A EUROPEAN MARKET FOR ELECTRICITY?

Monitoring European Deregulation 2

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October 1999

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List of Figures

List of Boxes

List of Tables

Foreword

The regulation of network industries has emerged as a key issue on the European policy agenda, yet there is little high quality research capable of informing European policy-makers on these issues. In 1997, the Centre for Economic Policy Research (CEPR) and the Swedish Center for Business and Policy Studies (SNS) therefore launched a new series of reports on *Monitoring European Deregulation*. The aim is to bring together annually a team which includes some of Europe's leading researchers in the field of network industries to specifically address the issues of regulation and deregulation in Europe. The first Report was published in September 1998. The initial section of the 1998 Report concentrated on the general issues which arise in the regulation of network industries, with a second section focusing specifically on the telecoms industry.

This is the second report launched as part of the *Monitoring European Deregulation* initiative and concentrates on the deregulation of the electricity industry. As with the previous title, the authors begin with a comprehensive guide to the key economic developments currently affecting the network industries as a whole. The detailed study of the deregulation of the electricity industry which follows is split into three distinct sections: the authors begin by analysing the key issues in electricity market integration and liberalisation; this is followed by six country studies; and then, in the final part of the Report, the authors examine the problems and experiences of liberalisation and the policy choices facing the regulators.

The research was financially supported by a number of European companies in the electricity industry. A Reference Group consisting of representatives of these companies (see the list on page xiii) commented on drafts and provided advice to the authors on the issues raised in the Report. The authors enjoyed complete academic freedom in writing the Report, but the industry practitioners in the Reference Group thereby played a valuable role in its preparation. CEPR and SNS are grateful for the financial support that made this venture possible and for the help and enthusiasm provided by members of the Reference Group, chaired by Mr Lennart Lundberg, former Senior Executive Vice President of Vattenfall (Sweden). A research grant from the Swedish Competition Authority is also gratefully acknowledged.

We would also like to thank the authors for all their hard work in producing this insightful Report which will, we are confident, be of great value to anyone interested in deregulation issues. The views expressed in the Report are those of the authors writing in their personal capacity and neither CEPR nor SNS take any institutional policy positions.

Hans Tson Söderström	Stephen Yeo
President and Chief Executive Officer	*Chief Executive Officer*
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October 1999

Executive Summary

All current members of the European Union and quite a few hopefuls are liberalizing their electricity markets. Some, like Sweden and the United Kingdom, started the process several years ago and have already accumulated significant experience. Others, spurred into action by the European Commission's Electricity Directive, which was issued in February 1997 and targeted for implementation by February 1999, have just begun to implement their new regulatory framework.

This Report, the second in the *Monitoring European Deregulation* series, explores the obstacles to a single European market for electricity, examining the policy choices facing the regulators at both national and EU levels. The Report combines analyses of key issues in electricity-market integration and liberalization with evaluations of practical experiences in the United Kingdom, the Nordic countries, Germany, Spain, France and Hungary. These experiences suggest one important lesson, according to the Report: liberalized electricity systems work – the technical breakdowns predicted by the sceptics just have not happened in the EU.

There has been great variety in different national experiences of liberalization in terms of the degree of concentration in generation, the stringency of unbundling requirements, the design of market mechanisms, and the extent and nature of public ownership and regulatory institutions. By combining theory with this empirical evidence, however, the Report is able to reach a number of significant conclusions and make several bold policy recommendations. It draws a distinction between observations that are relevant to the design of national electricity systems and those that are of particular importance to the emergence of a single European market for electrical power.

I. National issues

At the national level, the Report unambiguously calls for:

- *Reducing concentration in generation*. Whenever market size and the minimum efficient scale of existing power plants allow, a redistribution of generation assets is the preferred approach. The distribution of ownership appears to matter more than its public or private character.
- *Separation of ownership between natural monopoly elements of the system and other activities*. Accounting or even legal separation are not sufficient.
- *Ownership of the transmission system in the hands of the transmission system operator*. Where the whole transmission system is under single ownership, there are advantages in having systems operation in the hands of the transmission system operator. This ensures the solvency of the transmission system operator, which can then be made subject to powerful incentive schemes. In the case of several grids under separate ownership, transmission systems operation should be independent.

- *Regulated third party access to networks*. This is more transparent and hence preferable to both negotiated third party access and the single buyer model. These two alternatives give vertically integrated transmission owners the power to delay the transactions of their rivals. They are also likely to result in stranded contracts, which would hamper further liberalization of the market.
- *Universal service requirements and environmental policy objectives to be met through a combination of licensing requirements, taxes and emission permits*. In a liberalized market, such goals are achievable using these instruments.

Not all aspects of regulatory reforms lend themselves to such bold recommendations. It is, for example, too early to evaluate fully the effect of liberalization on investment incentives. Nevertheless, it appears that explicit incentives, such as capacity payments, are needed and that tender auctions might be the most efficient way of securing non-financially viable renewable generation or even some ancillary services. It is also a little early for a thorough evaluation of the benefits of retail competition. The evidence so far is that retail competition based on metering does not work. On the other hand, competition based on profiling with caps on transaction fees might be effective.

Finally, there are aspects of market design for which there is no clear choice. For example, generation contracts with decentralized dispatch can, in theory, achieve overall system efficiency provided that transmission tariffs are adjusted continuously and all agents react rationally to price changes. In practice, however, transmission tariffs are bound to be imperfect, so that the coordination function of a mandatory pool with centralized dispatch becomes valuable. In this regard, the proposed reform of the trading arrangements in England and Wales, moving from a mandatory gross pool to a balancing pool, could provide some useful evidence.

II. Single market issues

If the single market for electricity is to become reality, it must be as easy to trade electrical power between countries as between different parts of the same country. Access charges are the key to an integrated electricity market, the Report argues. Europe needs a transmission pricing system with the following characteristics:

- Access charges that are simple, transparent and only depend on the point of connection.
- An allocation of charges between entry and exit points that is uniform across jurisdictions and allocates at least a small share to the entry point.
- Some geographic differentiation of access charges to provide incentives to relieve congestion and reduce overall transmission loss.
- A scheme for financial compensation between transmission system operators for transit and loop flows.

III. An agenda for the European Commission

The Report concludes that the Commission should consider supplementing the Electricity Directive with:

- A required separation of ownership between generation and transmission/distribution.
- Strict competition policy oversight of integration between generation and retailing (supply).
- Harmonizing non-tariff conditions for access to transmission and distribution networks.
- The promotion of international transmission pricing rules based on the principles described under the single market issues above.
- The creation of a body in charge of identifying the need for new interconnection facilities, allocating the cost of these facilities between participants and drawing up compensation schemes that ensure a fair and efficient recovery of these costs.
- The organization of a system of trading permits for emissions.

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We received excellent and very valuable comments when a preliminary version of the Report was presented to a meeting at the European Commission in Brussels in June 1999. Special thanks go to Pier Paolo Merolla of DGIII and Christopher Jones of DGXVII for the comments and to Ioannis Ganoulis and Geert Dancet for organising the meeting.

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The views expressed in this Report are our own, and all errors are, of course, our own responsibility.

INTRODUCTION: Europe's Network Industries: Towards Competition

Chris Doyle and Martin Siner

The economic significance of network industries in Europe is widely recognized.[1] Politicians see them as playing a significant role in influencing key European objectives: sustaining economic growth, improving competitiveness and forging greater cohesiveness. These objectives have resulted in policies reforming all aspects of European economic activity: the introduction of competition in the network industries forms an important part of this bigger picture. In this chapter, we set the scene for the main Report on the electricity industry by looking at the network industries in general. We highlight key economic developments affecting the industries and discuss why some industries have progressed more rapidly towards competition.

Since the late 1980s, economic policy in Europe has aimed to remove barriers to trade and competition. Network industries like energy (electricity and natural gas), postal services, telecommunications, and transport (air, maritime and rail), which were historically sheltered from competition and operated within national or regional boundaries, have experienced great change as a consequence. Whereas at one time, most European consumers had little or no choice over the supplier of a good or service delivered by firms in network industries, they can now choose from an increasing number of firms. Competition is rapidly establishing itself in telecoms and in parts of the postal services and air transport industries, and it is beginning to emerge in the electricity industry. In some countries, notably the United Kingdom, competition has advanced significantly in most of the network industries.

The factors precipitating a change in European policy towards the network industries have, to a large extent, been technologically and market driven. In many cases, newer technologies are displacing natural monopoly. As this Report will highlight, it is no longer regarded as inefficient in many power markets to have several firms generating electricity. Increasing demand, notably in telecoms, is also facilitating competition.

Observed inefficiency of supply in Europe's network industries has also prompted reform. For example, it has been estimated that in the chemicals sector, European companies pay up to 45% more for energy than their US competitors.[2] Apart from differences in tax treatment, the lack of competition has been identified as a key factor in explaining the cost differential. It has been calculated that full liberalization of the European electricity market will provide substantial gains amounting to €10–12 billion per annum, or twice as much as the gains anticipated from the opening already agreed.[3]

Inefficiency, coupled with changes in market structure, has encouraged political acceptance of pro-competition measures. Yet only a few countries have exploited the political momentum in favour of liberalization, notably the United Kingdom, Spain and the Nordic countries. It would appear that in some countries, politicians have largely paid lip-service to liberalization. For the European economy as a whole to benefit from liberalization, it has been necessary to have a strong central body committed to initiating and coordinating pro-market reforms. Since the Single European Act of 1987, the European Commission has been committed to implementing liberalization in Europe's network industries. Indeed, without the Commission's efforts it is extremely doubtful whether Europe's economy would have benefited as much from changes affecting the network industries.

The Commission has been at the heart of the reform programme introducing competition in the network industries. It has been able to strengthen its position as the initiator of reforms because it operates in an increasingly sympathetic political climate. The Single European Act mandated the Commission to devise policies to bring about a single market in communications, transport and energy. This required a legislative programme focused on liberalization and harmonization.[4] The programme of reforms was strengthened following the Treaty of European Union in 1992. The Commission accelerated its programme of liberalization and harmonization in the network industries in the mid-1990s. By the end of 1998, many of the liberalization measures had been adopted and attention shifted towards the details of implementation and enforcement.

Although the changing political landscape unquestionably favoured reforms, another crucial factor helping to foster a competitive regime was the changing corporate climate. Traditionally, managers in most European network firms operated exclusively within their national territories, whereas today, many companies are increasingly expanding operations outside their traditional service areas. Managers in newly privatized companies in particular are keen to move into new markets, as is shown in this Report. Publicly owned companies in network industries are also engaging in ambitious expansion programmes, however. For example Telia, the Swedish state-owned telecoms company, has taken a share in the Irish telecoms company Telecom Eireann and Electricité de France (EdF) has acquired the privatized UK company, London Electricity.

The main factors facilitating competition in the network industries in Europe are:

- market structure changes – innovations and demand changes;
- inefficiency of monopoly – poor incentives;
- strong central support – the Commission;
- political legitimacy; and
- a more global corporate climate.

There are, however, also a number of obstacles to achieving effective competition, including:

- legacy of monopoly and long-term contracts (stranded costs);
- slow and/or idiosyncratic transposition of European legislation;
- ineffective regulation (regulatory risk) and/or regulatory capture;
- unwieldy European procedures;
- public ownership;

- standards;
- public service objectives;
- environmental issues;
- interconnection and interoperability;
- and badly designed market institutions.

These obstacles are discussed in more detail in relation to the electricity industry in Part 1 of this Report and, more generally, in the previous Report in this series, *Europe's Network Industries: Conflicting Priorities*. Table 0.1 summarizes the obstacles to competition in network industries and some of the proposed remedies.

0.1 The evolution of competition and regulation

Liberalization of Europe's network industries began in the air transport and telecoms sectors in the 1980s. Today, competition and monopoly elements co-exist in all the industries. Ultimately, deregulation may lead some of the industries to have fully competitive market structures. As described in detail in the first Report in this series, deregulation of the network industries in Europe means that they are evolving along a path from monopoly (phase 1), to monopoly and competition (phase 2), and possibly on to competition (phase 3).[5] The evolution of market structures is described in Box 0.1, along with the industries and sectors associated with each phase.[6]

The introduction of competition in network industries demands a corresponding increase in regulatory activity, at least in the short term. This is due largely to the presence of powerful incumbent firms and the need for interconnection. If favourable conditions prevail, competition will become more effective and regu-

Table 0.1 Obstacles to competition in network industries and remedies

Obstacles	*Remedy*
Legacy of monopoly/stranded costs	Sector specific regulation
Slow/idiosyncratic transposition of European legislation	Penalties, guidelines
Ineffective regulation (regulatory risk)/ regulatory capture	Auditing (accountability), transparency (e.g. clear employment rules)
Unwieldy European procedures	EU reform
Public ownership	Privatization
Standards	Coordination through negotiation and standards bodies
Public service objectives	Transparency in accounting
Environmental concerns	Taxation, quotas, tradable permits
Interconnection and interoperability	Sector specific regulation, guidelines
Badly designed market institutions	Trials, experimentation

latory activity should shift away from sector specific detail to general competition problems. Box 0.2 describes the evolution of regulatory activity over the three phases of market structure.

The Commission, in consultation with the European Parliament and the Council, has largely initiated EU policy on network industries. Table 0.2 summarizes this policy. The following sections deal with each industry (excluding electricity) in the order they appear in the table.

BOX 0.1 The evolution of competition

Phase 1 – Monopoly
One firm supplies services.
Airports, ports, most rail services and rail infrastructure, gas, reserved postal services and water.

Phase 2 – Monopoly and competition
Competition is gradually introduced into some or all markets.
Airport ground handling facilities, electricity, port handling facilities, some rail freight markets, most air services, and residential telecommunications.

Phase 3 – Competition
Competition is extensive and increasingly effective in some or all markets.
Some air and shipping services, some business telecommunications services, and non-reserved postal services.

BOX 0.2 The evolution of regulatory activity

Phase 1 – Monopoly
Regulation is concerned with the prevention of monopoly abuse in retail markets ad the attainment of public service objectives (e.g. universal service).

Phase 2 – Monopoly and competition
Regulation focuses on: monopoly abuse in both retail and interconnect markets by dominant incumbents; emerging competition issues; and public service obligations.

Phase 3 – Competition
Some light-handed regulation is needed, as in other competitive markets, to ensure fair trading practices and the maintenance of public service objectives.

Table 0.2 Europe's network industries in 1999

Industry	*Liberalization and competitive measures*	*Current status of competition in Europe*
Air transport	Three packages of regulations between 1983 and 1993. Directive 96/67/EC on ground-handling. Regulation 323/1999 on computer reservation systems. Proposed directive on airport charges COM (97) 154.	Air services liberalized. Remaining impediments to competition (infrastructure bottlenecks) being liberalized. Much of the industry in phase 2. Airport slots major issue.
Maritime transport	Four regulations in 1986. Green Paper December 1997.	Services liberalized. Bottlenecks carefully monitored. Shipping services in phase 2, some in phase 3.
Railways	Three directives (91/440/EC; 95/18/EC; 95/19/EC) opening parts of the industry. 1996 White Paper. Proposed directive on infrastructure charges COM (98) 480.	Policy still being developed. The industry is largely in phase 1, but some parts (e.g. freight services) are in the early stages of phase 2.
Electricity	Some measures in the early 1990s. Directive 96/62/EC gradually opening up the market. White Paper on renewable sources of energy, November 1997. See main Report for full details.	Gradual liberalization benefiting large users began February 1999. Industry approaching phase 2, although in some member states liberalization has proceeded much further than EU timetable.
Natural gas	Directive 98/30/EC along the same lines as electricity.	Gradual approach to liberalization. Industry will enter phase 2 from 10 August 2000. Some member states like the United Kingdom already in phase 2 and approaching phase 3.
Postal services	Directive 97/671EC and Notice on the application of competition rules. Further liberalization to occur by 2003.	Segmented market: very competitive, high value (non-reserved) sector mainly in phase 3; reserved sector in phase 1.
Telecommunications	Many liberalization and harmonization measures between 1987 and 1998. Review starting in late 1999.	Services and infrastructure fully liberalized and market in phase 2, some elements moving towards phase 3. (Excluding Greece and Portugal.)

0.2 Air transport

Prior to 1993, a network of bilateral agreements regulated Europe's airline services market. These agreements (which still govern markets with and between third countries) imposed constraints on the behaviour of airlines through regulating key economic variables, including prices, frequency and capacity. Although during the mid-1980s, some member states, including the Netherlands and the United Kingdom, took actions to liberalize these agreements, those in force between the majority of EU countries resulted in a tightly regulated regime. Routes were effectively operated as collusive duopolies: airlines had neither the incentive nor the ability to compete.

In January 1993, following a decade of incremental measures, the Commission succeeded in introducing a liberal multilateral regime. Except for certain public service objectives and restrictions relating to ownership (discussed further below), this regime is fully liberalized. In theory, it allows the airline of one member state to operate services between or, since April 1997, within any other member state without restrictions on prices, frequency or capacity.

The creation of a single European aviation market has generated significant changes in the behaviour and structure of the air transport industry.[7] For example, excluding the first year after the completion of deregulation, when most European economies were in recession, more new mainstream jet airlines have entered the market than exited. These new entrants contributed to a decline in the national airlines' market share of routes within the EU from 80% in 1992 to 70% in 1997 and in their domestic markets from 75% to 60% over the same period. Furthermore, the number of routes with more than two competitors increased from 4% in 1992 to 7% in 1997; on denser routes, this figure rose from 12% to 26%.

While trends in market share and new entry since liberalization are in the right direction, the retention of very significant market shares by incumbents and the lack of competitors on many routes suggest that there are barriers to effective competition. This is confirmed by the large variations in fares. Although there is evidence of intense price competition on some dense international routes and low-cost, no-frills carriers have introduced cheap discount fares, fully flexible and business fares have remained high and, on average, increased. So, while competition is developing in certain markets, the overall impact of deregulation is less than might have been anticipated.

As with other network industries, the principal impediments to competition arise from bottlenecks in the network infrastructure. In the aviation market, the attention of competition authorities has focused on four issues relating to essential inputs:

- computer reservation system (CRS);
- airport landing and take-off slots;
- ground handling facilities; and
- the appropriate framework for setting airport charges.

The following sections review the actions taken by the Commission in each of these four areas, plus alliances and state aids.

0.2.1 Computer reservation systems

Computer reservation systems are typically owned by airlines and enable travel agents, who are responsible for 80% of ticket sales, to obtain information and make reservations for customers on flights (and ancillary services) via a computer terminal. On 8 February 1999, the European Council issued Regulation (EC) No. 323/1999, amending the earlier (EEC) No. 2299/89, regarding a code of conduct for the use of computer reservation systems. The code is needed because of problems arising from information asymmetries. In particular, with customers often relying on the systems for details of services, airlines that own them can bias the system by, for example, displaying information relating to their services more prominently or making it easier to book them.[8] Naturally, this gives a competitive advantage to those airlines that operate the systems.

In order to facilitate fair competition, the code requires vendors of computer reservation systems to allow any airline to participate in the system on an equal and non-discriminatory basis and to provide information that is clear, accurate and non-discriminatory. One of the key changes introduced by the recent amendment was the extension of the code's scope to cover systems operating in rail transport (see below for recent liberalization measures in this industry).

0.2.2 Airport landing and take-off slots

The greatest impediment to the development of effective competition is the increasing level of congestion and the scarcity of take-off and landing slots (and associated infrastructure). Under existing arrangements, access to slots is granted principally on the basis of 'grandfather rights', which enable airlines to retain those slots used in the past. The consequence of this regime is to allow flag carriers to retain much of their historical dominance of airports' facilities, thereby restricting the scope for new entry.

CAA (1998) estimates that in 1995, 70% of the traffic on the 44 busiest intra-EU routes had end points at one of four seriously congested airports. It is on these busier routes that (in the absence of slot scarcity) we would have expected effective competition to be sustained.

In 1993, Council Regulation 95/93 was issued in an attempt to address the issue of slot allocation. In particular, it introduced a 'use it or lose it' clause allowing unused slots to be reallocated via a slot pool (which also includes new slots) from which 50% could be allocated to new entrants. This Regulation has, however, failed to have a significant impact with very few slots being granted to new entrants at congested airports at peak times.

With the demand for air travel increasing, the problem of establishing a more effective slot allocation mechanism becomes increasingly important. With significant expansions in capacity at congested airports unlikely on environmental and social grounds, the Commission is seeking to revise the existing slot regulations in an attempt to facilitate effective competition. These proposals are likely to introduce some form of market for trading slots. In the quest for improved economic efficiency, however, many practical difficulties arise. For example, commentators have suggested that allocating slots through price mechanisms could reinforce the position of dominant carriers and reduce the level of intra-EU competition. There is also the question of who owns the slots: is it airports, airlines or governments? The issue is further complicated by differences of opinion between member states that will make it difficult to reach an agreement acceptable to all parties. So, while reforming the method of slot allocation must be a key priority for the Commission over the next two to three years, it faces many political and economic difficulties.

0.2.3 Ground handling facilities

The ground handling activities provided at airports are essential inputs for an airline's services. In Europe, prior to liberalization, these activities were traditionally monopolies operated by either the flag carrier or the airport itself. Recognizing the difficulties that market power over an essential input could create for new entrant airlines, and that it would be feasible to introduce competitors, the Commission issued a Directive (96/97/EC) in October 1996 intended to make the market for ground handling more competitive. Subject to the level of traffic at the airport, an airline can now either operate its own ground handling activities or, since January 1999, use a third party. A number of derogations, requiring Commission approval, have been granted from this Directive (to German airports in particular). In keeping with liberalization, these exemptions have typically been limited in both scope and duration.

0.2.4 Access charges

The other infrastructure issue that the Commission has addressed is the appropriate framework for establishing charges for access. In particular, it has bey pressing for the adoption of a proposed Council Directive on airport charges (COM (97) 154 final, 23 April 1997), which provides a framework based on the principles of transparency, cost-relatedness and non-discrimination. The framework provides scope for charges to include congestion and environmental costs. On this issue more generally, the Commission presented a White Paper in July 1997, arguing the need for harmonization across the EU of the charging principles applied to transport infrastructure.

0.2.5 Alliances

As with other global industries, there has been a trend towards consolidation in aviation since deregulation. Ownership limits contained in bilateral agreements have, however, resulted in airlines seeking alliances rather than full mergers. These alliances deliver some of the same benefits of mergers through economies of scale, scope and density, and they still have the potential to increase market power. When these alliances are formed between EU carriers, the Commission, under Regulation No. 3975/87, has the authority to apply EU competition rules.

In August 1995, the Commission approved the alliance between SAS (the Scandinavian flag carrier) and Lufthansa subject to a number of conditions intended to ensure the potential for competition, including the surrender of slots to new entrants. On routes between the EU and a third country, however, the Commission's authority is diminished; it is the member states that have greater powers of enforcement in these cases. For example, in the proposed British Airways and American Airlines alliance, four competition authorities became actively involved: the Office of Fair Trading and the Department of Trade and Industry in the United Kingdom; the Department of Transport in the United States; and DG IV (Competition) in Europe.

Extending the scope of existing Regulations to cover air services between member states and third countries, which the Commission is proposing, could greatly increase the consistency with which EU competition rules are applied. Considerable resistance to such proposals would, however, be likely from member states and incumbent airlines.

0.2.6 State aid

Although state aids to airlines have been highly controversial, it is to be hoped that this issue is consigned to the past. In a speech on 30 October 1998, Neil Kinnock, then European Commissioner for Transport, said 'The state aid door is now firmly closed and I can foresee no circumstances in which re-opening it could be justified.' Just three months prior to this statement, however, a Commission decision of 22 July 1998 ruled that state aid granted to Air France between 1994 and 1996 was compatible with the common market. This was despite an earlier judgement by the European Court that condemned the aid on the grounds that it gave Air France an unfair advantage.

0.3 Maritime transport

Four Council Regulations, adopted in 1986, liberalized maritime transport in line with the basic principles of EU law. Following the development of an integrated European transport system, the completion of the internal market and technological changes, the potential for competition within and between seaports increased. In recognition of this, in December 1997, the Commission published a Green Paper that discussed the application of competition to ports and maritime infrastructure. On the basis of this Green Paper and the subsequent debate, the Commission is now preparing to submit proposals on the liberalization of port services.

Two principal concerns in liberalizing port services relate to infrastructure access (that is, ports and associated facilities) and the financing and charging of these infrastructures. Problems arising from access to ports, which by virtue of location are often monopolies, or port services, particularly when provided on an automatic basis by a monopoly, can be addressed by regulation (although this is not necessarily cost effective).

With infrastructure charging, the Commission is seeking to adopt an approach that is consistent with other modes of transport in an attempt to alleviate the distortions caused by different systems of charging. In keeping with the 1997

White Paper on infrastructure charging highlighted in the discussion of air transport above, charges will be related to social marginal costs, which include congestion and pollution costs. Moreover, rather than setting actual charges, the Commission's proposals are likely to establish a framework within which there will be flexibility to set levels providing the principle of non-discrimination between users is adhered to.

Nevertheless, beyond this general approach, specific difficulties could be generated by the varying degrees to which member states finance port facilities. As transport systems become more integrated, ports will increasingly find themselves facing competition and, in this environment, state financing would distort competition. Although the Commission suggests that an appropriately flexible framework for port charging could address these effects, it may become necessary to introduce guidelines for the application of state aid. If competition rules and state aid provisions are to be applied effectively, it is also necessary that greater transparency is introduced into ports' accounts, as the Commission has argued.

0.4 Rail transport

The first significant step toward liberalization of the EU's railways was taken with Council Directive 91/440/EEC, which came into force in January 1993. The Directive sought to provide companies with limited access to railway infrastructure. It requires greater autonomy for railway undertakings, reduction of their indebtedness and the accounting separation of infrastructure management and transport operations. These measures were only partially successful and so two further Directives were introduced (95/18/EC and 95/19/EC) with effect from 25 June 1997. These sought to establish common criteria for the licensing of railway undertakings and a transparent and non-discriminatory system for allocating infrastructure and setting infrastructure charges.

The next significant Commission initiative was the 1996 White Paper (COM (96) 421 final), 'A Strategy for Revitalizing the Community's Railways'. This argued for a 'new kind of railway'. It advocated action to improve the finances of railways and to introduce market forces through accounting separation of infrastructure management and transport operation, the extension of infrastructure access rights and the promotion of interoperability.[9] The White Paper also proposed to generalize the use of public service contracts between state and transport operators. Following the debate generated by the White Paper, the Commission is due to propose Directives on public service contracts and state aid in the near future. It is also seeking ways to increase the interoperability between national rail systems as this fragmentation is seen as a real impediment to developing a more efficient EU rail service.

The publication of the White Paper illustrates the Commission's intent to liberalize rail transport and create a more efficient service. Existing Directives are, however, limited in their scope and effectiveness. In particular, there is no requirement for the body that allocates infrastructure capacity to be separated from transport service provision. Consequently, national railways can implement the rules and set the conditions under which companies enter the market.

In recognition of this conflict of interest, and as part of a wider package of measures (COM (98) 480), the Commission has proposed a new infrastructure package to replace the existing Directive. This would require an organization independent of rail transport service providers to allocate capacity and set charges. Appeals against its decisions could be taken to an independent body. The proposals also outline the infrastructure that railway undertakings are entitled to access, the principles applied for allocating capacity (including the promotion of competition) and the principles under which charges for access are made. To make the system transparent, the infrastructure manager would be required to publish this information.

Other measures within the package seek to amend existing Directives. For example, to prevent cross-subsidies distorting competition, transparency is required through greater accounting separation between infrastructure management and transport operation and also between freight and passenger services. In addition, to prevent them becoming an entry barrier, rules on licences have been extended to cover all railway undertakings (and not just international services and combined transport). The proposed package of measures is intended to allow competing railways to exploit existing access rights effectively.

0.5 Natural gas

The European Parliament and the Council adopted a Directive outlining common rules for the internal market in natural gas on 22 June 1998.[10] The Gas Directive must be implemented by 10 August 2000. The approach in the gas sector follows very closely the rules that have been established in electricity, discussed in detail later in this Report. The Gas Directive lays down rules relating to the organization and functioning of the natural gas sector, access to the market, the operation of systems, and criteria and procedures applicable to the granting of authorizations for transmission, distribution, supply and storage of natural gas. The Directive also permits the imposition of public service obligations relating to security of supply, regularity, quality, price and the environment. As with all such obligations, they must be clearly defined, transparent, non-discriminatory and verifiable. As with electricity, the market is to be opened up to competition gradually.

The most ambitious liberalization programme to date in the European gas supply industry has occurred in the United Kingdom. Before the mid-1980s, natural gas in the United Kingdom was supplied by a state-owned monopoly. Today, the market for gas is fully liberalized, putting the United Kingdom far ahead of the schedule outlined in the Gas Directive. Subsequent to liberalization, the incumbent British Gas, which has also been privatized, voluntarily separated its businesses to ease its participation in the newly competitive market-place. The transportation component of the industry is operated by a regulated private monopoly Transco, and the supply part of the business is now performed by British Gas Trading (BGT).

UK gas retailing services are fully competitive for both business and domestic consumers. All consumers can now choose their gas supplier and competition is intense. By April 1999, there were 25 companies competing with BGT to supply gas to the domestic sector. As the Gas Directive suggests, competition in the United Kingdom was phased in according to size of consumer. Furthermore, the introduction of competition into the domestic sector was subject to trials, and was phased in gradually across the country.

According to Ofgas, the UK gas supply regulator, customers moving from BGT to an equivalent tariff with a competitor can save 10% or more.[11] This price margin, together with low customer switching costs, helps to explain why over a nine month period, the incumbent BGT lost on average around 15% of its connections to competitors. More recently, the UK National Audit Office has reported that nearly 25% of domestic customers have now switched gas suppliers.[12]

The phased introduction of competition in the United Kingdom has passed off relatively smoothly. Nevertheless, there is a need for continued regulatory oversight of the industry and the activities of the incumbent need to be closely monitored. It may be premature to judge how successful the programme of liberalization has been in the United Kingdom, but it is clear the Gas Directive will have almost no effect within the United Kingdom.

0.6 Postal services

Liberalization of European postal services began in 1992 following the publication of a Green Paper by the Commission.[13] In 1993, the Commission submitted to the European Parliament and the Council the findings of the consultation process.[14] In July 1995, the Commission proposed a Directive on common rules (harmonization measures) for the development of postal services and a draft Notice on the application of competition rules in this sector. The Postal Directive (97/67/EC) has been adopted by the European Parliament and the Council, as has the Postal Notice.[15,16] The Directive aims to introduce common rules for developing the postal sector and improving the quality of service, as well as gradually opening up the markets in a controlled way. Universal provision of postal services has played a key role in shaping the Directive.

Although initiatives to liberalize the postal sector began after moves in other network industries, much of the industry has moved very quickly towards competition. In some member states, notably Sweden, competition is already at an advanced stage. Interestingly, the United Kingdom is not at the vanguard of change in Europe in this sector. The Commission is currently reviewing the impact of liberalization in the sector. As part of this review, the Commission has launched studies on the costs and financing of universal service.[17] The Postal Directive requires that by the end of 2000, the Commission should report to the European Parliament and the Council on the application of the Directive. Further liberalization is likely to take effect in 2003, following proposals to be drafted by the Commission shortly.

0.7 Telecommunications

In terms of deregulation, telecoms is the most advanced of the network industries.[18] The Commission estimates that the European telecoms market has sales of around €148 billion in 1998, of which €28 billion was due to mobile telephony.[19] More generally, information technology is one of the largest and fastest growing sectors of the European economy, accounting for over 5% of Europe's GDP.[20] The significance of telecoms has not gone unnoticed by policy-makers in the Commission. Although telecoms was the main focus of the last Report in this series, substantial developments have occurred since the industry was fully liberalized in 1998.

0.7.1 January 1998 – the beginning of a new era

On 1 January 1998, Europe's telecoms markets were officially liberalized, marking the beginning of a new era in European telecoms. Against a rapidly changing technological backdrop, the Commission has been monitoring developments to gauge the success of this bold move. Member states have been implementing European legislation, and national regulatory authorities have been busy enforcing and defining new rules.

Competition is emerging in the formerly protected telecoms markets throughout Europe, but there remain great regulatory challenges. While initiatives at a European level have provided the catalyst for change, the momentum behind the reform process requires detailed regulatory work at a national level. European legislation needs to be transposed and enforced in each member state. As Herbert Ungerer of DG IV of the Commission has said, 'the devil is in the detail'.[21]

The Commission has formed a joint team comprising DG IV and DG XIII officials to oversee the implementation and enforcement of telecoms legislation in the member states. By the end of 1998, there were 89 infringement proceedings open against member states (30 relating to liberalization Directives and 59 to harmonization Directives). Despite the large number of proceedings, in the Fourth Report of November 1998, the Commission stated that 'there appear to be no areas in which significant failures have occurred in the practical application of nationally transposed legislation'.

Here, we examine three aspects of the liberalization programme in telecoms.

Ineffective regulatory structures and regulatory capture

Table 0.3 highlights the countries identified by the Commission as failing in certain areas connected with regulatory structures. A surprising number of countries have had the independence of their national telecoms regulator questioned by the Commission. As independence is essential to safeguard against regulatory capture, this is an unfortunate state of affairs.

Licensing

The framework governing licensing in Europe is laid out in general terms in the Licensing Directive.[22] To promote easier entry into the industry, the Commission has strongly encouraged member states to shift away from awarding individual licences and instead award general authorizations (or class licences). License procedures must also be published and conform to transparency and non-discrimination principles, and maximum time limits must be laid down. To ease the development of pan-European operations, the Commission has also responded to the many calls for a one-stop shop dealing with licence applications in Europe. The European Telecommunications Office, based in Denmark, will handle applications for licences in every member state through a single form.

Table 0.4 highlights the countries identified by the Commission as having problems in the areas of licensing. The opinions expressed by the Commission in Tables 0.3 and 0.4 suggest that the regulatory regimes in Europe are not fully developed or satisfactory. It would have been very surprising, however, had Europe shifted to an ideal regulatory state 1, immediately. Just as firms learn through making mistakes when entering new markets, regulators and member states also need time to develop satisfactory regulatory regimes. With the Commission playing a monitoring role in evaluating the performance of national regulators, this should lead to overall improvements in national regulatory frameworks.

Table 0.3 Status of National Regulatory Authorities (NRAs) in Europe

NRAs with overlapping jurisdictions	*NRAs with questionable independence*	*NRAs with human resource difficulties*	*NRAs demonstrating a lack of pro-activity*	*NRAs with weaknesses in areas related to interconnection*
Austria, Netherlands	Belgium, Finland, Greece, France, Ireland, Luxembourg	Belgium, France, Greece, Italy, Luxembourg	Denmark, France, Netherlands, Sweden	Germany, Luxembourg, Netherlands

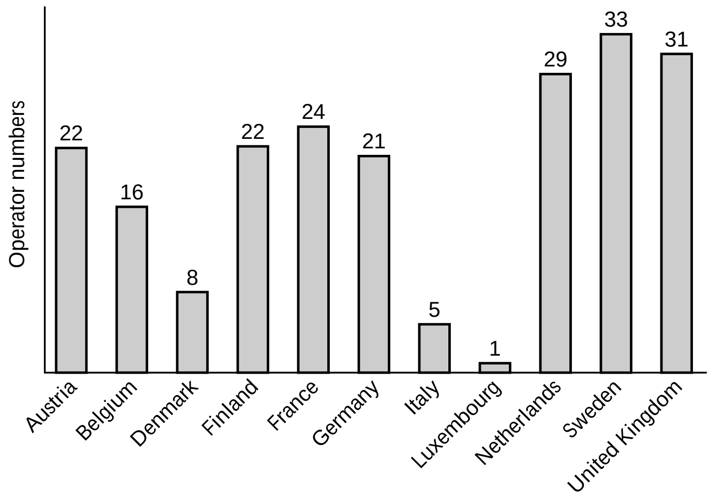
Note: Adapted from: 'European Commission Fourth Report on the Implementation of the Telecommunications regulatory Package, Communication from the Commission to the Council, the European parliament, the Economic and Social Committee and the Committee of the Regions', COM (98) 594, November 1998.

Table 0.4 Status of licensing in Europe

Concerns about licence applications	*Lack of transparency on licence conditions*	*Level of licence fees*	*Time limits for the issue of licences*	*Lengthy or cumbersome procedures*
Belgium, France, Italy, Spain	Ireland	France, Germany, Italy (mobile), Luxembourg (mobile)	Belgium, France, Greece, Italy, Luxembourg	Austria, Belgium, Italy, Spain

Note: Adapted from: 'European Commission Fourth Report on the Implementation of the Telecommunications regulatory Package, Communication from the Commission to the Council, the European parliament, the Economic and Social Committee and the Committee of the Regions', COM (98) 594, November 1998.

Figure 0.1 Number of operators authorized to offer national public voice telephony, August 1998



Source: European Commission, 'Fourth Report on the Implementation of the Telecommunications Regulatory Package', COM (98) 594, November 1998.

Evidence of competition

Competition is increasingly effective in the European telecoms market place. Figure 0.1 shows the number of national licence holders for a number of European countries. It indicates that, at least in terms of numbers, competition at a national level exists in all major markets.

Although the number of nationally licenced telecoms operators in Europe at August 1998 was 218, there are many hundreds more offering services. Most entry to date has occurred in the markets serving business users. Entry into the local loop serving residential consumers has been very modest to date due to the relatively high costs of rolling out alternative infrastructure plus uncertainty about regulation.

Tariffs for telecoms services have been failing by up to 30% for international calls.[23] The costs of supplying services are, however, also failing significantly. The extent to which competition is placing downward pressure on prices is difficult to quantify precisely, but it is striking that where competition has not been so prominent, as in the leased lines market, prices remain relatively high in Europe. According to a report published by a telecoms consultancy Philips Tarifica, European competitiveness is being damaged by relatively high prices for leased lines.[24] The company points out that a leased line from London to New York is cheaper than a number of much smaller links within Europe. Consequently, a lot of internet traffic is directed to the United States rather than in Europe. The report also identifies much inconsistency in pricing of leased lines in Europe. The absence of effective competition in the leased line market is likely to end, however, when new pan-European high capacity networks are brought on stream from late 1999 onwards.[25]

0.7.2 Interconnection – the devil is in the detail

The foundation of European policy on interconnection is the Interconnection Directive.[26] This seeks to establish a harmonized framework for interconnection with the following important characteristics:

- transparency, objectivity and non-discrimination in accordance with the principle of proportionality; and
- a priority given to commercial negotiations.

The Directive also provides clear responsibilities for national regulatory authorities in accordance with subsidiarity, including effective mechanisms for dispute resolution. The latter are crucial as the opening of Europe's telecoms markets inevitably means interconnection disputes will proliferate. Disputes are likely because small differences in interconnection rates can make or break a business. The scale of interconnect revenues and costs can be seen in the following figures. It is estimated that 10% of British Telecom's (BT) revenues, around $2.3 billion, derive from interconnect fees paid by other fixed operators, mobile and paging companies, and internet service providers. For Cable and Wireless Communications, around 40% of its operating costs, or 30% of its turnover, is spent on buying interconnection.[27]

In resolving disputes and setting a framework for interconnection, the Directive seeks to balance the interests of entrants and incumbents. This is achieved by setting out rights and obligations for all players in the market. Organizations with 'significant market power' are, however, assigned additional obligations. An organization is presumed to have significant market power if it has more than a 25% share of the relevant market.[28] The additional obligations are *inter alia*:

- the obligation to meet all reasonable requests for interconnection and special access;
- respect the principle of non-discrimination;
- provide suitable information to other parties; and
- communicate interconnection agreements to the national regulator.

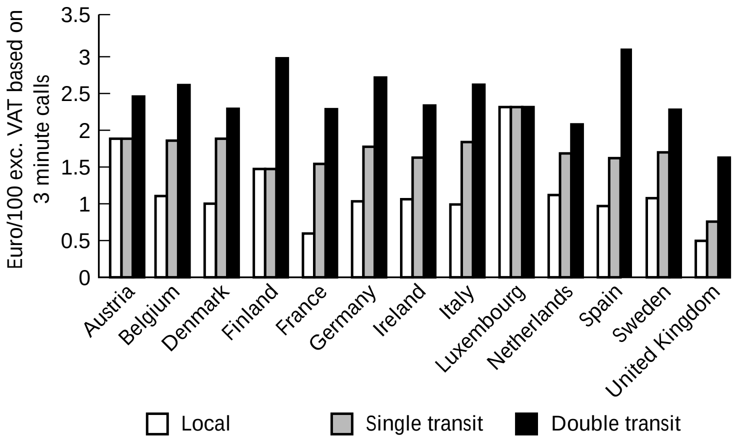
These obligations (and others) are intended to redress the imbalance in negotiating power between new, smaller, market-entrants and well-established incumbents.

Not surprisingly, national regulators throughout Europe have declared incumbent operators as organizations with significant market power. For example, Deutsche Telekom is required to:

- engage in non-discriminatory interconnect pricing;
- publish a reference interconnection offer including interconnect price lists;
- set cost-oriented interconnection tariffs;
- produce transparent cost accounts; and
- publish separate accounts for distinct components of the business.

The Interconnection Directive is general in scope and sets out principles; it is less useful on specifics. For this reason, and because of the significance of interconnection to the development of competition, the Commission has sought to

Figure 0.2 Interconnection charges per minute, March 1999



Source: Interconnection Tariffs in Member States, DG XIII/A/1, Brusels, 1 March 1999.

provide guidelines on interconnection by publishing a Recommendation. Part 1 of the Recommendation deals with pricing issues and advocates the use of long-run average incremental costs.[29] The time needed to establish suitable cost accounts to conform to these standards has led the Commission to recommend that in the interim 'best current practice' should be used. This benchmarking exercise means that until detailed cost accounts are produced (as of November 1998, only the United Kingdom met this condition), interconnection prices should fall in the range of the lowest rates prevailing in three countries for each of three distance categories (local, regional, national). Recent interconnect rates offered by incumbents with significant market power are shown in Figure 0.2.

Only two countries in Figure 0.2 have interconnection charges in all distance categories that fall into line with best practice: France and the United Kingdom.[30] The United Kingdom's presence is not too surprising given that competition has been a feature of the UK telecoms market for many years. The presence of France is, however, a surprise as competition is much more recent and there appear to be problems with interconnection (see Table 0.5 below).

Part 2 of the Recommendation was adopted on 8 April 1998 and deals with accounting separation and cost accounting systems.[31] This focuses on how operators with significant market power have to provide cost-oriented interconnection (see Table 0.5 overleaf).

In addition to the Interconnection Directive, the Commission published a Notice in March 1998 on the application of the competition rules to access agreements in the telecoms sector.[32] The main purpose of this Notice is to reduce uncertainty and provide explanations on how the EUs competition rules will be applied to deal with gateway issues. This illustrates a worthy move to allay fears about regulatory risk.

Table 0.5 highlights the countries identified by the Commission as having some problems in the interconnection sphere. Germany appears in each column where there has been much controversy over interconnection and the very closely related issue of access.

Table 0.5 Status of interconnection in Europe

Entrants claim excessive duration for interconnection agreements	*Substantial interconnection disputes reported*	*Entrants complain about the lack of completeness or inadequacy of the RIO*
Austria	Austria	Austria
Belgium	Denmark	France
France	Germany	Germany
Germany	Greece	Greece
	Sweden	Italy
	United Kingdom	Luxembourg

Source: European Commission, 'Fourth Report on the Implementation of the Telecommunications Regulatory Package', COM (98) 594, November 1998.

0.7.3 Number portability and carrier pre-selection – United Kingdom ahead and behind

An important amendment to the Interconnection Directive was adopted on 24 September 1998.[33] This brings forward the date by which number portability should be made available to consumers to 1 January 2000. In early 1999, only Finland has introduced full number portability, although France, Germany and the United Kingdom have partial number portability. The absence of number portability is regarded as a major impediment to the effectiveness of competition as it substantially raises customer switching costs.

In addition, the amendment requires the introduction of carrier pre-selection by at least all fixed network operators with significant market power by 1 January 2000.[34] Carrier pre-selection allows customers to pre-select an operator who will be responsible for the delivery of telephone calls. For example, a customer with an access line provided by Deutsche Telekom might choose to have all calls (or a subset of calls) delivered by another operator such as Mannesmann. In this case, Deutsche Telekom would bill the customer for access and Mannesmann for interconnection, and Mannesmann would bill the customer for the calls it delivers.

The fact that carrier pre-selection can be imposed on any operator that provides access has worried new operators investing in local loop infrastructure. As a result of this rule change, the profitability of new entrants in the local loop could be significantly harmed if a national regulator mandates carrier pre-selection on their businesses. Indeed, the amendment to the Inter-connection Directive is an illustration of the regulatory risks that prevail in the telecoms industry.

The United Kingdom has been at the forefront of moves to bring about number portability. With carrier pre-selection, however, it has requested a derogation from the timetable proposed by the Commission for around one year on technical grounds. To some extent, the UK authorities and the incumbent operator BT were surprised by the moves to mandate carrier pre-selection. It is seen by some as conflicting with the United Kingdom's policy of promoting infrastructure-based competition.

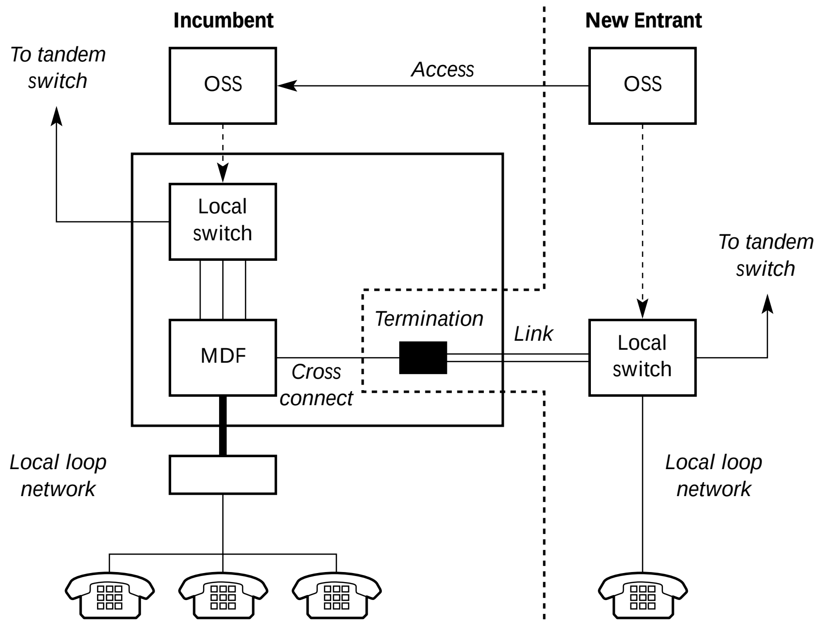
0.7.4 Access and local loop unbundling

Competition in European telecoms markets has been least conspicuous in residential access markets. In residential telephony, incumbents still reign supreme. In a few countries and regions, alternative access providers have appeared, largely on the back of cable television, but their presence is not very great. In an effort to accelerate local competition, policy-makers have, therefore, promoted indirect access.

Carrier pre-selection is an illustration of indirect access. The appeal of indirect access is that it enables competitors to enter the market without needing to invest in local loop infrastructure. Indirect access can facilitate relatively quick, service-led competition. The downside of indirect access is that service provision by competitors is heavily dependent on incumbent infrastructures. Indeed, indirect access may severely constrain the range of services a competitor can offer customers. For example, where an incumbent offers a customer a traditional narrowband connection, it is not possible for an entrant to offer higher bandwidth services.

There are two broad alternatives to indirect access: local loop unbundling (LLU) and infrastructure competition. LLU requires an incumbent to open its network in such a way that it allows entrants to rent some portion (maybe the last mile of the line connecting a subscriber to a network) of the local loop network. An illustration is shown in Figure 0.3. LLU could be where a competitor incorporates the line connecting the subscriber to the incumbent's local exchange into its own network.[35] In effect, a competitor would rent the copper lines from the incumbent and cross-connect them to their own access network.

Figure 0.3 Local loop unbundling through copper line rental



Source: European Commission.

Table 0.6 Status of LLU in Europe in early 1999

Country	*LLU imposed on incumbents*
Austria	Yes
Belgium	No
Denmark	Yes
Finland	Yes
France	Under consideration
Germany	Yes
Italy	Yes
Netherlands	Yes
Sweden	No
United Kingdom	Under consideration

LLU is a way to deepen competition in telecoms, but in Europe/there is no requirement for LLU. Decisions on LLU are taken at a national level in accordance with European legislation. The status of LLU in a selection of member states is shown in Table 0.6, which shows that the approach to LLU in Europe varies from country to country. It is interesting to note that the United Kingdom is currently considering the merits of LLU. The discussions on LLU in the United Kingdom are focused on broadband access rather than on deepening competition in voice telephony. Whereas competition is relatively recent in most European countries, the United Kingdom has had almost eight years of full competition. This has resulted in entrants gaining around 15% of access connections in the residential and small business market. By contrast, the figure for Sweden is around 1%.

The demand for broadband access and associated policy concerns surrounding e-commerce have raised policy concerns about the supply of broadband access. It is argued by some that without LLU, entrants will find it very difficult to compete against incumbents in the fast growing broadband access market. On the other hand, if policy is changed to mandate LLU to incumbents' local loop infrastructure, investment in alternative local loop infrastructures may be undermined.

An innovative approach to the incentive problems of LLU has been taken in the Netherlands. Here, the regulator has mandated LLU for a fixed period of five years, with the price of unbundled network elements rising over this period. Hence, over time, investment incentives rise and it is intended this will lead to alternative access infrastructures and more sustainable competition. The regulatory strategy is designed to assist entrants at a stage when the exploitation of economies of scale is not feasible one potential serious drawback of the scheme is the credibility of the five-year period.

0.7.5 Universal service – France and Italy stand out, others to follow?

Universal service is regarded by many policy-makers in Europe as an important social goal. Consequently, European legislators have passed rules dealing with a number of issues connected to universal service:

- targets for supply time and quality of service;
- provision of advanced services;
- discounts, low-usage schemes and other specific tariff provisions;
- availability of itemized billing;
- access to and use of directory services;
- provision of public pay-telephones;
- specific conditions for disabled users and people with special needs; and
- numbering issues.

The introduction of competition in telecoms requires a different approach towards universal service.

France is the only country that has implemented a universal service financing mechanism. Approximately FF 4.8 billion (1997) and FF 6 billion (1998) is the total estimated net cost of France Telecom's universal service (respectively 5.5% and 7.3% of the company's fixed telephony turnover). In Italy, a fund has been created and is to be applied this year (1999) on the basis of operators' results for 1998. According to the European Commission, the methodology for calculating the net cost is of concern. Until the end of 2000, France also has in place a supplementary access charge designed to counter the impact of gradual rebalancing. It is likely that other countries may follow the lead taken by France and Italy.[36]

0.7.6 Convergence

In December 1997, the European Commission published an important Green Paper on convergence.[37] On 10 March 1999, the Commission adopted a Communication on the results of the public consultation.[38] The Commission has concluded that similar regulatory conditions should apply to all transport network infrastructures.[39] This horizontal approach to the regulation of infrastructure is complemented by a vertical approach based on services. Services are to be regulated along current lines, that is, determined by the specific nature of the service.

0.7.7 Mobile telephony and voice over IP

Mobile telephony has had a dramatic growth in popularity in Europe and there are now over 60 million subscribers. Network externalities have played a key role in stimulating growth, but it was the emergence of prepaid services that spurred growth most in 1998. Unlike its fixed counterpart, the mobile sector has generally been lightly regulated. In 1998, however, following initial enquiries by DG IV, national regulatory authorities conducted investigations in a number of member states, examining alleged high prices for some services.

The prices for international roaming and the prices for calls from fixed to mobile networks have been the particular focus of regulatory scrutiny. In the United Kingdom, Oftel imposed price-cap regulation on the termination charges levied by the two largest mobile operators (BT Cellnet and Vodafone) for calls received from the BT fixed network. While the value of fixed telephony services regulated by Oftel in the United Kingdom has declined in recent years, the opposite holds in mobile telephony.

Regulators in Europe are also considering allowing indirect access to mobile network operators with significant market power under the Interconnection Directive. Oftel and regulators in Scandinavia have taken the lead in this area and have proposed indirect access to such mobile operators. This followed interconnection disputes brought to the attention of the regulators. Oftel and other national regulator are also considering the merits of virtual network operators.

Perhaps the biggest challenge facing regulators in Europe is fixed-mobile integration (FMI). FMI is technologically feasible and commercially some services have been launched, for example, in Denmark. FMI means that those mobile operators also operating fixed networks will be able to offer customers a complete portfolio of services. Customers may be attracted to FMI because of convenience: one bill and one phone, instead of two phones and two bills. If this proves to be the case, the position of incumbent fixed operators in Europe who operate a mobile subsidiary (that is, most of them), is likely to be strengthened considerably. FMI was completely unforeseen at the time of deregulation in the early 1990s and it illustrates how technological change in the industry can dramatically affect the landscape.

Licences for third-generation mobile systems, 3G, are currently being awarded in Europe. Finland has already awarded four in a beauty contest. 3G systems will offer broadband mobile access and will eventually strengthen the trend towards FMI.

A great deal is made of entry into the telecoms market through the internet. IP telephony is used increasingly on private networks by corporations, but its presence on public networks is negligible. This is likely to change in the near future not because of entry by smart new telecoms firms, but because incumbents are now shifting into this technology significantly. For example, BT has announced that it intends to set up an IP telephony network in Spain. The attraction of IP telephony is that it enables multimedia services to be supplied much more efficiently; but IP telephony requires regulatory intervention, once again in matters connected with LLU.

The pace of change in mobile telephony and IP telephony is such that regulators are playing catch-up. There is little time available for considered reflection about appropriate market structures and rules.

0.7.8 The 1999 Telecommunications Review

Competition is a reality in telecoms throughout most of Europe. For large users of telecoms services, there are increasing numbers of operators offering services. The provision of alternative access to residential users and small businesses – competition in the local loop – is, however, barely visible. For most small users, competition is service driven. This is not necessarily a bad thing: after all, it has meant that telephony users throughout Europe have seen significantly declining bills. Nevertheless, it is possible that the current state of affairs could be improved by changing the regulatory environment.

In late 1999, the Commission will launch a Review of Telecommunications in Europe with a view to implementing regulatory changes in around 2003. The Review is likely to concentrate on the appropriateness of existing legislation. The regulatory package that has been implemented in Europe was designed primarily to shift the industry from monopoly to competition: from phase 1 to phase 2. ONP as a framework will probably need to be scrapped; instead, there will probably be a desire to move to a greater reliance on competition rules. In effect, consideration will need to be given to reforming legislation so that the industry can move forward to phase 3, competition.

The significance of the Review has been underlined by Herbert Ungerer: 'We are not just talking about the future of an industry, but about the broader prospects of Europe in the future internet economy'.[40]

0.8 Concluding remarks

Europe's network industries now operate in an environment far removed from the monopoly world of the 1970s and earlier. Changes in demand and technological developments have contributed to a policy shift towards competition. Unlike many other industries, however, network industries have characteristics that present obstacles to the workings of competition. Access and interconnection are perhaps the two most significant barriers to effective competition, but the legacy of monopoly is also important. Fortunately, economic policy can be designed and implemented to overcome many of the problems associated with these obstacles.

The European Commission and EU member states have been busy reshaping the network industries by developing regulatory rules that seek to nurture competition. The challenge has not been an easy one. Telecoms, for example, is an industry experiencing tremendous technological change, convergence with media and information technology industries, and rising demand for services. The emergence of the internet is also pushing the industry to the centre of economic activity. At the centre of all this stand the regulators, changing rules to permit competition. By the time rules are implemented, the industry has marched on and in many cases further reforms are needed.

The European network industry that has made the most progress towards competition is telecoms. This is probably because the industry has benefited from significantly declining costs, changing scale economies that permit smaller operations, and dramatically rising demand. Although most of the other network industries are arguably less complex than telecoms, they typically do not share these three attributes to the same extent.

Notes

1 In this chapter, written by Christopher Doyle with Martin Siner, Europe refers to the countries comprising the European Union and policy refers to actions taken by the EU as a whole, unless otherwise stated.

2 *Fourth Report of the Competitiveness Advisory Group*, European Commission, December 1996.

3 See note 2.

4 Liberalization establishes the conditions, or market rules, necessary for the operation of the internal or single market; harmonization is aimed at bringing consistency across what had hitherto been industries predominantly shaped by national markets.
5 See CEPR (1998).
6 Box 0.1 characterizes the formal position at a European level. In several member states, competition is much more extensive than suggested in Box 0.1.
7 For details of the impact of deregulation, see EC (1997) and CAA (1998).
8 US research suggests that 80% of bookings made by travel agents are from the first screen of information displayed by a computer reservation system and 50% from the first two lines of the first screen (Doganis, 1991).
9 This was supported by Council Directive 96/48/EC, which sought to promote interoperability of, and improve access to, national high-speed train networks.
10 98/30/EC 22 June 1998: European Parliament and Council Directive concerning common rules for the internal market in natural gas.
11 Ofgas (1998), Chapter 6.
12 *Office of Gas Supply: Giving Customers a Choice – The Introduction of Competition into the Domestic Gas Market*, National Audit Office London, HC 403, 12 May 1999.
13 'On the development of the single market for postal services', COM (91) 476 Final.
14 'Communication on the guidelines for the development of Community postal services', COM (93) 247 Final.
15 Directive 97/67/EC of the European Parliament and the Council of 15 December 1997 on common rules for the development of the internal market of EU postal services and the improvement of quality of service.
16 'Notice from the Commission on the application of the competition rules to the postal sector on the assessment of certain State measures relating to postal services', OJ C 39, 6 January 1998.
17 See http://www.ispo.cec.be/infosoc/telecompolicy/post/en/ for details of these studies.
18 This section summarizes historical developments prior to 1998 and concentrates on recent events. See CEPR (1998), the first Report in this series, for details before 1998 and material on the European Commission website. The website also contains a number of documents referred to in this chapter.
19 'Fourth Report on the Implementation of the Telecommunications Regulatory Package, Communication from the Commission to the Council, the European Parliament, the Economic and Social Committee and the Committee of the Regions', COM (98) 594, November 1998.
20 'Commission Report to the European Council – Job opportunities in the Information Society: exploiting the potential of the information revolution', COM (98) 590, 25 November 1998.
21 Keynote address, 'Outlining EC Plans for the Further Development of Europe's Telecoms Regulation Framework', presented in London, 11 February 1999, at 'Managing the Strategic Impact of Competition Law in Telecoms'.
22 Directive 97/13/EC of the European Parliament and of the Council of 10 April 1997 on a common framework for general authorizations and individual licences in the field of telecommunications services.
23 See 'The liberalization of telecommunications in Europe and the role of regulators', speech by Jean-François Pons, Deputy Director General DG IV, Rome, 12 April 1999.
24 The Tarifica Leased Line Report, 1999.
25 In May 1999, DG IV announced that it was probing into the prices charged for leased lines in Europe.
26 Directive 97/33/EC of the European Parliament and of the Council of 30 June 1997 on interconnection in Telecommunications with regard to ensuring universal service and interoperability through application of the principles of Open Network Provision (ONP), OJ L 199/32, 26 July 1997.

27 *Communications International*, 1 April 1999.
28 Significant market power is to be distinguished from dominance as used in the application of the competition rules in the Treaty. It is an ONP concept used to apply specific obligations in an access/interconnect context. Dominance is usually applied to cases where an organization has a market share far in excess of 25%. It is possible for a national regulatory authority to declare an organization with more than 25% market share as not having significant market power, and for an organization with less than 25% share as having significant market power.
29 Commission Recommendation 98/195/EC on interconnection pricing in a liberalized telecommunications market (Part 1), adopted 8 January 1998, amended by Recommendation 98/51 1/EC on 29 July 1998.
30 During 1999, many more incumbent operators across Europe have fallen into line with best practice.
31 OJ L 141, 13 May 1998, p. 6.
32 'Notice on the application of the competition rules to access agreements in the telecommunications sector – Framework, relevant markets and principle', OJ C 265, 22 August 1998, p. 2.
33 Directive 98/61/EC of the European Parliament and of the Council of 24 September 1998 amending Directive 97/33/EC with regard to number portability and carrier pre-selection (OJ L 268, 3 October 1998).
34 Carrier pre-selection is a form of indirect access, whereby customers can access the services offered by other operators indirectly.
35 This would require collocation of equipment. The entrant's equipment would need to he housed inside the incumbent's distribution frame: the local exchange or remote concentrator. LLU of this form was mandated in the United States following the 1996 Telecommunications Act. For a detailed discussion on LLU and on the main alternative form it may take (bit stream access), see Ovum (1998) and Oftel (1998).
36 For example, a consultation process on funding universal service is expected to be published by Oftel in 1999.
37 See note 21.
38 Communication regarding the results of the public consultation on the Green Paper on the convergence of the telecommunications, media and information technology sectors and the implications for regulation, COM (99) 108, 9 March 1999.
39 Summary of the results of the public consultation on the green paper on the convergence of the telecommunications, media and information technology sectors; Areas for further reflection, SEQ (98) 1284 Final, Brussels, 29 July 1998.
40 See note 23.

PART 1: Issues in Electricity Market Integration and Liberalization

Michael Pollitt

1 Electricity Market Integration and Liberalization

The context of this Report is the European Electricity Directive, which came into force on 19 February 1997 and set a target of 19 February 1999 as the date by which it should be transcribed into national legislation. The Directive prescribes common rules for the progressive liberalization of national electricity markets within the EU, extending the 1985 single European market concept to the electricity industry.[1]

Since the Second World War, electricity has tended to be viewed as a natural monopoly industry in many countries. Governments have traditionally intervened in the industry because it has had a much wider impact on society than the 2% of GDP that it directly represents within a typical advanced economy. Hence, electricity has usually been produced by state-owned companies: in 1985, 19 out of 24 OECD countries had state-dominated electricity industries.

By 1997, however, nearly all of those countries were in the process of restructuring and privatizing their electricity industries.[2] There has been a sea change in government attitudes to the electricity industry – its competitiveness, its regulation and its ownership. In what follows, we set the scene for our later investigation of the process of electricity liberalization in Europe.

1.1 The structure of the electricity industry

Electricity is a commodity that is produced and delivered in a four-stage vertically interdependent process involving generation, transmission, distribution and retailing (or supply):

- *Generation* refers to the production of electric energy in power stations.
- *Transmission* is the transportation of this energy along high voltage cables constituting the main electricity *grid*.
- *Distribution* is the transportation of the energy at lower voltages to final customers.
- *Retailing* is the business of advertising, branding, contract bundling and billing of electricity for final customers. For some customers, retailing will include *metering* – the provision of equipment to measure consumption – but in many domestic markets, metering remains part of the distribution business. Retailing is called *supply* in the United Kingdom.

The *trading* of electricity refers to the business of facilitating exchange of *wholesale* electricity between generators, and between generators, and suppliers in order to meet contractual obligations. Such trading can take place via bilateral contracts, day-ahead markets, spot or balancing markets and futures markets. *Bilateral contracts* are usually between generators, and suppliers on the basis of long-term power requirements. *Day-ahead markets* (power pools) and *balancing markets* trade on the basis of short-run supply and demand conditions. *Futures markets* facilitate liquid and anonymous trading of electricity supply contracts, allowing companies to hedge price risks associated with the supply of longer term power needs.

Electricity can be produced in a range of power plants. Most electricity is generated in large-scale nuclear, coal, natural gas and oil-fired plants, which are each typically capable of producing enough electricity to serve a medium-sized city. These plants can be built at will and their cost is partly a function of the proximity of the plant to sources of locally produced fuel (such as coal) or the cost characteristics of national fuel distribution networks (such as for gas) or the availability of fuel import facilities. Other plants may use such forms of energy as hydro, solar, wind, biomass and waste power. The availability of these, often much smaller scale plants, is severely limited by geography and, at current levels of technology, they usually need subsidies to be competitive with cheapest fossil fuel power plants. Table 1.1 indicates the significance of different fuels in electricity generation across Europe.

Within most European electricity markets, there are a large number of power plants and it is thought that the market for generated wholesale bulk electricity is potentially competitive – and hence that active competition should be

Table 1.1 Generation technology (as a percentage of national output), 1996

State	*Nuclear*	*Coal*	*Oil*	*Gas*	*Renewable*
Austria	–	11.5	3.7	17.5	67.3
Belgium	57.6	24.2	1.7	14.6	1.8
Denmark	–	74.0	10.8	10.7	4.5
Finland	28.1	31.8	1.9	12.3	26.0
France	78.2	6.1	1.5	0.8	13.3
Germany	29.1	55.0	1.4	8.7	5.8
Greece	–	69.3	20.2	0.2	10.4
Ireland	–	48.4	14.2	33.2	4.1
Italy	–	10.6	48.9	21.0	18.1
Luxembourg	–	26.7	3.4	48.0	21.8
Netherlands	4.9	31.6	4.6	55.6	3.3
Portugal	–	36.6	17.5	–	45.9
Spain	32.5	31.5	8.0	3.9	24.1
Sweden	52.5	3.0	5.2	0.3	39.0
United Kingdom	27.3	42.4	4.0	23.6	2.7
Norway	–	0.2	–	0.3	99.5
Switzerland	45.2	–	0.5	1.2	53.1
Czech Republic	20.1	73.3	1.1	1.2	4.2
Hungary	40.4	28.3	12.6	18.1	0.6
Poland	–	97.1	1.2	0.3	1.5

Sources: IEA (1998a) and IEA (1998b).

encouraged. This is because economies of scale in power station operation are exhausted at low levels of output relative to the size of the market. In 1999, the cheapest new electricity plant uses gas-fired CCGT (combined cycle gas turbine) technology, which has a low minimum efficient scale. This means that most national electricity markets in Europe can support several companies or, if interconnections are strong enough, face disciplining competition from the wider supranational market.

A key characteristic of electricity as a commodity is that it cannot be stored except at very high cost in batteries. It can be converted (at substantial cost) to potential energy in a pumped storage hydro station and hydro power magazines for later reconversion back to electricity. Thus, electricity demand and supply must be instantaneously in balance. This means that electricity supplied at different times of the day and in different places are not perfect substitutes. This is different from standard commodity markets such as oil and grain. Even natural gas, which is perhaps the closest commodity in characteristics to electricity, can be stored in specialist storage facilities and in the gas pipeline network. Variations in the demand for gas do not require immediate variations in production because the pressure in the pipes can be allowed to vary.

Electricity transmission and local electricity distribution involve large sunk capital costs and capital equipment with significant visual environmental impact. These stages of electricity production are usually considered to be natural monopolies. Typically, each European country has had one company operating its national transmission network and a number of regional local monopolies operating its distribution networks. There is little scope for actual competition in the provision of electricity transportation services (though benchmarking is possible). Table 1.2 outlines Europe's transmission and distribution systems.

Electricity transmission and distribution systems require orderly arrangements for the dispatch of generating plant to satisfy demand from customers. This requires a *system operator*, who oversees the process of instructing plants on required availability and physically balancing the system in situations where actual supply and demand deviate from planned supply and demand. Such co-ordination is technically necessary, partly because transmission constraints may mean that running higher cost generating plants may reduce total system costs relative to running the lowest cost generating plant.

The system operator must ensure that certain *ancillary services* (such as reactive power, black-start capabilities and voltage control) are provided to the network to ensure its operation. These are purchased from the generators (and some electricity customers) by the grid operator. Usually, the operator of the transmission network has also been the system operator. System operation is a natural monopoly. It is not essential, however, that the transmission network owner and the system operator are the same company.

Electricity retailing or supply has traditionally been bundled with distribution, but recent liberalization efforts have demonstrated that it is actually separable from distribution and hence is competitive. Supply companies can purchase generated electricity and transportation services and compete on the basis of least-cost purchasing, metering and billing costs and quality of customer

Table 1.2 Transmission and distribution systems (using national definitions), 1997

State	*Transmission circuit (km)*	*Number of customers*
Austria	6024	N/a
Belgium	1151	4 816 000
Denmark	5465	2 913 500
Finland	20 000	2 907 000
France	47 072	30 000 000
Germany	40 730	43 299 500
Greece	9358	N/a
Ireland	2083	1 483 000
Italy	22 027	N/a
Luxembourg	1995	N/a
Netherlands	9064	7 033 000
Portugal	3580	N/a
Spain	29 781	20 981 000
Sweden	30 409	5 200 000
United Kingdom	23 236	26 757 000
Norway	18 154	N/a
Switzerland	5519	N/a
Czech Republic	4450	N/a
Hungary	3126	5 630 000
Poland	12 577	15 000 000

Source: UCTPE Statistical Yearbook, 1997.

service. In the Nordic countries, customers pay two bills: one for energy from traders and another for energy transport. Table 1.3 breaks down the structure of demand for electricity in European countries between industrial, commercial and residential users.

1.2 A single electricity market in Europe?

The electricity industry has traditionally been characterized by a highly vertically integrated market structure with little competition in the potentially competitive segments of the market – with the market defined as a national electricity market. The Electricity Directive envisages an opening up of competition in the process of providing new generating plants, between generating companies for the right to have their plants dispatched, and in supply. The Directive prescribes a separation of the monopoly elements of the business from the potentially competitive segments so that controllers of the monopoly parts are unable to use their market power to abuse their position in the other stages of production.

The Directive includes provision for eligible EU electricity customers to be able to choose their suppliers. This provision on market opening requires that at least 25% of each member states' electricity demand will be subject to competition from 19 February 1999, rising to 28% from 19 February 2000 and 33% from

Table 1.3 Structure of electricity demand (as a percentage of final sales), 1996

State	*Industrial* %	*Commercial* %	*Residential* %
Austria	38.7	34.2	27.1
Belgium	50.5	17.0	32.5
Denmark	30.9	35.6	33.4
Finland	54.9	19.5	25.6
France	39.9	28.8	31.4
Germany	46.4	25.6	28.0
Greece	36.9	30.1	33.0
Ireland	39.3	24.7	36.0
Italy	50.6	25.9	23.6
Luxembourg	61.0	23.7	15.3
Netherlands	44.9	32.5	22.5
Portugal	45.7	26.8	27.5
Spain	44.9	30.3	24.8
Sweden	41.9	24.4	33.7
United Kingdom	35.6	30.2	34.2
Norway	44.4	20.9	34.6
Switzerland	32.7	36.1	31.2
Czech Republic	39.9	30.5	29.6
Hungary	35.0	31.3	33.7
Poland	56.8	25.6	17.6

Note: 'Industrial' includes energy industries; 'commercial' is a residual.
Source: IEA (1998b).

