Regulating Unbundled Network Utilities

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1. Introduction

The new conventional wisdom is that network utilities 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, at least in electricity, are considerably more demanding than in normal product markets, so that competition law must be adapted if it is to be effective.

The three network utilities where competition appears attractive - telecoms, gas, and electricity - present different challenges. In telecoms, the proper balance between facilities-based competition and access price regulation is still finely balanced. In gas, particularly on the Continent, the evolution towards a satisfactory equilibrium that addresses import security and competition concerns is at an early stage. The electricity supply industry provides the richest body of evidence of the consequences of unbundling, and provides the sharpest test of the new conventional wisdom. This paper will therefore concentrate on the regulatory lessons from electricity unbundling.

2. Equilibrium utility structures

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 commissions and federal agencies under cost-of-service or rate-of-return regulation. This system of regulation had evolved over

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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 breakup 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.

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. The results of that experiment were encouraging - the industry was successfully sold, shareholders did well, consumers felt no pain and crucially, contrary to earlier fears, the lights stayed on.

Similar regulatory pressure on British Gas as that on AT&T encouraged that company to unbundle and divest its pipeline business, while a new Gas Act ended the gas franchise in 1998 and made supply as well as production competitive and largely unregulated activities. An earlier legislated timetable gradually increase the share of electricity supply open to competition, with the domestic franchise finally ending in 1999.

The old vertically integrated utility model no longer looked like a desirable or even inevitable equilibrium form. Technical progress had unsettled telecoms, but arguably for electricity and gas the destabilising force was mature or excess capacity that unsettled the regulatory compact (Gilbert and Newbery, 1994). If the utilities had little need for investment to finance expensive capacity, then consumer interests saw the merits of pricing closer to avoidable costs, letting the market expropriate at least some of the returns to capital. Developments since 1984 can be interpreted as a search towards a new and stable equilibrium which has still not worked itself out.

In the case of telecoms, it is reasonably clear that changing technology is very likely to have changed the range of feasible stable equilibria. Facilities-based competition is possible from cable, internet, wireless and a variety of other communications media, while the variety of different geographically overlapping networks makes interconnection imperative, and hence makes liberalisation feasible. Convergence of the means of delivery of voice, data, video, competition of traditional circuit-switched networks by packet-switching, combined with the continued decrease in switching and transmission cost, makes it clear that the old industrial structure is certainly inappropriate and probably unsustainable. Whether local loop unbundling is superior to facilities-based competition, for example in the delivery of broadband, remains controversial.

The case of natural gas is less clear, and the old structure may not even have been a sustainable equilibrium. The large-scale commercial exploitation of natural gas is relatively recent phenomenon, particularly outside the U.S. In 1970, Western Europe consumed 73 million tonnes oil equivalent (Mtoe) of natural gas. By 2000, this figure had grown to 413 Mtoe, or nearly six-fold. While Europe consumed 13% as much gas as the US in 1970, by 2000 this had risen to 70%.[1] Gas production, certainly offshore production in the North Sea, is capital-intensive, and building a high pressure gas pipeline system is even more so.[2] Where such development has been undertaken by private oil and gas companies (as has been the norm outside the Soviet bloc), they have been financed on the back of long-term contracts. Once the gas transmission and distribution network is mature, gas penetration high and the market developed, this equilibrium is vulnerable to regulatory opportunism, clearly demonstrated in the US and Britain (Newbery, 2000).

That does not mean that an unbundled gas industry is an inevitable

[1] Data from *BP Statistical Review of World Energy,* 1980 and 2000

[2] Gas delivered to Western Europe from Russia travels 6000 km from the wells through pipelines of 1200mm diameter.

outcome. The Continent is heavily and increasingly dependent on gas imports, mostly from politically unstable and distant countries, some of whom require transit rights through other, unstable or hostile countries. Britain and the US are almost alone in being self-sufficient (at least at present) and having fully restructured their industries. Other countries see gas imports as of major geopolitical concern, and are most unlikely to allow the industry to evolve solely in response to market forces and short-term consumer demands. Nor is a competitive downstream industry necessarily the ideal complement to upstream foreign monopoly as exemplified by Gazprom. As Britain shifts from a gas exporter to gas importer within the next five years, these issues will increasingly have to be addressed by the British Government. Already the gas interconnector with the Continent has ended the period of gas pricing based on gas-on-gas competition, and re-established the link between gas prices and oil prices, thereby wiping out many of the benefits of earlier UK gas liberalisation.

