Regulating electricity to ensure efficient competition

David M Newbery*
Department of Applied Economics
Cambridge, UK
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Abstract

The European Commission's attempt to update the Electricity and Gas Directives to underwrite unbundling and full liberalisation coincides with the California electricity crisis. The paper argues that compared to the US, much of the EU lacks the necessary legislative and regulatory power to mitigate generator market power. Unless markets are made more contestable, transmission capacity expanded and adequate generation capacity ensured, liberalisation may lead to higher prices. Ending the domestic franchise could remove the counterparty for the required contracts to sustain competitive pricing.

JEL classification: K23, L51, L94

Keywords: Competition, regulation, electricity, contracts, market power

1. Introduction

The new conventional wisdom is that the electricity supply industry (ESI) should be unbundled, with the potentially competitive segments under separate ownership from the natural monopoly network. Regulation should provide the same incentives as the competitive market, differing sharply from the traditional rate-of-return form evolved in the United States. But the new model has problems. Unbundling creates new price risks that require a variety of hedging contracts. The consequences of the risks and resulting contracts are often not well understood by regulators. The conditions for effective competition are considerably more demanding than in normal product markets, so that competition law must be adapted if it is to be effective.

If we look back two decades, we would see two apparently very different ways of managing the network utilities of gas, telecoms and electricity. The United States was unusual in that these were mainly in private or investor ownership, operating as vertically integrated franchise monopolies. They were regulated both by state public utility

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commissions and federal agencies under cost-of-service or rate-of-return regulation. This system of regulation had evolved over the previous century to protect both consumer and investor interests by setting prices or rates that were "just and reasonable". The potentially exploitative power of these private monopolies to set high prices was restrained by price regulation, while the political power of mass voting consumers to expropriate sunk assets was restrained by constitutional protection of private property. The franchise monopoly is the *quid pro quo* for the obligation to meet demand, and provides the means to finance the necessary investment.

The UK, along with much of the rest of the world, also operated these utilities as vertically integrated franchise monopolies. Prices were also held at reasonable levels in response to consumer political pressure, but for various reasons public ownership substituted for constitutional protection of private investment as the means to guarantee the required levels of investment in very durable sunk capital (Newbery, 2000).

The two different forms of ownership and regulation on opposite sides of the Atlantic shared many similarities, particularly the stability and durability of the industrial form. Public ownership had much in common with cost-of-service regulation, as the public paymasters attempted to restrict the budgetary costs of public utilities, paying as little attention to incentives as their US counterparts, the utility commissioners. Economists criticised rate-of-return regulation for its poor incentives, cost padding and gold plating. Economists in Britain criticised the nationalised industries for their low productivity growth, inefficient and expensive investment, and lack of response to consumer demand, notably the long waiting lists for telephone connection.

Perhaps by coincidence, 1984 marked the beginning of the end of this stable configuration on both sides of the Atlantic. The break-up of the telephone giant AT&T in the United States and the privatisation of British Telecom (BT) in Britain, marked the start of utility liberalisation. The seeds of the break-up of AT&T were planted when new entrants attempted to compete on the over-priced long distance routes that state regulators conspired to use as a means of cross-subsidising local rates. In 1974 the Department of Justice filed suit against AT&T for monopolising interstate communications. It gradually became clear that regulating an industry with competitive and natural monopoly elements in a federal system with divided regulatory responsibilities was unsustainable. By 1982, AT&T concluded that the only solution was to divest the local Bell Operating Companies. They owned the natural monopoly local loops, leaving AT&T to concentrate on the competitive long distance lines. The resulting Modification of Final Judgement came into effect in 1984 and vertically unbundled the US telecoms industry.

The motives for privatising BT in the same year were rather different and evolved from the Conservative Party's belief that "the business of Government is not the government of business". A variety of mutually reinforcing political reasons, such as reducing the power of the public sector trade unions, creating wider share ownership to support the defence of private property and hence of the Conservative Party, the recognition that state assets were valuable and could be sold profitably, ending the obligation to finance expensive public sector investment through the budget, all suggested that privatisation was desirable. Early successes in selling obviously commercial companies encouraged an increasingly ambitious programme that extended to the network utilities with the successful floatation of BT in 1984.

Once it had been decided to privatise BT it was recognised that it would be necessary to regulate such a powerful private monopoly. Stephen Littlechild was asked to advise on the best form of regulation, and took to heart the criticisms of the US form of rate-of-return regulation. He proposed a price-cap indexed to the retail price index, and also to the predicted rate of productivity increase, as real telecoms prices had been falling steadily for several decades. Littlechild (1983) saw price-caps as a transitional form of regulation until competition developed and took over the task of holding down retail prices. The merchant banks appreciated the predictability that RPI-X gave to future revenue streams, on the basis of which the privatisation prospectus could be written.

Across the Atlantic, the FCC gradually learned that rate-of-return regulation was inflexible and cumbersome in dealing with a still dominant incumbent firm facing competitive threats from new entrants. They too gradually adopted price-cap regulation or, more generally, incentive regulation.

If forms of regulation started to converge, the motives for reform on each side of the Atlantic were initially quite different. The emphasis in Britain was on ending state ownership, not on liberalising the network utilities, and BT was privatised as a *de facto* monopoly. In short order, British Gas was privatised as a vertically integrated monopoly in 1986, and the ten water and sewerage companies were privatised also as vertically integrated regional monopolies in 1989.

2. Restructuring Electricity

Economists, particularly Vickers and Yarrow (1988), were quick to point out that privatisation was not the same as liberalisation, and that the main benefits from restructuring network utilities would flow from increased competition, not the change of ownership. That was increasingly the political mood of the country, and when electricity was proposed for privatisation, it was decided that it should be unbundled to allow competition in generation.

UK electricity reform provides an excellent example of the benefits of restructuring and the importance of structural decisions. The UK tried all three possible models: in England and Wales the Central Electricity Generating Board (CEGB) was unbundled into three generating companies and the grid, the 12 distribution companies were privatised, and a wholesale market - the Electricity Pool - created. After the three years of transitional contracts, consumer prices were to be set by free generation and supply markets, combined with the regulated costs of transmission and distribution. Scotland retained the two incumbent vertically integrated companies with minimal restructuring and constrained export links to England. Northern Ireland adopted the Single Buyer model with the combined transmission/distribution company NIE holding long-term power purchase agreements (PPAs) with the three independent generating companies.

Newbery and Pollitt (1997) and Pollitt (1997, 1998) have completed social cost-benefit analyses of the three different models, with striking and intuitively plausible results. The restructuring of the CEGB immediately introduced daily competitive price bidding for each power station. All generating companies dramatically increased productivity and drove down costs, including the state-owned Nuclear Electric. The audit of the first five years was that the social benefits amounted to a reduction of costs of six per cent for ever compared to the counterfactual, equivalent to a 100% return on the sales price. These benefits were almost entirely captured by companies, for profits rose as costs fell and prices remained stubbornly high until continued and aggressive regulatory intervention forced extensive divestment of capacity.

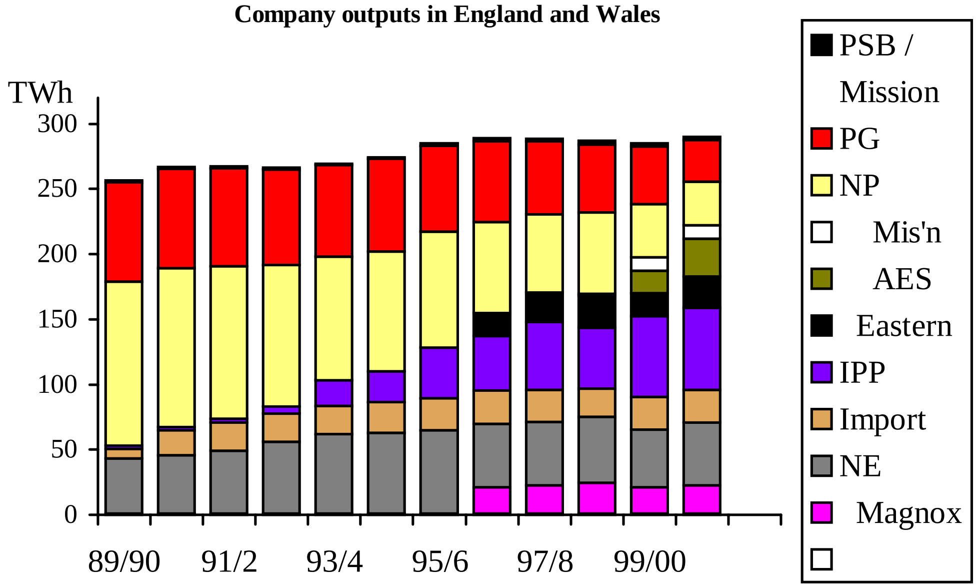

Fig. 1 Deconcentrating Generation

By the end of the decade the dominant duopoly had evolved into a relatively unconcentrated industry, as Fig. 1 documents. Entrants and incumbents operated efficient CCGT stations, a range of international generating companies bought divested plant, and the modern nuclear stations had been privatised.

