

# **Draining the Pool:**

## **The Reform of Electricity Trading in England and Wales**

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The British government has decided to abolish the “Pool”, the electricity spot market in England and Wales, and replace it with a series of bilateral markets. The government believes that the Pool has been biased against coal-fired generators, and that its price-setting rule (all generators are paid the bid of the marginal unit) has inflated the level of prices. In practice, many of the perceived problems in the Pool are the result of market power, not the basic design of the Pool, which is capable of sending the right price signals to generators. Efficient bilateral markets could well produce similar results. Prices could rise, however, if buyers are more risk-averse, and less good at trading, than sellers.

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## **Introduction**

For many people, the Electricity Pool of England and Wales has been the centrepiece of the radical reform introduced in 1990. The British government created a wholesale market through which all generators could sell their output on the same terms. When combined with non-discriminatory access to the transmission system, this made competition in generation possible. Similarly, all retail suppliers could buy electricity on the same terms, and this was combined with access to the distribution system to enable competition in supply. In the years after 1990, competition in both generation and supply became a reality, and prices to most consumers fell by around 30% in real terms. Electricity industries around the world were encouraged to follow the British example, and the Pool was seen as a central part of it.

Despite this, the British government has recently announced (Department of Trade and Industry, 1998) that the Pool will be replaced by a series of bilateral markets, as suggested by its regulator (Offer, 1998). In October 1997, the government asked the regulator to consider how a review of the Pool might be undertaken; the terms of reference were published at the end of January, and interim conclusions in June. Although these were subject to consultation, the regulator's final proposals were basically unchanged, and these were adopted by the government in October 1998, just a year from the start of the process. The Pool's critics, particularly the coal industry and some large electricity consumers, strongly supported the changes.

Why is the Pool being replaced? The "official line" is that it has discriminated against coal, and that electricity prices are too high, as a direct result of the way in which the Pool works. The Pool also contains an administered capacity payment which is felt to be incompatible with a properly competitive market, while the demand side plays very little part in price-setting. The proposed bilateral markets will be two-sided, and there will be no capacity payment. They will not favour any fuel against another, and prices are expected to fall in the properly "competitive" market.

In this paper, I will ask whether these claims are true. I will start by describing the Pool, and the part it has played in the electricity industry since 1990, a part which earned it many enemies. I will then examine the claims that it is biased against coal, and that its mechanisms have encouraged artificially high prices. I ask whether abolishing the capacity payment mechanism will have much effect on the pattern of prices. I will end with some comments on demand side participation.

## **The Role of the Pool**

The restructuring and privatisation of the electricity industry in England and Wales was announced in February 1988, when the government published a White Paper (Department of Energy, 1988) which set out its vision of a competitive industry. The Central Electricity Generating Board (CEGB) would be divided into the National Grid Company (NGC), for transmission, and competing generation companies. The entire industry would be privatised, with the transmission company owned by the 12 Regional Electricity Companies (RECs), to ensure its independence from the generators. The government hoped that this would allow entry into generation. There was also a suggestion that customers would be able to choose where to buy their electricity.

The RECs were privatised in December 1990, and the industry's conventional power stations in March 1991. Unfortunately, they had only been divided between two companies, National Power and PowerGen, because the government had hoped that the larger of these would be large enough to absorb the risks of nuclear power stations. This was not the case in 1990, although the more modern stations were eventually privatised in 1996. By that time, the 50,000 largest customers (taking half the industry's output) had been given a choice of supplier. This choice is due to be extended to every customer in the country between September 1998 and June 1999.

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 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.<sup>1</sup> 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.<sup>2</sup>

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.<sup>3</sup> Power Stations which were available would receive the

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<sup>1</sup> 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.

<sup>2</sup> 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 set, if they were allowed to set it after the shortage has appeared. In Australia, a (very high) administered price is used in these circumstances.

<sup>3</sup> 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.

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  $(1 - \text{LOLP}) \times \text{SMP} + \text{LOLP} \times \text{VOLL}$ . 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.

### **Contracts**

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.

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.<sup>4</sup> 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).

The Pool was designed in a hurry, and the designers knew that they had not created a perfect market. In practice, the Pool is not really an organisation, but a contract, the Pooling and Settlement Agreement, which all electricity companies have to sign. The Pool has a Chief Executive with a small staff, but most of its operations are sub-contracted to NGC, and it is governed by its members. The Pool Rules specify the procedures which NGC will follow in operating the market, and give the formulae for converting bids into prices. The Agreement contains clauses which allow its own modification, but the process has turned out to be tortuous. If a problem is identified, a sub-committee will be established to find a solution, and its proposals will eventually reach the monthly meeting of the Pool Executive Committee.<sup>5</sup> If the executive approves the proposals, work can start on implementing them, unless one of the member companies requests a Pool Members' Meeting, followed by a vote, followed by a weighted vote (with weights based on market shares). After this, the Pool's own procedures are exhausted, but a dissenting company can still appeal to the regulator, blocking the decision for another two or three months (and sometimes changing it). Several issues were identified as "too difficult" to resolve in time for the market opening in 1990, and were placed in a schedule for subsequent decisions. Most of them were going to create winners and losers, (which is why they could not be decided in 1990) and the Pool has not been particularly successful in dealing with them: in many cases, losers have exploited their powers of delay to the utmost, and the original deadlines for finding a solution are long past.

