

DAE Working Paper WP 0230



UNIVERSITY OF
CAMBRIDGE
Department of
Applied Economics

Regulatory Challenges to European Electricity Liberalisation

David M. Newbery



The
Cambridge-MIT
Institute

*Massachusetts Institute of Technology
Center for Energy and
Environmental Policy Research*

CMI Working Paper 12

DAE Working Paper Series



UNIVERSITY OF
CAMBRIDGE
Department of
Applied Economics

**not to be quoted without
permission**



The
Cambridge-MIT
Institute

*Massachusetts Institute of Technology
Center for Energy and
Environmental Policy Research*

CMI Working Paper Series

Regulatory Challenges to European Electricity Liberalisation

David M Newbery*
Department of Applied Economics
University of Cambridge
England
David.Newbery@econ.cam.ac.uk

Revised 27 September 2002

JEL classification: K23, L51, L94

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

Abstract

The European Commission proposed to reform the Electricity and Gas Directives to improve access to transmission, increase cross-border capacity, and fully open the electricity and gas markets. The California electricity crisis has weakened support for liberalisation, removed the commitment to full market opening, and raised concerns over supply security. Providing adequate reserve capacity is risky in a competitive wholesale electricity market without suitable contracts, and unattractive to oligopolists unless they face a credible entry threat from IPPs. Ending the domestic franchise could remove the counterparty for the contracts required for adequate investment to sustain competitive pricing. Gas liberalisation is key to making electricity markets contestable and reducing pressures on scarce electricity interconnection capacity. Environmental concerns increase uncertainty and further deter entry, while raising other policy issues that need to be addressed. Compared to the US, much of the EU lacks the necessary legislative and regulatory power to mitigate generator market power. Unless markets are made more contestable, transmission capacity expanded and adequate generation capacity ensured, liberalisation may lead to higher prices.

* Paper prepared for and presented at the conference *Regulatory Reform – Remaining Challenges for Policy Makers* arranged by the Economic Council of Sweden in Stockholm on June 10, 2002. I am indebted to Lennart Hjalmarsson and Michael Pollitt for his comments. Support from the ESRC under the project R000 238563 *Efficient and sustainable regulation and competition in network industries* and from the Cambridge-MIT Institute under the project 045/P *Promoting Innovation and Productivity in Electricity Markets* is gratefully acknowledged.

The EU Electricity and Gas Directives 96/92/EC and 98/30/EC were adopted in 1996 and 1998, giving member countries until February 1999 and August 2000 (with some extensions for specific countries) to incorporate their provisions into domestic legislation. At one level, the directives were the logical extension to public utilities, of the principles of the single market – “the free movement of goods, persons, services and capital.”¹ At a deeper and perhaps more significant level, they reflect the view that energy policy can be managed by the Commission at the European level, largely by using market instruments. Many of the challenges to European electricity liberalisation arise from the tensions between national sovereignty over a such a critical industry as energy, and federalist aspirations, combined with a technocratic desire to de-politicise apparently straightforward economic issues.

The attempted de-politicisation of energy is an admirable goal for an economist but, perhaps, surprising to a political scientist. It has been made possible by a benign set of circumstances that the recent Californian electricity crisis may disturb. Electricity and gas under privatisation and unbundling proved successful in Britain, leading to lower prices, substantial public sector receipts, and vigorous investment. Electricity privatisation largely completed the Conservative policy of restraining state and unionised labour power, and the shift to a market-friendly energy policy. Early liberalisation in Scandinavia was also successful. For a variety of reasons connected to the end of state socialism in the COMECON block, the financial drain on governments in developing countries, and substantial excess capacity in electricity in developed market economies (Newbery, 2000), the lessons of British energy liberalisation were eagerly adopted and widely disseminated (Pollitt, 1997).

The United States saw electricity unbundling as the route to lower prices in high-priced states as competition combined with the falling costs of recent technologies (such as combined cycle gas turbines, CCGT) offered an escape from backward-looking rate-of-return regulation to forward-looking competitive pricing (Joskow, 1997). In Europe, the attractions of de-linking coal subsidies from electricity prices and allowing large consumers in high-priced countries access to low-price suppliers abroad, were considerable. The end of the Cold War combined with the collapse of energy demand in the former Soviet Union reduced concerns about over-dependence on imported Russian gas. The increasing asymmetry of dependence of energy-exporting countries on energy-importing countries, combined with the success of the North Sea gas developments, further reduced energy security concerns. The Electricity and Gas Directives could be sold as removing market impediments to efficient trade and improving the competitiveness of Europe in an increasingly globalised world.

Individual member countries had a relatively brief period in which to respond to these directives before they came into force. Within two years, governments had to rethink their energy policies, reconsider how best to defend their national interests, and attempt to ensure that the directives allowed governments to deal with possible shocks that had previously been handled by domestic energy policy. Not surprisingly, France and Germany had considerable reservations that they expressed at the time and continue to express in the current discussions over the proposed revisions to these directives.

¹ Article 7A of the EC Treaty

1. The role of energy policy in energy markets

Security of supply is critical for economic activity and political independence. If markets work well, supplies are adequate and prices acceptable, as at present in Europe, the risks of energy dependence appear negligible. That does not mean that energy policy concerns have disappeared, only that they are not currently so salient. Nor are all energy markets equally affected by supply risks. Energy policy towards oil was heavily influenced by the Arab threat to use oil as a political bargaining tool in Mid-east politics in 1973. The IEA responded by requiring member countries to carry 90 days stocks and to agree sharing arrangements in the event of selective embargoes. Given the flexibility of the supply chain, the difficulty of enforcing the OPEC cartel, the rise of non-OPEC production, and the wish of Saudi Arabia to act as both a political and economic moderating influence, oil importing countries have been reasonably content to leave oil decisions to the market. Coal is primarily a domestic issue, as international coal markets are competitive, and coal stocks at power stations are the simplest insurance against supply disruptions. Supply disruptions are more likely to happen as a result of domestic labour unrest than international events (Parker and Board, 1994).

Electricity is different; it cannot readily be stored, so that supply and demand must be continually balanced. In an interconnected system, local failures to match demand and supply can lead to extensive load shedding over wide areas unless there are adequate security systems to limit the extent of these imbalances (see e.g. Stoft, 2002). The old model was one in which the electricity supply industry (ESI) was vertically integrated (at least between generation and transmission) and under single control. The system operator (SO) not only controlled dispatch, but also investment in generation and transmission. The SO was responsible for ensuring an adequate reserve margin, either within his area of control, or by long-term agreements with suppliers in neighbouring jurisdictions. In the US, reserve margins were monitored by Reliability Councils.

Energy policy towards the ESI typically consisted in ensuring that investment would preserve reliability (via the reserve margin) while meeting various goals on fuel use (either to reduce oil import dependence, as with the British and French nuclear investment programme, or to defend local coal-mining interests). Under the Electricity Directives there is no longer any automatic way in which this reserve adequacy can be ensured at the individual country level, and a new approach will be required. From an energy policy perspective it is somewhat surprising that member countries appear to have largely accepted this rather dramatic shift in responsibility for system security.

Gas shares some of the characteristics of electricity, but gas energy policy at present remains far more under individual country control. There is far greater physical control over cross-border flows in gas than electricity, where electrons flow according to the laws of physics, not of countries. Gas storage is needed to buffer daily and seasonal fluctuations in supply and demand, and provides short-term supply security. Import-dependent countries typically considerably increase the amount of storage to cope with longer-term supply disruptions. Gas imports are normally secured by long-term contracts. Government desire to retain policy control over gas is also stronger and more explicit than for electricity, and progress in liberalising gas has consequently been considerably slower.

