Conference on:
Competition in the Electricity Supply Industry:
Experience from Europe and the United States
Copenhagen September 23-24, 1994

Capacity Investment and Long-Run Efficiency in Market-Based Electricity Industries

by

Nils-Henrik Mørch von der Fehr
SNF Foundation for Research in Economics and Business Administration,
Department of Economics, University of Oslo.

and

David Harbord
London Economics

1. *Introduction*

A key characteristic of both the Norwegian and the UK electricity supply industries under the old regulatory regimes was inefficient levels of installed generation capacity. The pre-reform Norwegian industry suffered from considerable over-investment, resulting in spot market prices persistently below capacity costs. Due to lack of competitive pressures, excess capacity costs were recovered by monopolistic pricing in long-term contracts, which included extensive price discrimination between consumer groups. In the UK, under the old Central Electricity Generating Board (CEGB), investment in excess capacity was coupled with inefficient technology choices and lack of modernisation of plants.

Underlying the introduction of the new liberalised regimes[1] was a general presumption that by subjecting supply and pricing decisions to market forces, optimal investment decisions were likely to follow. Apart from some fairly general arguments however, concerning the benefits of competition and market-based transactions, this belief does not seem to have been subjected to a serious analysis taking into account the particular characteristics of electricity supply industries. As is well known, electricity industries feature a number of unique characteristics, including non-storability of the product and randomness of both demand and capacity availability. Least-cost investment in such an industry requires that an appropriate mix of base-load, cycling and peaking capacity be installed to meet expected demand at minimum cost, taking into account the pattern of short-run demand fluctuations and supply outages, and the cost of not meeting demand in all periods, i.e. rationing costs. In addition, long lead-times and life-times of investments, when coupled with the associated risks - including regulatory uncertainty - make investments in generation capacity unusually risky. The problem is further complicated by the need to co-ordinate investments in generation and transmission and distribution capacity.

Most important for our purposes is the fact that economies of scale in generation, and the large sunk costs associated with investments in capacity, mean that markets for generation capacity - and the associated spot markets for energy - are unlikely to be perfectly competitive. One implication of this is that 'peak-load' pricing principles, developed for administered pricing in public enterprises, may not be appropriate

[1] For a description of the new industry structures in the UK and Norway see the articles by Green and Hope et. al. in this volume.

when applied to market-based systems. Indeed we shall suggest below that there will often be a trade-off between implementing optimal 'peak-load' pricing and achieving efficient capacity investments in imperfectly competitive electricity industries.

An important problem for further research is therefore to identify the conditions under which decentralised, market-based decisions in electricity supply industries will result in efficient capacity investments.[2] In this brief paper we attempt to illuminate some of the theoretical issues which arise in analysing this question in a simple peak-load pricing context. Questions concerning the co-ordination of generation and transmission capacity, and problems arising from the uncertainty of returns on investment will, for simplicity, not be considered.

The paper is in six further sections. Section 2 discusses optimal capacity investments in a simple peak-load pricing model in which issues of market power do not arise. Section 3 considers the implementation issue of eliciting willingness to pay for capacity. Section 4 expands the simple model of section 2 to take into account imperfect competition in the capacity and spot markets, and illustrates the fundamental trade-off noted above. Sections 5 and 6 discuss some of the issues which arise when electricity industries are modelled more realistically, to include multiple technology types and demand rationing. Section 7 concludes.

2. *Peak-Load Pricing and Optimal Capacity Investments*

To efficiently utilise existing capacity under random demand and capacity availability conditions, electricity prices need be adjusted over time. The theory of peak-load pricing was developed to analyse how optimal electricity prices depend upon underlying demand and supply conditions, and to determine optimal investment levels given efficient pricing[3]. For concreteness, and as a way of illustrating some of the major points, our discussion will be centred around a simple model of peak-load pricing. This model describes an industry in which demand fluctuates randomly between peak and off-peak periods, demand can be rationed by price in all states, i.e. all uncertainty is resolved before price is determined, there exists only one type of technology, and there is no uncertainty concerning capacity availability. Generalising

