Generating less, it would also gain less from the higher prices which resulted.

Eventually, both National Power and PowerGen leased some of their plant to Eastern, one of the RECs. The regulator relaxed the limit on the company's investment in generation to allow this. One feature of the deal was an "earn-out": Eastern paid the lessors £6 for each MWh it generated. This solved the difficulty of valuing the stations, for the generators did not want to agree a price based on the earnings from mid-merit running, and find that Eastern was running it on base-load, but also raised Eastern's opportunity costs, and hence the level of its likely bids. In the event, Pool prices were slightly lower in real terms in the first year after the plant was transferred, but price increases during the winter of 1997/98 prompted the regulator's tenth report on competition in generation. He found that the companies had reacted to lower capacity payments by raising SMP (a logical strategy if they were targeting the Pool Purchase Price which they receive) and called for further plant divestitures.

The regulator and the government have also been considering changes to the way in which the wholesale market is organised. The coal industry has long believed that the Pool is biased against it because nuclear and CCGT stations can bid zero, guaranteeing that they will run, but still receive the Pool Purchase Price, or a contract price which may be even higher. It is certainly possible that some CCGTs have contracts which make it attractive for them to run, even when SMP is below the value of the gas they are burning.[13] This would distort the merit order, although it ought to be possible to renegotiate the contracts, reach a more efficient outcome, and share the resulting benefits among the parties involved. Many large industrial customers seem to believe that the single price auction raises their prices, and that they would pay less if each station received its own bid. This would certainly be the case if some stations continued to bid zero, but that is not a likely outcome! Other customers may believe that they can negotiate discounts if the industry moves towards a system of bilateral contracting, as they did in the days of the CEGB.

[13] This is partly because their gas is on "take or pay" contracts which ban its resale, and partly because some electricity sales contracts only pay the station if it operates, unlike the CfDs discussed earlier.

The regulator has accepted some of these arguments, and is proposing to replace the Pool with a series of bilateral markets (Offer, 1998a). Generators, suppliers, and customers would be free to make their own arrangements until a few hours before trading takes place, reporting their anticipated schedules to the grid controllers. NGC would run a balancing market in the final hours before trading, and would use it to set prices at which traders would settle the differences between their contracted commitments and the amounts they actually generated or took from the grid. The government has not yet announced its view on these proposals, but has agreed with the analysis of the Pool's faults.

This analysis seems somewhat flawed to me. Any distortions in the merit order are not due to the Pool system, but to the interaction of that system with bilateral contracts that lead companies to ignore the Pool's price signals. To increase the importance of bilateral contracts does not appear to be the most fruitful way of seeking a solution. It is suggested that since the move to bilateral contracts will ensure that every generator is paid its own bid, this will reduce prices. But few generators will want to receive less than the "going rate" for their power, and will aim to sell contracts at that price, which will be determined by the most expensive stations in use at each time, just as with the SMP system. Some stations will mis-judge the going rate (or be particularly keen to run) and sell for less, giving benefits to their counter-parties, but some buyers may mis-judge the market and pay more than the going rate. If these mistakes distort the merit order, costs will rise. Proponents of efficient markets would point out that these distortions could be arbitraged, and that expensive stations which had sold power would deliver it by buying from cheaper stations which had not found a buyer in the first stages of trading. If the transactions costs involved were not too high, that could lead to an efficient dispatch. It would also reduce the penalty for a generator which fails to sell its power at an early stage of the trading process, and hence the incentive for generators to set prices below their estimate of the going rate.

The large customers may believe that they will pay less with the new arrangements because they can negotiate better prices than the RECs, but the RECs are the generators' largest customers, and the ones most likely to get any discounts. Maybe the customers hope that the new system will be so much less transparent than the present wholesale market that some suppliers will be able to hide the fact that they are passing on their cheapest contracts to large customers, and discriminating against the others. This still leaves the question of why any supplier would wish to do this - the margins involved are small, and there are few long-term benefits to having a high current market share of such mobile customers.

I am not suggesting that the present trading system is flawless - the Pool has many faults. Its governance structure - an industry club in which a small minority can delay changes for years - is crying out for reform, but most of the faults in its trading rules are suitable for incremental reform. The Pool should not be blamed for problems which are due to market power, for they will probably reappear, whatever trading arrangements are chosen. The demise of the coal industry is due to excessive entry, and that was a response to the incumbent generators' market power. Along with the high prices, it implies that generation in England and Wales is not competitive enough.