3. Restructuring Electricity

If the forces influencing the structure of the telecoms industry are still rapidly evolving, and if the balance of interests and advantage in gas have still not equilibrated, that leaves the electricity supply industry (ESI) as an interesting test case of the possibility of multiple stable industry equilibria. Of course, change has also affected the ESI, particularly in the period since 1990. The development of combined cycle gas turbines (CCGT) makes this the natural choice for new generation, except where gas is not readily available, or local coal or hydro have overwhelming cost advantages. CCGT stations can enter rapidly (2 years) and at modest scale (50MW-500MW), compared to coal and nuclear stations (5-10 years and 1000MW). Gas in mature systems can be delivered closer to the final electricity market place more cheaply than electricity, reducing the need for expensive grid investments, and reducing the advantages of geography (well-placed coal mines or dams). CCGT technology therefore makes generation more contestable than before, and supports liberalisation.

These developments helped but did not dramatically change the case for liberalisation, which in Britain occurred before CCGT arrived. Generation stations in most of the larger industrialised countries are small compared to the market - the largest one in Britain (one of the largest in the world) had less than 8% of total capacity, and economies of scale of coal and nuclear stations fall off rapidly beyond 2% of total UK capacity. Smaller markets like Belgium are typically interconnected with a wider system, leaving only isolated small countries like Ireland facing a serious problem of indivisibility.

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.

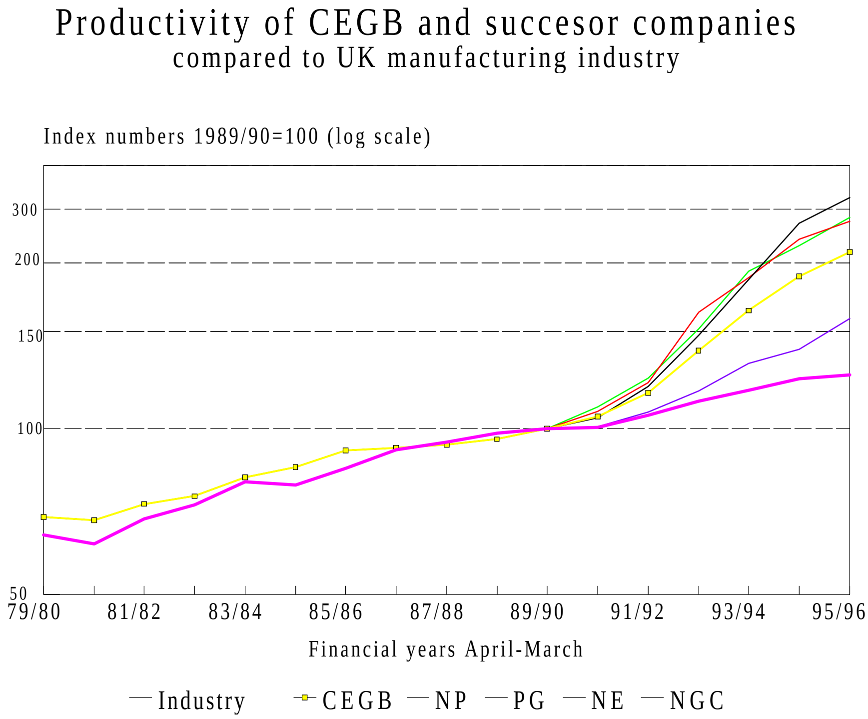

Fig. 1 Performance of the restructured CEGB

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 (see Fig. 1 above). 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. By the end of the decade the dominant duopoly had evolved into a relative unconcentrated industry, as fig 2 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.

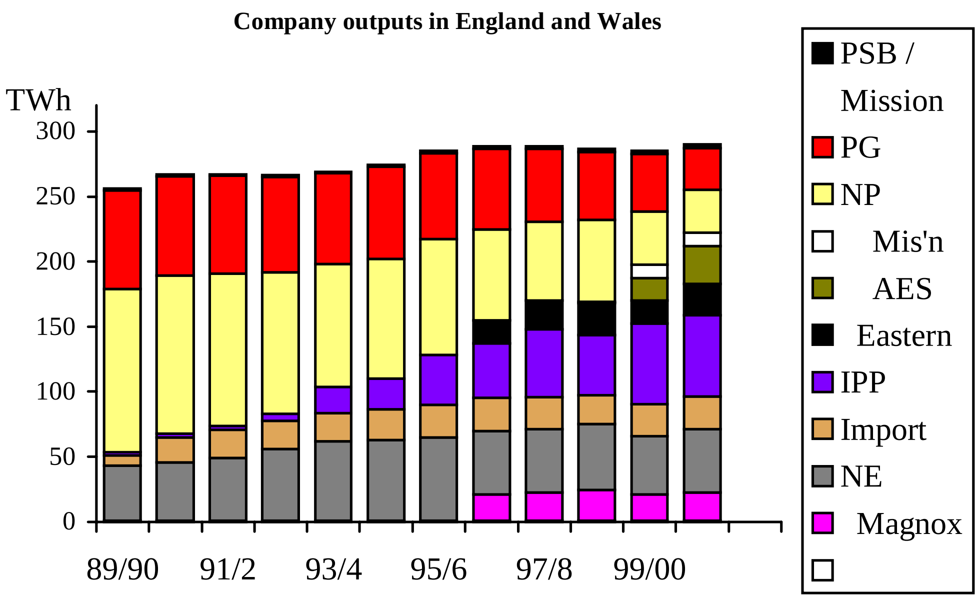

Fig. 2 Deconcentrating Generation

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 3. 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

