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Regulating Unbundled Network Utilities

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I 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 hedging. The consequences of the risks and resulting hedging 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. Competition law may need to be adapted to be effective.

The three network utilities where competition appears attractive – telecoms, gas, and electricity – present different challenges. In telecoms, the choice between facilities-based competition and access price regulation is still finely balanced. In gas, particularly on the Continent, finding a satisfactory equilibrium that addresses import security and competition concerns is at an early stage. Electricity provides the best evidence of the consequences of unbundling, and provides the sharpest test of the new conventional wisdom.

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II 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 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 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 held at reasonable levels in response to consumer political pressure, but public ownership substituted for constitutional protection of private property to guarantee investment in durable sunk capital (Newbery, 2000).

The two different forms of ownership and regulation were similar in the structure and stability of the industrial form. Public ownership had much in common with cost-of-service regulation, with the public paymasters paying as little attention to incentives as the US utility commissioners. Economists criticised rate-of-return regulation for its poor incentives and gold-plating. British economists criticised the nationalised industries for low productivity, 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 relied on to cross-subsidise local rates. In 1974 the Department of Justice filed suit against AT&T for monopolising interstate communications. It became clear that regulating an industry with competitive and natural monopoly elements in a federal system with divided regulatory responsibilities was unsustainable. In 1982, AT&T decided to divest the local Bell Operating Companies, leaving AT&T with the competitive long-distance lines, vertically unbundling the US telecoms industry.

The motives for privatising BT in the same year stemmed more from the Conservative Party's belief that "the business of Government is not the government of business" than a desire to liberalise. Regulation was clearly necessary for such a powerful private monopoly and Stephen Littlechild was asked to advise on its form. Taking to heart criticisms of rate-of-return regulation, he proposed the now familiar RPI-X price-cap formula, where X is the predicted rate of productivity increase (real telecoms prices had been falling steadily). Littlechild (1983) saw price-caps as a transitional form of regulation until competition took over the task of holding down retail prices. The 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 Federal Communications Commission (FCC) realised that rate-of-return regulation was too cumbersome to deal with a dominant incumbent firm facing competitive threats from entrants. They too gradually adopted price-cap 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 liberalisation, 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 as vertically integrated regional monopolies in 1989.

Economists pointed out that privatisation was not the same as liberalisation, and that the main benefits from restructuring network utilities would flow from competition, not the change of ownership (Vickers and Yarrow, 1988). When electricity was proposed for privatisation, it was decided that it should be unbundled to allow competition. The results were encouraging – the industry was successfully sold, shareholders did well, consumers felt no pain, and, crucially, the lights stayed on. Regulatory pressure on British Gas, as 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. The domestic electricity franchise ended in 1999.

The old vertically integrated utility model no longer looked like a desirable or even inevitable equilibrium form. Technical progress had unsettled telecoms, changing the set of feasible stable equilibria. Facilities-based competition from cable, internet, wireless and other media became possible. Whether local loop unbundling is superior to facilities-based competition for 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. Large-scale commercial exploitation of natural gas is a relatively recent phenomenon. Between 1970 and 2000,

Western Europe's consumption grew sixfold to 413 Mtoe, and from 13 per cent of US consumption to 70 per cent (BP, 2000). Gas production and transmission is capital-intensive, and normally financed in the private sector on the back of long-term contracts. Once the network is mature 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 outcome. The Continent is heavily and increasingly dependent on gas imports, mostly from politically unstable and distant countries. Britain and the US are almost alone in being self-sufficient 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. A competitive downstream industry may not be the ideal complement to an upstream foreign monopoly such as Gazprom.

III RESTRUCTURING ELECTRICITY

The development of combined cycle gas turbines (CCGT) makes this the natural choice for new generation. They are cheap, of modest scale and quick to build, making generation more contestable, facilitating competition. Even traditional generation stations are small compared to the typical market: economies of scale of coal and nuclear stations fall off rapidly beyond 2 per cent of total UK capacity. Smaller countries like Belgium are typically interconnected with a wider system, leaving only isolated small countries like Ireland facing a serious problem of indivisibility. Competition in generation therefore looks attractive.