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<sup>4</sup> 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.

<sup>5</sup> This originally contained five generator representatives (in practice, delegates from National Power, PowerGen, Nuclear Electric, and two representing the other generators) and five suppliers (four RECs, with each seat rotating among three companies, and an independent supplier). The four REC representatives often held a pre-meeting, after which they voted as a block. The structure has since been reformed to reflect the blurred distinction between generators and suppliers (many companies are both) and allow some customer observers.

## **What has happened since 1990?**

Special contracts were drawn up to avoid unpleasant surprises when the electricity industry was restructured. The generators were privatised with three-year contracts to buy fixed quantities of British coal, at above the world market price, and to sell electricity to the RECs. The prices in the electricity contracts were high enough to cover the cost of the coal (with a profit margin for the generators), and the RECs were allowed to pass the cost of the electricity on to their captive smaller consumers. This largely insulated the electricity companies from unforeseen events until three years after the restructuring (safely past the next General Election), and also protected the coal industry from competition. Small electricity customers would pay slightly higher prices in the first year, but after that, their prices would be held constant in real terms.

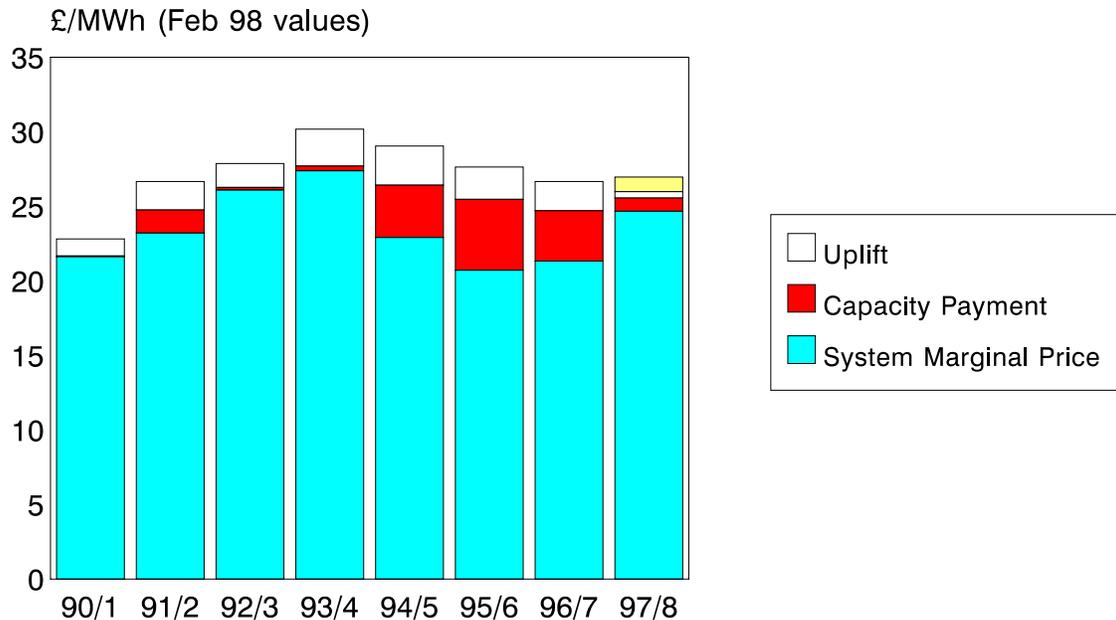
The government expected that Pool prices would be based on the cost of imported coal, since this would determine the generators' marginal cost. Larger electricity customers, able to shop around, could avoid paying any premium for the coal industry by choosing a supplier who was buying from the Pool, and so there was no attempt to make them contribute towards the cost of British coal. Instead, the electricity industry agreed contracts to cover sales to these consumers, at prices based on the forecast Pool price, which typically implied reductions of up to 10% on the prices they had been paying.

At first, Pool Prices were very low: much lower than the government had expected. The generators' contracts made them largely indifferent to Pool prices, and gave them an incentive to bid low and burn as much coal as possible. In April 1991, however, some of these contracts expired, and the generators felt able to raise prices (Helm and Powell, 1992), as shown in figure 1. Some large customers had been persuaded to buy at Pool prices, rather than at the contract prices which had turned out to be more expensive in 1990/1, but this left them exposed to the increase. Their complaints (and those of the RECs) led to the regulator's first enquiry into the major generators' behaviour: so far, he has published ten reports on competition in generation.