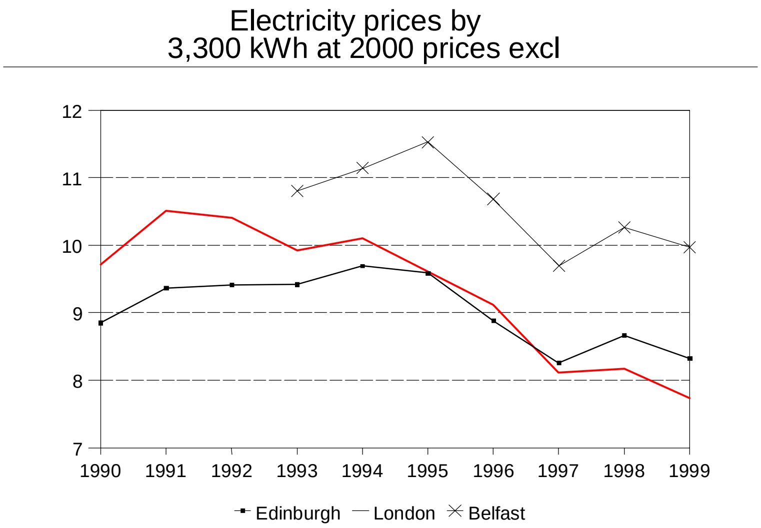

Fig 3 Poor Performance of Scotland

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.

The lesson that unbundling is necessary has been taken to heart in restructuring choices around the world, and particularly in the European Union. Vertical separation, preferably with legal separation of ownership, is increasingly recognised as the appropriate model and one that the European Union is pressing most strongly in its recent proposals for reforming the Electricity Directive. There is less agreement on the best form for the wholesale electricity market (and the Directive is not prescriptive on this). The single-price Pool model of England and Wales has found favour in a number of countries. Ironically, the Pool has been the focus of discontent in Britain, attracting blame for high prices that have more to do with the uncompetitive state of generation than the form of market arrangements. The Pool was replaced by the New Electricity Trading Arrangements in spring 2001 in an attempt to drive wholesale prices closer to the, by now, substantially lower generation costs.

4. Threats to the new consensus

The argument of this paper is that there is unfinished business for regulation in managing the combination of competition and regulation that is the inevitable consequence of liberalising network utilities. The regulatory challenge is to evolve a politically stable and sustainable form of regulation that combines the undoubted efficiency benefits of competition with the proper management of risk and adequate provision of investment. The central question is whether the old equilibrium of vertically integrated franchise monopolies is the only stable equilibrium, or whether there are other possible stable equilibria, whose relative merits may have changed or previously been concealed.

A few years ago, such questions would have been considered heretical to economists, and most European governments (with the possible exception of France). Privatisation and liberalisation, particularly structural unbundling, had been demonstrated successful in Britain and elsewhere. Impressed by the achievements of that model, the European Commission successfully introduced liberalising Directives for electricity and gas that came into effect in 1999 and 2000 (Bergman, et al, 2000). These enforced functional unbundling, opened networks to Third Parties to allow competition between producers, and opened one-third of final demand to competitive supply. Privatising and liberalising telecoms had been widely accepted much earlier.

With immaculate timing, events of the past two years have shaken political confidence in this liberalisation agenda. California led the United States in unbundling electricity, in the expectation that high consumer prices would fall as they had done in Britain, Australia, Norway and Argentina. Instead, wholesale prices trebled between 1999 and 2000, bankrupting the distribution companies whose retail prices were regulated but who had to buy in the spot market at unregulated and extremely high wholesale prices.

In Britain, the travails of the extensively unbundled railway system (over 100 companies created out of the former British Rail) culminated in the Hatfield rail accident - an accident that killed one third of the number of daily road deaths, but which brought the entire railway network almost to a standstill for the next six months. The successful completion of the gas inter-connector between Britain and the Continent allowed British Gas prices which had been set at low levels by gas-on-gas competition to adjust to oil-linked continental gas prices just at the time that oil prices doubled. Even telecoms companies, which had demonstrated their optimism about the future of third generation mobile in the prices they bid in spectrum auctions, faced collapsing share prices, heavy debt burdens, and were in danger of finding their expansion plans unfinancable.