19 February 2003. To achieve this, countries are required to set customer size thresholds for eligible customers that ensure that the required market opening occurs. Yet many countries have thresholds considerably lower than the minimum that would be prescribed by strict compliance with the Directive.

In this Report, we consider the impact of deregulation on the members of the EU, on Hungary and Norway, and, to a lesser extent, on the Czech Republic, Poland and Switzerland. These last five countries have been or are candidates for EU membership and are interconnected with EU electricity grids. If they became EU members, they would be expected to comply immediately with the Directive.

The drive behind the Electricity Directive is to create a single European electricity market in which there will be effective competition within and across Europe for contracts to supply electricity. The intention is that the market should be trans-European rather than national where this is possible.

The structure of the rest of Part 1 is as follows. Chapter 2 looks at progress up to 1999 in electricity liberalization across Europe. We will see that there has been widely differing progress: at one extreme, France's electricity market structure is largely unchanged since 1946; at the other, the markets in Norway and the United Kingdom have both undergone radical transformation since 1990. We suggest, therefore, that the process of liberalizing markets has some way to go.

Chapter 3 investigates the political and social factors that are important in electricity supply. Concerns over the effects of electricity liberalization on poor consumers, the environment and employment in industries directly supported by the electricity sector are likely to affect the pace of electricity liberalization in different countries.

Chapter 4 investigates the obstacles to the creation of competitive electricity markets across Europe. We observe that there are large issues – including market power, legal restrictions, tax differentials and market design – that must be addressed if liberalization is to have its most positive impact.

Chapter 5 closes Part 1 by examining the contents of the Electricity Directive in detail and the progress of individual countries in complying with it.

Notes

1 The text of the Directive can be found at http://europea.eu.int/en/comm/dg17/gazel_en.htm.

2 See Pollitt (1997a).

3 The western and northern European grid, UCTE (formerly UCPTE), and the eastern European grid, CENTREL, are synchronized and jointly operated. UCTE includes Switzerland. CENTREL includes the Czech Republic, Hungary, Poland and Slovakia. NORDEL, the Nordic grid that connects Denmark, Finland. Norway and Sweden, is interconnected to but, with the exception of Denmark, not synchronized with UCTE.

2 Progress with European Electricity Liberalization

In spite of recent moves towards restructuring and privatization, the electricity industry is still heavily regulated and subject to government intervention in most European countries. In accordance with the analysis of market structure in the introduction to this Report, the electricity industry is in the process of moving from phase 1 (natural monopoly) to phase 2 (monopoly and competition). In phase 2, competition is gradually introduced into some or all markets, with regulation focusing on monopoly abuse by dominant incumbents in both retail and interconnect markets, emerging competition issues and public service obligations.

In phase 3 (competition) it is envisaged that competition is extensive and generally effective, and that the market can be regulated with a light hand, as in most markets. It is in phase 2 that regulatory intensity reaches a maximum, which explains the increasing interest in 'deregulating' electricity markets in Europe. There is as yet little evidence, however, on when phase 2 will become phase 3, and when sector specific regulation can be abandoned.

National governments have sharply differing policy approaches towards the electricity sector, based on different histories and social objectives for the industry. The European Commission has taken a lead in setting out the future development of the sector within the EU, putting pressure on governments to align their policies more closely to the liberal market it is trying to promote. Some countries with different economic traditions – notably Greece and France – are only belatedly cooperating with the Commission.

At the same time, liberalization has released the deregulated and, in some cases, privatized electricity companies as agents of change within the industry. The more competitive companies – and large electricity consumers too – are actively promoting further liberalization by revealing the possibilities for profitable integration within Europe. In the context of a single European market, the presence of the industry as a powerful lobby means that the pressure for further liberalization will be difficult to resist.

This chapter surveys progress towards a fully liberalized electricity market in Europe. We observe the different attitudes adopted, the roles of government ownership and industry restructuring, the evolving role of regulators and the part played by the Commission.

2.1 The pace of liberalization

In 1985, the European electricity industry had a very stable market structure. In some countries, this took the form of large state-owned monopoly enterprises such as the Central Electricity Generating Board (CEGB) in the United Kingdom, and Electricité de France (EdF) in France. In others, such as Norway and Sweden, there was a mixture of state and municipal ownership within a more fragmented market structure. In a handful of countries, notably Belgium, Germany and Spain, there was substantial private sector ownership, with some companies part private, part state-owned: the German Länder, for example, were and remain substantial shareholders in electricity companies.

Across Europe, electricity companies had monopoly power – supported by legal protection, as in the United Kingdom, or government supported contracts between companies, as in the demarcation contracts used in Germany. The distinctive feature of the industry was that the incumbent companies were not subject to the threat of entry. International trade did exist, but it was limited to transfers between incumbents, who agreed to trade at prices that were meant to reflect the differences in marginal costs of their systems rather than market forces. Everywhere, governments dictated investment policy: in France, a huge nuclear power building programme was reaching its peak, while in the United Kingdom, new nuclear and coal-fired plants were still being planned and built.

After 1985, this comfortable situation began to change rapidly. In the United Kingdom, the re-election in 1987 for a third time of a pro-market Conservative government heralded a sustained push to restructure and privatize the United Kingdom's huge 100% state-owned electricity supply industry. By April 1990, the industry had been substantially restructured and a power pool had been introduced in England and Wales. In December 1990, the regional electricity distribution (and retailing) companies (RECs) were sold by public offer. Then followed the privatization of the fossil fuel electricity generating plants in 1991 and the vertically integrated power companies in Scotland later that year.

Over a similar period, the Norwegian electricity industry was restructured as the incumbent state-owned generator was split into an independent grid company and a generator, access to the existing power exchange was extended and consumers were allowed to choose their supplier. The Norwegian reforms differ from their UK counterparts in a number of respects, notably that the Norwegian restructuring did not involve ownership transfer.

The reforms in the United Kingdom and Norway have been followed in more recent years by radical reforms in Finland, Spain and Sweden. A substantial process of restructuring in the publicly owned Dutch electricity industry began in 1985 following the Brandisma Commission and accelerated sharply with the 1989 Electricity Act.

National pressures to liberalize electricity markets reflected the perceived benefits of introducing market forces into an industry previously viewed as a natural monopoly with substantial vertical economies. The Commission endorsed these liberal sentiments and began to lobby hard for the passing of an Electricity Directive that would set a timetable for the deregulation of all EU electricity markets, not just those overseen by pro-market governments.

The passing of the Directive in 1997 gave member states who had not already anticipated reform two years to prepare for the partial but progressive opening of their electricity markets by passing enabling legislation. Such legislation was passed in Germany and other EU countries prior to the official date of 19 February 1999. Ireland and Greece have derogations of one and two years respectively before they will be expected to comply with the Directive. Belgium was granted a one-year derogation but chose not to use it. Countries aspiring to join the EU have been informed that they will be expected to comply with the Directive soon after accession. Interestingly, the Czech Republic, Hungary and Poland were all further advanced with liberalization than several EU members by March 1999.

The approaches to electricity liberalization adopted by European countries can be characterized as follows:

- *Restructuring and privatization*: England and Wales, Northern Ireland, Czech Republic, Hungary, Poland.
- *Restructuring*: Norway, Sweden, Finland, Netherlands.
- *Privatization*: Scotland, Spain.
- *Gradual evolution*: Germany, Italy, Austria.
- *Slow progress*: Greece, Ireland, Switzerland, Belgium, Portugal, France.

These differences may reflect different regulatory cultures in Europe: the Anglo-American liberal tradition; the French tradition of regulation; the German tradition of 'Ordnungspolitik'; the Scandinavian tradition of consensus and pragmatic state involvement; and the Dutch tradition of negotiated agreement.[2]

The approaches range from liberalization in the United Kingdom – which involved vertical and horizontal separation of former state-owned companies, the creation of a power pool and privatization – to France and Greece – where as of March 1999, the plans for compliance with the Directive were not yet in place.

2.2 Ownership

There are considerable differences in ownership patterns in electricity across Europe (see Table 2.1). In France, the state-owned EdF controls 94% of generation and 95% of distribution, with the rest owned by other state and municipal companies. This ownership pattern is substantially the same as in 1946 when EdF was created. As of early 1999, there were no plans to privatize EdF. In Portugal, Spain and the United Kingdom, monopoly incumbents have been privatized (and in the case of the United Kingdom also broken up). In Italy, ENEL, the state-owned company that controls 80% of generation and 93% of distribution, has been a candidate for privatization since 1996.

EU policy does not explicitly promote privatization of state or municipal electricity companies. Indeed, Finland, Norway and Sweden have remained in the vanguard of electricity liberalization and integration in spite of having largely publicly owned electricity systems. The picture is complex. The process of reform in the Netherlands, for example, has been prolonged and significant: the govern-

Table 2.1 Market openness in selected countries at 19 February 1999

State	*% public ownership (by asset value)*	*Concentration in generation HHI*	*CR1*	*CR2*	*CR3*	*CR4*
Belgium	11	8125	0.90	0.95	0.95	0.95
Finland	50	1682	0.28	0.56	0.62	0.68
France				0.94		
Germany	c.35	~1500	0.29	0.50	0.60	0.70
Greece	100	10 000	1.00	1.00	1.00	1.00
Ireland	100	10 000	1.00	1.00	1.00	1.00
Netherlands	100	938	0.20	0.35	0.48	0.60
Spain			0.51	0.78	0.91	0.97
Sweden		3160	0.51	0.70	0.84	0.88
United Kingdom						
England+Wales	4.5	2008	0.32	0.56	0.71	0.81
Scotland	0	3374	0.38	0.71	1.00	1.00
Northern Ireland	0	4322	0.49	0.92	1.00	1.00
Norway	85		0.31	0.39	0.46	0.51
Switzerland	77	3030	0.38	0.73	0.88	1.00
Czech Republic			0.74			
Hungary		2252	0.42			

Notes:
HHI = Herfindahl-Hirschman Index (sum of percentage shares squared: monopoly = 10 000).
CRX = X Firm Concentration Ratio (market share of largest X firms: monopoly = 1).
Finland = 1995 data.

ment has not encouraged privatization, yet some municipal owners have been willing to sell their shares in one of the four regional distributors, UNA, to Reliant of the United States. In Sweden, the share of private ownership in generation and distribution has risen, as has the amount of foreign (though not all private) ownership in the electricity industry since liberalization in 1996. There appears to be no pressure to privatize in Denmark, where municipal power distributors are involved in extensive district heating schemes associated with combined heat and power (CHP) plants.

Patterns of ownership seem to be stable in mixed systems such as in Germany, where there are over 900 electric utilities. Many are municipally owned while some of the largest listed companies have significant non-federal government shareholders – VIAG, for example, is 25% owned by the state of Bavaria. Although there are many utilities in Germany, the market is dominated by four power groups – EnBW, RWE, VEBA and VIAG – and the size distribution of utilities is highly skewed with a few large companies dominating generation, transmission and distribution. In generation, the largest four firms have a combined market share of around 70%.

Economic theory and empirical evidence suggest that competition is a more important determinant of efficiency than ownership *per se*.[3] And public ownership itself can take a number of different forms. Municipal ownership may have the advantage over state ownership of superior public accountability and the possible development of a market for ownership rights between municipalities as different governments adopt different policies towards the industry.

Publicly owned companies can be legally organized in a number of ways: from a government department with budgetary integration with government revenue and expenditures (and effectively unlimited liability for losses) to a wholly owned public limited company subject to private sector company law. In New Zealand and Australia, there have been substantial improvements in efficiency following the 'corporatization' of state-owned electricity companies and a move to wholly owned public limited company status. In these cases, utilities such as Electricorp of New Zealand have been run 'as if' they were in the private sector while remaining in public ownership.

In Europe, Vattenfall, the Swedish state-owned power company, and Stattnett, the Norwegian state-owned grid company are just two examples of the many public sector utilities run as if they were in the private sector. In some cases, states and municipalities have chosen to reduce their shareholdings and allowed part foreign or private ownership in order to bring about economic change. This has occurred in Sweden, where Sydkraft, the second largest Swedish generator, is now 25% owned by Preussen Elektra of Germany and 25% by Statkraft, Norway's state-owned and dominant generator.

2.3 Vertical integration

It used to be assumed that electricity generation, transmission, distribution and supply enjoyed significant vertical economies that would be lost if the functions were placed under the control of different companies. Such economies arose from the reduced transactions costs, the improved incentives to invest in specific assets that would not be subsequently held-up, and the advantages of coordinated supply and demand side planning. In particular, it was almost universally observed that generation and high voltage transmission were integrated within the same company, as were distribution and retailing (or supply).

Vertical integration raises the possibility that incumbents may favour their own divisions as sources of inputs in the case of generation, or their own supply business in the supply of scarce transmission and distribution services. This is because there is a potential cost to the incumbent of allowing access to an outside company at the expense of its own division. Such costs create the incentive for incumbents to practice foreclosure – straightforward denial of access or services to an outside company – or price discrimination, where the outside firm is offered either low payments for purchased inputs or high charges for the supply of services.

These possibilities argue for vertical separation of different stages of electricity production. Two main types of separation are possible: accounting (functional) and legal. Accounting separation occurs when incumbents are forced to identify and publish costs and revenues within each stage of production separately and offer non-discriminatory terms to other generators or suppliers. This sort of separation usually involves no physical or managerial separation of production. Legal separation involves the creation of legally separate companies. This usually involves physical and managerial separation of the companies.

While the two types may be theoretically identical, accounting separation is subject to abuse of definitions and allocation of assets so that incumbents can continue price discrimination against outside firms. Legal separation, however, might not be enough to prevent price discrimination in the presence of cross-shareholding. In Germany and Spain, for example, substantial cross-shareholding has facilitated coordination of strategic decisions even in the absence of majority or even direct ownership.

The deregulations in England and Wales and the Nordic countries explicitly recognized that generation and transmission needed to be separated if there was to be effective competition in generation. The 1983 Energy Act in the United Kingdom had attempted to stimulate private generation by obliging the CEGB to publish a tariff at which it would buy wholesale electricity for transmission across its grid.[5] In the absence of appropriate regulation, however, no firm took up the CEGB's offer because the published tariffs reflected the fact that the CEGB did not want to displace any of its own generation plants.

Vertical integration between generation and transmission owners and the system operator may create incentives for the system operator to discriminate against independent generators. The EU Electricity Directive insists that the system operator should not discriminate between generators even when it also owns some of the generation plant. While 'Chinese walls' between system operators and generators may be possible, however, they are clearly problematic, exposing companies to increased risk of litigation and expensive regulatory scrutiny. British Gas's initial attempt at accounting separation of its production and supply arm (later Centrica) and its transportation business (later BG) proved only to be a precursor to demerger as regulatory pressure mounted and the economic rationale for integration (based on discrimination) was eliminated. It has been suggested that EdF may eventually opt for a demerger in order to allow the network part of the company to pursue a more aggressive policy of expansion outside France.

The continuing integration of supply and distribution has been recognized as an issue in the promotion of supply competition. The profits to be made in the supply segment of the electricity business are relatively small (if the market is competitive) and incumbent distributors have been relatively willing to give up market share. In the United Kingdom, the process of separating supply and distribution is well advanced: supply businesses have been separated in accounting terms since privatization and by mid-1999, three supply businesses were being sold off by their REC owners. There are substantial economies in supply (particularly in billing) and there seems little reason why the current 15 regional supply businesses in the United Kingdom will continue to be necessary to serve residential customers in a deregulated electricity market. Such a process of supply integration has been observed in Norway via mergers, joint ventures and cooperation between distribution and supply companies.

An emerging problem in some deregulating countries is that the private sector appears to be in the process of (re-)integrating businesses that the government initially kept separate. In England and Wales, both the major fossil fuel generators, National Power and PowerGen, have sought to acquire a distribution and supply business in order to increase access to final customers. These merger proposals initially came under close scrutiny as the competition authorities attempted to ascertain whether they reflected genuine vertical economies or whether they were largely aimed at exploiting a captive market. As with all the vertical mergers initiated by the private sector, there was probably a little of each of these motives behind the mergers. This was implicitly recognized when PowerGen was allowed to take over East Midlands on condition that it sold some of its generating plant to make the electricity pool more competitive.

2.4 Mergers

Liberalization that includes privatization leads to pressure for mergers and the threat of takeover. Indeed, property rights theory indicates that the threat and reality of mergers are some of the most important drivers of efficiency within a liberalized market.[6] Merger threats force managers to maximize profits for fear of losing their jobs, while actual mergers transfer ownership to superior management teams and allow more efficient aggregation of assets. The empirical evidence on whether mergers improve performance is mixed, however. In the United Kingdom, labour employed in the RECs fell 21% between 1990 and 1995; in 1995, the first takeovers of RECs were permitted and, in the following two years, labour employed fell a further 22%. This is evidence of the positive effect of focused mergers in line with current moves away from diversifying mergers.

Utility mergers come in three main forms: horizontal, vertical and multi-utility. Each has been observed in the liberalized electricity industry. The United Kingdom has seen a large number of mergers due to the presence of private companies in the industry and the lifting of initial merger restrictions in 1995. Since then, all of the privatized electricity companies, apart from Northern Ireland Electricity, have been involved in mergers or takeovers. The last independent distribution and supply company, Southern, was a takeover target from since 1996 and eventually merged in December 1998.

In the Netherlands, the government has explicitly promoted mergers via the 1989 Electricity Act, which set a minimum scale for generating companies of 2500 MW. This has led to the number of production companies falling from 15 in 1989 to 4 in 1999. In the Nordic countries, there has been a slow but steady process of merger and joint ventures, which has tended to increase concentration in the industry, particularly in distribution and supply. In Norway, the state-owned and dominant generator has taken shares in Oslo Energi, a vertically integrated generator and supplier with dominant municipal ownership, and in Sydkraft. In 1998, IVO and Neste merged to form Fortum, the biggest electricity company in Finland.

Economies of scale have motivated horizontal mergers between distribution and supply companies. It became clear that the United Kingdom's RECs were small by world standards and were likely to be taken over. Several were taken over by US power groups, presumably facilitating the transfer of best practice management. Within the United Kingdom, Scottish Power merged with Manweb and Southern with Scottish Hydro. Horizontal mergers between generating companies would not have been allowed within the United Kingdom given that the market was initially highly concentrated, though Eastern (the third largest UK fossil fuel generator) was recently taken over by Texas Utilities, an integrated US power company.

In Norway, the privately owned generator, Hafslund Energi, holds shares in Drammen Kraftomsetning and Oppdal Elverk, two vertically integrated generator–suppliers with dominant municipal ownership. In Sweden, Birka Energi, formed from the merger of Stockholm Energi and Gullspang, generates around 20% of domestic electricity consumption and has now been bought by Finland's Fortum. In the Netherlands, the government has promoted a rationalization of the electricity industry based on a minimum number of customers per distributor of 100 000 since 1985: the number of distribution companies has fallen from 82 in 1984 to 22 in 1999.

Economies of scope (cost savings arising from joint production of related products) seem to have been the motivation for a number of multi-utility mergers. Water companies were privatized before electricity companies in England and Wales (in 1989) and a number of these have merged with electricity distribution and supply companies: Hyder and United Utilities were formed by mergers of geographically similar companies while Scottish Power took over Southern Water. Only Scottish Power can be described as a genuine multi-utility with interests in gas, water, telecoms and electricity both within and beyond their original franchise area in southern Scotland. Hyder and United Utilities remain regionally-based water and power groups.

In Spain, Endesa has a strong position in cable technology and has entered into joint ventures with Gas Natural and Telefonica. Such investments may not fit naturally with electricity: in Germany, OtelO, a nationwide communications network owned by RWE and VEBA, has been sold to a non-electricity company, Arcor; while the United Kingdom's National Grid floated its telecoms subsidiary, Energis, in 1997.

In addition to mergers and takeovers within the deregulated national markets of Europe, there has been increased activity by liberalized European firms in other markets. The United Kingdom's PowerGen and National Power have deliberately attempted to expand internationally in order to become global power companies with interests in Australia, Hungary, Portugal, Spain, Turkey and elsewhere. As noted above, Finland's Fortum has bought 50% of Sweden's Birka Energi.

Even state-owned companies have joined in the takeover market: EdF acquired London Electricity in 1998 and owns a minority share in Sweden's Graninge; and Norway's Statkraft bought 25% of Sweden's Sydkraft (which is also 25% owned by Preussen Elektra). Meanwhile, US power groups have been active in the European power industry: Enron has expanded into generation and supply in several countries while a number of other US companies have acquired distribution (and supply) and generation companies in the United Kingdom: for example, Southern Company took over South Western Electricity. In Hungary, there have been many foreign takeovers: the Belgian-based Tractabel has bought the largest power station, Dunamenti; the US firm AES owns three power stations; and two distribution and supply companies (with a combined market share of around 40%) are owned by RWE and Bayernwerk AG.

2.5 Prices and costs

Table 2.2 reveals the wide differences between electricity prices in different European countries. The range of variation between the highest and lowest prices for both domestic and residential customers is substantial. These price differentials suggest that liberalization can immediately lead to downward pressure on prices as electricity flows from low to high price regions and as the more efficient firms put pressure on the less efficient ones to improve their performance.

Table 2.2 Electricity prices, 1998

State	*Industrial price (pence/kWh)*	*Residential price (pence/kWh)*
Austria	5.59	9.65
Belgium	4.79	11.33
Denmark	3.77	12.00
Finland	3.10	6.16
France	3.76	9.86
Germany	6.02	10.55
Greece	4.04	6.16
Ireland	4.38	7.56
Italy	5.98	9.95
Luxembourg	4.05	8.86
Netherlands	3.99	8.12
Portugal	4.77	9.44
Spain	4.14	9.10
Sweden	2.08	9.69
United Kingdom	4.15	8.76
Switzerland	6.23	8.30
Czech Republic	3.18	2.26
Hungary	3.30	4.15
Poland	2.20	3.79

Notes: For EU, excluding Sweden: industrial prices including local taxes excluding VAT for a 2.5 MW, 40% load factor supply at 1 January 1998. Residential prices include local taxes and VAT for 3000 kWh/year at 1 January 1998. Local currency converted at 31 December 1997 exchange rates. For other countries all prices are 1997 prices.

Source: *Utility Europe*, February (1999), p.17.

There are a number of factors behind the variation in prices:

1. Some countries' utilities are more efficient than others. Privatization and liberalization in the United Kingdom have dramatically improved the United Kingdom's relative prices – from being among the highest in Europe to being among the lowest.
2. The prices of fuels differ markedly between European countries. For example. the price of coal is very high in Germany but much lower in the United Kingdom, where the coal industry has been privatized and is subject to competition from imported coal and natural gas.
3. Prices reflect differences in accounting conventions and pricing policy. As much as half of the difference in prices between France and Germany can be explained by different accounting conventions, while France has a policy of cross-subsidizing industrial users from residential and commercial users.[9] Such a situation may be unsustainable in a competitive market where conventions and policies that raise prices will be forced to change.
4. Prices partly reflect tax differences: in Denmark, taxes on domestic electricity reflect taxes of 142.5% on the pre-tax price, whereas in the United Kingdom, the tax is a mere 8% of the pre-tax price.

Table 2.3 Generating capacity and output, 1996

State	*Installed GW**	*Net generation TWh*	*Imports TWh*	*Exports TWh*
Austria	17.52	53.2	9.43	8.48
Belgium	14.85	72.36	9.64	5.45
Denmark	11.11	50.64	3.78	19.18
Finland	14.57	66.36	5.37	1.71
France	109.45	490.49	3.62	72.43
Germany	114.07	516.21	37.40	42.67
Greece	9.13	39.20	2.66	1.31
Ireland	4.19	18.10	0.05	0.18
Italy	68.28	232.43	38.15	0.76
Luxembourg	1.30	1.27	5.71	0.81
Netherlands	20.44	81.49	11.29	0.70
Portugal	9.40	33.19	4.12	3.01
Spain	46.83	167.57	6.75	5.69
Sweden**	33.76	136.60	15.89	9.75
United Kingdom	73.26	329.6	16.7	0.0
Norway**	27.79	103.92	13.21	4.24
Switzerland	16.02	55.37	23.24	24.19
Czech Republic	15.00	59.90	8.81	8.81
Hungary	7.54	32.32	3.47	1.28
Poland	29.70	129.52	4.80	7.93

Notes:
* Includes auto-producers.
** 1996 was an unusually dry year and hence exports from Norway and Sweden were unusually low.

Sources: IEA (1998a) and IEA (1997a).

5. Prices reflect the underlying technology of electricity generation and the efficiency of capital investment in it. French nuclear power is sold relatively cheaply (though there is debate about whether this reflects government support for the nuclear power building programme). Nuclear power is more expensive in Germany, where there is also large reliance on expensive coal technology. Norway benefits from large amounts of cheap hydro-electricity.

There are already significant flows of electricity between European countries to exploit these price differentials (see Table 2.3). France is a significant exporter of electricity. Cheap French nuclear power supplies Belgium, Italy, Switzerland and the United Kingdom. Among the Nordic countries there are large year-to-year variations in trade according to hydrological conditions.

2.6 Regulation

Table 2.4 lists the various regulatory authorities involved in national electricity markets, while Table 2.5 lists which authority is involved in various aspects of the regulatory process.

Independent regulators, such as the Office of Electricity Regulation (Offer) in the United Kingdom, have different powers and operate under different amounts of freedom from the government.

Offer is a statutory regulatory authority with a Director General invested with statutory duties. This makes it very difficult for the government to intervene in the day-to-day running of regulation or regulatory reviews. The government may, however, use its reserved powers to thwart the wishes of the regulator, for example, via influence over the planning process. This occurred in 1997, when the government first introduced a moratorium on the building of new gas-fired power stations in spite of the regulator arguing that this would lead to higher prices in the electricity pool. Crucially, the government also exercises influence in the appointment of the regulator for a statutory term of office.

It is clear that there are several regulatory authorities involved in each country and that this can lead to the risk of double jeopardy. This happens in Germany where the Federal Cartel Office ('Bundeskartellamt') monitors abuse of dominant positions by utilities, and the state-level economics or environment ministries are in charge of authorizations, tariff regulation and licences: these authorities do not always agree. In the United Kingdom, a 1996 case considered proposed takeovers by National Power and PowerGen of some RECs: the electricity regulator opposed the mergers but the competition authority, the Monopolies and Mergers Commission (MMC), recommended allowing them to go ahead, only to have the responsible government minister block the mergers.

Government interference in the regulatory process is one key issue in regulation; industry capture of regulators is another. It is reasonably clear that government and the electricity industry have worked extremely closely together over many years. This has created an industry that has benefited from government protection of its monopoly and its expensive technology. Indeed, one of the benefits of privatization may be the end of government underwriting of expensive technologies for electricity generation and protection of monopoly networks.

Table 2.4 European National Regulatory Authorities in electricity

State	*Regulatory authorities*	*Legal status of regulatory authority*
Austria	Ministry of Economic Affairs	Government ministry
Belgium	Comité de Contrôle for Electricity and Gas for captive customers	Statutorily independent authorities
	Regulatory Commission for Electricity and Gas (CREG) open market	
Denmark	Energy Agency	Government ministry
	Energy Regulation Board	Statutorily independent
Finland	The Electricity Market Authority	Independent experts subordinate to Finnish Ministry of Trade and Industry
France	Electricity Regulation Committee (CRE)	Independent commission
Germany	Ministry of Economics/Environment Cartel Office	Government ministry
Greece	Electricity Regulatory Authority (ERA)	Statutorily independent
Ireland	Commission for Electricity Regulation	Statutorily independent
Italy	Independent Authority for Electricity and Gas Ministry of Industry	Statutorily independent
Luxembourg	Institute of Telecommunications and Electricity	Independent body
Netherlands	DTe, part of Competition Authority	Statutorily independent
Portugal	Entidade Reguladora ERSE	Statutorily independent
Spain	Ministry of Industry and Energy	Government ministry
	Electric System National Board, CNSE	Statutorily independent (but only advises ministry)
Sweden	STEM	State authority
United Kingdom	Department of Trade and Industry	Government ministry
	Formerly Office of Electricity Regulation (Offer), now Office for Gas and Electricity Markets (Ofgem)	Statutorily independent
	Office for the Regulation of Electricity and Gas, Ofreg (Northern Ireland)	Statutorily independent
Norway	Norwegian Competition Authority (KT)	Subordinate to government ministry
	Norwegian Water and Energy Authority (NVE)	Subordinate to government ministry
Switzerland	Competition Commission	Statutorily independent
	Price Control Authority	Ministry of Economics
Czech Republic	Ministry of Finance	Government ministry
	Energy Regulation Administration	Department of Ministry of Trade and Industry
Hungary	Parliament	
	Ministry of Economy	Government ministry
	Ministry of Finance	Government ministry
	Hungarian Energy Office	Department of ministry
Poland	Council of Ministers	Government ministers
	Energy Regulatory Authority	Independent administrative department

In Germany, continued significant ownership of utilities by the Länder seems to conflict with regulation of the industry at state level. In Spain, the new electricity law was agreed between the government and incumbents in a formal contract – the 'Protocolo' – before the law was even drafted or discussed in Parliament. The government has also regularly sided with the industry against the independent regulator. Thus, it seems that the privatization of Endesa has not lead to any decrease in the government's involvement in the industry. Reducing such government involvement with the incumbents in the United Kingdom has lead to a large degree of innovation of cheaper electricity generating technology (particularly in CCGT generation equipment) and abandonment on the grounds of cost of the nuclear power building programme.

Up to 1999, there has been no case of capture of independent regulators in European electricity that has come to light. Our experience with independent regulators, however, may be too short. Evidence from other industries suggests that regulatory capture is a risk: for example, the UK's first National Lottery regulator resigned over allegations that he had been captured by the Lottery operator. And US experience provides econometric evidence that regulators do act to reduce regulatory pressure on incumbents in the electricity industry. Regulators may be influenced by the prospect of well-paid jobs in the regulated private sector after their period of office, a prospect that has become a reality for some of the early UK regulators.

2.7 The role of the European Commission

The Commission's DG XVII, the Energy Directorate, is the body responsible for overseeing the implementation of the Electricity Directive within EU member states. As such, it directs the national energy policies and provides the leadership for area-wide deregulation. If member states do not comply with the Directive, in the absence of a derogation, they will be liable to actions brought in the European Court by those who might be able to claim that non-compliance has imposed costs on them. In particular, this applies to energy companies denied access to customers, or to large users denied contracts with cheaper suppliers.

DG XVII has been pivotal in shaping European energy policy along liberal pro-market lines in the context of a community of nations with sharply differing conceptual approaches to their energy policies. Prior to the Electricity Directive, it promoted the Transit Directive (1990), which attempted to open up access to electricity networks and, more recently, the Gas Directive (1998), which foresees a market opening in that industry similar to that envisaged in the Electricity Directive.[11]

It seems remarkable that the Commission has been actively promoting a policy that, on the face of it, only the United Kingdom, Sweden and Finland (and Norway outside the EU) endorsed wholeheartedly at a national level. The Commission's support for such liberalization relies on the fact that it follows logically from the Single European Act.

The Commission first began discussing deregulation of the EU electricity market soon after the passage of the Single European Act.[12] Regulation of EU

Table 2.5 Powers and functions of National Regulatory Authorities

State	*Granting of public electricity supply licences*	*Setting of pricing controls*	*Planning applications for power stations*	*Planning applications for transmission and distribution*	*Appeals bodies for disputes with industry regulator*
Austria	Ministry of Economic Affairs	Ministry of Economic Affairs	Ministry of Economic Affairs	Ministry of Economic Affairs	Ministry of Economic Affairs
Belgium	Ministry of Economic Affairs	Price Control Committee	National Committee for Energy Control Committee Ministry of Economic Affairs	National Committee for Energy Control Committee Ministry of Economic Affairs	CREG
Denmark	Energy Agency	Energy Regulation Board	Energy Agency	Energy Agency	Competition Appeals Board
Finland	Electricity Market Authority	Electricity Market Authority	For nuclear: Council of State and Parliament For hydro: the Water Court	Electricity Market Authority Ministry of Trade and Industry for inter-connections	The Administrative High Court of Justice
France	Ministry of Energy	CRE	Ministry of Energy	EdF-government contract	Paris Court of Appeal
Germany	Ministries of Economics or Environment in Länder	Ministries of Economics or Environment in Länder	Ministries of the Environment	Ministries of the Environment	Cartel Office
Greece	Ministry of Development	ERA	Ministry of Development	Ministry of Development	
Ireland	Commission for Electricity Regulation	Commission for Electricity Regulation	Local planning authorities	Local planning authorities	Appeal Panel
Italy		Independent Authority for Electricity and Gas			Latium Regional Administrative Tribunal

State	*Granting of public electricity supply licences*	*Setting of pricing controls*	*Planning applications for power stations*	*Planning applications for Transmission and distribution*	*Appeals bodies for disputes with industry regulator*
Luxembourg	Ministry of Energy	ITE	Ministry of Energy	ITE	Administrative Court
Netherlands	Minister of Economic Affairs	DTe in Competition Authority	Local and regional planning authorities	DTe and/or Minister of Economic Affairs	Minister of Economic Affairs and Appeal Board for Commerce
Portugal	Ministry of Economics	ERSE	Ministry of Economics	Direccad Geral de Energia (DGE)	
Spain	Ministry of Industry and Energy	Ministry of Industry and Energy	Ministry of Industry and Energy	Ministry of Industry and Energy	CNSE
Sweden	STEM	STEM	Court decision	STEM/courts	Court
United Kingdom	Offer OfReg	Offer Ofreg	DTI	Local planning authorities	MMC
Norway	NVE	KT (trade and production) and NVE (transmission and distribution)	NVE	NVE	Ministry of Oil and Energy
Switzerland	Ministry of Economic Affairs	Price Control Authority	Ministry of Energy	Ministry of Energy	
Czech Republic	Energy Regulation Administration	Ministry of Finance			Courts
Hungary	Hungarian Energy Office	Ministry of Economy	Parliament (>600 MW) Ministry of Economy		Ministry of Economy Courts
Poland	Energy Regulatory Authority	Energy Regulatory Authority	Energy Regulatory Authority	Energy Regulatory Authority	Energy Regulatory Authority

electricity markets is justifiable via appeal to Article 30 (formerly 36) of the European Treaty, which allows for national restrictions on transit of goods on the basis of the protection of health or on the grounds of public policy. The Commission published a working paper advocating electricity deregulation in 1988. This developed into a concrete proposal in 1991 to allow third party access within the national electricity markets of all member states. The Council of Ministers rejected this proposal and then began several years of wrangling between the Commission and the member states. By 1993, the concept of negotiated, as opposed to full third party access was one of the options for deregulation being discussed. In 1994, France introduced the single buyer option as an alternative to negotiated third party access. Eventually in mid-1996, a timetable for market opening was agreed and a choice of the three access regimes was given to each member state. (Chapter 5 has further details on these regimes.)

That the Electricity Directive ever made it through to law is testimony to the power of the Commission to initiate, promote and drive policy within the European Union. The Competition Directorate (DG IV) has also provided strong support for electricity liberalization. It will be responsible for enforcing Article 82 (formerly 86) in respect of market access and in examining applications for transitional schemes to deal with stranded costs. During the period of negotiation, DG IV threatened member states with tougher action on competition policy towards the energy sector under Articles 81 and 82 (formerly 85 and 86) if they did not cooperate with the passage of the Directive. Thus, the Directive has powerful institutional support from a Commission committed to the wider goal of a single market in Europe. It seems certain that the Commission will not let the current Directive with its rather high minimum energy demand thresholds for eligible customers be the last word on electricity liberalization in Europe: the Directive contemplates a report to see if it would be worth reducing the thresholds after 2006.[15]

Notes

1 See IEA (1985).
2 See Midttun (1997).
3 See Alchian (1965) for economic theory and Kwoka (1996) for some recent empirical evidence.
4 See Williamson (1985).
5 See Surrey (1996), p. 186.
6 See Alchian (1965).
7 See Hay and Morris (1991), pp. 524–31.
8 See Markides (1995).
9 See Nolden, et al. (1998).
10 See Upadhyaya and Mixon (1995), who find that regulators act to increase prices when profits fall.
11 The text of Council Directive (90/547/EEC of 29 October 1990) on the transit of electricity through transmission grids is available at http://europa.eu.int/eur-lex/en/lif/dat/en_390L0547.html. The Gas Directive (98/30/EC of 22 June 1998) http://europa.eu.int/en/comm/dg17/gashome.htm,

12 See Midttun (1997) and Yajima (1997) for histories of the development of the Directive.
13 See European Commission (1988).
14 See European Commission (1998) for a report that the Commission was dropping a competition case against the Belgian electric utility, Electrabel, on the grounds that the Directive was now coming into force.
15 Article 27, EU Electricity Directive.

3 The Social and Political Context of Electricity Supply

Electricity has several social externalities associated with it that provide some of the traditional justification for government ownership and control. These social externalities need to be addressed by national governments: liberalization often demands new social arrangements, which may be perceived as politically difficult to implement. This chapter examines four social externalities:

1. Electricity is an essential non-storable input to production that facilitates access to many of the goods and services of an advanced economy. Poorer members of society may be disproportionately disadvantaged if they cannot afford to pay for connection to the electricity grid or to pay usage charges. In Eastern European countries, this argument remains the reasoning behind relatively low charges for domestic customers.
2. Security of supply is a public good in the sense that consumers will tend to 'free-ride' on others' willingness to pay for security of supply.
3. Electricity supply has major environmental effects in terms of the safety of power stations (where possible dangers include dam leakage and nuclear waste), the production of damaging gases and large quantities of solid waste, and the visual impact of electricity assets such as transmission wires.
4. The electricity industry directly and indirectly supports a large number of jobs, many of them in isolated rural areas.

The first and last points concern economic justice or equity issues; the second and third points concern economic efficiency. Economic theory suggests that efficiency issues are a matter of getting the prices right – in this case, the prices for security of supply and environmental damage. Economic equity issues are usually addressed by an appropriate cross-subsidy, whereby richer consumers pay more relative to the cost of supply than poorer consumers. Economic theory suggests that taxation and direct subsidy payments are a better way of redistributing income towards favoured groups because of the effect of cross-subsidies on the supply and demand for the cross-subsidized goods.

We explore each of these aspects of the electricity industry and ask to what extent they represent barriers to liberalization of the European electricity market.

3.1 Public service and obligations to supply

There is a long tradition in the electricity industry of its product being viewed as a public service. This means that electricity production should not be motivated primarily by the desire to make profits, and at the margin, profits might be sacrificed to meet other objectives. Under this public service ethic, electricity is a 'good' to which all citizens of a decent society should have access at reasonable cost. Several implications have traditionally followed from this view:

1. That there should be a deliberate attempt to expand the network via subsidized connections. In particular, remote customers should not face prohibitive costs of connection. In practice, this meant that rural electrification proceeded in such a way that new customers faced connection costs well below their marginal costs of connection.
2. Even after connection, it was recognized that a lack of electricity supply due to poverty was a serious bar to full participation in society. Thus, for poor customers, standing charges, which have a similar effect to a poll tax, needed to be subsidized in order to prevent impoverishment.
3. Electricity companies were to emphasize security of supply at times of peak demand when it might be more profitable (in conditions of regulated prices) to disconnect customers or supply them at reduced voltage. This resulted in large reserve capacity margins and power equipment engineered to minimize the risk of failure, involving capital expenditure beyond what would be economically justifiable.

To many, the public service tradition and its implications are fundamentally challenged by liberalization: subsidized connection is not economically efficient; and liberalized companies will not want to supply customers who are unprofitable to connect to the grid or whose supply can only be maintained at a loss. This is not, however, as big an issue now that most EU households have access to electricity. Furthermore, it may be argued that subsidizing rural communities actually encourages inefficient migration to the countryside, which means expensive support services to accompany the migration, such as new hospitals and schools.[1]

Nevertheless, in some countries, notably France, there is still an ideological commitment to rural communities that makes it difficult to proceed with electricity liberalization based on the freedom to price discriminate between customers on the basis of the relative costs of supplying them. The fear is that this will disproportionately affect groups particularly dear to the heart of a nation. In these circumstances, however, it is preferable to move to tariffs that reflect costs better and that support the move by redistribution through the tax system rather than not implementing the move at all on the grounds of its distributional effects.

Poor customers are a problem for the electricity supply industry in two ways. First, they may be genuinely more expensive to supply, perhaps because they tend not to pay bills on time, not to pay by direct debit and because there is increased likelihood of legal sanction to enforce payment. In the United Kingdom, it is suggested that the difference between the costs of supplying of the poorest and the richest residential customers may be of the order of 10 times. One way of capping this cost is to install pre-pay meters in poor customers' homes, but this is a genuinely more expensive method of payment.

The second problem is that electricity payments represent a large share of poor households' disposable incomes. Price rebalancing, so that energy costs fall and standing charges rise as a result of liberalization, seems likely for such customers. Thus, in the absence of compensating changes in taxes and benefits, liberalization seems certain to reduce the welfare of the poorest in society relative to the richest. Even though absolute charges may fall as they have done in real terms in the liberalized UK gas industry, relative charges have gone up sharply for those, normally poorer, customers who use pre-payment meters.[2] Interestingly, relatively more of the poorer customers are switching supplier in the UK gas industry in spite of, apparently, higher relative prices.

3.2 Security of supply

Security of supply can be threatened in a liberalized market system where there may be insufficient incentives to maintain supply under exceptional circumstances. If the price of security is set too high, then the system incurs high capital costs in insuring itself against failure; if it is set too low, then increased supply failures are more likely to occur.

The centre of Auckland lost power for three weeks in February 1998 after a series of four power cable failures and there were problems reconnecting the supply.[4] It was subsequently revealed that the company responsible, Mercury Energy (a municipally owned company), did not have the required expertise to manage and operate the cables in question and that there were shortcomings in its corporate governance. While the problem occurred following liberalization, it seems likely that a more completely liberalized system (with better accountability and monitoring) would have improved the situation rather than exacerbated it. Thus, while liberalization was initially blamed for the failure, the problem appears to have been one of poor management skills in a publicly owned company.

Notwithstanding the dramatic illustration of Auckland, there seems to be little empirical justification in Europe for concerns that liberalization will lead to increases in the average length of time per customer for which there is no supply. Neither the United Kingdom nor Norway have suffered from any deterioration in the quality of supply; if anything, it has improved in the United Kingdom.[5] Arguably, the incentive mechanism in England and Wales, which ensures higher capacity payments for stations declaring availability as the loss of load probability rises, makes the liberalized system less likely to fail than under nationalization.[6] Interestingly, there are no capacity payments in the Nordic system (but there has initially been a large amount of available capacity).

3.3 Environmental effects of electricity

There are longstanding environmental concerns about the safety of nuclear power plants in Europe. Concerns were first raised following the Three Mile Island incident in the United States in 1979 and they grew after the Chernobyl disaster of 1986, which scattered radioactive particles over a wide area of Europe.

Table 3.1 details the significance of nuclear power in European electricity production and the current state of economic and political opinion about its future development. It shows that while many European countries have a significant nuclear power sector, only one – France – has both a positive economic and political attitude to further building. This is a function of the success of its building programme, which has seen costs for French-designed reactors fall below those in the more heterogeneous building programmes of the United Kingdom and Germany. The result is that France appears to think that new nuclear power stations are at least socially viable.

Italy has no nuclear power plants and a 1987 referendum voted against nuclear power; nevertheless, it imports substantial quantities of French nuclear power. In Scandinavia, there is widespread political opposition. For example, a Swedish ref-

Table 3.1 Attitudes to nuclear power in countries with existing nuclear stations

State	*Nuclear share by kWh of electricity market, 1996 (%)*	*New build planned*	*Extent of political opposition*
Belgium	57.6	No	Weak
Finland	28.1	No	New plants need 50% of votes in Parliament
France	78.2	Yes	Very weak
Germany	29.1	No	Government coalition investigating feasibility of early closure
Netherlands	4.9	No	Substantial
Spain	32.5	No	High
Sweden	52.5	No	Planned phasing out of one unit on 1 July 1998 awaiting supreme court ruling
United Kingdom	27.3	No	National opposition weak, local opposition has power to increase costs significantly
Switzerland	45.2	No	Strong with possibility of controlled retreat from use
Czech Republic	20.1	Power station under construction	Not known
Hungary	40.4	No	Moderate

Sources: IEA (1998a) and IEA (1998c).

erendum in 1980 voted to phase out nuclear power as soon as economically and environmentally competitive alternatives were available. Currently, nuclear power provides nearly half of Sweden's electricity and there is substantial opposition to further hydro and coal plants. The Swedish Parliament has now initiated the phase out with a decision to decommission two reactors by 2001 (the first of which has been delayed). In Germany, the Green Party is currently (mid-1999) demanding an early closure of nuclear power stations as the price of its continued participation in the coalition government.

While political opposition to nuclear power was extensive before the electricity markets began to be liberalized, liberalization has only served to weaken the case for further development. Unbundling of generation costs from total electricity costs reveals how much nuclear power actually costs, particularly in terms of long-term decommissioning and fuel reprocessing liabilities. In the United Kingdom, it resulted in the removal of nuclear power stations from the initial plan to privatize the electricity generation plants, this at a time of falling oil and gas prices.[7] Subsequently, the newer stations were privatized but only after a nuclear levy had accumulated enough money to fund the decommissioning and reprocessing liabilities.[8] Today, new nuclear power stations are not economically viable in a liberalized industry without a substantial carbon tax.

The electricity industry has a significant environmental impact in its atmospheric emissions. Coal-fired power stations emit carbon dioxide (CO_2), sulphur dioxide (SO_2) and nitrous oxides (NO_X) in considerable quantities. Table 3.2 shows that in many countries, the electricity industry is a significant contributor to national emissions of these gases.

Table 3.2 Electricity share of national atmospheric emissions in selected countries, 1996

State	CO_2 (%)	SO_2 (%)	NO_X (%)
Belgium	27	32	21
Finland	27	27	12
France	8	15.2 (1994)	3.5 (1994)
Germany	37.7	61.8	19.8
Netherlands	29	13	8.9
Spain	28	62.1 (1994)	23.2 (1994)
Sweden*	5	4.3	0.9
United Kingdom	27	67	22
Norway	0	0	0
Switzerland	0	0	0

Note: * 1997 figures.

Sources:
European Commission (1998) *Energy in Europe – Annual Energy Review*, Brussels: European Commission. Available at http://europa.eu.int/eu/comm/dg17/dg17home.htm
UK: DTI (1998), *Digest of UK Energy Statistics 1998*, London: HMSO.
Sweden: Vattenfall.

The environmental damage done by each of these gases is substantial. Monetary estimates vary wildly but reasonable estimates might be £4 per tonne of CO_2, £3760 per tonne of SO_2 and £3990 per tonne of NO_X.[9] In a government controlled industry, decisions to invest can be made to reflect the environmental impact of these emissions by devices such as switching from coal to gas-fired plants to reduce all emissions. Natural gas contains less carbon, no sulphur and produces less NO_X. The introduction of flue gas desulphurization (FGD) units to remove SO_2 and the fitting of low NO_X burners to existing coal-fired stations can reduce emissions of these gases by up to 90%.

In a liberalized system, the pressure is to employ the most profitable technology. At first glance, this suggests that in the absence of taxes on fuels and emissions that reflect the environmental damage caused by these gases, liberalization is likely to worsen the environmental impact of the electricity industry. One of the primary means by which this may happen is via trading with low cost electricity producers in Eastern Europe. Such producers may use brown coal (which produces more carbon and waste per MWh) or less thermally efficient power stations. Trading with them, which involves switching production from the West to the East, worsens the overall environmental impact. US simulations suggest that the effect on the environment of free trade in electricity is to raise CO_2 and SO_2 emissions substantially while the financial benefit is small.[10] This is because large flows of electricity between regions occur on the basis of small price differentials.

To date, liberalization in Europe has not led to environmental problems of this kind, primarily because there has been a large increase in the amount of gas being used for electricity generation and because subsidies to relatively dirty coal are being removed. So, a by-product of liberalization has been a distinctly cleaner environment as coal-fired plants have closed and gas-fired plants have opened, the latter mainly a result of the proximity of Europe to supplies of North Sea and Russian natural gas. Similarly, increased French exports of nuclear power, as other countries liberalize and demand more cheap French electricity, have further reduced the need for coal-fired generation, as for example, in the United Kingdom. In the Nordic countries, increased trade has allowed a saving in capacity and reduced emissions.

Liberalization may have beneficial effects on the environmental impact of existing power stations in at least three ways:

1. Liberalization is likely to improve energy efficiency in response to the rising pressure to reduce costs. Improved availability and plant-life extension delays the need for new power plants (though this may be worse for the environment as new plants are cleaner). This has happened in Northern Ireland, where it was projected before privatization that new plant would be required in 1994, but by 1999, there was still no new plant built due to improved availability and extensions of existing plant life.[11]
2. Liberalization may create additional cost savings that can be allocated to environmental clean-up. In the United Kingdom, improved financial performance of electric power companies made it possible to finance a substantial renewables programme and the retrofitting of two large coal-fired plants with FGD without rises in the real price of electricity.

3. Private electricity companies may be keen to develop an environmentally-friendly reputation by improving their environmental record. This is especially true in a market where they compete for end-users who may value the environmental quality of their products.

As an offset to these effects, where it lowers prices, liberalization may actually stimulate electricity demand and worsen the sector's impact on the environment.

An integral element of European electricity deregulation is the creation of effective markets for power. This requires the removal of transmission constraints. New transmission links are required and existing links need to be upgraded. Transmission wires have substantial environmental effects: they have a visual impact and have been subject to repeated allegations (unsupported by scientific evidence) that they produce potentially damaging magnetic fields in their immediate proximity. For example, in 1998, Spain had 1509 km of transmission wires under construction, though much of this may be using existing rights of way to minimize the impact.

The interesting aspect of transmission links is that they produce concentrated environmental damage, which can cause significant local opposition in situations where the benefits of the links are felt a long way from the costs. Two examples of this in the United Kingdom have been the delayed Northern Irish-Scottish interconnector and the North York Moors transmission link upgrade. There has been significant opposition to the 40 km stretch of new capacity required in Scotland and to the converter station required at the Northern Ireland landing of the undersea cable. The North York Moors upgrade would have improved the transmission of electricity from the north of England (and Scotland) to the south, but the upgrade has still not been approved in 1999. These problems are limited in the European Union because new transmission requirements are likely to be small and can largely be met by better use of existing rights of ways.

3.4 Electricity and subsidies to encourage employment

Table 3.3 shows the significance of some electricity-related energy employment in selected countries, in particular based around the coal and nuclear fuel industries. There are four ways in which the electricity industry has been used to subsidize employment:

- via the payment of high prices to support indigenous suppliers of primary energy;
- via the purchasing and financing of research for local technology for power production;
- via the manipulation of the tariff structure to offer low prices to energy intensive industry;
- and via the large amount of direct employment in the electricity industry itself.

Table 3.3 Employment in the primary energy sector of selected countries, 1998

State	*Employment in mining of energy producing material*	*Employment in coke, refined petroleum and nuclear fuel*
France*	14 200	33 212
Germany	150 000	25 000
Spain*	7 447	27 911
United Kingdom	42 800	26 600
Czech Republic*	82 000	N/A
Hungary*	34 000	17 000
Poland*	818 000	23 000

Note: * 1995 figures

Sources: For Hungary and Poland: OECD Industrial Structure Statistics – Core Data 1998

In Germany, Spain and the United Kingdom, the electricity industry has been the major consumer of high-cost, locally produced coal. Electricity consumers in these countries have paid well in excess of world market prices for the coal consumed in power stations. In addition, there has been a heavy reliance on coal where alternative technologies may have been cheaper. The result of liberalization has been to reduce the prices paid to domestic coal producers (leading to rationalization and pit closures) and to increase the amount of coal imported from low priced producer countries such as Australia and Poland.[12]

In the United Kingdom, direct subsidies between the two sectors have fallen from $23 per tonne to zero between 1990 and 1998, and the amount of domestically produced deep-mined coal has fallen from 73 million tonnes to around 30 million tonnes. Over the same period, the number of mineworkers in the formerly state-owned mines has fallen from 59 000 to less than 7000.[13] In Germany, miners have already staged strikes over threats of drastic relative declines in German coal mining should a similar course of liberalization be followed there.

In most countries, it is now the case that more people work in the electricity industry and indeed in electricity-related equipment industries than in the primary industries that supply fuel for electricity. Hence, subsidizing employment in primary energy industries is likely to be at the expense of other electricity-related jobs. Indeed, the recent United Kingdom gas moratorium, designed to support some of the few remaining jobs in the United Kingdom coal industry, is reported to be likely to lead to new jobs being lost in areas that would have benefited from gas-fired power generation.

In France and the United Kingdom, the electricity industry has further supported a substantial nuclear industry. In the United Kingdom in 1997, 30 000 people worked in the 'nuclear industry' (at nuclear power stations and in nuclear fuel handling and reprocessing) and the industry is a significant net exporter. Thousands more have worked in nuclear power station construction. In France, 26 000 people work in the nuclear power building programme. A substantial switch away from nuclear power will result in the loss of large numbers of jobs in this industry. In both France and the United Kingdom, the nuclear industry represents a substantial and powerful lobby with support from members of parliament in marginal rural constituencies where such plants are located. The industry also has a powerful public relations machine aimed at convincing the public of the benefits of nuclear power and presenting the risks in the best possible light.

Historically, governments have wished to subsidize energy-intensive industries such as chemicals and steel via cheap electricity. This was the case in the United Kingdom for the largest industrial users prior to privatization. After privatization, prices went up for this class of customer while it fell for other customers. It remains possible, however, for governments to ensure cheap power is supplied to preferred customers: in Norway, the Parliament has recently sanctioned long-term contracts that allow power intensive industries to buy power from the state-owned generator, Statkraft, at preferential terms.

The electricity industry directly employs around 0.5% of the work-force in a typical European country. In the United Kingdom, the numbers of employees in the electricity industry has declined from 150 000 in 1990 to less than 100 000 in 1999. In other countries, agreements with Trade Unions to reduce staffing levels have come about after long negotiations – as in Ireland – while in other countries – such as France – employee opposition to job losses is strong. In the United Kingdom, there were no compulsory redundancies, with most of the released workers going to generous early retirement packages or other jobs; electricity workers tend to be highly skilled and can find alternative jobs relatively easily.

3.5 Social impacts as constraints on free trade

The preceding sections have illustrated some of the social and political issues likely to be raised by electricity liberalization. Traditional concerns about these issues have led to the implementation of rules, regulations and laws aimed at meeting social objectives independent of their economic effect. For example, the French tradition of 'la service public' seems to act as a barrier to liberalization based on the Anglo-American market principles promoted by the EU.[15] Economic instruments like taxes and subsidies, which are designed to meet social objectives in ways that minimize the associated economic distortions, are often complicated and difficult to explain politically. (An example is the fossil fuel levy in the United Kingdom, which was never properly explained.)[16]

There is little doubt that it is only in countries where the social impact of electricity is actually small (or considered to be small) relative to the benefits that more radical liberalization can take place. Joskow (1997) notes the inverse relationship between the pace of electricity reform in a sample of US states and the price of electricity. This seems to indicate that equity considerations are easier to overcome as the net benefits increase.

Concerns about the social impact, the environmental impact or the impact on primary industries requires the introduction of rules or economic instruments. The evidence from England and Wales is that the benefits of energy liberalization are large, but unevenly distributed between the government, producers and consumers, with different sub-groups of consumers doing more or less well.[17] It seems to have been possible to achieve a 'Pareto improvement', where no one is worse off and some (indeed most) people are better off as a result of electricity liberalization (provided money can be a substitute for the ending of traditional mining communities). This is because the fall in costs has been so great that even with tariff rebalancing, moderate regulation has ensured that prices have not risen for any group.

In some countries, however, liberalization may mean higher prices for many groups, as it has in Poland and Hungary. This has occurred, however, in the context of a society where the social impact of redistribution has been to worsen social welfare as taxpayers are in general richer than the residential electricity consumers who face higher prices.[18]

What measures can be taken so that liberalization addresses social, environmental and employment concerns? Social concerns can be met via the tax and benefit system, where benefits and/or taxes can be changed to reflect the higher relative cost of electricity for poor consumers. Environmental concerns would seem to be best pursued via the EU proposals for carbon taxes and agreements on the emissions of SO_2 and NO_X.[19]

As for employment in primary industries, the solution might be to redistribute resources from those who gain to those who lose while still facilitating economic adjustment. This happened in the United Kingdom via the £1 billion government support programme for mining communities affected by pit closures in 1993. Lower electricity prices are likely to contribute to the growth of the rest of the economy, helping it to absorb the highly skilled labour released because of restructuring in the electricity industry.

Notes

1. In some countries, slowing migration to the cities is a serious political objective given the numbers of people involved and the pressure on urban infrastructures.
2. See Ofgas (1999), p. 21.
3. See Ofgas (1999), p. 20.
4. See New Zealand Ministry of Commerce (1998), available at http://www.moc.govt.nz/inquiry/final_report/index.html.
5. See, for example, Offer (1998a).
6. See Newbery (1998) p. 137.
7. See Henney (1994).
8. See Chapter 6 of this Report for more details.
9. See Maddison et al. (1996).
10. See Burtraw and Palmer (1997).
11. See Pollitt (1997b).
12. The production cost of coal in Poland is relatively high but is subsidized by the government to support coal mining jobs.
13. *Source*: UK CSO, *Monthly Digest of Statistics*, various.
14. DTI (1998d).
15. See Midttun (1997).
16. See Henney (1994).
17. See Newbery and Pollitt (1997).
18. See Newbery (1994b).
19. This has already happened with the Large Plant Directive and Second Sulphur Protocol.

4 Current Impediments to Efficient Trade in Electricity

A classic textbook 'free market' involves a number of assumptions. First, firms have equal access to all available technologies. Second, firms produce a homogeneous product. Third, there is free entry and exit to the market. Fourth, there are a large number of firms so that no one firm or group of firms can manipulate the market. Fifth, there is perfectly accurate information about prices and quantities. If one or more of these assumptions are not satisfied, then trade is likely to occur that is not on the basis of least cost.

This chapter investigates a number of problems that constitute deviations from the free-trade assumptions in the electricity industry. We examine ownership restrictions, entry restrictions on the establishment of new assets and transmission constraints – all of which constitute barriers to entry into the electricity industry. We look at issues surrounding the small number of competing firms in the electricity industry and the way that such firms can manipulate the market: these issues of market structure and market power arise because of the oligopolistic nature of the electricity market. We then discuss the distortions introduced by subsidies to particular technologies, the problem of stranded contracts, and differential tax rates, all of which can mean that firms do not choose technology on an economic basis. These impediments to efficient trade are identified in order that they may be removed.

Many of these issues are highlighted in the European Commission's 1999 Harmonization Report on the Electricity Directive.[1] This document explores the obstacles to completion of the single European market in electricity that remain in spite of the implementation of the Directive.

4.1 Ownership restrictions

One of the major benefits of privatization and the lifting of ownership restrictions in electricity supply is the creation of an active market for property rights in electricity firms. This offers the potential to discipline incumbent managements via the threat or reality of a takeover. It also allows the creation of firms of a more efficient size, capable of exploiting economies of scale and scope. The result has been an active takeover market in the United Kingdom. Yet, elsewhere in Europe, there are still substantial restrictions on who may own electricity companies (see Table 4.1).

In countries where companies continue to be state-owned, such as France and Italy, this raises a number of questions, notably whether bureaucratic structures will remain in place and whether management have sufficient incentives to seek the most cost effective outcomes. Allowing such companies to be taken over might improve managerial discipline: it would make the threat of being fired for underperformance credible in a way that it is clearly not in companies that are essentially part of the civil service.

In other countries, cross-shareholding by other companies (as in Spain) or by regional governments (as in Germany) has the effect of making takeover difficult and of reducing the competitive pressure on management. Even in highly liberalized markets, there are still restrictions on who may control electricity companies. In the Norwegian market, there is an effective ban on foreign ownership in generation because of restrictions on ownership of hydro-electric facilities (in sharp contrast to Sweden).

In the United Kingdom, the government protected the RECs from takeover via a 'golden share' until 1995, and it continues to hold golden shares in Scottish Power and Scottish Hydro-Electric (now part of Scottish and Southern Energy). This means that any proposed takeover of these companies needs government

Table 4.1 Restrictions on electric utility ownership in selected countries

State	*Restrictions*
Belgium	None
Denmark	Transmission and distribution networks are owned by customer cooperatives
Finland	Finnish competition authority can prohibit mergers if resulting market share in electricity distribution and supply exceeds 25% nationally
France	Public ownership of EdF
Germany	Normal competition law rules
Netherlands	Privatization needs ministerial authorization
Spain	Maximum ownership of market operator and system operator is 10%. The state retains a golden share of REE
United Kingdom	Vertical separation of National Grid. Government retains golden share in Hydro-Electric, Scottish Power and Northern Ireland Electricity
Norway	Foreigners cannot buy more than 20% of a production plant and no permission given to date
Switzerland	Normal rules of competition law
Poland	Licence holder must have Polish residence

approval. If liberalization does not involve a level playing field in ownership, then some companies may use ownership restrictions to pursue strategies that may be unprofitable and/or may reduce European welfare. At the end of 1998, privatized London Electricity was taken over by state-owned EdF in a reverse nationalization.

4.2 Entry restrictions

Entry restrictions take a number of forms in the electricity industry. In generation, there are restrictions in the granting of planning permission for new power stations as well as restrictions the grid operating company may impose regarding who is to be interconnected with the grid. In transmission and distribution, there is usually statutory restriction regarding who can build and operate a network in addition to the need to acquire local planning consent for new lines (though there is no restriction on distribution system construction in the United Kingdom). In supply, the restriction is both statutory and economic in that supply requires information sharing between the distribution company and a particular supplier. Usually, supply companies require a licence from the regulator to supply.

The most economically significant entry restriction is in generation. There may be statutory restrictions on new entry, as in the United Kingdom until 1983. Under the Electricity Directive, countries have the option of a tendering procedure that leaves the incumbent utility in charge of commissioning and adjudicating on bids to build new capacity. Even if countries adopt the alternative authorization procedure, whereby companies may propose new capacity subject to a non-discriminatory process, the subsequent planning process is expensive and subject to a large amount of regulatory uncertainty. This implies that even though entry may be profitable, it may take several years for actual entry to occur. The current average time taken to bring a gas-fired power plant through the planning and construction process is four to six years in the United Kingdom.[2] It would be longer for any other technology.[3] Uncertainty implies that waiting before entry has an option value, which further delays apparently profitable entry.[4]

Tables 2.5 and 2.6 in Chapter 2 show the number of regulatory bodies that may be potentially involved. In the United Kingdom, local planning permission is required to build a power station on a particular site. This may involve a planning inquiry and appeal, which are held in public. For nuclear power plants, these processes can last for years: with Sizewell B, the last nuclear power station to be built in the United Kingdom, the public inquiry lasted three years.

Established technologies on existing sites have a clear advantage. In the United Kingdom, initial permission is required from the Department of Trade and Industry, which has the right to refuse planning consent for a power station. In 1998, the UK government announced that it was having a gas moratorium, during which it would not grant any new applications to build gas-fired power stations.[5] In Norway too, in spite of recent liberalization, the government has maintained a very restrictive stance on granting licences for new generating capacity: in 1999, it is effectively impossible to obtain a licence to build a new gas-fired plant. This use of the planning process clearly constitutes an effective barrier to entry for a particular class of entrant.

In electricity retailing or supply (as distinct from electricity distribution, which is a natural monopoly), entry restrictions have existed right across the spectrum of customers. Initially, a supply licence was geographically specific (because supply and distribution were not separated) and all but the very largest customers (who could generate their own electricity or negotiate directly with the generation company) had to be supplied from their local supply company. The Electricity Directive envisages market opening for large industrial users so that they can be supplied by other companies.

In the United Kingdom, the monopoly franchise has been successively repealed so that even the smallest domestic users now have access to alternative suppliers. One problem with the process has been that gas liberalization occurred before electricity liberalization. Hence, electricity companies could offer joint gas and electricity deals before gas companies, creating an unfair advantage. Given the initially low rates of switching by residential consumers, however, this may not prove to be a long-term problem as electricity companies are unlikely to have gained a sustained advantage.[6]

4.3 Market structure

The current market structure of national electricity markets is highly concentrated (except in the Nordic countries), even in generation, the market segment that the Directive envisages as being open to competition. A concentrated market structure need not be a problem for the delivery of competitive prices in the presence of low entry barriers. Where there are significant entry barriers, however, actual competition not potential competition is what determines prices within a market. Thus, incumbent firms may enjoy the benefits of oligopoly for many years.

Green and Newbery (1992) estimate that splitting the United Kingdom's CEGB into five rather than two fossil-fuel generation companies would have yielded benefits of around £262 million per year, even if there was non-collusive behaviour in both cases. The strong message from their work is that market structure in generation should be fragmented as part of the restructuring process.

Splitting the generation industry into several firms is not the whole answer to the market structure problem since it is clear that generation plants have a degree of local and load profile monopoly. Transmission constraints may make plants close to demand centres relatively more valuable to society per MW. In a system with competitive bidding, such as the England and Wales power pool, competition between plants that load-follow and hence set the system marginal price is more important than competition between base-load power plants that have no short-run effect on the price. So it is important exactly how the plants are divided between generation companies.[7]

For effective competition between generation companies, the companies should have a similar profile of generating plant. In Spain, two dominant generating companies have different load profiles of generating plant: Endesa has largely conventional coal plants while the majority of Iberdola's capacity is hydro. This means that depending on water-level conditions, the marginal price is likely to be set by a single company for long periods of time. Nuclear power plant companies that produce base-load power will not compete effectively against fossil-fuel based companies that can load-follow.

For relatively small European countries, the problem of market structure may be solved by effectively enlarging the size of the market. For example, instead of breaking up Sweden's Vattenfall, which has more than 50% of the domestic market in generation, all institutional barriers to trade across the Norwegian-Swedish-Finnish borders were removed. This move effectively doubled the size of the market that the company operated in, and has had a significant downward effect on prices.[8]

Market structure is an issue in the vertical as well as the horizontal dimension. Integration between generation and transmission companies, and between generation and supply companies offers the possibility of foreclosure of rival companies seeking to gain access to final customer markets. Hence, vertical relations in the electricity industry must be carefully regulated. Most liberalizing electricity markets have gone for a formal separation of generation and transmission companies (though not in Scotland to 1999). Yet, generation companies have been allowed to operate as electricity suppliers to final customers. The initial monopoly of incumbent suppliers combined with the high switching costs of moving to a new supplier implies that customers, particularly in residential markets, may switch only slowly. The evidence from liberalized residential gas and electricity markets in the United Kingdom is that only 25% of eligible customers switch, even though all would benefit financially from switching.[9]

4.4 Market power

Market power is the consequence of a monopolistic market structure combined with entry barriers. Market power above and beyond the non-collusive oligopoly price can be exploited in a number of ways:

1. Incumbent firms can actively engage in behaviour that deters strategic entry, either by building power plants on prime sites or by manipulating the time profile of electricity prices so that entrants' expected profits fall at minimal cost to incumbents.
2. Incumbents have access to existing sites, cheaper capital, lower project management costs and market power in the gas market, all of which gives them an advantage in bidding for contracts.[10] Genuine new entrants face higher costs and are unlikely to be able to undercut incumbents. These factors may explain why all new entrants to conventional electricity generation in the United Kingdom have been financed by existing electricity and gas companies, and why a large number of proposed renewable power plants (proposed by independent companies) have subsequently failed to be built.

3. Incumbents may have superior market information that they can use to exploit the market. This occurs when incumbent firms have detailed knowledge about the costs and demands of existing customers so that new entrants are likely to suffer from a 'winner's curse', that is, they will only win contracts for which they bid too low.

The first outcome apparently occurred in the England and Wales pool when the two leading fossil fuel generators began to manipulate their bidding strategy in order to raise the demand-weighted pool price while reducing the time-weighted pool price.[11] This had the effect of reducing the profitability of base-load power entrants while raising the return to their demand-weighted portfolio of power station assets. This case also apparently involved price manipulation between the two firms: they set the price 90% of the time before 1996. The regulator has highlighted price spikes when marginal plant were bidding into the pool and which resulted in 180 times when prices were above £60/MWh in January 1999 compared with only 11 times in the fourth quarter of 1996.

Clearly, this kind of behaviour is much easier to implement in an oligopolistic market, particularly when incumbents are essentially playing a 'repeated game' and can quickly establish a mutually beneficial bidding strategy without recourse to explicit information sharing. Such tacit collusion is extremely difficult to prove and even more difficult to stop without recourse to new regulation. Competition law is usually weak on the illegality of tacit collusion: in the United Kingdom, it may be detected but the law still requires evidence of intent to collude, which means statements or written evidence of a deliberate strategy.[12]

In the third case, market power is essentially an informational rent. If it is to be eliminated, then load profile information on existing customers should be available to new as well as existing suppliers. The problem is most acute when the customer has no metering equipment and hence no record of its own consumption profile. Such an advantage of incumbency is thought to be the explanation for the initially slow market penetration by new suppliers in the Scottish industrial and commercial electricity market.[13] In Spain, the possibility of manipulating the wholesale price is increased by the fact that the two dominant companies have very symmetric shares in generation and distribution, so the wholesale price is essentially a transfer price from one part of the company to another.

4.5 Access to networks

A central part of the Directive is the requirement for transmission and distribution system operators to provide non-discriminatory access to their networks for third-party suppliers in order to facilitate the supply of eligible customers. There have been a significant number of cases of refusal to grant access that have resulted in legal disputes and competition authority rulings. Refusal to grant access is one of the ways that incumbent utilities can abuse their dominant position to prevent loss of market share to new entrants.

The Bundeskartellamt, the German competition authority, instituted proceedings against Elektromark in November 1998 after it refused to grant access to the US firm Enron for the purpose of transporting electricity to Stadwerke Ludenscheid. The competition authority initially ruled that there were no grounds for refusing access. Elektromark concluded an agreement with Enron and the investigation was discontinued.[14]

Enron was involved in a similar access dispute in Denmark. The incumbent utility, Eltra, refused to grant access to Enron under its access rules, which only allowed traders acting on behalf of distribution companies in Eltra's area to be granted capacity on Eltra's interconnectors. In March 1999, the Danish competition authority ruled that traders, market brokers and other actors should be allowed to reserve access on the interconnectors on a non-discriminatory basis.