Scotland was a different story. In 1990 electricity prices were 10% lower than in England, but the lack of competitive pressure meant that by the end of the decade prices were some 5% higher as shown in Fig 2. The very modest benefits of privatisation were entirely absorbed by the costs of restructuring, delivering no net benefit. Northern Ireland gives a mixed picture. The long-term PPAs provided powerful incentives for increased plant availability and cost reductions, so that the improved generator performance outstripped that of the CEGB by three times. However, these PPAs retained the benefits with the generating companies and consumers were only able to benefit by aggressive price reductions on the non-generating elements of cost, combined with Government subsidies to reduce the embarrassing price gap between Northern Ireland and Britain.

The lessons from UK electricity restructuring are clear. Increased competitive pressure on generation is needed to reduce costs and that requires separating generation from transmission and distribution. Whether these benefits will be passed on to consumers depends upon the intensity of competition - particularly the number of competitors and the existence of an open access wholesale market. Unrestructured industries, even if privatised, appear to deliver few benefits. Efficiency improvements in transmission and distribution require tough regulatory price controls. Improvements in the first five years under the initial price controls were modest, with most of the price cuts, efficiency gains, and transfers to consumers confined to the second and subsequent regulatory reviews (Domah and Pollitt, 2000). The evidence suggests that regulators have to work hard to transfer efficiency gains into lower consumer prices. They also need to take positive steps to counteract market power in the potentially competitive sectors, possibly including further divestment of capacity, if consumers are to gain from restructuring.

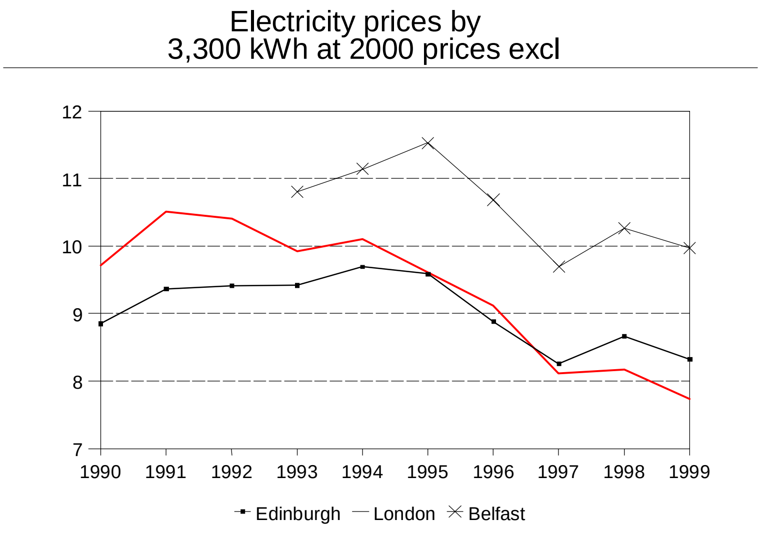

Fig 2 Poor Performance of Scotland

3. Reforms in the EU

The lesson that unbundling is necessary has been taken to heart in restructuring choices around the world, and particularly in the European Union. There, as elsewhere, public utilities such as gas, electricity, telecoms and rail) were vertically integrated, typically state-owned, franchise monopolies. The Treaty of Rome protected them against the scrutiny of normal competition policy because they provided essential services of national interest to member states. The evidence from Britain and Norway of the beneficial effects of liberalisation suggested to the Commission that "market forces produce a better allocation of resources and greater effectiveness in the supply of services",[1] and that therefore the principles of the single market - "the free movement of goods, persons, services and capital"[2] - should be extended to these public utilities. As a result, the Electricity Directive 96/92/EC was adopted in 1996, and had to be implemented by February 1999.

In late 1998, a group of us undertook a study of the rationale, progress and possible problems with implementing the Electricity Directive. The resulting book, *A European Market for Electricity?*, (Bergman et. al., 1999) drew attention to a number of unsatisfactory aspects of the reforms. Very similar conclusions were subsequently drawn by the European Council, which called on the Commission to accelerate the work to complete the internal market in electricity and gas at Lisbon in March 2000. Gas liberalisation had been considerably more contentious because of perceived issues of security of supply, and had taken eight years to introduce a relatively less demanding directive compared to electricity, but the European Parliament was anxious to completely liberalise both energy markets.[3]

In response the Commission proposed amending the Gas and Electricity Directives at the European Council in Stockholm in March 2001.[4] The main changes proposed were to require *regulated* Third Party Access (TPA) for both gas and electricity (denying the former option of negotiated TPA), to strengthen the requirements for unbundling to legal (but not necessarily ownership) separation of generation and transmission, to remove the option of the Single Buyer Model, and to allow all gas and electricity customers freedom to choose their supplier by 1.1.05, thus ending the domestic customer franchise monopoly. In addition the Directive would require all countries to establish independent regulators to approve transport tariffs *ex ante*, and to monitor and report to the Commission on the state of electricity and gas markets, particularly the supply/demand balance.

France, who missed the deadline for enacting the earlier Directives, and has done the minimal restructuring and market opening, opposed the proposals, arguing that it was too soon to deem energy liberalisation a success. Germany, with its preference for negotiated TPA and vertical integration, also opposed the proposals, particularly the requirement for an independent regulator. Pressure for reform from consumers and those countries that have liberalised continues, but for the present the Commission is reliant on competition law to bargain for further improvements in exchange for approval for further EU electricity mergers.

All the Commission documents on the web site go to some lengths to argue that the

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[1] EC communication *Services of general interest in Europe*, OJ C 281, 26 September 1996, p.3

[2] Article 7A of the EC Treaty

[3] resolution "Liberalisation of Energy Markets" A5-0180/2000, 6th July 2000.

[4] COM(2001) 125 final, 13 March 2001; available together with the Press Release and Working Paper at http://europa.eu.int/comm/energy/en/internal-market/int-market.html

proposed measures for the European energy market "will avoid the type of problems currently faced by California, which have resulted from an inadequate legal framework and inadequate production capacity" (EC Press Release). Clearly, the Californian electricity crisis has awakened fears that liberalised electricity markets may be politically unsustainable, at least, without careful design and regulation. The very high prices observed in California (and in the North- and Mid-West of the United States) have demonstrated very clearly that the scarcity price of electricity can reach extremely high levels when supply is tight. Defenders of the former electricity industry structure have argued that vertically integrated franchise monopolies with regulated final prices are the only politically sustainable structure, that is necessary to secure adequate capacity to avoid shortages and/or high prices (see, e.g. the pseudonymous Price C Watts, 2001). The cost of flawed liberalisation has now been demonstrated (by the high prices and the impact of economic activity in the event of power outages) to be unacceptably high, and calls into question the whole electricity liberalisation agenda.

The evidence from Europe and the United States suggest that there are a number of conditions for successfully liberalising gas and electricity markets. The first is that for the wholesale market to be competitive, potential suppliers must have access to the transmission system in order to reach customers. This is best achieved by ownership separation of transmission from generation, as the comparison between England and Scotland demonstrates (Bergman, et. al, 1999). In a federal (or multi-country) market such as the EU, this requires that suppliers, traders and consumers they also can gain access to trading partners in and through other countries. The Commission has endorsed this lesson.