The first reports concluded that Pool prices had been below the level of the generators' avoidable costs, and that it was difficult to object to an increase, although some specific bidding strategies were criticised. The regulator also criticised some features of the Pool Rules which led to price spikes, when the price might treble (or worse) for two or three half-hours. In the early years, this was often due to the way in which the scheduling program looked for spare capacity when there was little available, choosing to run expensive stations (which then set SMP), but this

## Pool Prices: Time-weighted averages

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Source: Offer (1998)

Uplift was split into two parts in 1997/98

Figure 1

has now been changed. Spikes still occur from time to time, largely when the program reacts in an unexpected way to a particular bid: the complexity of the program and the bids sometimes make it hard to determine the cause of a particular outcome. Price-setting is a mechanistic process which occasionally seems to give absurd results, but because contracts have been written around this process, the prices have to stand. Price spikes have been a big irritation to those larger customers who buy at Pool prices, although their main cause of complaint is still the average level of prices.

In his first reports, the regulator did not object to the level of prices, but in 1993 he decided that recent price increases had been unjustified, and threatened to refer the companies to the Monopolies and Mergers Commission. To avoid this, they promised to keep prices down for the next two years, and to sell about 15% of their plant. They complied, and the real time-weighted Pool Selling Price fell in each year between 1993/94 and 1996/97. Prices and quantities are positively correlated, and so the demand-weighted price (not shown) is higher than the time-weighted price, particularly between 1994/95 and 1996/97, when capacity payments

# Generation in England and Wales

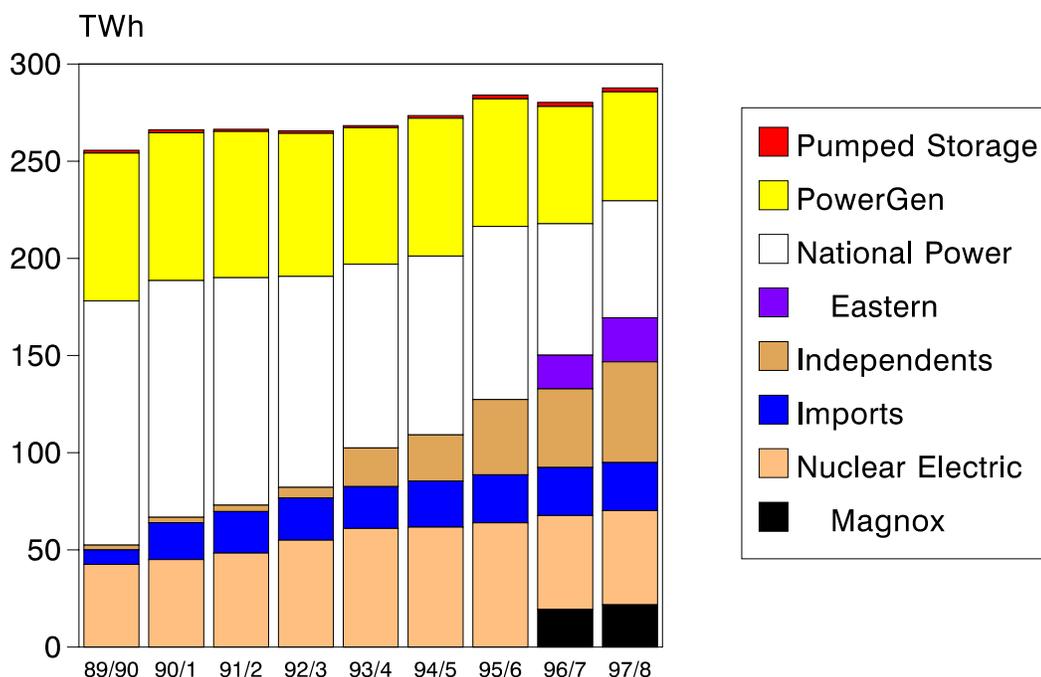


figure 2

were high. Note that the lower capacity payments of 1997/98 were more than offset by an increase in SMP, as the major generators raised their bids to maintain their revenues, and were criticised for this by the regulator.

## Entry

National Power and PowerGen might argue that the market is now far more competitive than when it was first established, and figure 2 shows how market shares have evolved since 1989/90 (when the companies existed in “shadow” form). Nuclear output has increased significantly: the Advanced Gas-Cooled Reactors which had been under construction since the 1960s finally began to produce significant amounts of power, and a Pressurised Water Reactor at Sizewell B was commissioned in 1995. There has also been a dramatic rise in the output of “independent power producers” (IPPs), almost all of them Combined Cycle Gas Turbine (CCGT) stations. Both trends have depressed the incumbent generators’ market shares. The market has become