The *economic* lessons of liberalisation from the experiments in Britain and Norway, combined with the experiences of regulating investor-owned utilities in the United States, are reasonably clear (see e.g. Bergman et. al. 1999). Effective competition in generation under

private ownership reduces costs and passes those cost reductions through to consumers in price reductions. Effective competition in generation requires regulated third party access to separately owned networks. This in turn requires *ex ante* regulation by specialised utility regulators, as competition law alone is inadequate given the special properties of electricity. For cost reductions to be passed through as price reductions there must be sufficiently many competing generating companies and a well-designed market for the various ancillary and balancing services, as well as adequate capacity. The number of actively competing generators may be increased by improving transmission links, as in the Nordic market. Otherwise, enforcing or encouraging divestiture of plant by the incumbent may be necessary. Contract coverage reduces market power and needs to be encouraged by the regulatory environment while entry barriers should be kept low.

1.1 Energy policy and security of supply

The policy question is whether the economic benefits of liberalisation can be realised without compromising the goals that previously motivated energy policy and, particularly security of supply. Energy security appeared to be reasonably assured in the early liberalising countries and so was less of an issue than might be the case in other, less well-placed countries. A failure to address these policy concerns may explain some of the tensions in the present energy debate.

Britain is an interesting case study of the tensions between traditional energy policy and the desire for a liberalised electricity market. It had the considerable advantage that at, and since, liberalising the electricity industry in 1990, it has appeared well placed in terms of security of supply. It is an energy-exporting island with an import capacity for electricity less than 4 percent of peak demand. Its reserve margin was 35 percent in 2001 and had risen rapidly in response to the low price of gas compared to the relatively high initial price in the oligopolistic electricity wholesale market.² Under Conservative Governments, there was thought to be no conflict between liberalisation and energy policy which should take market-friendly forms (e.g. tenders for renewable energy, the Fossil Fuel Levy to finance nuclear decommissioning costs).

The Labour Party came to power in 1997 with greater scepticism that the market could deliver a satisfactory energy policy. It imposed a moratorium on building gas-fired generation to protect coal. Instead of protecting British coal mining jobs, it encouraged coal imports and threatened to increase CO₂ emissions. It then devised a cumbersome and inefficient Climate Change Levy that applies at a uniform rate per kWh to all electricity except that from renewables (and ‘high quality CHP’), rather than logically on the carbon content of fuel. The collapse of the share price of the privatised nuclear power company, British Energy, in autumn 2002 demonstrated that the inconsistencies and weaknesses of such interventions can be more rapidly exposed by market reactions.³

² Low energy prices in 2002 caused considerable plant withdrawal so that by 2002 the margin had fallen to 25 percent (*Financial Times*, May 20, 2002). Much of this plant has been moth-balled and remains available if demand and/or prices increase.

³ The British Government is committed to reduce CO₂ emissions, but reluctant to ‘reward’ existing nuclear plant, concentrating its support to more politically acceptable forms of renewable electricity. Unless British Energy has freedom to renegotiate or suspend its inherited nuclear reprocessing contracts (with the State-owned reprocessing firm, BNFL) and to be exempt from the Climate Change Levy, it is unlikely to be commercially viable with current and forecast wholesale electricity prices.

These policy initiatives are greatly aided by Britain's essential isolation and energy self-sufficiency. Recent concerns about energy security (the increasing dependence on gas, which will shortly need to be imported, and concerns about regulatory incentives for long-term investment), together with the challenge presented by the Kyoto targets, caused the Performance and Innovation Unit (PIU) of the Cabinet Office to launch the Energy Review in early 2002. The resulting *Energy Review* noted that "recent trends in energy markets have been benign for policy but the future context will be much more challenging" (PIU, 2002, p6). The subsequent collapse of British Energy (see footnote above) revealed how rapidly market circumstances can change.

Norway, as an energy surplus, low-cost electricity producer, is similarly insulated against the major policy concerns of import dependence and supply security. Norway's liberalisation was not associated with dramatic changes in ownership, and reflected an evolution towards increased use of markets for co-ordinating decisions. As in Britain, liberalisation was a domestic political decision.

The United States is similarly self-sufficient in electricity, as well as gas and coal, the mainstays of the electricity supply industry. It also has federal jurisdiction over the industry through the Federal Energy Regulatory Commission, FERC, that has extensive powers under the 1935 Federal Power Act. Individual States have devolved regulatory powers, but FERC has a statutory obligation to ensure that wholesale prices are "just and reasonable". This gives FERC considerable powers to intervene if liberalisation fails to deliver satisfactory outcomes. That legal reassurance, combined with extensive experience and legal case history in managing privately owned utilities, underwritten by administrative law, respect for private property and legal and constitutional restraints, suggested that liberalisation posed no new threats, at least at the federal level. The Californian electricity crisis is illuminating precisely because it took place within an apparently favourable institutional and policy framework.

The other contrast with most EU countries is that Britain's liberalisation was carefully designed. It was built on a system of licensing and regulation that had been tested in the six years following the privatisation of British Telecom. Transmission and distribution were to be regulated by a sector-specific regulator, Offer, under price-cap regulation subject to periodic reviews and a dispute resolution process (referral to the Competition Commission). Although generation and supply (retailing) were considered potentially competitive segments, they were both subject to licence conditions that could be (and were) modified by agreement or referral to the Competition Commission.

Similarly, liberalisation in the United States took place within a well defined regulatory and constitutional framework that reserves substantial powers to FERC. If an electric utility wishes to sell at market-determined wholesale prices, this will be allowed providing "the seller (and each of its affiliates) does not have, or has adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry."⁴ Even then, the authority to sell at market-determined prices can be withdrawn and replaced by

Returning nuclear power to public ownership (where climate taxes and existing reprocessing contracts can be ignored or internalised) would suggest that current British environmental policy is incompatible with a privatised and liberalised electricity market.

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

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.”⁵

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

In contrast, mainland Europe was given relatively little time to develop the necessary regulatory institutions and legislation to meet the externally imposed requirements of the Electricity and Gas Directives. Member countries differ considerably in their energy dependence, market structures and energy policy concerns. It seems improbable that all member countries can painlessly accommodate their institutions and concerns to the ideals of a politically independent regulatory system charged with ensuring that energy markets work competitively like other commodity markets. Spare capacity helps to mute these concerns, but evidence from California that liberalisation may face problems has re-awakened underlying anxieties.

2. Developments since the Electricity and Gas Directives

The Electricity Directive reflected earlier debates about the extent of restructuring that would be required. As a result, it offered a variety of options for new generation (authorisation, or tendering),⁶ for restructuring (transmission was only required to be functionally unbundled from generation, not divested), and for access (both regulated and negotiated Third Party Access as well as the Single Buyer Model). Early commentators (Bergman et. al., 1999) drew attention to a number of unsatisfactory aspects of the reforms. Very similar conclusions were subsequently reached by the European Council which called on the Commission to accelerate the work to complete the internal market in electricity and gas at Lisbon in March 2000. Briefly, negotiated third party access and the Single Buyer Model were no longer considered satisfactory for delivering competitive generation markets, and as a result tendering (which is the natural mechanism for introducing competition with the Single Buyer Model) no longer made sense. More effective separation of transmission from generation was also necessary to prevent biases against entrants.

The Commission duly presented its proposals for amending the two Directives at the European Council in Stockholm in March 2001.⁷ The main changes proposed were to require *regulated* Third Party Access (TPA) for both gas and electricity (denying the former option of

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

⁶ Authorisation means that any company meeting the specified conditions and securing planning permission is allowed to build and connect new capacity. Tendering would be in response to an invitation by an authority to provide possibly quite specific plant (e.g. peaking plant at a particular location).