Enron has also experienced access problems in Austria. It attempted to supply electricity to Germany via Austria only to have its application for access rejected by the incumbent Austrian utility, Verbund. Refusal to grant access was justified on the grounds that one of the Austrian distribution companies involved in the deal was attempting to supply outside its normal service area. The Energy Office in the Ministry of Economics upheld the refusal though it is worth noting that the Ministry also administers the Austrian government's majority interest in Verbund.[15]

4.6 Transmission constraints and expansion of the transmission network

Free trade in electricity requires transmission capacity and transmission access. Electricity transmission does not conform to the simple linear laws that govern a standard vertically-integrated stage of a production process. Electricity will flow between two points via all the potential routes in inverse proportion to the resistance along each of the routes, that is, it will not all travel by the shortest route and there will be other loops by which it travels – the so-called 'loop flow effect'.[16]

Transmission of electricity between a power station and a customer can thus flow in such a way that other producers and customers find the flow of their electricity, and hence its costs, affected by the contracts of third parties. This implies that transmission constraints in one part of the network may be costly to parties apparently unrelated to the constraint. Thus, the upgrading of the Scottish interconnector with Northern England will benefit consumers in the South of England, and the building of an interconnector between Scotland and Northern Ireland will have benefits for the English electricity system.

This has important implications for the pricing of transmission services. Prices based purely on energy input or output (postage-stamp tariffs) or of distance and energy (contract-path tariffs) are not efficient given loop flow effects. Similarly, certain contracts will impose constraints on other users, which may mean they need to spend more on removing transmission constraints. Node varying transmission prices may be more economically efficient than postage-stamp or distance-related tariffs. Under such a scheme, producers and consumers pay positive and negative congestion charges for producing or consuming power at different points on the network.

In general, liberalized markets have not dealt with transmission constraints via efficient nodal or zonal pricing. Only a small number of markets attempt to make extensive nodal prices, including the Pennsylvania-New Jersey-Maryland (PJM) pool and the New Zealand market.[17] Other markets have limited zonal pricing for transmission, for example, the England and Wales pool and Nord Pool. In these markets, there are different transmission charges in different areas but the areas may be substantial. Under such pricing regimes, load or distance related charges may still be necessary to recover the fixed costs of the network.

Pricing transmission constraints usually gives rise to incentives to expand the transmission network in various places. Such transmission upgrades may be economically desirable, but they give rise to a number of problems:

1. There may be the kind of environmental problems noted in the previous chapter.
2. There may be difficulties with allocating payment for the upgrades. In the presence of certain regulatory regimes, such as those based on rate of return, incumbent transmission companies may have an incentive to 'gold-plate' their transmission systems by seeking upgrades to increase their capital base rather than those that are strictly necessary. It is also possible that by being price based and uncertain, the system of regulation may create incentives to underinvest since delaying investment raises profitability. This occurred in the United Kingdom with Transco and Railtrack, who were accused of failing to invest sufficiently in the gas and rail networks.
3. There may be incentives for different parties within the industry to spend money lobbying against transmission links that would benefit their rivals or reduce their transmission payments.

Some transmission links may not be economically viable in the sense that market participants may be unwilling to pay for them. This has led the EU to sponsor studies investigating the benefits of extending transmission networks in order to enlarge the single market. It has identified a number of projects that would bring benefits.[18] It has also provided support for the extension of networks to remote parts of the EU so that consumers in those areas can benefit from competition from other parts of the EU. One example is the structural funds support for the proposed Scottish-Northern Irish electricity interconnector, which will enjoy a £75 million EU subsidy, around one third of the cost.

Many incumbent transmission operators in Europe have a monopoly over the building of new transmission links between countries. This creates a particular access problem where one set of connection rules may exist within a country with prices being quoted for connection to the grid for a new generation plant but no prices being quoted to overseas electricity grids for interconnection. It also means that both countries involved must agree to the new interconnection, allowing a country with a less liberalized electricity market to stop economically beneficial transmission links being built. Hence, there has traditionally been undersupply of interconnection between countries. Proposals to upgrade the United Kingdom–France interconnector were opposed in the United Kingdom on the grounds of protecting coal-fired plants from closure.

4.7 Trading arrangements and market design

A market is an institution that facilitates the trading of goods and services between buyers and sellers. A well functioning market seeks to balance supply and demand in all trading periods and provide incentives for cost minimization and innovation. It should do so at a reasonable cost of running the institution.

Trading arrangements in a market refer to the organization of signalling by sellers and buyers of the quantities and prices they are prepared to trade at and the mechanism for undertaking trades subject to these bids and the settling of accounts. Market design refers to whom should be allowed to trade in the market and the nature of the product to be traded.

These definitions of markets suggest a number of ways in which actual wholesale electricity trading deviates from the theoretical ideal:

- It is difficult to facilitate direct trading between buyers and sellers in electricity because of the lack of transparency between buyers and sellers. Many small consumers of electricity do not know their demand for electricity at any one time, and many suppliers of electricity do not know the exact state of the market into which they are selling. This means that there has to be a large amount of *ex post* settling up of accounts once final supplies and demands are known. The Spanish regulator, CNSE, has complained that the rules of the new Spanish market are so opaque that they act as a significant entry deterrent.
- Electricity is a commodity where demand and supply need to be balanced continuously. Conventional markets have trading periods that are discrete, and during which trades are done and supply and demand are equalized. Actual electricity markets typically operate in 30 minute or one hour discrete blocks with zonal pricing according to the location of buyers and sellers on the system. This significantly reduces the complexity of the trading arrangements but represents a simplification of the underlying physical properties of the commodity being traded.
- A key problem for electricity markets is that price-based bidding is capable of distorting the underlying production of electricity, so that society incurs significant costs arising from uneconomic operation of plant. This occurs when incumbent generators misrepresent the availability or the cost of their plant in order to raise the price they receive in the market.
- Who should be allowed or forced to be in the market is a key question for electricity trading arrangements. Should only supply bids be allowed, or should both suppliers and customers be allowed to make bids? Should all producers be forced to trade all of their electricity through the market, or should participation in the market be optional? Theoretically, both suppliers and customers should make bids with participation voluntary. Thin trading in the spot market, however, may mean that prices do not reflect the true state of the market. So, the advantage of compulsory spot trading (as in the England and Wales pool) is that such a market provides accurate public information on the state of market power in the electricity market, which is then available to regulators and potential entrants. This may not be true of a bilateral contract market where the prices that might indicate the exploitation of market power are not visible.

- Markets are not costless institutions. The organization of an effective market for wholesale electricity is expensive. In England and Wales, the annual cost of the pool is around £25 million a year.[19] This is small in relation to the volume of electricity traded. Since much of this cost is fixed, however, smaller markets may not find it profitable to introduce a pool.

Some particular characteristics of electricity markets make market design difficult:

1. Electricity cannot be stored. This implies the need for sufficient reserve capacity to be available to the market if any of the current sellers are unable to produce. Thus, the market must provide for payment not only for those who supply energy but for those who offer reserve capacity. This implies two-part pricing: energy payments and availability (capacity) payments.
2. Electricity has more dimensions than simply energy content. The phase angle of the electricity current is important and this involves the provision of 'reactive power'. Provision for the buying and supplying of such power must be built into the trading arrangements.

Markets for full supply competition are more expensive, though less economically complex. Information on individual consumers must be transferred between suppliers if the consumer switches supplier and a certain amount of information must be available to potential suppliers of given customers. It must be possible for supply companies to keep the local electricity distributor informed about the characteristics of customers who are still physically, if not contractually being supplied by them. Green and McDaniel (1998) conduct a detailed cost-benefit analysis of the introduction of full supply competition in England and Wales and note the sensitivity of the result to the cost of introducing the computer systems to make competition possible.

It is important to note that trading arrangements can be separated from system operation. Trading arrangements are the contractual arrangements between buyers and sellers. System operation represents the physical coordination of supply and demand. Supply and demand for electricity must always be physically in equilibrium because of the laws of electricity (or else the system will fail). Trading arrangements must make it possible to cope with the unanticipated changes in supply and demand that system operation involves.

4.8 Stranded contracts

Stranded contracts refer to the contractual obligations of the electricity supply industry that will be rendered unprofitable by the process of liberalization. Some of the most important of these are contracts with nuclear power stations for the supply of electricity for the 40-year life of a nuclear power plant, or the contract between electricity firms and domestic coal producers to supply coal at above the market price. Liberalization changes the calculations on which decisions to invest in certain types of plants were made.

Stranded contracts may put incumbent firms at a severe financial disadvantage in the liberalization process because they may have to write down large quantities of assets that may well have been profitable under the previous regime.

Stranded contracts thus require financial restructuring of incumbent utilities and perhaps interim financial arrangements to compensate them for the change in the value of their contracts. This has proved to be a particular problem in the United States where privately owned companies have been left with 'stranded assets' worth billions of dollars. Such companies demand compensation before they will agree to cooperate in the liberalization process. Their stranded assets must then be paid for by levies or concessions to incumbents in the form of more favourable treatment in other aspects of the liberalization process.

In Europe, stranded assets are less of a problem when they involve government assets, since the government can choose to write down its assets without seeking compensation from electricity consumers. In the case of the nuclear industry, however, this may not be sufficient because funds still need to be raised to pay for future decommissioning. For example, the nuclear levy in the United Kingdom raised £7 billion over six years to pay for decommissioning.

Incomplete restructuring at the time of privatization can also lead to problems with stranded assets. The 1986 privatization of British Gas as a natural monopoly involved the continuation of some 25-year take-or-pay contracts for the supply of gas from the North Sea. When the spot price of gas fell sharply in the mid-1990s, British Gas faced a substantial stranded assets problem as it was attempting to compete in a deregulated gas market with assets with a negative net present value.[20]

Restructuring of the Northern Ireland electricity generation sector has been delayed due to wrangles about the stranded contracts between the generating companies and the electricity transmission and distribution and supply utility, NIE.[21] These contracts, signed prior to NIE's privatization, guaranteed inflation-proofed availability payments to the generators independent of output and are in the nature of take-or-pay contracts. The result has been that proposals to reform the generation sector and reduce the growing differential between electricity prices in Northern Ireland and in England and Wales have taken place subject to the constraint that the existing generators need to be compensated for any loss of net present value from changes to their existing contracts. This seems certain to perpetuate the market shares of the incumbent firms and delay the full benefits of competition.

In Spain, most stranded assets are in private hands, which perhaps explains part of the government's reluctance to further competition with incumbents. In Scandinavia, where public ownership often means local government ownership, stranded assets have been an issue. This is because the financial viability of some utilities has been threatened by deregulation and, unlike central governments, local governments are not in a position to cover the direct financial cost of the wider social benefits.

4.9 Subsidies

The previous chapter discussed the problems arising from subsidies from electricity consumers and the government to nuclear power and domestic coal production. Further impediments to free trade may arise from the desire of governments to subsidize renewable energy and CHP schemes.

Renewables other than hydro-electricity are of increasing importance in European electricity generation even though they are starting from a low base (see Table 4.2). CHP schemes are important components of district heating schemes in Denmark and other Scandinavian countries and in the Netherlands for greenhouses. District heating is environmentally attractive, but is currently uneconomic without substantial subsidy in all but the Scandinavian countries.

Many countries have specific targets for the amount of electricity they want to see supplied from renewable sources by specific dates in the future. The EU's White Paper on Renewables suggests that member states will be required to satisfy up to 12% of electricity demand with renewables by 2010.[22] The United Kingdom has a declared target of meeting 10% of its electricity needs from renewable sources by 2010.[23] This means that there will have to be considerable investment in new technology by that date. CHP schemes can either be in conjunction with district heating schemes or in association with industrial processes. The extra cost to electricity consumers of meeting this target is estimated to be substantial.

A key characteristic of the development of renewables and CHPs is that these technologies operate under essentially closed contracts where purchasers of the energy pay a fixed price for a number of years and there is no competitive bidding over the life of the contract. This is because the capital cost of such projects is high and they are often undertaken by firms that lack the financial resources of large power companies, who can afford uncovered operational risk.

Table 4.2 Market shares of renewables as a percentage of total generation, 1996

State	*Combustible renewables and wastes (%)*	*Hydro (%)*	*Wind/solar/ geothermal (%)*	*Total (%)*
Austria	3.3	64.0	–	67.3
Belgium	1.5	0.3	0.0	1.8
Denmark	2.2	0.0	2.3	4.5
Finland	8.9	17.1	0.0	26.0
France	0.4	12.8	0.1	13.3
Germany	1.4	4.0	0.4	5.8
Greece	0.0	10.3	0.1	10.4
Ireland	0.1	3.8	0.2	4.1
Italy	0.3	17.6	0.2	18.1
Luxembourg	8.6	12.0	1.2	21.8
Netherlands	2.4	0.1	0.8	3.3
Portugal	2.8	42.9	0.2	45.9
Spain	0.9	23.0	0.2	24.1
Sweden	2.0	36.9	0.1	39.0
United Kingdom	1.6	1.0	0.1	2.7
Norway	0.3	99.2	0.0	99.5
Switzerland	2.1	51.0	0.0	53.1
Czech Republic	0.6	3.1	0.5	4.2
Hungary	–	0.6	–	0.6
Poland	0.1	1.4	–	1.5

Sources: IEA (1998a) and IEA (1998b).

Such contracts for renewables and CHP give rise to the possibility of stranded contracts and hence prevent the electricity industry from being open to drastic innovation and the full play of competitive forces. The need to maintain and finance such contracts demands a degree of cross-subsidy (in the absence of direct government support) for renewables and CHP.

In the United Kingdom, renewables have been financed by part of the fossil fuel levy.[24] This has led to a number of orders for renewable plants being issued where contract prices are paid to bidders to supply renewable energy. The scheme has been very successful in sponsoring technological innovation with a successive reduction in the contract price of wind and waste schemes, to the point that wind schemes are almost competitive with conventionally generated electricity. Yet it is claimed that these schemes crowd out more economic plant *ex ante* (not *ex post* as they tend to have high capital and low running costs) and that they impose a significant cost on electricity consumers that is not related to the benefits. This is the case if the extra cost of the schemes is more than justified by the negative social externalities saved by replacing conventional production with renewables. A country with a large percentage of renewable generation would not engage in much electricity trading if renewable contracts prevented competitive new entrants gaining access to the market.

4.10 Electricity and fuel taxes

There are two main types of taxes that may distort trade in the electricity market:

1. *Taxes on the final sale of electricity*: Table 4.3 reveals the huge variation in taxes on domestic sales of electricity. It is not clear that such large deviations are sustainable in a fully deregulated residential electricity market. In these circumstances, companies may be able to sell electricity contracts in such a way that any *ad valorem* tax on electricity sales that is above the standard value-added-tax rate would be avoided. A simple example of this would be a gas company bundling electricity and gas supply, but charging only for the gas. Incumbent companies selling only electricity would be at a clear disadvantage in such a market as they would find it more difficult to avoid the tax.
2. *Taxes on the fuel for electricity generation*: Table 4.3 reveals some variation in the taxes on oil for electricity generation. This kind of tax distorts the market by making it possible that electricity generated in one country is cheaper than in another simply because of tax differences. So trade may reflect tax rather than cost differences.

Any single market requires a degree of tax harmonization to be truly effective. It is difficult to see how the current high tax differentials in electricity are sustainable. The consequences of tax harmonization are likely to be significant if flows of electricity adjust (though transmission constraints may prevent the effect on electricity flows being large). The result may be some consumers getting much cheaper and others significantly dearer electricity. These price changes will affect final demand and government tax revenue.

Table 4.3 Tax rates on electricity and fuel for electricity generation, 1997

State	*Taxes on domestic electricity*	*Taxes on industrial electricity*	*Taxes on fuel for electricity generation*		
	(% of final price)	*(% of final price)*	*Oil $/tonne*	*Gas $/10^7 kilocalories*	*Coal $/tonne*
Austria	16.7	0.0	0.00	0.00	0.00
Belgium	18.3	0.0	7.07	0.00	0.00
Denmark	58.8	13.9	N/A	N/A	N/A
Finland	24.6	0.0	40.17	11.41	0.00
France	23.4	0.0	20.17	N/A	0.00
Germany	13.0	0.0	32.11	24.46	0.00
Greece	15.2	0.0	47.83	N/A	N/A
Ireland	11.2	0.0	16.13	0.00	0.00
Italy	26.6	18.6	1.68	0.00	0.00
Luxembourg	5.7	0.0	N/A	N/A	N/A
Netherlands	23.9	0.0	34.56	8.72	N/A
Portugal	4.8	0.0	0.00	N/A	0.00
Spain	13.8	0.0	14.85	0.00	N/A
Sweden	34.8	0.0	N/A	N/A	N/A
United Kingdom	7.4	0.0	27.55	0.00	0.00
Norway	28.9	17.4	N/A	N/A	N/A
Switzerland	6.1	0.0	N/A	N/A	N/A
Czech Republic	4.5	0.0	0.00	0.00	0.00
Hungary	10.7	0.0	0.00	0.00	0.00
Poland	14.5	0.0	0.00	N/A	0.00

Source: IEA (1997) *Energy Taxes and Prices (1997) Q2*, Paris: International Energy Agency.

Notes

1 See European Commission (1999).
2 See Henney (1994), pp. 221–35.
3 See Yarrow (1988) on the build time of nuclear power stations at the height of the nuclear building programme.
4 See Dixit and Pindyck (1994).
5 See Holberton, (1997), p. 10.
6 See Hancock and Price (1998).
7 See Brunekreeft (1999).
8 See Amundsen, et al. (1999).
9 See Green and McDaniel (1998).
10 See Henney (1994), pp. 232–3 on the advantages of National Power and PowerGen in new capacity building.
11 See Offer (1995b).
12 See the White Salt case (MMC, 1986).
13 See Pollitt (1999).

14 See Bundeskartellamt press release, 11 January 1999, at www.bundeskartellamt.de/11.01.1999_english.html.
15 See *Power in Europe*, 24 May 1999, p. 8.
16 See Wood and Wollenberg (1984).
17 Henney (1998) compares the transmission pricing arrangements in three power pools: California, PJM and England and Wales.
18 European Commission (1997b).
19 Electricity Pool Annual Accounts.
20 See, for example, Corzine, R. (1996) 'The British Gas Contracts Dispute', *Financial Times*, 17 January 1996, p. 26.
21 Ofreg (1998).
22 See *Energy for the Future: Renewable Sources of Energy* which is available at http://www.europa.int/en/comm/dg17/599fi_en.htm.
23 See for example Aubrey, C. (1998), 'Renewables', *Utility Week*, 30 October 1998, pp. 15–17.
24 See Surrey (1996).

5 The EU Electricity Directive

This chapter explores the EU Electricity Directive and its implications for what needs to be done to implement the envisaged single European market in electricity. We begin by outlining the elements of the Directive. We then examine what countries need to do to comply with it in each of the five parts of the electricity industry: generation, transmission, system operation, distribution and retailing. We close with a discussion of the progress countries have already made in implementing the Directive.

5.1 The EU Electricity Directive

The Directive seeks to establish common rules for the generation, transmission and distribution of electricity.[1] The stated intention is not the achievement of 15 liberalized national electricity markets but one common European electricity market as part of the EU's single market programme.

In generation, member states must adopt one of two procedures for building new capacity: authorization (Article 5) or tendering (Article 6). Under the authorization procedure, companies may offer to build new power plants under an open and impartial procedure that decides whether they should be allowed to go ahead. Under the tendering procedure, a designated authority may decide what new capacity is required and solicit tenders, which are then accessed by an impartial procedure. The idea behind both procedures is that the market for new generation plant will essentially be competitive.

This section of the Directive means change for incumbent generators: it aims to remove the monopoly they may have on building new plant.

In transmission, the Directive rules that each member state must specify a transmission system operator (Article 7), whose job is to ensure dispatch of plant according to transparent and fair rules that do not favour plants owned by the same company as the system operator (Article 8). The Directive also specifies that all electricity producers and suppliers have the right to erect their own direct lines for supply of their own premises, subsidiaries and customers (Article 7.2). The system operator may favour renewable energy plants, waste or CHP and, subject to a maximum of 15% of demand, plants using indigenous fuels (Articles 8.3–8.4). This form of discrimination is called priority production.

This section of the Directive implies that the system operator must apply the same criteria for the dispatch of plant to incumbent generators as to new entrants.

In distribution, system operation must be on the same non-discriminatory basis as transmission (Article 10). Member states may impose requirements on distribution companies to meet certain public service obligations. These must fall under one of five categories: security of supply; regularity, quality and price of supplies; and environmental protection (Articles 10 and 11).

This section of the Directive potentially gives independent suppliers access to the distribution and transmission networks in order to supply final customers over incumbents' distribution networks.

The Directive also provides for management separation of businesses (Article 7.6) and functional unbundling of accounts (Article 14.3). These clauses require integrated electricity companies to separate the management of their generation, transmission, distribution and non-electricity activities and to produce separate accounts for each.

The centre-piece of the Directive is Articles 17 and 18 on access to the transmission and distribution networks. There are three types of arrangements: negotiated third party access (nTPA); regulated third party access (rTPA); and the single buyer model.

Under nTPA (Article 17.1), consumers and producers can contract directly with one another and then negotiate with the network operators for access to the network. Such negotiations should be subject to a dispute resolution procedure and there should be publication of average access prices over the previous year as a guide to potential entrants. Under rTPA (Article 17.4), prices for access are published and not subject to negotiation. The operator of the transmission or distribution grid may refuse access on the grounds of a lack of capacity, but duly substantiated reasons must be given for such a refusal (Article 17.5).

Under the single buyer system (Article 18), there is a single wholesale buyer of electricity. Electricity generation may be competitive, but supply competition is limited. Eligible customers may still conclude contracts with producers. The single buyer then pays the contracted producers a price equal to its own regulated sales price minus the network charges. A producer-supplier can then compensate the customer to the extent of the price indicated in the contract price. As with rTPA, there is a published tariff for transmission and distribution, and eligible customers can conclude supply contracts with independent suppliers. Single buyers must maintain separate production and distribution accounts and independent producers can erect their own lines to supply electricity for their own use. The single buyer model is intended to be equivalent to rTPA.

Member states are required to designate a disputes settlement authority, independent of the parties, to settle disputes concerning contracts, refusal of access and refusal of purchase (Article 20.3).

Mixtures of the three systems are possible. The Directive's rules on access ensure the fulfilment of the other parts of the Directive. The Directive foresees gradual opening of the market with the minimum definition of what constitutes an eligible customer being relaxed over the duration of the Directive.

Article 19 discusses the minimal requirements for market opening foreseen by the Directive. Each country has minimal market opening targets. These are based on ensuring that similar shares of the markets are opened in each member state subject to the shares in EU output set by the thresholds (40 GWh by 19 February

1999, 20 GWh by 19 February 2000, 9 GWh by 19 February 2003) being implemented at EU level. The approximate required market opening in each member state is 25% in 1999, 28% in 2000 and 33% in 2003.

The Directive incorporates the principle of reciprocity (Article 19.5), whereby states have the right to refuse access to their market for companies from member states that have not liberalized to the same extent.

The Directive allows states to apply to the Commission to set up temporary schemes to raise funds to pay for the costs of stranded assets resulting from the liberalization process (Article 24).

The current predictions are that by 2007, over 70% of the market will by fully competitive in Europe. Norway was 100% liberalized from 1991; Sweden and Finland from 1996; Germany from 1998; and the United Kingdom expects to be so by the end of 1999. It should be noted, however, that these figures are *de jure* rather than *de facto*. Article 27 commits the Commission to a re-examination of the thresholds by 2006 with a view to further market opening.

5.2 Complying with the Directive

5.2.1 Generation

There are a number of ways of fulfilling the Electricity Directive in generation. The UK electricity market has been in compliance with this part of the Directive since 1990. The power pool allows generators to decide whether they can make a profit from building a new power station essentially by using the pool price or a contract to estimate the likely sales revenue. They then apply to build the power station via the planning process and are dispatched according to the non-discriminatory price-bid based algorithm used by the pool operator. Thus, the United Kingdom operates an authorization procedure.

A half-way house towards this is for incumbent transmission and generation companies to publish tariffs that are the basis of the calculation of the sales revenue of generation business subsidiaries and which also constitute offers at which new plant will be paid for electricity. This system operated in the United Kingdom following the 1983 Energy Act. The problem is that it is extremely difficult to establish that the tariffs are non-discriminatory when the incumbent utility's plant continues to be dominant. A genuine authorization procedure would seem to remove any advantage to integration between generation and transmission businesses and rapidly begins to move towards a pool-based system.

The tendering procedure relies on the system operator deciding what new capacity is needed and soliciting offers for supply of that capacity. This system maintains some of the advantages of integration between generation and transmission in the short run. There will still be the possibility to coordinate closely the two stages of production without introducing devices that force a complete separation. The tendering procedure has been widely used in developing countries. It has the particular advantage that new entry is controlled and is not excessive.

One flaw with the UK system was that a non-discriminatory authorization procedure encourages economically inefficient entry if incumbent generators have market power. Another problem was that authorization procedures tended to lead to entry by one new technology, with low marginal cost, to the detriment of depreciated, high marginal cost plant. This was potentially economically inefficient and may eventually reduce fuel diversity in generation.[2] Tendering, however, has its own well known problems such as encouraging collusion between interested parties in the bidding process as well as the possibility of bribes in order to win the tender.

Both procedures involve transparency and unbundling. This will constitute a major cultural change for integrated utilities such as EdF in France and ENEL in Italy. It is difficult to see how these countries can comply with the Directive without fully splitting up generation and transmission. Indeed, the generation clauses of the Directive have already prompted Italy to indicate that ENEL will sell off 30% of its generation capacity in order to comply with the Directive. It had previously separated the accounts of its different businesses.

5.2.2 Transmission and system operation

The Directive requires non-discriminatory dispatch, except for renewable plant and a limited number of plants using indigenous fuels. (These exceptions represent reductions in the scope for genuine competition.) While the Directive allows for 'Chinese walls' between system operators and generators, it is not clear how practicable these are or what the advantage of integration is in the absence of discrimination. Currently, most large systems have integrated transmission and system operation. Prior to deregulation, dispatch is on the basis of marginal cost subject to a merit order. While this is clearly possible in a liberalized system, it does require incentives to be honest or the use of estimated costs based on assumed thermal efficiencies and indexed fuel costs – as used in Northern Ireland. Clearly, independent generators may be wary of revealing their costs to an incumbent system operator that also owns some generation plant.

5.2.3 Distribution and retailing

The implication of the Directive is that separate distribution businesses (at least in accounting terms) will have to be created where they are integrated with transmission and generation. This is only a problem in France, Ireland, Italy and Spain. Further, there will be no need to separate distribution and retailing formally. It seems likely that they will continue to be integrated in these countries for the foreseeable future.

Retailing is separable from distribution and the Directive does not clearly envisage a separation of distribution and supply businesses within integrated utilities. Indeed, the Directive does not distinguish between distribution and retailing (or supply). This is a potential problem because the bundling of supply and distribution might allow an incumbent distributor to pass on some retailing cost to a non-integrated electricity retailer, which would be double-charged for retailing to its customers. This was behind the requirement to separate distribution and supply businesses within the RECs in the United Kingdom. National Power was (in early 1999) the first company to acquire a supply business from an incumbent REC (Midlands), facilitating the first vertical disintegration of a distribution and supply business in the United Kingdom.

The imposition of public service obligations on the supply part of the distribution business is likely to limit competition. Competition needs to be restricted in such cases, however, because incumbents face 'cream-skimming' of the more profitable parts of their supply business by entrants who can choose not to supply high cost customers in a market where prices are smoothed geographically. This is only a problem in residential markets, but it could be quite serious. Obligations to supply that include restrictions on price discrimination either limit competition by putting undue burdens on entrants to cover the whole market or they penalize incumbents by not allowing them to offer discounts to their more profitable customers. Theory suggests that 'cherry-picking' is a problem, but the current evidence from the United Kingdom is that it is the richer customers who are less likely to switch.[4] Retail competition, however, is not something envisaged by the Directive given the small size of the thresholds for minimum percentage of the market to be liberalized.

5.3 Progress with implementing the Directive

Table 5.1 examines the progress that the various EU members have made in implementing the Electricity Directive.

Greece has a two-year derogation on implementation; Ireland has a one-year derogation; and Belgium has a derogation, but has decided not to use it. As of early 1999, Ireland and Greece had not fully clarified how they are going to implement all the clauses of the Directive. France has specified how it intends to meet the requirements of the Directive but has yet to complete the process of transposing it into French law: some aspects of implementation were still being debated in mid-1999 and it is forecast to become law in 2000.

Most countries have opted for an authorization procedure in deciding about new plant building with only four countries planning to make extensive use of the tendering procedure. Portugal only intends to use the tendering approach if there are insufficient applications forthcoming under the authorization procedure.

With transmission, a mixture of approaches have been adopted towards the separation of system operation from production and distribution. Only France will adopt the minimalist approach of having a functionally separate division responsible for system operation within an integrated company. Other countries have adopted either an independent system operator (as proposed in Greece) or left the function in the hands of a non-integrated grid company (such as the National Grid Company in the United Kingdom). The non-discriminatory charging regime for transmission is predominantly a form of postage stamp tariff, which many countries desire for a simple and transparent charging regime for transmission.

All countries have imposed public service obligations on their incumbent distribution companies, though these range from minimal in Germany to potentially very important in France. In the United Kingdom, holders of public electricity supply licences must offer to supply all eligible customers at the same price within a licensed area.

Table 5.1 Implementation of the EU Electricity Directive as at 19 February 1999

State	*New generation procedure*	*Transmission charging régime*	*TSO*	*PSO*	*Priority production*	*Extent of unbundling*	*Type of access*	*Market opening (%)*	*Minimum thresholds*	*Reciprocity clause invoked*	*Stranded contracts, transitional scheme, applied for*
Austria	Authorization	Postage stamp	Concession	Yes	RES	Functional, supply not specified	rTPA	26.7	40 GWh/year	Yes	8.7 bn ATS requested
Belgium	Authorization	?	Daughter company of existing companies	Yes	Yes	Functional, supply not specified	rTPA for inland, nTPA for international	33	100 GWh/year	Yes	Yes
Denmark	Authorization	Postage stamp	Eltra Elkraft	Yes	RES-CHP and waste	Legal separation, including separation of new supply companies	rTPA for inland, nTPA for international	90	10 GWh/year	Yes	Yes, scheme applied for in case of take-or-pay gas contracts
Finland	Authorization	Postage stamp	Fingrid	Yes	No	Legal separation	rTPA	100	No	No	No
France	Authorization with complementary tendering	Postage stamp	An independent part of EdF	Yes	RES	Accounting, not supply. Management separation of the TSO	rTPA	25	40 GWh/year	TBA	Yes
Germany	Authorization	Distance related over 100km	Several	Yes, but relatively limited	RES, CHP	Accounting	nTPA	100	No	Yes	Network access restrictions in eastern Germany

Table 5.1 continued

State	*New generation procedure*	*Transmission charging régime*	*TSO*	*PSO*	*Priority production*	*Extent of unbundling*	*Type of access*	*Market opening (%)*	*Minimum thresholds*	*Reciprocity clause invoked*	*Stranded contracts, transitional scheme, applied for*
Greece	Both	?	Independent body	Yes	RES, CHP and lignite	?	rTPA	23	Below 40 GWh/year	Yes	Yes
Ireland	Both	?	New state-owned company	Uniform tariffs, peat-fired stations and RES	RES	?	rTPA	28	4 GWh/year	Yes	Yes
Italy	Authorization	Postage stamp with distance correction	Independent body	Yes	RES, CHP	ENEL to sell at least 25% of generating capacity by 2003	Single buyer for franchise market, rTPA	30	30 GWh/year	No	Yes
Luxembourg	Authorization	–	–	Yes	–	–	rTPA	40	40 GWh/year	–	–
Netherlands	Authorization	Postage stamp	TenneT	No	RES	Legal, but not in ownership	rTPA	32	2 MW	Yes	8 bn guilders
Portugal	Both	Postage stamp	REN	Yes	RES, CHP	Legally separate for G,T,D and other	Single buyer for franchise market, nTPA when grid reinforce-ments required, rTPA	27 GWh/ year	30	Yes	Yes

Table 5.1 continued

State	*New generation procedure*	*Transmission charging régime*	*TSO*	*PSO*	*Priority production*	*Extent of unbundling*	*Type of access*	*Market opening (%)*	*Minimum thresholds*	*Reciprocity clause invoked*	*Stranded contracts, transitional scheme, applied for*
Spain	Authorization	Postage stamp	Part of REE	Yes	CHP, RES	Accounting separation throughout to turn into legal separation	rTPA	42	1 GWh/year	Yes	1 988 561 mPTAs
Sweden	Authorization	Zonal tariff	Svenska Kraftnät	Yes	No	Legal separation	rTPA	100	No	Yes	Yes
United Kingdom	Authorization	Connection, trans-portation and security charges	NGC, Scottish Power, Scottish Hydro-Electric, NIE	Yes	Nuclear	Different companies for G,T,D and S	rTPA	100	No, since September 1998	No	Yes
Norway	Authorization	Nodal	Stattnet	Yes	No,	Accounting separation	rTPA	100	No	Yes	No
Czech Republic	Tender	–	CEZ	–	–	–	Single buyer	–	–	–	–
Hungary	Tender	–	MVM	–	–	–	Single buyer, but considering rTPA	–	–	–	–
Poland	Authorization	Complex	PSE	–	–	–	rTPA	37	100 GWh	–	Yes

Table 5.1 continued

Notes:

TSO	=	transmission system operator
PSO	=	public service obligation
rTPA	=	regulated third party access
nTPA	=	negotiated third party access
RES	=	renewable electricity schemes
CHP	=	combined heat and power
G	=	generation
T	=	transmission
D	=	distribution
S	=	supply or retailing

Most countries are prioritizing some production, usually renewables. A significant number, however, are also adopting priority dispatch for CHP projects as well. Only in Finland and Sweden, where there is already significant hydro production compared to other EU members, is there no priority dispatch on environmental grounds.

Few countries are going beyond what the Directive requires on unbundling of different functions in the electricity industry. Only in the Netherlands, Spain, Sweden and the United Kingdom is there legal separation of generation, transmission and distribution. In only a few countries is retailing or supply distinguished from distribution, even in accounting terms.

Access was a key issue in the development of the Directive. In spite of France having delayed the discussions of the Directive with its proposal of the single buyer model, it has not adopted it. Indeed, only Italy and Portugal have adopted it and then only partially: Italy for a limited transition period and Portugal for the franchise market. Most countries have opted for rTPA.

The market opening picture is mixed. While some countries can say that their markets are 100% open, the overall picture is mixed. Germany is technically 100% open, but there seems little prospect of serious competition for smaller electricity customers in the current heavily concentrated market dominated by networks of related firms. Several countries have only opened the minimum level up to competition: Austria, France and Greece are closely followed by Ireland and Portugal. The minimum thresholds vary from 0 to 40 GWh.

Most countries have invoked the reciprocity clause in their own enabling legislation. There is a doubt, however, as to whether this clause can actually be used to hold up liberalization in member states as it is easily circumvented by routing contracts through subsidiaries operating in fully deregulated markets. Finally, most countries have applied for transitional schemes that allow the recovery of stranded contracts.

While progress in implementing the Directive has been mixed, the majority of countries have liberalized faster than the minimum required by the Commission in terms of market opening and have adopted the more competitive of the options where there was a choice: authorization over tendering and rTPA over the single buyer model.

The following chapters examine the details in a number of countries within and on the fringes of the EU – the United Kingdom, the Nordic countries, Germany, Spain, France and Hungary – and how they have been liberalizing their electricity industries in recent years. These countries exhibit different rates of progress in liberalization and complying with the Directive and, hence, allow examination of the obstacles to and consequences of liberalization in particular national markets.

Table 5.1 suggests a ranking of the country studies in roughly decreasing order of progress with implementing the Directive. We begin with the chapters on the United Kingdom and the Nordic countries, which may be thought of as countries adopting a more rapid liberalization programme: all currently have 100% market opening and have been arguably in compliance with the Directive since at least 1996.

We go on to examine Germany, which technically has had 100% market openness since 1998 but minimal unbundling of traditional utilities. Next, we look at Spain, which has made progress with market opening beyond the minimum threshold and has adopted reasonably competitive institutional arrangements. Spain is followed by France, which has followed a policy of minimal compliance with the Directive in spite of being the second largest national electricity market in Europe. Finally, we visit Hungary, which is aspiring to EU membership and demonstrates the particular problems of transition economies in complying with the Directive.

Notes

1 For a summary of the Directive, see http://europa.eu.int/en/comm/dg17/elec/memor.htm.
2 See Newbery and Pollitt (1997).
3 See McGurnaghan (1995).
4 Ofgas (1999).

PART 2: Country Studies

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6 The UK Experience: Privatization with Market Power[1]

The United Kingdom has three quite distinct electricity supply industries (ESIs) in the three different jurisdictions of England and Wales, Scotland and Northern Ireland. In England and Wales (with a population of just over 50 million and a peak demand of just over 49 GW), the industry was under public ownership from 1948 to 1990, and for most of this period the Central Electricity Generating Board (CEGB) operated all generation and transmission as a vertically integrated statutory monopoly, with 12 Area Boards acting as regional distribution monopolies. The CEGB had interconnectors to Scotland and France, with which it traded electricity.

Scotland (with a population of 5.1 million and a 1990 peak demand of 5.6 GW, including exports of 800 MW to England) has always retained a degree of autonomy in law and government within the United Kingdom, while England and Wales are normally treated as a single jurisdiction. In Scotland, there were two vertically integrated and geographically distinct utilities, combining generation, transmission, distribution and retailing (supply), one serving the north, the other serving the south. Scotland was export-constrained by the capacity of the interconnector to England, which has been upgraded from 800 MW to 1200 MW and is projected to rise to 2200 MW in 1999–2000, larger than the 1998 MW interconnector with France (see NGC, 1998).

Northern Ireland (with a population of 1.7 million and peak demand of 1.5 GW) is physically separate from the rest of the United Kingdom, and the grid connection with the Republic of Ireland to the south had been severed by terrorist activity so that it was a small isolated system. Now, the link to the south has been reconnected and there are plans to connect Northern Ireland by undersea cable to Scotland in 2001. The industry was privatized in 1992/3. At present, generation is shared between three companies and the transmission, distribution and retailing functions of the industry are part of a single vertically integrated state-owned company, Northern Ireland Electricity (NIE).

So the United Kingdom exhibits considerable structural diversity, in having four grids, three regulatory systems and two regulators.

6.1 Restructuring and ownership changes

The 1989 Electricity Act created the post of Director General of Electricity Supply (DGES) to regulate the natural monopoly wires businesses of the National Grid and the regional electricity distributors, and to set price caps, which would be reset at periodic reviews every four to five years. The DGES has a duty to ensure that reasonable demands for electricity are met and that licence holders are able to finance their activities, to promote competition in generation and retailing, to protect customer interests and to promote efficiency. The Office of Electricity Regulation (Offer) was set up by the government as an independent body under the Electricity Act, and is headed by the DGES.

The Electricity Act divided the CEGB, with its 74 power stations and the national grid, into four companies. 60% of conventional generating capacity (40 power stations with 30 GW capacity) were placed in National Power, and the remainder (23 stations of 20 GW) were placed in PowerGen. The 12 nuclear stations with 8 GW capacity were placed in Nuclear Electric, and the high tension grid, together with 2 GW of pumped storage generation, were transferred to the National Grid Company (NGC).[3]

These four companies were vested (created) as public limited companies (plcs) on 31 March 1990 at the same time as the 12 distributors, now known as the regional electricity companies (RECs). NGC was transferred to the joint ownership of the RECs, and the RECs were sold to the public in December 1990. 60% of National Power and PowerGen was sold to the public in March 1991, with the balance sold in March 1995. Competition in generation was introduced by requiring all generators (public and private) to sell their electricity in a wholesale market, the electricity pool.

The original plan was to place the 12 nuclear stations in National Power, which had been given the bulk of the fossil fuel generation, in the hope that the combination would be financially viable. At a late stage, it became clear the nuclear stations were not, however, saleable at a reasonable price. They were transferred to Nuclear Electric and kept in public ownership until 1996. The pumped storage generation of NGC was separated and sold to Mission Energy at the end of 1995, and the RECs sold their shares in NGC when it was floated on the stock market, also at the end of 1995.

The Electricity Act also set out a timetable for introducing competition into retailing. At privatization, the 5000 consumers with more than 1 MW demand were free to contract with any supplier (who can buy directly from the electricity pool), but all other consumers had to buy from their local REC, which had a franchise monopoly. In 1994, the franchise limit was lowered to 100 kW, and another 45 000 customers were free to choose their supplier. Since late 1998, the remaining 22 million customers have had that right too, and by mid-1999 the REC franchises had finally ended.

The Scottish system, with about 10 GW capacity, was also restructured on 31 March 1990, when the North of Scotland Hydro-Electric Board became Scottish Hydro-Electric, and the non-nuclear assets of the South of Scotland Electricity Board were transferred to Scottish Power. The nuclear stations were placed in a state-owned company, Scottish Nuclear. Both were privatized as vertically integrated regulated utilities in June 1991, free to sell into the English market, using the English pool price as the reference price for Scottish trading, and operating under the same system of regulation.

The publicly owned nuclear stations were restructured again when the five newer Advanced Gas-cooled Reactors (AGRs) with about 5 GW, together with the new Pressurized Water Reactor (PWR) at Sizewell, were transferred from Nuclear Electric (together with the two AGRs from Scottish Nuclear) to British Energy. British Energy was then privatized in 1996. Nuclear Electric's seven remaining old Magnox reactors with about 3 GW (which had negative net value) were transferred to the publicly owned British Nuclear Fuels Ltd, the fuel (re)processing company.

Northern Ireland is different again. The ESI is governed by the Electricity Order SI 1992 No. 231, which has similarities with, but some important differences from, the regulatory system on the mainland (see MMC, 1997, Chapter 4). The four power stations (with rather less than 2 GW and a peak demand of 1.5 GW) were sold in a trade sale to three different companies in 1992. NIE, which then just contained transmission, distribution and retailing, was sold to the public in 1993. Up to 1999, there is no competitive trading system as all electricity is sold to the Power Procurement Business of NIE under long-term contracts, effectively a single buyer system. There is no franchise monopoly and four second-tier suppliers are licensed, but they supply very few customers. The industry is regulated by Ofreg, which also regulates gas.

Thus, England and Wales were almost completely unbundled and restructured before privatization. Subsequent reforms attempted to complete the process as NGC sold its generation and was sold by the RECs, though at the same time, the RECs were integrating into generation. Scotland contains two vertically integrated regulated utilities that can compete for customers (and sell in England and Wales). Northern Ireland has separated generation from the wires businesses, but transmission, distribution and retailing are combined in a regulated franchise monopoly.

NIE's wholesale prices were about 42% higher than on the mainland in 1998, and the gap has widened over the years because of the lack of competition in generation and the protected long-term contracts with the generators. Scotland is the farthest from the ideal of separating generation from transmission, and perhaps as a result, retailing competition is relatively weak. Consequently, there are pressures for further restructuring in both Scotland and Northern Ireland.

After privatization, almost all of the RECs became joint investors with 'independent power producers' (IPPs) in building gas-fired combined cycle gas turbine (CCGT) generating stations, whose high efficiency, low capital costs, modest economic scale and use of cheap fuel made them attractive competitors to the predominantly coal-fired generation of National Power and PowerGen.

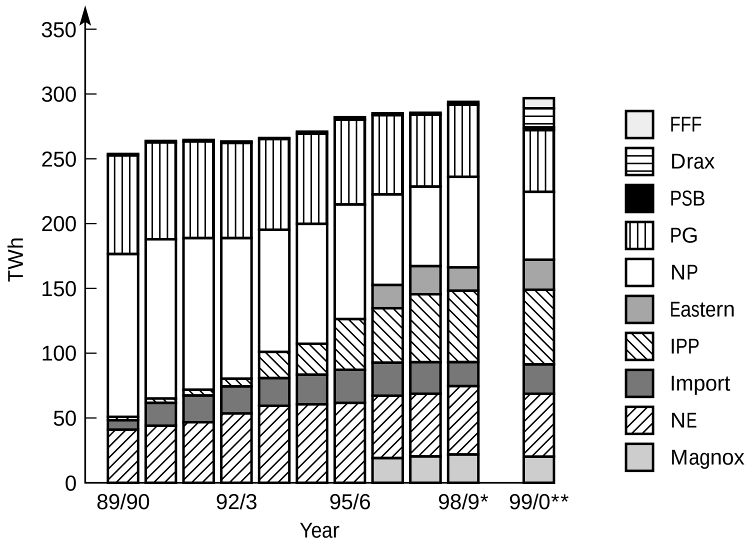
The next major structural change occurred in 1996 when, under regulatory pressure, National Power divested 4 GW and PowerGen divested 2 GW of coal-fired generation. They buyer was Eastern Group, one of the largest RECs, which thereby became a major generator with significant distribution assets. In August 1998, PowerGen agreed with the Department of Trade and Industry (DTI) to divest of two more large coal-fired power stations (4 GW) in return for permission to merge with the US-owned English REC, East Midlands. National Power has agreed to sell Drax – which, at 4000 MW, is one of the largest coal-fired power stations in Europe and which is equipped with flue gas desulphurization (see Chapter 3) – in exchange for DTI approval of its acquisition of the retailing business of Midlands Electricity. National Power also had to agree to modify the 'earn-out' clause from its earlier divestiture of 4000 MW of plant to Eastern Group in 1996.[4]

Figure 6.1 shows the evolution of each company's share of generation, and a forecast for 2000 if the divestitures go equally to two new companies with negligible generation assets. This restructuring would be the most favourable outcome from the point of view of competition. (One of the companies is named Drax, as it will inherit the Drax 4000 MW station; the other is called FFF as it will inherit Fiddler's Ferry and Ferrybridge. The outputs are based on recent average station outputs.) Figure 6.2 shows the evolution of fuel shares and especially the entry of new CCGT plants, half of which were built by IPPs, eating into the share of coal-fired generation.

The RECs had been privatized with the government holding golden shares in each. These could be used to block any takeover, but they lapsed in 1995. The subsequent takeover wave culminated in the attempted restructuring of the ESI by vertical integration between generation and distribution. In the following few months, eight of the 12 RECs were targeted, and six were successfully acquired. Two were bought by their local water and sewerage companies (also regulated utilities), one by the vertically integrated Scottish Power, one by the conglomerate Hanson plc to become Eastern Group, and two by US utilities.

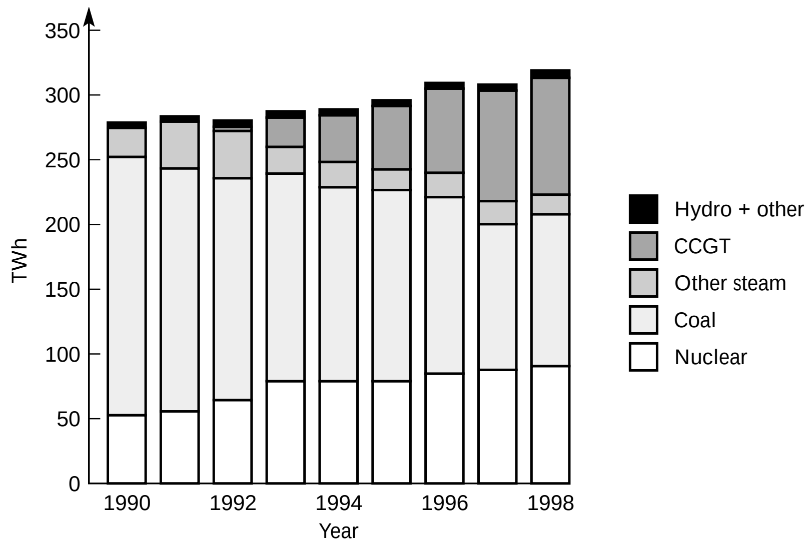
The remaining bids, by National Power and PowerGen, were referred to the Monopolies and Mergers Commission (MMC) and then rejected by the DTI, as attempting premature vertical reintegration of generation and distribution, that is, before adequate competition had been created. One of the target RECs, Midlands Electricity, was bought by another US utility group soon afterwards. Three more US utilities made successful bids in late 1996, and Electricité de France, still a state-owned company, successfully bought London Electricity from its US owner, Entergy, in November 1998. PowerGen merged with East Midlands in August 1998, Scottish Hydro merged with Southern Electric, the last remain-

Figure 6.1 Generation in England and Wales



Note: * First half, ** Forecast

Figure 6.2 UK electricity supply by fuel



Source: *Energy Trends*, Jan 1999.

ing independent REC, on 14 December 1998, and National Power bid for Midlands Electricity's retailing business in November 1998.[5] Two companies, NGC and Scottish Power, have made bids for US companies in 1998, reversing the earlier flow of acquisitions.

6.2 Industrial structure and market power

The aim of restructuring was to liberalize the ESI and create a competitive market for electricity, both at the wholesale level and for final consumers. Northern Ireland operates the single buyer model with an initial objective of opening 25.37% of the market to roughly 230 of the largest customers by February 1999. The current set of (poorly designed) contracts run until 2010, and although they are being renegotiated to reduce (slightly) the price of electricity, the UK government has lodged an initial request for a transitional regime under Article 24 of the Electricity Directive, primarily to cover the stranded costs of these contracts. In the rest of the United Kingdom, however, competition was introduced at the time of privatization and had been extended to the entire market by mid-1999, so that the mainland was fully compliant with the Directive.

6.2.1 The electricity pool

The most interesting institutional change in restructuring the ESI was the creation of the electricity pool, a bulk electricity spot market that determines the merit order and wholesale price of electricity. This operates as a compulsory day-ahead last price auction with non-firm bidding, capacity payments for plant declared available (determined as an exponential function of the reserve margin), and firm access rights to transmission (with generators compensated if transmission constraints prevent their bids being accepted).

Each day, generators bid their plant into the pool before 10 a.m. and by 5 p.m. they receive their dispatch orders and a set of half-hourly prices for the following day. The half-hourly system marginal price (SMP) is the cost of generation from the most expensive generation plant accepted, based on a forecast of demand and ignoring transmission constraints. Generators declared available receive this and the capacity payments, which together make up the Pool Purchase Price (PPP). All companies buying electricity from the pool pay a Pool Selling Price (PSP), and the difference between this and the PPP is known as the uplift: it covers a variety of other payments made to generators.

In addition to the pool, which acts as both a commodity spot market producing the reference price and a balancing market, most generators and suppliers sign bilateral financial contracts for varying periods to hedge the risk of pool price volatility. The standard contract is a Contract for Differences (CfD), which specifies a strike price (£/MWh) and volume (MWh), and is settled with reference to the pool price, so that generators are not required to produce electricity in order to meet their contractual obligations. The Electricity Forward Agreements market is a screen-traded over-the-counter market that allows contracts to be traded anonymously and portfolio positions balanced. It has not yet evolved into a futures market, partly because of the illiquidity caused by the large number of products (four-hourly periods for working and non-working days, for SMP, PPP and uplift).

Contracts are not only important for risk-sharing; they were also critical in managing the transition from a vertically integrated company able to pass all its costs through to its captive customers to a competitive industry in which customers were free to buy from the cheapest supplier. There were two major transitional problems:

1. Domestic coal was considerably more expensive than imported coal and was soon to be revealed as uncompetitive against gas.
2. The average costs of nuclear generation, once all the decommissioning and fuel cycle costs were included, were considerably above the likely equilibrium pool price.

The first problem was handled by a series of take-or-pay contracts between the generators and the still state-owned British Coal for the first three years at above world market prices. The generators in turn held contracts to supply the RECs for almost all their output for up to three years, which allowed the costs of the coal contracts to be recovered from these contract sales. There was the additional and very important benefit that the profit and loss accounts of the generators and RECs could be confidently projected for the first three years, and these provided the necessary financial assurance for the privatization to proceed.

The second problem was dealt with by imposing a Non-Fossil Fuel Obligation (NFFO) on the RECs (to buy electricity generated from non-fossil fuels, overwhelmingly nuclear power) and a Fossil Fuel Levy (FFL) on all fossil generation (initially at the rate of 10.8% of the final sales price). The levy was paid to

Nuclear Electric to build up a fund to meet its decommissioning liabilities of about £9.1 billion, which can be compared with the privatization proceeds from selling off the CEGB of just under £10 billion.

6.2.2 Achieving effective competition in generation

There are two routes to effective competition in generation:

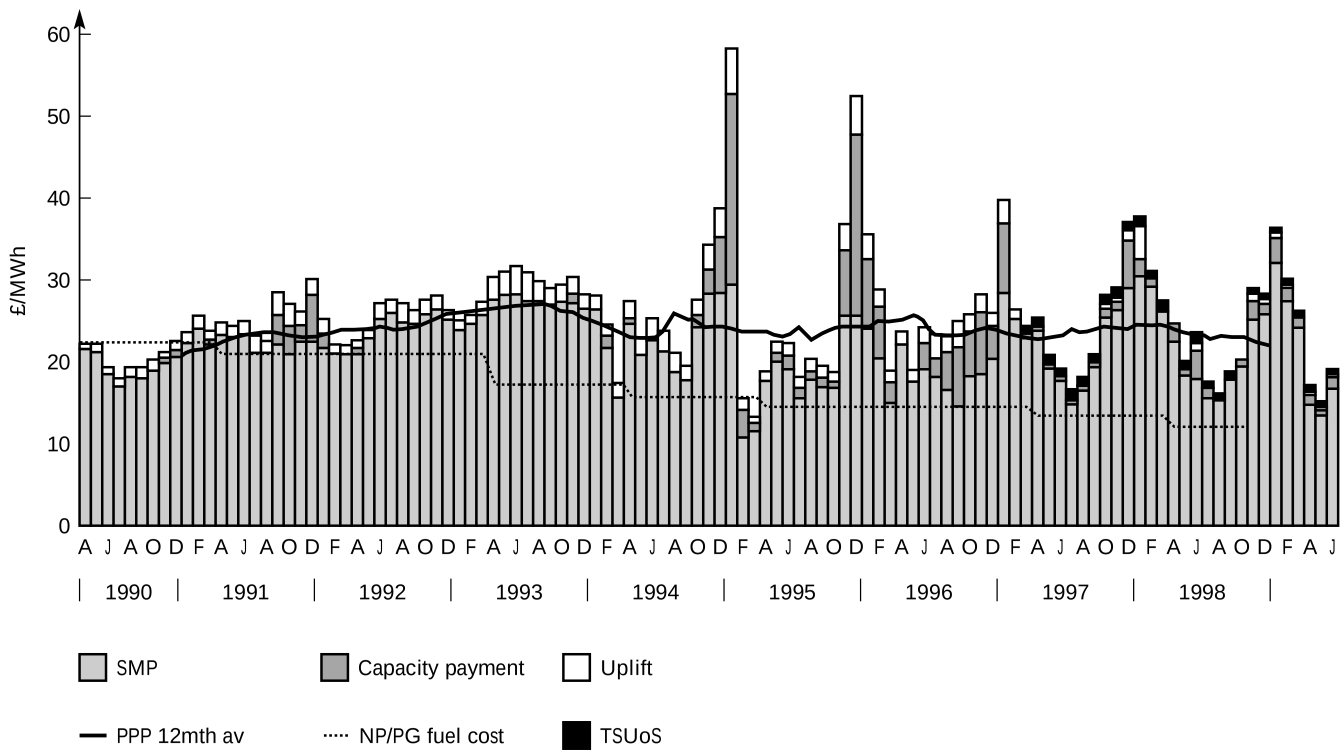
- The first and more satisfactory route is to ensure that capacity is divided between a sufficient number of competing generators so that no single generator has much influence over the price.
- The second and indirect route to competitive pricing is to induce generators to sell a sufficiently large fraction of their output under contract, and expose them to a credible threat of entry if the contract price (and average pool price) rises above the competitive level.

The first option was ruled out by the tight Parliamentary timetable for privatization, which gave too little time to reconsider plans once it became clear that nuclear power was unsaleable. At privatization, the two fossil fuel generators set the pool price over 90% of the time (the balance being set by pumped storage, which arbitraged a limited amount of electricity from off-peak to peak hours). Nuclear Electric, Scotland and France all supplied base-load power that never set the pool price. Green and Newbery (1992) calculated that a duopoly unconstrained by entry would have significant market power and would be able to raise pool prices to very high levels.

A generator that has sold power on contract only receives the pool price for the uncontracted balance. If this is a small fraction of the total (and it is usually about 10–20%), then there is little to gain from bidding high in the pool. High bids run the risk that the plant is not scheduled, leading to the loss of the difference between the SMP and the avoidable cost. Also, the trade-off between lost profit on uncontracted marginal plant and higher inframarginal profits is increasingly unattractive as contract cover increases. Contracts and entry threats are complimentary: entry threats encourage generators to sign contracts; and contracts facilitate entry.

The advantages of creating a sufficient number of companies for competition are that it does not need to rely on the continued contestability of entry, and it works well even when the competitive price is well below the entry price, in periods of excess capacity. As this route was not chosen, contracts and entry threats were all that remained, at least if price regulation was to be avoided. On vesting, the three generating companies were provided with CfDs for virtually their entire forecast output, for periods of between one and three years, and matched with comparable (take-or-pay) contracts to purchase domestic coal. As noted, this solved the problem of high priced coal and made the generators' income and expenditure streams predictable for the prospectuses on which they were to be sold. It also reduced their incentive to exercise spot market power to negligible levels, though not their ability to take advantage of transmission constraints and to game capacity availability. Figure 6.3 shows that for the first year, pool prices were indeed low, and below the average fuel cost of the price-setting generators.[6]

Figure 6.3 Prices in the Electricity Pool at 1995/6 constant prices (Monthly Averages)



Notes:
Transport uplift and reactive power were separated from uplift in April 1997.
Each year is split into FAJAOD = February, April, June, August, October, December.

When the time came to renew contracts, the generators were faced with a difficult choice. If they reduced contract cover, they would have the incentive and ability to increase their bids in the pool, and raise the average level of prices, revenue and profits. Meanwhile, IPPs, usually with equity participation by RECs, had demonstrated a technique for making the electricity market contestable. They could sign 15-year contracts with their REC for the sale of electricity, provided the REC could demonstrate to the regulator that these contracts met the economic purchasing condition of their licence (see Offer, 1992c). Given then prevailing pool prices, forecast coal and gas prices, the risk of carbon taxes and other environmental restrictions likely to raise the price of coal-fired generation, and the desirability of encouraging entry and competition, the DGES was prepared to accept that the contracts met that test. The electricity contracts in turn provided security for signing 15-year contracts for the purchase of gas. IPPs could issue debt to finance the purchase of the plant, creating a highly geared financial structure with low risk, and hence relatively low interest costs.

Such a package made the generation market contestable, as the potential entrant could lock in future prices and hence avoid the risk of retaliatory pricing behaviour by the incumbents. This package was so attractive that within a few months, contracts had been signed for 5 GW of CCGT plant, which, in addition to the incumbents' planned 5 GW of similar plant, would displace about 25 million tonnes of coal, or nearly half the 1992 generation coal burn of 60 million tonnes. The new CCGT capacity amounted to about one sixth of existing capacity, which was in any case more than adequate to meet peak demand.

At privatization, about three quarters of electricity was coal-generated, and electricity took over three quarters of domestic coal output. The dash for gas and the switch from coal more than halved the size of the remaining deep coal mining industry. The coal labour force had fallen from nearly 200 000 at the time of the 1984–5 coal miners' strike to about 70 000 by 1990, but pit closures reduced numbers to 20 000 by 1993 and less than 10 000 by 1998. Figure 6.2 on p. 93 charts the evolution of the shares of generation fuel that reflect these dramatic developments.

The impending collapse of the coal market in 1992 led to a parliamentary inquiry, which asked whether the new investment was justified on economic grounds. The eventual conclusion was that ever tightening sulphur limits would indeed require a shift of this magnitude to gas generation by the end of the century, but that about half of the new capacity could usefully have been delayed several years. During the inquiry, the industry was put under considerable pressure to sign five-year coal contracts, again at above world prices. The RECs signed five-year coal-backed contracts with the generators and were allowed to pass through the extra costs to the captive domestic customers. The new coal contracts made it possible for the government to privatize the coal industry for an acceptable price.

Entry demonstrated that the market was contestable and produced a more competitive outcome than might have been expected from the duopoly. The DGES was required to encourage competition and had few means available other than encouraging entry. This, together with favourably priced deals that the entrants signed with their REC partners, which could be passed through to domestic customers, helped to encourage excess entry. The duopolists may have believed that entry was therefore inevitable and that they had little to lose by keeping prices high. The DGES noted the growing discrepancy between rising pool prices and falling fuel costs since vesting, and specifically the sharp increase in pool prices in April 1993, as the previous year's contracts were replaced on 1 April (see Offer, 1994a and Figure 6.2). He concluded that their market power had enabled them to raise pool prices above competitive levels.

Faced with the alternative of a reference to the MMC, the generators agreed to a price cap on pool prices for the two financial years 1994/5 and 1995/6. They also agreed to divest 6 GW of plant, selling it all to Eastern Group, as noted above. This failed to introduce as much competition as hoped since as the two generators transferred the plant for a fixed sum plus an 'earn-out' of £6/MWh generated (nominally to cover the opportunity cost of the sulphur allowances transferred with the plant). This payment per unit generated encouraged Eastern to bid the plant exactly as before, and if anything National Power and PowerGen raised their prices in the winter of 1997–8, sacrificing market share to Eastern and other generators in a successful attempt to keep pool prices up while fuel costs continued to fall (Offer, 1998g).

In January 1999, the new DGES complained that pool prices remained at unjustifiably high levels given the continued fall in fuel costs (though such behaviour was unsurprising, given that in 1998 the government had imposed a moratorium of new gas-fired generation and hence removed the threat of entry that previously moderated excessive prices). The new DGES announced that he was considering his options under the Electricity Act, and issued a consultation document in February 1999, identifying the manipulations and the increasing number of price spikes (Offer, 1999).

By 1997/8, over 14 GW out of 62 GW total capacity was CCGT (23%), and this was forecast to rise to 17 GW in 1998/9 (27%) and 23.5 GW by 1999/2000 (33%) (NGC, 1998). The share of gas in generation rose from 23% in 1996 (third place behind coal and nuclear) to 31% in 1997, in second place and only slightly less than coal's 33% share (DTI, 1998d, p. 136). This second dash for gas coincided with the ending of the coal contracts signed in 1993, which were timed to expire at the end of the domestic franchise, and matured at the end of March 1998. Again, coal demand was threatened, but this time the Labour Party was in power, a traditional supporter of coal miners. Its immediate response was to prohibit any further gas-fired generation until the issue of coal was resolved in the now traditional inquiry.[7]

Critics of the ESI argued that the market was biased against coal, and Offer recommended reforming electricity trading arrangements and abolishing the pool (Offer, 1998f). The Parliament Trade and Industry Committee argued that overzealous sulphur emissions restrictions by the Environment Agency was at least partly to blame (House of Commons, 1998a), while the DTI concluded that the coal-fired plant that set the pool price were bid uncompetitively and that more competition was therefore required. The result was that PowerGen agreed to sell two power stations (Fiddler's Ferry and Ferrybridge) totalling 4 GW and National Power put the 4 GW Drax station on the market, in exchange for being allowed to integrate vertically into distribution and/or retailing. The controversial and price-raising earn-out clause is also to be modified. This brings us up to 1999 and the current set of problems discussed in Section 6.6 below.

6.3 Performance

Competition in the ESI in England and Wales may not have been sufficient to keep prices at competitive levels or to avoid the need for continuing regulatory concern, but it was certainly sufficient to improve performance dramatically. In the five years after 1990:

- labour productivity in the former CEGB doubled;
- nuclear output increased 28% overall with no increase in capacity, and nearly 50% from the more modern AGRs;
- gas-fired generation rose from almost nothing to 15% of output, and to 30% in 1997;
- new entrants accounted for over half of new capacity;
- fossil fuel cost/kWh fell 45% in real terms;
- nuclear fuel cost/kWh fell 60% in real terms;
- coal prices fell 20% in real terms;
- and CO_2 /kWh fell 28%, and SO_2 and NO_X fell by over 40%.

6.3.1 The impact of competition on performance

The claim that competition rather than privatization improved performance requires some defence. First, the productivity gains were shared by all three generating companies, even though Nuclear Electric remained state-owned until 1996. Every power station has to bid into the pool each day, and the resulting revenue provides a daily measure of performance that concentrates the minds of station operators wonderfully. The demonstrated threat of entry by IPPs meant that each station had to compete against the cost of CCGT generation to survive, and this entry price has continued to fall with improvements in technology and declining gas prices – both the result of competition in those two markets. Individual large coal-fired power stations have also doubled labour productivity to remain competitive.

Second, the wires businesses of the RECs retained their franchise monopoly, and did not experience any appreciable change in efficiency growth until the government's golden share expired and they could be taken over. Competition in the capital market then squeezed out considerable productivity improvements, which the regulator was eventually able to pass on in tightened distribution price controls.

Third, competition in retailing was originally intended for large customers, but relatively late in 1989 it was proposed to extend it to all consumers by 1998. Customer choice is critical in forcing the generators to adopt least-cost fuel choices. A franchise monopoly gives the government the means to influence fuel choices because the generators can be bought off in return for passing the extra cost through to the captive consumers. Initially, only about 30% of total retailing was competitive, but the 1994 extension increased the competitive share to about a half; by March 1999, it was completely open. The fact that half the market could choose their supplier forced the generators to halve their original coal contracts. The continuing domestic franchise allowed the remaining coal to be sold at above world prices, however, and kept domestic prices 9% higher than they will be when these contracts end. It is hard to believe that any REC will sign an uncompetitive contract in future once they have to compete for customers.

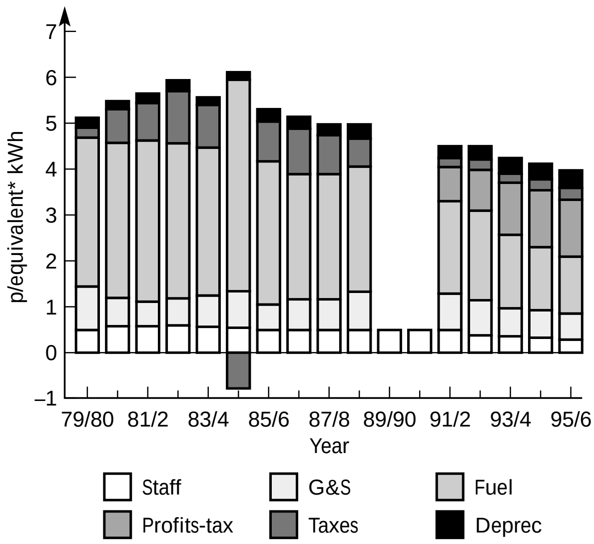
Finally, nuclear power was tested by the market and found wanting. Prime Minister Margaret Thatcher, one of the principal architects of privatization, was particularly keen to find a source of countervailing power against the coal miners. In 1974, a coal miners' strike had brought down the Conservative government and returned a Labour government to power. In 1984, the miners went on strike again, this time for nearly a year, with the stated aim of bringing down the Thatcher government. Not surprisingly, Margaret Thatcher was very keen on the planned nuclear power station programme, as the only way then available to diversify fuel supply (at that time, the EU prohibited gas-fired generation).

The first of what was originally intended to be ten PWRs was already under construction, and the whole privatization was structured to make nuclear power viable. The NFFO forced RECs to buy nuclear power at prices which included the FFL. This allowed Nuclear Electric to make a surplus over operating costs to accumulate a fund to pay for decommissioning liabilities. Nuclear Electric continued to argue that although the first station was uneconomically expensive, future PWRs would be cheaper and justified by their additional contribution to fuel diversity, reduced greenhouse gas emission, and promoting export sales of the technology. The market signalled otherwise, and when the modern nuclear stations were privatized in 1996, Nuclear Electric's successor company, British Energy, abandoned any intention of building more nuclear plant.

The market thus replaced policy-makers in determining the fuel mix, stopping the expensive domestic coal and nuclear options. Competition forced down costs, but was not sufficiently intense to lower prices to the same extent. Nevertheless, Newbery and Pollitt (1997), who estimated the costs and benefits of restructuring and privatizing the CEGB, found that even if there were to be no further improvements, and ignoring the considerable environmental benefits, the gains achieved and projected up to 1996 were equivalent to a permanent cost reduction of about 5% of generation costs. Figure 6.4 shows the evolution of costs and profits in the successor companies to the CEGB. In present value terms, that is equivalent to about 40% on the current cost value of the assets concerned, and about 100% on the privatization sales price. Environmental benefits could easily double this figure, depending on the values attached to the costs of CO_2, SO_2 and NO_X.

Newbery and Pollitt also tried to estimate who gained and who lost. Their best estimate was that the government (that is, the taxpayers) lost about £4 billion in present value terms, discounting lost revenues at 6% to 1996, after allowing for the sales receipts of about £10 billion. Consumers lost between £1 billion and £6 billion (also in present discounted value), depending how rapidly future prices fall back to their trend level. Shareholders gained a profit stream worth about £24 billion discounting at 6%, for a share purchase cost of £10 billion. In short,

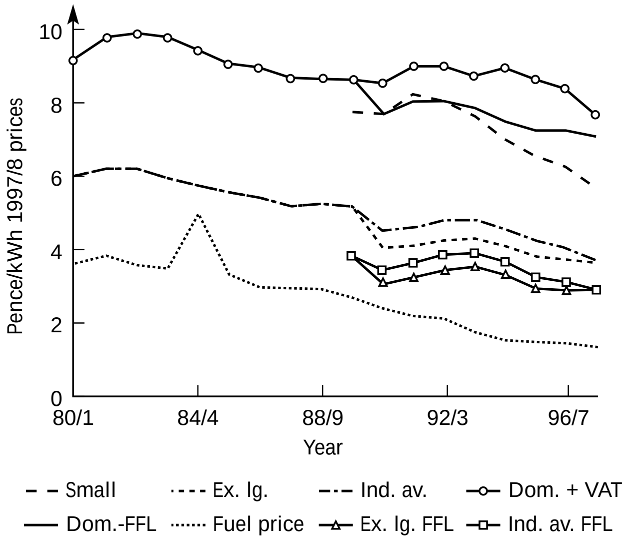
Figure 6.4 CEGB costs/unit equivalent output at 1994/5 prices



Note: includes transmission costs
*correct for changed balance gen:trans

the overall cost reductions were not huge – at 5% for ever – but then the industry was moderately well operated before privatization. All the gains were reaped by shareholders. This was because the price of electricity did not fall anything like as much as the cost of fuel or the reduction in other non-fuel costs, which also fell significantly.