further fragmented in the last two years of the figure, when Magnox Electric (owning the older nuclear stations) which was not privatised, was split off from Nuclear Electric, which was. Finally, Eastern Group has acquired the 6 GW of coal-fired capacity which the regulator persuaded National Power and PowerGen to sell. The regulator believed that these sales were needed because although the major generators were losing market share, they still owned almost all the mid-merit stations which actually set the System Marginal Price. They could still influence this price, even though their declining market shares made it less attractive to do so. Most of the early IPPs were not truly independent, but affiliated to the RECs, which had been allowed to invest in generation, within limits.<sup>6</sup> The stations had “back-to-back” gas purchase and electricity sales contracts, and since they faced few price risks, they could be largely debt-financed. The RECs faced a potential conflict of interest, since they could pass the cost of their electricity purchases on to their captive smaller customers, while their own stations’ revenues contributed to their profits. The RECs therefore had to be able to persuade the regulator that their purchase contracts were “economic”, but the incumbent generators were quoting high contract prices at the time, which gave the RECs a case to argue. The stations did have the effect of reducing the existing generators’ market power, but the high prices which the incumbents were quoting also allowed the new stations to sell their output at *prices* well above the avoidable *costs* of the existing stations which they displaced. Practically all the costs of a new station are avoidable at the time when the decision to build is made, while many of the costs of existing stations are sunk. While the existing stations are sufficient to meet demand (which was the case in England and Wales at this time; few stations were due to retire) then investment in new stations can only be justified on cost grounds if their total costs are lower than the avoidable costs of the stations which are displaced. This does not seem to have been the case for most of the investment of the early 1990s.

The CCGTs have had environmental advantages: they have practically no sulphur emissions, and their carbon emissions are far lower than those of coal-fired stations. These environmental advantages have been one reason why the incumbent generators have also built CCGTs, and have been able to scale back the investments in Flue Gas Desulphurisation

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<sup>6</sup> The limits, set in MW of capacity, were roughly equal to 15% of the peak demand in each REC’s area. Since the average electricity demand is about two-thirds the peak demand, a REC which was using all of its limit could have met about a quarter of its “native load”, or half of its sales to small customers (under 100 kW, who could not choose their supplier until 1998).

equipment proposed at the time of their privatisation. The need to reduce sulphur emissions would have justified building CCGT stations from the middle of the 1990s onwards, by which time some of the older coal-fired stations would also be due to retire (Newbery, 1994). But environmental constraints are not yet tight enough to justify the 14 GW of gas-fired capacity which has already been commissioned, with another 4 GW under construction. The over-rapid investment in the stations has increased the electricity industry's costs, and hastened the decline of the British 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 RECs' franchise over small consumers was due to end, in case competition made it impossible to pass on further premia.

The coal industry was privatised in a series of trade sales in 1994, with a single company, RJB Mining, buying most of the mines in England and Wales. There have been further closures and redundancies since the privatisation, as RJB has tried to bring its costs down to a level competitive with imported coal. Although transport costs give the British industry an advantage, the world coal price (in sterling terms) has weakened, and so the target has been moving in the wrong direction. Furthermore, while reducing costs will help the coal industry compete with imported coal, the greater threat to British coal still comes from losing market share to gas-fired stations.

## **The Pool Review and the Energy White Paper**

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.<sup>7</sup> 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 moratorium would last while the government reviewed its energy policy, and the regulator was asked to review the electricity trading arrangements in England and Wales.

The coal industry and many large industrial customers seem to believe that the Pool is biased and works to their direct disadvantage. They argue that the fundamental problem is the way in which the Pool pays the System Marginal Price, SMP, to all the stations which are scheduled to generate normally, regardless of their bid. Nuclear stations, and many CCGTs, bid close to zero, which ensures that they run, while they are allowed to earn a price set by other stations, usually coal-fired. These stations have to bid realistic prices, and coal is crowded out of the market as a result, undercut by unrealistic bids. Those large customers who have even and predictable demands would like to be able to contract directly with "baseload" stations, and object to paying peak Pool prices which reflect the costs of peaking and reserve plant. Paying all generators the same price is also believed to increase market power, since a large generator need only raise the bid of its marginal stations in order to increase its earnings from all of its plant.

Capacity payments are seen as an administered mechanism which should have no place in a competitive market, and allows the generators to earn high prices at the expense of their customers. As a short-term signal, it cannot support long-term investment in capacity, while it does not even signal short-term shortages well - a station is deemed to contribute to capacity for eight days after it becomes unavailable, as an anti-gaming device to discourage short-term capacity withholding.

The Pool has largely ignored the demand side of the market: generation is scheduled against a demand forecast provided by NGC, which is expressly forbidden to take account of any response to high prices on the part of customers. There has been a small-scale demand side bidding scheme since 1993, in which a few large customers bid "demand reduction blocks". These are treated as generation by the Pool, occasionally set SMP, and are self-despatched by the

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<sup>7</sup> 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.

customer, who is required to reduce demand whenever SMP exceeds their bid. In return, the price for that demand block (when it is being taken) does not include the capacity payment, on the grounds that no additional capacity is needed to supply this reducible demand - when capacity grows short, the demand will be reduced. The scheme is unpopular with customers, who feel that it does not offer them enough in return for managing their demand, but the electricity companies do not want to offer any more. Since there is political and regulatory pressure in favour of demand side bidding, but the electricity companies determine what happens in the Pool, the present scheme has continued to limp along. There is a second opportunity for demand management, however, because NGC now runs annual auctions for short notice reserve, open to generators and customers who can be dispatched by NGC when required.