---

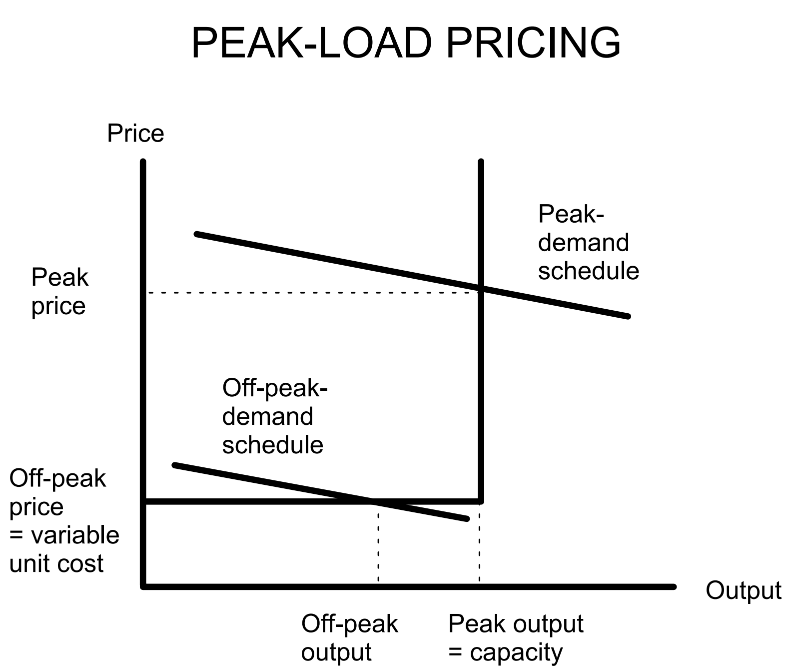
[2] von der Fehr and Harbord (1994) is one attempt to investigate this issue.
[3] See Crew and Kleindorfer (1986) for an overview of the literature.

to the case of inefficient rationing[4], multiple technologies and random capacity availability is cumbersome, but basically straightforward (see von der Fehr and Harbord (1994)).

2.1 *A simple peak-load pricing model*

Consider a single-technology electricity industry with constant variable costs of production v, and constant capacity costs c. Total industry generation capacity is equal to K - the capacity constraint. Demand in any time period may be expressed by an inverse demand function $w^t(q)$ which relates marginal willingness to pay w to the quantity consumed q in period t. For simplicity we assume only two types of periods, 'peak' and 'off-peak' respectively, with corresponding inverse demand functions $w^P(q)$ and $w^{OP}(q)$, where $w^P(q) > w^{OP}(q)$, for all q. The example is illustrated in figure 1.

Figure 1



[4] More precisely, to the case in which price cannot adjusted rapidly enough to ration demand. See the discussion below.

Efficient use of existing capacity requires that each unit of demand which is willing to pay at least the marginal cost of supply is satisfied when the capacity constraint is not binding. This implies that in periods in which demand at a price equal to marginal cost is less than total capacity, market price should equal marginal cost. That is, in off-peak periods $p^{OP} = v$ and supply, denoted q^{OP}, is determined by $w^{OP}(q^{OP}) = v$. If capacity is insufficient to cover demand at a price equal to marginal cost, demand must be 'rationed.' Efficient rationing requires that the market price is raised so as to reduce demand until it no longer exceeds available capacity; that is, in peak periods $q^P = K$ and the market price, p^P, is determined by $p^P = w^P(K)$. Optimal 'peak-load' prices and quantities are indicated in figure 1.

The premium of market price over marginal cost in peak periods, $p^P - v > 0$, reflects the short-run value of increasing capacity to satisfy additional units of demand. Note that in off-peak periods the corresponding premium equals zero, reflecting the fact that in such states additional capacity is of no value. In particular, in an industry with sufficient capacity to avoid 'shortages' in all periods, there is no economic benefit to increasing capacity, and consequently the market price should always be equal to marginal cost. Let π be the probability of a peak period occurring. Then the short-run welfare benefit, i.e. the increment in consumer plus producer surplus (gross of capacity costs), resulting from an increment in capacity is given by $V = \pi[w^P(K)-v]$. V is equal to the expected capacity premium, where the expectation is taken over all periods, or more familiarly, the product of the "value of lost load" and the "loss of load probability".[5]

Efficient capacity expansion requires that capacity be increased whenever the value of additional capacity exceeds capacity costs, i.e. $V > c$. At the optimum capacity level, market price in peak periods will just equal total unit costs appropriately measured, that is:

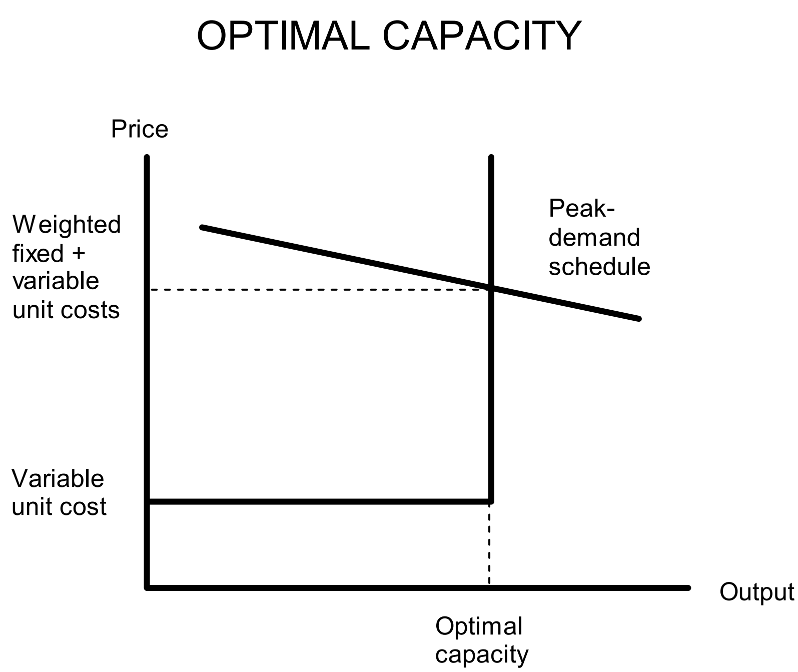
$$w^P(K^*) = v + c/\pi \tag{1}$$

[5] Strictly speaking, since demand is 'rationed' by price in our model, 'loss of load' never occurs. We are abusing the terminology here to relate our model to the familiar usage. The interpretation is that in peak periods some consumers willing to pay variable costs are priced off the market.

Or 'marginal willingness to pay' in peak periods equals variable costs plus fixed costs weighted by the 'load factor' of the 'marginal plant'. This is illustrated in figure 2.

In a market in which price is determined on the basis of competitive demand and supply bidding so as to clear the market in every period, price will correctly balance the underlying costs and benefits of increasing capacity. When perfectly competitive, i.e. price-taking, generators base their investment decisions on such prices, an efficient capacity level should result. To see this note that when (1) is not satisfied a price-taking (and risk neutral) generator can increase capacity by one unit and earn an expected profit of $\pi[w^P(K)-v]-c$. Such investments will be profitable until the 'capacity premium' is just equal to 'weighted' capacity costs.

Figure 2



3. *Eliciting Willingness to Pay for Capacity*

In peak demand periods price has two roles to play. On the one hand the market price serves as an equilibrating device that rations demand so as not to exceed available capacity. On the other hand, price signals the value of unsatisfied demand, i.e. the capacity premium, and thus the economic benefit of increasing capacity. In this section we briefly discuss the implementation issue of how to elicit consumers' willingness to pay for capacity.

There are at least three ways of implementing a pricing regime which will reveal willingness to pay for additional capacity (i.e. the 'value of lost load'): demand-side bidding in the spot market; a combination of marginal cost pricing and bidding for 'priority rights'; or marginal cost pricing with consumers bidding in prices at which they are willing to reduce their take (i.e., bids for 'load-shedding' of interruptible demand). We briefly consider each in turn.

3.1 Demand-side bidding in the spot market

The most straightforward solution is to allow consumers to 'bid in' their demand curves in the same way that generators 'bid in' supply curves, i.e. in a spot market or pool. Spot prices will then continuously balance demand and supply so that price is equal to marginal willingness to pay in all contingencies. In this case, spot prices always precisely reflect the value of unsatisfied demand, and the optimal capacity level is determined as described in the example in section 2 above.

Bidding in demand curves and continuously adjusting price to reflect varying demand and supply conditions may be impractical however, for various reasons. (See below and Chao and Wilson (1987)). More practical schemes, which have been suggested may therefore need to be considered.