⁷ COM(2001) 125 final, 13 March 2001; available together with the Press Release and Working Paper at <http://europa.eu.int/comm/energy/en/internal-market/int-market.html>

negotiated TPA), to strengthen the requirements for unbundling to legal (but not necessarily ownership) separation of generation and transmission, to remove the option of the Single Buyer Model, and to allow all gas and electricity customers freedom to choose their supplier by 1 January 2005, thus ending the domestic customer franchise monopoly. In addition the Directive would require all countries to establish independent regulators to approve transport tariffs *ex ante*, and to monitor and report to the Commission on the state of electricity and gas markets, particularly the supply/demand balance.

France and Germany opposed the proposals. France argued that it was too soon to deem energy liberalisation a success. Germany opposed the requirement for an independent regulator and *ex ante* regulation. By the time of the European Council of Stockholm, the electricity market in California was in a state of meltdown, with companies responsible for distribution and retailing filing for protection under Chapter 11, and winter prices averaging ten times their normal level. Although the arguments for reforming the Directives had taken place before the Californian crisis, the issue could clearly not be avoided at the meeting. The associated Commission documents on the web site go to some lengths to argue that the proposed measures for the European energy market “will avoid the type of problems currently faced by California, which have resulted from an inadequate legal framework and inadequate production capacity” (EC Press Release).

3. The lessons from California

California originally reformed and liberalised its electricity market because of dissatisfaction over high consumer prices (Blumstein, Friedman and Green, 2002). However, average wholesale prices in 2000 were more than three times those of 1999, while December 2000 prices were 10 times as high as normal, even though California is a summer-peaking system. 2001 started with rolling blackouts, stage 3 alerts,⁸ 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. Market power and withholding of capacity can amplify distortions in tight markets (Joskow, 2001; Joskow and Kahn, 2002).⁹ It also shows the danger of relying on significant imports to meet peak demand without ensuring supply adequacy elsewhere in the interconnected system.

The reasons for this supply inadequacy were long-standing but concealed by the apparent abundance of cheap surplus hydroelectric power that could be imported from the Columbia River. Under-investment in generation in California derives partly from disputes over nuclear power plant costs and safety, partly from environmental objections, and partly because misconceived long-term Power Purchase Agreements (PPAs) were considerably more expensive than imported power.

The reason that supply inadequacy lead to bankruptcy and major disruption were peculiar to the legacy of these high-priced PPAs. As a result, the California Public Utilities Commission (CPUC) was reluctant to allow the recently unbundled distribution companies to sign long-term contracts for electricity or hedging for fear that they would replicate the earlier

⁸ when reserve margins fall below 1.5% so that disconnection is essential to protect system integrity

⁹ The California Public Utilities Commission in a report published in September, 2002, argued that the power outages could have been avoided in 2000-01 if five energy companies had not withheld electricity they were capable of producing (John Broder, *New York Times*, Sep 18, 2002).

stranded QF contracts. That in itself might not have caused bankruptcy, but the CPUC also capped the final retail price (until sufficient revenue had been collected to pay off the assets stranded by the unbundling of high cost generation).¹⁰

Finally, NO_x emissions were capped by region (and in some cases by plant) on an annual basis. In the (not particularly) hot summer of 2000, gas demand for generation greatly increased, and pipeline capacity and storage were frequently inadequate to meet the demand. Californian gas spot prices more than doubled (coming on top of high prices caused by the doubling of crude oil prices), as did the contract prices from many QFs, which were indexed to gas prices.¹¹ The price of tradable NO_x permits also rose to unprecedented levels as the annual quota became inadequate, with permits trading at \$80,000/ton at their peak, compared with \$400/ton on the East Coast (Laurie, 2001). Electricity prices rose, not just in California, but in the whole western interconnection in which 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 Power Exchange). 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 and led to panic long-term contracting at high prices. 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).¹²

Joskow and Kahn (2002) have carefully documented the causes of the summer price rises in 2000 (which averaged five times those of 1998-9) and demonstrated that market power exercised in tight markets was responsible, although high gas and NO_x prices would have caused half the increase even in a competitive market. This was before the more serious problems of bankruptcy, inept intervention and outages started in December 2000, and hence a better test of the potential for exercising market power in tight but otherwise normal market conditions.

¹⁰ 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.

¹¹ 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 a fuel cost in a reasonably efficient generator of \$610/MWh (Bogorad and Penn, 2001).

¹² Evidence about manipulative trading tactics by Enron has subsequently emerged (*New York Times*, May 9, 2002).

Clearly, the Californian electricity crisis has awakened fears that liberalised electricity markets may be politically unsustainable, at least without careful design and regulation. The very high prices observed in California (and in the North- and Mid-West of the United States) have demonstrated very clearly that uncontracted generators can exercise considerable market power when supply is tight. Defenders of the former electricity industry structure have argued that vertically integrated franchise monopolies with regulated final prices are the only way to secure adequate capacity to avoid shortages and/or high prices (see, e.g. the pseudonymous Price C Watts, 2001).

4. Challenges to reforming the Energy Directives

Since March 2001, the proposals for reforming the Energy Directives as well as improving cross-border access have been examined by the Economic and Social Committee (OJ, 2002); the European Parliament (OJ, 2001), and others. These discussions have highlighted some of the remaining concerns, and identified possible remedies, as well as the need for continued vigilance to ensure that markets operate competitively. This paper aims to take that debate further, and to draw attention to challenges that may have been underestimated.

The Economic and Social Committee (ESC) has expressed its concern about the supply risks that led to such difficulties in California (OJ, 2002, 6.2.1) and argue that this requires that independent regulatory authorities are given responsibility for monitoring the supply/demand balance, and grid operators are required to maintain and develop the network. If there are indications of inadequate generation capacity, then tenders for additional generation capacity should be possible to supplement the normal process of authorising capacity. The ESC also argues that the cost of providing this security should be met by the whole system ‘either at national level or through a Community-wide system.’ (6.2.3).¹³ These supply risks could be alleviated if cross-border interconnector capacity were increased, as at present only 8 percent of total EU generation is traded across borders, ‘much lower than could be expected of an integrated European market’ (2.6).

The Commission is therefore proposing (at 4.1) a Regulation with “measures:

- establishing compensation mechanisms for flows of electricity;
- defining harmonised principles for cross-border transmission tariffs; and
- allocating available interconnection capacity between national transmission networks”

The ESC expressed its reservations about according the Commission such wide-ranging powers (at 6.11.3) and called on the Commission to “take account of the principle of subsidiarity.” The Commission would have to verify that the problems could not be resolved at the national level, and that its proposals would yield clear net benefits over actions that could be taken at the national level (6.11.5). This raises the question of whether adequate interconnection can be agreed by national regulatory authorities (NRAs) by, for example, discussions at the Florence Forum and/or the Council of European Regulators.

Interconnection is one logical solution to the problems of market power that amplified the Californian crisis and clearly concerns the Commission and the ESC. Apart from the obvious fact that most EU countries have a small number of dominant generators (in some

¹³ References to paragraph numbers hereafter are to (OJ, 2002).

countries still under common ownership with transmission companies), “the search for new markets and economies of scale in companies may lead to a process of concentration ... The European electricity and gas market may therefore end up being controlled by a limited number of large companies which, in practice, operate in their various areas of influence, distorting competition and abusing their individual or collective market power” (6.10.2).