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. 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) present social cost-benefit analyses of the three 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 reduced costs, including the state-owned Nuclear Electric. The social benefits amounted to a permanent reduction of costs of 6 per cent compared to the counterfactual – a 100 per cent 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 2001 the dominant duopoly had evolved into a relatively unconcentrated industry. 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 per cent lower than in England, but lack of competition led to prices some 5 per cent higher by 2000. The very modest benefits of privatisation were counter-balanced by restructuring costs, delivering no net benefit. Northern Ireland gives a mixed picture. The long-term PPAs provided powerful incentives for increased plant availability and cost reductions, outperforming the CEGB by a factor of three, but the companies retained the benefits. Aggressive price reductions on the non-generating elements, combined with Government subsidies, somewhat reduced the embarrassing price gap with Britain.

The lessons are clear. Increased competition is needed to reduce costs and that requires separating generation from transmission and distribution. To pass these on to consumers requires a sufficient number of competitors and an open access wholesale market. Unrestructured industries, even if privatised, appear to deliver few benefits. The evidence suggests that regulators have to work hard to transfer efficiency gains in transmission and distribution into lower consumer prices (Domah and Pollitt, 2000). They need to take positive steps to counteract market power in the potentially competitive sectors, including capacity divestment, if consumers are to gain.

The lesson that unbundling is necessary has been taken to heart by the European Union. Vertical separation, preferably of ownership, is recognised as the preferred model, although the EU requires only legal separation in the proposed new Energy Directive. There is less agreement on the design of electricity markets (and the Directive is not prescriptive on this). The single-price English Pool model has found favour abroad, but was replaced by the New Electricity Trading Arrangements (NETA) in 2001 to reduce claimed tacit collusion keeping prices too high.

IV THREATS TO THE NEW CONSENSUS

The argument of this paper is that there is unfinished business in managing the combination of competition and regulation that follows from

liberalising network utilities. The challenge is to evolve stable and politically sustainable regulation that combines the efficiency benefits of competition with the proper management of risk and adequate investment. The central question is whether the unbundled structure is sustainable or whether the old equilibrium of vertically integrated franchise monopolies is the only stable equilibrium.

A few years ago, such questions would have been considered heretical. Structural unbundling had been demonstrated successful in Britain and elsewhere. Impressed by the achievements of that model, the European Commission introduced liberalising Directives for electricity and gas. (Bergman, *et al.*, 1999). These enforced functional unbundling, opened networks to Third Parties to allow competition between producers, and opened one-third of final demand to competitive supply.

With unfortunate timing, recent events in California have shaken political confidence in liberalisation. California led the United States in unbundling electricity, expecting prices to 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 capped. The European Commission issued a press release arguing for more rapid opening of European energy markets. "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." (At <http://europa.eu.int/comm/energy/en/internal-market/int-market.html>).

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 which killed four people – one-third of the number of daily road deaths – but which disrupted the entire railway network for the next six 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 railways, and the Prime Minister's office launched an energy review.

V 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, therefore, grants the Office of Fair Trading joint powers with regulators to deal with utility competition issues. Setting price caps to transfer past efficiency gains is reasonably straightforward, though it is harder 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. NETA was introduced to reduce the perceived abuse of market power. The ill-fated Market Abuse Licence Condition introduced by Ofgem, contested by British Energy and AES, then referred to the Competition Commission and rejected, was an attempt to restrain 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 only be 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.”¹ 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.”² Legally, competitive pricing is considered “just and reasonable”. The reason that FERC is so concerned 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; Bogorad and Penn, 2001).

¹ *Heartland Energy Services, Inc*, 68 FERC 61,223, at 62,060 (1994), cited by Bogorad and Penn (2001).

² *Heartland* 68 FERC at 62,066.

This suggests a further contrast on the two sides of the Atlantic, reflecting their different histories. Deregulation in the United States was a cautious relaxation of regulatory control over prices, concerned with the potential problems of market power. Electricity restructuring in Europe has concentrated on creating markets, expecting them to be competitive. The dictum of confining regulation to natural monopolies has often resulted in too little attention to undesirable concentration in generation. Many EU countries lack the necessary powers to ensure that generation becomes adequately competitive. The Commission's confidence that Europe's reforms will avoid Californian problems 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, to which this paper now turns.

