Pool Reform and Competition in Electricity

David M Newbery*
November 1997

Abstract

The market power of the incumbents means that average pool prices are set by the costs of entry. Reforms which raise entry costs will be proposed and should be resisted. Reforms to capacity payments may have little effect on prices, but could affect system security. The values of VOLL and LOLP appear grossly incorrect, and if changed might affect reserve margins and the allocation of investment. Transmission constraints and locational payments emerge as the most difficult and important cause for concern and least controlled by entry threats. Little reform is possible without primary legislation to change Pool governance radically.

JEL classification: L51, L94, D43

Keywords: Electricity, pool, market, regulation, governance

* Paper presented to the IEA\LBS *Lectures on Regulation Series VII 1997* on 11 November 1997. Support from the ESRC under the project R000 23 6828 *Developing competition in the British Energy Markets* is gratefully acknowledged. I am indebted to John Carlton and Lewis Dale of NGC and Brian Saunders of the Pool for help in understanding LOLP, the reserve auction, and grid security standards, to Shaun Kent of Offer for his helpful information, Hugh Outhred of the University of New South Wales, Jim Gallaugher of the Victorian Power Exchange, Len Gill of Ecogen, and Phil Gall of Transgrid, for their insights into the Victorian electricity market, to Richard Green for information and discussions, and to Stephen Littlechild, Geoffrey Horton and Peter Scott for insightful comments at the seminar and afterwards. I have also benefitted from information in Henney and Bidwell (1997).

Pool Reform and Competition in Electricity

David M Newbery

Introduction

In October 1997 Stephen Littlechild, the Director General of Electricity Supply was invited by Mr John Battle, Minister for Science, Energy and Technology, to consider how a review of electricity trading arrangements might be undertaken and to draw up terms of reference. On November 5 Littlechild issued his consultation document,[1] setting out the objectives of the review as follows:

> The starting point is to consider what kinds of electricity trading arrangements will best meet the needs of customers and command their confidence. As the Electricity Act points out, these needs include prices, continuity and quality of supply. The arrangements should enable demand to be met efficiently and economically. They should enable costs and risks to be reduced and shared efficiently. In general, these aims will be promoted by competition in the market, by ease of entry into and exit from the market, and by widening the range of choices available to all market participants. Appropriate trading arrangements play an essential role in facilitating such developments.

The Electricity Pool of England and Wales is the centrepiece for the trading arrangements in electricity, and represents an ambitious attempt to create a genuine market in an industry that in the past has almost invariably operated as a regulated or publicly owned vertically integrated monopoly. Competition provides better incentives for efficiency than regulation, but is impossible or ineffective for the core natural monopolies of electricity transmission and distribution. The guiding principle in restructuring the electricity supply industry (ESI) in Britain in 1990 was therefore to introduce competition into generation and supply and to restrict regulation to transmission and distribution. Competition requires a market, but creating a spot market for wholesale or bulk electric power is difficult, and most earlier attempts to introduce competition into the ESI in Britain and the US were both modest and of distinctly limited success.

The design, development and creation of the Pool in 1990 was not only a remarkable conceptual innovation, it was also remarkably successful in meeting its main objective of creating a market while facilitating a smooth transition from the former state-owned vertically integrated Central Electricity Generating Board (CEGB) to an unbundled ESI in which generation was potentially competitive, without causing the lights to go off (as some feared), nor causing the immediate collapse of the coal industry (which was delayed until after a critical election). Yet the Pool has been singled out for some of the fiercest criticism in an industry most parts of which have been under attack at some time or another. What do these critics claim is wrong with the Pool? Can its faults be remedied by modest reforms or is the whole concept fundamentally flawed? For other countries contemplating the creation of a power market, what lessons should be

[1] on the internet at http://www.coi.gov.uk/coi/depts/GER/GER.html

drawn from the experience of the British Pool,[2] and what lessons can Britain in turn draw from the experience of other pools operating in the Nordic countries, Victoria, and elsewhere?[3]

Before turning to the list of criticisms, it is worth rehearsing some of the successes of the Pool, and the challenges it has had to face. Consider what it sets out to do - create a daily spot market that can match demand and supply at an efficient price, into which any licensed generator (above a modest size) can sell, and from which any buyer of above a certain size (100kW in 1997, but with no restriction from 1998) can buy at the same price. (Certain additional ancillary services are bundled with the raw power, which buyers pay for through uplift, but that does not alter the price-like nature of the Pool Purchase Price at which transactions take place.) Potential generators must make their best guess about the future evolution of pool prices in deciding whether to enter, and take upon themselves (or share with contracting counter parties) the risk that their forecast is wrong, with little comfort from regulators or the Government. Consumers can decide whether to buy spot power, or to buy on contract, either from their local Regional Electricity Company (REC), or from some other licensed supplier, and can choose between the various contracts on offer. They can hedge their choice through the contract market and possible adjust the specific contract terms in the Electricity Forward Agreement (EFA) market, and hence overlay any physical trade with a financial contract, just as commodity traders can through futures and options.

IPPs operating gas-fired combined cycle gas turbines (CCGT - overwhelmingly the most economic choice for new generation in Britain in the 1990s) can decide whether to burn gas to generate electricity for sale in the pool or whether to sell gas in the gas spot market and be available to generate only if the price is sufficient to cover the cost of substitute gas-oil, or even to sell spot gas and not be available at all for despatch. All these decisions are guided by the pool price, which therefore exercises a powerful influence over both the short and long run decisions of producers and consumers. In short, the Pool appears to operate as a classic commodity market with all the potential advantages this has over central planning.

Why are power markets problematic?

Electricity, even more than almost every commodity traded sight unseen, is remarkably homogenous (all electrons are identical), but, like other commodities, must be distinguished by time and place - a MWh at 5.30 pm on a winter weekday is very different (and has on occasion been as 100 times as valuable) as a MWh at 3am the

---

[2] The Pool is open to generators in England, Wales and Scotland (and France via the Interconnector) but not yet to Northern Ireland.

[3] Barker, Tenenbaum and Woolf (1997) compare Britain, Scandinavia, Victoria and Alberta. Argentina also has been operating a power pool since 1995 (Perez-Ariaga and Henney, 1994). I am grateful to Allan Fels of the Australian Competition and Consumer Council for arranging meetings with participants in the Victoria electricity markets.

following morning.[4] Likewise, electricity in the Northeast may not be substitutable with electricity in the Southwest during periods when transmission between the two is constrained. The key difference is that electricity cannot be stored (though water in storage hydro systems can provide a good proxy form of storage), and supply must be equated to demand second by second. In addition, the quality of electricity (frequency, voltage, phase angle) must all be maintained within tight limits, making refined power (meeting these quality standards) different from raw power (MWh), and requiring a host of ancillary services to transform raw into refined power. Most of the complications which make the Pool opaque and raise suspicions of market manipulation derive from the use of the computer scheduling program GOAL which takes information from each generating set and computes a central despatch schedule that minimises cost while ensuring system integrity and quality. Many of these complications can be avoided where there is adequate storage hydro under dispersed control which allows self-despatch and which can provide rapid load following and maintain quality at low cost. Such pools, and the Scandinavian pool is an excellent example, are relatively simple and appear to offer an attractive alternative model, but they are designed to solve a quite different, and much simpler set of problems. Lessons drawn from them may not be readily applicable in Britain.

The institutions required to support a power market

The English electricity market is not the only way to organise a market, but its structure gives an idea of the range of functions performed. The Electricity Pool, or more precisely, the Pooling and Settlement Agreement (PSA), is a contractual arrangement signed by generators and suppliers which provides the wholesale market mechanism for trading electricity. It defines the rules, and requires almost all parties wishing to trade electricity in England and Wales to do so using the Pool's mechanisms. It provides the supporting financial settlement processes to compute bills and ensure payment, but does not act as a market maker.

National Grid Company (NGC) owns and controls high voltage transmission, and as the Grid Operator, is responsible for scheduling and despatch. Elsewhere the Systems Operator is often legally required to be independent of generation and transmission. NGC also acts as the Ancillary Services Provider, the Settlement System Administrator and the Pool Funds Administrator, though again the provision of these services can be and often are separated from the provision of transmission services.

Efficient systems operation requires a mechanism to select which plant should operate when and for how long to minimise the total cost of delivering power to final consumers, where costs depend not only on short-run avoidable generation costs (mainly fuel), but on transmission losses. In addition, stations are constrained in how fast they can be brought on line from cold, while their operating costs may depend on how long they have been operating, whether they are running at low or high load, etc. The capacity of the transmission system may restrict the set of power stations that can supply consumers in a given area, while pumped storage plant may reduce daily operating costs by buying

[4] The Pool transacts in MWh or Megawatthours, where 1 MWh = 1000 kWh, the standard unit paid for by domestic consumers. Thus a price of £10/MWh is equal to 1p/kWh.

cheap off-peak power to pump water up into a reservoir for release later to generate at the peak. All these constraints and opportunities must be taken into account in the despatch schedule.

In addition, system operations requires the supply of a variety of services for stability, security and quality. Systems security is provided both through an adequately sized transmission grid and by ensuring that supply can be matched with demand in the presence of sudden, unforseen events such as a station failure, a transmission fault, or a sudden surge in demand. It must be possible to increase generation over time periods of seconds, minutes and tens of minutes, relying on thermal lags and automatic responses, spinning reserve (plant already running whose output can be rapidly increased), and plant which can be brought on with varying degrees of rapidity or loads that can be shed. Systems operation will also need access to reactive power to ensure that voltage and current in is phase, and to emergency services such as black-start capability (the ability to restart generation without external power). As demand may vary considerably over the day, adequate reserve capacity must be available to meet peak demand (with a sufficient safety margin to cover the risks that not all plant will be available at the moment demanded).

In addition to the short-run problem of operating the existing system efficiently, the system will need to be expanded to meet growing demand. This will require decisions on the timing, size, type and location of new generation and transmission capacity, again with the object of securing least-cost expansion and delivery to final customers. The problem is difficult as time lags may be long (4-8 years for traditional thermal or nuclear plant, though 2-3 years for modern CCGT plant), demand forecasts and future fuel prices uncertain, as are future technologies, environmental and safety constraints.

It may help to think of two polar mechanisms which could in principle meet these requirements. Central despatch in a vertically integrated industry (until recently the dominant model) is akin to central planning, using information about costs and technical capabilities to solve a computer optimisation problem, which informs the despatcher what commands to issue to station operators. Central planning similarly investigates least-cost expansion scenarios, considering the system (generation plus transmission) as a whole.

At the other extreme we can imagine organising decisions though a decentralised market. Somehow prices for each service at each future date would be revealed to decision makers, who would be guided as if by the invisible hand to choose the overall short and long-run system optimum. The informational requirements of this decentralised system should not be underestimated. The Pool currently quotes 52,560 prices annually for bulk power into the grid,[5] while England and Wales are divided into 16 zones for charging generators for transmission. The latter oversimplifies the potential spatial diversity compared to more decentralised systems that compute prices at each node in the system, which can vary independently as congestion and power losses vary over time. The Pool bundles together a whole variety of ancillary services, each of which ought properly to be distinguished. Each of over 200 generating sets quotes five prices and 35 technical parameters each day, while the price of gas varies daily in the spot market, and Transco distinguishes gas transport costs from 6 entry points to over 150 exit nodes,

[5] there are three prices for each half-hour: SMP, PPP and PSP

together with costs of storage and other services. Gasoil, fuel oil and coal are traded on active and volatile spot and futures markets.

Consider the (relatively simple) task facing a station manager in a truly decentralised system. Given a forecast of the price he would receive for power in each future time period (half-an-hour in the English model) he would decide whether it was worth bringing a station on load for some time period, and what level of output to produce, given the fixed costs of firing up and holding the station ready, as well as the variable generating costs. The time frame for such operating decisions for a large coal-fired station may be 48 hours or longer. The prices guiding this decision would need to ensure instantaneous and continuous balance of supply and demand as temperatures unexpectedly vary, storms damage power lines, stations fail, and consumers tune into unexpectedly popular television shows. The efficiency standard against which to compare this decentralised operation is, in the short-run, extremely high for an integrated centrally despatched system, though rather lower when it comes to delivering least cost investments over longer time periods.