Within a few months the comfortable political assumption that utilities could be removed from the political arena, able to finance their activities while delivering lower prices to contented voting consumers, had been undermined. The British government responded by putting in place the Strategic Rail Authority to sort out the problem with the railways, and the Prime Minister's office launched an energy review. The European Commission was moved to issue a press release arguing the case for opening up European energy markets more rapidly. "Thanks to these new measures, the European Union, unlike the United States, will have a truly integrated market, which means, for instance, that Europe will avoid the type of problems currently faced by California, which have resulted from an inadequate legal framework and inadequate production capacity."[3]

5. Problems of replacing regulation by competition

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 UK 1998 Competition Act grants the Office of Fair Trading joint powers with regulators to deal with utility competition issues and is a reminder of their importance. Setting price caps is reasonably straightforward for transferring past efficiency gains, though as argued below the harder part is to provide incentives for efficient and adequate capacity investment.

A substantial part of UK regulatory activity over the past few years has been directed to introducing competition, or intervening to improve competitive outcomes. Ending the franchise in electricity and gas was an example of the former, encouraging plant divestment and reforming electricity trading arrangements directed to the latter. The New Electricity Trading Arrangements in the wholesale electricity market were introduced to reduce the perceived abuse of market power. The ill-fated Market Abuse Licence Condition introduced as a licence condition by Ofgem, contested by British Energy and AES, referred to the Competition Commission and rejected, was again an attempt to improve the workings of the wholesale market and to detect and penalise supposed abuses that would not be reliably caught by the Competition Act (Competition Commission, 2000).

The United States, with its more legalistic approach, is much clearer on the duties of regulators when liberalising. Under the Federal Power Act 1935 (?), 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 utility "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."[4] 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

[3] Available at http://europa.eu.int/comm/energy/en/internal-market/int-market.html

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

characteristics the Commission has relied upon in approving market-based pricing."[5] FERC therefore assumes that competitive pricing is "just and reasonable". The reason that it is so concerned to monitor and take steps 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, cited by Bogorad and Penn, 2001).

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. The dictum of confining regulation to the natural monopolies has often been taken too literally, paying too little attention to the unnatural, or at least undesirable, monopolies in generation. 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. Good regulation must be robust against possible future problems, and the rest of this paper will concentrate on the problems electricity regulation will have to address.

6. 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,[6] and the major public utility, PG&E, filing for Chapter 11 bankruptcy protection (see fig. 4)[7]. California shows that poor market design

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

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

[7] 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.

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 minimize the downside potential of the journey on which they have embarked.”

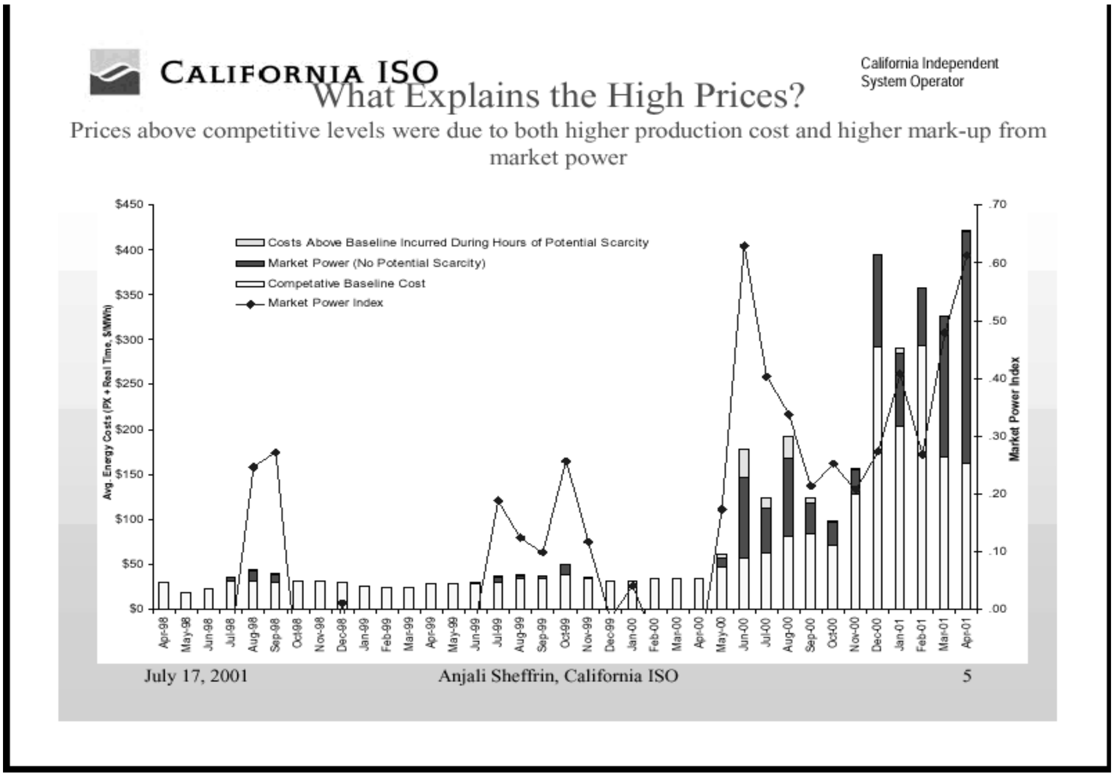

Fig 4 California prices and costs

What were the various contributory factors to this unhappy outcome? First, 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).[8]

Finally, NO 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.[9] The price of tradable NO 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 utilization 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 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

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[8] 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.