3.2 Priority rights (Chao and Wilson (1987))

One alternative is to price electricity at marginal cost in all contingencies, i.e. for all realisations of demand, but allow consumers to purchase 'priority rights'. Whenever available capacity is insufficient to satisfy demand at a price equal to marginal cost, supply is then rationed by serving consumers in order of their 'priority', until available supply is exhausted. In the context of our simple model a priority rights scheme might work as follows. At a spot price of p, a buyer with a marginal willingness to pay of w for power will be willing to pay up to w-p for a 'priority right', i.e. to avoid being rationed, in peak demand periods. Since in off-peak periods priority rights are of no value, willingness to pay for priority rights is $\pi[w^p(q)-p]$. Assuming the spot price is equal to variable cost, i.e. p = v, and that the market for priority rights is competitive - which implies that priority rights will be sold up to the point where all capacity is covered and therefore only buyers with priority rights will be served in peak periods - the market price for priority rights, ρ^r, will be such that $\rho^r = \pi[w^p(K)-v]$. A generator can increase its sales of priority rights by investing in additional units of capacity, and will wish to do so until $\rho^r = \pi[w^p(K)-v] = c$. Hence the first-best capacity level can be elicited from competitive generators using this scheme.

3.3 Bids for load- shedding

A second alternative is a scheme whereby consumers purchase power at a price reflecting marginal costs, but are compensated for the financial consequences of interruption when capacity is insufficient to meet demand at that price. Compensation levels may be determined by competitive bidding, or by the sale of insurance contracts. In our example, a 'load-shedding' scheme may work as follows. Again, a buyer with willingness to pay of w is earning a surplus of w-p when the spot price is p. For any payment exceeding w-p therefore, the buyer will be willing to reduce his consumption by one unit. If the spot price is equal to marginal operating cost, i.e. p = v, and bidding for load-shedding is competitive, the load-shedding price, ρ^S, will be determined such that in peak periods total consumption equals output capacity, i.e. q = K, and consequently $\rho^S = w^p(K) - v$. Thus the value of lost load, as expressed by the market, equals $w^p(K)-v$, and the expected benefit of marginally increasing capacity is $V = \pi[w^p(K)-v]$, or expected avoided load-shedding payments. Once again competitive generators can be induced to invest up to the optimal capacity level using such a scheme.

In the absence of transactions costs and consumer risk-aversion, these three forms of determining consumer willingness to pay for capacity are evidently equivalent in the sense that each results in optimal capacity investments by price-taking generators. In particular, the price paid for priority rights, and the compensation for load shedding, are the expectation of the mark-up of spot prices over marginal cost if prices were always set so as to clear the market. Demand-side bidding in the spot market has the apparent advantage of allowing buyers to adjust their bids continuously (i.e., period-by-period) whereas both priority rights and load-shedding contracts are potentially less flexible instruments, since these will typically cover extended periods of time. However transactions costs and risk aversion may make some buyers prefer to pay a fixed price for the energy they consume, and to pay separately for supply-security rights. This factor could favour one of the two alternative schemes. Chao and Wilson (1987) and Wilson (1993) provide more detailed theoretical discussion of consumer rationing schemes and the 'near-equivalence' of priority rights and spot pricing with demand-side bidding.

Demand-side bidding is an integral part of the Norwegian electricity market, and in both the spot market and the contracts market, large buyers bid in prices at which they are willing to purchase electricity. However, due to transactions costs and the cost of metering equipment, smaller consumers do not bid in their demands, and hence a substantial proportion of total demand is completely price inelastic in the short run. It follows that spot prices do not accurately reflect marginal willingness to pay, and hence that rationing by price must necessarily be inefficient. Since there has been an abundance of available generation capacity in the Norwegian system however, the costs of insufficient demand flexibility has not yet materialised in supply shortages, or inefficient non-price rationing.

In contrast, within the new market structure in the England and Wales industry, there is no mechanism by which marginal willingness to pay for additional capacity is revealed. The 'value of lost load' (VLL) was set initially at £2 per kWh and has subsequently increased in line with the Consumer Price Index. A 'loss of load probability' (LOLP), i.e. the probability that demand will exceed available capacity, is estimated half-hourly on the basis declared capacity availability and expected demand. All declared capacity is paid a capacity payment equal to VLLxLOLP. If the value of lost load accurately reflects actual average willingness to pay, this capacity payment would in principle provide a 'correct' investment signal (see section 4 below). However the pricing mechanism in the England and Wales pool does not provide a basis on which to ration demand in periods of supply shortage.