In practice, electricity pools which organise the trade of raw power and services fall somewhere between these two extremes, and the central institutional question is how to design the set of mechanisms and governance structures to achieve the best of both worlds - efficient technical operation and market responsive innovative expansion. The Pool (capital letters means the Electricity Pool of England and Wales) is unsurprisingly, as the first experiment in a predominantly and therefore demanding thermal system, closest to the centrally planned model while embracing market signals as far as possible. Thus the despatcher in the Pool uses the CEGB's old computer program GOAL to determine the merit order, or the order in which plant is despatched. The most obvious difference is that the merit order is based on bids and reported parameters rather than costs and technical parameters. The Victoria power pool is (in late 1997) possibly the closest to a decentralised system for a comparably dominant thermal system. Instead of the generating sets giving a computer program enough information to optimise over the next 48 half-hours, they reveal a set of bids and associated supplies that will determine a spot price (varying every five minutes). It is up to the station manager, using forecasts provided by the despatcher, to choose a bidding strategy that will lead to his plant covering its fixed and variable costs, and operating in a sensible pattern over time. The despatcher calls on generating sets in ascending order of bids to meet demand, with the marginal generating set setting the price in that five minute period. Prices are then averaged over half-hour periods for settlement purposes.

There is a direct correspondence between the shadow prices that emerge from the solution of the centrally planned optimisation problem and the set of efficient prices that should rule on competitive markets, though the relation may be obscured in a stochastic environment, where prices may include various insurance elements, particularly for the bundled set of services involved in supply stable, secure and reliable power. There is also a difference between the expected price the next hour, day, week or year ahead, and the realised spot price. This is most apparent in transacting for power of a given degree of security. Most consumers are clearly willing to pay a premium to be guaranteed a certain level of reliability - eg less than a 1 in 10 chance of a power outage anytime in the next year, or less than a 1 in 1000 chance in the next 24 hours. After the event, either the power has failed or not, so the risks are resolved into certainties. In a competitive market the cost of delivering a given level of security varies dramatically with the level of capacity relative to demand, as we shall see when discussing capacity payments later.

This suggests that more most of the time the efficient price is just the short run avoidable cost of generation, but occasionally the full cost of providing spare capacity, or of expanding the total capacity, will determine the market clearing price that rations demand to the available supply. Schematically, the supply schedule in electricity is very much like a reverse L, with a fairly flat section followed by a vertical section, facing a rather inelastic and rapidly fluctuating demand schedule. We should expect competitive prices to be low much of the time, but occasionally very high. Commodity markets with durable supply facilities like aluminium exhibit similar behaviour - even though they are able to buffer price fluctuations by storage far better than electricity.

The same point can be put rather differently. If the efficient price is avoidable cost most of the time (as there is spare capacity), and if the long-run marginal cost of expansion is close to the average cost (no significant economies of scale above a modest size of generation), then the fixed costs must be recovered in the small number of hours in the year when predicted demand comes uncomfortably close to available supply, and the price per hour to recover these fixed costs will necessarily be high. The same is even more dramatically the case for the transmission system, where the avoidable costs (marginal losses) may be less than one third of fixed costs.

Competitive electricity spot markets should be expected to be extremely volatile. The unpredictable element in this volatility can be hedged with financial contracts, and if the timing of the peak is very uncertain, the range of contract prices may be more moderate (the chance that any hour is the peak may be quite low for a large number of apparently similar hours). Nevertheless, large price fluctuations would arise in competitive markets, and are not reliable evidence of market manipulation. Indeed, manipulation may take the form of muting price fluctuations in exchange for higher average prices.

The institutional design must decide whether bidding into the pool is compulsory, or whether to allow trading and despatch outside the pool, how payments are to be made for the various services, and the degrees of vertical integration and bundling allowed in the supply of various services - critically, whether the transmission owner also operates despatch and organises the delivery of ancillary services, as in Britain, or whether the system operator should be independent of the grid and of the provision of ancillary services, as in Victoria. It will also need to determine whether there are constraints on who can build transmission (in Britain National Grid Company has the sole licence), on location of new generation (which in Britain only requires local planning permission after a quasi-automatic section 36 licence is granted), and whether there should be restrictions on or penalties for premature plant retirement.

Finally, the institutional design must meet exacting efficiency standards, for the gains from unbundling and creating competitive markets are likely to be modest, and could easily be lost by inefficient market design. Newbery and Pollitt (1997) estimated that restructuring and privatising the CEGB may have cut bulk electricity costs by 5%. Elsewhere, eg in the US, where the structural changes may be less dramatic (no ownership change), the gains from introducing markets may be more modest. Gains of a few percentage points could be easily lost by choosing the wrong level of reserve margin, by locating generating plant in the wrong place, or even by placing contractual restrictions on fuel use and hence on the order of despatch (as in Spain). In most developed countries vertically integrated utilities have managed the daily despatch of existing generation efficiently, and the inefficiencies lie mainly in poor investment choices and (moderately) high operating costs. For a market based system to improve on this it should not only reduce operating costs, but improve investment decisions and maintain the efficiency of despatch. As we shall see, these are demanding requirements.

The organisation of the Electricity Pool

The Pool (meaning the Electricity Pool of England and Wales) operates as a day ahead market in which bids are submitted by 10 am the day before, and the least cost unconstrained schedule then determines the SMP as the most expensive generating set (genset) required to operate in each half hour, assuming that there are no transmission constraints. The Pool Purchase Price or PPP is the sum of the System Marginal Price (SMP) and the capacity payment, and is announced at 5pm for each half-hour of the following day, starting at midnight. Capacity payments are made to each genset declared available for despatch, and are equal to the Loss of Load Probability (LOLP) multiplied by the excess of the Value of Lost Load (VOLL) over the station's bid price (if not despatched) or the SMP (if despatched). Finally, the costs of ancillary services and of dealing with the costs of transmission constraints are charged through the Transmission Services Use of System (TSUoS) to consumers on the basis of gross demand,[6] (and which cover that part of uplift that NGC now has an incentive to control), while other costs, such as errors in forecasting demand (both of which require payments to stations either as compensation for not operating or for having to operate) are added to the PPP to give the Pool Selling Price (PSP), paid for by consumers. Transmission services are made up of the cost of transmission losses (which are recovered by scaling up demand equally for all consumers by the ratio of generation to demand), the Transmission Network Use of System (TNUoS), charged on capacity, £/MW, and Distribution Use of System (DUoS) charges (for capacity and energy).

Criticisms of the Electricity Pool

The Pool has been under constant scrutiny by OFFER, the House of Commons Trade and Industry Committee (which replaced the earlier Energy Committee) and the media its launch in 1990.[7] The Energy Committee reported as early as February 1992 having decided that 'it was not too early to assess how satisfactorily the privatised industry was working' (§4 - references are to paragraph numbers in House of Commons or HC 1992). The report presents many of the criticisms which continued to be levelled at the Pool, and reveals the difficult the Committee had in deciding whether the complex arrangements and behaviour observed in the Pool were evidence that it either was or was not fulfilling its tasks. Indeed, they noted that the purpose of the Pool had no-where been set out, but they understood its three main functions to be determining the merit order, determining

---

[6] This is a new charge introduced on 1 April 1997, which is only levied in Table A periods, and is published daily along with PPP and PSP in the *Financial Times*. In October 1997 it was about £1/MWh. Previously it was included in uplift.

[7] See especially Offer (1992a,b,c; 1994a,b)

the prices for services traded, and ensuring sufficient capacity to maintain the system security. 'The Director General found "an element of artificiality about Pool prices which is unsettling for customers and generators alike, and which gives misleading signals to both groups" thereby casting doubt on the Pool's ability to fulfil any of its three functions' (§103). They attributed the artificiality both to the dominance of the two main generators and to the fact that initially 95% or more of the electricity traded was covered by contracts, put in place at vesting and all due for renewal by March 1993.

Criticisms of the Pool can be grouped into a number of headings, inevitably with some overlap between them. The criticisms concern capacity payments, market design, market manipulation, payments for other services, and criticisms of the governance structure. It will be useful to take them in order.

Capacity Payments

Capacity payments are both volatile, unpredictable, and have increased to what are claimed to be excessive levels in the period 1994-97. Their annual level is given in Appendix Table A1, the monthly averages are shown in figs. 1 and 3.

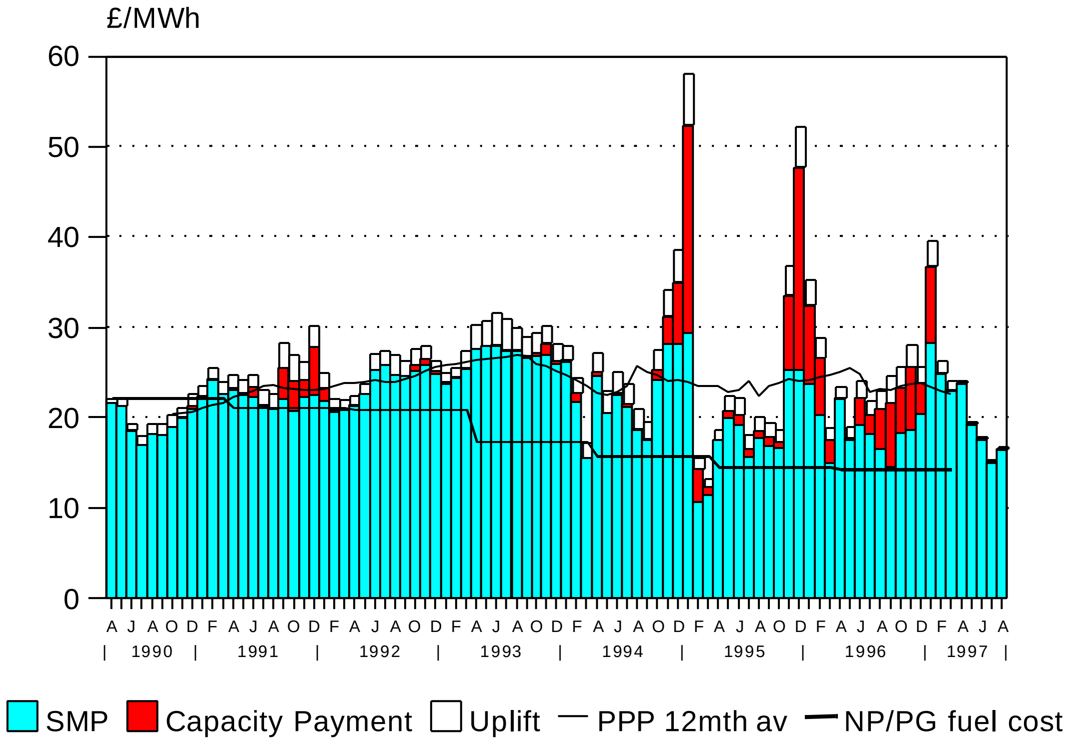

Fig. 1 Prices in the Electricity Pool
at 1995/96 constant prices (monthly averages)

Newbery (1995) argued that the system of capacity payment could provide incentives for dominant capacity holders to withhold capacity, raise the Loss of Load Probability and thereby drive up the payments artificially, as a form of market manipulation, and with the risk of prejudicing the security of the system. The calculation of capacity payments rests on the Value of Lost Load which has been criticised for being arbitrary, and possibly too high (HC 1992, §109), while the Loss of Load Probability is based on out-of-date information, and greatly over-estimates the risk of failure, thereby increasing capacity payments beyond the level required.

Market Design

The market has been criticised for being only half a market, with supply bids but no demand-side (HC 1992, §114-6). In response, some limited experiments with demand-side bidding involving about 30 large customers have taken place, but have not transformed the operation of the market. The market has been criticised for compelling all generators to bid, and defining a single half hourly price paid to all, rather than leaving generators to strike bilateral deals with customers and avoiding central despatch (§119), or, if they are centrally despatched, being paid SMP rather than what they bid. In addition, it has proven difficult to develop a liquid forward or futures markets on the back of the spot market, so that contracts remain specific, illiquid and confidential. Other commodity markets have benefitted from the increased competitive pressure that a liquid and transparent futures market brings.