Figure 6.5 Real electricity prices CEGB industry and domestic



Source: DTI Energy Trends

Figure 6.5 shows the evolution of prices for different categories of consumers, and also the unit fuel cost, over a long enough period of time to detect trend productivity improvements. It shows the margins between fuel costs and prices widening after privatization, partly because the FFL was introduced, but mainly, as Figure 6.4 shows, because of the increased profit margin. (The prices net of FFL are shown for domestic consumers, extra large consumers and the industrial average: from an initial value of nearly 11%, they have recently fallen to less than 2% as the nuclear levy has been ended and the funds are devoted solely to renewables.)

6.3.2 Performance in Scotland and Northern Ireland

Pollitt (1997b, 1999) applied the same cost-benefit methodology to measuring the benefits of restructuring and privatizing the ESI in Scotland and Northern Ireland. The results shed an interesting light on the relationship between the structure chosen at privatization and the extent of gains and consumer benefits. Scotland was privatized with little restructuring as two vertically integrated private regulated utilities and a state-owned nuclear company, which was sold as part of British Energy in 1996. The two electricity companies, Scottish Power and Scottish Hydro-Electric, are viewed as national champions and are protected against takeover by permanent golden shares, though this has not stopped them buying up other utilities in England and Wales. They are viewed with pride as very successful companies, but the detailed cost-benefit evidence provides a less flattering assessment.

Pollitt argues that restructuring and privatization had beneficial effects on the nuclear industry, by advancing the closure of the loss-making old Hunterston A station and extending the life of the profitable Hunterston B. The interconnector to the south was strengthened with beneficial effects, and altogether the investment effects were comparable to those in England and Wales, at about one third turnover. The environmental effects were small but negative, deriving from the early closure of Hunterston A and the increased interconnector capacity displacing CCGT output in England. The present value of the efficiency gains under the pro-privatization counterfactual were small (10% of turnover in Scotland compared to over 50% in England and Wales), but cancelled by the restructuring costs, which were also small (as little restructuring actually occurred). The total efficiency gain was about zero in the more favourable (pro-privatization) counterfactual.

The distributional effects were somewhat worse than for the CEGB: consumers lost £1.5 billion (80% of turnover, compared to 8% in England and Wales), the government sold the assets for £3.6 billion but suffered a fall in discounted receipts of £5.2 billion (excluding the subsequent windfall tax), while the owners received an increased profit stream worth £6.7 billion for their payment of £3.6 billion.

Northern Ireland is smaller, but has adopted a structure that appears to offer greater incentives for efficiency, though less ability to transfer the benefits to consumers. The generating stations were placed in three companies and sold in a trade sale with long-term power purchase agreements with the franchise transmission and distribution company, NIE. The generating stations have considerably improved performance and cut costs, but the very long-term power purchase agreements created an obstacle to transferring these gains to consumers. The investment (fuel switching) effects of the restructuring appear modest (10% of turnover compared to 34% in Scotland). The environmental effects were negligible, while the restructuring costs were high (£118 million, 24% of turnover) and were criticized by the Public Accounts Committee. The efficiency savings were large at £974 million, 195% of turnover (compared to 55% for the CEGB).

The net efficiency gains (excluding the negligible environmental benefits) discounting at 6% were £533 million on a sales value of £909 million, a return of 60% compared to the equivalent return of 99% for just the CEGB alone (which is flattering, as it ignores the value of the RECs). These efficiency gains were, as in the other cases, very unequally distributed: consumers gaining £1007 million (200% of turnover) after the price review had considerably lowered prices; the government realising a sales value of £909 million but foregoing future revenue streams worth £64 million; while owners (mainly NIE) lost £410 million (again as a result of the price review) at 6%, relative to the counterfactual (revised figures from Pollitt, 1999).

6.4 Regulation

The 1989 Electricity Act specified that utilities supplying services need a licence. Thus, there were generation licences for National Power and PowerGen, a somewhat different licence for the state-owned Nuclear Electric (specifying such issues as safety), individual licences for IPPs, a transmission licence for NGC, Public Electricity Supply (PES) licences for the RECs (which combined both distribution and retailing in the authorized area), and Private Electricity Supply or 'second tier' licences for others supplying consumers within a PES's authorized area. There is a proposal to create new licences that distinguish between distribution and retailing, so that RECs can choose whether to hold a supply licence, and generators would then be able to purchase the retailing business from a REC (as National Power wished to do in late 1998).

The Act requires the Secretary of State at the DTI to appoint the DGES for periods of office of five years to carry out functions assigned to him by the Act. Either the Secretary of State after consulting with the DGES or the DGES with the consent of the Secretary of State may grant a licence to generate, transmit or supply electricity. It is the prime duty of the Secretary of State and the Office of Fair Trading to review proposed structural changes to the industry, but it is the responsibility of the DGES to examine the current operations of the industry.

The Act set up Offer as a non-ministerial government department. Its budget is approved by Parliament and it is staffed by civil servants, many of whom are on secondment from the DTI. The DGES presents an annual report to the Secretary of State, but cannot be sacked (except for gross misconduct) before the end of each term of appointment. Offer exhibits considerable independence within the constraints laid down by the Act, and the first DGES has certainly been prepared to criticize aspects of government policy, such as the moratorium on building new CCGT plant imposed in 1998.

The bulk of the regulatory system is contained in the licences, which are drawn up to suit the specific circumstances of the licensee with the agreement of the Secretary of State or the DGES. The most important regulations are contained in the PES and transmission licences, which cover the natural monopoly parts of the unbundled industry created on privatization. Both licences contain conditions that control the average level of prices, require non-discrimination and prohibit cross-subsidy, and specify the conditions to be met to ensure security of supply. The PES licence requires the licensee to acquire electricity from the most economic sources and restricts the extent of own generation to preclude vertical reintegration. The transmission licence requires NGC to schedule power stations in order of lowest bids and to run a settlement system. In addition, the generators, suppliers, NGC, NGC Settlements Ltd (now called ESIS), and Energy Pool Funds Administration Ltd must sign a Pooling and Settlement Agreement (PSA), which contains the contractual obligations under which bulk electricity is dispatched and paid for.

Unless revoked, the licences continue until the Secretary of State gives 25 years notice, which may not happen for at least 10 years, ensuring that the initial licence is for at least 35 years. The conditions of the licence may be modified or amended by agreement between the licensee and the DGES or following a reference to the MMC. An example of an agreed modification is the insertion of a new condition 9a in the generation licences of National Power, PowerGen and Nuclear Electric, authorized on 24 July 1992, which enables the DGES to receive information that allows him to monitor whether the generators 'are restricting, distorting or preventing competition in the generation or supply of electricity'. This was agreed after PowerGen had manipulated the pool price by declaring generation capacity unavailable, causing capacity payments to reach very high levels, a manipulation that was compounded by redeclaring the generation stations available and thus eligible for these capacity payments (now no longer really needed) on the day of dispatch.

6.4.1 Regulating distribution

The 12 RECs have a relatively simple form of price-cap regulation, reviewed every five years. The initial price cap was not very onerous, and the RECs made considerable profits. The first review, which began in 1994, proposed tighter limits, but these were widely felt to be still too generous. A subsequent attempt by Trafalgar House, a conglomerate, to take over one of the RECs caused share prices to reach such heights that the DGES decided to re-open the distribution price review (Offer, 1995a), with a subsequent dramatic collapse of share prices common not only to the RECs but also of the generators. This happened at an embarrassing moment: during the sale of the second tranche of the two original generators by the government.

The RECs (along with other privatized utilities) were then widely perceived by the public to be fat, lazy monopolies, with directors who enjoyed unreasonably inflated salaries, selling electricity for which the domestic price had not fallen in real terms despite dramatic decreases in the price of fuel. This, and high profits in other utilities, led the Labour Party in opposition to promise to impose a windfall profits tax on utilities, which was duly implemented when they were elected in 1997.

Productivity certainly appeared to improve after the first review, and aggregate net operating costs (excluding depreciation, NGC exit charges and property taxes, that is, controllable expenditure) fell 28% in real terms between 1994/5 and 1997/8 (or 10% per year) to £1350 million per year (Offer, 1998h). Unfortunately, non-operational expenditure more than doubled (from £170 million per year to £400 million per year, some part of which is one-off investment) in response to the requirement to introduce competition into domestic retailing. The next periodic review will be for the period 2000/1 to 2004/5, and the RECs are forecasting that controllable operating costs will only fall 4% in total over this period, while non-load related capital expenditures will be nearly twice the level of the first price review. The process of setting the next set of price caps has only just begun, however, and the forecasts may merely be the opening positions in a lengthy process.

6.4.2 Regulating transmission

The RECs initially jointly owned NGC, whose implied sales price was £2.5 billion at March 1996 prices, but which was floated for £4.5 billion (which includes non-regulated assets like Energis into which NGC had invested £400 million – see Newbery, 1996). Offer accepted the market value and deducted an estimated market value for Energis of £250 million, leaving a regulatory asset value of £4.15 billion. Clearly, it was hard for the market to value NGC properly in 1990 without some evidence of its revenue flows, and there would have been a good case for delaying privatization (as with the nuclear power stations) until the market was ready (presumably in December 1995). The first transmission price control review after flotation came into effect on 1 April 1997 and cut allowed revenues by 20%, followed by a price cap of RPI-4% (Offer, 1996).

NGC's charges for transmission are quite simple. Generators pay an annual connection charge which varies (considerably) by zone, based on declared net capacity or, where the charges are negative, on system peak generation. Consumers pay an annual charge that also varies by zone, based on their demand in the three half-hours separated by ten days of system maximum demand. Generators receive and consumers pay the same price per MWh regardless of location as transmission losses are spread over all consumers equally.

The total revenue from transmission charges are regulated but the zonal pattern of charges is subject to agreement with the DGES. On privatization, this zonal pattern was known to be unsatisfactory and was subsequently reviewed and revised (see NGC, 1992). The present structure is based on the incremental capital cost of providing additional capacity on existing routes, and the costs of providing the additional spare capacity for systems security are then split between consumers and generators. This is somewhat arbitrary, but as it is the total transmission cost that is added to the generation price to derive the delivered price, the allocation up or downstream is irrelevant.

Ancillary services to ensure system stability and security are secured by NGC Ancillary Services, increasingly using incentives and other market-based mechanisms. One of the least satisfactory parts of the institutional structure of the ESI in England and Wales is the PSA. This specifies the contractual agreement signed by generators and suppliers that provides the wholesale market mechanism for trading electricity. It defines the rules, and requires almost all parties wishing to trade electricity in England and Wales to do so using the pool's mechanisms. It provides the supporting financial settlement processes to compute bills and ensure payment, but does not act as a market maker.

Physical constraints on transmission, speed of response of generation, frequency stability and the over-riding requirement of security and continuity of supply in a decentralized and notionally unregulated market require complex incentives, payments and obligations, which inevitably offer opportunities for sophisticated market manipulation. Because the PSA is a legal contract between a large number of signatories, many of whom have opposing interests, it is extremely hard to reach agreement to change, making the system under which the pool operates inflexible and unresponsive either to members' or regulatory criticism. The Pool Review, ordered by the government in late 1997, was intended to address such criticisms and propose reforms. It is discussed further in Section 6.6 below.

The Scottish transmission price controls were reset to run from 1 April 1994 for six years with a revenue cap which was based on a forecast number of units transmitted, subject to RPI-1% for Scottish Power and RPI-1.5% for Scottish Hydro-Electric, with a first year price cap of RPI-2.5%. These X factors were lower than those for NGC, reflecting lower transmission operating costs per MWh transmitted and hence less scope for productivity improvements (Offer, 1993).

Northern Ireland had an integrated transmission and distribution business that was initially subject to a price cap of RPI+3.5% for the fixed element (75% of the total) and RPI+1% per MWh transmitted. This was reset from 1 April 1997 with a step change downward of 31% followed by RPI-2% over the next four years. The decision was appealed by NIE to the MMC, which proposed a compromise of a price cut of 25%, followed by the same RPI-2% for the next four years. The regulator Ofreg decided not to accept the MMC finding, so NIE took Ofreg and won its case in the Court of Appeal in late 1998, reinstating the MMC findings (see Green, 1999). Ofreg took the case to the House of Lords and finally lost in 1999. The government has been considering the relationship between the dispute resolution procedure of the MMC and the powers of the regulators in its consultation on the reform of utility regulation (DTI, 1998a), and has proposed that regulators should seek the endorsement of the MMC on any modifications to the MMC's findings (DTI, 1998c, p. 31).

6.5 Support for renewables

One of the incidental consequences of the attempt to privatize the nuclear power stations by 1990 was the creation of the NFFO, which required RECs to take a certain amount of nuclear and renewable electricity. Combined with the FFL (levied initially at 10–11% on the final sales price of all electricity), this allowed nuclear power stations to sign contracts at above pool prices and receive a steady (and very substantial) flow of revenue for their future decommissioning and fuel reprocessing liabilities. In principle, this made them financially viable but, as it happened, the nuclear power stations were withdrawn from the initial sale, though both the NFFO and FFL survived. Together they also provided a mechanism for supporting renewables, where the intention was to provide transitional subsidies to identify which technologies were potentially commercially viable and support the creation of an industry that, with experience and scale, would eventually bring costs down to unsubsidized pool price levels.

The renewables part of the NFFO was originally intended to take place in five tranches of contracts between 1990 and 1998. After various upward revisions, the target was set at 1500 MW declared net capacity (DNC) by 2000. The early contracts would run until 1998, so that projects had to recover their excess costs compared to the pool price over the period remaining to 1998. The first NFFO Order (NFFO1) required RECs to sign contracts for 152 MW DNC of land-fill gas, sewage gas, hydro, wind, waste and biomass energy projects (see Mitchell, 1996).

NFFO1 required the RECs essentially to negotiate a cost-plus contract with the supplier, and to claim the difference between the negotiated price and the average monthly pool purchasing price from the Non-Fossil Purchasing Agency, which in turn received revenues from the FFL. The second order, NFFO2, was launched in 1991 for 472 MW DNC but with competitive bidding within each technology category. Each category would then receive the strike price of the marginal accepted project. Given that it would take some time to secure planning permission and complete projects, the shorter remaining time to 1998 led to high prices, for example, 11 p/kWh for wind energy, four times the pool price. Many of the projects that were accepted subsequently failed to get planning permission, but by September 1998, 50% of the capacity of the first two Orders (314 MW) was generating.

NFFO3 called for 627 MW DNC in December 1994. It differed in that contractors were paid bid prices rather than the strike price with the bid price, indexed to the RPI, to be paid for 15 years. The combined result was a dramatic fall in bid prices, which in the case of wind averaged 4.32 p/kWh. The cheapest projects were for municipal and industrial waste, averaging 3.84 p/kWh and taking 242 MW. The average price fell from 7.2 p/kWh for all projects accepted under NFFO2 to 4.35 p/kWh under NFFO3 (Mitchell, 1996, Table 8.4). Subsequent Orders have followed the same format of 15-year contracts at the bid price for accepted projects. NFFO4 in 1997 involved 195 projects with total capacity of 843 MW. It is expected that 65–70% of NFFO3–4 will be completed.

The results of NFFO5 were announced in September 1998 indicating that 408 projects with total capacity of 2579 MW are competing to be included in the Order. This awaited the completion of the government's review of renewables policy (DTI, 1998e). The purpose of the review is to see what would be necessary to achieve 10% of the United Kingdom's electricity needs from renewable sources by 2010, which translates into about 8300 MW of capacity. On the assumption that NFFO5 will be about the same size as NFFO4, the first 72 projects would yield 858 MW DNC at an overall average bid price of 2.86 p/kWh. The NFFO5 bid prices are 32% lower in real terms than the NFFO4 bid prices and 22% less than the prices of the NFFO4 awarded contracts. The estimated cost of NFFO5 over the 15 years might be £160 million, assuming an overall completion rate of 63%, giving an effective capacity of 536 MW. The estimated total NFFO renewables capacity under Orders 1–5 might be 1800 MW, accounting for just over 2% of generation, well short of the target of 10%. The FFL is now entirely devoted to renewables: since 1 April 1998, it has been set at 0.9% of final bills, collecting about £120 million per annum.

The change in electricity trading arrangements, the end of the REC franchises and the prospect of separating retailing from distribution all threaten the present arrangements. The main problem will be the apparent need for firm bids (especially a problem for wind power), and the lack of a reference pool price to be used to determine the transfer to the project. One answer might be to transfer the contracts to a supplier, who would bid for the franchise to contract the plant (like any other generator) in exchange for payments from the Non-Fossil Purchasing Agency equal to the difference between the NFFO contract prices and some relevant hourly marker price. The requirement to renegotiate the NFFO contracts offers the opportunity to eliminate some of the present obvious inefficiencies, such as paying a fixed price for generation, regardless of the pool price, and regardless of the environmental benefits secured.

A more logical arrangement might be to replace these by an equivalent subsidy per MWh. Future Orders might consider inviting bids for a subsidy per kW capacity and per MWh generated – the first to assist commercialization, the second to reflect environmental benefits. If there were to be a carbon tax, instead of the complex and poorly designed Climate Change Levy announced in the 1999 March Budget, then renewables would benefit from avoiding the tax. As it is, all electricity, regardless of how it is generated, will be subject to the Levy (estimated at 0.6 p/kWh, though sales to domestic customers will be exempt), so the question of how to treat any subsidy after the introduction of a carbon tax does not (yet) arise.

The main lesson to draw from the UK experience is that awarding contracts by competitive bidding dramatically reduces the cost of securing renewables, some of which (primarily municipal and industrial waste) would now be commercial at old electricity prices, though they remain uncommercial as other fuel costs have fallen so rapidly.

The other lesson is that there are better ways of securing the two benefits sought – that of encouraging research, development and commercialization of the most promising technologies; and reducing emissions of greenhouse gases. Competitively tendered performance-related subsidies (per MWh or per kW available capacity) and carbon taxes would seem to meet both objectives with less disruption to electricity trading arrangements.

6.6 Current issues and debates

The electricity pool has received constant criticism from the media, from Offer and from the House of Commons Trade and Industry Committee since its launch in 1990 (for example, in House of Commons, 1992; Offer 1992a,b,c and 1994a,b). In May 1997, a Labour government replaced the Conservative government that had privatized the ESI. In October 1997, the government asked the DGES to review electricity trading arrangements. The Pool Review Steering

Group agreed as the overall objective 'that trading arrangements should deliver the lowest possible sustainable prices to all customers, for a supply that is reliable in both the short and long run' (Electricity Pool, 1998), though the DGES has a longer list of objectives, including simplicity, transparency and involvement of the demand side.

The main criticisms were about market manipulation, market design (including criticisms about capacity payments, constraint payments and transmission charges), and the governance structure. Reforming (or replacing) the present governance structure was clearly critical as the PSA had impeded reforms in the past. The most serious criticism of the performance of the electricity market was that of the continuing market power of National Power and PowerGen, despite divesting 6 GW capacity and substantial entry by IPPs. The Pool Review accepted this concern, but decided that 'it would not be sensible to overload the very full agenda' by addressing market power issues (Offer, 1998f, p. 114).

Instead, the Pool Review concentrated on market design issues, where the main criticisms were that it was only half a market with inadequate representation of the demand side, that it was opaque, unpredictable, and therefore hard to hedge using standard contracts, and that it was compulsory, which prevented trading outside the pool and hence discouraged contracting. Paying all generators the same SMP further discouraged contracting and aggressive bidding, and the SMP was only loosely related to (and typically considerably higher than) the marginal energy price used to determine the merit order. In addition, capacity payments were volatile, unpredictable and excessive (Offer, 1998b-e).

The Pool Review argued that the complexities of price formation in the pool gave the generators more market power than a normal commodity market. It recommended that the PSA should be replaced by a Balancing and Settlement Code. The pool as such would end and be replaced by four voluntary, overlapping and interdependent markets operating over different time scales: bilateral contracts markets for the medium and long run; forward and futures markets operating up to several years ahead; a short-term bilateral market, operating from at least 24 hours to about four hours before a trading period; and finally, a balancing market from about four hours before real time. The system operator would trade in this market to keep the system stable, and use the resulting prices for clearing imbalances between traders' contracted and actual positions. This structure mirrors that emerging in the UK gas market, and has similarities with electricity markets in Scandinavia, Australia and the United States (see Offer, 1998f).

At the time of the Pool Review, the pool was operating as a balancing market, as about 90% of electricity is traded on contracts. The argument for replacing the method of determining the pool price from a complex bid involving start-up, no-load and marginal energy prices by a simple bid to make the market more transparent is, however, suspect. The simple bids would still have to combine fixed costs, start-up costs, and views about the likelihood of incurring flexibility costs, and will be harder to examine for the exercise of market power. The argument that pool prices are hard to predict and therefore hard to hedge, while true, is not counterbalanced by evidence that a rather thin balancing market would be more predictable and easier to hedge. Indeed, one of the main arguments made for the change is that the balancing market is intended to remove the pool's role as a reliable market of last resort, and thus to encourage contracting and the securing of balancing services well before the balancing market opens.

Part of the case for the new structure was that flexibility (provided by coal-fired plant) was under-rewarded, biasing the market against coal. At the time, coal-fired generators could provide the required amount of flexibility needed for system stability at very low marginal cost in adequate amounts, so its value at the margin was low. Under the pool system, individual failures to balance are automatically dealt with by aggregating, where many imbalances automatically cancel. Forcing each contractor to ensure individual balance raises risk and artificially raises the value by balancing services, thereby prejudicing the benefits of an integrated system. If the balancing market is so designed to favour flexible plant, it is more likely to encourage excess flexibility and to favour those generators who possess low-cost flexibility, namely those who are already credited with having excessive market power. In mid-1999, the various steering groups charged with advancing Offer's proposals were still wrestling with these and other design issues.

The proposal to end the pool that mechanically produces a transparent price and replace it with bilateral markets was warmly welcomed by traders, who were understandably enthusiastic about the proliferation of complex and largely opaque markets in which they can make their margin. The DTI reported that the major coal-fired generators supported the reforms, but that IPPs were sceptical about the proposals, arguing that the existing pool would work well if the problem of market power was resolved. (DTI 1998b, Section 6.7–6.8). It should be worrying if those with market power welcome the reforms and potential entrants and small competitive plant owners are concerned that it will disadvantage them. It suggests that the new trading arrangements allow the continued exercise of market power and that entry by new competitors may be made more difficult.

The main argument in defence of the new trading arrangements is that they will lower electricity prices, though there is no guarantee that they will lower costs (and some evidence that costs may rise). Offer estimated the restructuring costs at £500 million over five years or about 1.25% of PPP, while transaction costs look set to rise. Offer also argued that the restructuring costs would be more than covered by a fall in (final) prices of 1%, but from a resource point of view, a fall in prices is not the same as a fall in costs. Indeed, as noted above, Newbery and Pollitt (1997) argued that the restructuring of the CEGB had been socially beneficial because it lowered costs by 5%, even though it raised prices relative to the counterfactual.

The reason why prices are expected to fall is that participants can no longer rely on buying or selling in the pool and will be forced to contract. As 90% of electricity is already traded under contracts, any change will be modest at best. The claim is that on the one hand, contract price discovery will be encouraged once the pool price ceases to be a good guide to trading terms, while on the other hand, the lack of a clear reference pool price will encourage harder bargaining over the terms of these contracts, and they will be driven closer to cost. These two claims cannot easily be reconciled. If plant owners know the likely contract price, why would they accept less? This seems little different from the present situation in which plant owners cannot predict the future pool price with any confidence when they agree on what terms to contract.

Removing the only transparent market is likely to raise contracting costs, and so any benefits could only come from the argument that sequential contracts markets would reduce market power compared to the present system. While it is true that contracts reduce the incentive to manipulate the balancing market or pool as most revenue will already have been secured in the contracts, the real issue that is not addressed is what, given present allocations of plant, will determine these contract prices. The argument made above is that if generators have market power, then prices will be set by the conditions of entry, and will continue to be so set until more competition is introduced into the price setting part of the market. This claim continues to hold under the new trading arrangements.

At a deeper level, the argument that prices will fall seems to be that removing the option of being guaranteed sale at pool prices alters the outside option in the bargaining game between the generator and supplier, forcing down the bargained price. Buyers also lose this option, however, and it is not clear that the balance of power will shift in their favour. Furthermore, Offer's review recognizes that the pool reduces the entry risk for new entrants by providing them with the option of selling at pool prices. If the returns for entrants are made riskier and less attractive, the obvious conclusion is that there will be less entry, and that the threat of entry will exercise less downward pressure on prices.

The new markets seem designed to create more risk about the wholesale price. Wholesale price risk in an unbundled structure translates directly into profit risk: a high price shifts profits to generators away from the retailing business, while a low price benefits retailing at the expense of generators. The risk can be avoided or cancelled by vertical mergers in which generators are assured of a semi-captive market. This will also reduce the transaction costs of contracting, and reduce the risk of failing to find a buyer and hence being forced into a distress sale in the short-term bilateral or balancing market.

The rush to merge vertically is already evident from the deals currently being struck. The larger the share of the market covered by vertically integrated companies, the harder entry will be and the more disadvantaged will be those companies that remain unintegrated. A reintegrated industry will look more like the German electricity cartels than the competitive industry that was once the objective of the UK experiment. Such a structure and the lack of a transparent pool will discourage entry by further gas-fired generators, which appeals to the coal industry, though whether it is good for domestic coal is another story.

The government has stressed the importance of creating more competition and has been willing to accept mergers and vertical integration as a price worth paying to achieve this. The irony is that if generation is made adequately competitive, then a transparent pool would almost certainly deliver lower prices and lower cost than the proposed new trading arrangements, whose sole (and doubtful) defence is that they might reduce market power and lower prices in an otherwise unrestructured industry. Competition makes the reforms unnecessary, and merely requires changes to the governance structure of the pool to allow the various modifications that would improve its operation and which have so far been hampered by the PSA.

6.7 Costs and benefits of liberalizing the franchise market

In the first year that the 1 MW market was opened to competition, the RECs lost two fifths of their sales volumes, and their market shares have continued to decline. By 1996/7, Offer estimated that the RECs supplied less than 30% of this demand in their local market, with generators and other RECs competing to supply these customers. The size of the competitive market increased in April 1994, when the 50 000 sites with demands of between 100 kW and 1 MW were allowed to change their supplier. One quarter of them did so in the first year, and a half had done so by the following year. Prices fell, mostly because the non-franchise market was able to escape the coal contracts whose costs now fell on the remaining captive franchise customers.

One of the main benefits of retailing competition is that it makes it harder to sustain uncompetitive but politically attractive interventions to support favoured fuels like domestic coal. Of course, a determined government can still impose uncompetitive fuels on the industry. The NFFO and the FFL used to subsidize nuclear power provide an immediate example, but at least they were passed in legislation after democratic debate, and were imposed using taxes and transfers. The FFL and NFFO survive as mechanisms to subsidize renewable energy, where the revenue collected makes up the shortfall between the contract price of the renewables bid in a periodic auction, and the pool price. The distortions caused by this system of support are minor, as they do not affect bidding in the pool, and are confined to the demand side of the market, raising prices by rather less than 2%.

The plan was to allow the remaining 23 million consumers (with half the total demand) to choose their supplier from September 1998, making it difficult for RECs to pass on any uncompetitive contracts (with coal producers, or with equity-participating IPPs). It has, however, proven very difficult to design a cheap and simple form of domestic retail competition, and the costs of setting up the new system and operating it for the first five years are estimated at £726 million (House of Commons, 1998b). There are no new meters, and the costs arise from the very complex system of estimating and re-estimating the billing costs to charge to each supplier and the new information technology systems needed to keep track of a changing portfolio of customers. The potential efficiency gains are small as the retailing businesses' own costs are only about £600 million per year, unless investment efficiency in generation and transmission improves as a result. Of course, the potential benefit of removing the ability to tax consumers for inefficient regulatory choices is much larger, but this could surely have been achieved at lower cost.

The effect of ending the franchise on consumers is rather hard to predict. The RECs signed contracts with IPPs that could be passed on to these customers at above subsequent pool prices. In 1996/7 the RECs purchased 71.7 TWh of electricity under the 1993 coal contracts (discussed above) at 3.92 p/kWh and 28.9 TWh from IPPs at 3.84 p/kWh, when the time-weighted PSP was 2.572 p/kWh and the demand-weighted price was 2.793 p/kWh (Offer, 1997). If the IPP contracts were essentially base-load contracts for which the time-weighted PSP is the relevant comparison, then they cost nearly 50% more than buying in the pool. Offer (1997) suggests that the IPP contracts are more like contracts bought for the non-franchise market (which will be less peaky than overall demand, but more peaky than a base-load contract), which were 2.93 p/kWh, making the IPP contracts 31% more expensive than these contracts.

Customers who switch will presumably avoid these stranded contracts, and to protect those that remain with their incumbent supplier, the regulator has capped prices sold by RECs to their incumbent domestic customers. This regulated ceiling will fall by about 9%, reflecting the end of the over-priced franchise contracts discussed above. These caps are set rather high, and RECs are offering reductions of up to 10% outside their area.[9] Industry analysts were expecting a rapid concentration in the retailing business as companies merge or exit.

In early 1999, it was still too soon to say how domestic competition would work in electricity. We can look at evidence from the domestic gas market, which was gradually opened up from April 1996. Until then, British Gas was vertically integrated and signed long-term contracts for beach deliveries of gas, which it transported and sold to its 18 million customers. The gas industry has been gradually unbundled, a spot market has emerged, and the spot price of gas is about half the old contract price. New gas is therefore cheaper and new suppliers can offer considerable discounts on the British Gas price, effectively stranding the old contracts. About 25% of customers switched in response to a price reduction that was about £60 per year or 20% of the annual gas bill. British Gas has responded to competition as it lost market share, partly by promising a better deal for the combined supply of electricity and gas.

Green and McDaniel (1998) model the effects of competition, assuming that 25% of customers might switch in response to a 20% reduction in price. They suggest that customers who switch will do rather better than those that do not, and larger customers will do better than smaller customers. Overall, the ending of the franchise contracts benefits the franchise market by £285 million per year, but this is outweighed by losses upstream (and in levy revenue), so that the economy loses £130 million per year. Green and McDaniel argue that yardstick competition would have achieved comparable gains to consumers, more equitably distributed and at lower cost, with a net gain to the economy overall of £142 million per year.

By 2000, the regulator will need to decide whether to deregulate retailing completely, and rely on the option of switching to restrain incumbent suppliers. If about a half to two thirds of customers are reluctant to switch, then incumbent RECs and Centrica (British Gas) may be left with a comfortable quasi-monopoly position, much as the high street banks have in the United Kingdom. Pressures to cut costs (which yardstick competition might have encouraged) may then be less intense and the comparison even less favourable to ending the franchise. Against that, continuing the franchise market might have encouraged the government to collude with the industry in visiting the costs of any energy or industrial policies onto the domestic market, so the cost of competition may be the price to pay for freedom from such interventions.

6.8 Conclusions

As with most political decisions, the reasons behind the restructuring of the electricity industry were many and varied. Excess capacity and sluggish growth were common to most developed countries, and reduced the importance of ensuring the secure sources of investment funding that state ownership and vertically integrated franchise monopolies could guarantee. The mismanagement of post oil-shock investments was coupled in the United Kingdom with an over-dependence on high cost coal that was controlled by a hostile miners' union that had already caused the fall of one previous Conservative government and had only been narrowly defeated in its attempt to unseat another.

Privatization had been politically popular in altering the balance of power between labour and capital, and had delivered impressive productivity improvements. The new price-cap system of regulating network utilities had been designed for efficiency and successfully implemented. Privatizing electricity would have a sizeable impact on the national debt and the short-run public sector borrowing requirement, as well as advancing support for popular capitalism by wider share ownership.

Finally, while privatizing British Telecom and British Gas had been relatively simple as they were not restructured, the idea of transferring public monopolies to private ownership had been so strongly criticized that liberalization was essential. Fortunately, the government failed to appreciate just how hard unbundling the industry would be before it made the political commitment to restructuring and privatization. The final result, if far from perfect, was a great improvement on what went before, and was a remarkable achievement that demonstrated what was possible to the rest of the world, and certainly encouraged the passage of the EU Electricity Directive.

Notes

1 The author of this chapter is David Newbery.

2 The Labour government elected in 1997 granted greater autonomy to Scotland, and accepted the wishes of the 50.1% of the voting residents in a referendum to create a separate Welsh Assembly.

3 Turbines pump water up to a hill-top reservoir during off-peak periods, allowing generation in peak periods or to provide rapid response to meet shortfalls in generation.

4 Both the Office of Fair Trading and Offer wanted to refer the acquisition to the Monopolies and Mergers Commission, and Offer recommended that National Power divest between 5500 MW and 6000 MW (*Financial Times*, 10 April 1999).

5 The government plans legislation to separate retailing from distribution, but in March 1999, the DGES proposed additional licence amendments for Midlands Electricity to clarify the obligations that apply to the retailing business.

6 Though not below the opportunity cost of the fuel, which was on take-or-pay terms and could only have been exported at a low price or stored expensively for several years.

7 On 9 April 1999, in the run-up to elections for the new Welsh Assembly, the government granted permission to a 300 MW CCGT plant at Raglan Bay in Wales on the grounds that it would create jobs and thus political support (in Wales). The authorization procedure for

power stations, which in the United Kingdom permits a gas moratorium, evidently allows continued government intervention much as old-style energy policy, which the liberalized market was supposed to end.

8 Turnover was used by Galal et al. (1994) as the scaling factor, though it means the ratios of present discounted gains to annual turnovers tend to be rather large. At a 6% discount rate, the ratio of the present discounted benefits to turnover can be multiplied by 0.06 to give a comparison of annualized gains to annual turnover. The turnover of the ESI (including distribution) of England and Wales was £16 billion, while that of Scotland was £1.9 billion and NIE about £0.5 billion. There is an obvious problem in making comparisons across the three cases as Scotland and NIE are vertically integrated, while the case study of the CEGB excludes the RECs. The approach taken is to relate the CEGB to total ESI turnover and ignore any REC improvements, which understates its performance.

9 Green (1998) tabulates the offers by several RECs in others' areas for a 3300 kWh customer, and shows that in most cases the incumbent REC charges the highest price in its own region and undercuts incumbents in other regions.

7 The Nordic Experience: Diluting Market Power by Integrating Markets[1]

In 1991, Norway implemented a major electricity market reform, creating open access to transmission and distribution networks and competition between generators and wholesalers/retailers. Sweden implemented a similar reform in 1996 and a joint Norwegian-Swedish trading exchange – Nord Pool – was opened. At the same time, the border tariffs between Norway and Sweden were removed, and the two countries effectively became a single market for electricity. This market has subsequently been extended to incorporate Finland and, in 1999, steps were taken to add Denmark.

Although several barriers remain, an integrated Nordic electricity market is clearly emerging.[2] Certainly, the degree of integration means that it could be misleading to analyse individual markets from a purely national perspective. Yet important institutional and structural features of the national electricity markets in the Nordic countries do exist and are likely to remain for a long time.

This chapter describes and evaluates the design and functioning of the new Nordic electricity market institutions. We take the view that Norway and Sweden are pioneers of electricity market deregulation and integration, and that the experiences of these two countries offer valuable input to the creation of an integrated European electricity market. Section 7.1 discusses some general issues relating to generation, trade and market power; Section 7.2 focuses on trading arrangements, notably Nord Pool; and Sections 7.3 and 7.4 summarize and evaluate the experiences of Norway and Sweden respectively.

7.1 The Nordic market

In terms of population, the Nordic countries are small, but because of high per-capita consumption of electricity, total electricity consumption is quite large, particularly in Norway and Sweden. In 1995, aggregate electricity consumption in these two countries was 262 TWh, while aggregate Nordic consumption was close to 370 TWh. The corresponding numbers for Germany, France and the United Kingdom were 540 TWh, 423 TWh and 350 TWh, respectively. So the size of the Nordic electricity market is comparable to the major national markets in Europe.

Although development of an integrated Nordic electricity market has gained considerable momentum in recent years, this integration is not entirely new. For at least the last 20–30 years, there has been close cooperation between the national industries, including substantial year-to-year exchanges of electricity.

Table 7.1 Maximum import/export capacity between the Nordic countries, 1998 (MW)

From/To	*Denmark*	*Finland*	*Norway*	*Sweden*
Denmark	–	0	1040	2400
Finland	0	–	70	1300
Norway	1040	70	–	2900
Sweden	2220	1800	2700	–

Sources: Nordel and Svenska Kraftnät

Since individual countries have traditionally had policies of self-sufficiency in electricity, however, the interconnector capacities still mean that there are capacity constraints much of the time. Table 7.1 summarizes the currently available transmission capacities between the Nordic countries. Transmission capacity between Norway and Sweden amounts to only 10% of Norwegian and 9% of Swedish generation capacity.

7.1.1 Generation mix

The generation mix differs considerably between the Nordic countries. In Norway, more than 99% of production is based on hydro power, and there is a substantial hydro reservoir capacity (around two thirds of average annual production), which allows water to be carried forward from wet years to dry years. Sweden and Finland have more mixed systems. Moreover, Sweden has less reservoir storage capacity than Norway and generally runs down its reservoirs during the period of peak winter demand. In Denmark, electricity production is almost entirely based on thermal power, with coal the dominant fuel. In both Finland and Sweden, a very significant share of non-nuclear thermal power is generated by CHPs and industrial back-pressure plants. Table 7.2 summarizes production data for the Nordic countries.

Each country is self-sufficient in electricity on average. Depending on demand patterns and meteorological conditions, however, there may be considerable yearly and seasonal trade, mostly between the Nordic countries but also to some extent with Russia and Germany. As indicated in Table 7.3, both Norway and Sweden were net exporters in 1995, when the supply of hydro power, particularly in Norway, was higher than normal. In contrast, in 1996, which was an unusually dry year with a correspondingly small supply of hydro power, both countries were big net importers.

Table 7.2 Power generation in the Nordic countries, 1998 (GWh)

	Denmark	*Finland*	*Norway*	*Sweden*
Total production	39 040	67 183	116 953	154 340
Hydro power	27	14 602	116 277	73 727
Nuclear power	–	20 985	–	70 464
Thermal power	36 360	31 572	668	9 849
Wind power	2 653	24	8	300

Source: Nordel (1998)

Table 7.3 Power generation and trade in 1995 and 1996 (GWh)

	Denmark	*Finland*	*Norway*	*Sweden*
Production, 1995	34 339	60 541	123 499	143 700
Net import, 1995	–795	8 411	–6 491	–1 700
Hydro production, %	–	102.4	109.1	105.2
Production, 1996	50 367	66 367	104 878	136 011
Net import, 1996	–15 584	3 666	9 041	6 127
Hydro production, %	–	93.6	92.5	80.1

Note: Actual hydro production in relation to normal year production

Source: Nordel (1996)

7.1.2 Market concentration

As in most other European countries, there is a dominating generator in each of the Nordic countries. In Sweden, state-owned Vattenfall accounts for more than 50% of output (74 TWh); the next largest generators, Sydkraft (24 TWh) and Birka Energi (16 TWh) are substantially smaller.[3] In Norway, state-owned Statkraft accounts for around 25% of output (24 TWh), more than twice as much as the second largest generator, Norsk Hydro. In Finland, state-owned IVO accounts for around 25% of output (17 TWh), and is considerably larger than the second largest generator.

Despite the relative sizes of the largest generators, it is only in Sweden that the degree of concentration has led to serious concerns about market power. The degree of concentration can be described using various one-dimensional indicators, such as the Herfindahl-Hirschman index (HHI) or CR-X (where X is the aggregate market share of the X largest firms). The HHI value for the Swedish electricity market is around 3300 while the CR4 value is around 0.78.

The corresponding values for the integrated markets are considerably lower: the HHI values for the Norwegian-Swedish and Norwegian-Swedish-Finnish markets are around 1300 and 800, respectively, while the corresponding CR4 values are 0.55 and 0.46. These differences between the national markets and the integrated markets indicate that integration is effectively a transition from concentrated national markets to a common Nordic electricity market with a relatively low degree of concentration. So international integration may solve the problem of market power.

7.1.3 System operation

A basic feature of the Norwegian-Swedish-Finnish electricity market is that grid operation and system control is managed on a national basis while commercial trading between the market participants is multinational. Most trade is based on bilateral contracts, but an increasing share of commercial trading takes place in Nord Pool. There is also a supplementary market called ELBAS. Each generator is responsible for its own commitment and dispatch to meet contractual obligations under bilateral contracts and spot market trades. Thus, dispatch is determined at the company level on the basis of the outcome of the commercial trading and subsequent deals with the system operators.

The treatment of transmission constraints and balance adjustment is undertaken by the system operators – Statnett in Norway and Svenska Kraftnät in Sweden – using market-based instruments. The details of this process differ between the countries, however. The system operators are also responsible for the treatment of transmission losses and the provision of ancillary services. It should be stressed that the system operators are concerned only with the physical functioning of the system, such as stability of frequency and voltage level. The economic efficiency of dispatch is assumed to be guaranteed by regular market forces, that is, through voluntary trades between profit-maximizing buyers and sellers of electricity.

7.2 Nord Pool and ELBAS

Nord Pool is a power exchange open to all players in the Norwegian-Swedish-Finnish electricity market. It developed from a Norwegian power exchange for producers, dating from 1971. In 1991, major consumers were allowed to participate, and in 1996, when access was extended to Swedish participants, the name was changed from Statnett Marked to Nord Pool. Its ownership is split 50/50 between Statnett and Svenska Kraftnät.[4]

Nord Pool operates under a licence that gives it the right – though not an exclusive right – to organize physical trade of power, and membership is voluntary. As of early 1999, there were 156 members and 102 so-called clearing customers trading in the Nord Pool markets. These include generators, distributors, large power consumers, brokers and traders. The majority of the participants are from Norway, but there is also a large number of participants from Sweden and Finland as well as some from Denmark, Germany and the United Kingdom. Although the share of energy traded through Nord Pool is increasing, most energy is still traded under firm contracts outside the pool. In 1998, less than 20% of total electricity consumed in Norway, Sweden and Finland was traded through Nord Pool.

Nord Pool operates both a physical day-ahead spot market – Elspot – and markets for financial futures and forward contracts with a maximum duration of three years – Eltermin. As Elspot closes at noon, there are at least 12 and at most 36 hours between the time of trade and the time of delivery. During such a long period, supply and demand conditions may change to the extent that market participants want to adjust their net trades in one or several hours during the coming day. The supplementary market ELBAS, which opened on 1 March 1999, offers Finnish and Swedish players the possibility to trade after Elspot has closed for trading and up to two hours before delivery on an hourly market.[5]

ELBAS is operated by the Finnish power exchange ELEX and is based on an electronic trading system.[6] It basically replaces an 'adjustment' market operated by Svenska Kraftnät in Sweden and a Finnish market for continuous trade previously operated by ELEX. Trade at ELBAS is on a continuous basis, and the market is open 18 hours a day (between 00.00 and 18.00). The market is divided into two regions – Sweden and Finland – and the object of trade is 1 MWh electricity during a specific hour in one of the two regions. Norway is not currently a region in ELBAS.

7.2.1 The Elspot market

In Elspot, participants bid for day-ahead contracts for physical deliveries. A trading day runs from midnight to midnight and consists of 24 different hourly markets. Separate bids are made for each of these markets. On the basis of the received bids, the market operator clears each market by determining market clearing prices. The clearing process results in a series of contracts between Nord Pool and each of the market participants. A contract is related to a specific hour and consists of an amount of power (measured in MW) and the price of that hour (in NOK/MWh). Contracts are binding and consequently financial settlement can be undertaken as soon as the clearing process is finished. Deviations between demand/supply in the spot market and actual consumption/generation are priced in the balancing markets run by the system operators.

Bids are submitted electronically or by fax. A bid is in the form of a series of price-quantity pairs for each hour. This shows the quantities in MW that the participants are prepared to sell (a positive MW) or purchase (a negative MW) from the spot market at different prices. It should be noted that each bid has to refer to a 'bidding area'. While there is only one bidding area in Sweden and one in Finland, depending on expected transmission constraints in the system (see below), there may be several in Norway.

The market closes at noon the day before the actual trading day. Nord Pool balances supply and demand by stacking up the supply and demand curves of the market participants. A market clearing price in NOK/MWh is calculated for each hour of the day ahead. This price – the 'system price' – is calculated on the assumption that no transmission constraints are violated. Nord Pool also coordinates the bids and planned power flows over the interconnectors, however. If the comparison between planned and feasible power flows suggests that none of the transmission constraints will be binding, the system price will coincide with the 'area prices' in all bidding areas. Otherwise, the bids will be stacked by transmission constrained area, and market clearing prices for each one of these areas calculated.[7]

The system price and the market clearing area prices are found within two hours. Then individual spot contracts are determined, and each participant is notified about the prices and extent of their trades. Complaints must be submitted to Nord Pool within the next half hour, with prices and quantities recalculated if necessary.

Participants trading on their own account trade with Nord Pool as their counterpart. Clearing customers trading via a broker are also required to settle directly with Nord Pool. Settlements are made weekly and in NOK. The pool offers a currency exchange service, however, so that Swedish customers may trade in SEK. All participants must provide a bank security to back their financial obligations. The operation of the pool is financed by membership fees, which include an initial signing fee, a yearly fee and a fee related to each member's volume of trade.

The bid information of each market participant is held confidentially by Nord Pool and is not released to market participants. The market price and aggregate volumes are, however, publicly available. In Norway, statistics on reservoir fillings (key information in a system heavily dependent on hydro power) are published weekly on an aggregate regional basis by the central statistical bureau, Statistics Norway. Sweden also publishes statistics on aggregate reservoir fillings, as well as information about planned revisions of the nuclear power plants.

Figure 7.1 indicates that trade volumes increased very modestly in the first few years after the Norwegian spot market opened in 1991. This reflects the continued reliance on trade in long-term firm contracts outside the power exchange, and the relatively slow development of competition in the retail market (see below). The trend is, however, partly overshadowed by idiosyncratic events, such as the huge water inflow during the first half of 1992, which led to very high volumes of trade. Since the end of 1995, volumes in the spot market have increased sharply, reflecting the opening of the market to Swedish participants: in 1995, 20 TWh was traded in the spot market compared with 56.3 TWh in 1998.

In a system highly dependent on hydro power, prices vary considerably, both between seasons and between years. As Figure 7.1 shows, prices exhibit a strong seasonal pattern, generally much lower in spring and summer than in winter. Water inflow is high in spring and summer due to snow melting and rainfall, while in winter, water inflow is almost zero as rivers and streams freeze and precipitation is mostly snow. The seasonal price effects of varying hydrological conditions are exacerbated by demand variations. The peak in February 1994 was caused by the combination of extremely low temperatures and problems with securing supplies over the Danish interconnectors.

Yearly price variations primarily reflect differences in hydrological conditions between wet and dry years. The very high prices in 1996 seem to be explained by unusually dry weather conditions in both 1995 and 1996. Prices frequently deviate between countries as the inter-country transfer exceeds transmission capability and the markets have to be split.

Figure 7.1 Statnett Marked/Nord Pool, trade and prices, weekly 1991–7

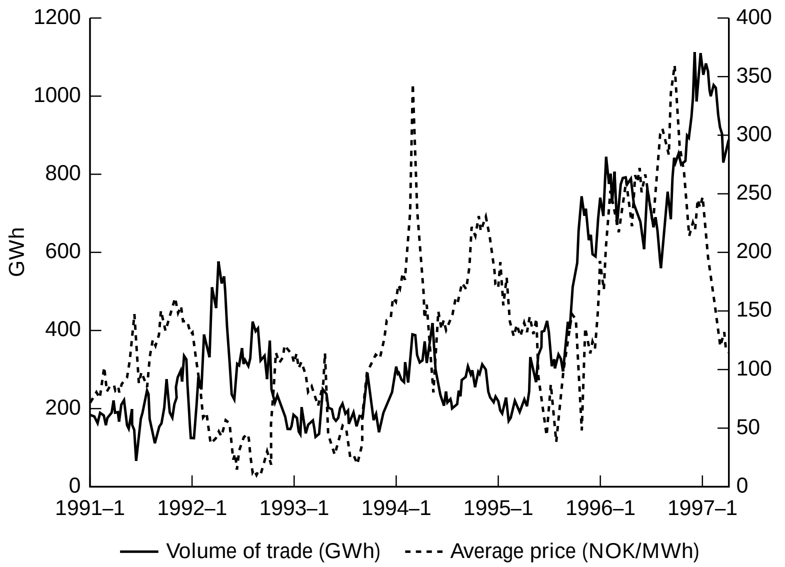


Table 7.4 Annual turnover at Nord Pool, 1993–9 (TWh)

	1993	*1994*	*1995*	*1996*	*1997*	*1998*	*1999**
Elspot	10.2	14.8	20.0	40.6	43.6	56.3	10.0
Eltermin	2.6	7.1	15.4	42.6	53.4	89.1	31.5

Note:* The ten first weeks in 1999

Source: Nord Pool

7.2.2 The Eltermin market

Nord Pool's financial market, Eltermin, allows participants to hedge price risks up to three years ahead. Contracts are standardized futures and forward contracts, which do not require any physical delivery of electricity. The futures contracts are settled daily, while the forward contracts are settled at the end of the contract period. Initially, two types of contracts were traded on Eltermin, one for base-load power and one for peak-load power. Trade in the latter type of contract was, however, very limited and was eventually closed.

The base-load power contracts cover 24 hours of each day for a full week. The futures contracts can be traded as 'single weeks' up to between 4–7 weeks in advance, as 'blocks of four weeks' from between 5–8 weeks and up to 52 weeks in advance, and as 'seasons of several blocks' 1–3 years in advance. The forward contracts can be traded as seasons ('winter 1', 'winter 2' and 'summer') or a full year. As Table 7.4 shows, the turnover at Eltermin has grown very fast, from 20% to 200% of the turnover at Elspot.

Both the futures and forward contracts are struck against the Elspot 'system price', which might differ from the area prices. Currently, the risks associated with deviations between the system and area prices cannot be hedged at Nord Pool though private brokers do offer this service. Since November 1996, trading is electronic (terminal based), and the market is open each weekday from 11.30 a.m. to 3 p.m.

Financial contracts are not only traded at Nord Pool. A number of independent brokers, the largest of which are Skandinavisk Kraftmegling and Markedskraft, also organize trading in financial contracts. In 1995 and 1996, Nord Pool established a market share of around 25% in the market for financial contracts. Recently, however, this share has been falling. Apparently, many players find that the benefits of participating in Nord Pool's financial market are not sufficient to justify the higher trading costs.

7.3 Norway

Eight years after the Energy Act took effect on 1 January 1991, it seems generally agreed that the reform of the Norwegian electricity industry has been a success. This is perhaps surprising given the considerable opposition at the time, particularly within the industry itself. Many felt that while competition and increased emphasis on profitability would perhaps reduce prices, they would also lead to excessive price volatility, deterioration in the quality of supply and ultimately to power shortages. Fortunately, these dire predictions have proved wrong; indeed, most observers appear to agree that the performance of the industry has improved under the new regime.

This apparent success is to a large extent explained by the fact that the reform did not represent such a fundamental break with the earlier development of the industry. Although the Energy Act extended the scope for product market competition further than in any other country – giving all consumers the right to take power from whichever supplier they want – the direct impact was, at least initially, relatively modest.

There were few attempts at changing industry structure. Apart from the establishment of a new and independent transmission company, which also acts as system operator, ownership and company structure were left intact. Various measures were introduced to safeguard against the abuse of market power by vertically integrated companies, such as the requirement to keep separate accounts for the network businesses. Consequently, even though ownership and company structure are gradually evolving through a process of mergers and acquisitions, the changes to industry structure have so far been relatively modest.

The reform of the wholesale market represented only a development of the existing trading arrangements. The old power exchange restricted membership to the major generators; the new power exchange is, in principle, open to everyone, including retailers, traders and consumers. Following reforms in neighbouring countries, the scope of the power exchange has gradually been extended, so that the Norwegian industry now operates within a more or less fully integrated Nordic market.

The main novelty of the Energy Act was the abolishment of the exclusive right of utilities to supply franchised customers. When the distance-related elements in the transmission tariffs were subsequently eliminated, competition for larger electricity consumers became quite fierce. Yet competition in the household and small and medium-sized enterprise sectors has developed only slowly. A series of measures, introduced gradually over a number of years, to reduce transaction costs have proved necessary for competition to extend to the whole of the retail market.

A process of gradual and pragmatic policy revision has been the hallmark of the Norwegian reforms. The regulator has not necessarily insisted on the immediate introduction of measures with the greatest potential for realising efficiency gains. Instead, it has been willing to accept incremental, and perhaps cruder, measures when these were simpler or more practical. On the one hand, the reform process may be criticized for being slow and piecemeal, and there certainly remain areas in which further reform is warranted. On the other hand, the strategy of gradual reform, when possible based on consensus views, has ensured a comparatively smooth development of the industry.

7.3.1 Industry structure and regulatory reform

Norway's population of just over 4 million inhabits an area of 324 000 sq. km, slightly larger than Italy. Total electricity consumption averages 115 TWh a year, implying that electricity use per capita is among the highest in the world. This is

Table 7.5 Electricity prices, 1994

All	28.8 NØre/kWh
Energy intensive industry	9.6 NØre/kWh
Households and agriculture	36.2 NØre/kWh

Note: 1 Norwegian Kroner (NOK) equals approximately £0.08 or €0.12. A krone is divided into 100 øre (NØre)

partly explained by the high level of average incomes and the cold climate, which leads to high levels of energy demand for domestic purposes, but mostly by the availability of cheap hydro, which has led to electricity being used for residential heating and has formed the basis for energy intensive industries. The energy intensive industries account for approximately a quarter of total consumption.

While domestic electricity prices are low on average, they vary considerably between consumer groups (see Table 7.5). The energy intensive industries have the benefit of low-priced power on long-term contracts sanctioned by Parliament, the Storting. There are also certain regional price differences, as well as differences between prices paid by small and medium-sized/large consumers, respectively. Some of these differences have developed after deregulation as a consequence of transaction costs that have limited competition in the small consumer segment of the market.

Development of the industry before deregulation

Locally based public initiatives were responsible for the electrification of most communities in Norway. Consequently, the majority of utilities are owned by municipalities or counties. By law, the regional utilities were local monopolies under obligation to supply all consumers in their respective regions. This obligation would be met by either own generation or long-term contractual arrangements with independent producers. Of the 230 regional utilities, most of which are quite small, about 100 operate their own generation facilities.

The government also played a major role in building generation capacity to supply the energy intensive industries and in the development of the national transmission network. The state-owned generation capacity (about 30% of the total), as well as 80% of the high voltage transmission network, was until 1990 operated by Statkraft, under the direction of the Norwegian Water Resource and Energy Administration (NVE). Statkraft also had exclusive rights to exchange power with neighbouring countries. The private sector is represented in the form of industrial auto-production and some generating utilities, which together account for some 15% of total production capability (see Table 7.6).

Table 7.6 Ownership of generation capacity, 1996

State	30%
Local government	55%
Private	15%

A peculiar feature of the Norwegian regulatory regime is the regulations on ownership of hydro facilities. Dating back to the early twentieth century, these regulations aimed to protect economic resources deemed of vital national importance from being bought by foreign interests. Anyone who wants to buy or develop a hydro facility must obtain a licence from the government. A licence is given for up to 60 years. For private owners, the licence normally includes the condition that, after the licence has expired, the facility (including all installations necessary to generate power) will be taken over by the government at no cost. The government also reserves the right of pre-emption if the facility is sold.

These ownership regulations affect the development of the ownership structure in the industry in various ways. To the extent that the capacity now operated by private companies is taken over by Statkraft as licences expire, the dominant position of this company will be enhanced. The regulations also introduce a certain asymmetry in the Nordic market by making it difficult for foreign companies to enter the generation end of the Norwegian industry. In principle, however, there are no restrictions on the transfer of ownership of utilities that do not have hydro generation facilities. Supply and network businesses can therefore be (more or less) freely bought and sold.

During the late 1970s and early 1980s, there was an extensive debate over how to improve the efficiency of the ESI. NVE advocated a plan for vertical and horizontal integration by the establishment of 20 regional utilities. This plan was strongly opposed by the industry. In the late 1980s, with the general change of policy towards deregulation and, to a lesser extent, privatization, the government changed its plans and decided instead to introduce a more market-based regime.

The 1990 Energy Act

The 1990 Energy Act, which took effect on 1 January 1991, set out a number of new principles for regulating the industry:

- extension of competition in generation and retailing (supply) by the provision of general access to the wholesale spot market, and by the removal of the exclusive right to supply final consumers previously enjoyed by the distribution companies;
- open access to the transmission and distribution networks for any licensed generator and supplier;
- vertical separation between grid operation and generation with the responsibility for the national transmission network removed from Statkraft and vested in a new company, Statnett. At the same time, the two companies became 'state limited liability companies' (100% state-owned) reporting directly to the Ministry of Oil and Energy, but with more independence over their operational decisions;
- a requirement on distribution undertakings to keep separate accounts for transmission, distribution and retailing; and
- liberalization of exports on long-term contracts.

NVE, which had previously been responsible for supervising the operations of Statkraft, was given a new and more independent role as a regulatory body charged with promoting competition and efficiency in the entire ESI, in particular by ensuring open access to markets and grid networks on fair terms. Unlike in England and Wales, the regulatory framework is not specified in great detail, but leaves the regulator with considerable discretion. Decisions made by NVE, however, may be appealed to the Ministry of Oil and Energy.

The operation of a network, which is considered a natural monopoly activity and hence subject to regulation, requires a network licence. The network licence imposes rules of open access and transfer of electricity on reasonable and non-discriminatory conditions. Tariffs are subject to approval by the regulator. Network businesses may be (vertically) integrated with other businesses, but separate accounts must be kept for the network business. Network operators are responsible for metering and for reporting information on network flows to the system operator according to rules laid down by the regulator. A new transmission or distribution line requires a separate licence (international interconnectors need governmental approval).

The system operator Statnett (the grid company) has a special licence that requires it to maintain supply quality, including frequency and voltage control. The system operator should take the necessary measures – using market-based instruments (see below) – to ensure that generation matches demand.

The competitive parts of the businesses fall under the rules of the Competition Law. The Norwegian Competition Authority (Konkurransetilsynet or NCA) is responsible for ensuring that companies act in accordance with the law. The sharing of responsibility between the industry regulator and the competition authorities has been a matter of some controversy, as there is some overlap in jurisdiction, in particular relating to matters concerning vertical integration. NVE and NCA have established a set of rules with the aim of ensuring smooth cooperation between the two bodies.

7.3.2 The wholesale market – competition in generation

Under the Energy Act, ownership and operation of the old power exchange was taken over by Statnett Marked, a subsidiary of Statnett. The restriction on membership was lifted, allowing entry by a range of new participants, including smaller producers, retailers, traders and large consumers. Foreigners were allowed to participate, although under special arrangement only. Trade with Elsam, the Danish electricity corporation responsible for energy supplies in Western Denmark (Jutland), was organized via Statkraft, the main Norwegian generator. In Sweden, the main generator, Vattenfall, had a monopoly on external trade and submitted its bids via Statnett Utland, another subsidiary of Statnett.

Market structure and organization

To understand the operation of the wholesale market it is important to keep in mind certain features of the organization and structure of the market. First, the market is not especially concentrated. About half of output is accounted for by five companies: Statkraft, which at 32 TWh is around 25% of total Norwegian output; Norsk Hydro (9 TWh); Oslo Energi (8 TWh); Lyse kraft (5 TWh); and Bergenshalvøens kommunale kraftselskap (5 TWh). On the demand side, distributors are on average relatively small, with the largest distributor – Oslo Energi (8 TWh and 300 000 customers) – over twice the size of the next largest distributor, Bergen lysverker (3 TWh and 120 000 customers). Since the Norwegian market is integrated with those of the neighbouring countries, the importance of individual players is less than these figures indicate.

Second, trading in the power exchange is voluntary. Nord Pool provides both short-term and medium/long-term financial markets for trading electricity. Most of the trade, however, occurs in bilateral physical contracts between generators and suppliers exchanged outside of Nord Pool. Trading volumes in Nord Pool are increasing, but so far the short-term market only accounts for 15–20% of physical trade.

Third, trade in the Nord Pool spot market is based on energy bids only. Each participant submits a price-quantity schedule with the total amount of energy it would like to buy or sell at different prices; in particular, generators do not make separate bids for individual plants. In the absence of transmission constraints, a uniform price is established across the entire market.

Since the Norwegian transmission network is quite strong, transmission constraints are relatively rare, although they have been occurring more frequently as load on the system is gradually increasing. When transmission constraints are expected, which make it impossible to facilitate dispatch according to the unconstrained merit order, spot market bids are used to level the market on each side of the constraint. The system operator requires the market to be separated into two or more regions depending on where the constraint is expected to occur. Bidders in the spot market are required to submit separate bids for each area, and these bids are used to equate demand and supply within each area. Consequently, when a bottleneck occurs, the market price in the constrained-off region will be lower than in the rest of the market.[8] Electricity flowing over the bottleneck is in effect taxed, with revenue (energy flow multiplied by the price difference between the two regions) accruing to the grid company.

Fourth, dispatch is completely decentralized since each generator is responsible for deciding how much it would like to produce at any given point in time. Following the determination of spot market trades, each generator is able to finalize the planning of its generation schedules. These plans, which include spot market and bilateral contract trades, are submitted to the system operators. System operation, particularly imbalances between actual trade and trade according to plans, is dealt with via an additional 'regulation' or 'balancing' market.

The 'regulation market' ('Regulerkraftmarkedet') was previously operated by Nord Pool on behalf of the system operator, but is now run by the system operator himself. Before each trading day, bids are accepted for the regulation market. These represent the prices at which participants are prepared to increase/reduce their output (or increase/reduce their demand) on the central grid. Participants are required to respond to notification of the need to adjust their production/demand within 15 minutes. Regulation prices are used to price discrepancies between participants' contracted quantities (including the spot contracts) and their actual generation or consumption. About 5% of total energy consumed in Norway is traded through the regulation market.

Ancillary service markets are not included in Nord Pool, but are provided by the system operator. Secondary reserve is essentially provided through the regulation market. Reserve capacity is, however, not contracted for since the hydro reservoirs, in combination with the considerable hydro power capacity, are considered to be adequate for this function. Spinning reserve and reactive power are not currently paid for by each generator but are simply required to be provided.

Market performance

Following deregulation until the autumn of 1992, prices in the spot market were quite low. Although some blamed the new and more competitive environment, low prices were mainly caused by an unusually large inflow of water (due to the combination of heavy rainfall and mild winters) and a slump in demand (due to the warm weather and economic recession affecting the energy intensive industries).

At the beginning of October 1992, spot market prices suddenly increased sharply. It seems clear that this was due to the main generator, Statkraft, publicly announcing a new policy not to supply at prices below 100 NOK/MWh. After some initial turbulence, when Statkraft apparently demonstrated its determination to discipline the market, prices stabilized at considerably higher levels than those prior to October 1992.

While it seems clear to most observers that there had been a deliberate attempt to push up the spot price, it is less clear that the effect was lasting. Prices soon started to fall back, reflecting the underlying abundance of supply. NCA investigated the matter, but decided that there was insufficient evidence of collusion to warrant specific actions. Claims of collusion and abuse of market power have since been voiced on numerous occasions, usually when prices have been particularly high. For example, some commentators have suggested that large generators have withheld water in order to drive up the spot price to ensure a favourable benchmark price against which bilateral contracts could be negotiated. Nevertheless, so far there is little hard evidence to substantiate such claims.

Stranded assets

The question of stranded assets has not been particularly important in Norway. This is partly because the industry was quite efficient and fairly well balanced (although with some over-capacity) prior to deregulation, and partly because the government has avoided introducing regulations (including environmental regulations) that would seriously threaten the financial viability of companies.

The very low prices soon after deregulation prompted speculation over the possible financial failure of some of the most heavily indebted utilities. The companies which invested in expensive hydro projects in the years just prior to deregulation were seeing electricity prices considerably below those required to obtain a normal return on investments. In most cases, however, these companies were earning sufficient net revenues on their older, more efficient plants to avoid immediate financial difficulties. As prices picked up again, the debate died out and since then prices have generally been high enough to allow generators to earn normal rates of return.

7.3.3 Competition in the retail market

A distinguishing feature of the Norwegian regulatory regime is the complete deregulation of electricity retailing. Before the Energy Act, utilities had an exclusive right (and obligation) to supply all consumers within their area. The Energy

Act removed this right, so that every consumer has been free to seek supplies from other sources.[9] No particular controls on retailing tariffs were introduced, apart from the general regulations implied by the Competition Law and the ability of the industry regulator to take action against what might be considered an abuse of the distribution licence.

The complete opening up of the retailing business to competition, without any safeguards to protect consumers unable or unwilling to take advantage of the new opportunities, must be seen in light of the ownership structure and history of the Norwegian industry. Traditionally, utilities were established with public support to supply the local community with cheap electricity and generally did not consider maximizing profits as their primary goal. Indeed, some of the opposition to the introduction of market-based competition in the ESI came from the fear that this would undermine the 'communal spirit' of utilities with the consequence that electricity would become more expensive.

Soon after the new regime took effect, competition for larger and medium-sized industrial consumers became quite fierce. A range of new and independent suppliers entered the industry and took advantage of the low prices in the spot market to undercut incumbent utilities. The incumbents reacted by introducing substantial contract termination fees as well as requiring customers who wanted to shift to an external supplier to give notice three months in advance. The fact that the rules for metering, billing and settlement were initially unclear also undermined competition.

Regulating competition in retailing

The current regulations relevant to retailing include rules for metering and settlement as well as caps on the fees that may be levied on external suppliers and on consumers taking their supplies from external suppliers. The network owner is responsible for all metering (although it may outsource this activity), including the metering of consumers that have contracted with external suppliers. Metering should be based on hourly meters if they are installed, or on estimated consumption calculated according to the relevant consumer 'profile'.

Metering of profiled consumers is based on an estimated net load for the relevant area equal to total input to the area less (estimated) losses and the consumption of consumers on hourly meters. This net load is divided between retailers according to the profiles of their respective consumers. The network owner is responsible for reporting estimated loads of all retailers within its region to Nord Pool on a weekly basis. These data are used by Nord Pool for settlements.

The profiles are updated regularly. Metering of profiled consumers must occur at least once a year.[10] Discrepancies between actual consumption and estimated consumption based on profiles are adjusted for in the financial settlement between the local distribution utility and the respective external retailer. They are valued at the Nord Pool spot market price.

Hourly meters are required for consumers with an annual expected take of more than 0.5 GWh. The cost of meters is born by the relevant network owner. Consumers with an annual take of less than 0.5 GWh have the right to be metered on an hourly basis, but must bear the costs of this metering themselves. Conversely, if a network utility requires hourly metering of consumers it must bear the costs itself.

A network utility must not impose specific fees or higher distribution tariffs on consumers who take their supplies from external retailers or who wish to change retailer. The network utility may impose an annual fee to cover metering, billing and settlement costs on each external retailer in his area. This fee is capped by NVE.

Market performance and regulatory intervention

While competition for larger consumers has been quite fierce since deregulation, competition in the lower end of the market has developed very slowly. This lack of competitive pressure was to some extent masked by the very low electricity prices in the first few years immediately following deregulation (due to the wet years of 1992 and 1993), which narrowed the geographical gaps in electricity prices. A county by county comparison of household electricity prices (excluding network tariffs), however, found that in 1994, prices still varied from a minimum of 12.7 NØre/kWh to a maximum of 19.6 NØre/kWh (SSB, 1996). With the general rise in prices in 1995 and 1996, price gaps increased again and it became apparent that competition, especially in the household segment, did not always work well. In January 1997, retailer prices for households varied from 10.5 NØre/kWh to 45.9 NØre/kWh.

To boost competition for the smaller electricity consumers, from January 1997, NVE reduced the 'switching fee' to zero, in effect eliminating the (monetary) cost of switching supplier. New measures have also been introduced that allow 'profiled' consumers to change supplier more often.

In 1996, NCA started investigating electricity retailing with the aim of uncovering abuses of market power. NCA detected an apparent lack of interest among local distribution utilities in competing in the retailing market. Of the almost 200 local distribution utilities, only 30–40 were willing to supply electricity to non-local customers. In fact, many of the utilities that were quoting prices to customers located outside their own distribution area generally quoted much higher prices than those for their local customers. This practice of price discrimination between local and external customers is probably an inheritance from the old regime, when the purpose of the utilities was to provide cheap power locally. The effect, however, is clearly to undermine price competition. In the end, the Ministry of Administration informed NCA that further investigation of the distribution companies was unwarranted. NCA has, however, decided to require retailers to report their prices to the authority on a regular basis and to make this information public via the internet.

The reduction in the costs of changing suppliers, the improved transparency of the market and the media focus on the industry over the last few years has led an increasing number of consumers to take advantage of the opportunity to change supplier. This development has been helped by the entry of new, aggressive suppliers, selling electricity 'over the counter', often in combination with other retailing activities (such as selling petrol or electrical appliances). Whereas less than 5000 consumers had a contract with an external supplier at the beginning of 1997, the number had increased to 90 000 by the beginning of 1999. Price differences have also been reduced. NCA recently concluded that competition in the household segment has improved.

Table 7.7 Networks

	Length	*Voltage levels*	*No. of operators*
Main grid	11 000 km	132 kV, 300 kV, 420 kV	1
Regional networks	18 500 km	33–132 kV	50–60
Distribution networks	270 000 km	240 V, 11–22 kV	200

7.3.4 Regulation of the networks

There are more than 200 network utilities in Norway. The network is organized as a three-level hierarchy, with a main grid, regional networks and distribution networks (see Table 7.7). Statnett is responsible for running the main grid, including system operation, metering, tariff settlement and investment planning. Parts of the main grid are owned by other utilities (mostly regional network utilities), and these are leased to Statnett.