The second condition is that there is adequate and secure supply. For electricity, there are three conditions that need to be satisfied for supply security: the network infrastructure must be adequate and reliable;[5] there is adequate generation capacity;[6] and there is security of supply of the primary fuels (gas, oil, coal etc.). Again, this is recognised by the Commission.

The final condition is that there is appropriate regulation of the markets of these liberalised utilities. This condition is less obvious, and has been largely ignored by the Commission and many EU countries, but without it, there are serious risks that the benefits of liberalisation may be lost, and the political costs of flawed outcomes may undermine support for reform.

[5]In practice, this means that the grid is built to an n-1 standard, allowing any circuit to fail without causing system breakdown.

[6] The reserve margin required will depend upon the reliability of the generation units, the variability of demand, and the response speed of the generation units, and should be available for at least the specified (and very high) fraction of the time so that the risk of capacity shortfall is less than a specified level.

4. Regulating wholesale markets

The mantra "competition where feasible, regulation where not" suggests that regulation should be confined to the natural monopoly elements, typically the networks. That would be mistaken, for the potentially competitive elements still need regulatory oversight to ensure that markets are not manipulated nor market power abused. The default assumption is that wholesale electricity markets are no different from other markets, and should therefore be subject to the same competition law as other markets, notably Articles 81 and 82 of the Treaty, which have been transcribed into national legislation (e.g. as the Competition Act 1998 in the UK). There are a number of obvious problems with this approach. First, because it is *ex post* and penalty-based, it is necessarily legalistic and inevitably slow compared to *ex ante* regulation. Second, the test of abuse of dominant position normally requires the dominant firm to have 40 per cent or more of the relevant market. Third, the presumption is that normally markets will be effectively competitive, so that the information needed to establish market abuse is not collected routinely, but only when an alleged abuse is investigated.

The British energy regulator, Ofgem, with over a decade of experience of dealing with the initially concentrated wholesale gas and electricity markets, is acutely aware of the limitations of normal competition legislation. In 2000, Ofgem persuaded the majority of large electricity generating companies to accept the Market Abuse Licence Condition (MALC), which specified certain forms of behaviour as *prima facie* abusive, meriting investigation and possible penalty. Two generators, AES (with 7% of total capacity, mostly under long-term sales contracts) and British Energy (with overwhelmingly base-load inflexible nuclear power) did not consider the change in licence conditions necessary and appealed to the Competition Commission. The condition related to behaviour in the Electricity Pool, due to be replaced by the New Electricity Trading Arrangements (NETA) in early 2001. Partly as a result of the limited remaining life of the Pool, the Commission were not persuaded that it would be against the public interest for AES and British Energy to continue without the licence modification (Competition Commission, 2000). Ofgem decided to withdraw the condition, and, with DTI, was by mid-2001 consulting on a possible replacement that would apply to NETA for up to two years while it bedded down.

Several important points emerge from this episode. First, generators in Britain require a licence to operate, and that licence contains conditions governing acceptable market behaviour. Grid codes contain additional, often technical, conditions to ensure that the System Operator has the requisite powers to balance electricity supply and demand and maintain system integrity and quality, but these are not sufficient to address many forms of market manipulation. Licence conditions can only be modified by agreement. If this is not possible, they are referred to the Competition Commission, who are required to determine whether the modification is required to prevent outcomes that are against the public interest.[7]

[7] The public interest test is normally interpreted as a social cost benefit test with a larger weight on consumer welfare than profits. There are proposals to replace it with a competition test, which could be

Second, the case for the MALC rested on distinctive features that favour the exercise of market power in apparently unconcentrated market structures (with Herfindahl-Hirshman indices below 1800). Specifically, electricity cannot be stored,[8] supply must be instantaneously matched to demand, transmission constraints require active systems balancing, and demand is highly inelastic in the short run over which daily price variations occur. The most obvious evidence of these distinctive characteristics is the considerable volatility over short time periods. The English pool price has moved from £11/MWh to £1,100/MWh over a single 24-hour period, and even more extreme price spikes have been seen in the US. If even modest-sized generators can profitably raise prices by only offering marginal capacity at very high prices for short periods, or in particular places, then such transient behaviour by non-dominant producers is unlikely to fall foul of normal competition law.[9]

Finally, licence conditions are important as they specify the information that must be made available to the regulator to monitor conduct. This includes details of all generating set behaviour (availability, output, bids, contract cover, for each discrete time period, typically an hour or less), as well as powers to investigate plant outages and retirement, both of which may be strategically manipulated to increase scarcity and prices. Without such information and the authority to act quickly and effectively on their evidence, price manipulation is to be expected in tight markets. Electricity prices in the California wholesale market during the off-peak winter season January-April 2001 were 10 times that in the same period in 1999, and the estimates of the additional profits that generators earned above the competitive level for the year 2000 amounted to over $8 billion (Wolak and Nordhaus, 2001). If there are no penalties or costs for this kind of behaviour, and such large rewards, private quoted generators would be in breach of their duty to shareholders if they did not exercise their periodically considerable market power whenever possible.

At least some EU countries have liberalised their electricity industries under the requirements of the Electricity Directive but failed to write the required information-gathering and enforcement powers into their electricity legislation. It is most unlikely that such information will be voluntarily provided. A full-scale competition inquiry with the necessary powers to request information may take months, and fail to find evidence that

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interpreted as placing sole weight on long-run average consumer welfare (which may well require adequate profit incentives and rewards to ensure investment).

[8] Except as water in dams in hydro systems (including pumped storage, of which there is 2000MW in Britain), but the ability to withhold water in low demand periods for release at high demand periods is very limited except in a small number of countries. Even when a significant fraction of capacity is hydro (as in California) it is typically capacity-constrained at the peak.

[9] Arguably, the markets can be narrowly defined (even down to a 15 minute period is a constrained transmission zone) to rule out some abuses, but even this will not deal with the case of general market tightness, where a change in supply relative to total demand of 5% can dramatically alter the market power of an individual generator and hence the equilibrium price.

would stand up to in court. If in addition generators are not required to hold a licence, regulators cannot follow the route open in Britain and modify the licence to prevent future abuse and to require provide necessary information to be routinely supplied.

The United States, with its more legalistic approach, is much clearer about the duties of regulators when liberalising. Under the Federal Power Act 1935, The Federal Energy Regulatory Commission, FERC, has a statutory obligation to ensure that wholesale prices are "just and reasonable". If an electric utility wishes to sell at market-determined wholesale prices, this will be only allowed providing "the seller (and each of its affiliates) does not have, or has adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry."[10] Even then, the authority to sell at market-determined prices can be withdrawn and replaced by regulated prices if there is "any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing."[11]

FERC therefore assumes that market pricing is "just and reasonable" so long as it is competitive. The reason for its concern to ensure that prices remain competitive is that any FERC-approved form of pricing greatly restricts the competition authorities from intervening. At the same time, existing antitrust laws are relatively powerless to enforce competitive outcomes in the energy industry as "the antitrust laws do not outlaw the mere possession of monopoly power that is the result of skill, accident, or a previous regulatory regime. ... Antitrust remedies are thus not well-suited to address problems of market power in the electric power industry that result from existing high levels of concentration in generation." (DOE, 2000).

This suggests a further contrast on the two sides of the Atlantic, reflecting the prior histories of the electricity industry on the two continents. Deregulation in the United States was in principle a cautious relaxation of regulatory control over prices, with considerable awareness of the potential problems of market power. Electricity restructuring in Europe has tended to overlook issues of market power, and instead has concentrated on introducing wholesale and often retail markets in the expectation that they will be naturally competitive. Many EU countries appear to lack the necessary powers and institutions to ensure that generation becomes an adequately competitive industry.

The European Commission's confidence that Europe's reforms will be sufficient to avoid the Californian problem may be justified in the short run, as capacity is adequate, though there are threats of market power emerging in some countries. However, it is less clear that the present regulatory system will continue to ensure that there is adequate capacity, and for that reason the Californian example is instructive.

[10] *Heartland Energy Services, Inc*, 68 FERC • 61,223, at 62,060 (1994), cited by Bogorad and Penn (2001).

[11] *Heartland* 68 FERC at 62,066, cited as above.