Market Manipulation

The ability of generators to tailor the technical parameters as well as the individual gen set bids on the basis of information about constraints in the system, degree of tightness of demand relative to capacity, and peculiarities in the GOAL scheduling algorithm have resulted in prices that seem poorly related to costs, and has led the Director General to make a whole series of criticisms of price setting in the Pool. Part of this market manipulation can be attributed to the market power of the two main generators, who between them set the Pool price 90% of the time in the first three years of operation. Fig. 1 reveals the rapid widening of the margin between pool price and fuel cost from April 1, 1993 which attracted the criticism of the regulator (Offer, 1994a).

There have also been complaints that the form of contracts between RECs and IPPs and between IPPs and gas traders has resulted in bidding behaviour which does not reflect the true costs of generating from gas-fired plant. Similarly it has been claimed that the Non Fossil Fuel Obligation and the Fossil Fuel Levy biased the market in favour of Nuclear Power and against fossil generation.

Payment for Services - Uplift

The various services bundled together as uplift have more than doubled since the first year of Pool operation (as shown in Appendix Table A2 and fig. 2), and there were concerns that there were inadequate incentives to reduce these costs, and that the system of charging for various services gave poor price signals. In fig. 2 (and Table A2) *Operational outturn* is the payment to generators whose output differed from the unconstrained forecast schedule, and these generators were compensated either by their lost profit, or their bid. Thus if they were unable to run because of a transmission constraint (ie they were ‘constrained off’) they would receive SMP *less* their bid price, whereas if they had to run to satisfy demand within a transmission constrained region (‘constrained on’) they would be paid their bid. A large fraction of these payments were for *transmission constraints* until NGC was incentivised to control them, the balance arising from forecast errors and generator "errors".

Ancillary services are services required for system stability, while *unscheduled*

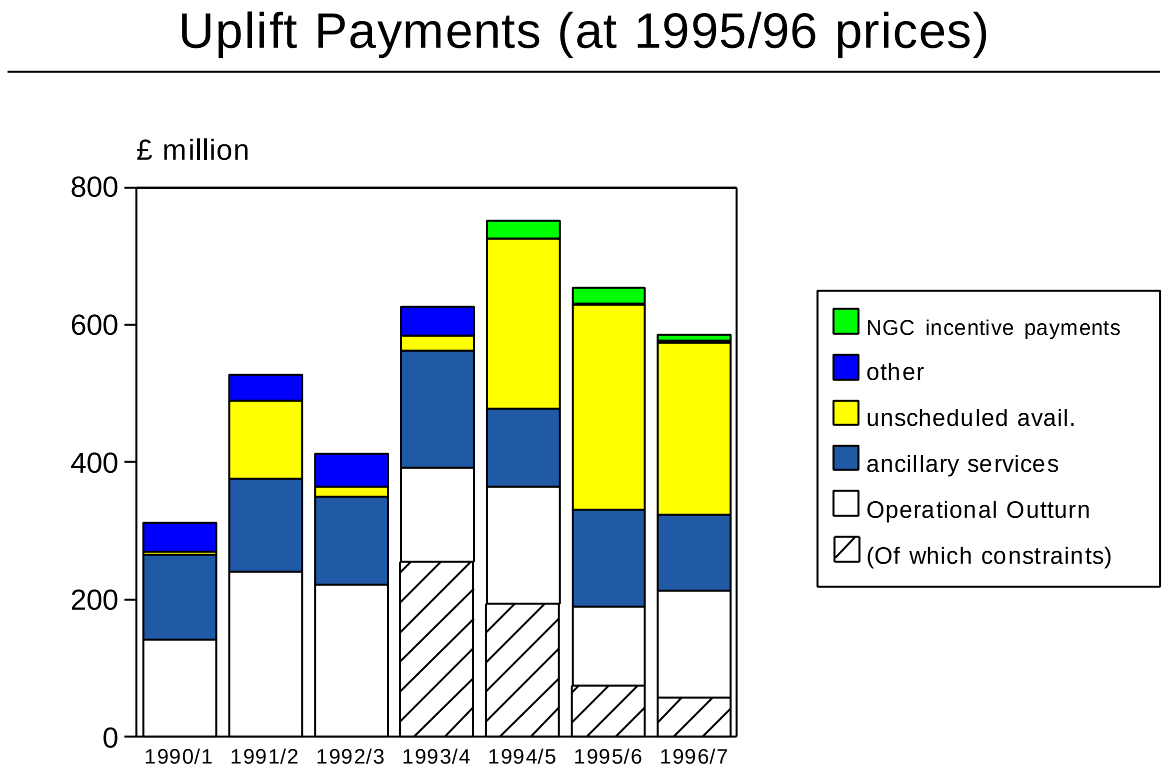

Fig. 2

availability is the capacity payments made to stations declared available but not called to run. Table A1 gives the yearly capacity payment per kW available, and dividing the unscheduled availability payments by these figures gives the payment-weighted amount of unscheduled capacity - which lies in the range 6,000 - 10,000 MW. Most of the variation in this component of uplift arises directly from variations in the level of capacity payment per kW. *NGC incentive payments* refer to the scheme introduced in 1994/95 under which NGC receives a fraction of cost reductions below and agreed target (and pays a fraction of any excess) for Transport Uplift and Reactive Power (those parts over which it has some control). From 1997 these are collected by TS Use of System charges collected from consumers in proportion to Gross Demand (MWh). It now also receives incentive payments for Energy Uplift which are recovered through the new PSP.

Transmission losses are not included in uplift, but are part of the cost of delivering power to consumers. They were paid equally by all, regardless of location, until the Pool proposed zonal scaling factors. This was appealed against and is currently under review. Failure to charge properly for transmission losses distorts the merit order of despatch and gives incorrect locational signals for new investment. It has also been argued that NGC's Transmission Network Use of System charges gives poor locational signals for new generation, though these have recently been slightly adjusted.

Governance

One of the most telling criticisms is that despite a whole series of reports by OFFER and the House of Commons Trade and Industry Committee and even by the Pool, the Pool has resisted making changes, and, because members sign the Pooling and Settlement

Agreement (PSA), a commercial contract, there is no obvious mechanism to cause them to change the rules under which they operate unless enough of them agree. As most changes are likely to benefit some but disadvantage other participants, changes will be resisted. The Committee recommended that the DGES should be able to impose changes on the Pool, possibly with the Pool members having the right of appeal to the MMC (HC, 1992, §130). The Pool is also charged with unnecessary complexity (§127).

The Trade and Industry Committee returned to the Pool in their 1997 report on *Energy Regulation*, and noted that 'the DGES has no statutory authority to intervene in the operation of the Pool...The DGES may require changes to the PSA, but only in the wake of an MMC finding that the Pool operates against the public interest ... We recommend that the Government conduct a thorough review of the relationship between Offer and the Pool..' (HC 1997, §84) and that the Government 'consider granting powers to the DGES similar to those of the DGGS over the Network Code' (*ibid*, §87).[8] On October 23 1997, the DGES announced that he would undertake such an inquiry, and invite views on possible changes to the present Pool arrangements, including capacity payments, uplift, the timing of bids, trading outside the Pool, and even replacing the Pool by different arrangements.

Modelling competition in the Electricity Pool

A competitive market is an efficient market which is the ideal against which the operation of the Pool can be measured. As explained, generators bid into the Pool by 10 am on the previous day, and receive the half-hourly price and despatch schedule by 5pm. Pool prices vary, often dramatically, over the course of the day, the week and the year. As with other volatile commodity markets, such price risks need to be (and are) hedged through financial instruments or contracts. The normal contract is a Contract for Differences or CfD, under which a generator receives, in addition to the normal pool price for any sales, a sum equal to the specified strike price *less* the pool price, multiplied by the specified number of units contracted. In addition to Contracts for Differences there is a market for Electricity Forward Agreements (EFAs) which allow the main components of electricity price uncertainty (such as the spot price between certain weekday hours, or the capacity charge) to be hedged on a short term basis.

The generators have to make three strategic choices - how to bid in their available plant each day, what level of contract cover to arrange, and how much plant to make available (normally each year when connection charges are incurred, but plant must also be withdrawn periodically for maintenance). Together these choices determine the daily range of the PPP and the long-run average around which they fluctuate. The spot and contract market are closely inter-related, and the contract price must be close to the expected spot price, otherwise buyers or sellers will prefer one to the other. Both are influenced by the amount of capacity, which will depend on the decisions of incumbents and entrants.

Green and Newbery (1992) showed how to model equilibrium in the spot market. Each generator submits a whole schedule of prices and quantities, which can usefully be

[8] The DGES is the Director General of Electricity Supply, charged with regulating the industry, while the DGGS is the Director General of Gas Supply.

thought of as a supply function (giving the price required to elicit the next unit of generation as a function of total supply offered up to this price). Indeed, National Power has explicitly referred to its bidding strategy as one of submitting a supply function. Suppose initially that there are no contracts. A generator with a small fraction of capacity at each price is unlikely to set the price in any period, and thus acts as a competitive price taker. His best strategy is to bid at short-run avoidable cost. A generator with a significant share of capacity in some active (ie price-setting) part of the aggregate supply function sets price for some fraction of the time, and can, by raising his price over this range, increase the SMP and his revenue from all despatched plant. If the bid price of the set is too high, then another generator would undercut, set the SMP, and the plant would not be despatched. The spot market is in equilibrium when each generator is content with its own supply function, given the chosen supply function of all other competitors. Green and Newbery (1992) showed that in the absence of contracts and any threat of entry, the market power of the main generators in the Pool as it was in 1990 would enable them to raise Pool prices substantially above the efficient level.

Contracts significantly alter this picture of market power. If a generator has sold CfDs exactly equal to the amount despatched in some period, then its income is entirely determined by the strike price of the CfD. It would have no incentive to manipulate the pool price to either raise or lower the SMP, as this would not affect its revenue. Indeed, if it bid a set above its avoidable cost, it would run the risk that it would not be despatched and would lose the difference between the SMP and the avoidable cost, while if it bid below avoidable cost it might have to run the set at a loss. It would therefore do best by behaving as a competitive price-taker and bidding at short-run avoidable cost.

The extent of market power that a generator has in the spot market is related to the excess of its supply at the SMP of that period over its contracted output. Its incentive to bid a supply function above the schedule of short-run avoidable costs is thus decreasing in the volume of CfDs signed. On vesting, the three generators were provided with CfDs for virtually their entire forecast output, for periods of between one and three years, and matched with comparable (take-or-pay) contracts to purchase British coal, thus making their income and expenditure streams highly predictable for the prospectuses on which they were to be sold. It also reduced their incentive to exercise spot market power to negligible levels, though not their ability to take advantage of transmission constraints and to game capacity availability.

When the time came to renew contracts, the generators were faced with a difficult choice. If they reduced contract cover, they would have the incentive and ability to increase their bids in the Pool, and raise the average level of prices, revenue and profits. Meanwhile, IPPs, usually with equity participation by RECs, had demonstrated a technique for making the electricity market contestable. They could sign 15-year contracts with their REC for the sale of electricity, provided the REC could demonstrate to the DGES that these contracts met the economic purchasing condition of their licence (Offer, 1992c). Given then prevailing pool prices, forecast coal and gas prices, the risk of carbon taxes and other environmental restrictions likely to raise the price of coal-fired generation, and the desirability of encouraging entry and competition, the DGES was prepared to accept that the contracts met that test. The electricity contracts in turn provided security for signing 15-year contracts for the purchase of gas, issuing debt to finance the purchase of the plant, creating a highly geared financial structure with low risk, and hence relatively low cost.

Such a package made the generation market contestable, as the potential entrant could lock-in future prices and hence avoid the risk of retaliatory pricing behaviour by the incumbents. So attractive was this package that within a few months contracts had been signed for some 5,000 MW of CCGT plant, which, in addition to the incumbents' planned 5,000 MW of similar plant, would displace about 25 million tonnes of coal, compared to the 1992 generation coal burn of 60 million tonnes. The new CCGT capacity amounted to about one-fifth of existing capacity, which was in any case more than adequate to meet peak demand.