[9] 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).

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).[10] As demand tightens relative to supply, inelastic and unresponsive demand[11] 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).

[10] 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.

[11] 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.

7. Electricity price determination in theory and practice

The electricity wholesale market has a number of distinctive features that profoundly influence price formation. Electricity cannot be stored,[12] 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. As a consequence, electricity markets are managed by system operators (SOs) who need short-run direct control over at least some plant, creating important differences with other commodity markets, even gas. 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 around the world.

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. 5 illustrates this for England, ignoring entry threats.

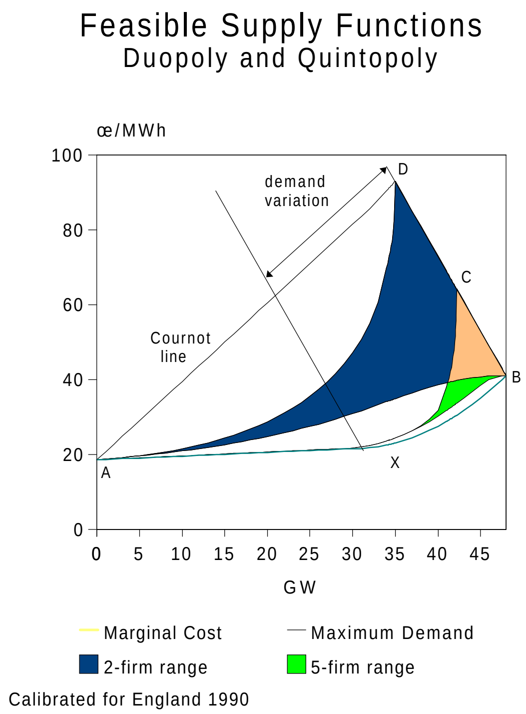

Fig 5 No-entry equilibrium price range

[12] Except as water in dams in hydro systems, 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.

Auction models have been proposed, and are useful for comparing single price and pay-bid trading arrangements, but are even less tractable.[13] 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 startup 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 capacity, but as the margin of available capacity decreases, competition becomes less intense and outcomes closer to Cournot (as in the SFE). Fig. 6, 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[14] 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,[15] 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).

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

[14] 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).