Sections 2 and 3 have shown, albeit in a simple context, that traditional peak-load pricing will result in optimal capacity investments in perfectly competitive electricity markets, and that there are a variety of near-equivalent ways in which willingness to pay for capacity can be elicited from consumers. Section 4 will consider the implications of imperfect competition for this analysis.

4. *Market Power and Capacity Investments*

Market power may distort capacity choices. On the one hand, when prices accurately reflect underlying costs, a generator with market power will typically be able to increase its profits by not investing in capacity up to the socially optimal level, as this will increase the number of states in which price exceeds marginal cost, and the 'capacity premium' (i.e. p-v), when it does. Such strategies will only be successful however in the presence of barriers to entry, regulatory or otherwise, since in their absence new competitors will enter the market and invest up to the optimal capacity level. On the other hand, if prices are distorted upwards - for example, by collusion or non-competitive bidding - the resulting increase in returns to investment can lead to over-investment in capacity. We illustrate these possibilities by modifying the model of section 2 to allow for the effects of imperfect competition on investment incentives and capacity choices. For a more general analysis see von der Fehr and Harbord (1994).

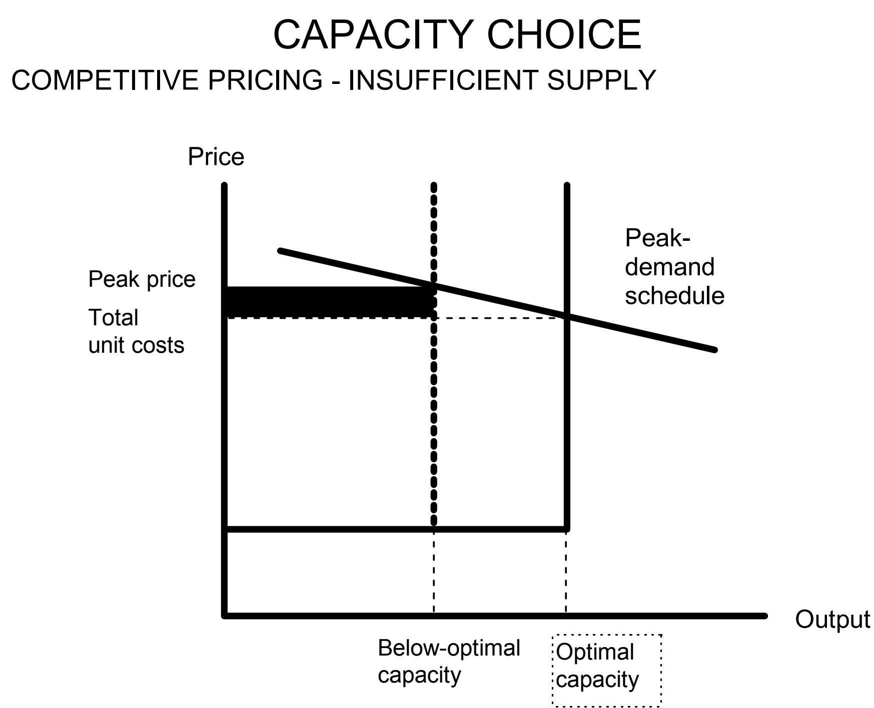
We consider now a two-stage model in which generators first make long-term capacity investment decisions and then compete in a spot market or electricity 'pool'. Assume first that pricing in the spot market is competitive, i.e., prices are equal to variable costs in off-peak periods and to marginal willingness to pay in peak periods. Such prices could result either from strong price competition in the pool or from a regulatory regime of audited bidding[6]. As already noted, at the optimum capacity level generator profits are zero. However, by reducing the level of capacity, the peak period price can be driven above total costs, increasing generator profits. This is illustrated in Figure 3.