VI THE CALIFORNIAN EXAMPLE

California liberalised its electricity because of dissatisfaction with 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,³ and the major public utility, PG&E, filing for Chapter 11 bankruptcy protection. 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. California has certainly alarmed European politicians and caused energy specialists to reconsider the merits of deregulation. To cite 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."

What were the various contributory factors to this unhappy outcome? First, California (and the neighbouring states) had under-invested 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

³ When reserve margins fall below 1.5 per cent so that disconnection is essential to protect system integrity.

abundant and cheap surplus hydroelectric power from the Columbia River. Second, after unbundling, distribution companies were strongly dissuaded from signing long-term contracts for electricity or hedging. This regulatory restraint was a response to earlier excessively-priced PPAs from the QFs. The Public Utility 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).⁴

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, but 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, that were indexed to gas prices.⁵ The price of tradable NO_x permits also rose to \$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 which power is traded. Thus the average price for the *whole year* at the Mid-Columbia hub north of California was \$137/MWh compared with \$27/MWh in 1999, higher than the California PX average of \$91/MWh. California's largest distribution companies were unable to pass on the high wholesale prices, precipitating bankruptcy.

High plant utilisation in the summer and autumn induced by high spot prices necessitated greater scheduled maintenance downtime in the normally quieter winter period. A dry winter in the Columbia Basin lowered hydro output and cold weather increased demand, which together caused a severe energy shortage, higher prices, defaults, and bankruptcy. Inept price caps caused generators to export, 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 the situation 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 are the lessons from the Californian experience? First, tight

⁴ 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.

⁵ By December 2000 gas prices had risen to \$15/MMBtu compared to a historic average of \$2/MMBtu, trebling electricity prices. Spot gas have reached \$61/MMBTU, equivalent to fuel cost of \$610/MWh (Bogorad and Penn, 2001).

electricity markets (reserves below 10 per cent) lead to volatile markets and high prices even when fairly competitive (four generating companies setting prices at the margin). As demand tightens relative to supply, inelastic and unresponsive demand⁶ means that large price rises have little effect on demand, but each supplier has increasing and eventually substantial market power. The large increase in price caused by any single company reducing supply more than compensates for the foregone profits, making such withdrawals 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. An unbundled industry therefore needs hedging contracts to insure against shocks to spot prices, particularly when suppliers sell at fixed prices. The British privatisation was accompanied by three-year contracts for both the 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 be under-supplied unless 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, injudicious local regulatory interventions in an interconnected system can have perverse effects, and damage inter-regional electricity trade (Wolak and Nordhaus, 2000; 2001).

VII ELECTRICITY PRICE DETERMINATION IN THEORY AND PRACTICE

Electricity has distinctive features that profoundly influence price formation. Electricity cannot be easily stored, 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 (where the peak price may be 100 times as high as the

⁶ 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.

trough). Electricity is therefore managed by system operators (SOs) with direct control over at least some plant, creating important differences with other commodity markets, even gas.

Modelling price formation to understand market power is both challenging and important for informed regulation. 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 like the English Pool. The model is challenging to solve and typically gives a range of possible equilibrium prices.

Auction models have been proposed, and are useful for comparing single price and pay-bid trading arrangements, but are even less tractable.⁷ 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. More sophisticated price-formation models capture strategic aspects and the non-convexities of start-up costs, which can dramatically influence short-run marginal cost. Despite this apparent diversity, 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). 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 demand⁸ means that in tight markets even apparently unconcentrated generation ($HHI < 1800$), can sustain extremely high price-cost margins. The wide range of equilibrium price strategies may make the threat of regulatory intervention effective, while

⁷ See von der Fehr and Harbord (1993), or Green and McDaniel (1999).

⁸The 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 per cent of California's consumers cut demand by more than 20 per cent to qualify for a 20 per cent price rebate, while temperature-corrected demand fell 12.4 per cent from June 2000 to June 2001, with peak demand down 14.1 per cent. (*Financial Times*, Aug 21, 2001).

repeated daily interaction encourages tacit collusion (and was the main argument for replacing the Pool).