5. The Californian example

California originally reformed and liberalised its electricity market because of dissatisfaction over high consumer prices. However, average wholesale prices in 2000 were more than three times those of 1999, and 2001 started with rolling blackouts, stage 3 alerts,[12] and the major public utility, PG&E, filing for Chapter 11 bankruptcy protection (see fig. 3)[13]. California shows that poor market design coupled with inappropriate regulatory and political intervention, can rapidly produce extremely unsatisfactory outcomes when capacity is tight, particularly if the shortages are unexpected. The Californian experience has certainly alarmed European politicians and caused several academic energy specialists to reconsider the merits of deregulation. In the words of the pseudonymous Price C Watts (2001) "It is clear that deregulation is a high-risk choice. Those jurisdictions that have not yet deregulated electricity generation need to think long and hard before they go ahead. Those that have done so need to figure out how to minimise the downside potential of the journey on which they have embarked."

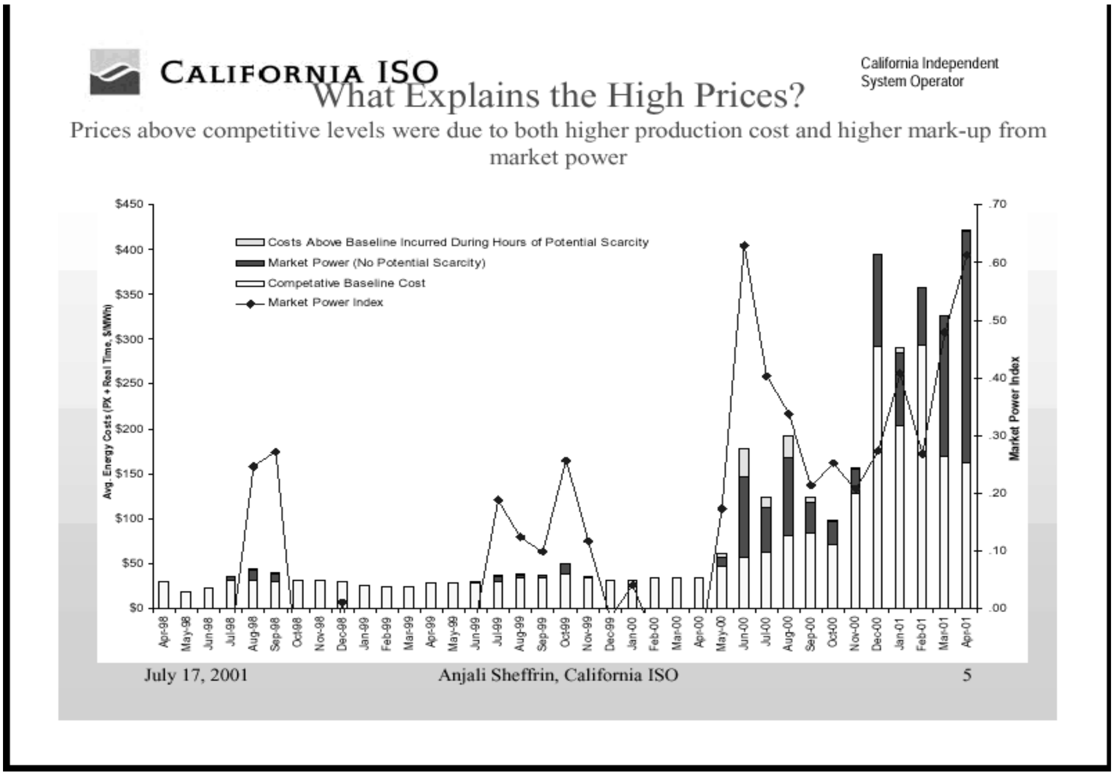

Fig 3 California prices and costs

What were the various contributory factors to this unhappy outcome? First,

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[12] when reserve margins fall below 1.5% so that disconnection is essential to protect system integrity

[13] Fig. 4 has been downloaded from www.caiso.com. The index of market power is the Lerner index, $(p-c)/c$, where p is price and c is the estimated competitive price, allowing for changes in gas prices.

California (and the neighbouring states) had for a long history of under-investment in generation, partly because of disputes over nuclear power plant costs and safety, environmental objections, and misconceived long-term Power Purchase Agreements (PPAs) with Qualifying Facilities, QFs, typically owned by "non-utility generators". This was sustainable because California imported extensively from the Pacific Northwest, making use of the apparently abundant and cheap surplus hydroelectric power from the Columbia River. Second, after generation was unbundled from transmission and distribution, distribution companies were strongly dissuaded from signing long-term contracts for electricity or hedging. This regulatory restraint was caused by the California Public Utilities Commission's poor experiences with earlier excessively-priced PPAs from the QFs. The Commission recognised the spot market price as the principal measure of wholesale electricity costs, and utilities were required to trade all their power through the Power Exchange (PX).[14]

Finally, NO_x emissions were capped by region (and in some cases by plant) on an annual basis. In the (not particularly) hot summer of 2000, gas demand for generation greatly increased, and pipeline capacity and storage were frequently inadequate to meet the demand. Californian gas spot prices more than doubled (coming on top of high prices caused by the doubling of crude oil prices), as did the contract prices from many QFs, which were indexed to gas prices.[15] The price of tradable NO_x permits also rose to unprecedented levels as the annual quota became inadequate, with permits trading at $80,000/ton at their peak, compared with $400/ton on the East Coast (Laurie, 2001). Electricity prices rose, not just in California, but in the whole western interconnection in that wholesale power is traded. Thus the average price for the *whole year* at the Mid-Columbia hub in the Northwest (i.e. not in California) was $137/MWh compared with $27/MWh in 1999, higher than in California (where it averaged $91/MWh on the PX). California's largest distribution companies were unable to pass on the high wholesale prices, precipitating a financial shortfall as revenue fell far short of cost.

High plant utilisation in the summer and autumn induced by high spot prices necessitated greater scheduled maintenance downtime in the normally quieter winter period. Unfortunately, the combination of a dry winter in the Columbia River Basin lowering hydro output potential, with higher demand due to the colder weather, and plant outages in California, caused a severe shortage of capacity and energy, leading to higher prices, defaults, and bankruptcy. Inept price caps caused generators to export to neighbouring states, rather than sell in California, while the non-utility generators refused

[14] In addition, the utilities considered that the contract prices offered were unacceptably expensive, compared to past experience, and were thus unenthusiastic about hedging. In the event the contract prices would have been extremely cheap compared to the subsequent spot prices.

[15] By the end of 2000 gas prices had risen to $15/MMBtu compared to a historic average of $2/MMBTu, and December electricity prices were estimated to be three times higher as a result. On one occasion after an accident disrupting deliveries on one of the major pipelines, spot gas reached $61/MMBTU, equivalent to an fuel cost in a reasonably efficient generator of $610/MWh (Bogorad and Penn, 2001).

to supply for fear of not being paid. The repeated interventions of the State Governor arguably made a bad situation far worse, as threatened seizures, price caps, and regulatory hurdles prejudiced investment in generation. Poorly designed trading arrangements, with caps on some markets that encouraged participants to under-contract in the day-ahead market and diverted power to the real-time market at very high prices amplified market power (Wolak and Nordhaus, 2000).

What lessons can be drawn from the Californian experience for electricity reform? First, tight electricity markets, where the reserve margin falls below 10%, are likely to lead to volatile markets and high prices even if they are fairly competitive (meaning that there are four or more generating companies competing with each other at the margin of supply).[16] As demand tightens relative to supply, inelastic and unresponsive demand[17] means that large price rises have little effect on demand, but each supplier has increasing and eventually very considerable market power. The large increase in price caused by any single company withdrawing a small amount of capacity is more than sufficient to compensate for the loss of profit on that volume of sales, making such withdrawals highly profitable in tight markets.

Second, any transition from a vertically integrated utility to an unbundled structure introduces price risks between generators and suppliers that previously cancelled out. High wholesale selling prices for generators gives profits upstream that are matched by the losses of downstream suppliers who have to buy at these high wholesale prices and sell at predetermined retail prices, unless these purchases are hedged by contracts. The transition to (and subsequent operation of) an unbundled industry therefore needs contracts and hedging instruments to insure against possible unexpected events that can have dramatic effects on spot prices, particularly when suppliers sell on fixed price terms. The British privatisation was accompanied by three-year contracts for both sale of electricity and purchase of fuel to reduce transitional risks.