Every MW of additional capacity created by entry would displace a MW of existing capacity and hence result in the loss of the difference between average pool price and cost for the owner that MW of capacity. Faced with this credible entry threat, incumbents had an incentive to commit themselves to bidding in such a way that the time-averaged PPP was just below the price at which contract-backed entry of IPPs was attractive. This they could do by signing contracts, which both were directly comparable to those offered by IPPs, and which would induce the incumbents to bid more competitively into the Pool, ensuring that contract and Pool prices converged. Newbery (1995, 1997) showed that the best strategy for the incumbents was to use contracts to lower the time-averaged price, while increasing the spread between peak and off-peak prices, raising the demand-weighted price and increasing price volatility in the Pool. Table A1 shows that in the first four years the demand-weighted PPP was 3% higher than the time-weighted PPP, but it jumped to 11% higher in the following two years. Fig. 1 shows the monthly volatility increasing in the winter months. The reason why this strategy is attractive is that the incumbents have almost all the mid-merit and peaking plant, which they can use to increase their output in periods of high price. The main constraint limiting mid-merit and peak prices is the risk that IPPs may find it attractive to build plant specifically to meet these parts of the load duration curve, if the price rises sufficiently high.

The third decision the generators have to make is the amount of capacity to connect to the system (which incurs an annual connection charge) and how much to declare available each day (which influences the LOLP). The amount of capacity connected will be the best estimate of the amount that should be declared available on the day of maximum demand. The amount declared available determines the amount of capacity payments, which, together with the bids that set the SMP, gives the PPP. Capacity declarations provide the final instrument needed to set the time-average PPP, which is constrained by the entry price.

Capacity payments

How does the system of capacity payments adopted by the Pool influence price levels, bidding behaviour and reserve margins? Stations despatched receive capacity payments equal to LOLP x (VOLL - SMP). Fig. 3 shows the monthly capacity payments per kW of capacity, assuming that the capacity was available on all the days when capacity payments were made, as well as the total received over the previous 12 months, showing a peak of over £50/kW. The level of annual capacity payments needed to keep a generator on the system or to induce entry will depend on the excess of average value of the SMP over avoidable (fuel) costs, which will depend on the age and fuel use of capacity in use, and the annual connection charges, which Appendix Table A3 shows varies from £8/kW to -£10/kW. If reserve is provided by an open cycle gas turbine costing perhaps £150/kW and located in a capacity constrained zone with negative connection charges, then the target of £35/kW set at vesting could surely be lowered to nearer £15/kW. Critics argue that both VOLL and LOLP have been exaggerated.

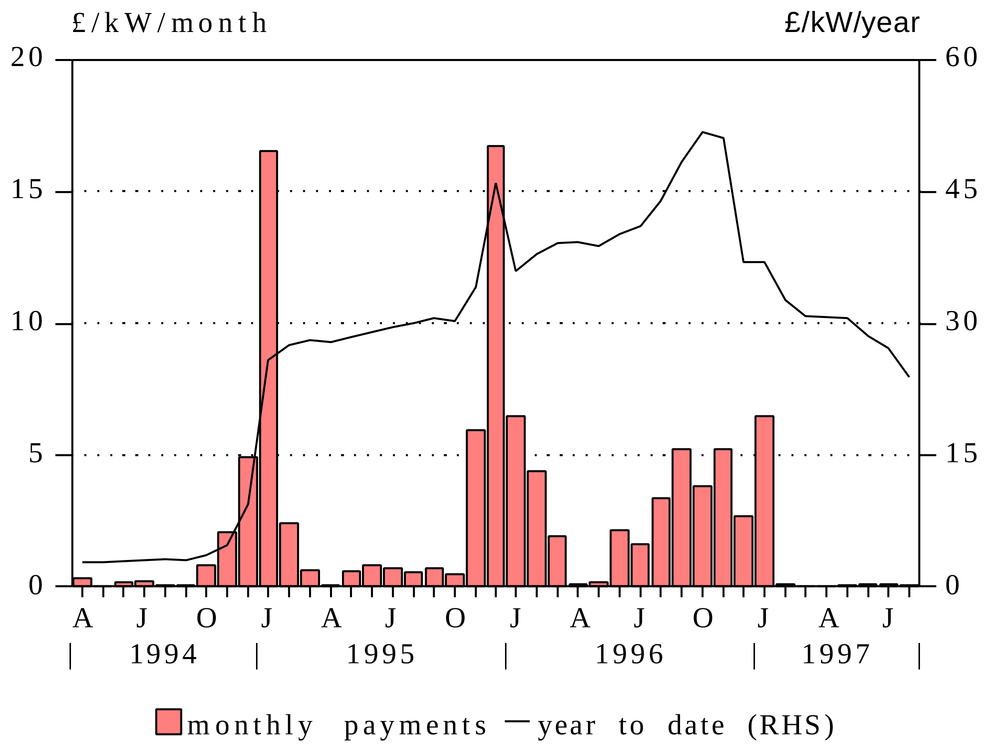

Fig. 3 Capacity Payments in the Electricity Pool

LOLP is intended to measure the probability of having insufficient capacity available to meet demand, and is estimated from the standard error in the demand forecast, and probabilities of "disappearance" of each genset between the date from which availability was deduced and the time of the forecast (Green, 1997). For pre-1990 plant, these disappearance ratios were set equal to their historical pre-1990 values, even though subsequent capacity payments have provided strong incentives to improve reliability and sustained availability.[9] The reliability of post-1990 plant is based on the previous year's operating performance, and is thus updated appropriately, but it is important to realise that the disappearance ratio is just the probability of a plant not being available on any random day of the year, given that it was available in the previous week. It makes no allowance for the various reasons why plant is not now available. There is the world of difference between withdrawing a genset in the summer lull for routine maintenance, and a genset failing at a time of maximum system stress, which arguably is the statistic of relevance

[9] The DGES wrote to the Pool on 15 September 1997 noting that "the improved performance of AGR plant is not reflected in Pool procedures. In consequence, the Loss of Load Probability seems likely to be overstated, leading to ... higher prices to customers."

in computing the reliability of the system at such moments when capacity payments are actually needed.

The computer program that computes the risk of failure takes some account of demand responses that the day-ahead forecast high prices might elicit. It also takes a modest account of possible supply side responses to high prices, but nothing like as large as those observed in practice (eg in the winter of 1996/7 as generators were told the day before of immensely attractive prices to be paid if their gensets were able to deliver).[10]

The meaning of "loss of load" is either a black-out, or, far more probably, a brown-out, in which voltage or frequency drops below operational limits but does not fail. The inherited CEGB standards were to ensure blackouts on no more than nine winter peaks in a 100 years and brown-outs 30 winters in 100. The value of lost load or VOLL is therefore a mixture of the value of an avoided blackout, taken as £2/kWh, or a brown-out, taken as 30p/kWh. These figures were taken from a 1985 CEGB paper which in turn cited evidence from Finnish consumer willingness to pay to avoid power cuts (in a rather frostier climate). The final choice for the 1990 VOLL of £2/kWh or £2000/MWh (to be uprated in line with the price level) might then seem high as ignoring the cheaper and more likely event of a brown-out, and was based on the assumption that brown-outs would occur on 20 hours per year, which, at £2/kWh would give an annual capacity payment of £40/kW, thought to be the required level (Henney, 1994, p345). National Power argued to the House of Commons that this estimate of VOLL was too high (HC 1992, §109).

Although each of the calculations of VOLL and LOLP might seem somewhat arbitrary, it is their combination that matters, and they were adjusted and tested out by simulating possible winter scenarios to meet the old CEGB standards, if anything erring on the high side to guarantee that the lights would not go out and take the gleam off privatisation. Some years later it seems sensible to consider whether their values are appropriate in the light of experience.

Figs. 4 and 5 show that LOLP and the associated capacity payments are a very non-linear (indeed exponential) function of the margin of available capacity to maximum demand. Fig. 4 gives the daily average payments in £/MWh[11] for the first five years of pool operation, showing payments on a truncated logarithmic scale (the very large number of observations less than £0.1/MWh are not shown, but are used to fit the linear regression line). Fig. 5 shows the maximum half-hourly payments, again plotted logarithmically against the peak reserve margin, computed as excess of the maximum value of PPP over that of SMP, giving values roughly 10 times as large (suggesting that the capacity payments are concentrated into short periods, in accordance with the smoothing algorithm applied to determine the payments).

---

[10] The assumed demand elasticity is -0.0085 and the supply elasticity is 0.003. Taken at face value these would imply that if the reserve margin were predicted to be as low as 10% without adjusting for demand and supply responses, SMP were £40/MWh, then without allowing for any response the PPP might be £247/MWh (using the data displayed in fig. 5), but taking account of responses would fall to £142/MWh and the reserve margin would rise to 11.5%. If, however, the unadjusted margin were 15%, the PPP would only fall from £54/MWh to £52/MWh and the margin increase to 15.3%.

[11] presumably time-weighted as they are derived from the daily average PPP and SMP

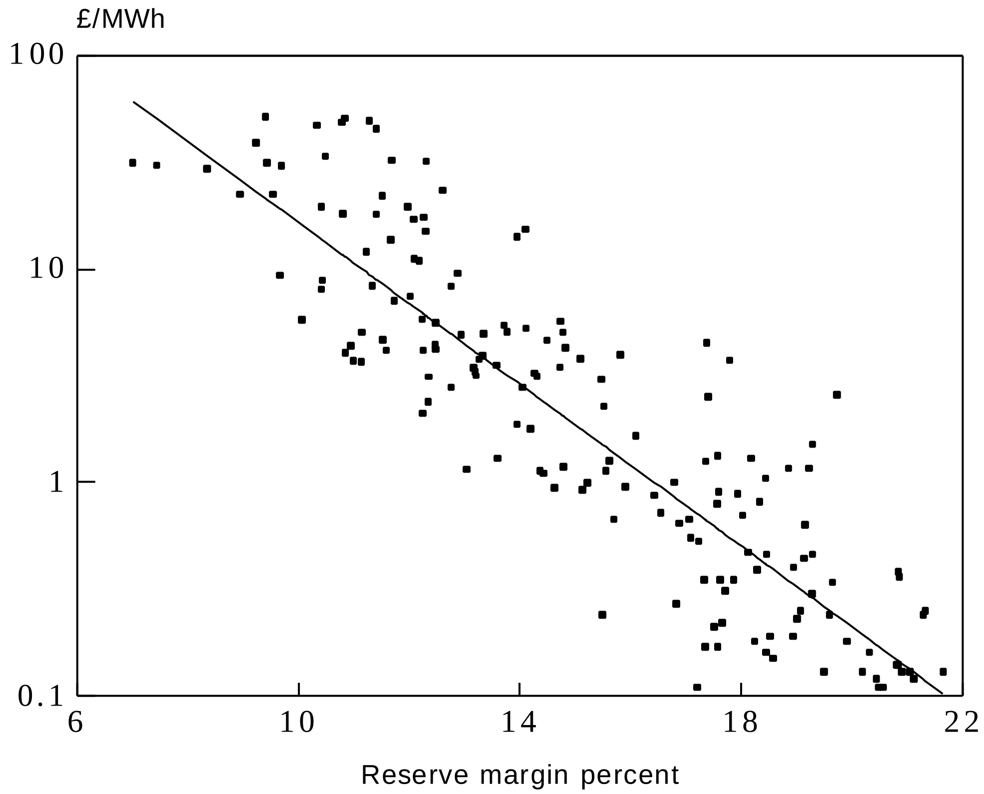

Fig. 4 Capacity Payments vs Reserve Margin
Daily averages, Electricity Pool 1990-95

The LOLP almost certainly overestimates the chance of a power failure, as this can be deduced from the payments made. The probability of failure per day can be roughly estimated from the daily maximum difference between PPP and SMP using the data for 1994/95 shown in fig. 5, and divided by (VOLL - SMP) using the formula above.[12] The estimated probability of a loss of load or failure on one of the 10 peak days is greater than 99.88%, while the chance of failing sometime during the whole year is greater than 1 - $4x10^{-8}$, essentially certain.