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 0.2,⁹ 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 – halving the elasticity of demand (at some reference price, quantity pair) would double the peak price-cost margin reached, *cet. par.*¹⁰ 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. Market power depends on concentration and demand conditions (both of which may be significantly affected by inter-regional trade), but also on entry and contracting conditions, which tend to be overlooked.

If incumbents can ignore entry and regulatory threats, then their logical strategy is to merge to increase market power, and close plant to credibly tighten the margin of spare capacity. Incumbents owning transmission can deter entry by capturing all capacity rents to generation and transmission in access charges to the grid, as in Germany (Brunekreeft, 2002).

If entry is relatively low risk, and there is adequate capacity within the industry, then incumbents benefit from bidding to keep average prices below the entry-inducing price.¹¹ Newbery (1998) showed that the annual average price would then be relatively insensitive to the number of competitive incumbents, but price volatility would be lower the more competitive the industry, provided the entry price remained unchanged with increasing competition. The entry price may, however, 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. 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 aluminium market is characterised

⁹ At the competitive price, higher at the monopoly price given assumed linear demand schedules.

¹⁰ Holding constant contract coverage and the number of firms.

¹¹ 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.

by lengthy periods where prices are low, 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, competitive and contestable electricity markets may produce 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 may be resolved in various ways. Incumbents will try to impede entry. Horizontal consolidation facilitates multi-market contact that may mute competition (Parker and Röller, 1997). 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 creating 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” prices.¹²

An alternative is for regulatory intervention to support competitive markets while reducing some of 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 per cent of households defined as fuel poor – that it is spending more than 10 per cent 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. 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. As 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

¹² Quasi-regulation is pricing at levels that just deters the regulator from intervening.

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.¹³ 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 is 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 to meet his service obligations. Eligible customers would be free to hold firm long-term contracts, or accept interruptible priority tariffs.

Neither of these options is particularly attractive to those who believe that liberalised markets can evolve fully decentralised solutions. It even suggests that the old vertically integrated structure may after all be a preferable model. Consider its advantages: in well managed, mature industrial economies cost inefficiencies appear modest – of the order of 5 per cent or so (Newbery and Pollitt, 1997). Regulated cost-based prices combined with vertical integration eliminate the price risks on intermediate wholesale markets, and are the regulatory quid pro quo to the requirement that the utility plans capacity 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, ideally by Ramsey pricing. Thus large industrial consumers face efficient prices (short-run marginal cost), and any revenue short-fall can be recovered by higher prices for commercial and domestic customers. This describes the 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 normally owns the grid, allowing him to charge cost-recovering prices. Competition is for the right to build plant, while the long-term power purchase agreements

¹³ 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).

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 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, allowing eligible buyers to bypass the Single Buyer. It has therefore fallen out of favour and the Commission proposes to remove it as an option (CEC, 2001).

The critical question is whether it is possible to evolve a sustainable unbundled equilibrium that 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.¹⁴ Capacity 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 finance additional interconnection to improve competition.

Within a single country, these spill-overs can be internalised, although only with careful regulatory design. Price-caps for transmission risk under-investment unless security and market broadening are recognised as valuable by the regulator and the transmission company is 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

¹⁴ Excess is measured relative to an efficient centrally planned system.

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 given the public good benefits 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).¹⁵ This is easy with the Single Buyer model, but more difficult if all consumers are free to switch suppliers and strand contracts. This can be solved – savings markets offer customers the choice between liquid less attractive contracts, and more attractive contracts with exit penalties (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 (Wolak, 2001). The EU lacks that power, and many EU countries lack even the requirement that generators hold licences whose conditions can be modified to address market power issues.

VIII CONCLUSIONS

Unbundling creates risks that require suitable hedging contracts. Supply competition shortens contract 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 economists to address these problems.

¹⁵ 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 .

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 lack demonstrated examples, at least without a domestic franchise. Regulators have yet to find 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 electricity systems. The benefits of competition are real, but not very large. The critical question is whether the extra costs – of spare capacity, of creating new market trading arrangements and the risk of power-cuts – will outweigh these benefits.

In federal or multi-country trading systems with different regulatory jurisdictions, such as the US and 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 well, regulators will need to co-operate to solve public-good problems and deal with market power. The US has the legal power to do this, but not necessarily the economic understanding, while the EU lacks both.

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