Therefore, in circumstances in which generators' capacity choices have a non-negligible effect upon spot electricity prices, underinvestment in capacity results. Note that underinvestment occurs even though generators do not have market power in the spot market, which contradicts the frequently-made claim that 'optimal spot prices' provide incentives or 'signals' for efficient capacity investments.[7] Optimal spot prices only lead to efficient investment under the assumption that firms ignore the effects of their capacity decisions on spot prices. This is of course often unrealistic. Economies of scale in generation, and the associated sunk costs, mean that generators are unlikely to

[6] Such as has been implemented in Argentina for instance; see London Economics (1991).

become 'small' relative to the size of the market, and hence unlikely to behave as ‘perfect competitors.’

Figure 3



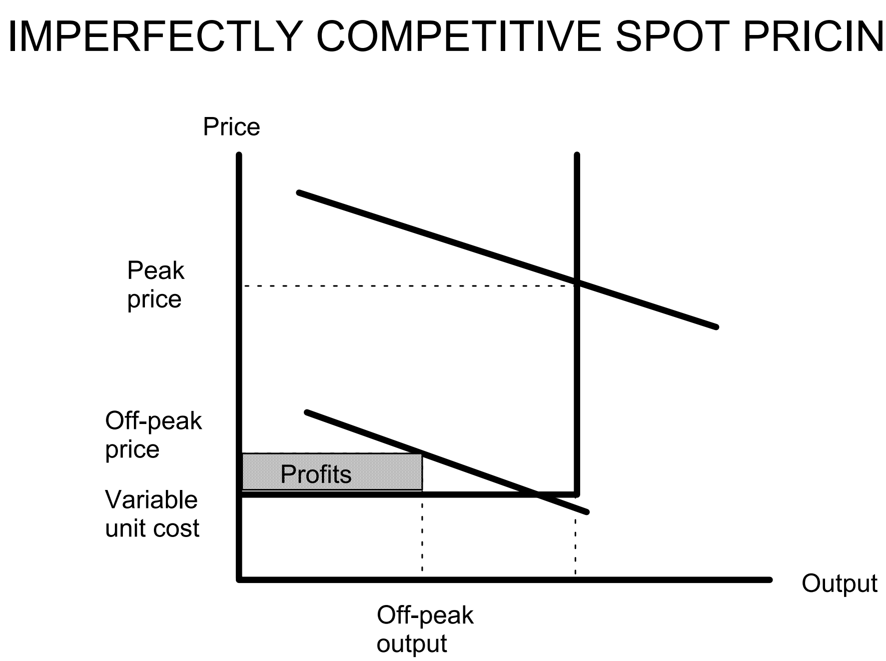
Consider next the case in which pricing in the spot market is non-competitive.[8] In particular, assume that the off-peak price exceeds variable unit, or marginal, cost while the peak price is set such as to clear the market. (See Figure 4 for an illustration).

Generators will now earn positive profits in off-peak periods. This introduces an additional incentive to invest which must be balanced against the negative effect of additional capacity on peak period prices. In certain circumstances, the above-

[7] See Schweppe et. al. (1988) for an exposition of the theory of optimal spot pricing.
[8] An analysis of unregulated bidding behavior in electricity pools is complex. Green and Newbery (1992) and von der Fehr and Harbord (1993) provide two alternative approaches to modelling bidding behaviour in the pool in England and Wales. A fairly robust conclusion,

marginal-cost-pricing effect may outweigh the effect of lowering peak period prices, and overinvestment in capacity may result. In particular, overinvestment is more likely the less price elastic is peak-demand and the more concentrated is the market structure.

Figure 4



To illustrate this, consider an example of a symmetric duopoly in which each generator holds ½K of total capacity and offers to supply at price $p^{OP} > v$ in off-peak periods. Assume that generators are ranked first with equal probability and that off-peak demand exceeds the capacity of one generator, i.e., $q^{OP} > ½K$, where q^{OP} solves $w^{OP}(q^{OP}) = p^{OP}$. Note that this implies that the marginal capacity unit of either generator will be called upon to produce with probability ½ in off-peak periods. Consequently, the expected gain to a generator from marginally increasing its capacity by dK is given by $½[1-\pi][p^{OP}-v]dK + \pi[w^P(K)+w^{P\prime}(K)-v]dK - cdK$ (the first element

however, is that there is little reason to expect competitive prices when the market structure is represent the off-peak period gain and the second element the peak period gain). This expected gain is positive at first-best industry capacity if and only if $-\partial w^P(K^*)/\partial q < ½[p^{OP}-v][1-\pi]/\pi$. In particular, if peak demand is infinitely price elastic, i.e., $\partial w^P(q)/\partial q = 0$, overinvestment results.[9]

We have thus demonstrated that imperfect competition in the capacity and spot markets may result in two opposing effects. Even when the spot market (or pool) is perfectly competitive, economies of scale in generation will mean that capacity investment decisions will have a non-negligible effect on spot market prices, resulting in an incentive to limit capacity, and hence output. On the other hand when the spot market is imperfectly competitive, generators may have an incentive to increase capacity in order to capture rents from above marginal cost pricing.