What will happen with competition in supply?

The industry is just starting the final phase of competition: about three-quarters of a million small customers have been allowed to choose their supplier since Monday 14 September, and competition should spread to the rest of the country by June 1999. No-one knows how many of these customers will bother to switch supplier, or what the impact will be if the market does become fully competitive, with a high degree of switching.

We do know that larger customers have learned to shop around, and that many of them have changed their supplier. Most suppliers now offer advice on electricity use, and some sell "energy services", when they will meet the cost of investment (in small-scale generation or energy conservation) in return for a share of the benefits. Second tier suppliers have often given the best prices (and the initial limits on the major generators' sales, designed to restrain moves towards vertical integration, had to be removed because customers complained that this stopped them getting some of the best prices in the market), but the incumbents have generally felt the need to offer reasonable terms. Even the smallest customers in the above 100 kW market will be spending around £20,000 a year on electricity, and have a strong incentive to shop around.

Competition is now being extended to customers who spend much less on electricity, and may be much less interested in switching supplier to make a small saving. Some companies have issued tariffs for customers outside their traditional areas, and in most areas, a domestic customer taking 3,300 kWh a year (the industry's "standard") could save between 5% and 10% of their bill, or between £10 and £20 a year, if they bought from the cheapest new supplier in their area (not always the same company). We have already had two years' experience of competition in the gas industry, where the new suppliers were offering discounts of up to 20%, or some £60 a year for the average domestic consumer. Despite these savings, British Gas has retained three quarters of its customers in the areas where the market has been open for more than a year, and the number of customers leaving seems to have stabilised. Waddams Price (1997) shows that domestic customers who took above-average amounts of gas, and stood to gain more, were somewhat more likely to change their supplier.

British Gas (as Centrica plc is known in the UK) has responded to competition by introducing a significant discount for customers who pay by the (cheaper) method of direct debit from their bank account, and has reduced prices in line with its price control, but has not attempted to match the entrants' prices. The company is not yet allowed to discriminate in order to win customers back, and cutting prices across the board would only be profitable if the company's marginal costs were a very long way below its prices.[14] Similarly, the RECs have

Table 1: Domestic Customers' Annual Charges for Energy and Supply

	Company Selling:				
Customer's Area:	Eastern	Manweb	Northern	Southern	Yorkshire
Eastern	**169**	152	167	147	161
Manweb	164	**171**	162	151	165
Northern	169	167	**189**	153	168
Southern	156	152	153	**155**	156
Yorkshire	153	155	152	148	**163**

Annual Bills (in £), net of transmission and distribution charges, for domestic customers on standard tariffs taking 3300 kWh a year, excluding Value Added Tax.

Sources: Company tariffs and Trade and Industry Committee (1998)

[14] Assume (optimistically) that British Gas could recapture all of its lost customers by matching the entrants, and cutting prices by 20%. Its sales volume and its variable costs would rise by one-third, but its revenues by only one-fifteenth (4/3×4/5-1). This would only be profitable if variable costs were less than one fifth of revenues, but the transportation charges alone (paid to Transco, a separate company) are roughly twice this.

rebalanced their prices, but appear to be charging the maximum allowed by the regulator, rather than matching the prices charged by second-tier suppliers in their home areas. Outside those areas, they are offering rather better prices. An average domestic customer in Cambridge, paying Eastern Electricity's standard tariff, could save about £10 a year by switching to Yorkshire Electricity, for example, but a customer in Yorkshire could save a similar amount by switching to Eastern! Table 1 shows how much five of the RECs will be charging domestic customers for energy and supply, deducting the (common) transmission and distribution charges from their tariffs. Yorkshire is the only company which is not charging its "home" customers (shown in bold) more than customers in other areas, and Southern is the only company which is not being significantly undercut by its rivals.

The lower prices which competitors are offering both in gas and electricity do not reflect great efficiency gains over the incumbents (particularly as most of the competitors are incumbents elsewhere) but are due to wholesale prices below the levels which the regulators have allowed the incumbents to pass on to their customers. In the case of British Gas, this reflects current wholesale gas prices which are well below those contained in some of the company's older long-term contracts, following a large rise in the level of North Sea activity. In the electricity industry, the regulator has determined the amount (in p/kWh) which each REC can charge in 1998/99 and 1999/2000, projected from its costs in 1996/97. In that year, the companies paid much more for the electricity they were buying for their smaller customers than for the competitive market, since both the coal-related contracts with National Power and PowerGen, and their contracts with IPPs were relatively expensive. The regulator assumed that these contract premia would fall in 1998, but is still allowing the companies to charge more than the recent level of the wholesale market price. Since the contract premia are usually effectively lump sums, the RECs can buy extra supplies for ex-franchise customers in other areas at the wholesale price for the competitive market, and this allows them to undercut the regulated prices.