The fact that such concentration has been allowed to progress can be interpreted as a sign of the difficulties of reconciling old energy policy concerns with the experience of market liberalisation. Britain was restructured and privatised with an over-concentrated market structure in generation and gas (Newbery, 1995, 2000). Two generators dominated price-setting in the English Pool (the wholesale market) until the regulator facilitated divestment of 6 GW of price-setting plant in 1996. Further political and regulatory deals encouraged additional sales until by the end of 2001 the market was moderately unconcentrated and, more important, oversupplied. Prices subsequently collapsed to Continental levels. A continuing duopoly in Scotland with control over limited interconnect capacity allowed prices there to increase substantially relative to England (Pollitt, 1999; Newbery, 2002a). By the time the Electricity Directive was enacted, there can have been little excuse for not actively reducing concentration in generation before liberalising the market.

The Netherlands provides a good example of the tensions facing member countries. There were strong and almost successful pleas to merge the four main generation companies into a single ‘national champion’, to offset the scale disadvantage compared with other electricity giants. The argument that large national companies would be more susceptible to domestic political influence and energy policy imperatives was compelling. The fear that smaller domestic companies would be acquired by larger foreign owners credible. The fact that the largest foreign companies with the deepest pockets and the lowest cost of capital were state-owned amplified these concerns.

Finally, the traditional tests of market power, at least in EU case history, do not readily translate to the electricity market. Electricity is non-storable, and the residual demand elasticity facing any individual generator can vary over a few hours from almost infinite (with adequate spare capacity of constant cost plant and few transmission constraints) to almost zero (when the market is fragmented by transmission constraints and capacity is locally tight). Defining the market is therefore problematic but critical for measuring the amount and effect of concentration. The size of the market may vary hourly depending on transmission constraints. A capacity market share of 40 percent within a country may not allow much market power, if that country is well-interconnected with enough independent suppliers. A domestic capacity market share of 20 percent may confer considerable market power in a Californian situation of tight markets and binding transmission constraints.

The complexity of this challenge to conventional competition policy is well illustrated by the difficulties experienced by the British energy regulator, Ofgem. Britain has a stricter test of monopoly (more than 25 percent of the market) than the European Commission, and also longer experience of the useful concept of a complex monopoly, as well as a public interest test of the likely consequences of market concentration. It is therefore considerably better equipped than Continental countries to deal with market power issues in electricity markets. Nevertheless, Ofgem, with over a decade of experience of dealing with the initially concentrated wholesale gas and electricity markets, is acutely aware of the limitations of normal competition legislation.

In 2000, Ofgem persuaded the majority of large electricity generating companies to accept the Market Abuse Licence Condition which specified certain forms of behaviour as *prima facie* abusive, meriting investigation and possible penalty. Two generators, AES (with 7 percent of total capacity, mostly under long-term sales contracts) and British Energy (with overwhelmingly base-load inflexible nuclear power) did not consider the change in licence conditions necessary and appealed to the Competition Commission. The condition related to behaviour in the Electricity Pool, due to be replaced by the New Electricity Trading Arrangements (NETA) in early 2001. Partly as a result, the Commission were not persuaded that it would be against the public interest for AES and British Energy to continue without the licence modification (Competition Commission, 2000).

The Commission and the ESC are similarly concerned at the discrepancies in retail competition as measured by market opening across the Union. They argue that liberalising supply (retailing) to large customers led to price reductions of 15-35 percent, with the largest price falls in countries with the most rapid and extensive market opening, but that smaller customers have not benefited as much “since these reductions go hand in hand with the ability to change supplier” (2.2). The Commission therefore proposes full market opening by January 1, 2005. The ESC endorsed this proposal (6.1.1). The Barcelona Council Meeting of 15-16 March, 2002 weakened this requirement of “freedom of choice of supplier for all European non-household consumers as of 2004 for electricity and for gas. This will amount to at least 60 percent of the market” (European Commission, 2002).

5. Analysis of the problems of electricity liberalisation

The central problem of energy liberalisation is the tension between the desire for efficient, competitive and unregulated wholesale and retail markets, and for long-term investment and security of supply. The next section will argue that success in gas liberalisation is critical for resolving part of this tension in electricity markets, because gas offers the prospect of contestable entry by modest-scale CCGT behind transmission constraints, within a commercially manageable construction time. Such technology reduces, but does not eliminate, the source of the tension between competition and investment viability. That tension can be seen most clearly in the electricity market.

Electricity cannot readily be stored, so unused capacity has potentially a very low spot value in a competitive market.¹⁴ The competitive price will be the short-run marginal cost of the most expensive plant required at any moment to meet demand. In order to have adequate reserves to meet demand at the peak with high probability, the reserve margin for much of the time will be sufficiently high that the marginal plant is likely to be reasonably efficient. In mature systems with sufficient capacity, the average system marginal cost is typically only about half the average cost of generation.¹⁵ In order to cover the fixed costs and make it

¹⁴ Electricity can be stored as water behind dams, but there is only a relatively small fraction of such capacity available (unconstrained by transmission capacity) to the main European demand centres. It may also be economic to store energy in fuel-cell form, though the cost is still high. Unused capacity has an option value measured by the Loss of Load Probability, but this is an essentially exponential function of the reserve margin (Newbery, 1995) and hence very low except when demand is tight.

¹⁵ If past investment has been low, so that there is still a large amount of old plant supplying mid-merit demand, the variable cost of the highest cost plant required for much of the year may be high compared to the average cost of new plant. That was the case in the first few years after privatisation in England before the entry of some 25 percent of existing capacity of CCGT. Without careful market

worthwhile retaining marginal plant to supply reserves, prices will either have to be very high some fraction of the time, or these fixed costs will have to be paid by some form of capacity payment. High spot prices in competitive (as opposed to oligopolistic) markets require tight markets and low reserve margins, and increase the risk of (very costly and disruptive) losses of load. A small error in forecasting future demand when deciding on investment in generation capacity could mean either that future spot prices are unprofitably low (slightly too much capacity) or very high (slightly too little), with the consequent risks of system failure, not to mention political or regulatory intervention.

Investing in competitive electricity markets is therefore very risky. More generally, liberalising the electricity market creates market risks at the wholesale level where previously there were none in a vertically integrated industry. Low wholesale prices shift benefits to consumers at the expense of generator profits and vice versa. The logical response to this new risk is to create hedging instruments that, once again, share the risk efficiently between upstream generators and downstream consumers (or suppliers acting on their behalf). Most commodity markets evolve a range of physical and financial contracts, including very liquid futures contracts, to hedge the spot market volatility.

Most commodities traded on such markets are homogenous, storable, and can be moved cheaply between markets, facilitating the emergence of standard and liquid contracts. Electricity appears to be homogenous (all electrons are identical) but because it cannot be stored its value can change dramatically from moment to moment. Electricity in successive trading sessions (half-hourly in Britain) is thus a different product. Contracts are therefore more bespoke, have higher transaction costs, and there are only limited possibilities for standardisation (base-load power is the best example, or constant amounts for groups of adjacent week-day hours). The resulting contract markets are either very short-term (day-ahead), or limited to a few standard contracts, and/or very illiquid. Whereas actively traded futures markets for other commodities may have trading volumes many times final delivery (10-20 times in some cases), electricity contract trade is rarely 10 percent of delivery.