If the system were operating to the old CEGB standard of 39 failures (9 black-outs or 30 brown-outs) per 100 years, the annual risk of failure should be less than 39%. Since

[12] VOLL was taken as £2500, and *k* is defined as (Max PPP - Max SMP)/(VOLL - Max SMP). The two extremes which bound the daily risk of a loss of load or failure are to either assume that the entire risk falls in a single half hour, or at the other extreme, that the risk is equal in three adjacent half hours. In the first case, *k* must be multiplied by three, as the raw LOLP is smoothed by a centred moving average of three adjacent half-hour values, and the daily probability of no failure is 1-3*k*, while in the second case the daily chance of no failure is $(1-k)^3$. If the resulting risk of not failing on day *i* is $1-p_i$, then the cumulative probability of no failure after *n* days is $\prod(1-p_i)$, $i=1..n$.

vesting, the system has not failed through inadequate capacity,[13] so it follows that the calculated LOLP greatly overestimates the risk of system failure. The reasons are obvious - LOLP is not at estimate of the risk of failure on peak days, but on randomly chosen days, assuming negligible supply response, little demand response, and based on out-dated information. The consequence is that VOLL.LOLP will be too large unless VOLL has been seriously underestimated.

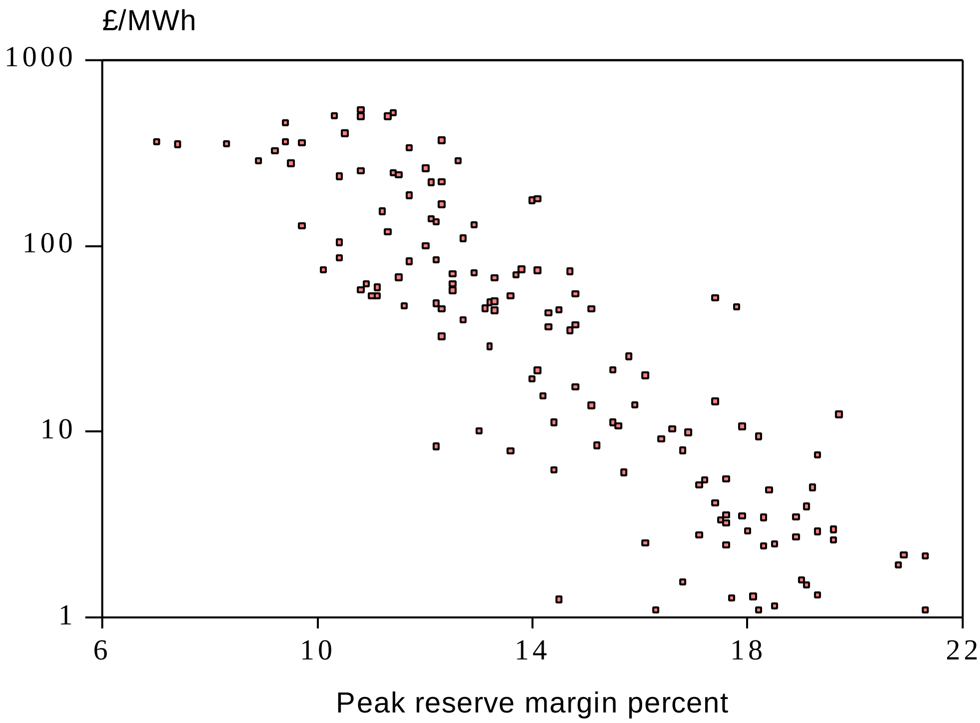

Fig. 5 Maximum half-hourly capacity payment
Electricity Pool 1994-95

In the Victoria Power Pool, generators submit bid prices and outputs which determine the SMP, and a set of negative prices, indicating the amount they are willing pay to remain on the system, rather than having to close down. Generators when formulating their bids must ensure they bid high enough to cover their fixed costs and any costs of starting from cold, for the pool price is set from the marginal bid with no capacity payments every 5 minute period. Because the market is truly a real-time spot market there is therefore no day-ahead schedule, no constraint payments to generators, and no need to predict the probability of a loss of load. The VOLL in Victoria was set at the same value ($A5000) as in England, but generators only receive the VOLL for capacity declared available if capacity is actually inadequate to meet demand, and the lights go off. This avoids the need for the System Operator to estimate the probability in advance, and leaves that calculation to the generators, who will consequently decide whether it is worth

[13] The risk of a brown-out or black-out in 7 years on the CEGB security standard is 97%, so the present system appears to do even better than the CEGB aimed at.

having capacity available given the probability that the lights will go off. The generators have every incentive to estimate the LOLP correctly, and could readily be given all the historical reliability information available to NGC in England.

The system had not been in operation in Victoria for very long before a series of very hot days was followed by two flood-lit sporting events - cricket and tennis, both dear to the Australian psyche. The lights went out in a most embarrassing way, partly because of heavy demands for air conditioning use, but proximately because bush fires tripped a 220kV feeder into Melbourne.[14] Irritatingly for the generators, the price in the pool failed to reach VOLL, as the reason for the failure was not inadequate generating capacity, but the black-outs caused much heart searching about system reliability and whether VOLL would ensure adequate capacity. Owners of peaking plant argued that given the actual payments received, they would need to run for over 50 hours per year to make continued connection worth while, but were lucky to run for 5 hours. The evidently unsatisfactory nature of the mechanism to ensure adequate reserves led to various reform proposals and short-run fixes. Increasing the VOLL by a factor of ten was suggested, as was an auction to determine the amount that capacity holders would need to keep reserve or peaking plant connected.

One can do a back of the envelope calculation about the cost of having an additional reserve margin of 5% of total capacity at the peak, if fuel costs are half total costs, and average capacity utilisation is 66%, then average electricity prices would have to rise by nearly 4%. This overstates the cost, as the fixed cost per kW of peaking or otherwise obsolete plant will be considerably lower than the average, but even if fixed costs of only £15/kW are to be recovered in the 10 hours of maximum LOLP, and the risk of failure during the year (concentrated into these 10 hours) is to be less than, say, 25%, then the implied VOLL is £50,000/MWh, or 20 times the current UK level.[15]

The problem is that whilst an insurance premium of 4% to avoid a power cut sounds quite small, the number of hours that a loss of load is at all likely (with efficient capacity declarations during the year) is also likely to be small, so all the cost is loaded onto these hours, making the implied VOLL in these hours extremely high. Indirect evidence that the VOLL is probably higher than the £2,500/MWh comes from the system of charging for TNUoS, where one third of the entire annual charge per kW is levied on each of the three triads - the three half-hours of system maximum demand separated by at least 10 days. Patrick and Wolak (1997) have studied demand responses to Pool prices for large customers paying Pool prices in one REC, and for these customers, the triad charges were £10,730/MW for 1994/95. Even though the triad charges are uncertain in advance, large consumers can subscribe to a forecasting service and endeavour to reduce their demand and save very substantial sums at the expected peaks. Perfect forecasting

[14] There was an earlier black out during an Australian rules football match at Waverly Park caused by a transformer fault.

[15] This calculation is very crude. Let p be the failure in each of 10 peak hours on different days, with no risk of failure at any other time. The risk of no failure is $(1-p)^{10}$, so if this is to be 0.75, $p = 0.0284$. This gives LOLP, and 10*VOLL*LOLP is required to be roughly £15/kW or £15,000/MW. VOLL is therefore £15,000/(10*0.0284) = £53,000/MWh. A 50% chance of annual power cuts would halve this figure. See the Appendix for a slightly more refined calculation.

would have allowed customers to save £7,153/MWh in each of the three triad half-hours in 1994/5, but in fact forecasting accuracy is about 0.13 (on plausible peak days), making the expected value of reducing load on possible triad days about £800/MWh, higher than any capacity payment (which are known with certainty a day ahead), and one-third of the VOLL.

Patrick and Wolak (1997) estimate the own and cross-price elasticities for a number of different firms (using half-hourly consumption and price data for each firm) and find that own-price elasticities at the peak are typically less than -0.025, except for water companies who can vary the timing of their pumping demand (for which it is -0.12), and non-ferrous metals (-0.05). This suggests that the response to these high prices is not large, suggesting that customers appear to be willing to pay large sums to continue consuming almost as much as before (which may be considerably below the willingness to pay to avoid an unexpected power cut, which is what VOLL is required to measure). It is also worth noting that most customers prefer to pay fixed prices for power, rather than exposing themselves to (hedgeable) price risks by buying at Pool prices, even though this would allow them to adjust demand and reduce their total electricity cost. This again tends to suggest that the value of not having to adjust demand (of which the extreme form is the risk of a power failure) is high, also indicating a high VOLL.

The VOLL is also relevant to managing load by reductions on the demand side. In the last two years NGC has operated an annual tender auction for the provision of standing reserve to assist in its system management function. Standing reserve is provided by open-cycle gas turbine and pumped storage plant, but also by demand reductions and non-centrally despatched small generators, though all must offer amounts in excess of 3MW. Large consumers can therefore specify their availability and willingness to reduce demand in various seasons and at various times of day, and NGC then accepts bids for which the total cost of providing load reductions are less than VOLL. In 1997/98 1809MW of centrally despatched generation and 458MW of demand modification and small scale generation were contracted (NGC, 1997b). Those consumers that are accepted are instructed through a PC-based mechanism, which also monitors performance and provides information to NGC's Ancillary Services settlement system on the basis of which payments are made. This mechanism is quite different from demand-side bidding (DSB), and avoids many of the apparent problems that have been encountered with DSB, including monitoring and performance. NGC is continuing to develop forms of contracting for load reduction, and presumably could be encouraged to broaden its range of services to cover those currently addressed by DSB.

The evidence from the tender auction is that for some customers for some times of the year and some periods of the day, given adequate notice, the value of reducing load is less than VOLL - but that at other times of the year or hours of the day, and for those customers who were not willing to participate, the cost of load reduction would exceed the present VOLL. (The graph in NGC (1997b) of the effective cost is fairly flat and is less than £250/MWh up to 2250MW, and rises sharply at nearly 2500MW, reaching £5000/MWh at 2750MW, mainly because of the fixed availability costs spread over a small number of hours despatched.) Clearly, unanticipated load reductions have a higher cost still and that is what is needed for avoiding outages. All this tends to suggest that if LOLP is reduced to its statistically correct level, some offsetting compensation through increases in VOLL might be warranted. It may also be that an extension of this system of load reduction more generally is more cost effective than capacity payments to generators.

If VOLL were increased and LOLP reduced, there would be a reallocation of investment away from reserve generation capacity towards reserve demand (ie load shedding) and transmission strengthening, because transmission reliability is also valued using VOLL. It is worth noting that most customers experience power outages once a year or so because of failures in local distribution, suggesting that if local delivery is not very reliable, it may not be cost effective to increase the reliability to grid points to very high levels. Clearly a proper investigation of trading arrangements would investigate this with the full armoury of statistical and econometric analysis.

Reforming the system of capacity payments

The more interesting question is what might happen in the Pool if the capacity payments were reduced, logically by a more accurate estimate of LOLP. On the assumption that entry remains contestable, the PPP is fixed by the costs of entry, in which case if the incumbents have the power to raise the SMP by the amount that the capacity element is reduced, they will do so. The amount of spare capacity will be reduced (for it must cover its fixed costs from the expected capacity payment, which has fallen), and the variability of prices might at first sight be expected to fall somewhat, as capacity payments are concentrated on a small number of hours, where the peak payments may now be lower. On the other hand, the profit maximising strategy of the incumbents is still to maximise the volatility of prices, subject to not inducing entry of peak capacity, which has been made less likely by the lower capacity payments. Incumbents may just increase base load contractual cover to induce lower base load prices and raise peak prices in compensation, essentially restoring the original volatility. The Pool Selling Price, PSP, should fall as the level of unscheduled availability payments, currently running at about £260 million, will fall in line with the fall in the reserve margin. If this were to fall by one-third, the PSP might fall by 0.04p/kWh or by a little over 1%.

The average *cost* of electricity for the incumbents will, however, fall, as capacity utilisation of the incumbents will have risen (but this will not affect any base-load IPPs), so incumbent profits should rise, as will the risk of power cuts. The end result looks like a potential public relations disaster - the generators make more profits for less reliable power at no lower price.