There were other concerns: bids in the Pool are “non-firm”, so that generators are not penalised if they fail to follow their operating schedules; the mechanism for converting a five-part bid into a single price was felt to be too complex; and hedging markets remained under-developed, despite eight years of Pool trading. One reason for this was felt to be the risk of market manipulation by the major generators, but the complexity of the price-setting process was also blamed. Finally, the nature of the Pool’s governance procedures, and its record on past reforms, meant that few people believed it was capable of reforming itself.

The regulator’s review accordingly proposed a new set of markets to replace the Pool.

“They include

- forwards and futures markets operating up to several years ahead if required;
- a short-term bilateral market, operating from at least 24 hours ahead to about 4 hours before a trading period, to give market participants the opportunity to “fine tune” their contract positions;
- a balancing market from about 4 hours before until real time, to enable the National Grid Company as System Operator to balance the system and resolve transmission constraints by accepting bids to buy or sell electricity; and
- a settlement process for calculating a price to recover the System Operator’s costs of dealing with imbalances and for charging generators and suppliers who were out of balance.

The present Pooling and Settlement Agreement would be replaced by a Balancing and Settlement Code to which market participants would be required to conform, and which would include more flexible and effective governance arrangements.” (Offer, 1998, pp. 1-2)

These markets would all be bilateral, for NGC would act as the counter-party to all trades in the balancing market, and for all imbalances. These bilateral contracts would be firm, so that parties would be financially committed to their positions as soon as the contracts were agreed. It will always be possible to escape physical delivery or acceptance (and must be, given the random nature of generator availability and customer demand), but this will now involve either trading in the balancing market, or having to “cash out” an imbalance, with the risk of a penal price in either case. The balancing market would involve simple one-part bids.

In October 1998, the government published a White Paper (Department of Trade and Industry, 1998) which broadly accepted the regulator’s proposals. “The core elements address the fundamental concerns of customers and others. They would address the current distortions that work against flexible generation plant and in favour of other plant, and help to provide a level playing field between different fuel sources” (ibid., p. 49). The government also confirmed that it would generally block applications for new gas-fired plant “in the interim while the reform programme is under way. ... The policy will be short-term, temporary and aimed specifically at protecting diversity and security of supply while the distortions in the market are removed, so that the final result is a competitive market that can operate more vigorously and effectively” (ibid., p. 12). The government would also be “seeking practical opportunities for divestment by the major coal-fired generators” (ibid., p. 11). PowerGen had already agreed to sell 4 GW of plant, in return for permission to buy East Midlands Electricity, one of the RECs, and National Power has offered to sell 4 GW if it is allowed to buy Midland’s Electricity’s supply business. These sales could make the electricity market more competitive. I do not believe that the new trading arrangements will do so.

### **What is wrong with marginal pricing?**

There have been many claims that the Pool’s system of marginal pricing has promoted inefficient entry, and raised prices, compared to the results of a bilateral market in which every trade is concluded at the price bid. The argument seems to be that a seller who is paid more than they ask for is getting too much, since they are free riding on high prices set by other participants. To quote the White Paper, this “give[s] a positive advantage to smaller players in the market, who are able to opt out of competition by bidding zero all or most of the time” (ibid., p. 8).

The question is, would paying stations their own bid, as with bilateral trading, produce different results? If we consider many other commodities markets, selling prices are clustered

around a “going rate”. Some trades will be slightly cheaper, some slightly more expensive, depending on the relative knowledge, risk aversion, and ability of the buyers and sellers, but no one will deliberately sell their product for less than they could get from another customer, or buy it for more than they could pay elsewhere. The Pool is not unusual in that all trades take place at the same price, but in that it turns this empirical regularity into a market rule. But what would the stations which presently submit low bids in the Pool do if they were paid their own bid?

In a bilateral market, we can assume that every seller will attempt to get the going rate for their product in each time period. They will have to be able to charge different prices at different times, or the market will be unable to differentiate between fixed costs and running costs, which could lead to great inefficiency. What will the going rate be? In a competitive market with perfect information, every station could afford to bid just less than the marginal cost of the cheapest station which is not required - the first extra-marginal station. That station will not be able to make a profit if it tries to undercut them, and nor will any of the more expensive stations. With perfect knowledge, the cheaper stations have no incentive to undercut this price, since they will not sell any more output with a lower price, and will only be giving away potential profits.