Decentralised competitive electricity markets thus face considerable obstacles if they are to handle risk and hence encourage investment. The capital markets are clear as to the solution. Concentration and market power offers the smaller number of competing generators the prospect of greater control over prices. This allows them to keep prices above variable cost and hence recover their fixed costs. More important, the ability to control prices reduces investment risk as future prices should be more controllable and hence more predictable. An uncontested monopolist has no problem deciding on investment, though it is more difficult in an oligopoly. They may be able to tacitly co-ordinate on future expansion (e.g. by taking turns to make expansion investments), and the threat of potential entry may persuade them to undertake possibly slightly premature investment to keep prices from attracting too much entry. It is possible to imagine a quasi-stable industrial structure that delivers enough investment to ensure supply adequacy at prices above, but not excessively above, the long-run marginal cost.

design, it will be commercially unattractive to keep such plant on the system, so the range of plant variable costs will be compressed, and the ratio of system marginal cost to average cost will fall.

5.1 Vertical and horizontal integration

The other solution, which the market has demonstrated to be attractive, is vertical integration between generation and supply, so that upstream and downstream profit risks cancel out within the firm. If successful, the Commission's (and the ESC's) enthusiasm for complete market opening will increase the attraction of a route that the British generators have embraced with enthusiasm in response to the end of the franchise and the introduction of the New Electricity Trading Arrangements (NETA). NETA has amplified trading risks by levying imbalance charges on each party out of balance after 'gate closure', about four hours before dispatch. Those long on energy have to spill at the 'system sell price' which is typically considerably below the market price, which is itself below the 'system buy price' facing those who are short. The buy price is both hard to predict and can rise to very high levels, encouraging over-contracting, inefficient self-balancing and excessive self-reserve provision. NETA thus encourages both horizontal and vertical integration to better handle these short-run (balancing) and medium-run risks.

The argument for ending the franchise is that customers are then free to switch from suppliers who are attempting to pass through high-cost contracts or simply price high to extract profits. The evidence from Britain (Green and McDaniel, 1998; UBS, 2002) is that the switching costs allow incumbents and subsequent suppliers to extract considerably more rent from consumers than when subject to regulation. One measure of the value of this rent is the amount that companies are willing to pay to acquire customers, either by buying an existing supply business, or by heavy advertising and promotion costs. UBS estimates this as on average £243 (Eur 390) per residential customer. Another measure is the extent to which the incumbent (the former monopoly franchise supplier) is able to price above entrants in the former franchise zone, and this is typically 10-20 percent of the bill (high relative to the small supply margin allowed under the former price-cap regulation).

Horizontal and vertical integration are entirely rational responses to attempts to increase competition in the electricity supply market. There may be a period of intense competition (as in Germany) during which wholesale prices fall in response to excess capacity and supply threats from external generators. This has the attraction to vertically integrated companies of lowering the market value of stand-alone generation companies (those that do not own transmission access or supply businesses) and making acquisition cheaper. Once the market has consolidated, unprofitable spare capacity can be withdrawn and the market tightened to the point that sustaining profitable prices is relatively easy.

5.2 Transmission and supply security

There is a danger that improving cross-border transmission capacity will have the same effect. The obvious response to domestic market power and price dispersion across Europe by the Commission and external observers (Bergman et.al. 1999) is to argue for increased interconnect capacity. This should increase (short-run) system security, allow more efficient dispatch (lower cost plant displacing less efficient higher cost plant), and mitigate market power (Newbery, 2002a). If generators from one country are to sell at lower risk in another country, they will benefit from integrating both into generation (to hedge the local spot market price variations) and into supply. Cross-border ownership is likely to amplify market power on the interconnectors unless market rules are carefully designed (Gilbert, Newbery and Neuhoff, 2002). It is certainly more difficult for national regulatory authorities (NRAs) to

properly monitor companies that may engage in market-relevant activities outside the country and jurisdiction of the NRA. Cross-border acquisitions typically are the responsibility of Brussels, rather than individual competition authorities, and that may cause further concerns. Some countries may consider that their local competition authorities will pay greater attention to the specifics of electricity markets and less to jurisdictional precedence from dissimilar markets than the European Commission.

Electricity market dynamics can be (perhaps simplistically) described as the pursuit of risk reduction and margin defence. Any attempt to create more competition will provoke counter-responses that may store up future problems if not anticipated. Ending the franchise may solve some problems (removing the opportunity for stranding contracts on the captive market) but create others (higher retail margins, more vertical integration and hence barriers to entry by smaller or less specialised firms). Increased interconnection would undoubtedly bring substantial benefits at probably low cost. The lack of past impulses to, or agreed mechanisms to pay for, interconnection almost certainly means that Europe is under-supplied with such links. A tough-minded pro-competitive Commission may even be able to resist further concentration that would become more attractive the more tightly interconnected markets became. But would increased interconnection reduce or increase long-run supply risks?

The obvious problem is that reserve capacity is a public good in an interconnected system, unless the value of the increased security can be properly charged to consumers. As noted above, the ESC argues that the cost of the security should be met by the whole system (6.2.3), and not just the companies or consumers in the country where the spare capacity is held (which, in California's case, was normally out-of-state). The better the interconnection, the wider is the area that can be served by spare capacity. Increasing interconnection may delay the time when reserve margins fall from their present EU-wide excess to their efficient level (which, in a broader market will be lower). When it does, shortages will have EU-wide rather than local effects.

5.3 Reconciling liberalisation and supply security

How, then, is the Commission to meet its objective of increasing competition and integrating the electricity market while not sacrificing security and quality of supply? In particular, who will be responsible for action if the future supply/demand balance looks unfavourable? The ideal solution is one that can be left to individual countries (subsidiarity) but which does not distort the market. A market-friendly solution might be to require any supplier to secure or contract for sufficient reserve capacity to match his customer profile. Those supplying interruptible industrial customers would need less reserve than those supplying domestic customers under the standard quality of service obligations.¹⁶ These contracts would in turn reduce the risks of building peaking plant for which the demand is both limited and very uncertain.¹⁷ The SO might be charged with conducting a tender auction for such capacity if

¹⁶ In effect, a supplier serving a customer in profile class c with peak demand Q would have to secure options on $(1+\theta_c)Q$ units of capacity, where θ_c depends on the characteristics of the consumer.

¹⁷ A one-sided Contract for Differences 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 .

the market price for reserves suggested market power by incumbents. This would be allowed under the proposed Directive as it would be directed to ensure reserve adequacy.

The main problem is the liquidity, time frame and credit risk of the underlying capacity or reserve market required to support this decentralised solution. A supplier may choose rationally to only cover predicted reserves for a few months ahead. The price of reserve may fluctuate considerably, but if all suppliers mark to market, the risks of not buying ahead are limited, while the risks of buying ahead and risking stranded contracts if the price falls are greater. It would be difficult to combine a regulatory obligation to buy reserves far ahead with a completely liberalised retail market in which customers can switch at 30 days notice. It may be that regulators will accept exit charges as the *quid pro quo* for contract cover, but these are potentially anti-competitive and may need even more onerous and expensive regulatory oversight than the former franchise market, thus defeating the purpose of ending the franchise.

Even if these problems can be overcome, credit risk remains serious, for uncapped electricity markets can reach bankrupting price levels within a very short time. That happened in California in early 2001, (and the Mid-West somewhat earlier), and is a risk more widely. The average daily retail sales value of electricity in Britain is about Eur 50-70 million. California demonstrates that average prices can increase ten-fold for periods of months. A supplier with 10 percent of the market (and there are six with 10 percent or more of the electricity market in Britain)¹⁸ might therefore face an increase in cost of Eur 1,500 million/month if unhedged. It might be cheaper to declare bankruptcy when such events occur and avoid the premiums involved in hedging ahead of time – and Enron provides a salutary example.