The fact that, *ceteris paribus*, non-competitive pricing increases incentives to invest in capacity introduces a regulatory trade-off between implementing optimal spot pricing and achieving efficient capacity investments. In the absence of a perfect planner who can implement the first best, it may be efficient to distort prices upwards from first-best levels to alleviate incentives for underinvestment in capacity.

The overinvestment result may have some relevance for the England and Wales electricity supply industry. As pointed out in the previous section, capacity payments in this industry are based on an estimated 'value of lost load', VLL. Since the VLL is determined exogenously, in the context of the present model this is as if peak demand were completely price elastic. Furthermore, there are good reasons to believe that pricing in the pool is non-competitive, and consequently we might expect overinvestment to result. Although this is consistent with the recent experience in the England and Wales industry, there may well be other more subtle, regulatory reasons for the observed 'dash for gas', or overinvestment in capacity, and hence the present analysis should be taken as suggestive, rather than as offering a complete explanation.

In this and the preceding sections our discussion has taken place in the context of a simple model which abstracts from many of the important features of electricity supply industries. In particular, we have assumed only a single technology type and that prices clear the market in all contingencies. However a fundamental feature of

---

concentrated, such as it is in the UK.

9 Note that generators will invest at most up to the point where $1/2K$ (i.e. the capacity level of each) equals q^{op}

electricity supply industries is the need to invest in multiple technology types in order to meet random demand at minimum cost. In addition prices cannot typically be adjusted rapidly enough to clear the market in response to supply and demand uncertainty. We briefly consider these issues in the following sections.

5. *Multiple Technologies*

Electricity industries are characterised by randomness of both demand and capacity availability. Since electricity cannot be economically stored, efficiency requires that an appropriate mix of technologies with different costs characteristics be installed to meet demand at minimum cost. Base-load plant typically has high capital costs and low running costs, whereas plant designed to meet peak demands will have lower capital but higher operating costs. The marginal cost of operation therefore varies as demand varies, and peak-load pricing schemes reflect these changes in costs. Optimal capacity choices for different technologies will thus depend upon the pattern of short-run demand fluctuations, and the probability of supply outages. Chao (1983) treats the problem of optimal technology mix and peak-load pricing in a general framework.

The issue of how market power affects investment incentives, discussed in the sections above, is further complicated when efficiency requires multiple technology types, so that achieving the optimal mix of technologies, as well as the optimal aggregate capacity level, is important. The existing peak-load pricing literature does not offer any insights on the way in which imperfect competition may influence the choice of technologies in electricity industries. von der Fehr and Harbord (1994) however address this issue.

6. *Demand Rationing and the Design of Competitive Electricity Markets*

In the model discussed in this paper we have assumed that all demand (and supply) uncertainty is resolved before price is set in each period, and hence that (non-price) rationing never occurs. From this it follows that the optimum capacity level does not depend on the rationing scheme, and that revenues exactly cover the costs (i.e. profits are zero) at the optimum capacity level. This assumption is unrealistic however. In practice, short-run demand and supply fluctuations occur so rapidly in electricity supply industries, that prices cannot be adjusted quickly enough to maintain continual demand and supply balance (i.e. to clear the market in every contingency). Therefore consumption decisions must typically be based upon expected, rather than on market-clearing, prices. In the UK for instance, estimated market (half-hourly) prices, based on demand forecasts and generator price bids, are published a day in advance, and some large buyers have an opportunity to adjust their demands relative to these (estimated) prices. Payments to and from the pool are then based on 'market clearing' prices calculated ex post, once demand is realised.