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

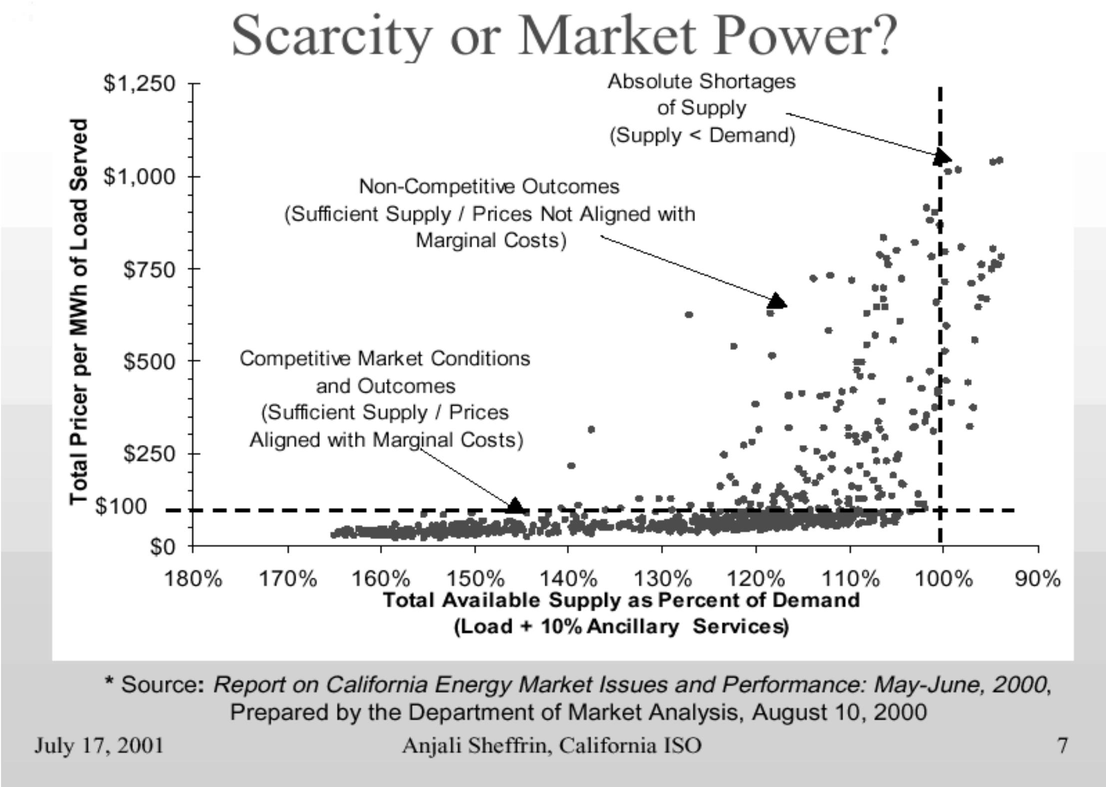

Fig. 6 Price-cost margins under varying market conditions

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,[16] 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.*[17] 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. Analyzing market power therefore has to pay attention not just to

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

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

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.

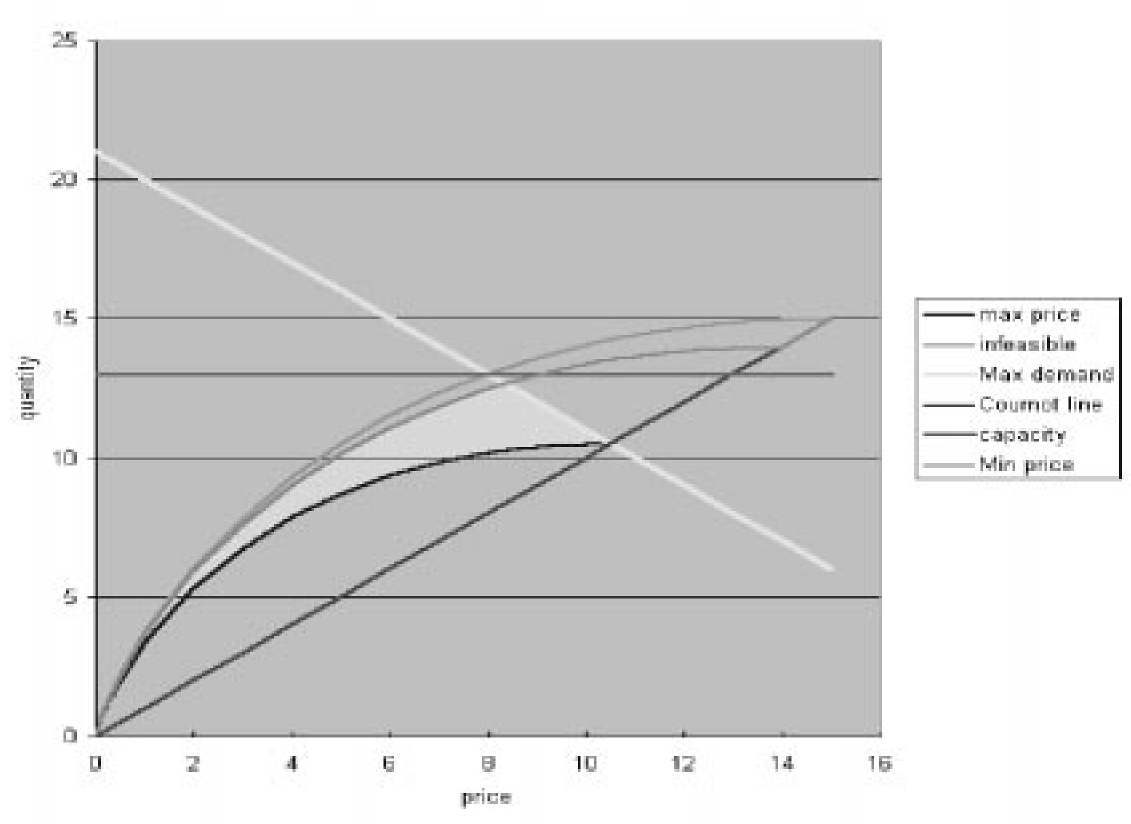

Fig. 7 Feasible prices depend on capacity and demand elasticity

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. 7, 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).

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.[18] 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. 8.