At the second level, there are 50–60 regional transmission networks. These regional transmission utilities are often vertically integrated into distribution and/or generation. The regional network companies are generally publicly owned, either by counties and/or municipalities.

At the lowest level, there are about 200 local distribution networks. The distribution networks differ considerably in size, from the major utilities, which cover an entire city, to minor utilities responsible for supplying only a small village. On average the distribution utilities have 5000 subscribers. The distribution companies are mostly publicly owned (by municipalities) though some are privately owned. Some distribution utilities own generation plants, but these are generally small. Most utilities are vertically integrated into retailing and many have ownership interests in regional networks (a few own parts of the main grid).

For tariff purposes, the Norwegian network is divided into six categories by voltage level (see Table 7.8). Most consumers, including domestic consumers, have power supplied at the lowest voltage level, level 5. Small industrial consumers may take their power at levels 3 or 4, while larger industrial consumers, including the energy intensive industries, are supplied at higher voltage levels.

Table 7.8 Network tariffs, 1996

Network level	*Voltage level*	*Average tariff rate (NØre/kWh)*
0 Main grid	400 kV, 300 kV, 132 kV	2.0
1 Regional nets	130 kV, 60 kV	3.0
2 Main transformer	Reduction to 20 kV	4.3
3 Local high-voltage nets	20 kV	8.3
4 Net station	Reduction to < 1000 V	13.1
5 Low voltage nets	< 1000 kV	15.3

Note: The calculations reported in the table are made on the assumption of an average yearly consumption of 2 GWh at levels 1, 2 and 3, and 0.2 GWh at levels 4 and 5. At all levels, the consumption period is set to 5000 hours.

By differentiating tariffs according to voltage level, consumers who are not dependent on lower level network installations do not have to contribute to the coverage of the associated costs. Consequently, the tariff at level L+1 equals the tariff at level L plus the additional costs incurred at level L+1.

There is some geographical variation in the main grid tariff, as well as variation over the day and season, depending on loss factors and the spot price at which losses are evaluated (see overleaf). There is also considerable geographical variation in tariff rates at lower levels, reflecting cost differences between utilities mainly due to differences in topography and density of population.

Regulation of the network utilities has concentrated on two main issues: tariff structure and tariff levels. In the years immediately following deregulation, the focus was on the development of a sensible structure of tariffs. The last few years have seen considerable changes to the way the levels of tariffs are regulated. The concentration on tariffs is to a large extent explained by the fact that at the time of deregulation, there was considerable (over-)capacity in the networks. As usage has gradually caught up with capacity, however, increased attention is being paid to the question of how to ensure adequate network capacity and quality of service. The fragmented ownership structure of the network business has received some attention from the regulator, but no major attempts have been made to change it. A gradual process of mergers and takeovers has reduced the number of network utilities to some degree.

Tariff structure

The old system of distance-related tariffs in the transmission grid was abandoned soon after the introduction of the Energy Act, and from January 1993, the system of nodal, or point-of-connection, tariffs was introduced in almost all parts of the network. The new tariff structure is generally acknowledged as a vital precondition for the eventual development of competition in retailing. The basic idea is that all market participants should be allowed access to the transportation network on equal terms and that tariffs should reflect only those costs that may be associated with an individual's use of the network. This is achieved by requiring open access and non-discrimination, and by allowing tariffs to differ according to the requirements and volumes of the user.

The nodal system has the added advantage of saving on transaction costs by allowing users to make payments only to the owner of the network to which it is connected.

The are four elements to the Statnett transmission tariff:

1. The *energy charge* is supposed to reflect the cost of increased network load. To take account of the importance of the location of the user in the network, and the fact that the marginal loss depends on total network load, loss factors differ between location, season and time of day. Losses are valued at the price of electricity in the spot market, and hence vary hourly according to demand and supply of energy. The energy charge is re-estimated regularly for each node in the system calculated from loss factors multiplied by the spot market price. The energy charge recovers approximately twice the actual cost of average losses.

2. The *capacity charge* comprises the excess revenue collected through the treatment of congestion. Statnett collects the difference between prices on either side of a transmission constraint on the energy flowing over the constraint.
3. The *connection charge* is intended to relate to the reliability of the transmission grid. Statnett estimates that around 15% of the total network exist solely to maintain system reliability. The connection charge is in NOK/MW of connected generation capacity or maximum load at the time of system peak at grid supply point, plus embedded generation. The charge is higher for consumption than for generation to reflect the cost of transformers that undertake voltage reduction.
4. The *power charge* is in NOK/MW of connected generation capacity net of load, or maximum load net of embedded capacity. (Since the basis for the power charge may become very small in cases in which demand and supply behind a given node are approximately equal, Statnett has set a minimum power level for determining the charge.)

Determination of the two variable elements of the tariff – the energy and capacity charges – is based on economic principles to optimize use of the network system. The connection charge, however, is based on estimated costs of maintaining system reliability. The power charge is in effect calculated residually so as to achieve the revenue goal of Statnett. In addition to these charges, Statnett offers reduced tariffs for interruptible demand. Customers on interruptible contracts do not pay the connection charge. They also obtain a rebate on the power charge, the size of the rebate depending on whether the customer is willing to accept interruptions on 2 or 24 hours notice, respectively.

From 1997, Statnett has introduced a system of reimbursements in cases when energy supplies are interrupted due to power failures in the main grid. Reimbursement is given for interruptions lasting longer than three minutes.

Imports and exports on bilateral contracts, which in effect take priority over spot trades with regard to interconnector capacity, pay ‘priority charges’. The priority charge is determined on the basis of the contracted volumes and consists of a power element and an energy element. In addition, all power traded with Denmark and Russia is subject to fixed and variable charges calculated according to the same principles as the national tariffs. Spot trades with Finland and Sweden are not subject to specific charges since the establishment of the common market (except for the capacity charge when the interconnector capacity across the borders is fully utilized).

At the distribution level, consumers pay a two-part tariff consisting of a fixed element and an energy element. The tariffs are equal for all consumers subscribing to the same utility, but may well differ between utilities, reflecting the fact that network costs depend on the size and topography of the region as well as the number of users.

Tariff levels

Until the end of 1997, Norwegian network utilities could set their tariffs so as to cover their costs. Since 1993, NVE set a maximum allowable rate of return, and in principle this could only be achieved if the utility performed efficiently. In practice, however, it was difficult to ensure that this principle was followed and consequently all utilities were able to achieve the maximum allowable return. In NVE's experience, such a cost plus regulatory regime had a number of drawbacks:

- lack of incentives for efficiency and cost reduction;
- owners do not need to set clear targets and priorities;
- over-investment; and
- lack of incentives for efficient industrial restructuring.

A number of studies have documented that the earlier regulatory measures did not ensure efficient operation and investment in the networks. The estimated potential for costs savings have ranged from 20–40%, depending on the time horizon of the study. In the short run, costs can only be reduced by increased efficiency in operation and maintenance. In the longer run, investment may be tailored to facilitate the development of a more efficient network structure.

On the basis of its experience, NVE introduced a new regulatory regime that took effect on 1 January 1997. The new regime was based on a set of consistent and comprehensive regulatory rules for all transmission and distribution activities based on revenue caps. On the basis of an estimate of reasonable costs, including capital requirements, a maximum allowable revenue level has been set for each utility. Within this revenue requirement, the utility is free to determine its tariffs (subject to a non-discrimination clause). The revenue caps will be adjusted yearly on the basis of annual inflation rates and efficiency requirements. After a five-year period, in 2001, NVE will reconsider the basis for the revenue caps.

The procedure for determining maximum allowable revenues, which was mainly based on historic costs, had the virtue of being simple. It also ensured that the very different characteristics of individual utilities were taken into account. Given that the efficiency of individual utilities might well differ considerably, however, the procedure allowed such differences to be brought through to the new regime. In particular, utilities that had previously performed quite inefficiently will, under the new regime, have a much greater potential for improvement and hence profitability.

A particular difficulty is the fact that although utilities are required to follow standard accountancy practices, practices vary considerably between utilities, in particular in the way capital costs are treated. In the estimated maximum revenue figures for 1997, operation and maintenance costs on average accounted for 43% while capital costs (including the normal rate of return) accounted for 44%. The operation and maintenance costs share varied from 8–80% between utilities, while the capital cost share varied from 0–90%. These figures reflect capital values based on historic costs and the varying practices with regard to how quickly utilities write off capital expenditures.

To meet these difficulties, NVE has introduced upper and lower bounds for allowable rates of returns: 15% and 2%, respectively. It also intends to adjust the revenue caps over time according to the performance of individual utilities.

The year-to-year productivity requirements are individualized. There is a general requirement of a 1.5% productivity increase, which must be met by all network owners, and in addition there are individual requirements varying from

0–3%. The idea is that utilities which perform poorly relative to actual efficiency improvements in the industry will face more stringent productivity requirements in subsequent years ('yardstick competition'). In practice, NVE has considerable discretion with the procedure it follows when setting individual productivity requirements.

Only half of any (expected) increase in energy volumes is allowed to be passed through in costs/revenues, reflecting NVE's belief that there are substantial economies of scale in transmission and distribution. To avoid utilities systematically overestimating expected increases in output, allowable revenues will be adjusted *ex post* every fifth year, based on actual increases in energy volumes. Eventual differences (appropriately discounted) relative to the revenue caps based on output forecasts will be adjusted for in revenue caps for subsequent years.

Currently, the quality of service (frequency variations, interruptions, etc.) in distribution and transmission is very high, as would be expected in a system that has allowed the pass through of all costs. NVE has, therefore, not found it pressing to introduce measures to ensure that utilities do not reduce service quality in order to cut costs. It is, however, considering alternatives, one or more of which may be introduced later, including:

- explicit minimum standards;
- regulatory intervention if quality of service becomes 'unreasonably' low;
- compensation payments at regulated prices for non-delivery (interruptions); and
- obligatory negotiated quality contracts with customers.

NVE is concerned that the regulatory regime should be neutral with regard to industry restructuring. Since the general view is that the current industry structure has not realized the potential for economies of scale and scope, it is particularly important that regulations do not discourage mergers of utilities. NVE will, therefore, allow the revenue cap of a merged company to be set equal to the sum of their individual revenue caps. This means that any cost savings from mergers will accrue to the owners.

7.3.5 Conclusion

From a strictly economic point of view, the main effects of the reform of the Norwegian ESI may be summarized as follows:

- *The saving on costs has been limited*. This might be expected in a system so dependent on hydro power, where most costs are sunk. There has clearly been a reduction in operation costs, particularly in the network utilities, and more savings are expected as the new regulations take full effect.
- *Investment in the industry has come to almost a complete halt*. As demand is gradually catching up with capacity, there appears to be a renewed interest in building new capacity.
- *The effect on prices has been somewhat mixed*. Large consumers were able to negotiate substantial reductions in prices more or less immediately after the market was opened up. The development of competition in the small and medium-sized enterprise and household sectors of the market has been slower

to emerge, although competition seems to have become much more effective in recent years. Electricity prices fell in real terms during 1991–8. Prices have also become more flexible, better reflecting changes in underlying demand and supply conditions (in particular, changes in water availability).

Although the impact of the Norwegian reforms has been much less dramatic than that experienced elsewhere, notably in England and Wales, the results are generally viewed as positive. Much of the initial opposition to the reforms seems now to have silenced. Although it is perhaps realized that all is not yet well, the consensus view seems to be that the market reform has been a success.

Much of the current debate focuses on future expansion of capacity. Environmental concerns have led to a very strict policy on developing new hydro facilities. There is also considerable opposition to building thermal (gas-fired) generation capacity. As a result, imports of electricity from neighbouring countries have been increasing in recent years. The challenge, as the current government sees it, is to introduce measures that, on the one hand, constrain the growth in demand and, on the other hand, encourage the development of environmentally-friendly generation capacity. Ideally, such measures should not interfere unnecessarily with the functioning of the market. From the regulator's point of view, facilitating a coordinated expansion of the transmission network presents a considerable challenge.

7.4 Sweden

Sweden's industrial structure, cold climate and historically low electricity prices all mean that per-capita electricity consumption is higher than in most other countries. In paper and pulp, iron and steel, and a few more export-oriented industries, the cost of electricity is a significant part of total production costs. In the household sector, a very large share of total electricity consumption is used for residential heating, and for households in electrically heated single-family houses, the cost of electricity is a significant share of total expenditures. So, the price of electricity is of major importance to some major industries and a large number of families.

Until the beginning of the 1990s, regulation of the Swedish electricity market was based on the Electricity Act of 1902 and the market had developed into a set of regional and local monopoly markets. As the major generator, and owner and operator of the central grid, state-owned Vattenfall had a dominating role in the Swedish ESI. In effect, it was a political instrument for influencing the power industry and the development of the electricity market: to a large extent, government control of Vattenfall was a substitute for formalized regulation. Consequently, the market was not, in a narrow sense, heavily regulated, for example, there was no specific regulation of electricity prices.[11] Yet the role of competition between generators and between suppliers was very limited.

In the early 1990s, a major restructuring of the Swedish power industry and the electricity market was initiated. The institutional changes designed and implemented during this process lead to a 'new' electricity market, similar to the one in Norway, but with some unique features.

7.4.1 The restructuring process

There were several driving forces behind the process of restructuring. One was the anticipation of closer integration of the EFTA and EU economies and the development of a single European market for electricity. Another was the new Electricity Act in Norway and the implications of Norwegian liberalization for cooperation between generators in the Nordic countries. A third factor was the new non-socialist government, which had a political agenda in which liberalization and privatization of state-owned enterprises were important.

The first step in the restructuring process was to transfer the central grid and responsibility for system operation from Vattenfall to a newly created public agency, Svenska Kraftnät. Vattenfall was transformed from a public agency into a state-owned company. The long-term aim was to privatize Vattenfall, at least partly. After general elections in 1994 and the return of a social democratic government, however, the privatization programme was abandoned and a strong commitment was made that Vattenfall should remain state-owned.

The second step in the restructuring process was a new Electricity Act that paved the way for competition in generation and retailing. One key element in the new legislation was the introduction of rTPA to transmission and distribution networks. Another was legal separation between, on the one hand, transmission and distribution and, on the other hand, generation and retailing. Transmission and distribution were regarded as natural monopolies and made subject to regulation of prices and quality. Generation and retailing were regarded as competitive activities, where prices should be determined by regular market forces. After some delay and last minute revisions, the essential legislation and institutional changes became effective on 1 January 1996, while the new Electricity Act became effective in January 1998.

7.4.2 System control and transmission pricing[12]

Svenska Kraftnät is both the system operator, and the single owner and operator of the central grid, that is, the 220 kV and 400 kV networks. The total length of the central grid, including the interconnectors to the other Nordic countries, is around 16 000 km. The regional – 40 kV and 130 kV – networks are owned and operated by the major power companies. The total length of these lines is around 25 000 km. As a comparison, the total length of the distribution networks, owned and operated by approximately 250 local distribution companies, is around 250 000 km.

System control is based on a voluntary agreement, the Balance Agreement, between Svenska Kraftnät and a number of market participants. The companies that sign this agreement are typically major generators or users. They are referred to as 'balance-responsible' companies. While Svenska Kraftnät is responsible for the physical balance in the system, each balance-responsible company is economically responsible for any deviation between its generation/purchases and load/sales. Moreover, each individual market participant that is not a balance-responsible company has to have a contract, directly or indirectly, with a balance-responsible company.

The minute-by-minute, or primary, regulation of the system is based on contractual agreements between Svenska Kraftnät and some of the balance-responsible companies. The latter are paid both for the regulation power actually supplied and for keeping regulation capacity available. Secondary regulation is based on a special market, the Balance Service. Generators that are able to increase or decrease their generation at ten minutes' notice, as well as major consumers who are able to adjust their load quickly, can place bids on the market for balance service.

The bids are arranged in increasing price order for each operating hour. When manual regulation is needed, Svenska Kraftnät activates the most favourable bid for regulating up or down. At the end of each hour, the price of regulation power is fixed as the highest regulating-up bid, or the lowest regulating-down bid. This price applies for all participants that have been called to regulate up or down. Thus, the participants in this market are paid for the regulation power they actually supply, but there are no payments for keeping regulation capacity available.

Transmission services are priced in accordance with a nodal tariff. The basic principle is that payment in one point, the point of connection, gives access to the whole network and thus to the whole electricity market place. So, consumers and producers connected to a local network will pay network fees only to the owner of that network, and they are free to trade with any other player in the entire Swedish-Norwegian-Finnish network. The local network owner will pay network fees to the owner of the regional network, who, in turn, pays network fees to Svenska Kraftnät at the point of connection to the national transmission network. In effect, this means that local network fees reflect local distribution costs as well as the network fees paid to the owner of the relevant regional network and to Svenska Kraftnät.

The point-of-connection tariff for the national transmission network comprises three parts:

1. *A once-for-all connection fee*, which is applied only if the connection of a new customer involves considerable cost.
2. *An annual latitude dependent capacity fee*: the fee varies between a maximum and minimum value depending on the latitude of the point of connection. As there is generally a generation surplus in the north where the major hydro stations are located, and a generation deficit in the south where the major consumption areas are located, the capacity fee for generators is relatively high (38 SEK/kW per year) in the north and relatively low (2 SEK/kW per year) in the south. The capacity fees for consumers are low in the north (2 SEK/kW per year) and high in the south (38 SEK/kW per year). The capacity fee is intended to generate around 50% of Svenska Kraftnät's revenues.
3. *A use fee*, reflecting the cost of transmission losses. It is calculated as the product of a location-specific marginal loss coefficient, the amount of power input or output at the location in question, and the current power price. So far, the 'current power price' is not the Nord Pool spot market price for the relevant hour, but the price agreed in contracts between Svenska Kraftnät and balance-responsible generators. The marginal loss coefficients for input typically are positive in the north and negative in the south. Thus, in the north, the use

fee is positive for a generator and negative for a consumer, while the opposite holds in the south. The use fee is intended to generate around 50% of Svenska Kraftnät's revenues.

The design of the transmission tariff implies that the price of electricity paid or received by a market participant at a certain geographical location is independent of the location of the trading partners of that market participant. This reflects the desire to promote competition. The design of the transmission tariff also implies that consumers have incentives to locate in the north, while generators have incentives to locate in the south. Unlike in Norway (and on the Norwegian-Swedish interconnectors), however, there is no congestion fee in the transmission tariff, and thus no incentive to instantaneous adjustment of generation and consumption in response to bottlenecks in the transmission network. Instead, bottlenecks are handled by the system operator within the frame of the 'counter-purchase' system.

The basic principle in the counter-purchase system is that whenever there is congestion in the transmission network, the system operator buys power in generation-surplus areas and sells power in generation-deficit areas. The system operator uses the Balance Service, buying regulating-up services in the generation-deficit areas and regulating-down services in generation-surplus areas. This obviously means that the price of regulation power will differ between various locations. Thus, while the counter-purchase system implies that the consumer price of electricity is independent of bottlenecks in the transmission network, the generators' revenues per kWh regulation power are not. This also means that, for the generators, there are price risks associated with the capacity constraints in the transmission network.

7.4.3 Regulation

The quality and prices of network services – transmission and distribution – are subject to regulation by a special regulator. Price regulation takes the form of a set of general guidelines with which the network companies have to comply. Transmission and distribution tariffs, however, are not subject to prior approval by the regulator. Instead, any dissatisfied customer has to file a complaint to the regulator. If the regulator finds that the tariff violates one or several of the guidelines, the company is asked to change the tariff. Only if the network company refuses to do so will the case turn into a legal issue.

The guidelines for network tariffs have several components, but the general rule is that they should be reasonable, non-discriminatory and designed in accordance with the (undefined) interests of the consumers. Three of the guidelines are specific: first, that the network prices should be stable, with adjustments to a higher or lower level implemented gradually over several (three to five) years; second, that the tariffs should reflect the structure of the network service's costs, with the fixed and variable components in the tariff reflecting fixed and variable costs; third, that the tariff should allow the provider of network services to recover all reasonable costs associated with the network operation.

It is obvious that these principles may not be compatible with each other. For example, stable network prices may not be compatible with cost recovery if, for historical reasons, the initial price level is very low. The precise meaning of the individual principles, as well as the trade-offs between conflicting principles, cannot be judged until a sufficient number of cases have been brought to court and settled. In addition to the guidelines laid out in the Electricity Act in 1997, however, the special regulator issued guidelines about productivity increases: the costs of regional and network companies are required to decrease by 2% per annum. In other words, the regulation of transmission and distribution prices has elements of both rate-of-return and price-cap regulation.

7.4.4 Ownership changes

The new Electricity Act requires that natural monopoly and competitive activities are operated in separate companies. The immediate effect of this new provision was that the number of companies on the Swedish electricity market almost doubled as most of the existing generation and distribution companies were involved both in competitive and regulated activities. The purpose of the separation requirement is, of course, to prevent cross-subsidization from the regulated to the competitive part of the industry. Except for transmission, however, there is no regulation of ownership, which means that an owner of a regional sub-transmission or distribution company is allowed to own a generation or retailing company and *vice versa*.

The institutional changes have induced significant structural and ownership changes in the Swedish electricity industry. In particular, the degree of foreign ownership has increased. Before the electricity market reform, foreign ownership in the Swedish power industry was close to zero, while the degree of public ownership was high. The ownership pattern in 1990, which is representative for the period up to 1996, is displayed in Table 7.9.

Following the reform, foreign ownership increased and reached 17% of installed generating capacity in 1998. Major buyers are: the German power company Preussen Elektra; Statkraft from Norway; the Finnish state-owned energy company Fortum; and EdF from France. The major sellers are: municipalities; pension funds; and insurance companies. These ownership changes mean that the degree of state ownership has actually increased, although it is not only exercised by the Swedish state.

Table 7.9 Ownership of generation and distribution, 1990

	*Generation**	*Distribution***
State	55	11
Municipalities/counties/coops	20	66
Private	25	23

Notes:
* Percentage share of electricity generation
** Percentage share of customers

Source: Hjalmarsson (1996), p. 133

7.4.5 Market power

There is a relatively large number of generators in the Swedish electricity market, but most of the power is produced by a few generators of which Vattenfall is by far the biggest. Vattenfall's market share exceeds 50%, while the aggregate market share of the four biggest generators exceeds 85%. It may thus seem clear that the wholesale market is very concentrated and that Vattenfall has a significant degree of market power, capable of increasing the market price by holding back its own production. Of course, however, the market power of incumbents depends not only on the degree of concentration, but also on the barriers to entry that potential new generators face.

A closer look at the situation reveals that the cost of new power, due to stringent environmental and other regulations, is high in relation to the variable cost in existing hydro and nuclear power plants. This means that, at the current level of demand, the incumbent producers are protected to a large extent against competition from new generators. Demand growth may eventually lead to increased competition, but current expectations about the rate of electricity demand growth suggest that the incumbents will remain protected against competition from new generators for quite some time.

There has been considerable concern about market power. Part of these concerns are reflected in the design of transmission tariffs, in particular the counter-purchase system. The market power problem, however, cannot be solved just by an appropriate design of the transmission tariffs. The solution proposed by the competition authority and several independent commentators is that Vattenfall should be divided into two equally big companies.

The government has, however, consistently seen the integration of the electricity markets in Norway, Sweden and Finland as the proper way to deal with market power, and consequently has not proposed a split of Vattenfall. Whether market integration is a sufficient means for eliminating market power remains to be seen, but it is a fact that the integration of the Nordic electricity markets has significantly enlarged the relevant market and, according to the standard measures of concentration, put the market power issue in a new perspective.

Nevertheless, the standard concentration measures implicitly assume that there are no capacity constraints in inter-country transmission links. Such constraints, however, do exist and, from time to time, turn the integrated Nordic market into a set of national, or even smaller, regional, markets. The transmission constraints are reflected in price differences between the countries, and such price differences are quite frequent. For example, in 1998, the Nord Pool prices for Norway and Sweden differed approximately 60% of the time.

When the transmission links from the other Nordic countries are congested, Vattenfall has a considerable degree of market power.[13] Its market power is particularly strong when the aggregated load exceeds the sum of the installed capacity of the other Swedish generators and the import capacity, that is, when demand reductions are the only alternative to production by Vattenfall. In 1998, these periods occurred approximately 25% of the time. So far, however, there are no indications that Vattenfall is exploiting its market power to any significant degree. Instead, all generators seem to have competed for market shares, thus producing at full capacity and depressing spot market prices in years when high precipitation has lead to an ample supply of hydro electricity.

7.4.6 Performance: prices and competition

When the common Norwegian-Swedish spot market opened in January 1996, the wholesale price of electricity in Sweden was 20–25 öre/kWh. There were widely held expectations that electricity prices would immediately fall as they did in Norway when its market was deregulated in 1991. The fact that the Norwegian spot market prices had been rather low, 10–15 öre/kWh, during most of autumn 1995 fuelled expectations about falling electricity prices in Sweden.

In fact, prices went in the opposite direction. Spot market prices immediately increased to 25–30 öre/kWh, and were much higher during short periods. The main reason for this was a very significant drop in precipitation and thus in the supply of hydro electricity. While the normal annual production of hydro electricity in Sweden is around 65 TWh, the production in 1996 was only 51 TWh. As the situation was roughly the same in Norway, the electricity market was hit by a significant 'supply shock'.

Before deregulation, there were claims by power industry representatives that the new market institutions – the combination of a spot market and an independent system operator – could not replace the traditional cooperation between the generators. The new institutions worked very well, however, in spite of the significant drop in supply, the market continuously cleared and there were no problems with system stability. Moreover, the merit order dispatch determined by spot market trade seems to have been reasonably cost-efficient.

In spite of the initially high spot market prices, major industrial users of electricity have been able to benefit from lower electricity prices. According to reports in the media, the major producers have competed actively for these customers and as a result, prices have dropped by 15–20%. As the contracts between producers and major industrial customers generally are secret, however, systematic statistical evidence on the development of industrial electricity prices is lacking.

The development of household electricity prices reflects a specific feature of Swedish electricity market reform. In principle, the 'new' market was immediately open for all customers, but to enter the market and thus to be allowed to change supplier, a customer is required to meter and report electricity consumption hour by hour. For a typical industrial or commercial customer, the cost of the necessary equipment is almost negligible in relation to the potential gains from a change of supplier. For a typical household with an annual electricity consumption less than 20 MWh, however, the situation is the opposite; the cost of buying and installing the required metering equipment is generally higher than the potential savings. This is also the case after the introduction (in July 1997) of a 2500 SEK price cap on the equipment in question.

In Table 7.10, the first three rows summarize the development of household electricity prices between 1996–9. Household prices are represented by the prices paid by three types of household consumers.[14] The reported prices are average values, excluding distribution charges and taxes, for all the approximately 250 different suppliers on the Swedish electricity market. To evaluate the development of retail prices, it is assumed that a representative supplier determines the (fixed) prices offered to household customers during a specific year in the beginning of September the year before. Moreover, it is assumed that these prices are equal to the price at which the supplier can buy electricity on the futures market, plus a mark-up. On a market with efficient competition the suppliers' mark-up, including the cost of load deviations, should be in the range 1.5–2.0 öre/kWh.[15]

The fourth row of Table 7.10 shows the development of futures prices in Nord Pool during 1996–9. On 1 September 1996, the price of electricity for delivery in 1997 was 24.8 öre/kWh, reflecting the low supply of hydro power in 1996. In 1997 and 1998, however, the supply of hydro power was close to normal, and spot market prices were much lower than in 1996. As a result, the futures price on 1 September 1997 of electricity for delivery in 1998 was 15.2 öre/kWh, while the corresponding figure for 1999 was 14.4 öre/kWh. As the Nord Pool futures market did not open until January 1996, a comparable price for 1996 is not available.

The figures in Table 7.10 suggest that the significant reduction of Nord Pool prices over the last few years has led to increased profit margins in the ESI rather than lower retail prices. In a competitive market, however, increased profit margins should induce new suppliers to enter the market, attracting customers by offering them lower prices. In practice, the entry of new suppliers has been quite limited and very few households have so far changed supplier. It also seems that there is limited competition between incumbent suppliers. This is indicated by the considerable though diminishing differences between retail electricity prices in various parts of the country. Table 7.11 summarizes the range of prices observed during 1996–9.

The fact that few households have changed supplier in spite of the significant spread between Nord Pool prices and average retail prices, and between retail prices charged by different incumbent suppliers, suggests that information and transaction costs associated with a change of electricity supplier have been quite high. It is likely that the cost of complying with the hour by hour metering

Table 7.10 Electricity prices (öre/kWh) for household consumers, 1996–9

	1996	*1997*	*1998*	*1999*
2 MWh/yr	28.0	29.5	30.0	27.7
5 MWh/yr	26.5	27.7	27.4	26.0
20 MWh/yr	25.3	26.4	25.5	24.7
Nord Pool	N/A	24.8*	15.2*	14.4*

Note: * Average value of futures prices for whole year on 1 September the year before.

Source: Swedish National Energy Administration, ER 6:1998 and Nord Pool

Table 7.11 The ranges of household electricity prices (öre/kWh), 1996–9

	1996	*1997*	*1998*	*1999*
2 MWh/yr	15.5–48.8	19.5–37.7	19.0–39.7	19.0–33.8
5 MWh/yr	15.5–37.2	19.5–32.4	19.0–32.4	N/A
20 MWh/yr	15.5–30.9	19.5–31.8	19.0–33.2	N/A

Source: Swedish National Energy Administration, ER 6:1998 requirement is the main obstacle to competition and lower prices on the retail market. As of 1 November 1999, however, the current metering and reporting requirements will be replaced by a system in which households and other small customers will be charged on the basis of standardized load profiles. As a result of this decision, major suppliers are offering new household customers retail tariffs in which the price of electricity is in the range 15–17 öre/kWh.

7.4.7 Performance: regulation

The special regulator oversees development of the prices and quality of transmission and distribution services. There is, however, no *ex ante* approval of the structure of transmission and distribution tariffs in terms of fixed and variable elements, As a result, both design of the tariffs and the level of prices vary significantly across different distribution companies. This is clearly indicated in Table 7.12. In some cases, the variations reflect differences in real costs, for example, differences in electricity consumption per sq. km, differences in maintenance costs, etc. In many other cases, however, the differences are due to different accounting principles in the past, which led to differences in the valuation of existing assets when the old distribution companies were divided into network operating companies and retailing companies.

The restructuring of the electricity distribution industry seems to have led to significant productivity increases. For example, Edin and Svahn (1998) report that mergers of distribution companies have led to reductions of staff by up to 50%. The numbers in Table 7.12 suggest that these productivity increases have led to lower distribution prices to a very limited extent. This outcome and the differences in distribution prices make it tempting to conclude that the regulation of the electricity distribution industry has been too light-handed.

Another regulatory failure relates to the separation of regulated and competitive activities, the aim of which is to prevent competition-distorting cross-subsidization. The key provision is that a generation or retailing company is not allowed to engage in transmission or distribution, while a transmission or distribution company is not allowed to engage in generation or retailing. The only exception is that a transmission or distribution company is allowed to buy electricity to compensate for transmission or distribution losses. An owner of a generation or retailing company, however, can also own a transmission or distribution company and *vice versa*.

Table 7.12 Electricity distribution prices (öre/kWh) for household consumers

	1996			*1997*			*1998*		
	Min.	*Mean*	*Max.*	*Min.*	*Mean*	*Max.*	*Min*	*Mean*	*Max.*
2 MWh/yr	19.1	**40.7**	72.4	19.7	**41.3**	71.8	20.7	**42.3**	68.9
5 MWh/yr	18.9	**36.1**	54.7	19.3	**36.4**	54.6	20.4	**37.1**	56.8
20 MWh/yr	9.7	**21.7**	33.5	10.1	**21.7**	33.2	9.1	**21.7**	29.6

Source: Swedish National Energy Administration, ER 6:1998

Experiences to date indicate that joint ownership can lead to cross-subsidization in at least two ways:

- The first relates to the allocation of overhead costs between the two types of activities. By allocating most of the overhead costs to the network company – the company with a monopoly position in its market – the competitiveness of the retailing company is enhanced.
- The second relates to the fact that a network operator is allowed to buy electricity to compensate for its own transmission or distribution losses. If the electricity needed is bought from the 'own' supply company at a price exceeding the market price, the competitiveness of the supply company is enhanced.

These observations suggest that joint ownership prevents a real separation between regulated and competitive activities.

7.4.8 Current issues and debates

Two issues related to the institutional design and regulation of the Swedish electricity market are currently the subject of considerable debate. The first concerns the pricing of regulation power and reserve capacity for dry years with limited supply of hydro power, and to the fact that some fossil power capacity has recently been closed down. According to the principles of the Balance Service, generators are paid for the regulation power they actually supply, but not for keeping regulation capacity available. In a similar fashion generators are not paid for capacity kept as a reserve for dry years.

Representatives of the power industry claim that the incentives to keep reserve capacity, both for regulation purposes and for regular production during dry years, are too weak, leading to an inefficiently low level of reserve capacity. Svenska Kraftnät claims, however, that no special capacity payments are needed, and that, consequently, the closing down of some reserve capacity should be seen as a sound response to the integration of the Nordic electricity markets.

The second issue concerns the regulation of network tariffs in conjunction with ownership changes in distribution companies. There is a large number of, usually municipally-owned distribution companies. Moreover, there are strong indications that there is a significant potential for productivity increases in most of these companies, and that mergers between distribution companies can lead to additional productivity increases. During the last few years, there has been a number of mergers between distribution companies. In most cases, these mergers have been orchestrated by one of the major power companies and combined with a change of ownership from a municipality to a power company, presumably more interested in, and able to implement, productivity increases.

As the book values of the municipally-owned distribution companies have usually been considerably lower than the relevant market values, most of the mergers have led to a revaluation of the assets of the merging companies. To a large extent, the revaluation of distribution company assets reflects expected productivity increases, but to some extent, they also reflect expected price increases. This is particularly the case for distribution companies with artificially low prices. A recent court ruling has, however, decided that a revaluation of existing assets is not a valid reason for increasing distribution prices. This has significantly reduced the rate of structural change in electricity distribution, and led to a heated debate about the principles for regulation of network tariffs.

Notes

1 The authors of this chapter are Lars Bergman and Nils-Henrik M von der Fehr.
2 The 'Nordic countries' refers to Denmark, Finland, Norway and Sweden. The electricity industry of the fifth Nordic country, Iceland is not physically interconnected to those of other countries. The term 'Scandinavian countries' is not useful for the purposes of this Report since it refers to Denmark, Norway and Sweden but not Finland.
3 Birka Energi was created in 1998 as a result of a merger between Stockholm Energi and Gullspång Kraft.
4 Thus, while the establishment of the England and Wales pool marked a complete break with the traditions of the wholesale trade of electricity in the United Kingdom, the establishment of Nord Pool represented a relatively smooth transition to an environment with more competition.
5 By trading at ELBAS, the market participants are able to reduce their need for trade on the balancing market operated by the system operator. They may also be able to avoid interconnector congestion charges by changing their net trades on different markets.
6 ELEX is jointly owned by Svenska Kraftnät and Fingrid, the Finnish grid company.
7 The relationship between this procedure and transmission pricing is discussed in Sections 7.3 and 7.4.
8 The system operator may determine that there are too few participants within a region for competition to be effective. In such cases, the 'monopoly region' will be considered as part of the neighbouring region when price is set (that is, the bottleneck is neglected as far as price determination is concerned).
9 The obligation to supply all local customers remains. The cost associated with this 'universal service obligation', which basically consists of network costs, must be recovered through network tariffs.
10 Taking effect from 5 June 1999, new regulations require metering to take place four times per year.
11 See Hjalmarsson (1996).
12 This section is to a large extent based on Svenska Kraftnät (1997).
13 See Amundsen, et al. (1999).
14 The three categories of customers are: households in normal-sized flats without electric heating and consuming 2000 kWh/yr; households in single-family houses without electric heating and consuming 5000 kWh/yr; and in single-family houses with electric heating and consuming 20 000 kWh/yr.
15 The load pattern of an individual group of customers usually differs from the standardized load pattern on which the prices of futures are based. The cost of these load pattern differences are borne by the supplier.

8 Germany: Negotiating Access[1]

Germany has the largest population in Europe (around 82 million) and the largest electricity market. Annual production is roughly 500 TWh, total capacity about 100 GW, and consumption per capita 5.8 MWh (see VDEW, 1998). The German ESI is, however, of wider importance: the country is regionally located so that it connects northern and southern European markets; and the interconnectors currently being built from the Nordic countries to Germany will allow substantial trading with Nord Pool. What is more, within the options allowed in the EU's Electricity Directive, the German government's choices are quite distinct from those of most other member states.

In order to implement the Directive, a new Energy Act (EnWG) came into force on 29 April 1998.[2] The name 'Energy Act' indicates that it is intended to apply to both the electricity and gas sectors. The government has, however, decided to wait for the EU's Gas Directive before implementing arrangements for the gas sector. At present, therefore, the EnWG applies only to the electricity sector: it has reformed the legal framework of the German ESI with an eye to greater liberalization and deregulation; but it has not restructured the sector nor changed ownership, though indirect effects on structure and ownership will be inevitable.

It is still somewhat premature to be conclusive about the success or failure of the EnWG. So, the developments and experiences discussed in this chapter should be understood as indicative rather than conclusive. It is more fruitful to concentrate on the reform as such, and to analyse the potential for competition. The emphasis, therefore, is on the legislative setting and the current structure of the German ESI.

8.1 Industry structure

The EnWG replaced the Energy Act of 1935, which favoured a concentrated and cooperative ESI. Until recently, the sector consisted of many small and large firms with a mixture of public and private ownership. Its most important characteristic, however, was that it operated as a cartel: firms agreed *demarcation contracts* – legally binding agreements not to compete, which demarcated service areas. There were also *concession contracts* – licences for the right to use public grounds for installing infrastructure: in effect, all electricity was 'taxed' by the concession fee payable for a licence. The concession contracts were granted exclusively, with the result that entry was impossible. A 1957 competition law

(GWB) prohibited cartels, but the ESI survived this prohibition by the introduction of an extra clause in the GWB, which exempted the ESI from the new law. From then until 1998, nothing really changed and the sector developed safe from competitive pressure.

The German ESI is made up of approximately 1000 firms, but is nevertheless relatively concentrated. Almost all of the firms are vertically integrated, but may be distinguished vertically by different core activities. Three classes of firms are commonly distinguished:

- the *Verbundunternehmen* (EVUs);
- the regional suppliers; and
- the communal distributors.

The eight EVUs own and operate the high voltage transmission networks.[4] They are heavily integrated with generation, the geographical division of their power plants largely overlapping with their respective transmission networks. Together, they produce the bulk of electricity (around 80%) and although it is not their core activity, they are also active in distribution, focusing on larger consumers and taking around a third of the market.

The other two classes of firms do not own transmission networks. The difference between them comes down to ownership: the regional suppliers are largely controlled by the eight EVUs, while the communal distributors are commonly owned by local communities. From an economic perspective, the regional suppliers and communal distributors are largely equivalent. They own and operate distribution networks, concentrate on supplying end-users (though regional suppliers may also supply communal distributors), but do also produce electricity, mainly for their own use. There are around 80 regional suppliers and 900 communal distributors.

German electricity generation is mainly conventional: 55% from coal, of which 29% is hard coal and 26% lignite, the latter mainly comes from eastern Germany. As in many other European countries, coal policy has less to do with efficiency and more with social policy: reducing relatively expensive domestic coal would create substantial unemployment of miners, especially in areas that already have high unemployment rates. Coal mines continue to be subsidized by the federal government though the subsidy is decreasing.

Roughly 30% of generation is nuclear. The current political climate supports an ordered withdrawal from nuclear power and so the share of nuclear power is likely to decrease substantially. What will replace it is an open question: renewables will certainly have some potential for growth, but another likely candidate is CCGT. Gas has a minor share currently, but with falling gas prices, improved technology and tougher environmental constraints, the contribution of gas is expected to grow. Moreover, the UK's 'dash for gas' suggests that gas is an attractive possibility for IPP entry. Imports, exports and co-generation have only minor shares.

Electricity consumption is roughly 25% residential, 50% industrial and the remaining 25% for commercial and agricultural usage. Prices are among the highest in Europe. A distinction is made between residential users (*Tarifkunden*), who are in principle protected by regulation, and large consumers

(*Sondervertragskunden*), who negotiate a contract. Residential electricity prices are around 28 Pf/kWh; and industrial prices around 17 Pf/kWh.[5] These numbers are rough indicators, because the degree of variation in tariffs is quite high. VEA (1999) shows price variation (depending on size and supplier) ranging from 9–28 Pf/kWh for industrial users to 21–32 Pf/kWh for residential users. Wirths (1998, pp. 103) suggests a systematic regional difference.

The eight EVUs are regionally defined and, to a certain extent, associated with the Länder. Only four are independent of each other: RWE, VEBA (Preussen Elektra), VIAG (Bayernwerk) and EnBW. The others are at least partly linked to the main four. 10% of VEW is owned by Bayernwerk and another indirect minority holding belongs to RWE. 12.5% of HEW is owned by Preussen Elektra. BEWAG is majority owned by Preussen Elektra and Bayernwerk. VEAG, the electricity supplier in eastern Germany founded after reunification, is fully owned by the other EVUs: RWE, Preussen Elektra and Bayernwerk each own 25% while the remaining 25% is divided among the others in a joint holding.

All the EVUs have majority or minority shares in the regional suppliers. Only a small portion (about ten) of the regional suppliers is independent.[7] The communal distributors are largely owned by *Stadtwerke*, communal holdings that handle all the communal utilities like public transport, electricity, gas, water, waste disposal and sewage. It is common practice in these utilities that the profitable parts (including electricity) cross-subsidize the unprofitable parts (notably public transport). EVUs seem to own some portion of the communal distributors, which suggests they do have influence. The main influence on communal distributors, however, comes from local politicians.

Across the entire ESI, there are four key groupings around RWE, VEBA, VIAG and EnBW.[8] The activities of these conglomerates are by no means constrained to electricity. They are also active in waste disposal, gas, mining and, more recently, telecoms.[9] The significance of these four in the ESI is indicated by concentration ratios: corrected for ownership links, their 1994 production market shares are listed in Table 8.1.

The ultimate ownership of the ESI is mixed. Measured in number of firms, it turns out that by far the larger share is publicly owned, but measured by annual production, by far the larger share is mixed ownership. Purely private ownership is low on both counts. The difference is in the relatively high number of small communal distributors, which are largely publicly owned by the communities.

Table 8.1 Market shares and concentration ratios in 1994 production

Firm	*Market share (%)*	*CR (#)*
RWE	29.42	CR1 = 29.42
VEBA	20.80	CR2 = 50.22
VIAG	10.66	CR3 = 60.88
EnBW	9.29	CR4 = 70.17

Source: Drasdo et al. (1998), p. 247.

Table 8.2 The German ESI

	Share in generation (%)	*Share in distribution (%)*	*Ownership*
EVUs	80	33	Partly private and partly Länder
Regional utilities	9	36	Mainly EVUs
Communal distributors	11	31	Mainly communities

Source: VDEW (1998) and Commerzbank (1997).

The larger EVUs are mainly in mixed ownership. Several Länder have majority or minority shares, whereas the remaining shares are in the hands of banks, insurance companies and other financial intermediaries and a non-negligible portion of the shares is traded in the stock market. Table 8.2 summarizes the structure.

8.2 Legislative setting

8.2.1 Entry and access

With the EnWG, entry into the ESI is completely free *de jure*: any firm can enter at any production stage. According to the Electricity Directive, building of direct lines must be possible and national implementation of this provision should allow entry at the network stages. For the German ESI, this implied that the rule of exclusive concession rights had to be abolished: the EnWG prescribes that granting concession rights is still the right of the communities, but they can no longer be granted exclusively. In principle, competition within the industry can now flourish, because demarcation contracts now come under rules on the prohibition of cartels. With a minor stroke, the ESI has been turned from a fully cartelized industry into a potentially competitive industry. And whereas the Directive sets threshold values for eligibility of end-users, in Germany, *all* consumers are eligible.

Even if *de jure* competition may seem possible, *de facto* obstacles remain. The transmission and distribution networks are monopolistic bottlenecks. For competition to evolve in generation and retail, competitors should have non-discriminatory access to the networks. As Part 1 of this Report indicates, there are various ways to organize the industry so as to ensure symmetric access. Vertical separation is one option and while it may have disadvantages, it seems particularly promising for securing non-discrimination.

The option of structurally separating the transmission networks has also been on the German political agenda. The government finally decided against it: it was aware of the advantages but feared that the required expropriation would be judged by the Supreme Court to contradict the constitution. The issue is controversial: it is not entirely clear whether a large part of the ESI can rely on the constitution – the more state-owned, the less likely that it can. It may be a missed opportunity that the government did not even test it out in court. Instead, the structure of the ESI has not been altered, which leaves the problem situation of vertically integrated firms, in which one part is a monopolistic bottleneck while a complementary part is subject to competition.

The Directive prescribes a choice between third party access (TPA) regulated or negotiated, and the single buyer model. The German government more or less chose both: clause 5 of the EnWG states that access to the networks will be according to nTPA as arranged in clause 6, except if clause 7 applies. The latter allows the possibility that at the *distribution level*, a single buyer can be granted if the distributor wishes so.[10] This rather inelegant provision is the result of a political compromise. The original plan was to have nTPA at all levels. The communities, however, protested because they feared severe cutbacks in the revenue flow (see Deutscher Städtetag, 1997).

The politically sensitive argument was that if the communities lack the revenues from electricity branches – the concession fees – they could no longer cross-subsidize public transport. The argument that has been put forward is that due to the introduction of competition (at the distribution level), the revenue from the concession fees would be reduced by about 50%.[11] This argument is theoretically unsound: the public grounds remain the monopoly of the communities, irrespective of what happens. By setting appropriate tariff structures and levels, it should still be possible to generate monopoly profits. The solution to the problem was to allow the possibility that communal distribution could opt for a single buyer. What this actually achieved is that in addition to the monopoly for concession rights and the distribution network monopoly, the communities got their way in having monopolies at the retail level.

One explanation may be that the concession fees are binding regulations while end-user tariffs are not. The federal *Konzessionsabgaben Verordnung 1992* (KAV) prescribes the maximum height of the concession fees in Pf/kWh.[12] Hardly without exception, the communities charge at this maximum, which suggests that this regulation binds. On the other hand, the end-user tariffs for electricity are regulated by the *Bundestarifordnung für Elektrizität 1990* (BTOElt). The BTOElt only prescribes some aspects of the tariff structure rather than the level, however; and with the level, it only prescribes that tariffs should reflect underlying costs.

The regulators at state level, normally civil servants working in state economics departments, should monitor and approve the tariffs. These sector specific regulators for electricity, however, are not to be understood as something similar as Offer in the United Kingdom. Their functioning is highly opaque. Firms' data on which the approved tariffs are based are treated highly confidentially, and except for statement that tariffs are approved, nothing is public. Moreover, in most cases there seem to be conflicting interests. The Länder are to some extent the direct owners of the EVUs, so they should to some extent regulate their own profit stream. It seems justifiable to conclude that the regulation of the end-user tariffs is not too binding. Another explanation is that consumer eligibility breaks down price discrimination in the concession fees. Currently, large consumers pay far less than small consumers. With eligibility and subsequent freedom of entry at the retail stage, the demand of small consumers can be bundled to qualify as a large consumer.

Although the communities succeeded in getting the option to request a single buyer, they hardly use the option. A year after the EnWG, only a minority of all communal distributors had actually opted for a single buyer.[13] There may be two possible explanations:

1. Perhaps the communities realize that the real bottleneck is the network and not retail. The single buyer attempts to monopolize the retail level, but this is largely superfluous if one already owns the distribution network, provided that the access charges are unregulated.
2. Perhaps the communities have realized that the provision in both the Directive and the EnWG that the single buyer should be equally competitive as TPA may be meaningful. The Directive prescribes that the single buyer must be modified so that (eligible) third party contracts must be allowed. Neglecting transaction costs, this provision makes the modified single buyer equivalent to the TPA. Only practice can be the judge whether these systems turn out to be equivalent, but it may explain why the communities do not opt for the single buyer after all.

Access to the transmission networks is a clearer issue. In an early proposal for the EnWG, the government did not intend to take up a special access provision, but rather to leave access issues, should they arise, to the antitrust agencies. This apparent negligence of the government's regulatory task has been heavily criticized. The federal antitrust agency (*Bundeskartellamt*) countered that the competition law was not well equipped for the task of enforcing access and pleaded for the introduction of an essential facilities doctrine. Simultaneously, political opposition pleaded for an explicit access provision in the EnWG. Both made it through the political process. Much in the spirit of the Directive, the EnWG now prescribes warranted non-discriminating TPA, unless the network operator can show that this is not possible or not reasonable. Simultaneously, an amendment to the competition law states that it is abuse of market power if access of a third party to a network or another facility (essential for competition) is refused without reasonable justification.

The legal value of these provisions is to reverse the burden of proof. Under both provisions, the network provider must show that access is not possible, rather than the third party proving that it is. Obviously, this is a major difference given that the third parties generally lack the required information. Still, it is curious that both provisions made it through the political process. There does not seem to be a legal difference between the two, which implies that in case of unjustified refusal of access, the discriminated third party can choose where it will submit a complaint: the antitrust agency, which applies the competition law; the regulatory authority at state level, which must use the EnWG; or both. Given the 'soft' reputation of the latter, chances may be better at the federal antitrust agency in Berlin.

8.2.2 Access charges

Since the government explicitly chose nTPA, the access charges for both the transmission and distribution networks are a matter of negotiation among the parties involved. The EnWG foresees that if the negotiation agreement on access charges turns out to be anti-competitive, the federal Ministry of Economics can propose a regulation directive, which should be approved by Parliament. This would effectively introduce sector-specific regulation. Directly after the EnWG became law, three representative associations agreed to the *Verbändevereinbarung* (association agreement), a document of 11 pages, setting out the structure of the access charges, but not the level.[14] The levels are left to the firms involved and are largely a matter of negotiation even if most utilities have by now published the level of the basic components. It is a rather artificial system, which leaves much room for negotiation, and its future is uncertain.

The association agreement states that access charges should reflect underlying costs but given a severe lack of information this will be quite hard to control. On paper, but even more so in practice, the system is characterized by a substantial degree of price discrimination. Basically, access charges are made up as follows. First, in order to recover fixed costs:

- a postage-stamp tariff for the transmission network; plus
- a distance-related price for the transmission network; plus (if applicable)
- postage-stamp tariffs for the distribution network.

Second, variable system costs:

- costs of voltage transformation;
- incremental (energy) losses;
- ancillary services; and
- metering costs.

The association agreement concentrates on fixed costs, with few specifications on variable system costs, although these are non-negligible. The ancillary services in particular are said to be a source of discriminatory potential.

The agreement rests on the contract-path principle. Access charges are calculated based on third party contracts. For every third party contract for which access is required, a straight line between the injection point and point of delivery is the (fictional) contract path; the underlying networks are said to be used. The entire network is subdivided regionally and according to voltage levels; every part is called a *network range*. The regional subdivision should reflect different regional costs, but also reflects the sovereignty of different network owners. The major part of the agreement is a structure simply to cover fixed costs. The basic component on which the structure rests is a network range's annual capacity price (DM/kW).[15] It is calculated as the annual fixed costs of a network range, divided through the highest load (kW) at any time during the year in the network range.

The access charge to be paid for use of the high-voltage transmission network(s) consists of two parts:

1. A *contract capacity price*, basically a postage stamp. This is calculated as the mean of the network capacity prices at the point of injection and the delivery point (minus the distance price, see below), multiplied by the contracted maximum load (kW).[16] It is to be paid only once, irrespective of how many network ranges (with their respective owners) are covered by the straight line. The network operators relocate the revenues among each other. Furthermore,

only one contract party pays: whether this is the supplier or the customer is irrelevant for the network operator; the contracting parties are to allocate the transmission costs among each other.
2. A *distance-related price*. This is determined by the distance (km) between the point of injection and the point of delivery times a predetermined, nation-wide distance price (per kW, per km). The first 100 km are free, which implies that the average distance price is progressive in distance. The predetermined distance price has been set at 12 DM/kW/100km.

The sum of these two components is the annual access charge for the transmission network. What remains is a postage stamp for the distribution networks. In principle, there is no distance-related component at the distribution level, only postage stamps for every used voltage level. The postage stamps are calculated as the postage stamps for the transmission network; with every network range having its own annual fixed costs. In principle, the point of delivery determines which postage stamp applies. If the point of injection is on a higher voltage level than the point of delivery, an extra postage stamp is to be paid for the next voltage level and so on, such that all used voltage levels (network-ranges) are paid for.

There is one confusing detail: if the point of injection and the point of delivery are on the same voltage level, but the distance (a straight line) between them exceeds some predetermined 'practice-oriented marginal value', a postage stamp for the next higher voltage level is to be paid and if the distance exceeds even the next 'practice-oriented marginal value', a postage stamp of the next higher voltage is to be paid. Although the agreement does not justify this principle, it seems intended to reflect underlying voltage transformations and thereby use of different network ranges, which might take place if the distance gets larger.

No doubt this structure has its advantages, but its has severe drawbacks as well:[17]

1. Only the structure is set out, not the level of the charges. And even with respect to the structure, the firms are left with (too) much room to manipulate charges.
2. The distance-related price has been criticized as being anti-competitive. Clearly, it disadvantages more distant suppliers as compared to the incumbent supplier, and thus creates an artificial competitive advantage for the generation department of the network owner.
3. It is entirely unclear where the level of the distance price (12 DM/kW/100km) comes from. There is no justification at all.
4. Although the association agreement says that the charges should reflect underlying costs, it is entirely unclear how this is achieved.
5. There is dependence on capacity claims (in kW) of all components.

The problem is that the transmission network is made up of several different owners, each having several network ranges, whereas the access charge is constructed as if there would be only one owner. The contract's postage stamp for the transmission network-ranges depends on the annual fixed costs of the network range of the point of injection and the network range of the point of delivery. It is independent of the fixed costs of the network ranges in between.

If a contract uses four network ranges, it pays for only two with its postage stamp; only the distance-related price is paid for the other two. To recover total fixed costs, the postage stamp of the network ranges of the points of injection and delivery should actually include the fixed costs of the network ranges in between. It is difficult to see how this works, except by extreme pooling. The obvious alternative is that each and every network owner charges a postage stamp, although this would result in 'pancaking', which would introduce yet another distance-related component. This type of problem is quite similar to the issues concerning pan-European transmission charges.

The fifth problem actually involves two issues. The first is a severe possibility of double-counting. Suppose there is only one network and suppose there is only a postage stamp as calculated above. The calculation of the contract capacity price rests on the claimed maximum capacity irrespective of the moment in which this takes place. Then, the network owner would exactly achieve cost-recovery if and only if all maximum capacity claims are simultaneous. If they are not, double-counting starts. The agreement is aware of this, and notes that the postage stamps will be corrected for *simultaneity-factors*. This is actually a rather complicated estimation of the expected value of the contract's capacity claim in the system's peak-load. It works with aggregated data, averages and experience values.[18] It goes without saying that this will be hard to control, since only the network owner has the information of aggregated data. This traditional engineering approach may have worked well in the former monopolistic setting, but does not seem suited for an open market.

Second, the reliance on capacity claims as the main basis for charging creates a bias in favour of long-term contracts. Given the capacity claim of a third party contract, the costs per kWh are minimized by having a constant flow during the entire year; given the capacity claim, the access charge is actually fixed costs for the user. Average access charges are then minimized by maximizing the quantity in kWhs.

Again, the association agreement is aware of this, and notes that special arrangements are to be made for short-term transactions, leaving it completely to negotiations.[19] There are signals that average short-term access charges tend to be higher than long-term charges.[20] This need not be an antitrust concern, although one hardly feels at ease, but a more important implication is that it seriously hinders the flexible development of a spot market, in whatever form. A related problem arises with the contract-path principle. In a real spot market, where the transactions may be largely virtual, determining a fictional contract path seems, if at all possible, unnecessarily artificial.

As an overall assessment, the association agreement leaves the impression that it reflects status-quo thinking: it will work as long as third party contracts are an exception rather than the rule. In other words, it will work for the industry structure as it was on 29 April 1998; it is likely to be highly problematic for a strongly liberalized and competitive environment, in which third party contracts are the rule rather than an exception.

8.2.3 Regulation

Sector-specific regulation is limited. Access charges are based on negotiations and although the structure stands, the specific level of the charges is left open.[21]

Through determination of the annual capacity price, the network operators can practically charge whatever they wish. The only regulation of the access charges is by international comparison and subsequent public pressure in case the charges turn out to be unreasonably high. The nTPA provision prescribes some information disclosure in that average values should be made public. Access charges under the single buyer provision must be published and need to be approved by the state authorities.

Concession fees are still to be paid to the communities and still based on the KAV, which determines maximum fees in Pf/kWh. There is a small problem here since it has not been arranged who exactly must pay the concession fee. This points to a deeper problem: the government seems to have forgotten that there may be competition in retail.[22] The entire structure of the EnWG and associated discussions centre on the vertical distinction: generation, transmission and distribution. Yet, the latter can and should be further subdivided into distribution-infrastructure and distribution-retail.

Since no constraints are placed on eligibility of end-users, this is clearly intended by the law and sooner or later, retail competition may very well take place. The formulation in the EnWG and the KAV suggests status-quo thinking: it is unambiguous if the distribution network and retail are one and the same firm. If they are not, however, the formulation gets ambiguous. The concession fees issue is only a minor detail, which no doubt can be satisfactorily settled, but it strongly suggests that the possibility – or rather inevitability – of retail competition is neglected. This impression is strengthened by other issues.

End-user tariffs for small customers are regulated by the BTOElt, but while the decree is there, it is unclear what it implies in practice. The BTOElt essentially makes two arrangements. First, it sets a general frame for the structure of the end-user tariffs. The structure allows multipart pricing and differentiated pricing between consumer groups. The consumer groups are households, commerce and agriculture. Prescribing the tariff structure has no doubt served its purpose in the past, but in a competitive environment, it is outdated and may even be harmful. The price system may not be able to react properly to signals from the market. If it turns out that this would be the proper price structure, the market will tell. It may be strongly recommended simply to skip this part of the BTOElt. As far as this conflicts with social and political goals, there are other instruments that may serve these objectives better.

The second arrangement is regulation of the price level, that is, approval of price ceilings. The BTOElt is not specific on this issue: it states that prices must reflect costs. This is indeed the very basis for regulating the end-user tariffs. Translated, this means that a few hands in state economics departments monitor and approve the proposals of the firms. The potential problems are numerous:

1. The regulators seem to have no independence. There are no institutions separate from economics departments with a clearly specified task and responsibility. Responsibility lies with the higher state politicians and these are to some extent involved in the management or supervision of the electricity firms.
2. Apparently even the regulators encounter severe difficulty in acquiring the information needed to monitor prices and their relation to costs.

3. Even if the regulators have some information available, the public does not. The approval of tariffs may be justified by the regulator, but the justification is not public. This makes it extremely difficult if not entirely impossible to control the regulator. The public simply has to believe that the electricity prices reflect costs; informed commentators seem to be quite sceptical.

As a defence, it may be argued that the system is outdated. Should competition at the retail level evolve, then there will be no need to regulate the end-user tariffs. It suffices to regulate the bottlenecks in the transmission and distribution networks. It may be recommended to install a nation-wide independent, sector-specific regulator, which concentrates on the networks. The preferred type of regulation may be price-cap regulation, because it can be clearly specified, is relatively transparent and leaves the tariff structure largely the regulated firm. If access to the networks is guaranteed and access charges are regulated properly, competitive pressure is likely to secure competitive prices in generation and retail. Remaining transitory problems can then be handled by antitrust agencies.

There is one other regulatory instrument: clause 19(1) of the competition law prohibits abuse of market power. Charging excessive prices qualifies explicitly as abuse of market power. The federal antitrust agency is well aware of the potential of the networks and seems prepared to use the provision against abuse of market power. It is not authorized to act against tariffs, which have already been approved by the state regulators, but since the transmission access charges need not be approved by the state regulators, the antitrust agencies can act against excessive access charges.

From the perspective of the vertically integrated network operators, a tension arises. If they were completely free to charge whatever they wish and could exhaustively charge monopoly prices, they would do so and they would not have an incentive to discriminate against third parties. If, as under the competition law, they are not free to charge monopoly prices, they have an incentive to monopolize complementary stages (generation and/or retail) by foreclosing these markets. Then, however, they would violate the essential facilities doctrine of the competition law, because in order to foreclose the complementary markets, they would have to refuse access to the networks. These two parts of the competition law will be the major instruments with which the federal antitrust agency seeks to secure competition in the German ESI.

8.2.4 Separate accounts

As noted above, it seems to have slipped the attention of legislators that competition at the retail level may develop. There is another indication for this: a well known regulatory instrument is to prescribe separate accounts. If a regulator or the public should control whether prices for the bottleneck are reflecting costs and are not discriminatory, then they should have information about the costs. Therefore, the books of the integrated firm should be kept separately for competitive parts and for monopolistic parts.

In accordance with the Directive, the EnWG prescribes separate accounting for the four stages of generation, transmission, distribution and extra-electrical activities. It does not, however, mention separate accounts for the distribution networks versus retail activities. Since in Germany, all end-users are eligible, retail competition is possible and may even be inevitable. It is possible that one day a firm will start offering contracts to smaller end-users, who may then switch their retailer. It follows that the regulatory task of securing non-discriminatory access to the distribution network and control of the access charges will be harder. It follows moreover, that the legislators apparently never took the possibility of retail competition seriously into consideration.

8.3 Early experiences and current debates

The main trading system is bilateral contracting. The contracts aim at the longer term, rather than the short term, an idea that is also reflected in the association agreement on the access charges. The EnWG does not prescribe dispatch or something similar as in a pool system. The network operators are responsible for the dispatch. This seems quite natural, but offers potential for discriminatory behaviour. Technically, a schedule order has to be made in which account can and should be taken of the contracts, but the economic law of contract may not always be feasible technically and priority rules may have to be set. It may be quite hard to control whether one's place in the queue is technically justified or not.

Leaving the details of the daily dispatch to the integrated network operators allows discriminatory behaviour, which may be prohibited (by both the EnWG and the competition law), but will be quite hard to control. An alternative of setting up a compulsory trading arrangement with an independent institution to operate and control the dispatch (as in Spain or the United Kingdom) is politically not feasible in Germany. There are ideas and proposals for power pools in several variations, but these will be mainly financial institutions and it seems out of the question that participation would be compulsory.

The proposals for setting up power pools in Germany are more like the Amsterdam Power Exchange. They are mainly private initiatives, although politicians do seem to show an interest. One serious candidate for setting up such a device is the stock market in Frankfurt. Without doubt, the market in Germany could be sufficiently liquid to allow several trading markets competing among each other. Moreover, an eventual German power exchange will have to face competition from the power exchanges in Amsterdam and Norway. Since it is the philosophy of the EnWG to leave the trading to the market, it is only natural that the government does not interfere in the set-up of such a device (or devices) and rather lets the market evolve. If it is not undertaken by the industry itself, the government may have a task in adjusting the system for the access charges so as to allow a spot market. At present, the association agreement's emphasis is on long-term contracts.

The association agreement calculates some indicative examples with 'fictional' numbers (see Table 8.3).The specific access charge (per kWh) may vary severely. The calculation of 'representative' examples from the association agreement ranges between 1.31–3.19 Pf/kWh. Alternative contract configurations calculated by the Brattle Group (1998) range from 1.20–5.00 Pf/kWh. What is clear is that it

Table 8.3 'Fictional' numbers for the various price components in the access charges

Price component	*Price*
Capacity price (transmission-HV)	35 DM/kW
Capacity price (distribution-HV)	40 DM/kW
Capacity price (distribution – MediumV/LowV)	90 DM/kW
Distance price	12 DM/kW/100km (for distance > 100km)
Simultaneity factor (for 2500 hrs.)	0.7
Transformation	15–35 DM/kW
System services	24 DM/kW

Note: Taken from the association agreement. Price components may apply according to contract specification.

depends strongly on the contract specification. Essentially, the charge for the network rests on claimed capacity, implying that price per kWh increases if the duration of the contract is short. This is somewhat toned down by the simultaneity factor, but does not compensate.

Furthermore, it is expensive to go through different voltage levels. The access charge of around 1.30 Pf/kWh concerns the transmission network only, and no other voltages levels. If on the other hand, transformations to lower levels do take place, which is necessarily the case if (smaller) end-users are supplied by third parties, the average price (Pf/kWh) increases rapidly.[24] The distance-related component is said to be not too relevant empirically but a closer look may question this.[25] For contracts that concern the transmission network only, a distance of 'only' 380 km equalizes the distance-related component with the capacity price (35 DM/kW).

The examples in the association agreement have been compared with real-world values for the EVUs by VIK (1999). It turns out that on average the real world values are similar to the examples of the association agreement, but there is variation between the network providers. Most notably, BEWAG in Berlin is exceptionally expensive with an average of 4.62 Pf/kWh as compared with the total (unweighted) average of 2.91 Pf/kWh. Moreover, this average is relatively high in international comparison. The Brattle Group (1998) suggests that on average the difference with other countries is larger than this.

How regulation of access charges will develop in the future is unclear. While the EnWG was in preparation, the political opposition ('*die Grünen*') pleaded for more state intervention in the bottlenecks of the sector, much inspired by similar organizations in the United Kingdom. One point is regulation of access charges. Shortly after the presentation of the association agreement, an alternative arrangement was presented by an institution called the EnergieForum based in Berlin. Backed up by left-wing political parties at state-level, this alternative aroused attention, but never made it through the political process.

The political climate in Germany, however, changed with the new government elected in September 1998. *Die Grünen* are now part (although a minor one) of the federal government and withdrawal from nuclear power has the highest political attention. At the end of September 1999, the current association agreement ends and, on current expectations, a considerably improved version will take its place. Much will depend on experiences made today, whether this crucial issue gets renewed attention or whether it is felt that it can be left to the industry.

An important indicator is to be expected soon: in mid-1999, several complaints of refusal to give access were being dealt with by the federal antitrust agency in Berlin. Curiously, in five out of six cases, the Berlin-based utility BEWAG has refused access. Its main justification for refusal is capacity constraints. Two complaints stem from RWE and EnBW respectively. This may be interpreted as an indication of willingness to compete. The four dominant EVUs now accuse each other of behaving anti-competitively.[26] Moreover, despite the apparent discriminatory potential of the integrated network operators, the number of requests for access is fairly large. So much so that apparently the network operators cannot handle the number of negotiations and voluntarily decided to offer standardized contracts with published and thereby binding tariffs.

There is a legal issue that has not been entirely settled yet. Before the market was opened up, the trading, arranged by long-term contracts (up to 20 years), was designed from the perspective of closed-service areas. It appears now that the contracts did not foresee the option that the legislative frame would change, allowing choice for the distributors (and of course other customers). What happens at present is that distributors breach their contract with their former monopolistic supplier, arguing that because the legal frame changed substantially, the contracts based on the old legislation no longer hold. On 16 April 1999, a (lower) court in Mannheim decided that these contracts are indeed no longer valid and switching may take place.[27] It is expected that an appeal will follow, forcing a decision by the Supreme Court. Clearly, the legal outcome has severe consequences for the competitive potential of the sector.

Another notable development is that large industrial consumers are rearranging their terms of trade. Whether this is an indication of competitive pressure is not entirely clear. What happens is that large industrial firms, with consumption points all over the country, bundle their contracts to a few or only one supplier. Until recently, they had a separate contract in every service area. Obviously, they save transaction costs by bundling the contracts and it may be suspected that they are offered quantity discounts. In principle, this qualifies as competition: if the large consumers are going to reshuffle and renegotiate their contracts, it may be expected that they will find out the lowest price. Even if they do not actually change their main supplier, it may be expected that they get better conditions.

On the other hand, it is argued that the electricity firms (the network operators) only cooperate on a reciprocal basis among each other. In the reshuffling, the firms lose one customer here and win another there. This is not, however, entirely convincing:

1. It is hard to believe that reshuffling effects would even remotely cancel out.
2. Losing one customer while winning another is actually much what of competition does by definition.

3. There are indications that the price for large end-users has already fallen substantially. VEA (1999) notes a 7.8% decrease in tariffs to large end-users on average (as compared with January 1998). Variation is large, however: in some cases, utilities have decreased prices to large end-users up to 20%.

Not surprisingly, small end-users do not (yet) switch their retailer (except for one or two cases). As found elsewhere, the switching costs for small end-users are relatively high; and it is clear that not much will happen as long as the consumer must search for its alternative retailer, rather than that the retailer searching for the consumer. Retailing firms are beginning to emerge, however, for example, Ampere AG in Berlin, which 'pools' and then represents smaller customers (shops, etc.) in order to get discounts. This is exactly what retail competition is all about. And, a joint venture between VIAG (Bayernwerk) and METRO (a large retailer of domestic appliances) has started a trader/retailer called Euro Power Energy.

As argued above, it seems that retail competition has not been given a very good chance in the EnWG. For the smallest consumers, an unresolved issue concerning retail competition remains: the metering problem. Experience abroad has shown that the time-of-use metering problem can be an obstacle to retail competition. As long as they are prohibitively expensive for small end-users, demand profiling as in the United Kingdom and the Nordic countries may serve as an alternative. Apparently, however, incumbents are preparing an extensive scheme for demand-profiling. This is a positive sign, but it remains to be seen whether its implementation will be non-discriminatory. The regulator (or antitrust agency) should not neglect the issue, because the incumbents obviously have no incentive to find a proper pro-competitive solution. An unsolved metering problem serves as entry barrier at the retail level.

A further important development is the reorganization of the industry. Experiences abroad show that a newly liberalized market gives strong incentives for reorganization of the industry structure, mostly scale-enlargement by mergers and acquisitions. This now seems to be starting in Germany. The first major change was the merger of Badenwerk AG and EVS AG – two EVUs – into EnBW AG, in 1997. It can only be expected that shareholding of the EVUs in other EVUs will be strengthened, causing the classical antitrust dilemma: increased concentration versus increased efficiency.

Much will depend on the transmission network, both within the country and the interconnectors to other countries, and the system of the access charges, whether competition will be hindered by mergers, should they take place. At the distribution level, firms are increasingly cooperating in buying electricity. If they cooperate, they are larger and scale matters in negotiations. Furthermore, there seems to be a tendency for increased vertical integration, replacing long-term contracts by ownership shares. The reason may simply be to reduce transaction costs: a firm's own department is unlikely to breach a contract. Intensified vertical integration, however, also intensifies horizontal concentration at the distribution level.