Since ex ante, price will not clear the market in most states of the world (i.e. contingencies), in states in which declared capacity is insufficient to meet demand, rationing will occur. Expected social welfare will then depend upon the rationing scheme employed. Two types of rationing scheme are often considered: *random rationing*, under which each unit of demand has an equal chance of being served, and *efficient rationing* which allocates supply to those consumers with the highest willingness to pay first. Rationing, or 'outage', costs may influence not only the choice of rationing scheme, but also 'optimal' (i.e. second-best) capacity levels. When rationing is costly, it may be optimal to increase aggregate capacity to reduce the incidence of rationing - see for instance, Crew and Kleindorfer (1986), Chapter 4.

In addition, with consumer rationing optimal peak-load prices will only in special cases result in (expected) revenues sufficient to cover (expected) generation operating and capital costs, even when capacities are at their first best levels. Chao (1983) summarises a number of results in this area. In particular the surplus or deficit of revenues over production costs depends upon (i) the nature of the demand uncertainty and (ii) the rationing scheme. When demand uncertainty is additive, then expected profits are always negative. For multiplicative uncertainty expected profits may be negative, positive or zero depending upon the rationing scheme. Thus implementation of the first-best price and capacities will therefore in general require that the planner or regulator be able to make lump-sum transfers to or from generators in order to impose a zero profit condition.

All of this poses a difficult problem for the design of a competitive electricity market, where lump-sum transfers to or from generators will not usually be possible. Optimal pricing may not result in sufficient revenues to cover generation costs, and hence prices may need to be distorted in order to overcome this problem. One approach would be to introduce a form of Ramsey pricing to ensure that (expected) consumer payments always equalled (expected) generation costs (Sherman and Visscher (1978);

Crew and Kleindorfer (1986)). However in electricity markets in practice, payments to generators and revenues from consumers are simply required to balance on average. The implications of adopting either of these approaches for capacity investments in imperfectly competitive electricity supply industries have not yet been researched.

7. Conclusions

The likely performance of market-based electricity supply industries with respect to capacity investments is a complex issue which has yet to receive much serious analysis. Given the importance of this question for the processes of reform which are taking place world-wide, this may be unfortunate. In this brief paper we have described a number of important issues which merit further study:

- the trade-off between optimal short-run pricing and providing incentives for efficient investment when capacity and/or electricity spot markets are imperfectly competitive;
- the importance of providing incentives for investing in the right technology mix, and not just the aggregate capacity level;
- the design of electricity markets in environments in which revenues generated from first-best pricing schemes may not recover total generation costs;
- mechanisms for eliciting willingness to pay for capacity.

Electricity industries feature a number of characteristics which make their analysis particularly complex. But a better understanding of these issues is crucial for the appropriate design and regulation of the newly liberalised industries such as those in Norway and England and Wales.

References

Chao, Hung-po (1983) "Peak load pricing and capacity planning with demand and supply uncertainty", ***Bell Journal of Economics***, 14: 179-90.

Chao, Hung-po and Robert Wilson (1987) "Priority service: pricing, investment, and market organization", ***American Economic Review***, 77: 899-916.

Crew, Michael A. and Paul R. Kleindorfer (1986) ***The Economics of Public Utility Regulation***, London: Macmillan Press.

von der Fehr, Nils-Henrik M. and David Harbord (1993) "Spot market competition in the UK electricity industry", ***The Economic Journal***, 103: 531-546.

von der Fehr, Nils-Henrik M. and David Harbord (1994) "Oligopoly, capacity competition and uncertainty under different regulatory regimes", (mimeo) Department of Economics, University of Oslo, Norway.

Green, Richard and Newbery, David M. (1992) "Competition in the British electricity spot market," ***Journal of Political Economy***, 100: 929-953.

London Economics (1991) ***An International Review of Reforms in Electricity Supply Industries***, (mimeo) London.

Schweppe, F.C., M. Caramanis, R. Tabors, and R. Bohn (1988) ***Spot Pricing of Electricity***, Boston: Kluwer Academic Publishers.

Sherman, R. and M.L.Visscher (1978) "Second-best pricing with stochastic demand," ***American Economic Review***, 68: 41-53.

Wilson, Robert (1989) "Efficient and competitive rationing", ***Econometrica***, 57: 1-40.

Wilson, Robert (1993) ***Nonlinear Pricing***, Oxford: Oxford University Press.