Despite this, the savings on offer are fairly small, and it seems likely that relatively few customers will switch. Green and McDaniel (1998) present a cost-benefit analysis of the introduction of competition, and suggest that customers will gain by about £300 million a year (compared to a non-competitive scenario in which wholesale prices remained at 1997/8 levels). The largest gains would go to the small proportion (fewer than ten per cent) who changed supplier. Electricity companies and the coal industry together would lose more than £400 million a year at first: not only would prices be lower, but they will also have to pay more than £500 million[15] towards computer systems to keep track of customers in the newly competitive market. A complex system of profiling has been developed, so that each customer's consumption can be allocated across the half-hours since their last meter reading (several months away) and their supplier can be charged the correct amount by the Pool. Other systems give each customer a unique identifying number, and ensure that only one supplier is responsible for selling to them at a time. These systems have proved to cost much more than was first hoped, and the start of competition has been delayed for several months because the industry was not ready in time. This delay is more sensible than the approach taken when the 100 kW market was opened up in April 1994. These (larger) customers needed to have a half-hourly meter with a properly registered communications link to the Pool, but many were allowed to change supplier before this was in place - the regulator decided that competition had to start on time. They had to endure several months of incorrect and estimated bills, and were later charged for the cost of sorting out the chaos!

If we do find that most customers are not interested in switching supplier, then the introduction of competition will leave the RECs with a lot of market power. The regulator has set price controls for the first two years alone, in case competition will be strong enough to make them unnecessary after this time, but this may not be the case. If each REC retains a "natural franchise", then vertical integration will be a good way for generators to secure a customer base. PowerGen tried to merge with Midlands Electricity in September 1995, followed a week later by National Power's proposed merger with Southern Electric. These mergers were referred to the Monopolies and Mergers Commission, and eventually blocked by the government. The motives for the mergers included the desire to create a "natural hedge" for the companies' generation and supply businesses, making the risky wholesale price irrelevant, and to create stronger companies, better able to compete to supply domestic customers after 1998. The main problem was that vertical integration between these generators and two major suppliers was likely to make the wholesale contract market much thinner, impeding entry into both generation and supply. The government took "the view that, in the current state of the market, there would be significant detriments to competition if these mergers proceed[ed]" (DTI, 1996).

[15] Later estimates suggest that the total, including the two Scottish companies, will be nearly £: billion.

The statement blocking the merger repeated the government's view that vertical integration *per se* was not ruled out. Scottish Power had already been allowed to buy a REC (Manweb), and Eastern was allowed to take over the 6 GW of plant divested by National Power and PowerGen. PowerGen is now attempting a vertical merger (with East Midlands Electricity) for the second time, and has offered to sell one of its large power stations (2 GW out of the 15 GW it owns) as a *quid pro quo* for getting government clearance. Southern Electric, the last independent REC, has agreed to merge with Scottish Hydro Electric. Many commentators have suggested that the industry may finish up with a small number of vertically integrated groups. If vertical integration is used as a way of internalising risks, while the companies continue to compete against each other, this might be a good thing, but there is a risk that they would find tacit collusion more attractive than competition.

If domestic customers do learn to shop around and switch supplier, then the RECs will no longer have a "natural franchise", and vertical integration will be less attractive. Furthermore, it may become harder to enter the generation market, for suppliers may be reluctant to take the price risk involved in traditional long-term contracts with generators. Other contract structures to permit entry may evolve, of course, and this remains a subject for further research (and observation). It is at least possible, however, that a very competitive supply market will lead to a concentrated generation sector, as only large incumbents can accept the price risks of building new stations (or, rather, use market power to avoid these price risks).

Since generation accounts for far more of the industry's costs, it would seem more important to aim for competition in generation than in supply. That requires freedom of entry, and it may be that a less competitive supply market helps with this. It would not make competition in generation inevitable, however, for incumbents will always benefit from barriers to entry, such as vertical integration. The worst of both worlds would be to discover that competition in supply is limited, without achieving a competitive generation market.

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