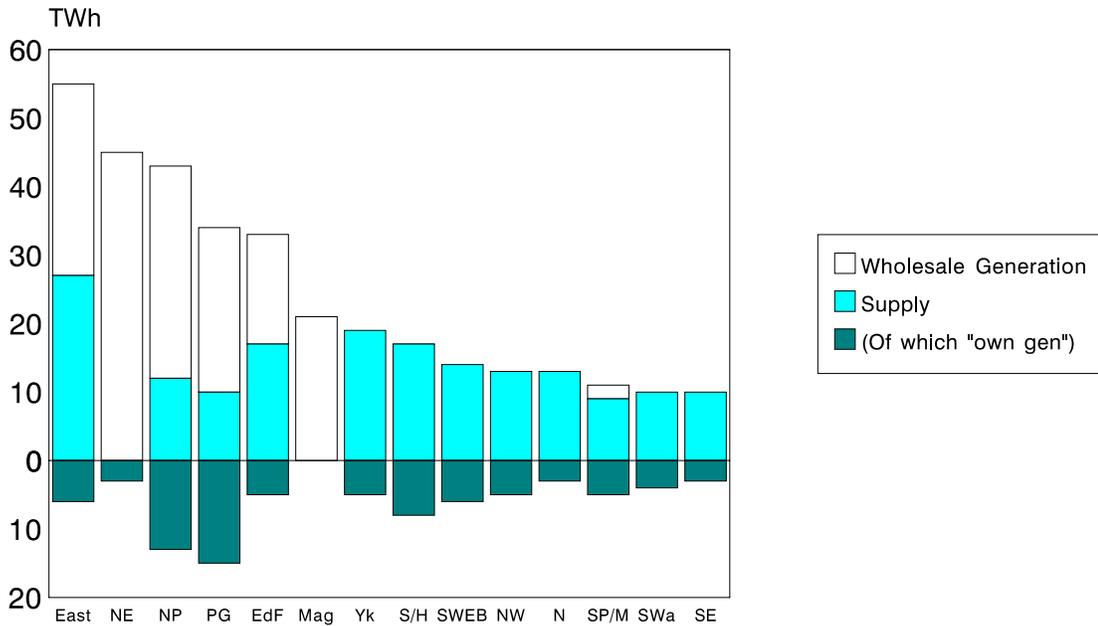
Continuing with perfect information, but adding market power, we know that the larger generators in a marginal-price system will bid above their costs (Green and Newbery, 1992). In a pay-bid system, would they try to sell at the same (high) price from the most expensive station which is going to run? And if they did so, would they set the same price for all their other stations? They have taken the response from consumers, and other sellers, into account when calculating the profit-maximising bid in the marginal-price system. If these are price takers, their response should not change in a pay-bid market. So we might expect large generators to set prices above costs for their marginal stations, even in a pay-bid system, and to raise all their other prices in line with this. Auction theory has many “equivalence results”, which show how two apparently different trading rules turn out to give the same expected revenue, and this could well be one of them.

Would generators continue to sell power at this going rate in a more realistic setting, with imperfect information? Those who are bad at trading will probably fail to do so, and those who are desperate to sell might deliberately attempt to undercut the rate, to increase the chance that they will find a buyer. Will generators be desperate to sell? If they don't sell power in the long-term markets, they have another chance in the short-term market, and if that leaves them with an unsuitable schedule, they can trade with NGC in the balancing market. If all else fails, they may

even be able to get away with deliberately creating an imbalance by running without having sold their output in advance, and accepting the risk of a very low imbalance price. Assume that customers have bought power to cover their expected demand, and that a station which “ought” to be running (being one of the cheaper stations available) has not been able to sell its output. That implies that one of the stations which has sold some output has higher costs than the unsuccessful station. There is an arbitrage opportunity here, for both the high-cost station and the low-cost station could increase their profits if the low-cost station ran instead, selling power to meet the high-cost station’s obligation to run at a price somewhere between the costs of the two stations. This reasoning implies that generators will not lose much if they are not scheduled in the early rounds of trading, while a generator which sells too cheaply has locked itself in to a low price for good.

What about the buyers’ trading skills and risk aversion? Most wholesale electricity buyers are retailing power at fixed prices with thin margins. They may well be more eager than the generators to “lock in” to a purchase contract, and willing to overpay for the privilege. Furthermore, figure 3 shows that all but one of the companies with the most electricity to trade are net generators. The shaded bars give each company’s supply business sales: the part below the horizontal axis represents (approximately) the amount which RECs have bought under long-term contracts from IPPs, or generators’ sales through their own supply businesses, neither of which are part of the “normal” contract market. Sales by the RECs linked with large generators are not netted off, since these RECs are not allowed to buy from their linked generator for resale to customers in their own areas. The companies with the most at stake are likely to have the greatest incentive to hire the best traders. If they succeed in doing so it will tend to be the buyers, and not the sellers, who end up on the wrong side of the going rate in the reformed market. The government’s claim that small players have an advantage under marginal pricing might well be reversed: they have a disadvantage under pay-bid. Unfortunately, the small players in question could well be customers.

# Forecast electricity trades



Data for 1996/7 (supply) and 1997/8 (gen) adjusted for mergers/divestitures in 1998

Figure 3

If generators gave quantity discounts, (some) customers' prices could fall, and the large customers may be hoping for this. In a competitive market, a firm may give a quantity discount to a large customer as a competitive device to ensure that the firm, rather than a rival, gets the advantages of large-scale production; some large orders can have a significant impact on the firm's production schedule. Discounts can also reflect the lower costs of organising the trade, and pass on the benefits of cheaper bulk delivery. But large electricity customers already get lower supply charges and distribution charges, which pass on the savings in organising and delivering their purchases. And in the electricity industry, production does not depend on making deals with particular customers. Only a handful of customers actually take a significant amount of electricity from the point of view of a generator. Why should a generator sell a small portion of its output to selected customers at below the going rate, when it could get the market price elsewhere? I know that the CEGB did so, and that some customers mourn the passing of this regime, but it is not a feature of a competitive commodities market. Brokers may give lower

commission rates to favoured clients, but few follow Nick Leeson in selling below the market price.