Third, in an interconnected system operating under a variety of different regulatory and operational jurisdictions, spare capacity is a public good that may not be adequately supplied unless some care is taken to ensure that it is adequately remunerated. Fourth, it is even harder for a decentralised market under multiple jurisdictions to ensure adequate reserve capacity with a potentially energy-constrained hydroelectric system, particularly where reservoir storage is limited, and annual water volume variations are high. Finally, uncoordinated and injudicious regulatory interventions in such an interconnected system can have perverse local effects, and very damaging impacts on the efficient pattern of inter-regional electricity trade (Wolak and Nordhaus, 2000; 2001).

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[16] There are problems in using standard tests for market concentration, such as the HHI for either capacity or output, for what matters is the extent of competition between generators with bids near the market clearing price.

[17] If consumers face prices unrelated to spot wholesale prices they will not reduce demand even if wholesale prices increase dramatically. All domestic and most commercial and industrial customers are in this position.

6. Electricity price determination in theory and practice

Modelling price formation to understand market power and market efficiency is both challenging and important if regulation and market interventions are to be intelligently applied. Green and Newbery (1992) modelled the English Electricity Pool by adapting Klemperer and Meyer's (1989) supply function equilibrium (SFE) model. This approach is both natural and empirically supported for a single-price gross pool with a daily bidding round - as in the English Pool. The model is challenging to solve and typically give a continuum of equilibrium prices. Fig. 4 illustrates this for England, ignoring entry threats.

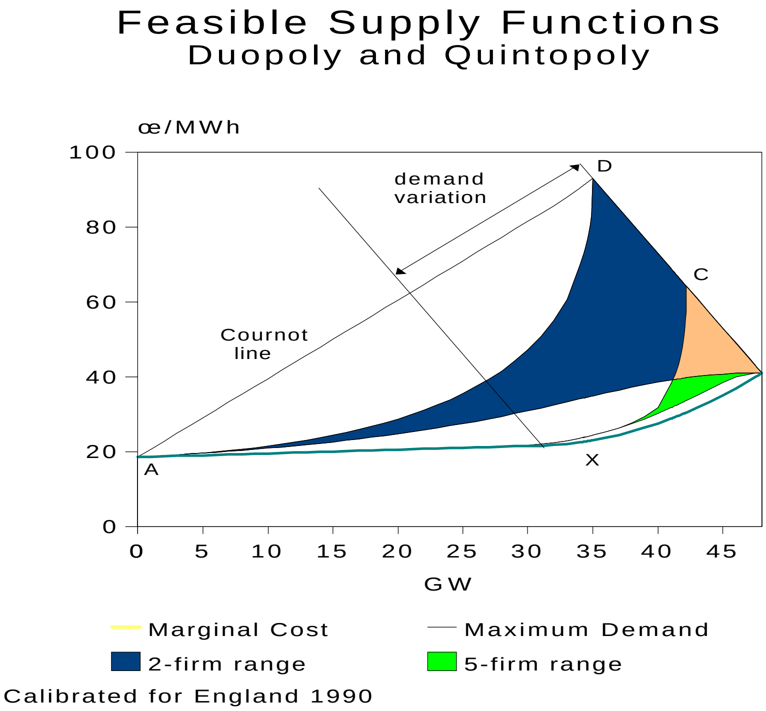


Fig 4 No-entry no-contract equilibrium price range

Auction models have been proposed, and are useful for comparing single price and pay-bid trading arrangements, but are even less tractable.[18] Standard Cournot oligopoly models are simpler, can be defended in tight market conditions, but suggest a more deterministic outcome than supply function models with their range of indeterminacy. Increasingly, consulting companies are developing price-formation models, the best of which capture the strategic aspects of supply function models with more careful modelling of the non-convexities of start-up costs which can dramatically influence the cost of providing additional power for short periods.

Despite this apparent diversity of approach, theory and evidence suggest considerable agreement about the nature of the resulting equilibrium. Competition is more intense (closer to Bertrand) and prices closer to avoidable costs with spare available

[18] e.g. von der Fehr and Harbord (1993), or Green and McDaniel (1999)

capacity, but as the margin of available capacity decreases, competition becomes less intense and outcomes closer to Cournot (as in the SFE). Fig. 5, also taken from the California ISO web site, illustrates these points nicely. Contracts lock in prices and reduce the influence of spot prices on generator revenue, making the relevant market size that for uncontracted output. The dominant short-run strategy for a fully contracted generator is to bid short-run avoidable cost (Newbery, 1995). The threat of entry by competitive generators limits the average price that can be sustained and encourages incumbents to contract and bid to maximise profits without inducing excess entry. Peak prices depend on the relation between maximum demand and maximum available capacity. The returns to peaking plant depend on the prices reached and the number of hours for which they are paid. Inelastic demand[19] means that in tight markets even apparently unconcentrated generation (e.g. with Herfindahl-Hirshman indices below 1800), can sustain extremely high price-cost margins for short periods. The considerable degree of discretion in choosing price strategies even without tacit or other collusion may make the threat of regulatory intervention effective,[20] while repeated interaction on a daily basis can certainly encourage tacit collusion (and was the main argument for replacing the Pool by the New Electricity Trading Arrangements).

Green and Newbery (1992) argued that the restructuring of the CEGB into two price-setting generating companies gave too much market power to the incumbents, and, on the basis of a demand elasticity of 0.2,[21] argued that dividing the generation capacity among five equal size firms would be highly pro-competitive. This conclusion, which appeared to be influential in restructuring the Victoria electricity market in Australia, seemed to be borne out by the evidence of significant price falls there, compared to apparently excessive price-cost margin in England. We were arguably too sanguine about demand elasticities, and lower but quite plausible values would confer considerable market power even with five or more generators, at least, as capacity shortages emerge. Halving the elasticity of demand (at some reference price, quantity pair) would double the peak price-cost margin reached, *cet. par.*[22]

[19]The majority of electricity is sold at fixed prices based on the average spot price, and hence very insensitive to peak prices. Even if consumers would adjust demand in response to these spot prices, most have no incentive to so respond. Nevertheless, demand responses are not zero - almost 30% of California's consumers cut demand by more than 20% to qualify for a 20% price rebate, while temperature-corrected demand fell 12.4% from June 2000 to June 2001, with peak demand down 14.1%. (*Financial Times*, Aug 21, 2001).

[20] Important in the English Pool, and certainly credible given the power to refer generators to the competition authorities.

[21] at the competitive price, higher at the monopoly price given assumed linear demand schedules.