What would happen if there were more equally placed generators bidding into the spot market and hence making it more competitive, as in Victoria? Victoria has four generators using similar plant and fuel (opencast very cheap brown coal) and one smaller generator with peaking capacity, as well as transmission and trading links with the pool in NSW and also to the federal Snowy River hydro scheme which can sell either into Victoria or NSW, as well as a normally constrained transmission link to South Australia, making competition in non-peak periods intense. The crucial difference with England and Wales is that entry threats are not necessary to keep prices low in the pool, though at some stage as demand expands relative to existing capacity, new plant will be required, and will only be justified once the average price rises to the average cost of new plant - essentially the same condition as in a contestable market. Indeed, it should have to rise above this price, for demand is uncertain, but once investment has occurred, the capacity is available for 25-40 years, giving delay an option value. To the extent that the English market can be relied upon to keep prices tracking the entry price, the risk of premature entry is reduced, and long run (year to year) volatility may be lower than in a more competitive market. Not surprisingly, competitive markets are uncomfortably volatile places whose risks incumbents wish to mute by horizontal and vertical integration.

A more competitive spot market reduces the ability of the bidders to raise SMP much above avoidable costs, except in tight markets, and to that extent will make adjustments to capacity payments have direct effects on average pool prices as well as on the risk of power outages. It is noteworthy that the Victorian pool revealed the possible underestimate of the cost of providing security rather rapidly, and has provoked a swifter response within the industry and by the regulator to address the question of reforming the system of capacity payments. The more difficult part will be to balance the benefit of lower pool prices against higher risks of failure. The rather generous system of capacity payments in Britain has prevented power failures, but the market power of the incumbents weakens and may completely eliminate the trade-off of lower prices in return for lower security.

Several conclusions follow from this analysis. Provided entry remains contestable, and provided some new capacity would be economic, given the growth in demand and the need to replace older stations, the incumbents will be forced to keep the prices at competitive levels on average, and will be encouraged to mimic the extreme daily and seasonal volatility of a competitive market. Second, the level of the PPP, which includes the capacity payments, may not be very sensitive to the exact form of capacity payments where the incumbents retain available price-setting power. Third, the degree of system security may be quite sensitive to the exact form of these capacity payments, as will the cost of providing the security. Fourth, the main deviation of market behaviour in the Pool from competitive behaviour is likely to occur in periods when entry is not a threat, typically when there is excess capacity and no economic case for investment, or if barriers to entry appear, of if the willingness of counter-parties to sign long-term electricity contracts weakens. Finally, the relatively benign experience of the English Pool (where prices have not risen as much as was feared would follow from the unfettered exercise of market power by two price-setting generators) depends critically on the ease of entry at modest scale with CCGT plant. This in turn depends on the availability of cheap gas in the presence of aging coal plant, and will not necessarily translate to other countries with different plant and fuel prices.

Changing the form of capacity payments to meet objections will not be easy. The advantages of a decentralised market mechanism are considerable but uncomfortable. It encourages generators to make plant available when it is most needed, but to retire plant that cannot cover its annual costs. It forces those overseeing the industry to question closely the value of lost load, and, if this is not rather high, to accept the higher implied risk of system losses of load (in addition to the existing frequency of local outages). It encourages consumers to consider the value of reducing demand at the peak, and may prompt a variety of lower cost solutions to the peak than centrally despatched plant with the attendant need for adequate transmission capacity. It moves electricity pricing closer to the efficient ideal where overhead costs are loaded onto the peak or expected peak, even where the spot market may not be very competitive - at least, provided the market remains contestable.

There are a number of possible reforms that do, however, appear timely. The

LOLP should be based on a proper statistical evaluation of the relevant aspect of reliability, namely, the chance that a genset will not be available at a period of demand when capacity payments are appreciable. At present, the disappearance ratio is computed from the likelihood of a genset that was available in the previous week not being available on a given date, regardless of whether it has been taken off for scheduled maintenance, or because the plant is clearly not going to earn any capacity payments and is hence surplus to requirements. Generators that are or would be "constrained off" are clearly not in a position to help meet peak demand, and perhaps ought not to be eligible to receive capacity payments, though they may make some smaller contribution to system security, which should be recognised by a modified value of loss of load in the constrained region. Finally, generators are currently not penalised if they are not in fact available when they have been declared available.[16] Logically, they should then be required to pay any additional costs that arise because of their failure. This would directly address the present incentive that some gas-fired generators have to decide on the day to sell their gas into the gas spot market rather than generate the electricity they claimed to be available to deliver. Whether the VOLL will need adjusting will then depend on whether adequate demand side bids at an acceptable cost can be arranged.

Would it be possible to replace the whole system of capacity payments by some alternative? The present system has two great attractions and several drawbacks. The attraction is that it provides a decentralised and responsive signal to build more capacity and scrap obsolete plant, and it gives powerful signals to ensure that such plant is available when most needed. The drawbacks are that it fails to give the right signals for new plant to locate to maximise system stability, and the exponential nature of payments against the tightness of demand makes it hard to predict future capacity payments and hence hard for potential entrants to decide sufficiently in advance to provide needed reserve capacity. It is an interesting question in auction design to see if one could devise a mechanism in which the system operator forecasts desirable levels of capacity at peak periods in each zone (bearing in mind demand side responses) and then accepts bids for payment for capacity availability, which would then be paid contingent on being available in all periods where LOLP were higher than some predetermined level. This might reduce the unpredictability of capacity payments, facilitate the entry of mid-merit and peak plant, while retaining a market rather than central planned element. It does, however, substitute planning for the market in determining future capacity.

Market manipulation and entry conditions

In the first three years the apparent market power of the two incumbent generators caused the DGES to publish a series of reports on pricing behaviour in the Pool. Offer (1994a) criticised the growing discrepancy between rising pool prices and falling fuel costs since vesting, and specifically to the sharp increase in pool prices in April 1993, as the previous year’s contracts were replaced on 1st April. The regulator observed that the duopoly fossil generators between them set the Pool price over 90% of the time, with almost all

[16] This is not quite correct. Plant which is unavailable despite being declared available is labelled as "unreliable", and has to demonstrate, on the evidence of actually running when despatched, that it has become "reliable". If such plant were "constrained off" it would not be able to provide this evidence (but base load CCGTs would have no difficulty in re-establishing their reliability).

the balance set by pumped storage, whose electricity had been purchased at prices set by the two majors. Fig. 1 shows the pool prices and the fuel cost of the two majors, and reveals the rapid widening of the margin between them from April 1, 1993.

As a result of the enquiry, the DGES agreed with the majors that they should bid to ensure that both the time and demand-weighted Pool prices over each of the two years starting in April 1994 were kept below agreed levels,[17] and by the end of that period they should divest 6,000MW of plant (4,000MW from National Power compared to its then capacity of 26,000MW, 2,000MW from PowerGen compared to its then capacity of 20,000MW) to create more competition in the price-setting part of the market. In each of the two years they were able to bid to within 1% of both price caps, despite the remarkable level of monthly pool volatility - a testament to their ability to control the level of pool prices. In due course Eastern Group took 6,000MW of plant on 99 year leases for an impressively high price, and agreed to pay the owners £6/MWh generated, thus encouraging bids in the price setting part of the market (and ensuring essentially no change to the pattern of bidding and generation shares of these stations and of the market as a whole).

Competition between incumbents remains somewhat muted, and the threat of entry is still the main competitive force placing an effective cap on pool prices. If entry became more difficult or costly, then pool prices would likely rise more than if there were more equally placed price-setting generators, and it follows that more regulatory vigilance is required over the conditions of entry than would be the case in a more competitive market. It was largely for this reason that the President of the Board of Trade refused permission to National Power and PowerGen in their respective merger bids for two of the larger RECs in late 1995. On May 9, 1996, Ian Lang defended his rejection of the mergers and stated clearly that the Government would use its golden shares in National Power or PowerGen to block any bid 'until competition in electricity generation has become fully established...' (*DTI Press Release*, P/96/329, May 12).

Some market manipulations may be relatively harmless, if they affect prices payable to all, are predictable by potential entrants, and are part but only part of the method of setting the time average PPP, which in turn is constrained by entry threats. Such manipulations may affect the time pattern of prices, but not the average level, and hence can be insured against through contracts. Others are more pernicious if they confer advantages on particular generators not available to entrants. Some of the bidding behaviour for constrained plant comes into this category, and has attracted a series of reports by Offer. Encouraging NGC to contract for constrained services partly alleviates this problem. The new powers of the DGES under the proposed *Competition Bill* (HL Bill 33, 15 October 1997) may also be useful, as it shifts the nature of competition law to a prohibition based system modelled on Articles 85 and 86 of the EC Treaty. The DGES would be able to fine companies abusing a dominant position, and dominance would be defined relative to a relevant market. Constraints greatly reduce the size of the relevant market, and make it likely that generators behind such constraints would be in a dominant position. The DGES would be required under the proposed *Competition Bill* to spell out what he considered to be abusive and benign behaviour.

---

[17] 2.4p/kWh time weighted, 2.55p/kWh demand weighted, in October 1993 prices.

There are doubtless a whole variety of ways in which generators are able to take advantage of the complexities of GOAL and of the PSA rules, most of which require the ability of the DGES to intervene to change the PSA. One such is the ability of generators to bid a modest price for 95% or so of capacity, and a very high price for the remaining few percent. When directed to generate up to a limit of 95% or so of capacity, they are able under current Pool rules to overgenerate up to the margin permitted, and be paid their (very high) bid price (rather than the SMP, which, if the overgeneration were the fault of the company, would be the logical basis for payment).

Demand side bidding

The Norwegian pool allows traders to submit a schedule of supplies and demands, typically in the form of a downward sloping net demand schedule, such that above a certain price the trader is willing to sell into the pool, and below that to buy out. The overall market clears at a price at which demand and supply are in balance, or aggregate net demand at that price is zero. The effect of allowing demand side bidding is to make the net demand schedule appear more elastic, which would reduce the extent of market power and opportunities for market manipulation. However, it should be remembered that in Norway the traders are frequently distribution companies with their own hydro capacity, and they are effectively deciding whether to buy or sell water - a net demand means that they can supply their customers from the pool rather than their own dam, while a net supply means that they generate both for their own customers and to sell a surplus. The actual final demand may be as inelastic is in Britain.[18]

At the moment demand responses are taken into account in three ways - though the calculation of the LOLP which affects capacity payments, via NGC's tender offer to provide standing reserve for system management (described above), and through a small scale demand side bidding (DSB) scheme introduced in 1993, and now involving some 30 customers. The idea behind DSB is that customers should be treated symmetrically with generators, except they bid for reductions in demand, and would receive capacity payments in proportion to the extent they offered to reduce peak demand, symmetrically with generators who offer capacity and receive payments. The system apparently is poorly monitored, though it seems that NGC's tender offer system avoids most problems of monitoring and performance, and might replace this relatively unsatisfactory arrangement, provided some market maker had the incentive to set up the service.

It is worth asking whether there is any substance in the claim that the present Pool is only half a market, as it suppresses the demand side. First, note that consumers have every incentive to reduce demand at times of peak demand, for they pay large triad payments that amount to sums comparable with peak capacity payments. Second, to the extent that large consumers can (and presumably do) sign CfDs for specified quantities, they have an incentive to reduce demand and profit by effectively selling their unsold demand (ie the excess of the amount specified in the CfD and what they take) back into the market. The problem seems to lie not in the incentives that consumers have to reduce

[18] Norway has some 7 TWh/year of dual electric-oil steam raising capacity, which allows these companies to switch if the electricity price rises above the equivalent cost of oil-fired steam raising. At that point the demand does become suddenly elastic - an option not economic at British electricity prices.

demand at periods of high pool prices, but in the inability of the scheduling algorithm to model these demand responses in computing the market clearing price. Ironically, a true spot market on the Victorian model would find the intersection of actual demand and supply, but because prices are not quoted firmly a day ahead, as in Britain, consumers are less well placed to respond.

There are several possible solutions. The simplest would seem to be to adapt GOAL to accommodate predicted demand responses, which might be improved by a knowledge of the fraction of demand facing marginal Pool prices (ie those customers with fixed quantity CfDs), and an automatic updating procedure of re-estimating the forecasting equations of demand on the basis of out-turn demand. The PSA would have to be modified to allow this (and other) updating procedures to the scheduling algorithm - and this is not easy, as the section below on Pool governance indicates.

A more dramatic change would be to shift to a continuous spot market to determine price on the basis of actual supplies and demands, while retaining the day-ahead market for scheduling and deriving predicted prices. Generators and suppliers would have the option of choosing whether to accept the predicted or ex-post prices at the time of bidding, and the system operator would need some incentive to narrow the gap between ex ante and ex post prices. If LOLP were properly calculated, then presumably the same choice could be extended to capacity payments, which would have the same expected value ex ante as the realised average ex post, but, given the presence of market power and the complex determination of PPP via entry threats, contracts, and competition, this proposition should be properly tested before being accepted at face value.