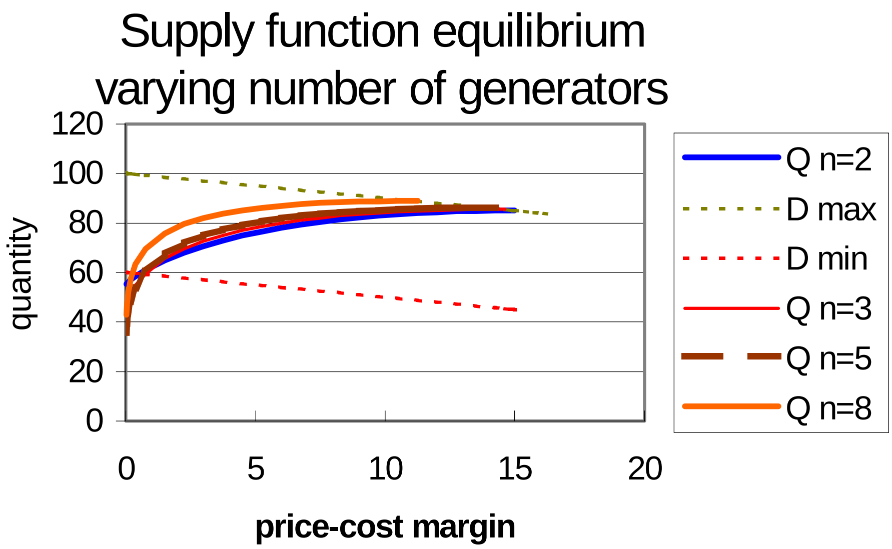

Fig. 8 Average Price set by entry conditions

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 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

[18] 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.

(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 we are now seeing 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.[19] 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 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'.[20]

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.[21] 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

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

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

[21] 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.

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.[22] 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 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

[22] 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).

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 maybe 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.[23] 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

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

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).[24] 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 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.

8. Mitigating market power in regional markets

California provides good examples of the problems of dealing with market power within a jurisdiction that imports extensively from other regulatory jurisdictions. The FERC response in December 2000 to "unjust and unreasonable" prices was to

[24] 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.

impose `soft' price caps (i.e. price caps that could be breached on the evidence of good cause) on the spot and ancillary service markets within California. This did not address the temptations of withholding capacity to drive up prices in the whole Western Security Coordination Council (WSCC), nor that of `megawatt laundering' or transferring trade from a capped market to one with less stringent or no caps (nor various other abuses).[25] FERC's June 2001 Order proposed to extend the price caps to the whole WSCC, and requires all generators to offer all capacity to the real time energy market, as well as various other conditions.[26]

Wolak, as chair of the California Independent System Operator Market Surveillance Committee (MSC), has strongly criticised this approach of price caps on spot markets (Wolak, 2001).[27] New capacity cannot be built within 18-24 months, so high prices have little effect on entry before that date (except as an indicator of the way the market may work in future). Well-designed price caps might therefore reduce current market power without prejudicing investment. The MSC proposal is to require that the three investor-owned utilities that still possess market power sell at cost-based rates (as under the default system of regulation required by the Federal Power Act), and to only allow other generators to sell in California at market-based (as opposed to regulated rates) if they offer 2-year forward contracts at `competitive prices' (determined according to a defined methodology, and about $54/MWh), for 75% of their total capacity. In exchange, they would be free to sell the balance at the market-clearing spot price.

All generators would file an annual maintenance schedule for outages, and except then would be required to bid all capacity into the day-ahead spot market (or would have a competitive cost-based bid entered instead). Any outage would then require the generator to pay the excess of the spot over bid price to compensate buyers, providing a strong incentive to not withhold capacity to drive up prices. Consumers would be entitled to buy 85% of their corresponding

[25] In tight markets, the details of trading arrangements for the various inter-related markets (day-ahead, for reserves, ancillary services and real-time balancing matter, and poor design induced both buyers and sellers to undercontract for predicted load in the price-capped day-ahead market, forcing the ISO to pay distress prices in the real-time market (Wolak and Nordhaus, 2000). In self-dispatch markets like California, trading arrangements should encourage, not discourage, forward contracting and self-balancing to mitigate market power.

[26] 95 FERC •61, 418 (2001). Details can be downloaded from http://www.caiso.com

[27] The FERC June 2001 order has been largely ineffective at mitigating any market power, for the following reasons. First, it fails to address the soft-cap problem that any cost-justified bid needed to serve demand is paid as-bid. Generators with gas affiliates were able to consistently maintain prices for natural gas more than 3 to 4 times the price just outside California. The FERC order only covers transactions made in the ISO's real-time market, which is currently less than 5% of the energy delivered in California in any hour. Most power is purchased state under long-term contracts that reflect the very market power that should have been mitigated.

2000 demand (by hour, day, month or however previously contracted) at the corresponding 2000 price. Suppliers would then presumably be entitled to acquire the favourably priced contracts to cover this obligation, solving the problem of how to prevent these contracts retailing at their substantially higher scarcity price.