Has the Pool been the cause of inefficient entry and operating decisions? There are two aspects to this: first is the decision to enter; second, the amount of generation from a new station. There have been claims that there has been too much entry, and that the new stations have been running, even when coal-fired stations had lower operating costs. Decisions to enter the market have been a response to the falling cost of CCGT stations, and to the incumbent's market power, which gives entrants the prospect of high prices. I have already argued that changing to a pay-bid system is unlikely to reduce prices. It might make entry more difficult, because the market will be less transparent. In that case, the incumbent generators could have more scope to keep prices high without provoking entry, again to the disadvantage of consumers.

The load factors of existing stations ought to depend upon their relative costs. If every station bid its costs into the Pool, then the cheapest stations should be selected to run. A station which bids less than its costs runs the risk that it will be scheduled to operate at a time when the Pool price will be below its costs, and so the station will lose money by running. A standard, "firm," contract for differences will not affect this conclusion, because the payments under the contract, which may raise the station's revenues, are independent of the station's running patterns. If gas-fired stations were bidding their costs, then they would only be in the wrong place in the merit order if coal-fired stations were bidding above their costs, and that would again be a problem of market power, not of the trading arrangements.

In practice, many gas-fired stations have bid less than their marginal costs. There have been suggestions that this is due to the take-or-pay nature of their gas contracts, but most of those contracts give the station some flexibility over the amount of gas it burns, and only a contract with a rigidly fixed volume (up and down) would have a marginal cost of zero. Even then, if gas-fired stations were inefficiently displacing coal-fired stations, this implies an arbitrage opportunity: the gas contract could be renegotiated with a lower volume, and the resulting savings shared between the generator and the gas supplier.

The main problem is actually due to the electricity sales contracts which many of the CCGTs have signed. These are "non-firm" CfDs, so that the station gets the (high) contract price whenever it generates, but no payments are made if it does not run. This appears to give the station every incentive to ignore the Pool price, and run as much as possible, even if cheaper stations are available. Once again, however, there should be an arbitrage opportunity, in which

the contracts could be renegotiated to allow cheaper coal-fired stations to run, sharing the savings among the parties. Once again, there is no sign that any of these opportunities has been taken up. The decline of the coal industry is not because of the Pool, but despite the Pool, because its price signals have been ignored.

The industry's failure to arbitrage so far is also a bad portent for the efficiency of the new trading arrangements. They can only lead to an efficient dispatch if a second stage of trading allows companies to replace expensive, contracted, generation with cheap generation which has not yet been scheduled. Given enough time, and no impediments such as market power, this could happen, though it sounds a little like the "twin pool" system which had to be abandoned in 1989. But one of the Government's main reasons for changing the system is the belief that generators are burning gas when it would be cheaper to burn coal. If generators are deliberately avoiding an efficient dispatch at present, why should we expect them to be interested in spending time and money in trading their way towards an efficient dispatch in the future?

### **Paying for Capacity**

Capacity payments are one of the most disliked features of the Pool. For much of the time, they contribute practically nothing to the Pool price, and might as well be ignored, but at some peak times, they can add several hundred pounds per MWh to the Pool Purchase Price, and slightly more to the Pool Selling Price, which includes the cost of capacity payments to stations which have not been scheduled to run. Critics argue that an administered mechanism has no place in a competitive market, and that the capacity payments do not provide adequate signals, either in the short term or the long.

I have already argued (on page 5) that since capacity payments can be hedged in an annual market, this provides a suitable signal for plant retirements. If a station can sell a hedge with revenues which equal or exceed the cost of keeping it open, doing so will not only be privately profitable, but also socially efficient, as long as the capacity payments are calculated in an appropriate manner. Furthermore, adjusting capacity at the margin should drive the expected capacity payment to equal the cost of keeping open marginal capacity. If the formula for the capacity payment is mistaken, we should not get the wrong price, which is set by the stations' costs, but the wrong capacity margin. If the loss of load probability is over-estimated, (so that 10

GW of spare capacity appears to imply the risk of power cuts which would not actually occur until spare capacity fell to 5 GW), we will not face significantly higher prices, but excess (old) capacity and too low a risk of power cuts - not necessarily something to which consumers would object.