It is questionable whether the antitrust agency is going to welcome such mergers or takeovers. Interestingly, the antitrust agency prohibited VEBA from increasing its share in the distributor Stadtwerke Bremen; on 22 April 1999, a court in Berlin overruled the antitrust agency, with the argument that the new competitive environment may have increased the relevant market so that the antitrust law no longer applies for the case at hand. It is now up the antitrust agency to show that it does apply. Privatization, if applicable at all, is not a formal issue, but there are signs that an increasing proportion of shares are floated. A notable example is EnBW AG. The largest shareholder, the state of Baden Württemberg, already announced its willingness to sell its shares. A possible buyer is said to be EdF, and RWE and/or VIAG (Bayernwerk) seem to be interested. In the latter case, concentration would increase considerably and it is unlikely the antitrust agency would welcome this.

8.4 Conclusions

The main characteristics of the new Energy Act are: completely free entry at all stages of the ESI, eligibility for all consumers; and an access provision based on nTPA. In addition to the access provision in the EnWG, the recently modified competition law includes an essential facilities doctrine, which aims at enforcing access to the networks. The access charges are largely unregulated and left to the industry to negotiate.

Representatives of the industry have reached an association agreement, which sets out the basic structure of the access charges. The level of the charges is, however, left to negotiations. The association agreement has been criticized, especially with respect to the distance-related component, which would give incumbent generators that are simultaneously the network owners an unjustified competitive advantage. The access charges are high by international standards and show substantial variation in several respects.

The future of the association agreement is unclear. It ended formally in September 1999, and something else should take its place. Apart from the fact that representatives have already announced that the distance-related component will be taken out, however, it is open how a new arrangement will look. End-user tariffs for small end-users are formally regulated, but in practice this may mean close to nothing.

In this chapter, it is recommended that a national sector-specific regulator be installed to concentrate on access charges, while the remaining antitrust problems in generation and retail are left to the antitrust agencies. Currently, the antitrust agency concentrates on anti-competitive behaviour, but this may be at the expense of excessive profits for the networks, which are in principle unregulated. Since all consumers are eligible, the government should be aware that retail competition is a phenomenon that cannot and should not be neglected as it is at present.

Whether liberalization of the German ESI works is something of a paradox. There are movements and indications in both directions. Distributors and large consumers are renegotiating their terms of trade and switching their supplier. Prices for large end-users have dropped on average by 8% already. On the one hand, there are cases that strongly suggest anti-competitive behaviour, while on the other hand, something seems to have been set into motion that cannot be stopped.

Notes

1 The author of this chapter, Gert Brunekreeft, would like to thank Jens Perner and Christoph Riechmann for useful discussions.
2 *EnergieWirtschaftsGesetz* (EnWG), BGBl. 1998, Teil I, Nr. 23.
3 The 1957 competition law is called *Gesetz gegen Wettbewerbsbeschränkungen* (*GWB*).
4 Until recently there were nine, but in 1997, Badenwerk and EVS merged into EnBW.
5 See IEA (1997b), p. 100–1; Kumkar and Neu (1997), p. 23; Drillisch and Riechmann (1998), p. 76; VEA (1999); Wirths (1998).
6 Except EnBW which sold its shares to the joint holding.
7 More extensive information is in Drasdo et al. (1998), pp. 467; various Annual Reports; and Commerzbank (1997).
8 See Perner and Riechmann (1998b).
9 A joint venture of RWE and VEBA, until recently, owned 'OtelO'; EnBW (with SwissCom) owns 'Tesion'; and VIAG owns 'VIAG InterKom'.
10 Currently constrained to the year 2005.
11 Which corresponds to approximately 3 billion DM.
12 For off-peak demand 1.20 Pf/kWh, and for peak demand from 2.60 Pf/kWh for small towns to 4.69 Pf/kWh for large cities.
13 This is reminiscent of the case of France (see Chapter 10 of this Report).
14 The three parties are: Bundesverband der Deutschen Industrie (BDI), Verband der Industriellen Energie- und Kraftwirtschaft (VIK) and Vereinigung Deutscher Elektrizitätswerke (VDEW).
15 *Jahresleistungspreis*.
16 The time need not coincide with the *system's* maximum load.
17 See Perner and Riechmann (1998a).
18 Moreover, it results in an energy price component (DM/kWh).
19 Preussen Elektra already responded by offering optional tariff structures.
20 Although in principle, access charges are determined for *every* contract, a third party supplier can bundle to some extent through the simultaneity factor.
21 In practice, details of the structure may change as well.
22 See Brunekreeft (1998), for more extensive discussion.
23 See Brunekreeft (1997), for more thorough and more general discussion.
24 An example calculated on the website of VEW gives the following values, which may serve as a rough indication. A household (9 kW; 544 h; 50 km) would pay something like 12 Pf/kWh. Whereas an industrial user (3600 kW; 4400 h; 100 km) would pay 4.36 Pf/kWh. If applicable, the costs include distribution and ancillary services.
25 This is the main reason why the federal antitrust agency approved the agreement.
26 BEWAG is partly owned by Preussen Elektra and Bayernwerk.
27 The parties concerned are EnBW and Stadt Waldshut-Tiengen.

9 Regulatory Reform in the Spanish Electricity Industry: Same As It Ever Was?[1]

The Spanish electricity market is surprisingly small. In terms of consumption per capita, Spain is in 13th position in the EU with a little less than 4000 kWh in 1997.[2] This amounts to total consumption of 162 071 GWh, making Spain the fifth largest market in the EU. Industry typically accounts for 50% of total demand, households for 25%, and transport, agriculture and commercial uses for the remaining 25%. Although small, the Spanish market is home to some of the largest electricity companies in the world.[3] What is more, these companies have been active in foreign electricity markets, primarily through acquisitions and joint ventures in Latin America.

The Spanish electricity industry is characterized by a large generation capacity. Total installed capacity is about 44 GW and the maximum observed load is 27.4 GW, yielding a maximum load factor of less than 0.7. Spain has a well developed transmission network formed by 14 070 km of 400 kV lines, 15 711 km of 220 kV lines, 567 400 kV substations and 1 522 220 kV substations (see Mielgo, 1997).

Linkages to neighbouring countries are minimal. The transmission capacity is 3270 MW with France; 3740 MW with Portugal; and 700 MW with Morocco. Moreover, for 'security reasons', the effective use of these links has been capped at 700 MW, 1000 MW and 300 MW respectively. In 1995, international exchanges of electrical power led to net imports of 5547 GWh from France and net exports of 914 GWh to Portugal, 1.28 GWh to Andorra and 28 GWh to Switzerland.

From the early 1980s until 1 January 1998, the Spanish electricity industry was subject to a comprehensive set of regulations, which was eventually consolidated into the 1987 regime known as the Marco Legal Estable (MLE). The process of regulatory reform began in 1994 with the elaboration of the 'Ley de Ordenacion del Sector Electrico National' (LOSEN) by the socialist government. Since the application directives for this law were never written, however, the era of increased competition effectively began on 1 January 1998, when the 'Ley del Sistema Electrico', designed by the Conservative Partido Popular (PP) government, came into force.

9.1 Evolution of market structure and ownership

The Spanish electricity industry is characterized by a high degree of horizontal concentration in generation, as well as a high degree of vertical integration between generation, distribution and retailing. For most of the period of the MLE, electricity generation was in the hands of 11 companies. One of them, Endesa, was publicly owned and operated only in generation. The other ten, mostly private, companies were all vertically integrated into distribution through the ownership of various local monopoly franchises.

Generation activities have become more concentrated over time. The percentage of total production accounted for by the two largest firms, Endesa and Iberdrola, went from about 36% in the early 1980s to 46% in 1990 and almost 60% in 1995. Moreover, since Enher, ERZ, Hidruya and Viesgo were controlled by Endesa, the total production accounted for by the two largest entities was almost 65%.

In 1995, as part of its plans to liberalize the industry, the PP government decided to privatize Endesa completely. Privatization could have been used to break up the firm into a number of smaller competitors in order to increase competition in the future liberalized market. Instead, the government opted for 'strengthening' Endesa prior to the sale by allowing it to acquire both Sevillana and Fecsa. As Table 9.1 shows, this consolidation gave the new Endesa group a market share of 51%, increasing the share of the two dominant entities to 78.5%. It seems fair to characterize this market structure as a duopoly with a fringe. This suggests that in the absence of significant entry into generation, the liberalization of the market for power is unlikely to yield prices that are close to competitive levels.

Table 9.1 Market shares in generation and distribution, 1995

Main independent companies	*Companies controlled by Endesa*	*Market shares in generation*	*Market shares in distribution*	*Public ownership (%)*
Iberdrola		27.6	38	0.0
Union Fenosa		12.9	15	9.9 (I/E)
Cantabrico		5.6	5	0.0
Endesa		31.2	0	66.89
	Enher	1.6	7	91.4 (I/E)
	Others in old Endesa group	4.4	8	60–100 (I/E)
Old Endesa group		37.2	15	
	Sevillana (CSE)	7.2	14	
	Fecsa	6.5	11	
New Endesa group		50.9	40	

Notes:

Based on 'Informe sobre las Consecuencias que las diferentes formas de venta de las participaciones del estado en las empresas electricas pueden tener en el precio de la energia electrica en Espana en los proximos anos', CNSE (June, 1996).

(I/E) means indirect control through the holdings of Endesa. Generation shares do not add up to 100 because of auto-production.

The consolidation of the Endesa group also resulted in greater concentration in distribution and an increased degree of vertical integration between generation and distribution. Since the 'Ley del Sistema Electrico' maintains the organization of distribution as a series of regulated local monopoly franchises, increased concentration in distribution does not directly enhance the market power of the firms involved. Still, it can limit the efficiency of possible 'yardstick' regulation.

Vertical integration between generation and distribution is a concern for two reasons:

1. Until 31 December 2000, incumbent firms are only required to have accounting separation between the two types of activities. Such separation is purely cosmetic as it does not prevent integrated firms from coordinating the decisions relating to the two activities. In contrast, legal separation of generation and distribution activities is immediately required of newcomers to the industry.
2. As discussed in Sections 9.3 and 9.4 below, vertical integration is likely to affect bidding behaviour in the newly designed markets for electrical power.

Since 1985, the majority of the high-tension transmission lines has been owned by Red Electrica de España (REE), a publicly controlled company that was also assigned the role of managing the national grid. As Table 9.2 shows, however, other companies do own substantial shares of the network, especially at the 220 kV level. Still, 98% of total capacity is connected to the network of REE.

The new law only changes this ownership structure by turning REE into a privately owned company and creating the figure of the 'system operator' entrusted with the physical management of the national grid. The law also initially leaves the function of system operator in the hands of REE. Although this activity was supposed to be spun off as a separate private company after 1 July 1998, this separation has not yet occurred. The state retains a 25% share in REE. There are limits to private ownership in both REE and the newly formed system operator. No single agent can own more than 10% of its capital and the cumulative share of agents that participate in the electricity markets cannot exceed 40%.

Table 9.2 Transmission lines and substations, 1996

Company	*400 kV lines*	*220 kV lines*	***Total lines***	*400 kV substations*	*220 kV substations*	***Total substations***
Red Electrica	13 823	4 315	**18 138**	446	174	**620**
Endesa	18	5 267	**5 285**	45	657	**702**
Iberdrola	229	4 609	**4 838**	70	496	**566**
Fenosa	0	1 380	**1 380**	5	174	**179**
Cantabrico	0	140	140	1	21	**22**
Total	14 070	15 711	**29 781**	567	1522	**2089**

Source: Mielgo-Alvarez (1997)

The remuneration of the market operator and of the various owners of the transmission system remains regulated. As in the era of the MLE, these compensations are based on an estimate of recognizable costs updated according to a RPI-X formula. Although the precise procedure to be used has not yet been specified, it is worth noting that the fact that the transmission grid is in the hands of several firms makes it possible to use some form of yardstick competition.

9.2 Investment decisions

During the years of the MLE, investment decisions were taken in a 'consensual' manner by the Ministry of Industry and Energy and industry participants. Investment needs were typically spelled out in a five year 'Energy Plan' elaborated by the government after broad consultations with the electricity companies. Investments in generation were then allocated among incumbents through a negotiation process; investments in distribution were made by the owner of the local franchise; and investments related to the transmission network went through the public procurement process.

Over the last 15 years, a large proportion of the system's investments went into generation and the transmission network, at the expense of distribution. This has led to significant differences in the reliability of the different activities: for example, distribution lines account for more than 85% of breakdowns.

Under the new law, entry into generation is only subject to administrative licensing. Any firm that can demonstrate the necessary expertise and financial backing can build a new power plant provided that it meets national and regional criteria for safety and environmental friendliness. This does not necessarily mean that there is 'free entry' into the sector. The criteria for administrative approval of new generation capacity are vague enough to ensure quite a margin of manoeuvre for the government. Indeed, one of the first decisions of the Ministry under the new law was to 'freeze' the administrative review of new generation projects. Given the history of governmental intervention in the sector and the continued closeness between government and incumbents (see Section 9.5 below), it remains possible that entry into generation will continue to be controlled rather tightly.

Investment in the distribution and transmission networks will continue to be determined by the government after consultation with the companies involved. Additions and improvements to the transmission network will be adjudicated through 'tendering'. As before, investment in distribution will simply be assigned to the relevant distribution company.

9.3 Pricing mechanisms

Under the MLE, generation and distribution activities were rewarded according to a complex mechanism that essentially amounted to a price cap without any systematic adjustments for productivity gains (that is, RPI-0).[4] The government and the electricity companies occasionally negotiated tariff adjustments, however:

these led to a 16.2% decrease in electricity prices in real terms between 1988 and 1998. As this regime left most of the benefits from productivity improvements with the firms, it led to significant increases in efficiency as well as considerable improvements in the financial health of the electricity companies.

Increased efficiency is illustrated by the reduction in the average time of interruption of installed capacity, which fell from an average of 9.6 hours a year in 1987 to 3.36 hours a year in 1996.[5] The improving financial stability of the sector is reflected in the level of outstanding debt of the sector, which went from 3151 billion pesetas in 1983 to 2565 billion pesetas (not adjusted for inflation) in 1996 in spite of important investment programmes. With a debt to own funds ratio of 1.356:1, Spain was in the middle range of EU countries at the end of 1995.

In the spirit of the EU's Electricity Directive, the new 'Ley del Sistema Electrico' establishes the progressive liberalization of retailing. Under the current rules, all industrial consumers with yearly consumption at or above 5 GWh are already eligible, while consumers with yearly consumption between 1–5 GWh, representing 42% of total consumption, will become eligible on 1 October 1999. All consumers will become eligible by the year 2007 at the latest. This is significantly faster than the minimum imposed by the Directive.

The status of eligible customer is also granted to distribution companies and to any retailer that sells to eligible customers. Non-eligible consumers continue to pay a regulated price set in a yearly tariff. Eligible consumers have the (non-exclusive) choice between meeting their needs at the tariff rate or through the deregulated market.

9.3.1 The wholesale market

Under the new regime, the wholesale price of electrical power is set freely through the interaction of a number of markets and contracting possibilities. The new law explicitly authorizes the creation of (possibly several) spot markets, future markets, a market for reserve capacity, a market for auxiliary services and a market for transmission constraints. A notable feature of the Spanish system is that the spot and future markets are supposed to accommodate active bidding on both the supply and demand sides. In addition, suppliers and eligible customers can sign (financial or physical) binding bilateral contracts. Direct exclusive transmission links not connected to the national transmission network can also be built.

The set of markets that currently operates is somewhat more limited. It includes:

- *The daily market*: this deals with sales and purchases of power for *each hour of the following day*. It opened on 1 January 1998 and is operated by the Compaña Operadora del Mercado Español de Eléctricidad SA, a private company.[6] The supply side consists of private generation companies, which must submit a bid for every generation unit of at least 50 MW, specifying quantities and prices at which they are offered. Minimum revenue requirements, indivisibilities and programmed unavailabilities can also be included in the bids. On the demand side, the market is accessible to distribution companies, retailing companies and eligible consumers. These agents can only make simple offers specifying prices and quantities.[7] All transactions are billed at the marginal wholesale price of electrical power and the corresponding quantities exchanged are determined by the intersection of the supply and demand schedule resulting from the bids.

- *The intraday market*: this deals with the additional quantities required to adjust supply and demand. It started on 1 April 1998 with just two daily sessions, has now moved to five daily sessions and plans eventually to introduce up to 24 sessions. This market was operated by REE until 1 July 1998, when it was replaced by the market operator. The agents in this market are generators and buyers that have decided to produce or purchase more or less than what they contracted for in the daily market. Contrary to the rules of the daily market, both demand and supply bids can incorporate clauses such as minimum revenue/maximum payment requirements, maximum total energy or minimum number of hours contracted.
- *Markets for complementary services* opened on 1 January 1998. Generators enter bids for the supply of services for 'secondary' and 'tertiary' regulation of the system. Secondary regulation services involve the supply of power bands of reserve used to maintain the stability of the system in real time. The market establishes marginal prices for the supply of power bands as well as for the increases or decreases in the amount of energy actually supplied. Tertiary regulation deals with reserves that can be made available within 15 minutes and cannot be used for more than two hours. Again, the market determines a marginal price for energy increases as well as a marginal price for energy withdrawals. The costs of complementary services are met by the purchasing agents in proportion to the quantities acquired in the daily market during the hours when those services are used.

To date, there are no futures markets, but sellers and buyers can of course sign whatever bilateral financial contracts they want. Transmission constraints are handled directly by the system operator in consultation with the market operator. The addition or withdrawal of units to remove technical constraints must follow the ranking of bids made in the daily market. Generation units that must be added to the dispatch plan are compensated at the value of their bid on the daily market, while units that must be withdrawn still get the corresponding hourly marginal daily market price. The resolution in real time of discrepancies between demand and supply is the responsibility of the system operator, who must use the complementary services contracted in the order of their bids. Agents that deviate from their contractual commitments are penalized.

Generators also receive a capacity payment of 1.3 pesetas/kWh. This payment applies to the generation units that are available during the hours of peak demand. This cost is paid by the agents on the demand side of the market in proportion to the value of the energy acquired during the same peak hours.

9.3.2 Regulated prices

The final price of electricity for smaller consumers will continue to be regulated, although the new law does not specify how tariffs are to be set and how the distributors will be compensated. Eligible consumers also retain the right to be served at their corresponding regulated tariff rates.

The tariff remains uniform over the whole territory for any given class of power contracted and type of use. The public service obligation to supply electricity to 'satisfy all consumers needs' rests with distribution companies. The reference point for the determination of the tariff is an estimated average price for the acquisition of electrical power on the wholesale market. The reference point chosen for 1998 was 4.55 pesetas/kWh. Once expected charges for constraint management and auxiliary services were added, the expected gross wholesale price was 6 pesetas/kWh.[8] The tariff was then designed so that, based on demand forecasts, the recognized costs of the distribution and transmission companies and other 'system costs' would be covered.[9,10] The distribution of recognized costs for 1998 was 92 776 million pesetas for transmission (to be revised according to RPI-1), 380 261 million pesetas for distribution (RPI-1) and 75 176 million pesetas for retailing costs incurred by distribution companies.[11]

The process according to which the effective revenues should be distributed among participating companies has still not been officially determined. For 1998, the electricity companies and the government agreed that revenues should be shared essentially in proportion to the old 'standard costs' recognized for each company under the MLE. There was also no word of whether there would be any *ex post* adjustment to take into account the discrepancy between the estimated average gross wholesale price of 6 pesetas/kWh and the actual average gross wholesale price.

This cost-based procedure is also the basis for the determination of access prices to the transmission and distribution networks. In order to avoid an uneven spread of transmission and distribution costs between eligible and non-eligible customers, access charges to the transmission and distribution networks were set so as to reflect the same share of transmission and distribution costs as the one attributed by the tariff for the same type of consumption. Hence, access charges vary according to the total amount of power delivered to the consumer and by the type of use of this power. Since eligible consumers can choose to be served at the tariff rate, this system creates a knife-edge in the sense that a seller can only make an attractive offer if the actual gross wholesale price of electricity is below 6 pesetas/kWh and/or if its costs of retailing are lower than those built into the tariff. If, for example, the estimate of retailing costs used in the tariff are correct, then the scheme essentially imposes a cap of 6 pesetas/kWh on the gross wholesale price of electricity.

This procedure raises two important questions:

- First, how is the 'expected' average gross wholesale price determined? If experience under the MLE is any guide, discrepancies between expectations and outcomes are likely to be resolved through adjustments in the following years. Hence, it can be reasonably expected that the estimated wholesale price will be linked systematically to past wholesale prices. Unfortunately, such a link gives an incentive to manipulate the wholesale price. If the generating firms set that price higher than they would in a purely myopic one-period context, it is likely that the 'expected' wholesale price for the following year will be revised upward, leading to higher tariff rates. This provides two benefits for the generating firms: first, it increases revenues from non-eligible consumers; second, it enables the firms to set higher prices to eligible consumers without fearing that they will choose to be served at tariff rates.

- Second, the method of distribution of tariff revenues between distribution companies might be important given the continuing vertical integration between generation and distribution.[12] For example, a method that would tie the share of distribution revenues allocated to a vertically integrated firm to the amount of energy actually transported on its network might put independent companies at a disadvantage. For such companies, access charges to the distribution network would be an integral part of the marginal cost of serving the corresponding customer. For an integrated company, however, the contribution to marginal cost would only be equal to the access charge minus the share of this charge accruing to its own distribution company as additional volume-based revenues.

9.3.3 Evaluation

It is still too early for a thorough appraisal of the performance of the new liberalized system. Still, at a basic level, the system has been a success: in spite of a very short planning period and a rather ambitious market design, the daily and intraday markets have worked without any major incident and, importantly, without any physical disruption of supply.

Nevertheless, the regulatory agency and market participants have complained about a certain lack of transparency of the system as well as inadequate monitoring of participants' behaviour.[13] For example, as of May 1998, nobody seemed quite sure which of the numerous versions of the rules of operation of the electricity markets was supposed to be applied. Moreover, these rules were not easily available to agents not currently operating in the Spanish market.[14]

At the same time, generation companies still did not know the price at which energy supplied for secondary regulation since 1 January would be paid, forcing them to make decisions without knowing what the relative compensation of alternative uses of their capacity was likely to be. Transparency concerns also arose from the rules about the confidentiality of information given to the operators by market participants. Not only were the criteria used to determine which information would be treated as confidential unclear, but some 'confidentiality' was apparently used to withdraw information from outsiders that was routinely available to all current market participants.

Finally, the system apparently lacks adequate measurements of effective energy flows, especially on the demand side. One consequence of this lack of monitoring has been that the cost of dealing with unreported real-time deviations from contracted sales and purchases has had to be spread over all agents, whether or not they bore any responsibility for the deviation. As the regulatory agency pointed out, this procedure creates perverse incentives by penalizing the agents that either duly report their real-time deviations or use the intraday market sessions to manage their changes of plans efficiently.[15]

Table 9.3 Components of the average gross wholesale price, 1998

Components	*Pesetas per kWh*	*% of wholesale price*
Daily market price	4.266	73.4
Technical constraints	0.041	0.7
Technical operation of the system and auxiliary services	0.237	4.1
Intraday market	–0.008	–0.1
Capacity payments	1.274	21.9
Total	5.810	100.0

Reliable price and volume data are only available for the first year of operation. From 1 January 1998 to 31 December 1998, the total power exchanged on the daily market was 154 455 GWh with a high of 14 455 GWh in December and a low of 11 814 GWh in May. The average gross wholesale price of electrical power was 5.81 pesetas/kWh. This price is broken down into its components in Table 9.3.

The costs of running the system and dealing with transmission constraints account for less than 5% of the gross wholesale price. This is a sign that the procedures and markets designed to handle constraints and balance the system have worked quite well in spite of the presence of severe constraints during the peak tourism season of the summer. On the other hand, capacity payments account for more than 20% of the total wholesale price. Given that the Spanish system has a high capacity to peak demand ratio, this suggests that the system of compensation for reserve capacity might currently be too generous.

During 1998, 36.9% of supply came from nuclear plants, 37.44% from coal plants, 2.62% from gas plants, 20.03% from hydro power and 2.97% from imports.[16] There were significant monthly variations in these shares, however, linked to the changing levels of water reserves: hydro power was significantly more important in the first half of the year while fossil fuel plants dominated the second half of the year. The marginal price was generally set by coal plants in off-peak hours but by hydro units during peak hours. Since bids are not yet publicly available, however, it is not certain which companies were usually involved in setting the marginal price.

The joint share of Iberdrola and the Endesa group in the daily market was about 80% in both sales and purchases. The capacity which was contracted with EdF (550 MWh each hour) was used to its maximum for almost all of the period. On the demand side, we know that direct purchases by registered retailing agents and eligible consumers accounted for 3.12% of the total energy exchanged. Unfortunately, we do not know what proportion of the sales to the distributors were ultimately used to serve eligible consumers.

The intraday market only started on 1 April 1998. The total energy exchanged during that month was 191 GWh over two daily sessions. This amount steadily rose to reach 865 GWh over five daily sessions in December. A striking feature of this market has been the dominance of generation companies, which accounted for 95% of the energy exchanged. A possible explanation for this asymmetry is that agents on the demand side find it harder to forecast the differences between quantities contracted and needed. There are two reasons for this:

1. The industry is still in the process of perfecting metering equipment on the demand side.
2. Demand is intrinsically harder to forecast than the conditions of supply so that the firms might only be aware of significant discrepancies quite close to real time.

These two factors suggest that demand side participation in the market should increase as metering is improved and the number of sessions of the market increase.

Table 9.4 shows the evolution of the average marginal price on the daily and intraday markets. The consistent positive difference between the two prices is somewhat puzzling. One possible explanation is that this discrepancy corresponds to arbitrage possibilities that market agents have so far not been nimble enough to exploit fully. In that sense, the fact that the difference decreases sharply at the end of the period would suggest that agents are finally learning.[17]

The effect of the new market design on the intensity of competition in the liberalized segment of the industry is hard to assess given the lack of any systematic information on final prices paid by eligible consumers and on the evolution of market shares in this segment of the market. Nevertheless, the scant information that is available suggests that competition in the spot market has not been fierce, but that competition to sign financial contracts with eligible customers has been significant.

Table 9.4 Average marginal prices in daily and intraday markets (Pesetas per kWh)

Month	*Daily market*	*Intraday market*	*Difference*
January	4.363	–	–
February	3.952	–	–
March	4.220	–	–
April	4.282	2.828	1.554
May	3.682	2.575	1.107
June	3.673	2.413	1.260
July	4.329	2.926	1.403
August	4.561	3.013	1.548
September	4.017	3.399	0.618
October	4.150	3.116	1.034
November	4.688	3.837	0.851
December	4.091	4.066	0.025

The first piece of evidence is the average level of the marginal price observed in the daily market. A natural benchmark for comparison is the level of 4.55 peseta/kWh that was chosen as the energy-acquisition component of the tariff for non-eligible consumers. Although this figure is presented as an 'estimate' of the average marginal price in the daily market, it appears to have been set to guarantee generators a total compensation close to what they obtained under the MLE. Since the actual average marginal market price was about 4.3 pesetas/kWh, it can be inferred that the new pricing mechanism led to a price decrease of about 6%. This modest performance is not too surprising for two reasons:

1. Endesa and Iberdrola clearly have significant market power in the market.
2. As a result of vertical integration, electricity companies are the dominant bidders on both the supply and demand sides. As the two dominant firms have roughly equal shares in generation and distribution, the price in the spot market is essentially a transfer price between two parts of the same companies. This seriously reduces the competitive role of spot market prices and makes them rather useless as reliable economic signals.

The available information about transactions in the wholesale market suggests that its opening has not led to increased participation. 1998 has neither seen any bilateral physical contracts or any eligible consumer participating directly in the wholesale market;[18] nor has there been any significant intervention of retailing companies that are not affiliated with Endesa, Iberdrola, Hidrocantabrico or Union Fenosa.[19] Accordingly, the total payments for third party access to networks was only 0.04 billion pesetas, or less than 2% of the total tariff revenues.

There is some more precise information about the behaviour of eligible industrial consumers in Cataluña.[20] As of the beginning of 1999, 180 out of 507 eligible companies (35%) had renegotiated their electricity contracts, averaging decreases in the final price between 25–30%. These were financial not physical bilateral contracts. These percentages compare favourably to those observed in England and Wales during the first year of liberalization.[21]

Moreover, there is anecdotal evidence that large electricity companies have been fighting over large accounts: Endesa replaced Iberdrola as the sole supplier of Ford's manufacturing plant in Almussafes, but was forced to grant a deep discount to Seat to avoid losing its contract to Iberdrola. There is also some evidence that independent retailers might eventually move into the market as more than 40 companies, several of them foreign, are registered with the market and system operators. To date, though, the volume of energy handled by these companies has not been significant.

In summary, the tentative picture emerging from the first year of experience is one where competition for contracts has been quite effective, while the spot market has had little economic relevance. Some recent developments are more worrisome. On 28 May 1999, the electricity companies asked the government to increase the tariff rates of large industrial consumers.[22] Since these consumers are eligible, this request can only make sense if the main electricity companies are confident that they will be able to increase both spot market and financial contracts rates above the regulated tariffs. This means that the 20–25% discounts obtained by some large consumers could soon be a thing of the past.

Table 9.5 Net available capacity by fuel type, 1995 (% of total net available capacity)

Fuel type	*New Endesa group*	*Iberdrola*	*Union Fenosa*	*Cantabrico*	*EdF*	*Total*
Fossil fuels	29.2	11.1	6.5	2.7	0.0	49.5
Nuclear	7.8	7.4	1.7	0.4	1.7	19.0
Hydro	11.7	15.7	3.2	0.8	0.0	31.4
Total	48.8	34.2	11.5	3.8	1.7	

9.4 Input markets

Table 9.5 shows the distribution of net generation capacity by type of fuel. Existing generation capacity is dominated by coal and hydro. CCGT plants have not yet made significant inroads into the Spanish market. How fast this is likely to change is uncertain. Although the majority of new plants are expected to be gas-powered, two factors suggest that the speed and extent of gas-based entry are likely to be significantly lower than in the United Kingdom: the first is the existence of large reserve capacity; the second is the possibility that entry into generation might be limited through the process of administrative authorization. As for nuclear, a longstanding ‘nuclear moratorium’ has prevented the development of new projects as well as the completion of partially built power plants. It seems likely that the share of nuclear will decline steadily over the next 10 years.[23]

The imbalance in the fuel structure of the two dominant generation groups is rather striking. While the Endesa group has 60% of its capacity in fossil fuels and only 24% in hydro, these two fuel sources account for respectively 32% and 45% of Iberdrola’s capacity. This suggests that the strategic interactions between the two dominant firms might be somewhat more complex than suggested by standard models of duopoly.[24]

Given the significant reliance on coal-powered plants and the attractiveness of CCGT for new capacity expansion and entry, it is important to describe the Spanish market for these two types of fuel:

- *Coal*: most Spanish coal production comes from economically depressed areas in the north. Reducing the electricity industry’s reliance on coal is therefore a politically sensitive issue. Under the MLE, the electricity companies agreed to use a minimum amount of national coal even though its price is twice as high as the world price. The cost of that policy was passed on to consumers in the form of higher tariffs. Under the new law, the government can subsidize the use of national coal with subsidies of up to 1 peseta/kWh. It also reserves the right to intervene in the normal order of dispatch in order to ensure that sufficient national coal is used. From 2004, this policy will be maintained only up to the point where national coal represents the 15% of total primary energy consumption specified by the Electricity Directive.

- *Gas*: until quite recently, access to natural gas was extremely limited in Spain as most of the supply had to be shipped by special tankers. This situation has improved somewhat with the opening of the Maghrebian pipeline in 1997. There are still significant barriers to new CCGT entry: first, the total supply of gas is still quite limited and faces significant political risk as most of it comes from Algeria (by pipeline) and Libya (by boat). In particular, the Spanish pipeline network is only linked to the rest of the European network by a single, relatively small capacity 'gaseoduct'. Second, the available gas supply is largely in the hands of a single firm, Gas Natural, which controls 85% of total supply. This monopoly power could lead to high prices and, therefore, discourage CCGT-based entry.[25]

The competitive picture is further complicated by two factors. The first is the constantly changing relationship between Gas Natural and the incumbent generators. As recently as 1998, Gas Natural, which is controlled by the large Spanish oil group Repsol, threatened to enter the generation business itself by building several CCGT plants. The response of the electricity companies was to try to integrate backwards into natural gas. Endesa sought international alliances with oil companies and actually acquired 8% of Cepsa, the second Spanish oil group and an affiliate of Elf Aquitaine, while Iberdrola agreed to form a wide-ranging alliance with Repsol. Cepsa also threatened to invest in a second gaseoduct connecting Spain to the European network.[26]

These activities appeared to set the stage for a confrontation between two integrated oil-gas-electricity groups. Spanish business wars, however, often have happy endings. In October 1998, Endesa entered into a strategic alliance with Gas Natural, ensuring that Gas Natural would be the sole supplier for Endesa's planned CCGT plants. This alliance is currently under review by the Spanish competition authority.[27] It is, however, strongly backed by the Ministry of Industry. Finally, on 16 January 1999, Endesa announced that it had acquired 3.64% of Repsol and that it would sell its stake in Cepsa. In spite of this, Repsol claimed that Iberdrola remained its privileged partner for gas-based electricity ventures.[28]

If this were not enough, account must also be taken of the intricate pattern of cross-ownership that permeates the Spanish economy. In this case, the Iberdrola-Repsol alliance is backed by two banks, the BBV and La Caixa; while the BCH bank holds a substantial stake in both Cepsa and Endesa. As Cepsa is not likely to let itself be locked out of supplying the two largest electricity groups, the pattern of alliances and acquisition is likely to keep changing for a while.[29] The overall tendency, however, seems to be towards a 'grand coalition' of gas and electricity incumbents.[30] This does not bode well for the prospects for increased competition through gas-based entry.

The second complicating factor is the liberalization of the natural gas industry imposed by the 'Ley del Sector de Hidrocarburos' of 7 October 1998. The general approach of this law is the same as the one adopted for the electricity sector. Essentially, the retailing of natural gas will be progressively liberalized over a period of 15 years. Currently, eligible consumers are those with an annual consumption of at least 20 million cubic meters, representing 45% of the industrial market. The qualifying limit will be reduced to 15 million in 2000, 5 million in 2003 and 3 million in 2008. All consumers become eligible by 2013.

Gas Natural remains the monopoly owner and operator of the gas transportation network, but it must legally separate these two activities within two years. To that effect, Gas Natural has announced a restructuring of the company: Enagas will become a pure transportation company, which will have to spin off its 'operator of the grid' component; 'Gas Natural Commercialization' will handle retailing; while regional distribution activities will remain managed directly by a holding company. Third party access to the transportation and distribution network will be guaranteed on the basis of access fees set by the newly created National Energy Commission, which will eventually supervise all energy industries, including electricity.

The liberalization of the natural gas industry responds to some previous criticisms of government policy.[31] As with electricity, however, no steps have been taken to reduce the high degree of concentration in the industry: the required separation of activities is likely to be rather ineffective, and the lack of connections to the main European network removes any significant competitive pressure from abroad. It is unlikely therefore that there will be any drastic increase in the competitiveness of the Spanish market for natural gas over the next five years. As a consequence, the lack of competitive access to gas is likely to remain a significant barrier to the entry of new companies into electricity generation.

9.5 Regulatory process and institutions

Spanish electricity markets are currently regulated by the Ministry of Industry and by the Comisión Nacional del Sistema Eléctrico (CNSE), the independent regulator created by the LOSEN in 1994.[32] CNSE is headed by a President and eight council members nominated by the government for a period of six years with half the council members renewed every three years.

The functions of CNSE are merely consultative, as it makes suggestions to the government about the evolution of the sector and helps write the detailed documents required for the applications of Royal Decrees. CNSE also determines responsibilities in case of failure of the system; inspects (at the request of the ministry) the installations of market agents to verify that safety standards are observed; informs the Spanish competition authority of any anti-competitive behaviour in the industry; and can be used as a (voluntary) private law arbitrator by participants in electricity markets. CNSE also has final decision power in conflicts about third party access to networks. All other decisions, including planning, the level and structure and electricity prices and the design of electricity market institutions are in the hands of the government.

The relationships between CNSE and the government have not been good. The latter has systematically ignored the advice of the former on such important issues as the privatization of Endesa, the speed of liberalization or the treatment of stranded costs. The government has also systematically undermined CNSE by publicly questioning its competence and accusing it of 'politicizing' the debate about the liberalization of the industry. On 11 February 1999, the President of CNSE resigned and his resignation was immediately accepted.

The main reason for this history of conflict is the traditional closeness between the Spanish government and industry incumbents. This can be traced back to the beginnings of the MLE. This regime emerged from the government's attempts to rescue the industry from a late-1970s over-investment binge that nearly bankrupted every company in the sector. The overwhelming concern of the MLE was, therefore, to provide a 'stable' environment, where the firms could recover their financial health and where every important decision, such as investments, would be made in a consensual fashion by government and industry.

The ensuing cosiness between government and incumbents remains to this day. Remarkably, the design of the Ley del Sistema Electrico began with the signing of a contract between the government and the electricity companies. Known as the 'Protocolo', this contract indicated not only what the general rules of the new regime would be but also the precise amount of compensation due to the incumbents to 'allow' such liberalization to take place. It should be noted that this contract was signed before any discussion of the law in Parliament and without any consultation with the consumer side of the industry. This tradition has been upheld since the law was passed: every important decision from the operation of the markets to the design of tariffs or the acceleration of liberalization has essentially been taken jointly by the government and industry incumbents with little significant input from any other party. It seems fair to say that the current regulatory regime is one of absolute discretion by a central government that is quite receptive to the arguments of industry incumbents.

Under the 'Ley del Sector de Hidrocarburos', the functions of CNSE will progressively be absorbed by the National Energy Commission, which will jointly oversee all energy sectors. Dishearteningly, the head of this Commission is a former long-time lawyer for Endesa. In contrast with CNSE, which widely publicized its views, the Commission will not be allowed to release any study without prior approval of the government.

9.6 Conclusions

To date, the reform of the Spanish electricity industry receives high marks for style, but falls short on substance and pro-competitive effects. There is a sense that the government and the industry successfully handled the most difficult challenges, but that the government failed to take some simple but essential steps.

On the positive side, the new law was elaborated, passed and applied within a remarkably short period of time: less than two years elapsed between the beginning of government-industry negotiations and the opening of the wholesale market. This success is all the more remarkable given that Spain chose to liberalize supply quickly and designed a set of electricity markets that is one of the most sophisticated in the world. The accompanying liberalization of the natural gas industry adds to this overwhelming feeling of achievement. Neither should it be overlooked that, although the evidence is quite thin, competition to sign up large consumers to financial contracts appears to have led to significant price cuts.

On the negative side, however, the government clearly did not learn from the experiences of countries like England and Wales when it failed to use the privatization of Endesa to reduce market power in generation or when it failed to set up a strong, independent regulatory agency for the sector. These and other shortcomings have led to a beautiful, complex set of markets that has not brought any new entry or any significant increase in competition.[33] One must have some sympathy for the former president of CNSE who recently said 'We can say that we (now) have a well regulated monopoly'.[34]

What are the main elements that shield such 'monopoly' from competition and might help keep Spain isolated from the competitive pressures of an integrated European market? The most significant barrier to entry into Spanish electricity markets has to be the close relationship between the government and incumbents, compounded by the lack of power of the regulatory agency. This closeness discourages entry in two ways:

1. It gives large incumbents tremendous influence on the detailed rules that govern the various electricity markets as well as on the setting of access charges.
2. It results in a system which lacks explicit rules, where many issues are dealt with 'as they arise' through discussions between the government and electricity companies. This creates a lack of transparency apt to discourage outsiders.

Possibly as a consequence of the government-industry nexus, the rules governing the markets are replete with pro-incumbent biases. It suffices to mention the stricter business separation requirements imposed on new entrants, the arbitrary granting of 'transition cost' compensations to incumbents or the more favourable treatment of existing capacity in the remuneration of capacity reserves.[35]

Other barriers to entry can be traced to market structure. While the effect of the high horizontal concentration in generation on entry is ambiguous, the high degree of vertical integration between generation, distribution and retailing (supply) has perverse effects as it allows the two dominant firms to manipulate the wholesale price without having much effect on the overall profitability of their operations. Even though the new law goes further than the Electricity Directive in requiring the (eventual) legal separation of regulated and non-regulated activities, few observers believe that this will prevent the different parts of the resulting holding companies from coordinating their strategies.

Another significant barrier arises from the structure of the market for natural gas, where in spite of the recent liberalization, the dominance of Gas Natural is unlikely to be eroded quickly. This dominance is all the more worrying given the intricate web of agreements between Gas Natural and the dominant electricity companies. In that sense, the decision of the Spanish competition authority about the alliance between Gas Natural and Endesa will strongly affect the possibility of getting access to natural gas on non-discriminatory terms.

The physical isolation of the Iberian peninsula is also a significant factor. The lack of connection to other European grids limits the competitive pressure from exports and the lack of connection to the main European gas transportation network limits the possibility of new entry through the creation of new local CCGT plants.

Finally, it must be asked whether the government is really willing to relinquish its control of the electricity sector. The administrative procedure governing entry into generation is vague enough to leave quite a bit of discretionary power to the government. After two decades of thoroughly controlling the industry, such power might be hard to give away. Recent developments demonstrate that regulation of electricity is still considered as a tool to achieve various broad economic and political objectives: In April 1999, faced with rising inflation, the government decided to lower the electricity tariff by 1.5% more than what had been agreed with the electricity companies.[36]

Notes

1 The author of this chapter Pierre Régibeau would like to thank M. Lasheras for his willingness to answer numerous questions. Any remaining errors as well as the opinions expressed here are clearly not his responsibility nor that of the CNSE. Pierre Régibeau would also like to thank Kai-Uwe Kühn for many helpful discussions.

2 Eurostat, 'Energie: statistiques annuelles, 1994'.

3 In terms of customers, the new Endesa Group and Iberdrola each have more than twice the number of the largest company in England and Wales and are about twice as large as PG&E, the largest US firm in the sector (see CNSE, 1996).

4 A company would essentially receive revenues equal to the sum of the 'standard costs' administratively assigned to each of its generation, transmission or distribution units. Its profits would, therefore, be equal to the difference between these 'recognized' total costs and the actual total costs of the firm.

5 See Rivero (1997). For other measures of efficiency, see Arocena (1996) and Arocena and Rodriguez (1996).

6 No shareholder can own more than 10% of the company's equity and the cumulative share of all agents involved in the wholesale electricity market cannot exceed 40%.

7 From 1 January 1998 to 1 April 1998, the demand side of the market was only opened to distribution companies and pumping stations. Distribution companies were also restricted to presenting only pure quantity (inelastic) bids.

8 1.3 pesetas for reserve capacity and 0.15 pesetas for complementary services.

9 System costs include the budget of the CNSE, the costs of fuel diversification, including the nuclear moratorium, and the compensation of both the market operator and the system operator.

10 A complicating factor is that, in their 1996 negotiations, the government and the electrical companies agreed on minimum rates of decrease in the average tariff of 3% in 1997, 2% in 1998 and 1% in 1999 and 2000. How is this compatible with a procedure for getting prices as the sum of recognized costs and the gross wholesale price? The answer for 1998 is that the agreed tariffs were higher than the sum of the 6 pesetas/kWh imputed to the purchase of energy and the recognized costs of the system. The difference was used as payments to electrical companies for the 'costs of transition to competition'. For 1999, however, the transition costs are supposed to be recovered through a simple pre-set unit tax on electrical power. This means that actual tariffs will have to fall more than 1% and/or that the 'expected' wholesale price will have to be revised upward.

11 For transmission, 51 121 million pesetas for REE and the rest for the other owners of the high-tension grid.

12 Accounting separation is likely to be ineffective and even legal separation might have limited effects since the law still authorizes the reintegration of distribution and generation activities within the same holding companies, which, in Spain, have traditionally been much more than a simple portfolio of assets.

13 See CNSE (1998c).

14 These problems have now been resolved as the rules of the market are available to anyone from the website of the market operator.

15 See 'Informe de la CNSE sobre las liquidaciones del mercado de produccion en el primer semestre de 1998', CNSE, Madrid, 8 September 1998.

16 This does not include the production of 'auto-producers'.

17 Another possibility is that generators with market power are using the sequence of markets to play a multi-stage price/quantity game. The author is not aware of any existing theory that can be used to analyse such a scenario.

18 The quantities assigned to bilateral contracts in the statistics of the market operator essentially refer to exchange of energy with France, Portugal and Morocco.

19 A very small volume of business was done by SKS (Swedish) and Enron.

20 See *La Vanguardia*, 10 February 1999, p. 63.

21 See Chapter 6 of this Report.

22 See *La Vanguardia*, 29 May 1999, p. 70.

23 About a year ago, the Ministry of Industry 'floated' a plan to repeal the nuclear moratorium in order to slow the release of greenhouse gases. The heated reaction that this proposal received suggests that the nuclear policy is not likely to change soon.

24 One could, for example, fear the emergence of 'cycles' whereby Endesa cedes market share to Iberdrola until its hydro capacity is sufficiently depleted to allow Endesa to obtain a large market share at high prices. Still, there is so far no strong evidence of such behaviour although the changes in the market shares of coal and hydro observed over the first four months of operation of the system are worth tracking.

25 Currently, prices are actually the seventh lowest in the world behind the United States, Canada, Australia, Belgium, Finland and the United Kingdom (see *Expansion*, 18 May 1999, pp. 46–7). This is a result of the government's fight against inflation and might have little bearing on what might occur in a non-regulated market.

26 *La Vanguardia*, 15 April 1998, p. 58.

27 *La Vanguardia*, 12 February 1999, p. 70.

28 See *La Vanguardia*, 23 March 1999, p. 69.

29 In fact, Cepsa and the number three generator, Union Fenosa, have recently announced an alliance (see *Expansion*, 3 March 1999).

30 This is confirmed by a last minute development: On 31 May 1999, Iberdrola announced that it would acquire shares in Repsol (*La Vanguardia*, 31 May 1999, p. 55)

31 See Kühn and Régibeau (1998) and CNSE (1996).

32 The Ley del Sector de Hidrocarburos (7 October 1998) creates the Comision Nacional de Energia, which will become the single regulator for all energy industries, including electricity, once the mandate of the current CNSE members expires.

33 On 20 May 1999, Electricity Supply Board, an Irish company, got the authorization to build a CCGT plant with capacity between 700 MW and 750 MW. This was the first new plant approved for a new entrant.

34 *La Vanguardia*, 12 February 1999, p. 70.

35 Capacity put in service before 31 December 1997 is fully compensated while units entering service after that date are only paid for 80% of the capacity made available.

36 The incumbent vertically integrated companies will, again, be compensated for this price cut (see *La Vanguardia*, 14 May 1999, p. 71). In that sense, it must be seen as a disguised inflationary tax on the non-eligible consumers. It is worth mentioning that, given the multiple links between the regulated and the liberalized parts of the market, this price cut is likely to also hurt independent generators, who will not get any compensation.

10 France: If it Ain't Broke?[1]

France is one of only two EU countries without an exemption that did not meet the 19 February 1999 deadline for translating the Electricity Directive into national law. The description of the French system included in this chapter must, therefore, be taken as tentative. It is based on the text of the proposed law approved by the lower chamber of the French Parliament in March 1999. To become final, the text must still be adopted by the Senate, where it can be amended, and then returned to the Lower Chamber for approval. We have also taken account of the transitory measures adopted by EdF in its attempts to comply technically with the Directive while the legislative process runs its course.

10.1 French electricity means EdF

In 1997, total electricity consumption in France was 414.7 TWh, making it the second largest market in the EU. The shares of industrial, commercial and residential use in consumption were, respectively, 27.1%, 34.7% and 38.2%. This market is completely dominated by state-owned EdF: in 1997, EdF had a 90% share of total production and 95% of distribution sales.[2] Within EdF, distribution is organized into 104 public utility distribution centres, functioning under concession from the municipalities that they serve. EdF is also the owner and operator of the national transmission network. The only fragments of the system that are not controlled by EdF are about 150 small non-nationalized distribution companies, mostly small rural companies and cooperatives, as well as 10% of total production, coming essentially from auto-producers and from a number of low power generation units owned by private companies, including several large water distribution companies.

Figure 10.1 shows the distribution of total output between primary fuel sources as well as between exports and domestic consumption. The dominance of nuclear power is striking, accounting for 82% of EdF's production compared to 14% for hydro and only 4% for conventional thermal plants. This is clearly a system based on nuclear plants with hydro and thermal power used to adapt to the peaks and troughs of demand.[3] Accordingly, the share of these two fuels in installed capacity is larger than in production (see Table 10.1).

Unlike all other EU countries, France is committed to building new nuclear plants. In 1998, for example, EdF brought on line 1450 MW of new nuclear capacity at Chooz and another 1450 MW at Civaux. EdF must also purchase the output of 'clean energy' power plants. With other producers, it is involved in the

Figure 10.1 Output by plant type (TWh, 1997)

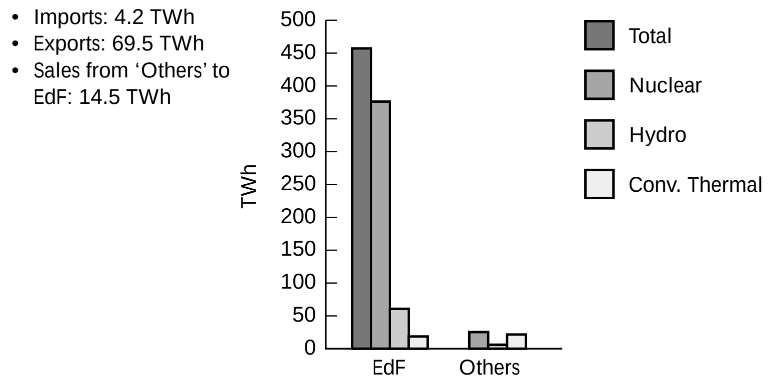


Table 10.1 EdF's installed capacity by fuel type, 1997

Primary fuel	*Installed capacity (MW)*	*Percentage of total capacity*
Nuclear	61 500	60.0
Fuel/coal/gas	17 700	17.3
Hydro	23 300	22.7
Total	102 500	100.0

development of significant wind-powered generation, with plans for up to 500 MW of installed capacity by 2005. This added capacity will be assigned through a tendering process that will specify the terms of a long-term contract for purchase of the output by EdF.

Another notable feature of the French market indicated in Figure 10.1 is the importance of net exports, which, at 65.3 TWh, represent 13.5% of total national production. In a typical year, the leading export markets for French electricity are, in descending order of size, the United Kingdom, Italy, Switzerland, Spain and Germany.

Although EdF is state-owned, it has enjoyed some managerial independence. The relationship between EdF and the state has been governed by four-year contracts specifying the objectives to be reached during that period. These goals are extremely varied, typically including targets relating to tariff levels, debt, distribution of profits to the state, quality improvements, investment policy and exports, as well as 'social variables', such as employment and wages.

Although EdF's operating profits have declined in recent years, they have remained positive in spite of a significant decrease in the company's financial debt (see Table 10.2). The ratio of financial debt to fixed assets fell from a high of 0.585 in 1985 to a low of 0.157 in 1997. While some of this spectacular decrease is due to a drop in the rate of expansion of fixed assets, the bigger part of the decline can be attributed to debt reduction.

Table 10.2 EdF's financial data (millions FF)

	1980	*1985*	*1990*	*1995*	*1997*
Operating profits	8568	30231	23321	12937	12865
Financial debt	93025	241026	252434	159521	136926
Fixed assets	167459	411791	624436	810695	871569
Debt to assets ratio	0.555	0.585	0.404	0.197	0.157

10.2 The reform

After championing the inclusion of the single buyer model as one of the alternatives recognized by the Electricity Directive, the French government finally chose to organize the liberalization of its electricity system around the principles of bilateral contracting between independent suppliers and eligible consumers and rTPA.

The heart of the project for liberalizing the French electricity market is the continued dominance and integration of EdF. The company will keep all of its generation assets and all of its distribution franchises.[4] Moreover, it will remain as both the owner and the operator of the transmission system. The new law will require accounting separation between generation, transport and distribution activities, but it does not seem to contemplate any separation between distribution and retail activities. EdF will also be obliged to separate the management of its transport activities: this involves a duty to preserve the confidentiality of economically or technically sensitive information that EdF might obtain thorough its function of system operator. Sanctions for violating this duty of confidentiality apply only to the specific employees involved and not to EdF's transmission arm.[5]

Companies that are involved in other industries must also separate the accounting of their electricity and non-electricity businesses. Legal separation is required for whatever non-electrical line of business which the company is dominant in. This might mean, for example, that large water distribution companies would have to separate their water and electricity businesses legally.

The proposed law establishes a strict distinction between eligible consumers and the part of the market that is ruled by a regulated tariff. EdF remains the monopoly supplier of all non-eligible consumers. While it might choose to purchase power from independent producers it is under no obligation to do so.[6] Eligible consumers are defined by a minimum level of annual electricity consumption at a given site.[7] Distribution companies cannot, however, generally qualify.[8] Article 22 of the law states that 'the government wishes to keep the degree of opening of the electricity market to the minimum values set by the Directive'. This means that, in 1999, about 26% of the market will be open.

In order to speed up the introduction of effective competition within these preset market shares, the law establishes that consumers can end their existing supply contracts within two years of becoming eligible. Producers can also end existing contracts with EdF within a year of publication of the application decrees of the new law. Both types of contracts can also be ended by EdF. At the same time, some 'stickiness' will be introduced by requiring that contracts between eligible consumers and producers cannot be shorter than three years.[9] The law does not offer any justification for this requirement.

Entry into generation can follow two procedures:[10]

1. A financially and technically qualified company can solicit the administrative authorization to build a plant and connect it to the network.
2. The government can use the tender approach in order to secure the construction of plants of a type or location that would not spontaneously be supplied by the market. Tendering is, therefore, a way of reconciling the incentives of private companies with the energy and regional policies of the government. The winner of such auctions will be determined by the Ministry of Industry, after consulting the independent regulatory agency (see below). When the winner is not EdF, it is also awarded a purchase contract with EdF. The terms of this contract are spelled out in the tender offer. Both procedures must be based on non-discriminatory criteria.

Although entry into generation will be liberalized, the proposed law insists that new generation capacity must be compatible with the objectives of the five-year energy plan elaborated by the government. The plan can indicate the desirable amount, location and type of capacity, and is partially based on recommendations from the system operator, EdF. A new law 'indicating the main directions of the new plan for investments in generation' must be approved before the end of 2002.

Since there is no power pool, competition for eligible consumers will be on the basis of bilateral physical contracts.[11] Participants in the system are obliged to submit daily production and/or consumption plans to EdF. As the system operator, EdF will handle transmission constraints. During a transitory period, EdF will also provide the capacity reserves required to adjust demand and supply in real time. Later, independent generation companies will also be able to bid for the supply of reserve capacity. The cost of these services will be factored into the price of access to the network. In the absence of an adopted law and its accompanying application directives, it is not possible to say precisely how these charges will be spread among users. The daily plans submitted by producers must also include economic conditions for adding or withdrawing capacity in real-time. When dealing with constraints and real-time adjustments, EdF is required to respect the 'economic order of dispatch' resulting from these conditions.

Any producer will be able to get access to both distribution and transmission networks on the basis of regulated access charges. Although the proposed law is silent about the way in which such charges will be computed, EdF has already adopted some temporary access tariffs that are valid until the law and the relevant decrees and rules are adopted (see Table 10.3). This tariff applies to generators who want to serve eligible consumers, temporarily defined as agents with annual site-specific consumption of at least 100 GWh.

The access charges shown in the second part of Table 10.3 cover all system-related costs, including the cost of providing reserve capacity. There are three tariff categories based on the tension at which the customers are connected to the network: the higher the voltage, the lower the tariff. Within each category, the tariff includes an annual fixed cost/kW, an annual flat management fee of FF 5300 per year and a cost/kWh. The size of the fixed cost/kW and of the cost/kWh both depend on the season (winter/summer), and timing (peak/off-peak, long/short duration) of use.

Table 10.3 Temporary access tariffs

(a) Customers connected to a voltage between 130–350 kV

Length of use	*Yearly fixed fee (FF/kW)*	*Reduced power coefficients*			
		Winter		*Summer*	
		Peak	*Off-peak*	*Peak*	*Off-peak*
Very long usage	121.37	1.0	0.79	0.59	0.28
Short usage	106.15	1.0	0.79	0.59	0.28
Excess consumption (FF/kW)		3.64	2.87	2.13	1.03

Length of use	*Administrative fee (FF/Year)*	*Variable fees (FF/kWh)*			
		Winter		*Summer*	
		Peak	*Off-peak*	*Peak*	*Off-peak*
Very long usage	5300.00	0.0320	0.0239	0.0215	0.0213
Short usage	5300.00	0.0467	0.0312	0.0266	0.0261

(b) Customers connected to a voltage between 40–130 kV

Length of use	*Yearly fixed fee (FF/kW)*	*Reduced power coefficients*			
		Winter		*Summer*	
		Peak	*Off-peak*	*Peak*	*Off-peak*
Very long usage	170.02	1.0	0.79	0.59	0.28
Short usage	142.11	1.0	0.79	0.59	0.28
Excess consumption (FF/kW)		5.1	4.01	2.99	1.44

Length of use	*Administrative fee (FF/Year)*	*Variable fees (FF/kWh)*			
		Winter		*Summer*	
		Peak	*Off-peak*	*Peak*	*Off-peak*
Very long usage	5300.00	0.0407	0.0283	0.0245	0.0241
Short usage	5300.00	0.0676	0.0416	0.0338	0.0330

Table 10.3 continued

(c) Customers connected to a voltage between 1–40 kV

Length of use	Yearly fixed fee (FF/kW)	Reduced power coefficients			
		Winter		Summer	
		Peak	Off-peak	Peak	Off-peak
Very long usage	284.23	1.0	0.79	0.59	0.28
Short usage	108.33	1.0	0.79	0.59	0.28
Excess consumption (FF/kW)		8.53	6.71	5.00	2.41

Length of use	Administrative fee (FF/Year)	Variable fees (FF/kWh)			
		Winter		Summer	
		Peak	Off-peak	Peak	Off-peak
Very long usage	5300.00	0.0488	0.0323	0.0274	0.0268
Short usage	5300.00	0.2069	0.1108	0.0821	0.0790

To get an idea of the orders of magnitude involved, fully using the capacity of a 100 MW plant for 6000 hours a year with an equal mix of peak, off-peak, summer and winter deliveries would involve a total transmission charge of FF 0.0248 per kWh if all customers are connected at voltages between 130–350 kV; FF 0.0296 for voltages between 40–130 kV; and FF 0.0341 for voltages between 1–40 kV.[12] Table 10.4 offers an international comparison of transmission charges based on 5000 kW, 5000 hours, connection between 10–50 kV and, for the networks with a distance-related component, 300 km. Since the voltage categories chosen by EdF do not coincide with those used in the international study, we have computed EdF's charges for both the 40–130 kV and the 1–40 kV ranges. In each case, EdF's tariffs appear to be well below the average.

The electricity sector is regulated by the Ministry in charge of energy and by a newly created Commission de Regulation de l'Electricite (CRE). The latter is made up of six members, who cannot be fired nor renewed, and has its own budget. Liaison between the CRE and the Ministry is ensured by a 'Commissaire du Gouvernment', who relays information between the two authorities and communicates the views of the Ministry. The Commissaire can put items on the CRE's agenda but does not attend its decision-making sessions.

The Ministry is responsible for authorizing entry into generation as well as for organizing tenders for additional generation capacity. It also sets the tariffs for the regulated sector after consulting the CRE. Access tariffs are also set by the Ministry, but are based on a proposal from the CRE. The CRE is also consulted before application decrees and rules are approved by the government. The CRE has the power to decide in conflicts about third party access to networks. It can impose pecuniary sanctions and/or temporarily prevent a party from connecting

Table 10.4 International comparison of transmission charges

Companies	*Charges (Pfennigs per kWh)*
EnBW (Germany)	4.0
HEW (Germany)	3.5
GEW (Germany)	5.3
SW Hamm (Germany)	4.4
RWE (Stadt) (Germany)	3.2
Bay. Werk/OBAG (Germany)	4.6
SW Bremen (Germany)	4.3
EdF (40–130 kV)	1.95
EdF (1–40 kV)	2.1
Eastern	3.0
London	3.4
Viken Energinett	1.8
Trondheim	1.2
Stockholm Energi	1.75
Vattenfall	2.1
Sydkraft	2.85
Helsinki	3.8
Tamperen	2.7

Sources: EWI Cologne, and EdF's temporary tariff.

to the network. Its decisions in that matter cannot be overturned by the Ministry; they can only be appealed in the Paris Appeal Court. Finally, the CRE can refer to the French competition authorities the restrictive practices that it might uncover during its investigations of disputes over third party access.

10.3 Evaluation

The proposed French legislation certainly satisfies the formal requirements spelled out in the Directive. Many observers fear, however, that the liberalized system will actually usher in rather little competition. Their concerns mainly revolve around the continuing dominance and integration of EdF.

One source of concern is the possible lack of effective separation between EdF's network related activities and its generation arm. The setting of tariffs for third party access is not the main issue: they will be set through a process that is as transparent and independent as in the most advanced EU countries. Moreover, the temporary tariff published by EdF is simple and does not appear to be excessive. Nevertheless, EdF's transmission activities could bias competition in generation in two main ways.

1. As owner of the transmission network, EdF is responsible for making the necessary investments. Since decisions about which transmission links should be built or upgraded can affect transmission constraints and thus the relative competitiveness of existing plans, EdF's competitors might be concerned that the choice of investment projects might not be neutral.

2. The way in which EdF, as system operator, handles transmission constraints.

The potential for abuse will depend on the zeal of the CRE, which has the power to look into both types of bias.

The proposed law does attempt to address these concerns by imposing the separation of management of EdF's transmission activities. It is not yet clear, however, how such separation would work in practice. How can one ensure that high level 'strategic' decisions, such as investment in the transmission system, are truly taken independently? While the CRE is a credibly independent authority dealing with access disputes, it does not appear that its competence would extend to reviewing EdF's pattern of investment in the network.

Questions also arise about the confidentiality of the information obtained by EdF as system operator. While the law includes sanctions for employees that break this confidentiality, it does not appear to include sanctions for EdF itself. Moreover, will the career paths of the personnel employed in transmission be confined to this division of EdF? If not, how are these managers supposed to segregate the confidential information previously obtained from their decision-making in other parts of EdF?

Somewhat comfortingly, the version of the law approved by the lower chamber of the French Parliament provides for some control of the career paths of system operator employees by the Director of the system-operation arm of EdF (Article 13). The Director is himself chosen by the Ministry of Energy after consultation with the CRE, from a list of three candidates submitted by the President of EdF. The appointment is for six years and can only be terminated by the Ministry after consulting the CRE. Although the Director of the system operator cannot be a member of EdF's Board, there are no restrictions on the Director's career path once the appointment expires.

The prospects for the entry of independent companies into generation are also uncertain. The main question mark comes in the way the Ministry in charge of energy will choose to administer the authorization and tendering procedures. While this concern arises in most countries, it is especially acute in France because of the government's insistence that new generation capacity must be 'compatible with the energy plan'. This is a leitmotif of the proposed law, where the government also underlines its right to impose priorities in terms of primary fuel sources.

The situation is made even more worrying by the fact that much of the information relative to the need for new capacity is likely to originate from EdF itself. This might make it possible for EdF to limit indirectly the rate of expansion of capacity aimed at servicing the liberalized sector. It is questionable what would happen to effective competition in generation if the government were to insist that, to implement its legitimate energy policy, most of the new capacity must consist of nuclear plants, for which EdF is likely to be without any serious rival.

The structure of the French market for natural gas is another potential impediment to entry into generation. Currently, the market for gas is completely dominated by the state-owned Gas de France (GdF). In 1997, 93% of the gas used in France was imported while 7% was produced locally by Elf. By law, GdF has monopoly rights in the importing and transport of gas. The company accounts for 96% of retail distribution and sales (30 Gm^3 in 1997). It also controls the industrial market (15 Gm^3) through its participation in two distribution companies, CFM and GSO. Such dominance is unlikely to ensure low fuel costs for CCGT plants.

GdF is also closely linked to EdF. GdF and EdF are two legally distinct entities and their accounts are completely separate. A large part of the distribution and retail activities of the two companies, however, are shared in EdF/GdF Services.[13] The two companies also share personnel and 'social relations' departments, and have recently been involved in joint ventures abroad. This closeness is unfortunate given that GdF's pricing and access decisions are likely to have a significant influence on the costs of some of EdF's rivals in electricity generation.

Although France is committed to implementing the EU Gas Directive, to date, there is no approved law and no indication of how far this reform will go towards eliminating potential barriers to entry into the market for electricity.

On the brighter side, there are already some potential entrants that are likely to limit EdF's remaining market power:

1. With the exception of the links with the United Kingdom, Spain and Italy, there are no transmission constraints on importing power from other EU countries.
2. Some local companies such as Vivendi and Lyonnaise des Eaux-Suez already have expertise in electricity generation through their exploitation of very small plants in France and their participation in foreign markets (for example, through Electrabel or Dalkia). Moreover, water companies like Lyonnaise have significant expertise in retailing and good relationships with local authorities.

The proposed law insists on the importance of preventing cross-subsidization between different types of activities.[14] This is why accounting separation is imposed throughout and why firms with a dominant position in a non-electricity business must legally separate it from their electricity operations. Clearly, the usual warnings about both accounting and legal separation apply: as long as common ownership is still allowed, there is no reason to expect the different parts of a company or holding group to behave as independent profit-maximizers. The objections to the French solution go beyond this traditional argument, however, because EdF remains a monopolist in the regulated part of the market. If there is real concern about the prospect of cross-subsidization, it is probably worth wondering how it can be ensured that the tariffs set for the regulated sectors are not generous enough effectively to subsidize EdF's activities in the competitive segment of the market.

It is also regrettable that the government made a decision to stick to the slowest possible schedule of liberalization. As the experience of other countries suggests that there are very few obstacles to faster liberalization, it is unfortunate that the government did not feel the need to advance any argument to support its position (see Article 22 of the proposed law).

On the positive side, it is worth emphasizing that the degree of independence of the newly created CRE appears to be quite significant. Of special importance are the irrevocability of its members, the devolution of decision-making power in matters about third party access and the fact that the CRE's decisions must be appealed through the court system. As an additional warranty, it would be desirable to appoint members that are not closely linked to EdF. This would be a strong signal of the government's commitment to maintain an impartial regulatory body for the industry.

10.4 EdF: national champion and social instrument

The monolithic dominance of EdF is disturbing to most economists, who believe that considerable efficiency gains can be obtained from introducing competition in at least some segments of the industry. It is important, however, to understand that this point of view is definitely not widely shared by EdF, the French government or even the French public.[15]

The attitude of EdF is easy to understand: given a choice, most companies would prefer to be shielded from competition. Yet, EdF's management appears genuinely to believe that EdF's size and degree of vertical integration has led to significant efficiency gains. To support their claim, they point to the high degree of technical efficiency of their nuclear plants and to EdF's success in exporting both its electricity output and its expertise. While the French government also stresses technical achievements and EdF's positive contribution to the country's trade balance, it is also quite sensitive to the fact that public ownership of the dominant electricity company makes it easier to implement its energy, environmental and social policies in the sector.

In that respect, the style of the proposed law is quite revealing. The whole text does not mention even once the potential gains from increased competition.[16] On the other hand, it repeatedly asserts the government's right to influence the industry so that its behaviour conforms to the government's objectives in fuel choice and environmental protection (for example, burial of transmission lines). It also justifies the continuing monopoly of EdF over the regulated sector by the need to assume public service obligations that are vital for 'social cohesion'.[17]

The French public seems to take national pride in the foreign success of EdF and comfort in the fact that electricity supply is guaranteed by a reliable company under the strict control of the state. Most components of French society appear to consider EdF an efficient company that contributes to both national wealth and national cohesion. The general feeling is that the system has worked well in the past and that there are no good reasons to change it. On that view, the Electricity Directive is mostly an undesirable constraint imposed from the outside and the main concern is to satisfy its formal requirements without overly disrupting the current organization of the sector.

How valid is this position? The first issue is whether the French electricity industry has actually been efficient in the past. This a difficult question to settle as the dominance of nuclear power makes comparisons with other systems (in terms of energy efficiency and percentage of availability of plants) somewhat meaningless. In terms of prices, France has performed better than the EU average (see Table 10.5).

Table 10.5 Electricity price indices, 1997, before taxes (France = 100)

State	*Industrial use (1000 kW × 2500 h)*	*Residential use (3500 kWh/year, 1300 h of which at 'night' rate)*
Austria	132	96
Belgium	123	128
Denmark	62	54
Spain	125	135
Finland	61	58
Greece	115	94
Ireland	145	95
Italy	174	196
Luxembourg	117	107
Netherlands	103	95
Portugal	178	200
RFA	122	134
Sweden	–	58
United Kingdom	111	111
France	100	100

Source: EdF (1998) 'Comparaison des Prix de l'Electricité dans l'union Européenne en 1997 et de 1985 à 1996'.

Nolden, et al. (1998) also find the French electricity system to be significantly more efficient than its German counterpart. Price comparisons can be misleading, however: not only are they clouded by variations in exchange rates and the definition of various consumer categories, but it can also be argued that French prices include not only the price of electricity but also the price of the energy, environmental and social policies implemented through EdF's monopoly. To the extent that the pursuit of such objectives in the electricity sector is more intense in France than elsewhere, a strict comparison of prices would underestimate the relative efficiency of the French system. Another concern is that French electricity prices might fail to reflect the full cost of nuclear power as the future cost of disposing of residual fuels and shutting down obsolete reactors might not be adequately reflected in the current electricity tariffs.

The second issue is whether efficiency is likely to be enhanced by the continuing integration and dominance of EdF. Several countries (for example, Spain and the Netherlands) have claimed that they need large electricity companies to ensure their competitiveness in a unified EU market. In most cases, this argument does not stand up to scrutiny. Size is linked to efficiency through static and/or dynamic economies of scale. With the advent of CCGT technology, the minimum efficient scale of production has dropped to levels that cannot justify the formation of electricity giants. Similarly, the world markets for most primary fuels are large and efficient enough that the size of an electricity company should not significantly affect the prices that it faces.