If the over-riding aim is to retain market instruments to secure adequate reserves while avoiding undue concentration, then the simplest solution is to retain the domestic franchise. That, in effect, is what the Barcelona Council meeting now allows, though individual countries are free to end the franchise if they choose. A domestic franchise can be required to contract for reserve in return from the right to pass the contract costs through to customers, hence avoiding the risk that contracts would be stranded and hence unattractive. Contract cover also reduces generator market power (Newbery, 1998), but runs the risk of sweetheart deals with affiliates unless monitored (Newbery, 1995). This can be countered by benchmarking captive customer contracts, as in The Netherlands, though at some increase in risk, and hence cost.

There are also costs in retaining the franchise, for it requires continued and possibly intrusive and costly regulation that complete supply liberalisation might avoid. The balance between the costs and benefits of supply liberalisation are not yet sufficiently clear to draw conclusions. If switching costs are high, and credit-worthy suppliers few, then domestic consumers may face higher prices and less reliable supply than they would under an efficiently regulated franchise. If regulators are captured, or bureaucratic and ineffective, then prices may eventually be higher under regulation as costs fail to fall as fast as under competition.

There are additional competition risks that may have to be monitored. If reserves are to be secured from abroad on medium or long-term contracts, then it will be necessary to also

¹⁸ Innogy (19 percent), Centrica (17 percent), TXU (15 percent), Scottish and Southern (14 percent), Scottish Power (10 percent), and EdF (10 percent). (UBS, 2002).

contract for the same amount of interconnect capacity, reducing the amount available for spot trading. If the suppliers in one country benefit from congestion on the interconnector, then they will have a defence against the natural restrictions that might be placed on such long-term contracts.¹⁹ It may be possible to require companies with more than a specified share of the market to secure domestic reserve capacity, though this would raise their costs and might be held discriminatory.

All of this suggests that workable electricity liberalisation is very different from deregulation. If anything the regulatory requirements to ensure security and quality of supply, not just in surplus but also tight markets, are far more demanding than for other utilities, as the speed with which system-wide problems can emerge is considerably faster. I have argued at length elsewhere (Newbery, 2002b) that most European regulators lack FERC's residual powers to intervene in generation and wholesale markets if prices become "unreasonable and unjust", and lack Britain's powers to modify generator licenses to mitigate market power. The European ideal that potentially competitive markets like generation and supply can be left to the competition authorities is in contrast to this apparent need for more sophisticated, informed and possibly interventionist regulatory power to ensure satisfactory wholesale market performance.

5.4 The importance of gas liberalisation

The gas industry has been far more successful than the electricity supply industry in resisting liberalisation, both because its cost structure is more opaque, and because of the evident importance of long-term contracts to finance production and develop the infrastructure. Import dependence raises security issues that are also logically handled by long-term contracts. The fact that while electricity fails to safety while gas fails to danger favours large vertically integrated concerns whose reputation delivers safety. Finally, compared to the US, the European gas market was, until recently, relatively immature. Whereas Continental Europe was dominated by a small number of mainly state-owned enterprises, the US had over 8,000 producers, with the 40 largest accounting for only 57 percent of 1990 gas production. They were connected to more than 1,600 Local Distribution Companies through 44 major interstate pipeline systems and hundreds of smaller pipeline companies (IEA, 1994). In an immature market the main emphasis is on building the network and connecting customers rapidly, so there is likely to be relatively little interconnection and spare capacity that would allow spot markets to develop.

Traditional monopoly gas suppliers typically sell gas at prices linked to the alternative fuel cost of their customer, and this ability to price discriminate allows them to extract substantial rents that they are anxious to protect. Britain has, as a result of a decade of regulatory activism, made unbundling a less unattractive alternative for the original monopolist, British Gas. This was possible as Britain reached maturity (in the sense of a dense and adequate network) before privatisation. With a variety of different producers delivering into a flexible and eventually unbundled delivery system, combined with rapid demand growth for electricity generation, liberalisation delivered gas-on-gas competition that lowered prices and de-linked them from other energy prices, particularly oil (Newbery,

¹⁹ The Netherlands restricts parties to no more than 400 MW of interconnect capacity. Gilbert, Newbery and Neuhoff (2002) argue that oligopolistic generating companies should be debarred from obtaining import interconnect capacity to mitigate market power.

2000). Prices subsequently rose to European levels when the producers built the Gas Interconnector to the Continent, allowing them access to a market still linked (at a higher level) to the oil price.

The benefits from similarly liberalising the Continental gas market are likely to be at least as dramatic. As in Britain, a major beneficiary should be the electricity industry, but again the challenges are considerable. Once transmission is unbundled from production and retail, regulated Third Party Access no longer runs into such strong resistance from the companies that control access to protect rents. That in turn opens the prospect of spot markets and gas-on-gas competition to emerge, eroding the need to link gas contracts to verifiable oil prices. However, to reach that stage, the companies, many of which are in the private sector, have to be persuaded to accept unbundling. As this would erode their rents, this will not be easy. It took a decade of competition inquiries and legislative activism to achieve it in Britain, and rather longer in the U.S. where it was finally precipitated by the serious market perversities resulting from policy responses to earlier oil price shocks.

If this is successful, the next challenge is to secure adequate long-term investment in transmission and storage. The latter can be mandated, but the former requires decisions on routes and capacities to meet an unpredictable future spatial pattern of supply and demand. This can be managed by setting transport tariffs at LRMC and requiring the regulated transmission company to meet demand, providing the company has a guarantee that it can recover (the efficient level of) investment costs. The idea of auctioning off future capacity to guide investment decisions has an obvious appeal in a liberalised market, but may run into similar problems of under-provision that concerns policy analysts in the electricity market (McDaniel and Neuhoff, 2002).

Nevertheless, if these obstacles can be overcome, the benefits would be considerable, for it is normally cheaper to move gas by pipeline than electricity by wire. Although international coal prices are such that coal is normally competitive against gas on variable costs, the average cost of new CCGT is considerably lower than new coal, and certainly new nuclear power. Once European electricity prices rise to cover the cost of new CCGT capacity, entry into each country near demand centres is the logical consequence, provided entry barriers or perverse access charges do not hinder it. The most obvious barrier to entry is access to gas on contractually cost-reflective terms. Unfortunately, cost-reflective tariffs run counter to a long history of value-based pricing (i.e. charging the individual consumer the maximum he is willing to bear).

If each country can acquire new generation on similar terms (as implied by the low marginal cost of gas transport), then local demand/supply imbalances can be rectified, and the need for electricity (as opposed to gas) interconnection is reduced. If the wholesale electricity market is kept contestable (and barriers to entry caused by vertical integration and poorly designed wholesale markets, such as NETA, discouraged or overturned), then entry threats (and actual entry) should keep the average price at LRMC while facilitating investment. Supply security will then have been achieved at the country level and the objective of subsidiarity will have been achieved.

5.5 Environmental impacts of liberalisation

One of the criticisms levelled at electricity liberalisation is that “if the internal market causes electricity and gas prices to fall, this in turn would probably lead to an increase in

consumption... causing an increase in pollutant emissions and hindering attempts to honour commitments made in Kyoto.” (OJ, 8.2.2002, 6.4.9.2) The EU is pressing hard for an increased share of renewables, supported by a carbon emissions trading system with a target date of 2005, while several countries have introduced green certificates to support renewable energy sources. The case for additional support beyond a carbon tax (or carbon scarcity price) presumably rests on the external benefits of cost reductions from learning-by-doing. Ideally these should be quantified to allow the subsidies to be made explicit and defensible.