[22] Holding constant contract coverage and the number of firms

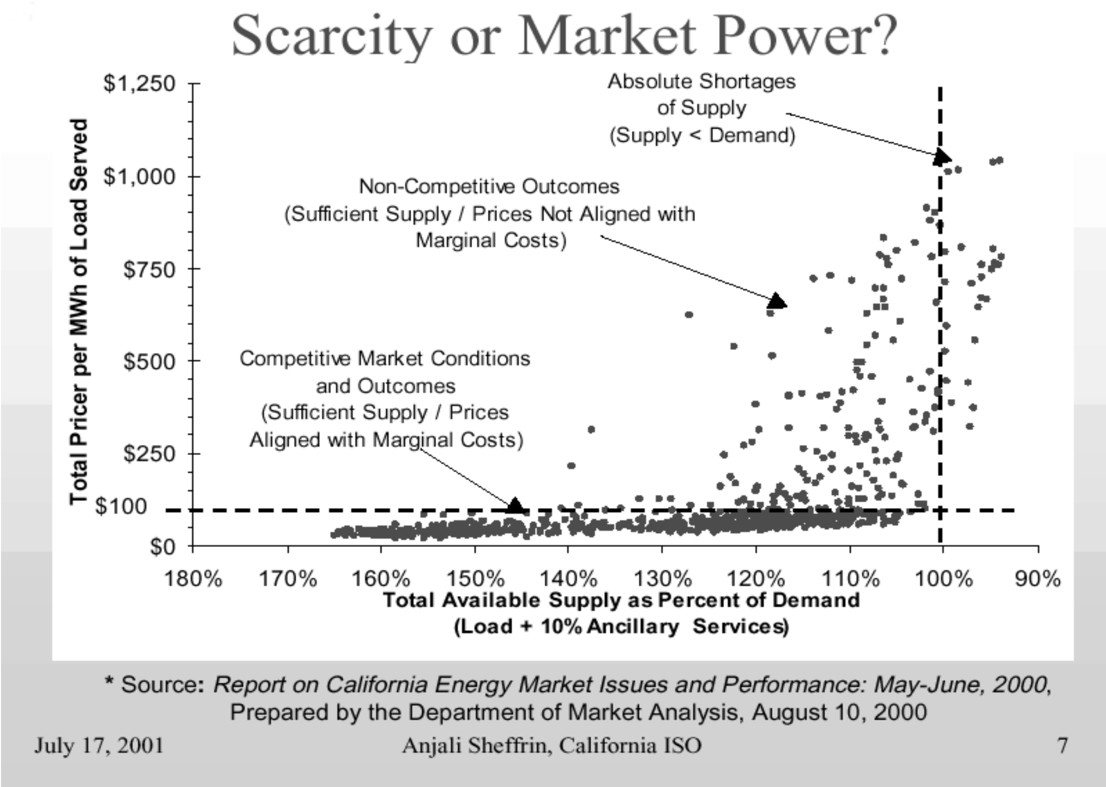


Fig. 5 Price-cost margins under varying market conditions

Later work by Newbery (1998) argued that the conditions of entry and the extent of contract coverage were both critical in determining the average price level and its volatility, so that other things would not remain constant if demand elasticities changed. Analysing market power therefore has to pay attention not just to concentration and demand conditions (both of which may be significantly affected by inter-regional trade), but also to entry and contracting conditions, which tend to be overlooked in most discussions.

If incumbents do not need to worry much about entry or regulatory intervention, then the logical strategy for companies in a competitive ESI would to merge to increase market power, and close plant to tighten the margin of spare capacity. Fig. 6, taken from Newbery (1998), plots the SFE quantity supplied at each against price, (thus price is on the *x*-axis, is in contrast to normal representations). It shows that the range of equilibrium market prices depends on capacity, demand, and the Cournot line (the choice of output ignoring supply responses by other generators, which itself depends on the demand elasticity and the number of competitors). Making contracts unattractive to exploit consumer risk aversion increases the size of the residual market. All these actions increase market power and hence allow non-collusive price bidding to reach high prices. Incumbents owning transmission can deter entry by capturing all capacity rents to generation and transmission in access charges to the grid. That appears to be the game being played out in Germany, where the incumbents are vertically integrated, subject only to negotiated third party access, and with no specialist regulator to oversee their behaviour (Brunekreeft, 2001).

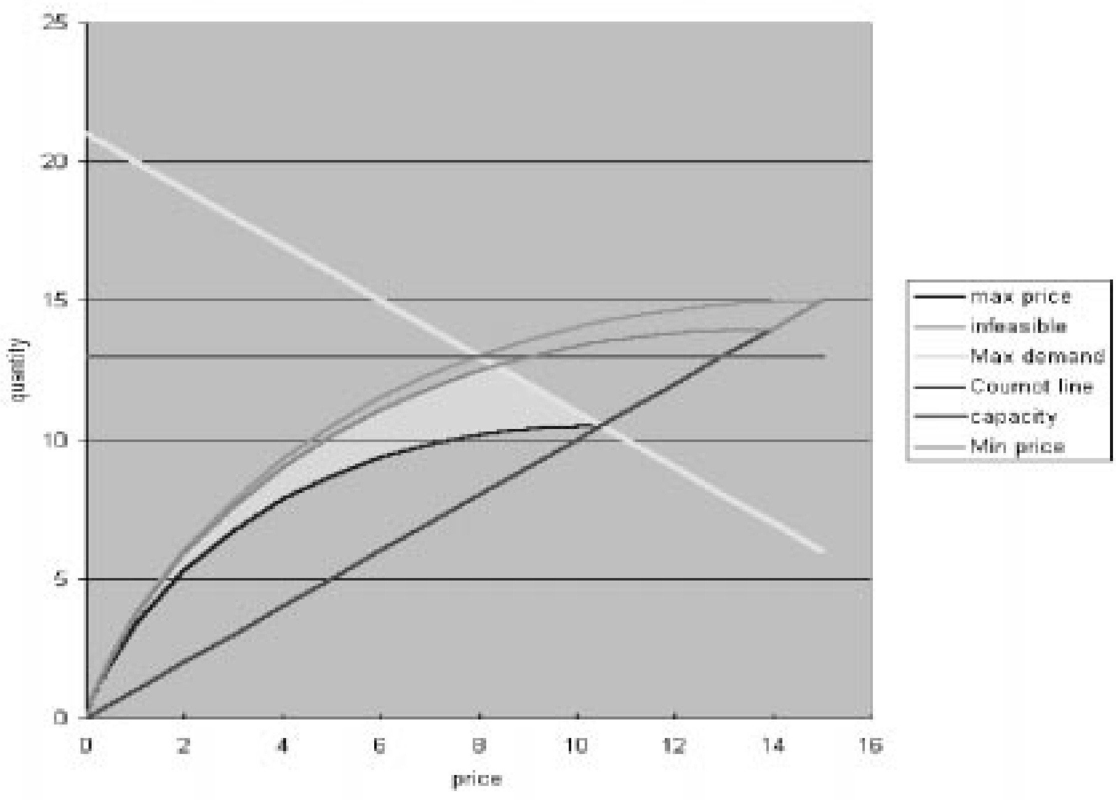


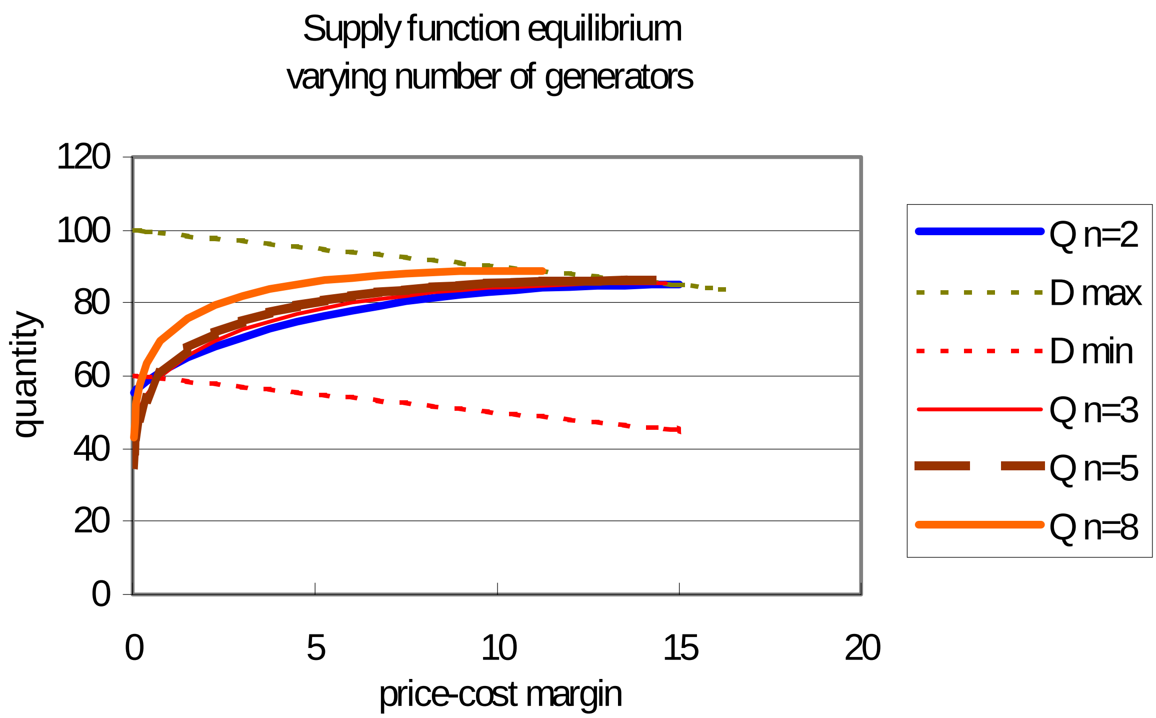
Fig. 6 Feasible prices depend on capacity and demand elasticity

If entry is relatively low risk, and there is adequate capacity within the industry, then incumbents benefit from credibly committing themselves to bid so that the average price remains below the entry-inducing price.[23] The entry price will be typically above the avoided cost of existing generation, and the cost of inducing entry is foregoing the difference between the entry price and the avoidable cost of some existing displaced capacity. Newbery (1998) showed that in such cases the annual average price would be relatively insensitive to the number of competitive incumbents, but the volatility of such prices would be lower the more competitive the industry, provided the entry price remained unchanged with increasing competition, as shown in Fig. 7.