Other economies of scale might stem from the ability of large firms to finance large investment projects out of retained earnings. One would think, however, that the significance of that advantage has been significantly reduced by the greater efficiency of global financial markets as well as by the decrease in the size of investment projects associated with the emergence of CCGT plants. Finally, dynamic economies of scale mostly appear through the learning by doing associated with building, and possibly running, some types of power plants: since many European firms do not design their own plants, these benefits must also be typically rather small.

These counter arguments do not apply with the same force to EdF. Because of the French government's decision to rely extensively on nuclear power, EdF faces much larger minimum efficient scales of production and larger, lumpier investment projects than most other European electricity companies. Moreover, it cannot be denied that, partially because it has been the monopoly provider of nuclear powered electricity in France, EdF has acquired significant expertise in the design, construction and operation of nuclear plants. In other words, the size of its captive market has probably allowed EdF to 'move down its learning curve' fast.

Hence, France's reliance on nuclear power might partially justify its preference for a concentrated market structure. Of course, this only raises the more fundamental question of whether France's choice of fuel mix is itself efficient. Unfortunately, we do not have the necessary information to investigate this issue satisfactorily. In fact, one could argue that one of the benefits of a thoroughly liberalized electricity market would be precisely to offer a more transparent assessment of such choices.

The last question to be addressed is whether EdF is a good instrument of public policy or whether the French government could still satisfactorily implement its energy, environmental and social policies with a more competitive electricity sector. This issue is discussed in some length in both Part 1 and Chapter 13 of this Report. The bottom line is that most economists believe that equivalent policies can be implemented in a more decentralized manner compatible with competitive markets through the judicious use of taxes and subsidies.

This is not the approach chosen by the French government. Public service obligations will be assumed by EdF as monopoly supplier of the regulated sector. Environmental policy will be partially enforced through the authorization and tendering of generation capacity. Interestingly, the government has also found a way of keeping some control over the employment policies of the electricity sector: the proposed law establishes that wages and working conditions will become the object of sector-wide bargaining. Given the weight of EdF in the sector, this might seriously restrain the flexibility of independent electricity companies in labour matters.

10.5 International competition

EdF's international involvement takes three forms:

1. EdF exports a significant share of its production to other European markets. As it still has significant excess capacity and there are few transmission constraints between France and other EU countries, these exports are likely to increase as EU markets become progressively more open.

2. Through its subsidiary, EdF International SS, it acquires generation, transmission and distribution assets abroad. At the end of 1998, the value of EdF's outstanding foreign investments reached €4.26 billion. In distribution, EdF is involved in serving 15 million customers outside of France. In generation, it is associated with a foreign capacity of about 14 500 MW. Many of these investments take the form of joint ventures: for example, EdF is associated with Endesa in Spain (via Elcogas), Graninge in Sweden, PVO in Finland, Demasz in Hungary and ECK-SA in Poland.
3. EdF has long sold its technological know-how, especially in the building and management of nuclear facilities.

The international dimension of EdF's strategy raises three important issues:

1. The size of EdF's exports might help guarantee the openness of the French market for electricity. Since the Directive allows a country to deny access to foreign firms on the grounds of a lack of 'reciprocity', EdF has a vested interest in avoiding blatant anti-competitive rules and behaviour in its home market.
2. EdF relies heavily on nuclear power, in both domestic production and some of its international ventures. In that sense, EdF's exports to EU countries from France or from Eastern European facilities could be seen as undermining other countries' s strong anti-nuclear stance. This might create significant tension with other EU members especially if some of the associated costs, such as nuclear waste disposal, are perceived to be imposed on other states.
3. EdF has already spun an extensive web of European alliances. This observation serves to underline the fact that, as the electricity market becomes more European, such alliances will call for increasing scrutiny by the European competition authorities.

10.6 Conclusion

The law that emerges from the current legislative process is likely to be a compromise between three goals:

- The first, and perhaps most important, is to avoid overly disrupting an electricity system that has so far worked to the satisfaction of most French constituencies.
- The second is to comply with the Electricity Directive and ensure that EdF is not denied access to other EU markets on reciprocity grounds.
- The third, and by far the least important, is to experiment with competition under rather controlled conditions to determine the extent of its compatibility with the variety of non-economic objectives that the French government has traditionally pursued through its control of the electricity sector.

In spite of some legal precautions, the continued integration and dominance of EdF as well as the structure of the French gas market create at least the potential for anti-competitive practices. Whether this translates into actual barriers to competition will largely depend on both the effectiveness of the newly created electricity regulator and the strategy that prevails at EdF. An increased emphasis on international operations would be likely to lead EdF to focus on further improving its efficiency and ensuring, through fairness at home, that foreign markets remain open to its exports. In contrast, an emphasis on defending local market share would probably be bad news for competition in the French market.

Notes

1 The author of this chapter, Pierre Régibeau, would like to thank Jean-Michel Trochet of EdF for answering his many questions, providing useful information and reading carefully a draft of this chapter. Of course, neither he nor EdF should be held responsible for any remaining factual errors or for the views expressed here.

2 Total production includes the power generated by auto-producers.

3 Only half of the hydro capacity is used that way. The other half comes from uncontrolled water power ('as the river flows') and is used as base-load.

4 Since the nationalization law of 1946, the local distribution franchises must be assigned to EdF even though the local authorities retain ownership of the distribution networks.

5 The sanction amounts to about €15 000.

6 The only exceptions are the output of small environmentally-friendly plants and, usually, the excess output of auto-producers.

7 The exceptions are railroad companies and urban transportation companies, which qualify based on their company-wide consumption.

8 The non-nationalized distribution companies, which represent 6% of the market, can, however, act as retailing agents for the eligible consumers located in their monopoly franchise.

9 See Article 22 (III). The writing of the law is not clear: paragraph III could be read as imposing the three-year requirement only on contracts with producers that are not located in France. Since this would be a flagrant violation of EU rules, we have chosen the more benign reading that imposes the requirement on all contracts.

10 An exception is power plants with a capacity of less than 3 MW, which only require notification to the Ministry.

11 Although there is no plan to form a national pool, agents operating in the French market could of course participate in the pools organized by other EU countries.

12 These charges could be considerably higher for shorter periods of use.

13 The sales forces are, however, distinct.

14 See, for example, Article 4 (I).

15 See Poppe and Cauret (1997) for a similar view on that theme.

16 With the exception of a vague reference to the 'the strengthening of the public service in electricity and introduction of controlled elements of competition that will help France's competitiveness…' in the second paragraph of the motivation of the law.

17 See for example, Article 1: 'France must define for electricity a modern and performing public service that meets the needs of the citizens. This service contributes to the achievement of essential objectives of energy independence, security of supply, good management of national resources, respect for the environment, social cohesion, economic development of the country and strengthening of the country's capacities to sustain technological progress'.

11 Hungary: Restructuring, Privatization but Delayed Price Adjustment[1]

Hungary was one of the earliest countries of Central and Eastern Europe to embark on economic transition, and it has led the region in restructuring and privatizing its ESI. It was the first transitional country to join the International Energy Agency (in May 1997) and it is actively pursuing an agenda of creating the legal and institutional framework to join the EU.[2]

In the energy sector, fulfilling the EU accession requirements will involve implementing the Directives on Gas and Electricity, which require a degree of liberalization that is in advance of most EU countries, let alone Hungary. Indeed, when Hungary started serious negotiations over accession in 1995, its institutional and structural approach to the energy industries was comparable to, if not ahead of, most EU countries, though that has ceased to be true now that the Electricity Directive has been implemented in most EU countries. Nevertheless, Hungary continues its typically cautious progress towards liberalization under its new government at a pace that may be influenced by the speed of progress towards full EU accession.

11.1 Restructuring and ownership changes

Before 1992, the Hungarian ESI was a vertically integrated utility. Magyar Villamos Müvek Tröszt (MVMT, a holding conglomerate) was restructured, 'corporatized' and partially unbundled in January 1992 into eight power companies, six distribution companies (regional electricity companies or RECs) and one transmission company, collectively known as MVM Rt, or the Hungarian Power Company Ltd, in preparation for privatization.

At the end of 1998, the industry had available capacity of 7850 MW, of which 1840 MW was in the nuclear plant of Paks, 4500 MW was in oil- and gas-fired plant, and 1954 MW was coal or lignite-fired. 51 small hydro plants accounted for a further 48 MW. Peak demand in 1998 was 5818 MW for a population of about 10 million. Peak demand has fallen by 12% since 1989 with the collapse in industrial output associated with the transition. Generation in 1998 amounted to 37 TWh, 38% of which was nuclear, 26% coal, 34% hydrocarbon (oil or gas) and only 0.5% hydro. Gross imports were 3.4 TWh, net imports only 0.7 TWh, down from 10.5 TWh (net) in 1986. Imports in 1998 were roughly one third from Ukraine and two thirds from Slovakia, with exports going primarily to Austria and the former Yugoslav countries.

In addition to producing electricity, most power stations also supply hot water or steam. Of the 58 PJ of fuel used for heat supply, 53% came from gas, 29% from coal, 16% from fuel oil and just over 1% from nuclear power, giving an output of 46PJ, worth perhaps 10–15% of the total revenue of the ESI.[3] Of this, 11 PJ came from non-cogenerated (that is, heat only) plant. Steam (mainly for industrial use) has fallen by 38% since 1986 (from 35.3 PJ to 22 PJ), reflecting the fall in demand from heavy industry, while hot water (for district heating) has increased slightly.

The decline in heavy industry has also shifted the pattern of electricity demand towards households and away from industry. In 1996, households accounted for 10 TWh and manufacturing for 9 TWh out of net consumption of 30 TWh. Losses were 13.6% of gross consumption. In common with other former command economies, Hungary inherited a tariff structure that subsidized electricity sales (and gas) to domestic consumers by higher tariffs on industrial and especially commercial customers and by paying generating companies a low average price, well below the marginal cost of replacement power. District heat was also subsidized about 60% by the state through the municipal owners, as part of the policy of providing low cost housing for workers. As a result, both energy and electrical intensity (kWh/$GDP) are high by OECD standards.

Five of the eight generating companies have integrated coal mines (all except Paks, Dunamenti and Budapest), which in 1996 produced 13.2 million tonnes of low calorific value coal (8.3 GJ/tonne compared to 26 GJ/tonne for good international coal) for energy use.[4, 5] Many of the coal-fired power stations are 30–40 years old with an average age of nearly 30 years. Average coal-fired thermal efficiency is only 27% and some have thermal efficiencies as low as 16%.

The oil- and gas-fired stations are slightly younger and more efficient (30%). With the exception of a few stations refurbished in the 1980s, most will have to be closed by 2001–6 on both cost and environmental grounds. Even the refurbished stations will have to install FGD to meet the stringent EU emission limits that are due to come into force at the end of 2004. Although SO_2 emissions fell by a third in the 1980s, since 1990, there has been no further improvement. Total SO_2 emissions from power stations in 1996 were 425 000 tonnes, averaging around 25 tonnes SO_2/GWh.[6] Five of the coal stations average over 65 tonnes SO_2/GWh, and will not meet emissions limits. Most of the older thermal hydrocarbon stations typically burn gas in the summer and oil in the winter (to ease the gas peak), and thus emit SO_2 in the winter. Their average SO_2 emissions is less than 7 tonnes/GWh (except for the older small Dunamenti I, where it is twice this level).

The single nuclear plant, Paks, has four water cooled and water moderated 460 MW PWRs, based on the Soviet VVER-440/213 design, but with western control improvements. It has a utilization rate and safety record that compares with the best in the OECD (IEA, 1995, p. 143).

11.1.1 Privatization

The unbundling of the ESI prepared the way for privatization, for which the arguments were strong but not overwhelming:

1. It fitted into the general programme of privatization designed to reduce the role of the state in economic activity.
2. The assets were valuable, and the case for realising them by sales to foreign investors in exchange for reducing Hungary's cripplingly high foreign debt was persuasive.
3. The assets were old and in need of replacement or refurbishment, but electricity prices had been kept down so that MVM Rt's ability to finance the large investment programme (estimated at $1.5 billion over the decade) was severely constrained. In addition, Hungary had in the past been heavily dependent on imported electricity from the East, but realignment with the West and the wish to join the UCTE system (now achieved), required reducing imports from the East and hence reducing the ability to meet power demands from imports. More domestic generation was required, though the fall in domestic demand made this less urgent in the short run.

It was recognized that electricity prices would have to be raised to remunerative levels for privatization, which meant that it should also have been possible to finance new investment under continued state ownership, thus overturning this argument (Newbery, 1994a). As Vince (1996) argued, however, there were two weaknesses with this claim:

1. Privatization would require providing investors with confidence that their investment would be assured of continuing remunerative prices, which would require a system of licences and regulation based on a secure statutory basis. Such a step was necessary to ensure that prices were depoliticized and the industry's future revenues streams assured. Only the requirements of privatization would force the necessary institutional changes required.
2. The industry needed to embark on its investment programme before the revenue streams accumulated sufficient funds for the investment, making borrowing necessary. State borrowing by a heavily indebted country would at the margin be expensive, while borrowing by solvent cash-rich Western utilities (the target future owners) might be less costly, and might reduce Hungary's vulnerability to possible exchange rate shocks, as these debts would not be guaranteed by the state.

Slightly less than 50% of the shares in the six distribution companies were offered for sale in a tender document dated 31 July 1995, together with seven of the eight power companies (all except the nuclear power plant at Paks). Successful bidders would be required to make further investments to acquire a controlling share via pre-emption rights to increase ownership to 50% plus one share later. 24% of MVM Rt itself was also offered, with constraints on ownership – not more than two RECs, two power companies and 10% of MVM Rt for a single bidder, or three of each plus 10% of MVM Rt for a consortium, but no more than 30% of 1995 generating capacity.

Despite criticisms (particularly from United Kingdom bidders about regulatory uncertainties affecting the RECs), the RECs received 10 bids and were successfully sold to continental European electricity companies (who, unlike the British, were perhaps more used to the more discretionary and negotiating style of continental regulation).[7] The average price paid amounted to $84/MWh of sales revenue (with a range of $64–104). The generating stations received 14 bids, but only three generating companies were sold in the first wave for an average of $170/kW.[8] In 1997, three more were sold, leaving one small fossil-fuel plant (Vértes) and the nuclear power company in the ownership of MVM Rt, which remained 99.8% owned by the Hungarian state (and 0.2% owned by municipalities).[9] In addition, three new power companies have entered, of which the largest is PowerGen, which purchased an existing small company supplying electricity and heat on Csepel Island in Budapest. PowerGen obtained a licence to build a new 389 MW CCGT station to replace the obsolete 44 MW of old plant.

By the end of 1997, 68% of the privatized power companies were foreign owned as were 48.6% of the RECs, or 31.6% of the ESI as a whole. This foreign ownership share rose to 42.5% of the ESI by the end of 1998, and 75.4% of the RECs (HEO, 1999). There is currently an active debate as to whether MVM Rt should be further unbundled to separate generation from transmission, and whether part or all of the remaining state-owned companies should be privatized.

11.2 The regulatory structure

Hungary's energy policy was approved by Parliament in April 1993, and included the following main strategic goals:

- Reduce one-sided energy import dependence.
- Restrict the state's role in the energy sector to the minimum justified level.
- Improve energy efficiency.
- Adopt least-cost solutions and flexible energy systems adaptable to demand, including the involvement of private finance.
- Liberalize prices to allow tariffs to reflect economic costs.
- Take account of environmental priorities.
- Adopt a regulatory framework suitable for a market economy while controlling monopoly activities.
- Involve the public in energy investment decisions.

Parliament passes the laws which govern the sector, while the government implements these laws and energy policy by issuing decrees and directives. The two key laws are the Act on Gas Services (Act XLI of 1994) passed in July 1994, and the Act on Production, Transport and Supply of Electric Energy (Act XLVIII of 1994 – the Electricity Act). The Act on Gas Services set up the Hungarian Energy Office (HEO) to regulate both the gas and electricity industries: the details of its responsibilities for the ESI were set out in the Electricity Act.

Parliamentary approval is required for all generating plants above 600 MW and all nuclear power stations, while government approval is required for any plant between 200–600 MW. Between 50–200 MW, the approval of the Minister of Industry, Trade and Tourism (MITT) is required, while plant of less than 50 MW does not require approval (and several such plant have recently been built as dedicated suppliers to industrial customers). The Electricity Act stipulated that prices must cover justified operating costs and earn 8% return on investors' equity (as a group) by 1 January 1997.

The regulatory responsibilities of the HEO fall into three categories:

- to issue licences, approve operational codes, and approve ownership changes;
- to prepare rules for price regulation and propose price changes for Ministerial approval;
- to protect consumers, provide information and improve energy efficiency.

The HEO was set up subordinate to the MITT, and its price proposals must be agreed by the Minister, who exercises the price regulation authority, and the Minister of Finance, before they can be implemented. In 1995, HEO conducted a cost review with independent energy auditors and set standardized costs for each power plant to run until December 2000 with a formula for price adjustments. In 1996, the early proposal to increase prices sharply to meet the targets specified in the Electricity Act were felt politically unacceptable, and Prime Minister Horn appointed a Special Commissioner to advise his office on price proposals, in part to provide a counterbalance to the MITT, which was thought to be over-sympathetic to investor interests. The new Fidesz government elected in June 1998, decided to absorb the MITT into a larger Ministry of Economics on German lines, with a department responsible for energy. The Special Commissioner resigned, and the Prime Minister's office appears to have weakened relative to the Ministry of Economics, though the Prime Minister retains the last word on some issues.

The HEO has the same legal position as any other government entity, in that its decisions can be appealed to the Minister (previously of Industry, Trade and Tourism, now of Economics), after which the only recourse is to the courts – there is no appeal to the competition authorities as in the United Kingdom. The HEO is accountable to Parliament and must report annually. Its fourth report was issued in March 1999 (HEO, 1999). Licences issued by the HEO can be appealed against in the first instance to the HEO, and if the appeal is rejected by the HEO, the plaintiff can appeal in the second instance to the Minister.

The HEO regulates the average prices for generation, and the prices of wholesale and retail electricity, which are set by the Minister according to a formula that runs from 1 January 1997 to 2000, at which point there will be a review. This review will need to take account of the EU's Electricity Directive and any consequential changes required in the electricity market, in legislation, and other reforms that may be introduced, particularly moves to introduce more liberalization.

Price caps were supposed to allow for an initial return of 8% on equity, and are adjusted in line with inflation but with an efficiency factor somewhat like the UK's RPI-X system of price caps (though with a multiplicative factor that is sensitive to the actual rate of inflation). Fuel costs are passed through for generators, as are the costs of generation and transmission to distributors. The allowable costs are supposed to include those necessary for safe and reliable delivery of electricity (such as reserve margins, ancillary services, etc.), meeting environmental standards, and the costs of meeting environmental obligations when closing down facilities. The intention is to provide a price structure that encourages efficiency, and a degree of competition that reduces costs.

In January 1999, the new government announced its energy strategy, affirming a medium-term goal of meeting EU requirements, and raised electricity and gas tariffs by 6–8% from 4 January. On 18 February, the Ministry of Economics announced plans to liberalize rather less than 15% of the market by allowing some large customers to buy electricity on the open market and to import electricity from January 2001. If this were successful, the market opening would be increased, but further liberalization might be delayed if EU accession is delayed. The Official Gazette of 19 March published a decree on electricity and gas pricing, signed by the Economics Minister. A new set of tariffs has been announced from 1 July 1999, which rebalances the industrial and domestic rates, lowering the former by 4–5% and raising the latter by about 2%, while at the same time abolishing the life-line domestic tariffs. The new tariffs should enable all owners to earn the promised 8% on their equity (including MVM Rt). The new government is, therefore, gradually addressing the various obstacles to meeting the Directive.

11.3 Operation and pricing

MVM Rt holds the single transmission licence, which provides for MVM Rt to contract for buying, selling, importing and exporting power, and places obligations for security of supply by ensuring adequate generating and transmission capacity, forecasting demand, and developing plans for least-cost capacity expansion. MVM Rt acts as the key player in the ESI, as it has long-term contracts with all licensed power generators, is the sole transmission company, and is responsible for dispatch. The Power Purchase Agreements (PPAs) specify the annual capacity payment (HUF/MW capacity available), the energy payment (in HUF/kWh), and, for integrated power and mining companies, the royalty on mining. They also specify the price for hot water and steam (both of which are subject to a regulated ceiling), and the terms under which ancillary services are provided, and the penalties (if any) for non-availability.

These contracts are typically for 20 years for new plant, though of shorter durations for the plant sold at privatization and for older plant. The contracts set out the parameters within which annual planning and monthly detailed scheduling is arranged, the latter covering such issues as non-availability for plant maintenance and the like. The terms of the contract are indexed by regulation to ensure an initial 8% return on equity, and are thereafter indexed to the Producer Price Index (excluding food) for capacity, and with cost pass-through adjustments for fuel price changes for the energy component.

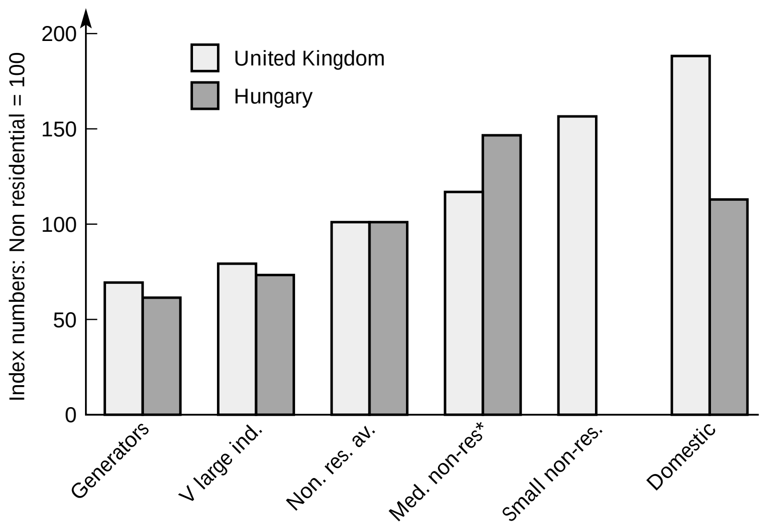
The RECs hold licences that oblige them to supply customers within their regional franchise area. They buy power on an annual basis, in which they specify (and pay for) their maximum demand, which they can exceed by a considerable margin (14%) before paying penalty rates. They are subject to country-wide uniform price caps for each category of customer, which limit the average charge (though allowing for this to be recovered through fixed and variable charges). The price caps were set to earn an average return of 8% for the

RECs as a whole, and it was up to each investor to scrutinize the costs of the particular REC to decide what would be a sensible bid. Were it to be continued after 2000, this system of price regulation would effectively be one of benchmarking, which gives powerful incentives to each company to cut costs, though increasing the risks to each that they encounter special circumstances that makes their costs higher than the average.

The key reforms required are to rebalance the rate structure (which had been planned but abandoned in 1997), then to introduce competition to reduce costs further, and allow RECs (and large customers) direct access to cheaper imports (for example, from Slovakia). Both these have been accepted by the new government, though liberalization will have to wait until January 2001. The RECs would also like to see dispatch separated from transmission in an independent system operator, as suggested by the Directive.

Figure 11.1 shows how unbalanced the pre-1999 electricity tariffs were in Hungary compared to the United Kingdom. These figures exclude VAT, which was 12% in Hungary and 5% in the United Kingdom, both being below the standard rates of 25% and 17% respectively. The different sales prices are represented as percentages of the average non-residential price/kWh. In England and Wales, the price shown for generators is the demand-weighted average pool price, which is typically below the contract price that is the main determinant of generator revenue. The most obvious difference is that the domestic average in Hungary was only 11% above the non-residential average, while in the United Kingdom it is 87% above this average (both excluding VAT).[13] The other price relativities do not look so different across the two countries, given the ambiguity in comparing the Hungarian general non-residential tariff, which apparently applies mainly to the non-profit sector, rather than to commerce and small industries, as in the United Kingdom.

Figure 11.1 Structure of electricity prices: Hungary 1997, United Kingdom 1993–7



Note: *General tariff in Hungary

The feature of the domestic tariff not shown in Figure 11.1 is the increasing block rate for domestic consumers. Before 1999, those consumers taking less than 50 kWh/month (600 kWh/year) paid only 86% of the average domestic normal tariff, those taking between 50–300 kWh/month (600–3600 kWh/year, which would include the typical UK domestic consumer's consumption of 3300 kWh/year) paid 104% of the average, while those above paid 122% of the average. This compares with the United Kingdom, where the London average prices in December 1996 for those taking 2500 kWh/year were 105% of the average (of 3300 kWh/year), while those taking 6600 kWh/year pay 91% of the average.

This system of increasing marginal prices is a logical way of reconciling the equity and efficiency considerations discussed below, but will be discontinued from July 1999. On 1 January 1999, this process of unifying the domestic tariff started, with the lowest band having a price increase of 24.4% (from 1 January 1998), the middle having a price increase of 16.6%, and the highest only 6.8%, compared to inflation in 1998 of 10.3%. The July prices lower the highest two bands, while raising the lowest band by a further 11% from January 1999 (and by 38.5% from January 1998, compared to the estimated inflation of 14% over that period).

11.4 Structural tensions in the present system

The regulatory system put in place by the Electricity Act has its merits. It has demonstrated its credibility with the successful sale of the RECs and the strong response to the invitation to tender for new plants, which allayed concerns that the new foreign owners would be unwilling to invest and hence would prejudice security of supply. Continental investors appear confident in the durability and enforceability of their contracts, and although there are disputes about the operation of the price regulation system, the companies are broadly content with the outcome – and presumably made allowances in their initial bids for the likelihood that prices might be held below the statutory level for political reasons.

There appears to be a feeling that it should be possible to strike a satisfactory balance between the competing interests of domestic consumers and foreign investors, though this may be at the expense of greater liberalization and competition. Investors take considerable comfort from Hungary's commitment to negotiate EU membership and hence to implement the necessary legal and institutional changes to strengthen the market economy and the rule of law. It is also noteworthy that German investors have large stakes in Hungarian utilities: the fact that Hungarian trade is dominated by Germany means that German investors probably feel they can appeal to the German government to defend their interests. One possible source of concern is that this influence could extend to creating the opaque and ineffective system of regulation observed in Germany before market liberalization has proceeded far enough to be irreversible.

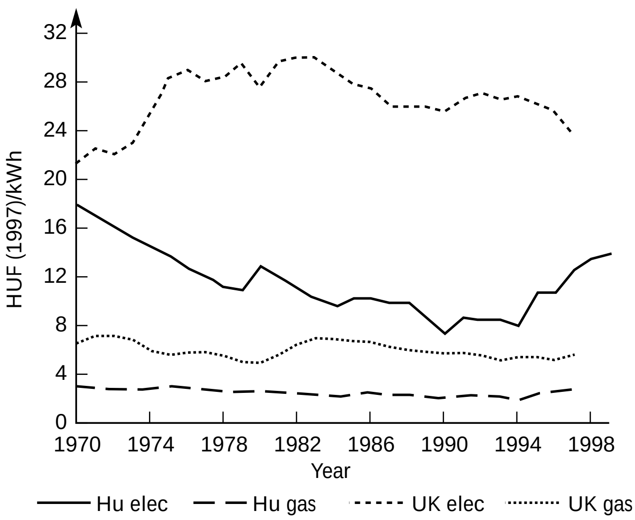
It is also not difficult to understand the political bargain that has been struck for the restructuring and regulation of the energy industries. It would be naive to believe that these political pressures will dramatically change with the new

Fidesz coalition government, though some of the coalitions, particularly those involving municipalities, may change membership and strength. Undoubtedly, the conditions required for EU accession remain one of the most potent factors shaping regulatory reform, now that a large part of the energy utilities have been privatized.

The most visible inefficiencies of the system of regulation are to do with the level and structure of tariffs for gas, electricity and hot water, which are interrelated and primarily explained by distributional concerns. The price regulation system is to set price caps based on audited costs as at 1 January 1997, which are thereafter uprated in line with inflation, allowing for an efficiency factor. The inherited system of subsidies and cross-subsidies was designed to protect domestic consumers from excessive price rises, though political interests favoured some groups more than others (for example, gas consumers over district heating), while Hungary's high inflation, with few prices other than those of energy subject to any price control, also induced the government to hold down these energy prices as part of their counter-inflation strategy.

Figure 11.2 shows the evolution of real domestic (tax-inclusive) prices (that is, the price deflated by the retail price index) for electricity and gas in Hungary and the United Kingdom, computed at the exchange rates prevailing over the three years up to mid-1997 (and which are very close to the exchange rate for 1 January 1997, taken as the base of the price comparisons). The top two continuous lines are the electricity prices in HUF/kWh (200 HUF = £1 or 2 HUF = 1 p or 1.65 US cents). While Hungary and the United Kingdom started from quite similar initial positions in 1970, prices in the United Kingdom were hit by the oil shocks while those in Hungary drifted steadily down, so that by 1990 they were less than one third the UK level. Competition and regulation were gradually reducing prices in the United Kingdom (but not

Figure 11.2 Real domestic electricity and gas prices: Hungary and United Kingdom



Note: *1997 prices and exchange rate, 1999 forecast
Hungary\HUUKElec; Hufuel. WK1

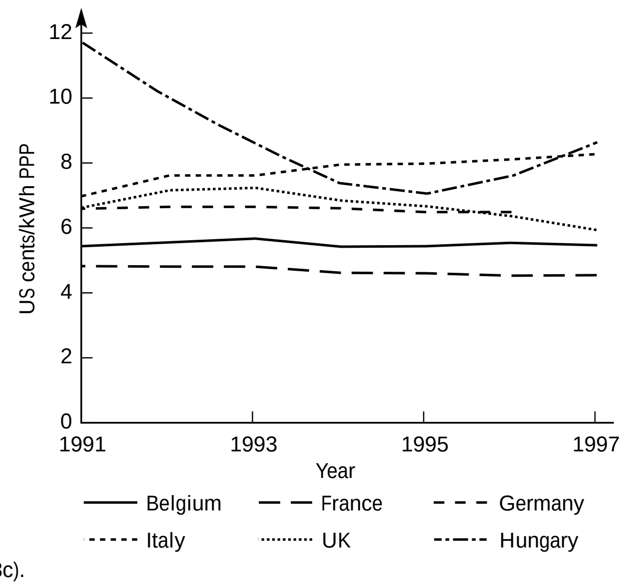
by nearly as much as fuel costs had fallen), while adjustments of prices towards costs were gradually raising prices in Hungary (which, even after the further price adjustments in July 1999, remained below the cost-justified level, though the change from 1994 is striking).

The bottom two dotted or dashed lines in Figure 11.2 give the domestic gas price (also in HUF/kWh), showing the remarkable constancy and low level of Hungarian prices compared to those in the United Kingdom (which, by 1997, were based on essentially the same world price of gas at the beach-head or into the import pipeline as in Hungary).

Figures 11.3 and 11.4 show the evolution of industrial and domestic electricity prices in a number of EU countries and Hungary at purchasing power parity (PPP) prices, taken from IEA (1998a). They show that Hungary's industrial electricity prices were converging on the more expensive EU countries (though they have now risen to a relatively higher level), but that even at PPP prices, Hungary's domestic prices had fallen to well below those of other EU countries and have only recently started to converge on the cheaper countries. Although PPP figures are useful in giving a sense of the ability of consumers to pay (and are measured relative to the general level of prices within the country), free trade in electricity will take place at market exchange rates and to that extent convergence (or its lack) is better measured at the market, not PPP, exchange rates.

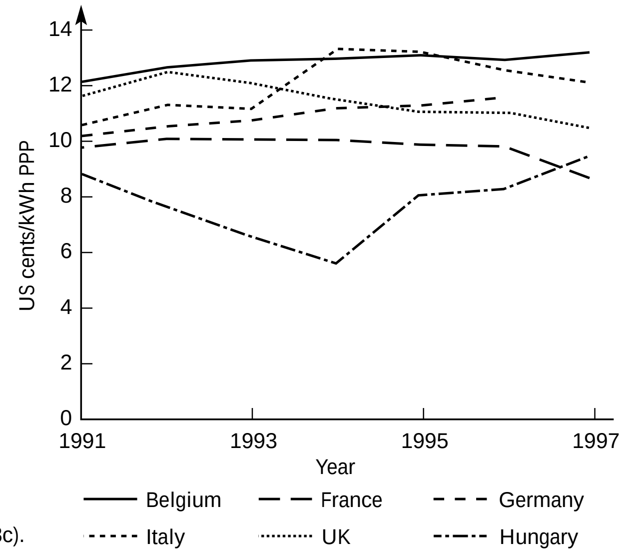
Subsidies and cross-subsidies can be sustained provided MVM Rt is the sole interface between upstream producers and downstream customers. This allows any subsidy at the production or wholesale level to be passed through intact to final consumers, while the inability of final consumers to contract directly with producers means that almost any structure of relative prices can be sustained (though there are problems if domestic prices are too far below commercial or industrial prices, as small businesses may succeed in obtaining supply at domestic

Figure 11.3 Industrial electricity prices pre-tax at PPP rates



Source: IEA (1998c).

Figure 11.4 Domestic electricity prices pre-tax at PPP rates



Source: IEA (1998c).

tariffs). It would be partially threatened by meeting the conditions of the Directive allowing large buyers direct access to generators in Hungary or abroad.

In 1998, the wholesale price of electricity was set on the basis of generation and transmission costs at 1 January 1997, which should have included a return of 8% on equity, as well as environmental and decommissioning costs. In the event, this would have required too large a price increase in 1996, and the state waived its right to a positive return on MVM's assets – both the transmission assets and the base-load nuclear power station at Paks, which generated 40% of total power in 1997. MVM Rt buys power from each generating company under a contract made up of two elements: a fixed capacity charge (payable when the station is available for dispatch); and an energy charge, related to the cost of fuel. The capacity charge covers non-fuel costs and a return on asset value. The cost of wholesale power is then the cost of generation plus the cost of transmission and other ancillary services, and the average wholesale price is capped by a formula that allows for variations in fuel and other prices.

The wholesale price was kept below the price that would prevail in a competitive pool for three reasons:

1. The price was heavily influenced by the average cost of written down plant, rather than the cost of signing new PPAs, though MVM Rt launched a capacity tender in July 1997 to lower this cost.
2. The average costs excluded the return on capital of a large part of the asset base.
3. The electricity is jointly produced with hot water and the price received for hot water may have been too high, effectively subsidizing the cost of producing electricity.[15] This effect is likely to be small, as the revenue from sales of heat appears to be less than 15%. Nevertheless, if the price of hot water were to be reduced by 25%, then the average cost of electricity would rise by perhaps 3%.

11.4.1 Competitive tenders for new power

The first two reasons are being addressed, as follows: as new plant takes a larger share of the total, it will inevitably play a larger role in determining the price, either because electricity will be priced at the marginal cost of entry, or because new plant will dominate the average cost base. The results of the recent capacity tender make interesting reading.[16] There were two tenders: one (97/1) for 800 MW of non-nuclear plant of size no larger than 200 MW, with a limit of 50% of the total to be gas-fired; the second (97/2) for 1100 MW excluded gas-fired generation. After revising the dates and amounts offered (down to 500 MW with the approval of the HEO), tenders were opened on 9 October 1998.

24 bids were submitted for the tender 97/1, with a gross capacity (after eliminating site duplication) of 3052 MW, about six times the nominal capacity of the tender invitation. Three fifths (1840 MW) of the total capacity of the bids were based on natural gas in CCGT plant, one third (1038 MW) on coal and only 173 MW on other energy sources (oil, geothermal, steam). More than a third of the total capacity of the bids (1045 MW) planned co-generation.

The winners of tender 97/1 were AES Fonix Kft with a 191 MW CCGT plant at Tisza II, and Budapesti Eromu Rt. (Budapest Power Plant Ltd.) with a 110 MW co-generation CCGT to be installed at the Kispest site. The average total cost of electricity produced by the project AES Fonix will be 6.43 HUF/kWh, while that produced by the Kispesti plant will be 6.87 HUF/kWh (both assuming 7000 hours per year utilization and indexed to January 1998). The average price deflated by the Producer Price Index to January 1997 would be 5.69 HUF/kWh.

The total capacity of the nine bids submitted for the tender 97/2 was 4017 MW net of alternative variants, again more than six times the nominal capacity offered. Nearly three fifths (2360 MW) of the total capacity of the bids were based on coal, one quarter (926 MW) on lignite, and less than one fifth (731 MW) on nuclear fuel. Among the coal-fired projects, 1600 MW was based on imported hard coal, 760 MW on mostly imported hard coal. In the event, none of the bids were accepted.

The average cost of this new plant ought on efficiency grounds to be setting the average price. In fact, the average price paid to generators on 1 January 1997 was 5.80 HUF/kWh (HEO, 1998, p. 24), while the average price paid to the early CCGT entrants (in prices of the same date) was 8.4 HUF/kWh, 45% higher. The average price of the accepted 1997 tenders was thus 2% *below* the (1997) average generation price, suggesting that the generation price may not have been too far out of line with its efficient level, though the tender prices were for base-load, which would be lower than the average (demand weighted) price (the off-peak energy price to distribution companies is about 62% of the peak price). It is worth noting that the competitive tender managed to lower the Power Purchase costs by about 20% in nominal terms (possibly as much as 33% in real terms), indicating the considerable benefits of competitive tendering.

The second reason for the depressed generation price was that the average costs exclude the return on capital of a large part of the asset base. The average cost of power from the nuclear power station at Paks was 3.55 HUF/kWh (1 January 1997 prices) and MVM Rt estimated that to recover 8% on its written down asset value would require a further 1.52 HUF/kWh to bring its cost up to

5.07 HUF/kWh, in turn raising the average cost of electricity by 6%.[17] The full cost of transmission is above the 0.5 HUF/kWh currently allowed, and the 8% return on assets would require a further 0.14 HUF/kWh, though the effect of the tight price-cap has been to induce MVM Rt to reduce costs. The latest results from MVM Rt suggest that they expect to reach their target rate of return of 1.5% for 1998, despite a smaller than expected increase in the price cap.[18] The price adjustments from 1 January 1999 are intended to allow the company to earn the full 8% return on assets.

A favourable interpretation of this strategy of apparently underpricing electricity relative to 1997 costs is that future CCGT costs might fall with more competition between, and more confidence by, investors, that future imports of electricity from neighbouring surplus countries (such as Slovakia) might be on favourable terms, and that, therefore, the current average cost of power would converge to the marginal cost of additional or replacement supplies.

To give a quick example of the kind of calculation that would have been easy to do in 1997, if the cost of CCGT (including site costs) is taken as £350/kW ($570/kW; 96 000 HUF at 1 January 1997 prices, which may be somewhat on the high side), and the thermal efficiency (gross calorific value) is taken as an undemanding 47%, then at a gas wholesale price of 449 HUF/GJ (the price at 1 January 1997, equivalent to $2.85/million BTU), the energy cost would be 3.6 HUF/kWh. If the annual non-fuel operating costs are as high as 3000 HUF/kW, and capital is amortized at 10% over 15 years with a load factor of 88%, then the average total cost of base-load electricity is 6.2 HUF/kWh (where all prices are computed at the reference 1 January 1997 level). This is about 9% above the tender offers, but 27% below the price contracted with PowerGen, only 7% above the 1997 average purchase price, suggesting that the average generation price may have been about right, and that MVM was right to seek competitive tenders for new power.

11.5 Reform issues

In 1998, Hungary was still deciding whether to continue with the single buyer model, but by 1999, the government had indicated that this approach was to be abandoned in favour of TPA, though whether this will operate with a more competitive wholesale market is not yet clear. Hungary already meets or could readily adapt to the requirements of the Directive on distribution (which is largely left to subsidiarity), while the requirement of unbundling, which requires accounting separation, is not demanding. Eligibility to contract is defined in terms of percentage of the market, which from February 1999 is (at least) 26.48%, corresponding to the rather high level of 40 GWh/year averaged across the EU member states. The second step increases market opening to at least 28%, corresponding to 20 GWh/year at the EU level one year later, and the third step increases the share to at least 33%, corresponding to 9 GWh/year (or less) in 2003. This last state is more restrictive than the original step in the United Kingdom of allowing all with demands of more than 1 MW the right to a choice of supplier or freedom to buy in the pool.

In Hungary, the limit of 40 GWh/year would allow 41 end-users consuming 18.9% of total consumption, and hence the limit would have to be lowered to meet the market share test. The government is willing to experiment with an initial market opening of rather less than 15% in 2001, or fewer than 41 end-users, but might allow this to be increased. Moving the limit down to 20 GWh/year would increase this to at least 95 end-users, but as they take only 24.3% of consumption, this would still not meet the first stage requirement of the Directive. Even moving the limit down to 9 GWh/year would liberalize at least 200 end-users, accounting for 29.2% of consumption, comfortably above the required second stage limit of 28%, but well short of the third stage. Hungary appears to be planning to introduce a very modest amount of competition into its electricity market, and we can ask whether this imposes any significant tensions on current arrangements.

As of mid-1999, generators are required to sell their entire output to MVM Rt under a PPA, and some of them receive less than the average price paid by MVM Rt, and certainly less than the cost of new generation. If, as planned, the single buyer is replaced by TPA, then some adjustments and rebalancing of these contracts will be required, though if the contracts are not voided by the change in industrial structure, they can presumably be renegotiated to produce the same revenue to the generators at the reference level of output (and presumably higher profits at market-determined levels of output). If required, MVM Rt could preserve its profitability by adjusting transmission tariffs to recoup any possible loss of income, and in any case, over 70% of consumption would still be captive and hence could be charged whatever it cost to ensure security of supply to that market.

Replacing the single buyer might, however, seem to threaten the inherited system of cross-subsidy, where domestic consumers are subsidized by industrial consumers. Even this domestic subsidy might be preserved, though, by raising high tension transmission costs and reducing low voltage connection charges, as well as raising tariffs to the non-domestic captive consumers. Designing such a system of cross-subsidy would be quite complex, though, as the proportion of sales to industrial, commercial and domestic consumers varies across the RECs. The new energy policy intends to eliminate these cross-subsidies gradually, so this issue may not arise.

A more serious threat might seem to arise from the intention to allow large end-users to contract with foreign producers, who might be selling at below the cost of new entry, particularly given the excess capacity in neighbouring countries. This might result in MVM Rt as the holder of the stranded contracts losing the profits on the cheap imports that would have to be recovered, either through higher transmission tariffs or from the captive franchise market. Prices to domestic consumers would then almost certainly have to rise further.

11.5.1 Tariff structure and level

The other major issue which is gradually being addressed is the structure and level of prices. These remain inefficient, though it is also a quite effective method of transferring most of the remaining rent in the system to domestic consumers, while allowing domestic prices to rise gradually to the efficient level, set by the average cost of new entry. The inefficiency of the 1998 system of domestic consumer subsidy was probably small, for there was an increasing marginal price, and most evidence suggests that domestic electricity consumption is inelastic by income and price, given the existing stock of durables. The main price responsiveness comes from the choice of heating, and as gas and possibly district heating are also underpricing, the durable decision may still be efficient, even if the amount of insulation is sub-optimal. Clearly, though, as these other competing fuels are repriced the electricity price also needs to be adjusted. In January 1999, the lowest price band was increased by the largest percentage as part of the planned July 1999 move to a uniform tariff.

An alternative method of rebalancing marginal domestic tariffs more rapidly might have been to retain the underpricing of the 600 kWh/year block and to move to efficient pricing of the amount above that. If this results in too large an average increase in domestic tariffs, then the first block could be chosen so that 65–75% of domestic customers consume more than this. In 1997, there were 4.6 million household consumers consuming 9.76 TWh, suggesting an average consumption per consumer of 2122 kWh/year. Setting the block size for the first tranche of cheap power at 1800 kWh/year might allow the marginal price to be raised to the proper level in one step, without raising the median electricity bill by an unacceptable amount. Such a proposal could be investigated using household budget survey data (with which Hungary is very well-endowed, though the 1999 decision to unify the tariff appears to rule this out).

Would it be desirable to raise the wholesale price to the efficient level? The efficient level is the system marginal price (SMP), which could be computed as the avoidable cost of the marginal set, plus the extra costs of start-up spread over the hours needed. Judging from the UK experience, this can vary by a factor of three to six over a normal day, and has varied by much larger factors, for example if the full annual costs of keeping available the marginal plant required for the peak are charged to the peak hours. As it is desirable to invest in new plant, it must be the case that the (appropriate) average of the SMP would cover the annual costs (including interest and depreciation) of this new plant, and hence the level would have to rise, as well as the time-profile changing.

The argument for having an efficient wholesale price is that it gives clearer signals for auto-generation and co-generation, both of which are discouraged by low prices (and possibly also the flat average price, which may discourage installing plant for peak-lopping, or even managing demand).[20] One natural way to make the wholesale price approximate the efficient price more closely is to liberalize the wholesale market, and allow it to be set by competition, as in an electricity pool.

An additional advantage of the pool model is that facilitates retailing (supply) competition, which in turn aligns prices with costs and encourages cost reductions in metering and billing. Suppliers are free to buy from generators or in the pool at the pool or pool-related contract price, whereas with the single buyer, each power station will be paid a different amount at the margin, and must be prevented from contracting for marginal sales with final consumers unless they can somehow be charged for the fixed costs. The consequence is that the single buyer takes all the risks of plant choice and may find that it has inherited a set of stranded assets, if at some later date a pool is introduced and consumers can contract directly with power stations. As MVM Rt increases its contract exposure with each new tender, the risk of stranded contracts increases, and this may explain the current view that the single buyer should be abandoned in favour of a pool.

What are the drawbacks of the pool model?

1. Prices would move up to the SMP, which might give windfall gains to existing generators and raise prices to consumers, especially to domestic consumers. This can be avoided by ensuring that existing generators continue to honour existing PPAs, which could be transferred to a holding company that receives the profits of bidding these plants into the pool and paying the agreed PPA terms. Such a company might in turn be jointly owned by the RECs in proportion to the number of domestic customers, and the profits could be used (as was the case up to 1999) to subsidize the first block of domestic tariffs, via the setting of price caps.
2. Competitive pools seem to find difficulty in ensuring adequate margins of infrequently run plant, judging from the case of Victoria in Australia. This again can be avoided by charging the independent system operator to contract for such plant and include the costs with other ancillary charges.
3. A pool may or may not be perceived as more risky than contracting with the single buyer. If the contracts with the single buyer are considered secure and enforceable, then the risks should be less than a pool, which, as a competitive market, suffers both from price and demand uncertainty as well as regulatory risk from possible intervention. The England and Wales pool is currently under review and possibly dramatic changes are proposed, which are intended to reduce market power and thus lower prices (Offer, 1998c). Investors might fear that similar reforms would threaten any pool set up in Hungary.

11.6 Further restructuring and privatization

MVM Rt remains in state ownership, and remains integrated with both transmission and nuclear power generation. Several countries have demonstrated that both the grid and nuclear power stations can operate under private ownership, though there are also good arguments for delaying their sale to ensure the market has adequate performance information to value the assets. Whether or not MVM Rt should be further unbundled is logically separate from whether or not transmission or Paks should be privatized.

The argument for unbundling is the normal one of ensuring unbiased treatment of existing and new generation. The argument for continued integration is that Paks would not (often) set the price of electricity in any pool that were to be set up, though if MVM Rt were allowed to build new generating plant or to continue to own Vértes then it might well set the marginal price, and would thus have a stake in ensuring favourable dispatch. The other arguments mainly have to do with financial stability, which might give MVM Rt the ability to invest abroad (or even at home, though this again raises issues of vertical reintegration).

Whether or not this is desirable is less clear: the ambitions of well-funded technological imperialists may not coincide with the interests of consumers, shareholders or the country. As the industry matures under its new structure, the existing and impressive talent and experience that resides in MVM Rt may be less critical to the continued success of the industry, and the lower profile role of a transmission company may be the preferred final structure for MVM Rt. Subsequent restructuring decisions will clearly be easier if the company (together with Paks) remains in public ownership. Selling Paks on its own to a generation company would not seem to raise any important problems, and would be an intermediate and perfectly acceptable solution to the need (if it exists) for the government to raise more revenue from privatization.

Selling the remaining shares in the rest of the ESI presents fewer problems, though there would be a good case for transferring the residual shares into a state pension fund, as they should provide exactly the steady income stream needed for such purposes, and provide some offset if prices rise to pensioners, as profits should also then rise.

11.7 Conclusions

The restructuring, regulation and privatization of the ESI represent a significant achievement for Hungary, placing it in a leading position among transitional countries. The legal framework and the regulatory institutions have been able to win the confidence of foreign investors, both during privatization and in response to invitations to tender for additional capacity. The present system is still in transition, though, as it is still adapting to the requirements of the Electricity Directive (and other EU standards for safety, environmental emissions, etc.), and it has not yet weathered its first regulatory review when the price cap may be reset. Prices remain below efficient levels and the structure of prices remains unbalanced, with large cross-subsidies paid to domestic consumers, though these inefficiencies are gradually being addressed. Gas and district heating prices are also distorted, further complicating rational fuel use and investment decisions. These inefficiencies reflect very reasonable distributional concerns, and the resulting inefficiencies are probably modest.

Planned market liberalization should increase the pressure to cut costs, and would be most likely to put pressure on any remaining subsidies. Some of the current underpricing of domestic electricity is politically and distributionally justified, so liberalization should be carefully designed to ensure that rents are not transferred from consumers to shareholders, at least not without adequate recompense. It should be possible to do this without great difficulty, so distributional considerations are not a compelling argument against liberalization nor against improving the efficiency of price signals in the industry.

The Directive appears to be influencing Hungary's energy policy in desirable directions, possibly against some political opposition, as there are suggestions that electricity liberalization will be delayed if Hungary's accession to the EU is postponed. The most promising steps in the near future are liberalizing imports by eligible customers, as that is likely to put downward pressure on prices and create support for further liberalization.

Notes

1 The author of this chapter, David Newbery, is indebted to András Kacsó, Pál Valentiny and Jozsef Balogh for helpful comments.

2 See European Commission (1997a) for the Commission's opinion on Hungary's application for EU membership.

3 PJ = petajoules, 1 million GJ (gigajoules), a measure of energy. 1 tonne of oil is about 40 GJ.

4 Thus, the mines produced only 4.2 million tonnes coal equivalent.

5 In 1989, 13 out of 27 coal mines were closed, the number of employees reduced from 50 000 to 21 000, and the output of deep mines cut from 12.5 mt to 7 mt, the balance coming from lower cost surface mines. The coal has low calorific value and high sulphur content, and except for a possible new lignite power station at Matra, the coal mining industry will continue to decline.

6 To put this into perspective, the coal and oil-fired generators of National Power in England and Wales released on average 8.9 tonnes SO2/GWh in 1995-6, varying from a high of 14.8 tonnes/GWh to 3.24 tonnes/GWh at Drax, where FGD has been installed (National Power *Environmental Performance Review 1996*).

7 49.23% of Titasz (3.14 TWh) was sold to Isar-Amperwereke for $132m, 47.71% of Demasz (3.56 TWh) and 47.55% of Edasz (5.68 TWh) were both sold to EdF (for $155m and $197m), 47.25% of Dedasz (3.56 TWh) was sold to Bayernwerke for $108m, and 46.15% of Elmu (7.81 TWh) and 48.81% of Emasz (4.61 TWh) were both sold to RWE-EVS for $358m and $164m.

8 48.76% of Dunamenti (1870 MW) was sold to Powerfin SA for $141m and 38.09% of Matra (800 MW) was sold to RWE-EVS AG for $74m. 80.81% of Tisza (1281 MW) was sold to AES Corp. The price/kW capacity refers to the first two bids for which bid prices are known.

9 The apparent greater ease of selling distribution companies can be explained by the system of regulation and the structure of subsidies. The value of the distribution companies depends on the margin between the buying and selling price of electricity, which could be adjusted to remunerative levels while preserving the politically desired final price level by holding down the wholesale price of power. The profitability of the generation companies depended on the cost of fuel (which was expected to rise to world market levels) and the wholesale price, which buyers feared would continue to be subject to political intervention. It required a demonstration that wholesale prices would be set at remunerative levels for foreign investors to make satisfactory bids. No doubt the successful sale of the distribution companies to large and politically influential foreign buyers increased the credibility of Hungary's electricity privatization programme.

10 The Electricity Act was amended in 1998 (Act XIII of 1998) to modify the rules on vertical and horizontal integration, but otherwise did not adapt the law to meet the requirements of the Electricity Directive. In 1999, a new Electricity Bill was under discussion.

11 The data are averages of the ratios for the United Kingdom for 1993/4 to 1996/7, taken from the *Digest of UK Energy Statistics*, which have a coefficient of variation (CV) of up to 5%, and the average of the four quarterly ratios for 1997 in Hungary taken from HEO (1998), which have a CV of around 1%. The relativities continue to apply in 1998, but change with the tariff rebalancing of 1999.

12 The pool price in the United Kingdom excludes the coal surcharge that is included in the average contract prices and passed on to domestic customers, while in Hungary the low ratio of domestic to non-domestic prices lowers the wholesale price relative to the non-domestic price, so neither comparison is quite as simple as it looks.

13 The UK consumer price includes the coal surcharge (to pay for domestic coal at above world market prices), which raises the consumer price above its efficient level. In addition, all the UK sales prices include the Fossil Fuel Levy, which until 1998 was 10%, but was then lowered

to 1%, to pay for nuclear decommissioning (until 1998) and renewables. This decreases the ratio of generator pool price to the sales price (though it remains higher in the United Kingdom than Hungary).

14 Those taking 10 000 kWh/year of which 5500 kWh is at the lower night-time rate pay 66% of the average, but this is not directly comparable. (*UK Digest of Energy Statistics 1997*, p. 181).

15 Apparently, the cost of hot water was subsequently reduced, so as of 1999, this may no longer be relevant.

16 See http://www.mvm.hu.

17 This includes contributions to a fund of 100 billion HUF for decommissioning costs. The value of Paks may be higher than its written down book value, if it can displace power otherwise produced by new CCGT at current tender price levels.

18 See http://www.mvm.hu.

19 The same effect can be achieved in other ways, for example, charging the fixed costs, including the costs of the reserve margin, in proportion to demand taken or nominated at the system peak. Which is best probably depends on how power is metered and charges are levied.

20 Again, whether this is a problem depends on the structure of the contract for selling wholesale power to large users. As a general rule, contracts in vertically integrated systems tend to oversimplify the underlying price variability, but the high average demand factor in Hungary suggests that load management is quite good. IEA (1995, p. 128) commented that the 1994/5 tariff structure was quite sophisticated in reflecting time of day differentials, but was unlikely to track marginal costs properly, and this assessment may well still apply.

PART 3: Policy Lessons for the European Electricity Market

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12 The Problems and Experience of Liberalization

The countries examined in Part 2 of this Report are at very different stages of the liberalization process. Only England-Wales and Norway-Sweden have had significant experience of their chosen path to greater competition. At the other extreme, as of early 1999, France had not yet officially adopted the legal texts required to implement the European Commission's Electricity Directive. Both Spain and Germany are in an intermediate situation, where newly designed electricity markets and/or regulations are in place but have had little time to provide reliable evidence of their effectiveness. Finally, Hungary is an interesting example of how the Directive is already affecting countries aiming to join the EU within the next few years.

As Tables 12.1–12.6 show, there is considerable variety both in the initial situations of these countries' electricity industries and in the ways they have chosen to implement the Directive. This chapter compares progress to date in liberalization across the various countries. It then examines the strength of the connection between country-specific factors (such as energy endowments, initial industry structure and 'social preferences') and their different approaches to liberalization. Finally, we draw some lessons for policy.

12.1 Progress to date

12.1.1 Ownership and concentration

Although most of the countries began with some public ownership in the electricity sector, they chose a variety of methods of restructuring the industry. England and Wales had a single publicly owned generating and transmission company, but reduced the initial concentration in generation by dividing the public assets between three companies before privatization. A similar path was followed in Hungary where the non-nuclear generation assets of the state-owned MVMT were separated into separate companies and most were then sold to foreign investors. Spain also decided to privatize the publicly owned generator Endesa, but only after allowing it to absorb two other companies.

In contrast, France, Germany, Norway and Sweden chose not to privatize any of their publicly owned generation and transmission companies. Yet, these countries still ended up with very different market structures: Norway and, to a lesser extent, Germany were already blessed with a large number of independent firms, while France's EdF and Sweden's Vattenfall controlled more than 90% and 50% of their respective national markets.

Table 12.1 Ownership and concentration

State	*Public ownership before liberalizing*	*Privatization*	*Initial concentration ratio (CR) in generation**	*Imposed restructuring*
England and Wales	Complete in G+T+D+S G+T in CEGB D+S in 12 Area Boards	Generation: National Power (1991,1995); PowerGen (1991,1995); British Energy (1996) Transmission: NGC (1990, 1995) Distribution (1990)	CR1=1.0	Independent transmission Three independent generation firms CR1=0.49, CR2=0.85 Further divestment of generation capacity subsequently
Scotland	Two vertically integrated G+T+D+S	Scottish Hydro and Scottish Power (1991), Scottish Nuclear (1996)	CR1=0.73 CR2=1.0	Nuclear stations transferred to Scottish Nuclear, CR1=0.38
Northern Ireland	Complete in G+T+D+S	Trade sale of three generating companies (1992), NIE (1993)	CR1=1.0	Unbundled G, separated into three companies, CR1=0.49
France	EdF (G = 92%, D+S = 94%, T = 100%)	None	CR1=0.92	None
Germany	Mostly mixed	None	Low, but non-compete agreements and cross-ownership links – correcting for these links, CR1=0.29, CR2=0.5, CR3=0.6	None
Hungary	Complete in all segments	Extensive: all of D, about 50% of G. Grid still state-owned	CR1=1.0	Break-up into eight generators (CR1=0.42) and six distributors
Norway	State: G = 30%, T = 80% Local govt: G = 55%	None	CR1=0.25 CR2=0.32 CR5=0.5	Independent transmission company
Spain	G = 38% T = 52%	Sale of all generation assets mostly before liberalization	CR2=0.65	Consolidation to CR2=0.78
Sweden	Vattenfall (G = 50% + grid). Scattered ownership on regional net and in distribution	None (on grid)	CR1=0.5	Independent transmission company

Notes:
*CR1, CR2, CR3 … are the shares of total electricity output generated by the biggest 1, 2, 3 … firms.
G = generation, T = transmission, D = distribution, S = supply

Distribution activities were universally organized as a set of local or regional monopoly franchises and they have remained so. There were, however, considerable differences in levels of vertical integration among the countries. Initially, France, Germany, Hungary, Northern Ireland and Scotland had almost complete integration of generation, transmission, distribution and retailing (supply) activities, while England and Wales combined generation and transmission in a single company.

Still, there were significant differences in the level of centralization of these national systems. In Hungary, the whole sector was controlled by a single holding company. France concentrated 92% of generation capacity, 94% of distribution and retailing and the entire transmission network in the hands of EdF. In England and Wales, the CEGB operated all generation and transmission while distribution was in the hands of 12 Area Boards with local monopoly franchises. In Germany, eight EVUs (see Chapter 8) – ultimately controlled by only four firms – own 80% of generation, 33% of distribution and all of the transmission network.

Less extreme forms of vertical integration were found in Spain, Sweden and Norway. Spanish electricity companies were generally involved in generation, distribution and retailing, but transmission was mostly controlled by the publicly owned REE. Although Vattenfall had a 50% share of generation and controlled 100% of the Swedish transmission grid, investment in the grid was effectively determined by a common board, where all companies operating on the grid were represented. In Norway, the state-owned company Statkraft controlled 30% of generation and 80% of the transmission network, while about half of the local distributors were also involved in local hydro generation.

12.1.2 Vertical separation

The degree of vertical separation imposed in the newly liberalized markets varies widely across countries. England and Wales, Norway, Spain and Sweden, have all opted for the creation of a legally independent transmission company that also acts as transmission operator.[1] At the other extreme, Germany and France have not changed the ownership structure of their grid, simply requiring accounting and management separation between grid-related activities and the other activities of the vertically integrated firms.

All countries have chosen weaker forms of separation between generation, distribution and retailing activities, all allowing joint ownership of these vertical links. The weakest requirements are found in France: they only require accounting separation of distribution and generation. Most other countries have gone one step further by also imposing accounting separation of retailing. The most demanding requirements are in Sweden (where distribution must be legally separated from generation and retailing) and Spain (where legal separation of all three types of activities will soon be imposed on all market participants).

12.1.3 Transmission

Germany opted for negotiated third party access (nTPA) to transmission and decided to let distribution companies choose between this approach and the single buyer model. Hungary started with a single buyer model, but is considering a switch to regulated third party access (rTPA). All other countries have decided that access to transmission and distribution networks would be granted on the basis of rTPA charges. This apparent uniformity hides significant differences in the way these charges are set, however. Sweden has a rather informal regulation mechanism: for example, it does not regulate the structure

Table 12.2 Vertical separation and distribution

State	*Initial vertical integration*	*Mandatory vertical separation*	*Supply monopoly franchises*	*Access to distribution*
England and Wales	G+T, 12 D+S	Transmission Some restrictions on integration between G+D	<1 MW until 1994 <100 kW until 1998 None by mid-1999	rTPA (price cap)
Scotland	G+T+D	Accounting separation of G, T, D	As England and Wales	rTPA (price cap)
Northern Ireland	G+T+D	G separated from T+D	None *de jure*, almost complete *de facto*	Single buyer
France	Almost complete	Accounting separation of G, T, D Management separation of T	Yes (94% EdF)	rTPA
Germany	Almost complete (G+T+D+S) 8 EVUs have: 80% G, 100% T, 33% D	Accounting separation throughout Management separation for T	None *de jure*	nTPA + single buyer (until 2005)
Hungary	Complete	None	Yes	Single buyer (until 2001?)
Norway	Significant integration G+D	Accounting separation throughout Separate company for T	None	nTPA (two-part tariff)
Spain	Extensive between G+D; generators own about 40% of high tension wires (mostly 220 kV)	Accounting separation throughout; legal separation of G, D and S to be required later	<5 GWh until October 1999 <1 GWh after that None from 2007	rTPA
Sweden	Extensive integration T+D; and G+S	Legal separation of natural monopolies activities (D, T)	None	rTPA

Note: G = generation, T = transmission, D = distribution and S = supply

Table 12.3 Transmission

State	*Owner of transmission system*	*Transmission system operator*	*Access to transmission system*	*Transmission charges*
England and Wales	National Grid Company	National Grid Company	rTPA (price caps)	Zonal connection, transport and security charges
Scotland	Scottish Power, Scottish Hydro	Scottish Power, Scottish Hydro	rTPA	Under review
Northern Ireland	NIE	NIE	Single buyer, but changing to bilateral trading	Postage stamp, use of system per kWh
France	EdF	EdF	rTPA	Postage stamp
Germany	Eight firms (EVUs)	All grid owners	nTPA/single buyer (temporary)	Distance related (over 100 km)
Hungary	MVM Rt	MVM Rt	Single buyer (MVM Rt), possibly moving to rTPA.	Nodal
Norway	Statnett	Statnett	rTPA	Nodal
Spain	Red Electrica de España (about 55%) and electrical companies	Red Electrica de España (supposed to be spun off)	rTPA	Postage stamp
Sweden	Svenska Kraftnätt	Svenska Kraftnätt	rTPA	Nodal

of transmission and distribution tariffs and their level has only recently been subjected to a kind of price-cap regulation. Norway, on the other hand, has recently moved to a formal regulation regime for both transmission and distribution tariffs. England and Wales have a rather transparent system, which imposes a price cap on distribution services while both generators and consumers pay regulated zone-based annual transmission charges. Somewhat oddly, Spain combines strict regulation of network access charges with a serious lack of transparency: the rules governing how these rates are set are vague enough to be 'renegotiated' every year between the government and industry incumbents.

12.1.4 Investment

One of the main concerns initially raised by liberalization and the associated unbundling of vertically-related activities was that the new system might not

Table 12.4 Investment

State	*Generation*	*Transmission*	*Distribution*
England and Wales	Authorization	To maintain service quality by owner and 'meet all reasonable demands'	
Scotland	Authorization	As for England and Wales	
Northern Ireland	Authorization	As for England and Wales	
France	Authorization + tender	Transmission Systems Operator (EdF)	Relevant distribution franchise owner
Germany	Environmental authorization	No formal requirements	No formal requirements
Hungary	Authorization from Parliament (>600 MW), Government (200–600 MW) or the ministry (50–200 MW)	TSO (MVM Rt)	Relevant distribution franchise owner
Norway	Authorization	Authorization	Authorization
Spain	Authorization	Tender	Assigned to owner of monopoly franchise
Sweden	Authorization	Authorization	Authorization

provide adequate incentives to invest and/or to coordinate investments across activities (particularly the location of new generation and the extension of the grid). These concerns motivated the inclusion of tendering for investment projects and the single buyer model as possible options under the Directive. The Commission were determined that the single buyer model should be as close as possible to rTPA. This removed its possible attractions for incumbents wishing to protect their market, while exposing them to the risk of stranded contracts.

Most countries have chosen to use administrative authorization procedures for investments. Still, there is some variation in the stringency of these procedures: in Germany, the only authorization needed is an environmental licence; in France, investment projects have to 'be compatible with the Plan'; and in England and Wales and Spain, delays or fuel-based restrictions on entry have already been imposed by the government. In addition, France reserves the right to use tendering to foster socially desirable investment in generation that would not otherwise be provided by the market. Hungary, which uses the single buyer model, continues to hold periodic tender auctions for new investment.

12.1.5 Electricity markets

Electricity markets have been organized in a variety of different ways. At one extreme, France, Germany and Hungary have chosen to rely solely on bilateral contracts.[2] All other countries have opted for some form of pool. Sweden and

Table 12.5 National electricity markets

State	*Electricity pool*	*Capacity payments*	*Physical contracts*	*Market operator*
England and Wales	● Compulsory ● Gross ● Limited demand-side bidding ● Forward market	Yes	No, but can be achieved by bidding and financial contracts	NGC
Scotland	No	Yes	As for England and Wales	SHE, SP
Northern Ireland	None	Part of PPA	Yes	NIE
France	None	Yes. Reserves provided by EdF. Users of the grid are charged for the service	Yes	N/A
Germany	None	No	Yes	None
Hungary	None	PPA	Yes?	(MVM Rt)
Norway	● Nord Pool (with Sweden and Finland) ● Voluntary ● Net ● Futures market	No	Yes (85% of physical trade)	Statnett Marked (1990) Nord Pool ASA (1996)
Spain	● Compulsory ● Gross ● Demand and supply-side bidding	Yes	Yes (negligible quantities)	Private company with restrictions on ownership by market participants
Sweden	● Nord Pool (with Norway and Finland) ● Voluntary ● Net ● Futures market	No	Yes	Nord Pool ASA

Norway share Nord Pool, a voluntary net pool with a spot market and a futures market. This system is complemented by a set of balancing markets administered by the national system operators. It leaves the provision of ancillary services to the system operator and does not offer capacity payments. England and Wales have so far used a single compulsory, gross pool with a spot market and a rather illiquid forward market. Capacity availability is rewarded. The Spanish pool is also compulsory and makes capacity payments. It combines bidding on both the supply and the demand side. The pool includes a set of balancing markets as well as markets for ancillary services, but it does not yet offer a futures market. After providing the world with the prototypical model for a pool, the United Kingdom is now contemplating a change to something closer to Nord Pool, suggesting that the most suitable format for a wholesale market remains unsettled.

12.1.6 Regulation and social policies

Germany is the only country that has not appointed a sector-specific regulator. Instead, it chooses to rely on the oversight of the Ministries of Economics and the Environment of its Länder and the federal competition authority. All other countries have set up at least one statutorily independent regulator. There can still be important differences in the effective power of these regulators, however. At one extreme is Spain, where the CNSE has mostly consultative powers and has consistently been ignored by the Ministry of Industry and Energy. At the other extreme is England and Wales, where the Office of Electricity Regulation (Offer) appears to have exerted significant influence on the industry, not only in controlling prices, but forcing further divestiture of generation.

Finally, with the exception of Germany, all countries have maintained some form of public service obligation. All have also kept some form of energy policy through the imposition of various taxes, direct interference in the dispatch order and/or restrictions on entry into generation. For example, England and Wales have a non-fossil fuel obligation, a fossil fuel levy and a moratorium on gas-based entry. Spain imposes a fuel diversification levy, which supports both coal and nuclear power; it also gives priority to non-fossil fuel units and can modify the order of dispatch to favour coal-based units. In Germany, access to networks can be denied if it would imperil the use of eastern German lignite-based plants. Generation using renewables is also favoured in a variety of ways across the EU.

12.2 Different models for different situations?

The evidence from the country studies raises two important questions:

1. Why do the 'models' chosen by these countries differ so much? In other words, are there any reasons to believe that country-specific factors, such as energy endowments, initial industry structure or 'social preferences', largely predetermine each country's approaches to liberalization?
2. Can one still draw any sufficiently robust policy conclusions from such a disparate set of national experiences?

Table 12.6 Regulators and social policies

State	*Regulators*	*Public service obligations*	*Energy policies*
England and Wales	DGES and Offer – statutorily independent	Yes	• Non-fossil fuel obligation • Fossil fuel levy • Gas moratorium • Coal stocks
Scotland	As for England and Wales	Yes	• NFFO • Nuclear Energy Agreement
Northern Ireland	Ofreg	Yes	• NFFO • Natural gas from Scotland, interconnector
France	CRE – statutorily independent	Yes (obligation to supply placed on EdF within the regulated sector)	Fuel priorities (nuclear, renewable)
Germany	Ministry of Economics of Länder and Federal Cartel Office	No	Eastern German lignite (possible access refusal)
Hungary	Hungarian Energy Office, Minister of Industry and Trade, Miniser of Finance	Yes (obligation to supply placed on RECs)	• Energy conservation • Clean air • 1993 Parliamentary resolution on Hungarian Energy policy
Norway	NVE Ministry of Oil and Energy	Yes	–
Spain	CNSE – statutorily independent but mostly consultative. Ministry of Industry and Energy	Yes (placed on the distribution companies within the regulated sector)	Subsidies to coal and priority dispatch of coal units up to 15% of primary energy requirements Priority to renewables Fuel diversification levy
Sweden	STEM	Yes (obligation to connect, not to supply)	Plan to phase out nuclear power. Subsidies to wind power and renewables

This section discusses whether there is a strong link between the specific situations of the countries reviewed in Part 2 and their approach to liberalization. If the answer to that question is positive, then it might be argued that each country has essentially designed the most appropriate system given its own special circumstances, and that it is therefore vain to try to draw policy lessons from a comparison of their respective experiences. If on the other hand, country-specific circumstances have had only a moderate influence on different national approaches to liberalization, then basing policy conclusions on cross-national comparisons may still be useful.