The EU has already indicated that member countries should not discriminate between renewable (“green”) generation within and outside the countries in which consumption takes place. In the Netherlands, for example, domestic consumers who buy green electricity do not have to pay the significant eco-tax of 6 euro-cents/kWh (compared to a pre-tax domestic price of about 10 euro-cents in the first half of 2001). This value can be passed back to the ultimate producer of green electricity and in equilibrium would allow such producers to sell at 6 cents/kWh above the market clearing price. The Commission requires that this subsidy be available to any eligible EU producer. In response, the Dutch government requires that any green supplies obtained from outside the Netherlands must secure import capacity. Given that import capacity is often scarce, there were concerns that the green electricity market would increase the cost of imports of all electricity and hence raise prices in importing countries such as the Netherlands.

The objective of encouraging green electricity is to reduce greenhouse gas emissions, and it does not matter where these reductions take place for the purpose to have been achieved. Requiring each member state to meet its target for CO₂ reductions is a way of equitably spreading the burden, but an efficient market in carbon permits or green certificates ought not to introduce additional trade distortions. Logically, therefore, there should be no need to require that the green electricity is actually delivered to the final consumers, nor even that the time profile of production of green electricity should match that of the consumption of those holding green certificates. This last point is extremely important, as the variation in market clearing prices over 24 hours may be very large and it would be cumbersome or even impossible to match domestic green consumption with production. Again, it does not matter much when the green electricity is produced as a tonne of carbon displaced at 4a.m. (by reducing production of grey electricity then) is as valuable as a tonne of carbon displaced at peak hours.²⁰

In the short run, there are a variety of methods of reducing CO₂ emissions from electricity generation within the EU, even ignoring the direct solution of reducing consumption through taxes and energy conservation measures. Fuel switching from coal to gas would be encouraged by carbon taxes and international trade, while investment in gas-fired generation would similarly be stimulated. In Britain the “dash for gas” reduced the coal share from 80 percent to 35 percent in a decade, with a dramatic fall in CO₂ emissions from the sector. More stringent EU targets for CO₂ reduction will enhance the benefits of increased

²⁰ At least, to a first approximation, since the displacement is actually of kWh generated by the marginal plant on the system. This is likely to be more inefficient thermal plant at the peak than off-peak (when only efficient base-load units are kept on line), so green electricity at the peak saves (slightly) more carbon than off-peak. Except for a small number of hours per year, the difference is unlikely to be more than the difference between plant of thermal efficiency of perhaps 34 percent and 37 percent, or perhaps 10 percent difference in carbon emissions.

interconnection. Nuclear power releases no CO₂ from generation, so avoiding their premature retirement is undoubtedly the least-cost short-run solution.

In the longer run, new investment in gas-fired generation displacing coal reduces, but does not eliminate, emissions. The least-cost technology for zero emissions is almost certainly wind power, at least over the next decade, though optimists still press the case for nuclear power. The commercial economics of wind power depend sensitively upon the way wholesale prices are struck and imbalance charges are levied. Under the New Electricity Trading Arrangements in Britain, generators must predict their output accurately about 4 hours before dispatch, and must by then have secured matched consumption or face imbalance charges. The unpredictability of wind until relatively shortly before generation makes contracting difficult and imbalance charges, which heavily penalise imbalances in either direction, very onerous. Other trading arrangements, in which there is an efficient method for securing balancing services, a single price for imbalance, and better methods for aggregating uncontracted electricity (as in the old British Electricity Pool), can greatly reduce the costs of trading unpredictable electricity such as wind power. Energy from waste, in contrast, is predictable and does not suffer from these problems, though supply will be constrained by available fuel.

Unless EU countries evolve compatible, cost-reflective and liquid wholesale and balancing markets, renewables generation will be disadvantaged in some countries and possibly cross-subsidised (above the explicit green certificate subsidies) in other countries that do not impose cost-reflective imbalance charges and/or do not charge deep connection charges for distant wind-farms.²¹ This is likely to put greater pressure on interconnect capacity, as countries favouring wind power will seek to export at least some of the greater instability of domestic generation in order to reduce the domestic costs of balancing the system. In any case, the increased instability in locationally unpredictable production will require SOs to reserve a greater fraction of interconnect capacity to ensure system stability, and this may reduce the available transfer capacity for ordinary trading arrangements.

That suggests an additional reason for investing in interconnect capacity, to allow wind power to be located in the most favourable places (where wind speeds are predictable/strong and environmental protests weak). As SOs improve their ability to predict short-term wind production by location, and as they improve their ability to predict loop flows, so it should be possible to improve the short-term interconnect capacity market to develop and make use of otherwise unpredictable transmission capacity. Ideally, this would allow greater short-term competition and greater convergence in prices across country borders. In practice, as with other new risks in the wholesale market, vertically integrated companies that can internalise these transactions will be advantaged. In this case, vertically integrated means owning generation and supply businesses on both sides of congested inter-connectors. The problem of market power will therefore be affected by future developments of renewable energy, and may encourage apparently innocuous mergers before these impacts on cross-border trade become visible, and hence before competition authorities are well placed to gauge their likely impact.

²¹ Off-shore wind-farms will require a connection to the grid, which should be paid for by the wind-farm. If the grid connection point is at the end of the network, further reinforcement may be required and, under a system of deep connection charges, would be paid for by the wind-farm. Shallow connection charges tend to socialise and possibly cross-subsidise these costs.

The Commission is also anxious to increase the penetration of Combined Heat and Power (CHP) plant, as this makes potentially more efficient use of energy and should cut CO₂ emissions. Again, there are problems with some trading regimes such as NETA in handling small-scale, inflexible and possibly unpredictable electricity supplies, which are resolved if charges are cost-reflective. A carbon tax (or trading regime) would remove the need to provide any additional subsidies. If changing the access and balancing charges is difficult, then their adverse effect may be overcome by compensation equal to the difference between the cost-reflective and actual charges. The other argument for subsidies to CHP is that gas prices may be substantially above the opportunity cost of the gas. CHP is likely to be gas-based, and if the likelihood of gas liberalisation increases with gas demand from new (large) users, then such gas use has positive externalities. If, however, increased gas use increases concerns over import dependence which is used as an argument against liberalisation, the converse is true. The main lesson is that gas liberalisation increases the efficiency of the electricity supply industry.

If CHP is either actively encouraged (by obligations to achieve certain penetration rates),²² or if it is economic (least-cost for additional capacity given proper carbon prices and cost-reflective system charges), then logically one would expect extra investment in CHP. Some existing plant will now be seen to be obsolete and will need to be replaced. If existing but obsolete plant is kept available ('moth-balled') then system security will be further enhanced. If CHP is supplied by independent companies, then concentration will fall, though not necessarily in the price-setting part of the market. The main impact on competition is likely to be the short-run effect on increasing the reserve margin.

6. Conclusions

California teaches us that liberalisation requires adequate reserve margins and sufficiently numerous generators competing in the same market, defined by transmission constraints. At present the margin of spare capacity is adequate in Europe (although it has been falling fast in response to lower prices and capacity withdrawals). The vulnerability of reserves to weather outside Scandinavia is lower than in California, although regulators in Europe face the same problems as the California Public Utilities Commission in obtaining sound forecasts of future capacity. Member countries are right to worry that liberalised markets may reduce future quality and safety unless active steps are taken to avoid under-investment. Private owners benefit from high prices, which in electricity markets require either market power or low reserve margins. Holding idle capacity may be socially beneficial in reducing supply and price risks but is privately costly unless the social values are reflected through the market price structure. If regulators or SO's react to expected shortages by tenders for new capacity, without addressing the reasons for under-supply (entry barriers supporting market power), then the new investment may just displace marginal existing plant with little change to reserve margins.