What would happen if capacity payments were abolished? We will still need a few stations which are only used infrequently, and they must be able to cover their costs from doing so. In a competitive market, prices should be based on marginal costs at all the times when these stations are “spare”, and so they will only recover capital costs when there is no slack in the system - either very little reserve, or actual demand rationing (by price or power cuts). In a “pure” market without too much NGC intervention, generators might provide reserve in the hope of getting a really high price on the rare occasions when it was needed - how high the price will go depends on the amount of price-responsive demand that could react in time to affect the price, and whether there would be a ceiling for when non-price rationing was imposed, as in Australia. Alternatively, NGC might contract with some stations for reserve, giving them lots of lower, but more predictable, payments. I hope these payments would be linked to the value of having the reserve available - that is, linked to the expected value of the sort of payments that might be the outcome of a pure market system.

It would probably be “safest” to have NGC contracts, but stations bidding for these would only be able to bid above the marginal cost of providing reserve on the few hours each year when there was no surplus capacity. (If there were more than a few such hours, it might be a sign for reinstating mothballed plant, while if there were none, closures would be suggested). NGC’s prices in those hours would have to cover the plants’ fixed costs. If those costs were £10,000 per MW, and they were spread over 100 hours, we would need an average payment of £100/MW per hour for providing reserve, over and above the marginal cost of doing so. In a market equilibrium, entry and exit would ensure that stations got (just) enough to cover their costs, while (I hope) that NGC would be paying them the value of having those stations available.

Arbitrage between the reserve market and the generation markets would imply that stations would only want to generate at the times of scarce capacity if they could get a similar surplus above their generating costs. So the price for generation would also have to rise quite a long way above marginal generation costs. If generators have to bid before they know that

capacity will be short, they would include the expected value of this surplus. Prices set in advance would therefore be much less volatile than prices set close to the time of dispatch. The end result could well look rather like the pattern of prices seen in the present Pool and contract market.

### **Demand-side bidding**

I agree that the demand side needs to play a greater role in setting electricity prices. At present, if the Pool announces high prices, some consumers may reduce their demand in response, and the most expensive generators may not be scheduled. Although those stations were responsible for setting the high price, the fact that they were not used will not reduce SMP. In fact, the cost of compensating them for being “constrained off” will be added to Uplift, increasing prices! At the very least, NGC should be encouraged to take more account of demand response when predicting demand, but active bidding by suppliers would be preferable.

We should differentiate between suppliers who have demand-responsive customers, and those who do not, however. Demand-responsive consumers can see high prices, react to them by shedding load, and reduce the amount of generation and reserve required. This would tend to produce a flatter peak, with less total capacity required, and would probably imply lower peak prices, but for a longer period. This would be a useful feature of the market.

Demand-side bidding by suppliers who do not have price-responsive consumers cannot alter the amount of generation required. In the Pool system, it could lead to gaming, as suppliers under-estimate their demands in the hope of setting a lower Pool price, even though this would lead to higher Uplift payments as extra stations were brought on line to meet the undeclared demand. In a system with several bilateral markets, generators could react to such gaming by reallocating their sales between the markets. If suppliers reduced their demand in the long-term markets, hoping to buy power more cheaply at the day ahead stage, generators could reduce the amount of capacity they offer to those markets. Arbitrage should ensure that the expected price in each market is the same, but this sort of demand-side participation, where suppliers have to choose how to purchase power to meet fixed demand levels, will not reduce prices on its own. The only way to do that is to ensure that price-responsive demand can react to prices, and that the reaction feeds back to the price-setting process.

## **Conclusions**

The Pool has made many enemies in the years since 1990, and it is now to be abolished. In the past, the coal industry and some large customers were able to trade with the electricity industry at advantageous prices, and this is hard to maintain in an open market with published prices. It may be that they hope that a system of bilateral markets will allow a return to the era of special deals. The electricity industry has not been able to defend the system: the RECs are associated with the gas-fired power stations which have caused the decline of the coal industry, while the largest generators may gain from the changes. Their market power may be enhanced in the less transparent world of bilateral trading, while the government's restrictions on new entry remove a significant threat to their position.

Blaming the Pool for the decline of the coal industry has been politically convenient for the government, since it implies that replacing the Pool could be sufficient to arrest the decline. This is unlikely to be the case. Excessive entry by gas-fired power stations has been a response to market power which was facilitated by bilateral contracts, and it is those contracts which have caused them to operate at times when it would have been cheaper to burn coal. The Pool has generally sent the right price signals, but they have been ignored. Increasing the role of bilateral contracts hardly seems the best way to deal with this problem!

The idea that paying people more than they asked for raises prices and distorts competition is superficially attractive. A little analysis should reveal that prices in a pay-bid system could well be almost identical to those in the Pool, or those that a reformed Pool, with some of its anomalies cleaned up, could produce. For I am not pretending that the Pool is perfect. Its governance structure, which allows small minorities to delay sensible changes for years, is crying out for reform. The demand side needs to play a greater role in setting prices, and the rules have too many loopholes for generators to "game". But overall, it has been a sensible foundation for the electricity reforms in England and Wales. An efficient bilateral market would probably produce very similar results to the Pool. Abolishing the Pool in favour of a less transparent market, at greater risk of manipulation by the dominant generators, does not seem a rational policy.

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