This solution has an obvious appeal to economists. It preserves price incentives where they matter, at the margin, while capturing the intramarginal scarcity rents for consumers, as required for political sustainability. It has much in common with the `dual-price' system used to introduce market prices for State enterprises into the Chinese economy (Newbery, 1993).[28] It does not prevent out-of-state market manipulation from infecting the California spot market, though the capacity availability requirement reduces the ability of in-state generators to exercise market power. It may encourage new entrants to locate in neighbouring states rather than California, particularly if other states do not impose comparably strict rules. It caps the upside returns but does not underwrite the downside risks, and so may encourage underinvestment unless the cap is correctly set. The correct strike price for the contracts will depend on whether these are effectively one-sided or two-sided contracts (i.e. whether they only cap the price or carry the obligation to pay the strike price even if it is above the spot price). One-sided contracts, like those proposed, either require a higher cap or an option payment to be equivalent to a competitive price.

This solution has attractions if backed by FERC-like powers, but would require supplementing for an importing country facing exporters with market power. Long-term import contracts might be the solution, but again require counterparties that are most readily supplied by franchised suppliers. Domestic generators could be required to offer all capacity into the domestic market (with the inducement of penalty buy-backs if not available), and to offer forward contracts at price-capped levels (during tight market conditions or when prices were evidently above long-run marginal cost), going some way to insulating the domestic market from the exercise of extra-territorial market power. This is a far cry from the concept of an unregulated competitive wholesale market that lies behind the proposed EU Directive. A compromise would be to retain the power to impose this solution if market prices reflect abuse of market power, while aiming at structural remedies to increase competition and transmission capacity for normal times.

[28] Enterprises were required to sell planned output at fixed prices, and allowed to sell any surplus at the free market price.

9. Conclusions

Unbundling creates risks that require suitable hedging contracts. Supply competition shortens contracts length and may prejudice long-term investment in generation. Regulators are learning that competition is more fragile and prone to manipulation in electricity markets than normal (storable) product markets, but are unsure how to react. The US tradition in which FERC retains the power to suspend market-based pricing when it is "unjust and unreasonable" reflects a very different tradition to that motivating liberalisation elsewhere. The US tradition may either reflect a century of regulatory capture, or the evolutionarily stable outcome of the political process. If market liberalisation is the goal, rather than the means to a regulatory end, then regulators and competition authorities will need the help of I-O economists to address the problems identified in this paper.

A better understanding of the nature of risks will help regulators distinguish between pro-competitive and anti-competitive contracts. The nature of trading arrangements and forms of contracting, particularly with final consumers, will affect the conditions of entry that are critical to passing efficiency gains through to consumers. Future demand will remain unpredictable, as will the weather in hydro systems. Investment decisions will therefore remain risky, but the consequences for price risk depend very much on industrial structure and contract coverage. At present most developed countries enjoy the benefits of cheap gas combined with rapid-build efficient CCGT technology, but if gas prices rise and coal and/or nuclear power becomes economically attractive, planning time-lags will amplify the risks of capacity investment and raise prices.

Vertically integrated franchise monopolies are an attractive and simple way of reducing the price risks associated with capacity miscalculations. Finding suitable contracts to replace this structure is conceptually possible, but we examples that have been demonstrated, at least without a domestic franchise monopoly supply. Regulators have not yet implemented a reliable and robust form of incentive regulation that delivers adequate capacity for transmission and reserves. Liberalised markets require greater spare capacity to work efficiently than tightly managed vertically integrated centrally planned electricity systems. The benefits of competition are real, but not very large. The critical question facing reformers is whether the extra costs - of spare capacity, of creating new market trading arrangements and the risk of power-cuts - will be outweighed by these potential benefits.

In federal or multi-country systems with different regulatory jurisdictions trading with each other, as in the US and on the Continent, there is the additional challenge of decentralising the public-good aspects of security and capacity adequacy. If this can be achieved, the benefits of trade and additional competition are attractive. If they are poorly designed, then some forms of regulation may not be internationally sustainable. A pessimistic scenario would be that cross-border market power contagion will reinforce the attractions of autarkic vertical integration. For the optimistic scenario of unified electricity markets to work, regulators will need to cooperate to evolve consistent solutions to public-good problems. Regulators and competition agencies will need to recognise the special problems of market power in electricity markets and evolve appropriate responses. The US has the legal power to do this, but not necessarily the economic understanding, while the EU lacks both.

Economists in regulatory agencies, market monitoring commissions and universities and played a critical role in developing the techniques to understand this rapidly evolving industry. They have the reward that mistakes can be rapidly exposed and the value of prior analysis and predictions quickly demonstrated. In many countries, data for testing hypotheses are abundantly available, and many of the tools needed to analyze the market have already been developed, particularly in the analysis of risk, auctions, option pricing, and price determination. The challenge is to combine these disparate approaches, all of which may be relevant for understanding market outcomes and the possible effects of particular regulatory interventions. That challenge remains and makes the issue of regulating network utilities of continuing fascination.

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