The central problem is the tension between market structure and investment adequacy. Without appropriate hedging instruments, a competitive generation industry may find long-term investment too risky, and prices are likely to be unacceptably volatile. The combination

²² The economic level of penetration will vary with location and climate, as CHP is likely to be more socially profitable in new, dense housing developments in cold countries (and some industrial uses). Uniform targets by country are likely to be very inefficient.

of long-term contracts backed by a domestic franchise with obligations to contract for reserve may offset the problem. That suggests some caution in pressing for the end of the domestic franchise. The other extreme of allowing concentration in generation combined with contestable entry from independent CCGTs, and extensive contract coverage to mitigate market power, may deliver desired investment but possibly at higher average price-cost margins (judging from the early experience of the British market).

Making entry more contestable probably requires further gas liberalisation, particularly unbundling transmission from supply to foster liquid spot and contract markets. If the gas price is market-determined and gas becomes more like oil, then the link to oil prices for import contracts can be broken, opening the prospect of more gas-on-gas competition, periodically lower prices, hence making investment in CCGT more attractive.

It is widely recognised that additional cross-border transmission is required, and agreement about the pricing issues that have to be resolved. If these decisions can be devolved to experts, and if they are able to agree a set of efficient use charges, combined with an allocation of fixed costs among the major players, then the prospects are promising. Wind-power is likely to increase the need for interconnect capacity, as does the desire to mitigate local market power, while gas liberalisation may reduce the amount needed in the long run, though this may still be considerably above current levels.

Perhaps the greatest remaining uncertainty affecting investment decisions is the future treatment of renewables and CHP. If Europe introduces a carbon tax, then CCGT investment may be stimulated as well as wind-power, but if a high renewables target is to be met by green certificates, then other forms of generation will be discouraged. Wind-power delivers relatively little firm capacity per kW installed, so firm peaking capacity will need to be paid relatively more than base-load, and that may stimulate a rather different form of investment. But the main message is that uncertainty raises the option value of delaying irreversible sunk investments, of which generation is a prime example.

The other concern is whether traditional European regulation and competition policy is adequate to the task of ensuring that the emerging electricity and gas markets deliver quality and security at acceptable retail prices. Compared to the United States, European regulators have limited default regulatory powers to intervene in wholesale markets if prices become “unjust and unreasonable”. The lack of generator licence conditions hampers market surveillance, while the lack of functioning information exchange between national regulatory authorities (NRAs) makes predicting potential market problems that can spill over borders more difficult. This difficulty is compounded where there is no NRA (Germany) or where the NRAs are recent, inexperienced, and lack the powers to obtain market-sensitive information. At present, competition authorities seem more relaxed than is desirable in allowing concentration to continue. In Britain, mergers were allowed in exchange for other desirable structural changes (such as divesting generation), but there is little evidence of a coherent Continental strategy for market structure or an articulated desired end-state for the industry.

Europe is fortunate that the current level of spare capacity gives a breathing space during which some of these problems can be addressed. The speed with which the electricity market has changed under the existing Directive is encouraging, and the caution expressed at further reforms understandable. The main concern is that this period will be mainly used to increase market concentration, rather than refine the regulatory framework.

References

- Bergman, L., G Brunekreeft, C. Doyle, B-H von der Fehr, D M Newbery, M Pollitt, and P Regibeau, (1999), *A European Market for Electricity?* London: Centre for Economic Policy Research.
- Blumstein, Carl, L. S. Friedman, R. J. Green. (2002), *The History of Electricity Restructuring in California*, University of California Energy Institute WP-103, download from <http://www.ucei.org/PDF/csemwp103.pdf>
- Bogorad, C.S. and D.W. Penn (2001), *Cost-of-service rates to market-based rates to price caps to ?!#?#!?*, *The Electricity Journal*, May, 61-72.
- Competition Commission, (2000), *AES and British Energy*, Dec. London: Competition Commission.
- European Commission (2002), *Presidency conclusions Barcelona European Council 15 and 16 March 2002*, D/02/8, External Relations, Brussels, 16 March at http://europa.eu.int/comm/external_relations/w12/1.htm
- Gilbert, R.J., K. Neuhoff and ., D.M. Newbery (2002), *Mitigating market power in networks*, mimeo, Cambridge, Department of Applied Economics.
- Green, R. and T. McDaniel (1998), *Competition in electricity supply: will "1998" be worth it?* *Fiscal Studies* vol 19.
- IEA (1994), *Natural Gas Transportation: Organisation and Regulation*, IEA/OECD, Paris.
- Joskow, P. (1997) *Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector*, *Journal of Economic Perspectives*, 11(3), Summer 1997, 119-38.
- Joskow, P. (2001), "California's Electricity Crisis," *Oxford Review of Economic Policy*, 17(3), Autumn 2001, pp. 365-388.
- Joskow, P. and E. Kahn (2002), *A quantitative analysis of pricing behavior in California's wholesale electricity market during summer 2000: The final word*, Cambridge CMI Electricity Project Working Paper 2, (can be downloaded from <http://www.econ.cam.ac.uk/electricity/publications/index.htm>)
- Laurie, R.A. (2001), *Distributed generation: reaching the market just in time*, *The Electricity Journal*, Mar 87-94.
- McDaniel, Tanga and Karsten Neuhoff (2002), *Use of long-term auctions for network investment*, Cambridge CMI Electricity Project Working Paper 4, (can be downloaded from <http://www.econ.cam.ac.uk/electricity/publications/index.htm>)
- Newbery, D.M. (1995), *Power markets and market power*, *Energy Journal* 16(3), 41-66.
- Newbery, D.M. (1998), *Competition, contracts and entry in the electricity spot market*, *Rand Journal of Economics*, 29:726-49.
- Newbery, D.M. (2000), *Privatization, Restructuring and Regulation of Network Utilities*, Cambridge, MA: MIT Press.
- Newbery, D.M. (2002a), *Regulating unbundled network utilities*, forthcoming in *Economic and Social Review*, 33(1), 23-43. (available at <http://www.econ.cam.ac.uk/dae/people/newbery/index.htm>)
- Newbery, D.M. (2002b), *Problems of liberalising the energy utilities*, *European Economic Review*, 46, 919-27. At <http://www.econ.cam.ac.uk/dae/people/newbery/index.htm>.
- OJ (2001), *Proposal for a Regulation of the European Parliament and of the Council on conditions for access to the network for cross-border exchanges in electricity*. Official Journal C 240 E, 28/08/2001, p 72-8.
- OJ (2002), *Opinion of the Economic and Social Committee*. Official Journal C 36 E, 08/02/2002, p 10-19.
- Parker, M. and O. Board, (1994). *Coal in the UK*, Oxford,:OXERA Press.
- Pollitt, M.G. (1997), *The impact of liberalization on the performance of the electricity supply industry: an international survey*. *Journal of Energy Literature*, Vol.3, No.2, 3-31.

- Pollitt, M.G. (1999) 'The restructuring and privatization of the Electricity Supply Industry in Scotland', Cambridge: mimeo.
- Price C. Watts (2001), Heresy? The case against deregulation of electricity generation, *The Electricity Journal*, May, 19-24.
- Stoft, S (2002). *Power System Economics*, New York: Wiley-Interscience.
- UBS (2002), Retail Gas and Electricity Markets in the UK, UBS Warburg Global Equity Research, 22 Jan.
- Vázquez, C., M. Rivier and I. Pérez-Arriaga (2001), A market approach to long-term security of supply, IIT Working Paper (IIT-00-0078A), available at URL <http://www.iit.upco.es>
- Wolak, F.A. and R. Nordhaus, (2000), An analysis of the June 2000 price spikes in the California ISO's energy and ancillary services market, California ISO Market Surveillance Committee, Sep. 6