An intermediate option would be to have both a day-ahead market as at present, and a balancing market operating on the day to make adjustments and ensure continuous balancing of supply to demand, thereby reducing the costs of forecast errors and possibly some other components of uplift. Whether this would be much different from the balances currently achieved from the bids of plants "constrained on" is unclear, and it would still be necessary to reconcile the two sets of prices, perhaps again offering options to trade either at day ahead or spot market prices.

Finally, note that if pool prices are set by the costs of entry, then most of these reforms will have little effect on the average level of prices. The main effect of DSB may be to encourage consumers to be more aware of high peak prices, and to actively consider ways of reducing demand then, thereby lowering the cost (if not necessarily the price) of electricity.

Pool by-pass, WYBIWYG, and other Pool reforms

Several large customers have proposed direct physical trades with individual generators, and have also argued that they should be credited with placing less stress on the transmission system and having lower reserve requirements than other more fickle customers. The first point to make is that it is hard to imagine a physical trade that could not be replicated with greater security and no higher cost by a financial contract, since CfDs allow the designated generator to effectively buy power in the pool whenever the PPP is lower than the avoidable cost of generation, thereby saving costs and improving efficiency. The main arguments for allowing physical trades have to do with reforming the nature of the Pool to achieve different systemic outcomes, favourable to the proposing party, or with indirectly criticising the cost of transmission and other ancillary services. The most obvious distortions that should be corrected are that large customers in export constrained areas (ie in the north and Scotland) are paying too much, as the shadow price of power is less than the SMP. To some extent, but perhaps inadequately, this is dealt with by the regionally differentiated TNUoS charges (see Table 3 below), but it may be that these should be revisited to investigate what the opportunity cost of supplying power to baseload consumers in export constrained regions is.

If physical trades by-pass the pool, they would be struck at negotiated prices (and the proponents hope would be charged lower uplift). A related reform that has been proposed is that generators bidding into the pool are paid their bid rather than SMP - often called WYBIWYG, or What You Bid is What You Get. It is proposed by those who wish to make the Pool less competitive, less contestable, and more opaque.[19] The larger incumbents, whose diversified portfolio of plants gives them an advantage in crafting a profitable bid structure under WYBIWYG, and market traders, who would exploit their information, would be at an advantage over the owners of single stations (IPPs) and most consumers. They could no longer rely on bidding honestly at avoidable cost and receiving the PPP set by the most expensive set, but would instead have to guess what the Pool price might be and bid accordingly. Since the Pool price varies on a half hourly basis, either they would have to bid in a time-varying schedule of bids, or they would have to hope that most time variation were eliminated by coordinating bids on a acceptable level, in which case the merit order would be prejudiced and the pricing function of the Pool lost. This issue was visited by Offer (1994b) and rejected then.

Since then the arguments for a compulsory Pool with a SMP, compared with a voluntary Balancing Pool (possibly at SMP) have been rehearsed at length in the US context. The fact that such a system works quite well in the storage hydro systems of Scandinavia does not mean that it would work at all efficiently in a predominantly thermal system as in Britain. The idea that a balancing pool, which would operate on the day, might eliminate forecasting errors and reduce uplift offers a partial defence, but does not argue for either Pool bypass or a physical market, both of which run the risk of out-of-merit running for no obvious gain. Stoft (1997) has cast doubts on the motives of those arguing for it in California, and suggests that it may lead to considerable efficiency losses. Remembering that a cost rise of 4-5% would completely eliminate all the gains from restructuring, it follows that such proposals should be treated with some scepticism.

There are other reform proposals that have been made from time to time and which bear further investigation. The most obvious is that the technical characteristics of plant should be taken as fixed, possibly subject to audit, or properly priced in the annual connection charge (reflecting their value to the system in terms of security, stability, etc). They would not then be available to manipulate and game the scheduling rules. One might also ask why it was necessary for generators to adjust their plant bids on timescales shorter than that over which fuel prices change. Indeed, if fuel prices were particularly volatile, but marked to market in a liquid spot market (preferably one on which contracts or options could be written), then bids might better be submitted as a combination of heat

[19] or by large consumers who think they will be able to strike better bargains, but who are unaware of the longer run implications for average price levels.

rates and fuel type, to be priced on the basis of spot fuel prices. Heat rates would be adjustable as generators chose to alter the running order of gensets to optimise plant operation, though perhaps on a monthly or quarterly basis.

Whether these reforms are valuable depends on whether gaming differentially benefits some incumbents over other smaller players or entrants, and on the degree of contestability of entry. If entry costs determine average pool prices, there is little to be gained from changes (other, perhaps, than greater predictability and transparency, which might be quite pro-competitive in the contract market). If the market is not contestable, then manipulation is more likely to be anti-competitive (but might also be dealt with under the prohibition-based approach of the proposed *Competition Bill*).

Constraints, losses, and locational pricing

Many of the problems of the Pool can be laid at the door of failing to accommodate locational price differences. The issue is simply stated but not so simply solved. The efficient price of electricity at any moment will vary from place to place because of losses, and, more importantly, because of transmission constraints. If a region is export constrained, the most expensive bid accepted (the local SMP) within that region will be less than the most expensive bid outside (the external SMP). Conversely if a region cannot import because of constraints, the local SMP will be higher than the external SMP. If generators could be relied upon to bid honestly at avoidable cost, and if the local rationing price could be properly set by a VOLL*LOLP mechanism, with LOLP locally computed, then each region could set its own SMP, which would be equal to the system-wide SMP when transmission was unconstrained, but would otherwise would differ.

The problem is that market power is far more of a problem in regional pools, where there are very few competing generators, than in country-wide pools. The British compromise is to set a single Pool price, to maximise the number of competing generators, at the expense of inefficient regional energy prices. In effect, generators have a guaranteed right to supply, and are paid compensation for constraints. Consumers pay a single energy price with a comparable right to be supplied.

How might this be dealt with? The problem is similar to the capacity reserve problem, but is less likely to be handled by making each regional sub-market contestable, particularly in export constrained regions where entry is positively not wanted. What is needed is a way of rewarding capacity according to its contribution to regional security of supply, which may differ dramatically from the country level. It might be relatively simple to compute regional LOLP values, and hence regional capacity payments, though this would not eliminate the incentive to distort bids away from avoidable cost. Here it depends whether constraints bind for a large or small fraction of the time, and whether the plant is on the margin of being withdrawn. If constraints are infrequent, then they may not influence bidding behaviour much, and if the DGES publishes the Guidelines on abuse of dominant position, as he will be required to do under the proposed *Competition Bill*, then he could define a significantly different bid when constrained to unconstrained as evidence of abusing a temporarily dominant position, subject to penalty. Alternatively, the compensation for being "constrained off" could be equal to SMP *less* the highest bid of that genset over the previous year.

If the high constraint payments are required to adequately reward and hence maintain capacity, then this should be handled automatically by the regional version of capacity payment, or by a direct contract with NGC, as at present, for system stability. Finally, although existing generators have a guaranteed right to supply, there is no obvious reason why this should be extended to new generators in constrained regions, who, perhaps for the first five years, might reasonably not be compensated for not being despatched, as they made their locational decisions in the light of existing patterns of constraints.

Similarly, if large base-load customers in export constrained regions contribute to system stability, their TNUoS charges should be computed to reflect this, as should their regional PPP, which includes the regional capacity payment, not forgetting the regional loss adjustments, which will reduce the cost of delivering power in these regions.

Losses have increased from 1.6% in 1990 to a forecast high of 2.4% in 1999 (NGC, 1997a, table 6.6), mostly because of high peak power flows from north to south, in part because generators are locating too far from load centres. NGC (1997a, Table 6.7) shows that a new power station in the North (zone 1) generating 100MW only meets 93MW of national demand averaged across the system at the predicted 2003/4 winter peak, while 100MW located in Peninsular (zone 16, ie Cornwall) meets 110MW of demand by alleviating power losses - or 18% more than the Northern station. Since all the capital cost should ideally be collected at system peak, this differential implies that lifetime generating costs might be 12% too high for an incorrectly located station (on the assumption that half the cost is capital, and operating losses add another 4%).[20] The Pool proposed a system of charging generators for zonal losses but this was appealed against, as it will adversely affect northern generators.

Until losses are properly charged, the only locational signals to guide the siting of new generation are the annual TNUoS charges. These are determined from the investment cost related pricing (ICRP) of system expansion (as explained in the footnote to table A3), with 25% of the balance of the regulatory income of NGC being recovered from generators, and 75% being charged to consumers (who in addition receive the ICRP, effectively as negative generators reducing the need for transmission), the total being collected through the triad charges. Table A3 shows the zonal tariffs for generators and consumers before and after the 1997 Transmission Price Control Review (which led to an increase in the number of generation zones and a change in several boundaries). Generators who face positive charges are charged on registered capacity, while those facing negative charges are paid on the average of the 3 highest levels of generation separated by 10 days in the winter period. Consumers are charged on the three triad half-hours.

Between 1990 and 1996 most of the new generation located north and east of London, none in inner London, and only a small amount in outer London. Plants closed in NGC zone *South Coast* and a negligible amount located in *Peninsular* (ie Cornwall). Compared to last year, the range between the *North* and *Peninsular* for generation has been widened from £14.37 to £18.09/kW or by 25% while for customers the range has narrowed from £16.67 to £15.38/kW or by 8%. Clearly generation charges are attempting to signal the very high opportunities of locating new plant in the *South Coast*, *Peninsular*

[20] The average marginal loss between North and Peninsular is 12%, so if the load factor is 66% and half the costs are variable, the variable loss is $12 \times \frac{2}{3} \times \frac{1}{2} = 4\%$

and *South Wales*, though with little success to date. Part of the problem may lie in the difficulty of adjusting charges by large amounts from year to year, given the durable nature of location decisions and the unpredictability of future charges. The obvious solution would be to give the option of long-term contracts for connection, based on current best estimates of future charges, and then adjust generation charges by possibly large amounts each year to signal changing needs more accurately. This will require a careful (but economically defensible) definition of what is meant by discrimination if charges to different generators at the same place differ - the contract reflects differing views of the future which can be revalued each year if appropriate.

The incentives for by-passing transmission (ie by own generation) are given by the sum of the TNUoS charges, which for Northern have fallen from £10.8 to £8.86/kW or by 18%, though the sum in the South West has fallen from £13.1 to £6.13 or by 50%, and is now lower than in the north. It is not clear that the cost of providing security (which is primarily the service offered by TNUoS charges) is now lower there or has fallen more than in the north, and it may just be that consumers in the south have been more effective at complaining about high prices there. Again, it would be useful to know whether the price signals are muted by the felt need to make gradual adjustments which might be addressed by longer term contracts.

Finally, NGC operates to double circuit outage standards, a higher security standards than almost all other high voltage transmission systems. Thus for any six transmission lines between two points, two are active and four idle, while the more conventional single circuit standard would allow three active and three idle circuits, a 50% increase in capacity. Offer (1992) found that high levels of constraint payments were made when the risk of a double circuit fault seemed low, and invited NGC to undertake a review, which they did in 1994. NGC found that relaxing the security standard might save some £35 m in constraint payments at an extra cost of £10 m in transmission losses, and that these payments would fall once NGC were given an incentive to reduce constraint costs, as subsequently happened. Offer published a short note in March 1996, inviting NGC to relax their Operating Standards (though he had no power to insist of this). This NGC chose not to do, arguing that it could achieve the same benefits at lower cost. Offer also considered whether cost-benefit techniques should be applied to transmission planning, but balked at the difficulty of evaluating environmental gains. NGC argued that very few existing transmission lines would not be needed at a lower security standard, but the real question is when new investment is required, whether the extra cost of a higher standard would be justified given the higher risk of failure. The suspicion for both publicly owned and regulated utilities where their revenue is primarily determined by their asset base that there will be a temptation to over-engineer standards, and this may be a case in point. The question is whether the reliability of final delivery to customers is achieved at least cost, and whether competition in the Pool would be enhanced by lower reliability and fewer transmission constraints. At present, local distribution is less reliable than the grid, and may undermine the value of the high level of grid security. Such a review would require a careful economic and engineering analysis.