Fig. 7 Average Price set by entry conditions

There are, however, reasons for expecting the entry price to be higher the more competitive the industry, for the following reason. Future demand growth is uncertain, plant highly durable, and investment decisions irreversible. The more competitive the

[23] Entry is low risk with CCGT whose efficient size can be small relative both to the total market and demand growth, particularly given long-term contracts for fuel inputs and electricity off-take.



industry, the lower the prices will be if demand has been over-estimated and markets remain less tight and hence prices closer to costs. Less competitive markets would sustain a higher price-cost margin even with excess capacity, and reduce the risks of over-estimating demand. Electricity generation is similar to aluminium smelting in that the avoidable costs are typically only about half the total cost, the rest being mainly the return on capital. The aluminium market is characterised by lengthy periods where prices produce a sub-normal return on assets, no investment takes place, and demand gradually increases until the market tightens and prices rise to extraordinarily high levels (Baldursson, 1999). These prices remain high until the option value of delaying investment to resolve uncertainty about future demand is adequately rewarded. At that point entry occurs, prices fall, and the (long-period) price cycle restarts. Consequently, a truly competitive and contestable wholesale electricity market runs the risk of producing unacceptable price volatility, not just in the short run (where contracts would eliminate the impact), but for possibly lengthy periods before new capacity comes on-line, as in California.

The tensions suggested by this scenario are likely to be resolved in one of a number of alternative ways. Incumbents will surely attempt to impede entry to make the market less contestable, reducing the risks to their profits. Horizontal consolidation facilitates multi-market contact that may mute competition.[24] Reforms to trading arrangements may affect entry conditions. There are serious concerns that the New Electricity Trading Arrangements (NETA) in Britain have concentrated excessively on improving short-run

[24] see e.g. Parker and Röller (1997), Ivette and Rosenbaum (1997)

competition at the expense of longer run contestability of entry, while extensive vertical integration into supply protects incumbents from price risk, makes markets less liquid and creates additional barriers to entry. The resulting equilibrium might be a quasi-regulated (or price-capped) oligopoly as regulators respond to pressures for 'just and reasonable'.[25]

The alternative is for regulatory intervention to support competitive markets while reducing some of the their adverse side effects. If competition and future demand uncertainty increase medium-run price risk, there are two compounding effects leading to inadequate capacity on average and hence higher than efficient prices. The first is the incentive to delay in the presence of price uncertainty. The second is more serious and derives from a market and regulatory failure in the treatment of price risk. Britain in 2001 after a sustained period of falling energy prices, had 20% of households defined as fuel poor - that it is spending more than 10% of their income on fuel. Average market-clearing final prices for electricity in periods of scarcity could easily be twice or three times as high as normal average prices.[26] Given the considerable price and income inelasticity of demand for electricity, a large number of consumers would be highly price-risk averse to long-period price volatility. Indeed, given the fact that most governments accept a universal service obligation as a political necessity, generators would not expect that market clearing prices would be allowed to reach such high levels except for very short periods handled by normal contracts. Consequently, entrants will mark down the expected returns in periods of scarcity, but will still be faced with lower returns in normal periods. Their response will be to further delay entry and under-invest relative to the efficient level of capacity, raising average prices.

If the system operator (SO) is instructed by the regulator to ensure adequate reserves and has the right incentives to make timely forecasts of demand and capacity adequacy, then the SO might need to contract for long-term reserves. This would have the advantage of reducing the risks of occasionally-run plant.[27] This is not without problems, as spare capacity drives down average prices, reducing the incentive to either enter or keep capacity available without guaranteed payments from the SO or some other source. One simple solution to this problem would be to require the SO to secure adequate capacity, thereby effectively making him a Single Buyer. A second solution is to retain a franchise for domestic consumers and require that the franchise-holder secures long-term contracts for adequate capacity to meet his service obligations. Eligible customers would be free to hold firm long-term contracts, or accept interruptible priority tariffs (Wilson, 1993).

Neither of these options is particularly attractive to those who believe that

[25] Quasi-regulation is pricing at levels that just deters the regulator from intervening.

[26] Domestic retail prices are typically about twice competitive wholesale prices. Californian average wholesale prices from Jan-April 2001 at $300/MWh were more than ten times those of Jan-April 1999, even with price-caps.

[27] A guaranteed annual payment of, e.g. £30/kW for availability will be more attractive and less risky than expecting to earn an average of £1000/MWh for an expected 30 hours per year, where each number is highly uncertain. See also Vázquez, Rivier and Pérez-Arriaga (2001).

liberalised markets can evolve decentralised solutions that retain the unbundled and open access character of the industry. It raises the question whether the old vertically integrated structure is not after all a preferable model. Consider its advantages: in well managed, mature industrial economies cost inefficiencies appear modest - of the order of 5% or so (judging from the estimates of Newbery and Pollitt, 1997). Regulated cost-based prices combined with vertical integration eliminate the price risks on intermediate wholesale markets, and are the *quid pro quo* in the regulatory compact to a requirement that the utility plans generation and transmission capacity efficiently to meet its service obligation. The bias towards under-investment is replaced by a bias to over-investment in which the excess costs can be recovered efficiently by Ramsey pricing. Thus large and industrial consumers trading on world markets would face efficient prices (short-run marginal cost), and any revenue short-fall can be recovered by higher prices for commercial and domestic customers. This model is a good characterisation of the old CEGB and EdF, although the US system of regulation was less able to sustain efficient cross-subsidies in the face of a politicised regulatory rate-setting process. Most industrial countries had substantial excess electricity capacity after the 1974 oil shock but were able to protect their financial viability until the collapse of the regulatory compact in the 1990s.

The Single Buyer model has the apparent attraction of introducing competition into generation (for, not in the market), while retaining the risk reduction and planning benefits of vertical integration. The buyer is normally the transmission owner, as the grid is an essential facility to deliver electricity to consumers and thus gives its owner the power to charge cost-recovering prices. Competition is for the right to build plant, while the long-term power purchase agreements required to assure generators provide continuing incentives for efficiency in generation. Eligible customers can be left free to contract directly for surplus power but at market determined prices, while the franchise customers have no choice but to accept the long-term contract prices. The model is, however, vulnerable to regulatory opportunism that risks stranding these long-term contracts. The EU Electricity Directive reinforced this risk by making the model functionally equivalent to regulated Third Party Access (intentionally making it unattractive by allowing eligible buyers to bypass the Single Buyer). As a result the model has fallen out of favour and the Commission now proposes to remove it as an option (CEC, 2001).

The critical question is whether it is possible to evolve a sustainable unbundled equilibrium than transfers the benefits of competition to consumers without risking politically unacceptable high prices and capacity shortages. Theory and evidence alike suggests that this will require a relatively unconcentrated wholesale generation industry, with no ownership interests in transmission and no artificial or market-induced impediments to entry by new competitors. The choice of wholesale market design remains problematic - single-price pools may be prone to collusion, but pay-bid residual balancing markets (as under NETA) amplify risk for non-portfolio generators and may deter entry. Transmission constraints fragment markets and reduce the number of generators able to compete against each other.