Remaining market concerns

The main argument of the paper is that market failures can only be assessed in the context of all the factors which bear on the determination of the price level and its structure. These in turn are affected by the spot and contract markets, the conditions and incentives for entry (of which capacity payments are an element), and the handling of spatial constraints and losses. If, as in Britain, there are few price-setting generators, then the conditions of entry must play the main role in restraining prices and encouraging generators to adequately contract. Entry alone may not be sufficient to overcome local pockets of market power, unless spatial price signals are both well designed, and can be locked into contracts by entrants choosing between zones. Anything which makes entry more difficult may reduce the competitive pressure on the incumbent large generators, and is a cause for concern.

In the past entry has been facilitated by the long term contracts offered by RECs to IPPs (in which they often had an ownership stake). The 1998 ending of the franchise monopoly makes these contracts less likely, and hence makes entry more risky. It would be unfortunate if the introduction of supply competition for consumers resulted in less competition in generation and higher prices to consumers. The main source of optimism is that the gas spot market and gas competition makes it more attractive for gas suppliers to diversify into electricity generation as a portfolio hedge, while the low price of gas makes such entry attractive. If the gas interconnector to the Continent drives up English gas prices to continental levels and creates adequate demand to remove the gas overhang this could change. It would be worrying if as a result the incumbent large generators captured most of the market for new power stations - and they already take about half of all new capacity.

Governance

Almost all reforms require changes to the PSA, which as a contract can only be changed by agreement, or by replacement which would require primary legislation. Pool reform therefore requires major changes comparable to those introduced by the *Gas Act 1996*, which introduced the network code for gas transmission. The logical structure of a reformed Pool would be a two-tier form of governance, perhaps similar to that of Victoria and proposed for several regions of the US (Barker et al, 1997). The lower tier represents the stake-holders, as in the present Pool (though perhaps with more consumer representation), and if they are able to reach agreement on changes which are not opposed by the DGES, they would be directly implemented. If not, or if they fail to propose satisfactory remedies to identified problems, then a higher tier, presumably the DGES, or whatever form of governance the utilities review proposes, would have the power to intervene, subject to the appeal procedure set out in the proposed *Competition Bill*.

There may be other satisfactory governance structures, possibly even better ones, but any structure has to combine the advantages of detailed operational knowledge without the present deadlock that those adversely affected can prevent or indefinitely postpone changes. Changing the legal basis of the Pool from a contract to a company, independent of the current Pool participants, with a legal persona subject to regulation would address the second problem, but would only meet the first requirement if it had the right staff, mandate and incentives. One of the main tasks of the Pool Inquiry will be to invite carefully articulated and supported submissions on the future Pool governance structure.

Conclusions

Judging the validity of criticisms of the Pool and electricity trading arrangements require a proper understanding of the nature of competition in all the electricity markets - for spot power, for contracts, and for capacity. Until the number of equally placed, actively competing price-setting generators increases to four or more, the main burden of competition is placed on the conditions of entry. Where the market is contestable, reforms are unlikely to have major impacts on average price levels, and some apparently sensible reforms may have unintended consequences, such as reducing system reliability with little gain in lower prices. It follows that the main test of reforms is their effect on prices, costs, capacity, and reliability, given the actual state of competition among existing participants, and, most importantly, by potential entrants.

The set of problems which the threat of entry is least likely to remedy are those to do with transmission constraints and the need to differentiate prices by location, to signal where entry should occur, exit be discouraged, and load management is best directed. If prices are to play a more active role in encouraging efficient locational decisions, they will need to be capable of more rapid and possibly larger adjustment. This will require some way of insuring agents against future price changes while still providing them with incentives for short-run efficient management of their existing capacity. Contracts for differences offer the logical solution. NGC should be asked to revisit the allocation of constraint costs, security payments, and other system management costs by zone and between generators and consumers, for although the present capital costs are allocated regionally by a defensible methodology, the balance between consumers and generators still appears arbitrary, and the underlying price signals do not appear to be translated into adequately differentiated charges.

Finally, having identified the desirable reforms, major changes to the governance structure of the Pool will be required before most of them can be introduced. Without such changes the Pool Inquiry will be a purely academic exercise. If a new system of governance can be created which can respond to problems, and if the proposed *Competition Bill* confers the promised powers on the regulator, then problems can be addressed as they arise, in the light of growing experience of the variety of remedies being market tested in power pools round the world.

References

Barker, J., B. Tenenbaum and F. Woolf (1997) *Governance and Regulation of Power Pools and Systems Operators: An International Comparison*, forthcoming World Bank Discussion Paper

Green, R.J. (1997) 'The political economy of the Pool', in M.D. Ilic, F. Galiana and L. Fink (eds.) *Restructuring, Power Systems Engineering and Economics*, Norwell, Ma: Kluwer

Green, R.J, and D.M. Newbery (1992). 'Competition in the British Electricity Spot Market', *Journal of Political Economy*, 100(5), October, 929-53.

Henney, Alex (1994) *A study of the privatisation of the electricity supply industry in England and Wales*, London: EEE Ltd

Henney, Alex and Miles Bidwell (1997) *Reforming the Pool of England and Wales - a report for Mr John Battle, Minister for Energy, Science and Industry and Pool Members*, London: EEE Ltd

HC (1992), *Consequences of Electricity Privatisation*, Energy Committee, House of Commons, London: HMSO 1113-1

HC (1997), *Energy Regulation*, Trade and Industry Committee, House of Commons, London: HMSO

HL Bill 33, *Competition Bill*, House of Lords, 15 October 1997

NGC (1996), *Transmission LC 10 Statements of Charges for Use of System and Connection to the System 1996/97*, National Grid Company plc.

NGC (1997a), *1997 Seven Year Statement*, National Grid Company plc.

NGC (1997b), *Report on the Tender for the 1997/98 Standing Reserve Service*, National Grid Company plc.

Newbery, D. M. (1992), 'Capacity-constrained Supply Function Equilibria: Competition and Entry in the Electricity Spot Market' DAE Working Paper, Cambridge

Newbery, D. M. (1995) 'Power Markets and Market Power', *Energy Journal* **16**(3), 41-66

Newbery, D.M. (1997) 'Competition, Contracts and Entry in the Electricity Spot Market', mimeo, Department of Applied Economics, Cambridge

Newbery, D.M. and M.G. Pollitt (1997), 'The Restructuring and Privatisation of the CEGB- Was it worth it', *Journal of Industrial Economics*, XLV (3), 269-303

Offer (1992a), *Report on Constrained-on Plant*, Office of Electricity Regulation, Birmingham, October 1992.

Offer (1992b), *Review of Pool Prices*, Office of Electricity Regulation, Birmingham, December 1992.

Offer (1992c), *Review of Economic Purchasing*, Office of Electricity Regulation, Birmingham, December 1992.

Offer (1994a), *Decision on a Monopolies and Mergers Commission Reference*, Office of Electricity Regulation, Birmingham, February, 1994

Offer (1994b), *Trading outside the Pool*, Office of Electricity Regulation, Birmingham, 14 July.

Patrick, R.H. and F.A. Wolak (1997), 'Estimating the customer-level demand for electricity under real-time pricing', paper presented to the POWER conference, March, Berkeley: University of California Energy Institute

Perez-Ariaga, Ignacio and Alex Henney (1994), *The Organisation and Operation of the Electricity Supply Industry in Argentina*, London: EEE Ltd

Stoft, S. (1997), 'What should a power market want', *Electricity Journal*, June

Appendix Adjusting the values of VOLL and LOLP

Suppose we wish to find what values of VOLL and LOLP would give an annual risk of a loss of load of 0.25 or less, while maintaining the same reserve margins as in 1994/95, and suppose that the required annual capacity payment needed to achieve this is £15/kW. Suppose also that the correct value of LOLP is a constant fraction α of the one used in 1994/95, and the actual risk of failure on day *i* is taken as $p_i = 3\alpha k_i$, where k_i is (Max PPP_i - Max SMP_i)/(2500 - Max SMP_i), as defined in footnote 12 above.[21] The resulting risk of not failing on day *i* is $1 - p_i$ and the cumulative risk of failure is $\prod(1-p_i)$, (i = 1,..,365). The value of α was adjusted to ensure that this was 0.75, giving a value of α of 0.0174 (which seems remarkably low and clearly needs to be checked). Given this new value of LOLP, and assuming that the relationship between capacity payments in non-peak hours on the day and at the peak remained the same on each day, the VOLL required to give a cumulative capacity payment of £15/kW was then computed to be £75,000/MWh, rather higher than the very short-cut method of footnote 15.

If the annual risk of failure is allowed to double to 0.5, then α becomes 0.042 (rather more than double), and VOLL falls to £31,000/MWh, rather less than half.

Table A1 Annual average Pool prices

pence/kWh or £/kW/yr

	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97
Time-weighted p/kWh							
SMP	1.74	1.95	2.26	2.40	2.08	1.94	2.06
Capacity	0.00	0.13	0.02	0.02	0.32	0.45	0.35
PPP	1.74	2.08	2.28	2.42	2.40	2.39	2.41
Uplift	0.09	0.16	0.14	0.23	0.24	0.20	0.19
PSP	1.84	2.24	2.42	2.65	2.64	2.59	2.60
Demand-weighted p/kWh							
SMP	1.81	1.99	2.31	2.44	2.19	2.07	2.18
Capacity	0.01	0.17	0.02	0.04	0.45	0.61	0.40
PPP	1.82	2.16	2.33	2.48	2.64	2.68	2.58
Uplift	0.10	0.18	0.15	0.22	0.27	0.24	0.20
PSP	1.92	2.34	2.48	2.70	2.91	2.92	2.78
Demand-weighted at 1995-96 prices, p/kWh							
SMP	2.11	2.21	2.49	2.59	2.26	2.07	2.13
PPP	2.12	2.40	2.51	2.63	2.73	2.68	2.52
NP + PG Total Revenue from generation at 1995-96 prices, p/kWh							
		3.90	3.87	3.52	3.56	3.42	
Capacity payments at 1995-96 prices, £/kW/yr							
	0.47	19.91	2.80	2.55	29.13	39.30	27.64

Sources: Offer (1994a), *Pool Statistical Digest*, Company Accounts

[21] The alternative $(1-\alpha k)^3$ gives essentially the same result.

Table A2 Uplift (1995/96 prices)

£ million

	1990-1	1991-2	1992-3	1993-4	1994-5	1995-6	1996-7
Operational outturn	183	280	270	434	364	190	213
(of which constraint costs)				(255)	(194)	(74)	(57)
(of which notional reserve)	(42)	(39)	(49)	(42)			
Ancillary services	124	135	128	170	113	141	110
Unscheduled availability	4	114	14	23	248	298	252
NGC incentive payments	n/a	n/a	n/a	n/a	26	23	9
Uplift	311	529	413	627	752	655	587

Source: Offer

Table A3 Use of System Zonal Tariffs

£/kW

Generation Zone	*Generation tariff 1996/97*	*1997/98*	*Demand Zone*	*Demand tariff 1996/97*	*1997/98*
North	7.873	7.975	Northern	2.929	0.880
Humberside	4.889		Norweb		5.328
Yorkshire	4.870		Yorkshire	7.722	4.819
Rest of Yorks		3.733			
North Wales	4.121	5.484	Manweb	8.631	5.584
South Wales		-4.936	Swalec		14.834
West and Wales	-0.500		West and Wales	15.688	
Inner London	-5.476	-9.885	Inner London	17.443	
			London		13.457
Outer London	1.037	0.021	Outer London	13.019	
South Coast	-2.096	-4.036	Southern	14.349	12.630
Peninsular	-6.495	-10.111	Peninsular	19.602	
			South Western		16.263

Source: NGC (1997a) and fax update for 1997/98; zones aligned as far as possible

If g_i is the charge to generators in zone i computed from the Investment Cost Related Pricing methodology, then $-g_i$ is charged to consumers there, and if q_i is generated and d_i demanded, then the revenue from these charges is $\Sigma g_i(q_i - d_i)$, and the balance is charged 25% to generators, 75% to consumers.