As even quite unconcentrated markets are prone to market power, there are considerable competition and hence social benefits from “excess” transmission capacity to maximise the geographical extent of the market. Similarly, “excess” generation capacity keeps the equilibrium closer to Bertrand competition but requires a mechanism to pay for capacity.[28] Capacity in both transmission and generation has public good-like qualities, in that it increases security, reliability, and competition, all of which benefit consumers connected to the system. If the system is also interconnected with other jurisdictions, then spare generation capacity will improve their security and tempt them to free ride. The EU is still searching for a viable way to stimulate efficient cross-border trade and to finance additional interconnection, so as to overcome these barriers to market competition.

Within a single country, these spill-overs can be internalised, although only with careful regulatory design. The present system of price-caps for transmission combined with tough efficiency targets risks under-investment unless security is recognised as a valuable attribute by the regulator and the transmission company given incentives for its adequate provision. In Britain, Ofgem is attracted to the idea of extending competition to the provision of transport capacity, particularly in gas, and considers that auctions for entry capacity and possibly for transmission should guide investment decisions. Again, the problem is a mismatch of contract duration - auction rights may extend for up to five years, while pipelines have an effective life of 50 years. Auctions work well for allocating scarce existing capacity, but are of doubtful value for signalling the amount of new capacity required, especially in the presence of economies of scale and public good externalities of increased competition.

Compensating for the tendency to under-invest in generation requires the equivalent of a two-part tariff, with a capacity and energy element (one-sided contracts for differences have a similar structure).[29] This is easy with the Single Buyer model, but more difficult if all consumers are free to switch suppliers for this will discourage suppliers for entering into long-term strandable contracts. It is possible to imagine various solutions to this - savings markets offer customers the choice between liquid but less attractive contracts or those with a degree of lock-in or exit payment (for savings bonds, mortgages etc). The practical question is whether the advantages of supply competition for domestic customers justifies the extra costs and risks needed to avoid such problems. Green and McDaniel (1998) cast doubt on whether this was the case in Britain.

Matters are more complicated when electricity trade crosses country or regulatory borders, as in the EU and US. The US has the advantage that FERC has the legal power to intervene when prices are deemed "unjust and unreasonable", as it did in California at the end of 2000 (Wolak, 2001). The EU lacks that power, and most EU member countries

[28] Excess is measured relative to an efficient centrally planned system.

[29] A one-sided CfD for *Q* MW with a strike price *P* and a cost *C* entitles the holder to buy *Q* MW at that price whenever the spot price is higher. The payment *C* is equivalent to a capacity payment. Vázquez, Rivier and Pérez-Arriaga (2001) suggest this as a means of securing capacity adequacy and present the formula to compute the value of *C*.

have not yet adequately addressed this problem. The UK is consulting on a replacement to the Market Abuse Licence Condition that was undermined by the Competition Commission's decision, but many EU countries lack even the requirement that generators hold licences whose conditions can be modified to address market power issues.

7. Market power and market fragmentation

The EU has adequate, arguably surplus, generation capacity, modest demand growth, access almost everywhere to gas that enables new entry by rapid-build modest scale combined cycle gas turbines (the least-cost choice except perhaps for hydro in favoured areas). These are ideal enabling conditions for a competitive generation market, for theory (Green and Newbery, 1992) and evidence (Newbery, 2000) alike suggest that with a sufficient number of competing generators and adequate spare capacity, prices will be close to the competitive level. Even if generation is concentrated, provided entry is contestable (and entrants can contract with suppliers or customers), then wholesale prices should be restrained to the long-run marginal cost of generation (Newbery, 1998), even if they are too high with spare capacity.

Yet although there has been some convergence of retail prices for large customers (CEC, 2001), there are few wholesale spot markets, and those that exist are not fully arbitraged. In some cases the price differences are visible in the high auction prices for interconnection between countries, notably between Germany and the Netherlands and between France and England, although even allowing for the cost of securing interconnection, there remain systematic profitable arbitrage opportunities. In other cases the interconnect auction prices are low, as between exporting Belgium and The Netherlands, although Belgian costs are well below Dutch spot prices. Thus for the period 30 April - 10 August 2001 (after the initial turbulence of market opening at the start of the year) the ratio of the Amsterdam to Leipzig weekday daily average spot price was 1.9:1, and for hours 9-18 the ratio was 2.36:1.[30]

In the absence of the kind of information routinely available in the US, it is difficult to be sure why the promise of the single integrated EU-wide electricity market has not been delivered, but there are some possible theories that could, with access to the right information, be tested. The absence of a wholesale market in Belgium or France, the dominance of the incumbent company in each of these countries, and the fact that Electrabel also owns the largest generating company in The Netherlands gives cause for concern. The lack of wholesale markets and transmission constraints both hinder arbitrage and amplify market power in the resulting isolated markets.

Germany provides an interesting case, because the spot prices have been very low

[30] The four-week moving average ratio for hours 9-18 exceeded 4:1 in July. Hourly spot price data can be downloaded from www.apx.nl and www.lpx.de, while interconnect auction data is at www.tso-auction.org. A strategy of buying 1 MW each hour from 10-16 in LPX, buying interconnector capacity (RWE-TenneT) and selling in the APX every weekday for at least a month has a high probability of profit.

in 2000-2001 (compared to the long-run marginal cost). Brunekreeft (2001) argues that the best strategy for vertically integrated generating/transmission companies wishing to deter entry is to charge avoidable cost for generation and recoup fixed costs through transmission tariffs. That strategy is possible as transmission tariffs are negotiated, and there is no sector regulator to ensure non-discriminatory access. Not surprisingly, Germany is resisting the proposed changes to the Electricity Directive. Given spare capacity, low prices are a feasible equilibrium strategy, and have the attraction of reducing the cost of buying other generating companies, allowing increasing concentration. Once the industry reaches the limits of acceptable (to the competition authorities) concentration, market power can be restored by reducing spare capacity - and plant retirements started in mid-2001.

If regulators lack the necessary competition powers, the EU electricity market risks two unattractive alternatives. At present the lack of power exchanges forces most electricity to be bought on contract - which reduces short-run market power and hedges price-spikes (Newbery, 1995). Without a new Directive, distribution companies retaining a domestic franchise and subject to yardstick regulation of their power contracts could provide countervailing power against generating companies. The distribution companies could contract with entrants (or even build their own capacity) to cap unreasonable price increases. However, opaque markets, lack of information and the regulatory power to enforce competitive pricing, combined with horizontal and vertical integration may lead to the old German-style equilibrium (as described in Müller and Stahl, 1996) - safe but rather expensive.

With the new Directive, the end of the franchise by 2005 is likely to encourage generators to integrate forward into supply, and risks removing the counterparties to longer-term contracts that would facilitate entry. If entry is impeded, and markets remain national and thus concentrated (because of interconnector constraints), then it will be profitable for companies to reduce the spare capacity margin, with possibly Californian consequences (worse if the regulators lack the legislative power to intervene).

7. Concluding remarks

The best short-run method of supporting electricity liberalisation is to rapidly increase transmission capacity (offered at efficient prices). This would increase the number of generators competing against each other, dilute market power, and reduce the need for regulatory market intervention. That is difficult as it requires agreement between different regulatory regimes in each country, and because the desirable `excess' transmission (relative to an efficient centrally managed system) is a multi-country public good. Even if successful, in the longer run, the problem is that if demand grows and generators find it profitable to tighten capacity, high prices would be transmitted Europe-wide. To avoid that requires adequate generation capacity. Ensuring adequate capacity and contestable entry without the normal pattern of long-period commodity price swings needs good long-term contracts, possibly combined with capacity payments. Neither of these is easy in a fully liberalised market, compared to the former vertically integrated franchise model, or even the disfavoured Single Buyer model. A competently regulated domestic franchise may be preferable to a fully liberalised supply market, judging from the cost-benefit analysis of Green and McDaniel (1998), and that ignored the additional contracting benefits noted here.

There are additional problems in ensuring that the benefits of capacity adequacy are captured by those providing them (the multi-country spill-over problem again). Wolak (2001) recommends firm forward contracts for California (heavily dependent on out-of-state imports). As a general point, regulators should aim for capacity adequacy and maximise plant availability by ensuring maximal contract cover, and should confine any price caps to the contract market. This may require further reforms to trading arrangements, and will certainly require that regulators have adequate competition powers.

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