We identify three main sources of 'country-specificity': access to primary energy sources, initial industry structure and social preferences.

12.2.1 Access to primary energy sources and initial fuel mix

Because of the efficiency of CCGT plants, access to natural gas is an important determinant of potential entry into generation. Entry can have a pro-competitive effect in at least two ways:

1. Actual entry can reduce the degree of monopoly power in generation.
2. In a market dominated by bilateral contracts, potential entry keeps the contracted prices in check.[3]

If country-specificity plays an important role in the liberalization process, one might expect countries where access to gas (and other sources of competitive pressure, such as international trade) is more limited to pay more attention to the issue of market power than countries where entry through CCGT is credible. The evidence does not support such a link. England and Wales had ready access to natural gas, but it was still thought to be important to divide up the generating assets; and since privatization, there have been further forced divestments. Spain, where access to gas is problematic and trade severely constrained, chose to increase concentration in generation.

With the notable exception of France, the initial importance of nuclear power has only had a limited effect on the countries' approaches to liberalization. There are two main reasons for this:

1. Most countries have abandoned the construction of new power plants and have dealt with the economic viability of existing plants in a fairly neutral manner through the use of 'nuclear taxes' tagged onto final electricity prices (for example, England and Wales and Spain) and/or by keeping non-performing plants in the public domain (England and Wales).
2. Nuclear power plants are used for supplying base-load power, which means that they do not directly affect the marginal price of electricity in pool based systems.[4]

The situation is quite different in France where most of EdF's capacity is nuclear and where the commitment to a continuing nuclear programme is strong. The preponderance of nuclear power has been used to justify the lack of both horizontal and vertical break-up of EdF. According to these arguments, EdF's large share of the generation segment makes it possible to reap significant dynamic economies of scale ('learning by doing') in the design and building of nuclear facilities, while the greater cost of breakdown under a nuclear system argues for the continued integration of generation and network activities.

The availability of hydro power has not had a profound impact on regulatory schemes. The experience of both Norway and Sweden indicates that the most significant consequence of large amounts of hydro power has been the lack of capacity payments. It has also lead to low electricity prices. Those who believe that privately owned firms are intrinsically more efficient than publicly controlled companies might argue that these low prices help explain the lack of pressure to privatize that is characteristic of these two countries.

Finally, the most significant effect of historical reliance on costly and inefficient national coal or lignite has been to motivate energy policies such as coal subsidies, dispatch priority or, in England and Wales, the gas moratorium.

12.2.2 Initial industry structure

As Section 12.1 above showed, there were considerable differences across countries in the initial degree of concentration in generation, the degree of vertical integration and the extent of public ownership. There are, however, few clear links between those initial conditions and the subsequent policies adopted by the various countries.

Clearly, countries like Norway that began with a fragmented industry structure did not have to worry very much about designing markets that could perform well in the presence of market power. In contrast, countries with significant concentration in generation, like England and Wales, France, Hungary, Spain and Sweden, adopted very different approaches to the problem. They ranged from ignoring the issue (France and Spain) to forceful restructuring (England and Wales and Hungary) or diluting market power through international market integration (Sweden).

Policies toward public ownership also exhibit a somewhat unpredictable pattern. Extensive privatization has taken place both in countries with large initial levels of public ownership (England and Wales) and in countries with a more moderate share of public assets (Spain). Continued public ownership was chosen by countries with one large public company (EdF) as well as countries with a more diverse structure (Germany, Norway and, to a lesser extent, Sweden).

Finally, it is hard to discern any systematic relationship between the initial state of vertical integration and the stringency of measures of vertical separation imposed by liberalization policies.

12.2.3 Social preferences

Social preferences have strongly affected national electricity policies in at least three respects:

- The first is the public attitude toward nuclear power. This is a very significant factor in explaining the differences between France, where the ‘taming’ of nuclear power is seen with pride as a national achievement, and all other countries, where any revival of a nuclear programme is either politically unthinkable or not commercially viable.
- The second aspect concerns attitudes toward public ownership. Norway and Sweden’s receptiveness to the benefits of ‘benevolent’ local public ownership contrasts with a greater taste for privatization in England and Wales (and even, increasingly, Spain) and with the French glorification of the giant public enterprise as national champion and agent of social justice.

- Finally, social preferences have also been moulded by the history of cross-subsidization between different types of electricity customers. This is most clearly seen in Hungary where the tradition of extremely low prices for household consumption has somewhat hampered the government's ability to provide foreign investors with satisfactory rates of returns.

12.2.4 Initial conditions and subsequent policy choices

The basic conclusion of this section is that while differences in the initial situations of the various countries help explain some of their divergent policy choices, they certainly do not account fully for the considerable variety of 'liberalization packages' adopted. Indeed, it is clear that the early experiences of liberalization in Norway and the United Kingdom had a considerable influence on the Commission in deciding how to extend the single market to electricity. In preparing the Electricity Directive, those arguing for a more liberal set of conditions for electricity trade could point to these early successes. Defenders of the old order, who claimed that any radical approach would run into difficulties, lost the argument.

Later on, EU members were subject to 'benchmarking by embarrassment', when they were asked to explain how their preferred choices of options (such as the single buyer model) were superior to demonstrable alternatives that clearly worked. The rapid pace of liberalization owes much to the ability to learn from other examples, and this is increasingly being encouraged by regular meetings of the regulators, who can exchange their experiences. One can, therefore, usefully compare the experiences of these countries in an attempt to derive policy recommendations.

12.3 Policy lessons

Since the number of countries analysed and the cumulative length of their liberalization experiments are both quite small, our policy recommendations are necessarily somewhat tentative, especially on subjects like transmission pricing, where the available evidence is even more sparse.

The first unambiguous conclusion is that the Cassandras were wrong. Whatever the speed of liberalization and the degree of vertical unbundling, the newly designed electricity systems *have performed well technically*, with the possible exception of access to the international transmission grid. The introduction of competition has not led to any system-wide crashes and it does not seem to have led to any deterioration in the quality of services, at least in isolated countries such as the United Kingdom, or those with long experience of managing international trade, such as Scandinavia.

There was an incident in Belgium in 1997, when the system operator, relying on contractual information, experienced unexpected power flows from France through Belgium to the Netherlands in spite of contracts indicating that the power should flow the other way. This demonstrates the futility of relying on contract-path information, and the importance of designing satisfactory transmission operations in a shared, interconnected system such as that in the Continental heartland. With that important and instructive exception, there have been essentially no technical problems to date in Europe.

The experience of countries such as England and Wales, Norway and Spain has also shown that, contrary to earlier claims, complex pricing systems in either the pool or transmission can be technically implemented.

The rest of our conclusions deal with various aspects of the liberalization process. Whenever possible, we try to support our recommendation with examples from the country studies as well as some theoretical considerations. More detailed presentation of the theoretical arguments are in Part 1 of this Report. Some themes, like the theory and practice of transmission pricing, are also developed further in the final chapter.

A: It is important to reduce concentration in generation

The experiences of England and Wales and Spain strongly suggest that competitive outcomes cannot be reached without sufficient dispersion of the ownership of generation assets. The two cases are interesting in their differences. Spain is, to some extent, a less convincing example because of the existence of severe barriers to new entry (for example, the lack of access to gas and the lack of transparency). We do not know, therefore, whether to attribute the lack of competitiveness of the Spanish market more to these barriers or to the high concentration in generation. This ambiguity is resolved in the case of England and Wales, where substantial entry actually occurred, but the two dominant generators were still able to sustain prices significantly above competitive levels.

A related point concerns the way in which concentration in generation should be reduced. There are two main approaches:

- The first one consists of breaking up existing companies into smaller ones. This is achieved more easily when there is significant public ownership in generation but, as England and Wales have shown, divestment of privately owned assets can also be obtained through the use of (or the threat to use) competition laws.
- Alternatively, one can try to dilute market power by extending the market itself. This was the route chosen in Sweden, where the relevant market share of Vattenfall was significantly decreased by the integration of the Swedish, Norwegian and Finnish markets.

In small markets, there are limits to how much competition can be introduced through a redistribution of assets. In Hungary, for example, this approach is limited by both the size of the market and the existence of one large nuclear plant accounting for about 40% of the total production of electrical power. Still, whenever possible, it is better to rely on the redistribution of generation assets. This is because, in the presence of remaining national preferences, outstanding contracts, transmission constraints and the complexities of international transmission pricing, the benefits from the ‘market extension’ approach are likely to be both more uncertain and less immediate.

B: Effective vertical unbundling is desirable and requires some separation of ownership

In contrast to telecoms, there are no serious arguments that the infrastructure of wires should be duplicated to create facilities-based competition between vertically integrated electricity companies. In electricity markets, unbundling and confining regulation to the core network utility is desirable to foster competition without the very costly duplication of transmission and distribution networks.

Still, vertically integrated companies remain dominant in some countries where there is a desire to retain the vertically integrated structure, either because of political preference or because of property rights enshrined in the constitution. Moreover, France has forcefully argued that transmission and nuclear generation need to be tightly coordinated to maintain safety and integrity of supply. There is also the usual reluctance of monopolies to give up control over the key bottleneck components of the system unless regulators make these bottlenecks relatively unprofitable. Such countries limit themselves to the functional unbundling required by the Electricity Directive. The initial impression from Germany is that this may not be sufficient to bring the full benefits of liberalization.

The evidence from the United Kingdom and Scandinavia is that, even in the presence of significant nuclear power, there are few efficiency losses from vertical unbundling. This suggests that the synergies of vertical integration are modest, and are more than offset by the improved competitive pressure lowering costs in the different layers of the industry.

C: Separation of transmission and distribution activities is not necessary; on the other hand, separating distribution and retail activities is desirable

The rationale for separating the vertical links of the industry is not equally strong at every stage. There is no strong reason to separate the ownership of transmission and distribution lines in small countries like Northern Ireland. Since both activities have strong natural monopoly elements, there is no fear that a bottleneck in one activity could be used to exercise undue monopoly power in the other. In fact, one can argue that transmission and distribution represent a single ‘transportation’ activity and that the distinction between high and low voltage lines has essentially no economic significance. Yet, there are clear regulatory advantages in having a reasonable number of distinct distribution companies if the country is large enough to support them, as this permits yardstick regulation. Most EU members satisfy this criterion, and the main exception, Northern Ireland, is a small, traditionally isolated system.

The principal argument for separating retailing from distribution (and also for transferring meter provision and reading from distribution to retailing) is the desirability of separating potentially competitive businesses from the regulated natural monopoly business. There are three reasons why such separation is desirable (some of these concerns also apply to the separation of metering and meter reading, which may be obtained more cheaply if subject to competition):

1. The retailing business will have access to information from the distribution business that may give it an advantage relative to other suppliers.

2. The costs may be reallocated from the competitive to the core monopoly business where they can be recovered through regulated charges, thereby giving a competitive advantage to the competitive business.
3. The integration of the two businesses may be conducted to discourage consumers from moving away from the competitively owned subsidiary to a rival.

In the United Kingdom, Offer would like to require the RECs to separate their distribution and retailing businesses, and give each an appropriate licence. There are a number of issues that have to be addressed in this separation, one of which is the allocation of meter services. Another key problem is the allocation of the costs of currently shared services (head office, personnel, information technology, transport, call centres, etc.). These may have to be placed in a service company (making services available to distribution and retailing in a non-discriminatory way) and/or subject to competitive tendering for such services to the retailing business. There is the final, still unresolved question of what the separation will cost and whether the benefits are sufficient to exceed the cost. At present, the RECs are arguing that the costs are high, though Offer is sceptical about the validity of many of the claimed costs.

It is regrettable that Germany and, apparently, France have decided not to require any effective separation of distribution and retail activities, and have not undertaken any cost-benefit analysis in defence of this decision. England and Wales, in contrast, are planning legislation to force this separation; already, some retailing businesses have been voluntarily separated from their host REC.

D: The distribution of ownership matters more than its public or private character

Two separate approaches appear to be functioning reasonably well:

- The first relies on the traditional 'textbook' model of competition between a sufficient number of comparably sized private generating companies. This is the approach chosen in England and Wales, where the importance of dispersed ownership has been amply demonstrated.
- The second attempts to replicate the conditions of competition in a setting with significant public ownership. For this approach to work well, the precise type of public ownership is also quite important.

France remains unusual in that its industry is still primarily under central state ownership. Elsewhere (for example, in Germany and Norway), public ownership usually takes the form of municipal ownership, sometimes in partnership with private owners. Not only does the latter ownership structure tend to produce a greater number of smaller companies, but the municipally owned companies can also compete with each other in a way that is less plausible for state-owned enterprises, all of whom share the same owner.[5]

The main advantage of privatization is that it requires an explicit system of regulation, whereas public or municipal ownership can claim to represent consumer interests without explicit or transparent regulation. The Directive makes much of the need for open, transparent and non-discriminatory treatment, and this is more readily achieved under private ownership than under either mixed or public ownership.

An additional argument for private ownership is that activities which work well under private ownership should not be conducted by the state, as this increases the state's already considerable power and share of the economy. The recent evidence suggests that private ownership works well for the electricity industry, weakening any case for continued public ownership.

E: Trading mechanisms can only work well if concentration in generation is low and if markets are transparent

We have argued above that reducing concentration in generation is highly desirable. It is even more desirable when a significant share of electrical power is traded through a pool-type wholesale market. The greater the degree of contract cover, the less is the incentive to manipulate the pool price or the balancing market, so markets that encourage contracting may be less prone to manipulation. Nevertheless, market power remains problematic, even in the contract market, so reforming trading arrangements without addressing issues of market power may not solve problems of high or distorted prices.

The performance of trading mechanisms is also likely to be improved if markets are transparent. One aspect of transparency is the application of clear market rules that are readily available not only to market participants, but also to potential entrants. For example, the initial confusion about market rules might help explain the lack of entry and competitive pressure during the first year of operation of the Spanish spot market.

Another aspect of transparency is the availability of information about the conduct of market participants. Here the golden rule is that all information made available to market participants should also be publicly available. One can, for example, argue about the desirability of making bidding information available at all. It might rightly be feared that such information would help sustain more collusive outcomes in the market. This is one reason why bidding information is kept confidential in Nord Pool. There is, however, no possible justification for the rules of the Spanish market, where bids are made available to market participants after 30 days, but not to the public, including potential entrants.

F: Electricity mergers can be treated according to normal competition policy rules, but with a special concern for the degree of vertical integration and a view to keeping yardstick competition viable

Even if initial restructuring has been successful, subsequent mergers can threaten the competitiveness of electricity markets. There are, however, few reasons for treating electricity mergers differently from other mergers. One should only insist that the issues of horizontal concentration and vertical integration are treated jointly and that some regard be given to the importance of keeping enough dispersion in the ownership of distribution franchises to ensure the effectiveness of yardstick regulation.

G: Regulated third party access (rTPA) is preferable to negotiated third party access (nTPA); moreover, the single buyer option has drawbacks and has proved to be unattractive

A remarkable feature of the recent liberalization experience is the lack of popularity of the single buyer model. Among the countries reviewed in this Report, it was only fully adopted in Hungary (and that only as a transitional step) and it was offered as one of two options to German distribution companies. Even a country like France, which fought hard to have the single buyer model included in the Directive, finally decided to rely on rTPA. Hungary is now considering switching to rTPA.[6]

Several factors might help explain such a strong pattern:

- One possible interpretation is that the Directive perfectly achieved its goal of making the single buyer model and rTPA 'economically' equivalent so that countries chose to avoid the stigma associated with the less competitive 'look' of the single buyer model.
- It is also possible that the single buyer model involves greater transaction costs than rTPA. The former runs a greater risk of stranding contracts if fuel prices or technology change.
- Finally, one of the potential benefits of the single buyer model is that it might foster a better coordination of investment. France claims that this beneficial aspect can also be obtained within a rTPA framework by reserving the right to put some investment projects up for tender. Others are doubtful that what EdF claims is rTPA is in fact very different from nTPA.

Germany stands out as the only country that chose nTPA. Both theory and experience suggests that this might create some difficulties. On the theoretical side, nTPA does not limit a transmission or distribution company's ability to foreclose on a firm that would compete with them in either generation or retail. The experience of natural gas in the United Kingdom is also sobering. British Gas was created as a vertically integrated monopoly gas company with its own fields, storage, transmission, distribution and retailing business. A series of investigations by the Monopolies and Mergers Commission (MMC) in 1988 and 1993 and the Office of Fair Trading (OFT) in 1991 found evidence of extensive price discrimination, cross-subsidies and predatory pricing. They argued that the only viable solution was to separate the different businesses, publish transport tariffs and, although this language was not used in the reports, to shift from nTPA to rTPA.[7]

It is perhaps not surprising, therefore, that disputes over German transmission and distribution networks have already arisen. In 1998, for example, Enron was denied network access by Elektromark. As noted in Part 1 of this Report, Elektromark eventually relented after receiving negative signals from the federal competition authority. Still, these kinds of delays are likely to hurt the competitiveness of the firm requesting access. Nor was this an isolated incident: in early 1999, the federal competition authority was considering at least seven major cases of access refusal.

It is clearly too early to say whether these conflicts will be endemic, or to know how effectively and quickly they can be resolved by the German competition authorities. Interestingly, all transmission owners and quite a few distribution companies have now published access tariffs. We still do not know, however, whether these tariffs are true posted prices or if they are just a point of departure for further negotiations. Still, we believe that this voluntary publication reflects both the large transaction costs of full-fledged nTPA and a desire to appease the federal competition authority. If this trend continues and if antitrust scrutiny avoids excessive charges, the German nTPA could soon become quite close to rTPA.

H: Getting transmission pricing right is hard

We have already said that one of the lessons from the country studies is that the technical implementation of complex transmission pricing schemes is not problematic. It would, therefore, be comforting to believe that transmission services can easily be priced to ensure the creation of an efficient, competitive, Europe-wide market that would dilute local market power and allow a more efficient fuel mix. Unfortunately, as discussed in the final chapter of this Report, no country has yet found a way to reconcile the need to prevent the emergence of local market power while establishing clear signals for investment and location decisions and the efficient handling of system-wide externalities from electricity flows. Clearly, these difficulties are compounded by the presence of several system operators, as in Germany, and even more, across the entire EU market.

I: Although no problems have surfaced so far, it is too early to evaluate the efficiency of investment incentives

The short-term objectives of 'liberalization packages' are to improve the efficiency with which existing assets are operated and priced, and to reflect falling fuel costs in falling final electricity prices. The longer term objective is to sustain investment that is efficient in terms of quantity, quality and, importantly for a fixed network industry like electricity, location. Fears that the market might not provide the correct signals are reflected in the Directive, which allows countries to choose the single buyer model, in which investment requirements are forecast, optimized and may be put out to tender. The other major concern is that adequate reserve capacity will not be forthcoming in a competitive generation market. Again, some countries, notably Spain and the United Kingdom, have adopted special capacity payments to ensure adequate reserve margins.

Fears about inadequate generation investment have proven groundless. The emergence of cheap, modest scale, short construction time CCGT technology, coupled with lower gas prices (in part resulting from deregulation and increased competition in the gas market), has made new investment profitable against existing coal-based generation costs. New UK capacity over the last eight years has amounted to over one quarter of the existing, already adequate, capacity under an authorization (free entry) procedure. Hungary, under the single buyer model, had a surprisingly strong set of offers for proposed new generation capacity, and accepted tender prices considerably below previous negotiated contract terms. In a sense then, the emergence of CCGT technology has temporarily removed any concern about capacity investment and has, therefore, delayed any stringent test of the investment incentives provided by the various market mechanisms.

Elsewhere, conditions of entry into generation vary. In Scandinavia, the costs and availability of new hydro schemes make advance investment at current electricity prices unattractive. Meanwhile, Germany and Sweden have expressed considerable hostility to further nuclear investment, but have not yet resolved the question of what form of generation will replace it. Germany is well connected to the European gas grid and CCGT must be the cheapest option for expansion there, but Sweden is relatively isolated from gas and may choose to import electricity instead. At some stage, gas pipelines will become economic and gas-fired generation can be expected in both Norway and Sweden. How these countries' markets will handle such a transition remains to be seen.

In principle, financing transmission investment is relatively straightforward, as it remains a regulated natural monopoly with the ability to raise adequate revenues to cover investment costs. Certainly, in the United Kingdom, there would be no financial impediment to strengthening the network were this necessary and economically justified. In practice, the main obstacle is the resistance by environmental groups to further overhead power transmission. Financing international links may prove more difficult as it is harder to justify placing the costs on domestic consumers.

J: Still, investment incentives cannot be dissociated from market design

As discussed above, a single buyer system needs very little explicit investment incentives while a market system might require some specific mechanisms to ensure that sufficient capacity reserves are available and that transmission and generation investments are appropriately coordinated. Investment incentives are also affected by the specific design of market systems. For example, the Spanish spot market produces equilibrium prices that have little economic relevance. As argued in the country studies, this is because the bidders on both side of the market are essentially the same agents and because of the linkages between the spot market price and the tariffs for the regulated sector. One of the costs of such a design is that the market price provides very little information as to the desirability of new investment in generation.

K: Domestic retail competition based on metering does not work; retail competition based on profiling might

The experience of Norway and Sweden shows that metering requirements create switching costs that are high enough to stifle retail competition for domestic customers. Barring breakthroughs in metering technology, the only viable approach is to base retail competition on profiling.

L: Liberalization has initially benefited large customers not small ones; its effect on sellers has been mixed.

The only systematic evidence on the gains and losses from liberalization in any of the countries surveyed in Part 2 of this Report is that given in Newbery and Pollitt (1997). This study was based on a comparison of the actual performance of the industry with a counterfactual trying to predict what would have occurred in the absence of liberalization. Hence, for example, the simple fact that electricity prices for small consumers have decreased since liberalization does not mean that they benefited from the reform because lower fuel prices would have lead to lower prices anyway. Using this methodology, the researchers find that liberalization in England and Wales did indeed generate sizeable benefits, but that these gains accrued mostly to sellers.

In the absence of a proper counterfactual, the experience of other countries such as Norway, Spain and Sweden are harder to evaluate. Still, it appears likely that, in all three countries, large customers have been made better off. The evidence on sellers is mixed: Swedish firms have seen their profits cut almost in half, while Spanish electricity companies appear to be at least as profitable as before the reform.[8]

There is not much evidence that liberalization has as yet benefited small consumers anywhere. On the contrary, faced with prices that did not fall as fast as fuel costs and with declining tax revenues, small consumers in England and Wales appear to have been made worse off by the reforms (Newbery and Pollitt, 1997). Since that study was completed, the electricity market has been fully liberalized, and prices offered to domestic customers by new suppliers are up to 10% cheaper than those offered by incumbents. By mid-1999, only one month after the full market opening, nearly 10% of customers had switched. The gas market, which has been fully open for nearly two years, has seen about a quarter of domestic customers switching supplier (in response to larger price reductions). This suggests that the benefits to small consumers take longer to feed through, and may require full liberalization or vigorous regulatory pressure.

M: Public service obligations can be met in liberalized markets

Governments do not appear to have had any trouble maintaining universal service obligations, or ensuring the security of supply, without significantly interfering with the workings of the liberalized markets. On the other hand, the goal of energy diversification has so far been pursued with blunter instruments (such as the gas moratorium in England and Wales), possible access denials (Germany) and interference with the market-determined order of dispatch (Spain). This issue is revisited in more depth in the final chapter.

N: It is important to have a strong, independent, sector-specific regulator with the power to refer cases to the competition authority: a joint gas-electricity regulator appears to be desirable

The need for a strong, independent regulator is relatively uncontroversial. As amply demonstrated by the Spanish situation, strong powers and independence from the central government are needed to ensure that the liberalization process is not effectively captured by the producers' lobby. Moreover, the United Kingdom shows that there is not necessarily a conflict between regulation and the application of general competition rules. In England and Wales, the industry is regulated by Offer, but also has to meet the conditions of various competition legislation. With mergers, the inquiry is normally conducted by the OFT, which may refer the merger to the MMC or its successor, the Competition Commission (CC). The MMC (CC) also acts as a dispute resolution mechanism when a utility will not accept a proposed licence modification made by Offer.

The key issue is whether there should be a specialized regulatory agency, and if so, whether this agency should deal just with electricity or also with gas. The advantages of a specialized agency are that the natural monopoly elements require regulation that is best informed by specialized knowledge of the industry. Detecting abuse of market power in the wholesale and retail markets also benefits from specialized knowledge. Reliance on a general competition agency is also likely to be more cumbersome and slow moving, though in compensation, it may reduce the probability of capture and may lead to lighter handed regulation.[9]

Heavy-handed regulation is more likely to be needed when incumbents retain market power; conversely, light-handed regulation is more likely to evolve as different countries model their rules and licence conditions on international best practice, and information becomes transparent and available for cross-country comparisons and implicit benchmarking. In that sense, a sector-specific regulator is likely to be especially useful during the early stages of the liberalization process.

While the arguments in favour of a sector-specific regulator are strong, it is important to note that there is essentially no evidence on the relative performance of sector-specific regulators and general competition authorities as overseers of electricity markets. It will therefore be quite interesting to appraise the quality of oversight in Germany, which is the only country in our sample without a sector-specific regulatory agency.

The convergence between electricity and gas markets is extensive. Currently, gas is the fuel source for the most efficient electricity generating technology. This means that competitive access to gas is essential to guarantee competition and entry in electrical power generation. This provides a strong argument for overseeing both markets jointly, a rationale that is reinforced by the fact that many electricity firms have integrated backwards into gas production and gas trading. This situation has apparently convinced many governments of the need for joint gas-electricity regulation. In the United Kingdom, the government has merged the two regulatory bodies, Offer and Ofgas, into Ofgem. Spain is progressively replacing its electricity regulator by an Energy Commission, which will oversee gas, electricity and oil markets. Several other countries have adopted a joint regulatory agency for gas and electricity from the start.

Notes

1 Spain has gone somewhat further as REE is supposed to spin off its system operation activities as a separate company.
2 Clearly, this is not incompatible with the eventual emergence of voluntary pools. What matters here is that the governments did not find it necessary to impose or even promote such pools.
3 See Chapter 6 on the UK's experience for a more detailed statement of this argument,
4 In the longer term, however, the failure to replace low marginal cost nuclear capacity is likely to shift aggregate supply functions up and affect the marginal price.
5 This advantage is less important in the presence of a wholesale market that allows individual generating stations to be compared in terms of performance and profitability and, to that extent, provides incentives for improved efficiency. Similarly, even in a state-owned system, distribution companies are typically sufficiently numerous that they can be benchmarked against each other.
6 Although the convergence on rTPA is quite remarkable, it is important to note that non-price elements of the tariff are not always strictly regulated so that some room for negotiation might remain.
7 See MMC (1993) for strong supporting evidence.
8 The claim for Spain is tentative as the reform is just over one year old. The appraisal is further complicated by the fact that some electrical companies, like Endesa, are significantly involved in non-electricity businesses.
9 This advantage of reduced likelihood of capture is likely to be lost if a specialized 'electricity section' is created within the competition authority.

13 EU Issues and Recommendations

This final chapter focuses on the requirements of the Electricity Directive in the light of the experiences of the EU's member states, comparing alternatives where these are offered, and identifying additional steps that will be required to complete the single market in electricity. In particular, we focus on what is needed in order to '*create one single market, not 15 liberalized or partly-liberalized, but largely independent electricity markets*'.[1]

In the first section, we discuss the suggested alternatives for reforming generation, transmission and distribution. Issues relating to market institutions are dealt with in the second section. Market integration and international trade in electricity are the main topics in the third section; and in the fourth section, we discuss issues related to public service obligations and environmental protection. The fifth section presents optimistic and pessimistic visions for the future development of the single electricity market, and the final section concludes by pointing out some unresolved issues.

13.1 Structural reform

13.1.1 Generation

To promote competition in generation, the Directive prescribes two alternative mechanisms for constructing new generation capacity: authorization and tendering. Authorization means that a plant investment can be refused on certain grounds provided there is no discrimination between investors. It cannot be refused because of lack of demand, however. The authorization model is compatible with decentralized decisions about generation capacity expansion. Tendering, on the other hand, requires a system planner (perhaps the transmission system operator – TSO – or the single buyer) to forecast future demand and supply.

Authorization implies that the risks associated with investments in new generation capacity are borne by the individual investors, while tendering means that the risks are transferred to the body issuing the tenders. Thus, to some extent, the tendering model implies a lack of confidence that the market will ensure an adequate level of investment in the right choice of plant (fuel, size and technical characteristics), and in the right location to minimize overall transmission and generation costs. The tendering model presumably means, however, that the extra (positive or negative) transmission costs associated with different bids can be taken into account in the decision process, and it may also reduce the risk of inadequacies or inefficiencies in investment choice.

The EU member states have clearly decided overwhelmingly against the tendering option and have adopted various forms of authorization. Some countries, like Germany, do not require special authorization to build generation capacity, but leave it to the normal planning process (in which the ability to meet increasingly stringent environmental conditions will be an important requirement). Others, like the United Kingdom, require prospective generating companies to obtain authorization. In the past, authorization has been a formality in the United Kingdom, but under the Labour government elected in 1997, it became an instrument of fuel policy with the 1998 moratorium on building gas-fired plants. Only Portugal has chosen tendering for the public system, though not for the private system. Like several other countries aiming to join the EU, the Czech Republic and Hungary currently operate a tender system.

The evidence presented in this Report, particularly for the United Kingdom, suggests that investment in new generation capacity is not a problem, provided the market is designed so as to provide adequate reward for capacity availability, ancillary services and energy. Location decisions are more difficult to guide by market signals, and they place demanding requirements on the location signals of transmission connection and use-of-system tariffs. Nevertheless, our conclusion is that the authorization model promotes competition in generation better than the tendering model.

At the same time, although there seems no reason to adopt tendering for investment in commercially viable generation, it may be the most efficient way of securing non-commercial renewables generation. Tender auctions also appear to be a cheap method of securing various ancillary services. The Hungarian experience strongly suggests that competitive tender auctions are considerably better than negotiated power purchase agreements with new entrants who are not required to compete for the right to connect. These auctions, however, appear to be a feature of the transitional stage from a vertically integrated company, via the single buyer, to a fully liberalized market.

13.1.2 Transmission and system operation

The TSO is the entity responsible for running the high-voltage transmission grid, including the interconnectors with other systems. Within a country, there may be one single TSO, as in Spain, or several, as in Germany. The TSO may be responsible for both dispatch and the provision of ancillary services, as in England and Wales. In the Nordic countries, where dispatch is determined in a more decentralized fashion, the responsibilities of the TSO are limited to the short-term balancing of the system and the provision of ancillary services. In any case, the TSO may influence the dispatch of generating units and thus, should have no conflicts of interest that might lead to discrimination between generators and/or suppliers.

The Directive does not distinguish very clearly between the operation, ownership and management of the transmission system. There is strong evidence from the United Kingdom, however, that systems operation benefits from incentives to reduce 'uplift' costs (securing ancillary services, handling losses and constraints, dealing with redispatch, etc.) Incentives, including penalties, pose financial risks for the TSO, and variations in income arising from incentives could be large compared with the margin required to reward the TSO.

This suggests that the TSO will need a capital adequacy requirement of the kind that is naturally available to a regulated grid company to avoid the risk of bankruptcy. It is worth noting that where the supply of TSO services has been put out to competitive tendering, it has usually been won by foreign grid companies. An additional argument for combining systems operation and systems ownership and management is that constraint costs depend critically on the timing of maintenance and systems reinforcement.

The case for an independent system operator arises in systems like those in Germany, where the optimal dispatch area is larger than (or overlaps with) the areas of grids under different ownership. This has been the preferred solution in the United States. If there is strong constitutional protection of ownership rights that make it difficult to encourage vertically integrated utilities to divest generation from transmission, then an independent TSO would seem essential.

13.1.3 Unbundling

In the past, most national electricity industries in Europe were vertically integrated. To prevent vertically integrated companies from discriminating in favour of their own generation and retailing businesses, the Directive requires at least a minimum degree of unbundling of generation and transmission, based on separate management and accounts ('Chinese walls'). Most member states have chosen to go one step further and legally separate transmission and generation. Yet, two of the largest countries at the centre of the major electricity trade flows, France and Germany, have not.

Unbundling was strongly resisted by some countries in the early debates over the single electricity market. The argument for vertical integration was based on the large scale of efficient generating units, with their long construction periods, and the need to coordinate transmission and generation development centrally. These arguments have some force in a fossil fuel system, where there is a degree of location flexibility in siting power stations. They apply less in hydro systems. The extreme would be a mainly nuclear industry, as in France, where nuclear power stations can be sited wherever there is adequate cooling water and where the stations have inflexible operating characteristics.

EdF has argued that the tight coordination of generation and transmission makes unbundling undesirable, possibly prejudicing system security. The CEGB argued similarly before being unbundled in 1989, but its claims were rapidly shown to be groundless. The evidence from the United Kingdom is that unbundling, far from raising costs, allows competition to be introduced on a daily basis into generation with dramatic improvements in availability and performance. The performance of NGC has also improved, though less dramatically, suggesting that any synergies or coordination benefits from vertical integration are more than outweighed by the inefficiencies of the resulting entrenched monopoly. The experience in the Nordic countries is also consistent with this view.

Legal separation formalizes the Chinese walls, but does not eliminate the incentives for discrimination. Thus, common ownership may give rise to suspicions that, in one way or another, the TSO is inclined to favour their own generation company. In England and Wales, NGC was eventually encouraged to sell its pumped storage business to avoid accusations of favouritism in securing ancillary services and dispatch. Most privatized utilities have found it uncomfortable to retain regulated core monopolies and competitive businesses within the same company and have usually chosen to unbundle functionally (that is, to place the different activities in separate subsidiaries) even before they were legally required to do so. In some cases, notably British Gas, the company voluntarily decided to divest the core network from the trading parts of the business. Separate ownership is, therefore, the only completely satisfactory solution.

Where the transmission company remains vertically integrated with generation, this should ideally be solely for a transitional period. This gives time during which the generation and transmission businesses can produce profit and loss accounts on the basis of which the separate businesses may be better valued for subsequent market flotation or divestiture. During the period of vertical integration, it is critical that the TSO is independent, and subject to adequate governance to monitor performance and compliance.

13.1.4 Access to transmission

Third party access (TPA), subject to capacity availability, is the key to a competitive market for electricity. The Directive requires the member states to implement third party access, but offers a choice between three alternatives: nTPA, rTPA and the single buyer model. The single buyer model is intended to be functionally equivalent to rTPA, but it seems to have few if any advantages and several obvious disadvantages. The suspicion will remain that the single buyer model is less transparent and a mechanism for favouring particular generators and/or customers, while also risking problems of stranded contracts, which will create future difficulties if liberalization continues. There was some lobbying for the single buyer option to be included in the Directive, but in fact, all member states have opted for nTPA or rTPA. Moreover, only three member states (Denmark, Germany and Greece) have chosen nTPA, though Denmark plans to move to rTPA at the end of 1999.

Given the objective of a single competitive market for electricity in Europe, the choice between nTPA and rTPA seems obvious. The latter is transparent, open and non-discriminatory in a way that is far less likely with nTPA. Moreover, there is empirical evidence that nTPA does not promote competition. The gas industry, for example, has been remarkably slow to liberalize and allow markets to emerge precisely because all contracts were, initially at least, negotiated. International trade in electricity has always been by negotiation, and is equally non-transparent while failing to secure most of the advantages that an open access liberal market would deliver. Evidence from Germany suggests that the lack of transparency surrounding nTPA sustains local monopolies, either operated in the interest of municipalities as sources of local finance or of the shareholders of larger combines. It is not surprising that Germany has one of the highest levels of electricity prices in the EU and has been one of the harder markets for new entrants to penetrate.

It has been argued in defence of nTPA that it encourages efficient bargaining between well-informed companies without burdensome regulation, and that it would work well if it were accompanied by complete disclosure. One of the main problems with nTPA is that it gives the incumbent the power to delay, during which it can approach the customers targeted by the entrant and buy them off, thus foreclosing entry. It is hard to see that even with full disclosure and close scrutiny from competition authorities, this would work well enough to justify the apparent lightness of regulation.

Fortunately, there are countervailing pressures pushing the few nTPA countries towards rTPA. The sheer difficulty of negotiating a large number of contracts and being able to demonstrate non-discriminatory behaviour to a pro-active competition authority or the European Commission has made some companies publish regulated tariffs rather than choose to negotiate. In addition to publishing tariffs, though, liberalization requires that all the other terms and conditions for access are known, and applied in a non-discriminatory way. Continued pressure from regulators making cross-country comparisons will continue to be needed until access terms are completely transparent.

13.1.5 Distribution and retailing

The Directive concentrates on distribution (the wires business) and only briefly mentions supply (or the retail function). The distinction is not very sharply drawn, nor is the desirability of their separation discussed. As the Directive does not require more than 33% of the market to be liberalized, many countries will retain the franchise market, in which case the incumbent distribution company will also manage retailing for these customers. The case for separation is to place the natural monopoly activities in a separate company from the competitive retailing business, though this is less pressing if the franchise is retained and supply to non-eligible customers continues to be closely regulated. Some countries are actively considering placing these two functions in separate companies, following the example of Sweden where legal separation is required.

The Directive leaves considerable flexibility in meeting the requirements for managing the distribution system, except that the operator must not discriminate between system users (including retailing businesses, one of which it may own) nor favour its subsidiaries or shareholders. Many distribution companies own both retailing businesses and embedded generation, or even larger scale, centrally dispatched generation, and most countries still retain a franchise market to which the distribution company has sole access through its retailing business. Distribution companies may, therefore, be tempted to contract with their own generation companies for the supply of electricity to their franchise market.

These problems can be mitigated by complete liberalization of the franchise market and separating the retailing business from the distribution business, again to ensure equal treatment of all suppliers. Of course, switching costs may allow the incumbent distribution company to retain most of his former franchise customers, and even to raise prices once they cease to be so tightly regulated. Retail competition should, however, eliminate the incentives to favour a company's own generation. Retail competition may encourage vertical integration between suppliers and generators as it reduces wholesale price risk and, if combined with market power in generation, could cause concern. This will require close monitoring by the competition authorities.

The attractions of retaining the franchise market are that it allows cross-subsidies to continue, providing a simple mechanism for financing public service obligations, including support for renewables. The objections to retaining the franchise are that the benefits of competition in the form of lower prices may not be transferred to customers in the captive market, and that the government may be tempted to continue costly energy policies without explicit taxes or subsidies. Ending the franchise does not necessarily end political interference ('energy policy'), though it restricts the modalities through which these interventions can occur.

As with transmission, distribution requires regulation, and again the form of regulation should provide incentives for efficiency and cost reduction. Price-cap regulation has this property and can deliver impressive increases in efficiency, particularly when coupled with an active takeover market (which occurred in the United Kingdom with the ending of the government restrictions on takeovers of RECs in 1995).[4] This form of regulation encourages utilities to cut costs, but raises fears that quality may suffer. One of the important lessons from the United Kingdom is that a set of closely monitored performance standards, combined with penalty payments to disadvantaged customers, is needed. With this system, the United Kingdom has been able to improve standards of service while in its absence, the distribution company in Auckland, New Zealand, caused an extremely expensive disruption of power to the city for more than six weeks.

Yardstick regulation solves many of the problems of asymmetric information, but requires a sufficient number of RECs with a distribution business providing separate accounts on a consistent basis. Maintaining an adequate number of RECs places limits on the extent of horizontal mergers within the electricity supply industry. Mergers with other regional utilities (water and gas companies) may allow synergies (in head-office functions, information technology and billing systems, meter reading, etc.) without compromising the ability to make cross-REC comparisons, though cost allocations between the different businesses may cause problems. As regulators increasingly compare experiences, they may also be able to agree on a common format for RECs and transmission companies to report the costs of conducting their regulated businesses. If successful, this would greatly increase the range of companies available for benchmarking

13.2 Trading arrangements

The Directive is silent on the trading arrangements and market institutions that need to be put in place to support access to the network and the management of the transmission system in an integrated Europe-wide market. It could be argued that Europe has more pressing needs in eliminating discriminatory practices, reducing incumbent market power and encouraging cross-border trade, without concerning itself with the fine details of market design. While we agree that some of these market design issues can be deferred for future discussion at the

EU level, many will need to be addressed rather earlier by member states. It is also important to remember that the goal of a single electricity market requires markets to function well in each member state, so the Commission will be concerned with the choices made at the national level.

Some kind of trading arrangement will be needed even where contracts between new suppliers and eligible customers are negotiated, and where there is only nTPA, the TSO will need some mechanism for pricing imbalances from the contracted arrangements. Transmission constraints, generation failures and under- or overconsumption by the customer will all lead to discrepancies between the contracted and actual levels of production and consumption. The TSO must be able to call on least-cost suppliers of balancing services and have some method of pricing and charging these services. Again, the spirit of the Directive suggests seeking market solutions, and creating markets or periodic tender auctions for the supply of these services.

In this section, we aim to answer the following questions:

- To what extent must trading arrangements be designed by the government, and to what extent can their development be left to private initiative in the market?
- To the extent that government regulation is warranted, what are the principles of good market design?

13.2.1 Physical trade

In the short term, the fundamental economic problem is how to ensure efficient use of the existing generation and transmission capacity. In principle, we can distinguish between two entirely different ways of organizing the arrangements for (wholesale) physical deliveries of electricity based on, respectively, centralized and decentralized dispatch.

Centralized dispatch
With centralized dispatch, the output decision of any generator (and possibly, any consumer) is under the control of the TSO.[5] In traditional, non-market systems, the operator's dispatch decisions would be based on an assessment of the costs at different generating plants or sets. In market systems, however, generators make bids at which they are willing to supply electricity.[6] These bids then form the basis for calculating a least cost configuration of output from the various plants, that is, a production plan or 'merit order'. Generators failing to meet the plan are penalized.

The obvious advantage of the centralized model is that it ensures that dispatch is both feasible and consistent with the character of the transmission system. Transmission capacity acts as a constraint on the feasible production plan, while transmission losses affect the least-cost configuration of plant. When optimizing the system, the operator ought to take both considerations into account.

The major drawback of the centralized model is that it limits the scope for decentralized decisions and the contractual freedom of market participants. No contracts traded outside the pool can be allowed: in particular, since dispatch decisions are the responsibility of the TSO, no individual generator can commit to a future production plan. Another potential drawback is that the centralized model gives the TSO considerable power, which could conceivably be abused to discriminate between users and distort dispatch in ways that are inconsistent with overall efficiency of the system. This is more likely in partially vertically integrated cases, or in the case of the single buyer with stranded contracts.

Decentralized dispatch

When dispatch is decentralized, any generator is, in principle, free to generate as much as is desired. To facilitate feasibility and consistency of individual output decisions, a system of transmission tariffs is introduced to reflect the (short-run) cost of using the system. Contracts with traders or consumers are needed to ensure supply and demand are matched.

In theory, if tariffs are adjusted continuously, and generators and buyers react rationally to price changes, an optimal set of transmission tariffs and generation contracts can ensure overall system efficiency. In practice, transmission tariffs cannot be relied on to produce a feasible solution in all contingencies. The tariff system is, therefore, complemented by some mechanism for ensuring an overall feasible outcome, including last minute intervention in cases when imbalances are about to occur. This can be done in separate markets run by the TSO. For example, last-minute balancing is typically achieved via a balancing or regulation market in which bids are accepted for short-run adjustments to output. In particular, when transmission bottlenecks occur, trading in the balancing market may be undertaken to achieve electrical equilibrium on each side of the constraint.

Which model?

It would seem that history and geography have played important roles in determining the choice of trading arrangements for physical deliveries of electricity. In England and Wales, a compulsory bid-based gross pool for centralized dispatch was a natural development of the mechanism used by the monolithic CEGB for a system based on large fossil and nuclear generators. In the Nordic countries, voluntary decentralized dispatch had always been the preferred option and market reforms did nothing to change this.

Does this mean that the choice of model is, in effect, arbitrary or are there more fundamental reasons that can explain the different choice of models?

Clearly, the merit of decentralized dispatch depends on how well the tariff system works in providing market participants with the right price signals. If transmission losses are fairly constant over time, and the occurrence of bottlenecks infrequent, transmission tariffs do not have to vary much. Consequently, market participants can quite easily inform themselves about the profitability of choosing a particular level of output at any given time. If, however, transmission losses vary widely (depending on, perhaps, unpredictable changes in load flows), and bottlenecks occur frequently, transmission prices will be difficult to forecast and output decisions correspondingly hard to make. In such cases, the balancing market will have to play a more central role since system imbalances will be more likely.

Although historically the transmission capacity was not always high in the Nordic countries, at least since the introduction of regulatory reforms, the grids have had adequate capacity. This may go some way to explain why the decentralized model has worked so well there. As we discuss further below, however, the recent experiment with a highly sophisticated system of nodal transmission pricing in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) market suggests that a system of decentralized dispatch works reasonably well even in cases in which transmission prices vary considerably across time and space (see Hogan, 1998).

Defenders of the compulsory gross pool of England and Wales with system marginal pricing argue that Nord Pool is an inappropriate model that works well because of the particular characteristics of a dominantly storage-hydro system. Storage hydro means that the price of electricity is stable and predictable from hour to hour, with the main variations in price taking place between seasons and over years of varying hydrological conditions. Hydro-electricity can be started or stopped at short notice with no penalty, making it extremely simple and cheap to balance the system.

In contrast, the United Kingdom relies on coal-fired power stations to load-follow, and these stations may take several hours to warm up, and have limits on the rate with which they can increase or reduce power output. Whether it is cheaper to run a station part-loaded and increase output or bring another station onto the system, or even bring on high cost, but fast response, open-cycle gas turbines requires complex calculations over the 24 hours to find the least-cost dispatch schedule.

The complexities of bidding in the United Kingdom derive from the large number of parameters needed to use the dispatch scheduling algorithm, which will only work as intended if the parameters declared reflect the true technical and cost characteristics of the generation sets. Critics have argued that these parameters are manipulated, leading to distorted and high prices. The proposed new trading arrangements in England and Wales will replace this gross marginal pricing pool with bilateral contracts and a voluntary balancing market. Defenders argue that the ability to part-load thermal plant provides the flexibility that Nord Pool derives from storage hydro, and point to the experience in Victoria and California where bidding patterns are simpler. Victoria is dominated by inflexible brown coal-fired plant dispatched in real-time with self-commitment. That pool, however, has marginal pricing and is compulsory, while the presence of the Snowy River hydro system provides the necessary flexibility for the system to operate well. Similarly, California has access to considerable storage hydro and few transmission constraints.

Despite the common claim in the recent debate about reform of the England and Wales trading mechanism, it seems unlikely that the choice between centralized and decentralized dispatch matters much for the problem of market power. The ability of participants to influence prices is a problem in any concentrated market. The problem is particularly acute in the presence of transmission constraints, as the market is then effectively split into smaller segments, within which competition is correspondingly less. In extreme cases, an individual generator can become a monopolist in an area constrained off from the rest of the market. With centralized dispatch, market power typically distorts the basis for calculating an efficient merit order, as bids are not cost reflective. Similarly, with decentralized dispatch, generators may distort the balancing market, as well as the terms negotiated in bilateral contracts for physical deliveries.

The claim that market power is as much of a problem for centralized as for decentralized dispatch must be qualified. By requiring all power to be traded in the pool, the market will be both more transparent and more liquid than when much of the trading takes place on a bilateral basis and the balancing market is used on the margin only. On the one hand, this may reduce transaction costs and the ability of individual players to manipulate market prices. On the other hand, transparency may make it easier for generators to coordinate on a market outcome that is less competitive than what might otherwise occur. In general, it is difficult to determine the relative importance of these concerns.

Another criticism of the England and Wales pool has been directed at the level of trading costs. In order to facilitate central dispatch, a complicated framework must be established that allows for very detailed information to be exchanged between each generating set and the TSO. The situation is less complex when dispatch is decentralized, partly because only information about the terms at which generators are willing to adjust output is needed, and partly because typically only a small number participate actively in the balancing market.

Although a straightforward comparison is difficult, the cost of operating the England and Wales pool does seem high compared with the cost of running the balancing markets in Norway and Sweden. And even though the costs are lower, most participants in the Nordic market have used their contractual freedom to conduct physical trade on bilateral contracts, presumably because this is an even cheaper form of trade. Although the costs of the UK pool itself are quite low (about £25 million per year) compared to annual turnover (£8000 million per year), the main costs may lie in the difficulty that traders face in hedging risks in such a complex and unpredictable market.

We conclude that, on purely theoretical grounds, it is difficult to argue conclusively in favour of either of the two alternative models for arranging physical trade. It is clear that both arrangements work in practice and that they each have weak points. Presumably, only a practical experiment, which allows for a comparison of the performance of the two arrangements on the same system, can tell which model is preferable. In this light, the proposed reform of the England and Wales trading arrangements, which would take the system in the direction of the Nordic model, is of particular interest.

13.2.2 Transmission pricing

Transmission pricing is important, not only as a means of allocating costs of operating and expanding transportation capacity, but also for facilitating trade and efficient development of the electricity industry. For the single electricity market to work, customers in one country must be able to contract with generators in another country, and to be assured of the necessary transmission rights (where these are available) on non-discriminatory terms. Non-discrimination means that all equally placed customers are treated alike, in particular, that they have access on the same terms and at the same transmission price as the incumbent supplier. Different systems of charging for transmission access and use will, however, have very different effects on the degree of competition in the domestic market, and can therefore be designed either to protect incumbents or to promote competition for the benefit of consumers. Different systems of charging and granting access rights may also affect the profitability of new interconnectors, and hence influence the extent and efficiency of interconnection.

The fundamental principle of efficient pricing is that users should face prices that reflect the costs inflicted on others. In electricity systems, this requirement is complicated by two facts:

1. It is in many respects very difficult to calculate true economic costs, taking into account how these depend on the entire configuration of installed capacity and power flows.
2. Tariffs set according to efficiency criteria typically do not raise enough revenue to cover all relevant costs. In order to ensure cost coverage, tariffs must therefore be raised above the levels dictated by efficiency criteria alone.

We deal with the first of these issues immediately below, considering in turn what we have termed, respectively, short-term and long-term efficiency considerations. Later, we discuss the issue of cost coverage.

Short-term efficiency considerations

As argued above, transmission tariffs play a crucial role when physical trading arrangements are based on decentralized dispatch.[8] Ideally, since the marginal transmission cost for any given user varies both with location and overall use of the system, tariff rates should vary both geographically and over time. Real-time nodal pricing has been objected to on practical grounds: it is argued that it would be impossible, or at least very costly, to calculate and transmit such detailed information to market participants. Recent experience, in Europe and elsewhere, casts doubt on this claim.

In the Nordic countries, there has been a gradual development towards a more sophisticated system of nodal, time-varying transmission tariffs. Energy-related payments are differentiated according to geographical location and time of day; enabling approximation of how losses vary across the system depending on location and load pattern. In Norway, losses are also priced at the spot price of electricity to reflect the actual opportunity cost of energy losses. For transmission constraints, the Norwegian solution involves a system whereby, in effect, the market is split between surplus and deficit regions; an additional ‘congestion fee’ is levied on consumption (generation) in the deficit (surplus) region and paid back to generation (consumption) within that same region. In Sweden, a different mechanism is in operation, whereby the TSO pays generators in the surplus (deficit) region to reduce (increase) their output (‘buys regulating services’).

Hogan (1998) describes the problem that the PJM market encountered in its original design of a zonal pricing system. An interim transmission access and pricing system was approved in March 1997 with a voluntary real-time spot market that computes a single price for the entire PJM system, thereby ignoring transmission constraints. Generators were paid zero if they were constrained-off from the spot market, in contrast to England and Wales where generators affected by constraints are compensated. Participants could, however, schedule bilateral contracts and pay their share of the total congestion cost. As Hogan points out, constrained-off generators faced with a zero payment from the spot market could, however, (and did) make a bilateral contract and force the independent TSO to constrain-off some other generator or schedule alternative generation. The whole system threatened to unravel and the independent TSO had to intervene to avoid the market collapsing by banning bilateral trades in June 1997.

This flawed system was replaced by a nodal pricing system from April 1998 with around 2000 nodes between which prices can differ. The difference between the lowest and highest nodal price in any hour in April 1998 was \$282/MWh and the median price range was \$33/MWh. Hogan argues that it would take a very large number of zones, perhaps up to 100, to ensure that nodal price variations within each zone were small, though a more interesting question is how the dispatch efficiency (the total cost of generation and transmission) compares to one with a smaller number of zones and constraint payments made to generators.

In any event, experience to date clearly demonstrates that practical considerations alone do not constitute a valid argument against nodal energy transmission tariffs. The real question is which system offers least scope for inefficiencies arising from the exercise of (often very localized) market power. Recently, a market for transmission contracts has been introduced in PJM to allow participants to hedge against variations in the transmission tariffs and these contracts may also influence market power.

Long-term efficiency considerations

The long-term efficiency consideration concerns the efficient development of the overall capacity of the system. The main criticism of vertical unbundling is that generation and transmission investment must be coordinated to minimize total system costs: it may be cheaper to pay more to locate generation near demand to avoid the cost of building extra transmission. In a market system, transmission tariffs play a vital role in the solution to this difficult coordination problem – how to signal where consumers and generators should locate, and how to decide when and where to build additional transmission capacity. The question is whether the price mechanism is a sufficiently precise instrument to solve this problem, or whether some form of direct intervention is warranted.

The experience in England and Wales illustrates the difficulties that may arise (though it is far from clear that they would have been resolved by efficient transmission pricing, given the underlying problems of market power).[9] At privatization, the initial transmission charges were drawn up rather hastily, to be reviewed after two years. Unfortunately, very substantial entry occurred before appropriate price signals were put in place. For example, several new entrants required connection in the north, where there was a shortage of transmission capacity to the main centres of consumption in the south. Under the existing rules, the substantial cost of strengthening transmission fell in the first instance on NGC.[10] Had the generator connected further south, the small extra generation cost would have been greatly outweighed by the saving in transmission investment.

The system of constraint payments provides somewhat perverse location incentives, for a constrained-off plant is compensated for its notional lost profit. This can encourage generators to locate in an export-constrained area and bid zero for periods they can expect to be constrained-off. It is not obvious that NGC should offer the same right of secure transmission to generators who choose to locate in regions that may be export-constrained and where their capacity is less valuable. In due course, the location charges were revised as described above, but too late to affect the early mislocations.

If energy transmission payments are set efficiently, according to the principles outlined above (or, in a system with centralized dispatch, the configuration of dispatch takes into account transmission losses and constraints), a strong location signal is already built into the tariff system. For example, a new generating plant will then be more profitable if it is located in a region in which transmission losses are low or supply deficits occur frequently. Since energy tariffs are based on marginal losses, however, and since the variable, energy-related payments may not be sufficient to recover all (fixed) costs, additional fixed charges will have to be added, and these should be differentiated geographically as well.

To take into account how the value of additional capacity is related to the event that capacity is fully utilized, capacity elements typically depend on output and consumption in periods of maximum demand. The difficulty with such rules is that the basis for calculating transmission payments may be strategically manipulated by users. For example, in the UK system consumers are charged one third of the entire annual charge per kW on each of the three triads – the three half-hours of system maximum demand separated by at least ten days.

Patrick and Wolak (1997) have studied demand responses to pool prices for large customers paying pool prices in one REC, and for these customers, the triad charges were £10 730/MWh for 1994/5. Even though the triad charges are uncertain in advance, large consumers can subscribe to a forecasting service and endeavour to reduce their demand and save very substantial sums at the expected peaks. Perfect forecasting would have allowed customers to save £7153/MWh in each of the three triad half-hours in 1994/5, but in fact forecasting accuracy is about 0.13 (on plausible peak days), making the expected value of reducing load on possible triad days about £800/MWh, higher than any capacity payment (which are known with certainty a day ahead), and a third of the value of lost load. To avoid such problems, payments may have to be based on measures that are not so easy to manipulate, such as installed capacity.

A particularly difficult problem is how to ensure that investments in transmission capacity are coordinated with the development of generation and consumption. In principle, at least, optimal transmission tariffs provide a signal for the profitability of expanding transmission capacity. The gain from increasing capacity is reflected in the reduction in transmission payments resulting from smaller losses and fewer, or less severe, constraints. If, in addition, users are compensated for power outages that are due to failures in the transmission system, the benefit of improved security of supply can be measured as well. With the establishment of a suitable market for transmission contracts, one can, in principle, envisage a system whereby decisions about transmission investment are completely decentralized. In practice, we would expect regulatory oversight to be necessary to ensure an efficient development of the transportation network, including a system of economic incentives imposed on the grid owners/operators.

Sharing of costs

As mentioned above, transmission tariffs set according to efficiency principles will typically not be sufficient to cover all costs. How the remaining cost should be shared among users of the system is, to a large extent, a matter that must be decided by judgements of equity or fairness, on which economic principles have little bearing. Nevertheless, in order not to undermine competition and efficiency, it is important that costs are allocated in a way that minimizes distortion to trading arrangements.

To take just one example, in the United Kingdom, the fixed charges are divided between consumers and generators in the proportion 75:25, on the argument that the minimal system required just to deliver raw (and unreliable) energy would only cost 25% of that required to provide system security, which is deemed to benefit consumers. The UK philosophy is that customers will choose to connect to the grid (and hence pay the fixed charge) if they value the reliability it provides sufficiently. The main problem is to measure the value that consumers actually place on reliability (which is a public good) and then to provide the optimal amount. Large scale auto-generation would be an indication that the balance had not been properly struck.

Does this division matter and, if so, how and how it should be set? In a competitive system, if the market price of electricity is m and transmission costs are c, then the delivered price is $p = m + c$, and it would not seem to matter how the transmission costs are allocated. For example, if the generator pays a share y of the transmission costs, or yc, and hence bids $m + yc$ and the consumer pays $[1–y]c$ on top of the bid price, the result it that the final price to the consumer is once again $p = m + c$.

The allocation of costs may, however, affect the choice of whether to buy from the grid or whether to buy from embedded generation (that is, generation that is connected directly to the local distribution system and not to the high tension grid, of which an extreme form is auto-generation).[11] More to the point, it will also affect which generator the customer chooses, if the generation component depends on location, and in particular, in which country the generator is located. It is now widely agreed that whatever division of the charge between generation and consumption is chosen, there are strong arguments for harmonising this division across Europe to facilitate trade (see Section 13.4 below for a further discussion of this issue).

13.2.3 Financial contracts markets

When implementing market reforms, governments have typically taken considerable trouble to establish financial contract markets. In England and Wales, most of the generation capacity was covered by long-term contracts with the RECs in order to safeguard them against immediate increases in electricity prices. Considerable regulatory effort has subsequently gone into establishing a market for financial ‘contracts for differences’. In the Nordic countries, the grid companies have taken over the operation of the markets for day ahead and longer term contracts; Nord Pool now operates an integrated Nordic contracts market. In Spain, an ambitious plan for a set of contractual markets is currently being implemented under government supervision.

Interestingly, while government involvement has been substantial, much of the trading in financial contracts takes place outside the 'official' markets. In England, the Electricity Forward Agreement market has relatively little trade except on base-load strips. In the Nordic countries, and notwithstanding considerable efforts from Nord Pool to increase its share of the trading, only 15–20% of total energy volumes are traded via Nord Pool. In fact, some independent trading houses have been quite successful in establishing alternative trading arrangements and now offer trading places for a range of different types of such contracts.

While we would not rule out the possibility that some government regulation may be helpful in establishing markets for financial contracts, it would seem that, at least when markets mature, specific regulation is unnecessary. Some regulatory oversight to ensure orderly trade and the financial viability of market operators (as is customary in other financial markets) may well be warranted. It seems, however, that market participants do welcome a certain freedom to choose their own contractual forms, and that entrepreneurs respond to the various needs and develop the necessary market institutions. It also seems that this is an area in which competition between different contractual forms may prove helpful in reducing transactions cost, facilitating trade.

Judging from the experience so far, as well as from other commodity exchanges, the quest will be for an attractive and standardized commodity for spot and futures trading, where a base-load strip, perhaps in seasonal tranches, is likely to be the most liquid contract. Over the counter and/or screen-based trading may develop for other contracts, depending on demand. If different exchanges offer the same contract, then arbitrage will rapidly identify the transmission charges and constraints, and perhaps guide the development of improved interconnection. The Californian approach is to allow different power exchanges to compete with each other to determine the best design by Darwinian selection. It may be that different trading arrangements may also identify themselves in competition between adjacent power markets.

13.2.4 Retailing

The evidence surveyed in this Report demonstrates quite conclusively that competition for large electricity consumers will be effective almost immediately after markets are opened up. Although there may be transaction costs – in installing meters and establishing settlement procedures – these are generally small relative to the value of the volumes traded. The development of trade in this market segment may be facilitated by allowing large consumers to participate in the organized spot, or longer term, contracts markets.

The evidence is equally clear that it may be more difficult to establish effective competition in the small consumer segment of the market. Arguably, this is not part of the Commission's remit, as market opening is only required for 33% of the total. Nevertheless, countries that fully open their markets may feel less comfortable trading with countries that have only partly opened their market, and may fear that the captive market is being used to cross-subsidize the competitive market, to the disadvantage of fully liberalized countries. We would argue that the extent of liberalization therefore remains an EU concern, though one that may usefully be deferred for the moment.

Since in this segment, individual volumes are small, relatively minor transactions, costs may make changing supplier uneconomical, even when price differences are considerable. The fact that, initially, consumers have little experience with buying electricity on an open market may add to the (perceived) switching costs. It does, therefore, seem as if some government regulation, at least in the very beginning, may be necessary to develop competition in retailing.

While the Norwegian experience (based on the longest history of any completely open retail market) underlines the potential difficulties associated with creating effective competition in retailing, it also points to how these difficulties can be overcome. The combination of caps on transaction fees, contracts based on consumer profiling and clear rules for metering and settlement between distributors and retailers does seem to go a long way in establishing an active market. When these measures were finally in place, at the beginning of 1997, the retail market developed rapidly. Whereas less than 5000 consumers had a contract with an external supplier at the beginning of 1997, the number had increased to 90 000 by the beginning of 1999.

The importance of reducing transactions costs, in particular by avoiding costly metering, is further underlined by the Swedish experience. The Swedish government (which originally required installation of an hourly meter as a pre-condition for switching supplier) recently changed its policy, and consumer profiling will be introduced towards the end of 1999. Interestingly, electricity prices reacted more or less immediately when the change of policy was announced, perhaps reflecting expectations of a more competitive environment.

While the system of consumer profiling is evidently not perfect (for example, only the installation of hourly or half-hourly meters can provide consumers with the incentives and information needed to optimize their use of energy over the short run), it does seem like a comparatively efficient trading arrangement. While the much more ambitious programme being implemented by the UK government may lead to greater efficiency gains in the future, it does seem unnecessarily costly if the goal is simply to bring the benefits of competition to smaller consumers as well as larger ones.

13.3 Market integration and international trade

If the single market for electricity is to become a reality, it must be as easy to trade electricity between countries as between different parts of the same country. This puts quite specific requirements on the rules for access to interconnectors, on the principles of congestion management and on the structure of cross-border transmission tariffs. In spite of the obvious importance of these matters for the development of a single market for electricity, the Directive is silent on these issues.

The Commission's strategy is to encourage countries to pursue a more radical reform strategy than is mandated by the Directive – by shaming the laggards and questioning the arguments used to defend less liberal solutions. If successful, voluntary reforms are likely to be far swifter than the slower process of negotiations to strengthen the Directive, though that remains a default option. Periodic meetings of each country's regulators are an important part of this process, where the importance of fully unbundling transmission is stressed. They will be critical for facilitating market integration. From 1 July 1999, the new set of TSOs replaced the UCPTE for negotiating international terms of access, and the Commission is taking a lead role in proposing more satisfactory solutions, for example, by commissioning reports such as that by Haubrich et al. (1999).

13.3.1 Transaction-based and non-transaction-based approaches

A key issue in relation to market integration and international trade in electricity concerns the choice between so-called transaction-based (contract path) and non-transaction-based approaches to congestion management and transmission pricing. The choice between these two approaches has several implications for the development of a single market for electricity:

- The transaction-based approach is based on the transaction between pairs of named parties (for example, a generator and a final consumer), and it requires the trader to report to the TSO the injection and withdrawal points of each transaction.
- The non-transaction-based approach is solely based on the point of connection of generators and final consumers, and the reporting to the TSO is limited to traditional load forecasting and generation schedules.

With congestion management, the transaction-based approach implies that each individual transaction is subject to approval by the TSO, and that the determination and announcement of available transfer capability is a key responsibility of the TSO. With the design of transmission tariffs, the transaction-based approach implies that the transmission prices depend on the path between the source and the sink. This requires that a path over a transmission route from generator to customer has to be traced. In practice, this is problematic since, in a meshed network, the actual flows caused by an extra injection and withdrawal of power will affect the flows over almost all the links in the network. In general, the transaction-based approach leads to transmission prices that include transit charges to network owners between the source and the sink and thus depend on the distance between the contracting parties.

Within a non-transaction-based approach, congestion management is based on aggregate net power flows rather than individual transactions. This means that a considerably smaller amount of data has to be exchanged, and that the disclosure of commercial relations can be avoided. From the individual user's point of view a non-transaction-based approach means that access to the network is always firm, and that, consequently, available transfer capability is never an issue. If imminent congestion is, however, detected, the non-transaction-based approach implies that the TSO cannot reject individual transactions. Instead, general countermeasures such as redispatch, counter trading or market splitting have to be used.[12, 13] With transmission tariffs, the non-transaction-based approach implies transmission prices that do not depend on the path between sources and sinks, and thus do not include transit charges.

From the point of view of the development of a single market for electricity, the transaction-based approach has several serious drawbacks. One is that the need for approval of individual transactions may lead to the suspicion that some users are discriminated against, that is, they have their transactions rejected more often than others when there is congestion in the network. In addition, the process of getting approval may cause delay and uncertainty. This may deter entry of new market participants and thus impede competition. A second drawback is that inclusion of transit charges in the transmission tariff leads to 'pancaking', that is, adding several layers of transit charges. This leads to artificially high prices for transmissions across several national borders, and is obviously a barrier to international trade with electricity.[14]

Cross-border transmission tariffs aimed at promoting competition and international trade should be simple, stable and transparent. In order to provide incentives for efficient use and expansion of the network, however, the transmission tariffs should properly reflect the relevant marginal costs. As the power flows in transmission networks are complex, a fully cost-reflective tariff also tends to be complex. Thus there is a trade-off between competition-promoting simplicity and efficiency-enhancing complexity. Given the objective of creating a single market for electricity, our conclusion is that cross-border transmission pricing should rely on a non-transaction-based approach, leading to simple and transparent transmission tariffs. At the same time, efficiency in network use and expansion should be secured through supplementary arrangements involving the TSOs.

13.3.2 Outline of a cross-border transmission pricing system

The common electricity market in Finland, Norway and Sweden is the world's first truly international electricity market with full retail competition, but a separate TSO in each country. Congestion management and transmission pricing is non-transaction-based. Thus, the users of the network are charged only at the point of connection, and there are no transit charges. The point-of-connection or nodal charges are, however, locationally differentiated and, to a limited extent, time-dependent in order to reflect the relation between the use of the transmission network and the marginal losses associated with injections and withdrawals of power at various locations. Congestion is managed by closely cooperating TSOs by means of counter trade (within Finland and Sweden) or market splitting (in Norway and between the three countries). Although the cost-reflectivity is far from complete, the transmission prices do provide incentives for users to relieve congestion and reduce overall transmission losses.

The common Nordic electricity market has not been functioning for very long, but so far it has been functioning well. It seems that the system for congestion management and transmission pricing has been able to promote both competition and efficient use of the transmission network. The market and system operation institutions have, however, also been supported by various favourable conditions. One is that the ample supply of hydro power makes short-term regulation and congestion management relatively easy. Another is excess capacity in generation and transmission, which means that the effectiveness of the signals for location and capacity expansion decisions have not so far been tested. Yet the Nordic example suggests that a single market for electricity is feasible.

On the basis of the experiences of the Nordic system, and the analysis and proposals put forward in Haubrich et al. (1999), we conclude that a transmission pricing system with the following characteristics would encourage trade and promote the development of a single market for electricity in Europe:

- Access charges that are simple and transparent and which only depend on the point of connection, that is, non-transaction-based nodal transmission prices.
- An allocation of charges between entry and exit points that is uniform across jurisdictions, but allocates at least a small share to the entry point.
- Access charges that are locationally differentiated, to an appropriate degree, and provide incentives to relieve congestion and reduce overall transmission losses without adding significant complexity to the transmission tariff.

To complement the transmission pricing system, there should be an inter-TSO scheme for financial compensation for transits and loop flows. This scheme should be based on actual net power flows rather than on individual transactions. Congestion management should be non-transaction-based and conducted within the frame of close cooperation between the TSOs.

13.4 Public service obligations

A central message of the Directive is that liberalization and public policy are not contradictory and should not be used as a pretext for closing electricity markets from competition. While there is no widely shared definition of public service among member states, the Commission lists three broad categories that are widely recognized:

- The first is that of universal service and consumer protection, which provide requirements to connect customers to electricity on a regular basis at reasonable prices, and in some countries to protect the poor, the elderly and disabled.
- The second concerns environmental protection, where many countries support renewable energy and CHP systems.
- The third involves security of supply, both at the technical level and in terms of adequate diversity of generation sources and ability to withstand external supply disruptions, such as the oil shocks of the 1970s, and over-dependence on gas imports from politically unstable countries.

The Directive allows considerable discretion in deciding which of these various objectives are important and how they should be met, subject to the condition that they should not restrict trade and competition more than is necessary. Most if not all of these obligations can be addressed via market instruments in a deregulated system. Deregulation is to a large extent compatible with other social and political concerns. Thus, public service obligations can be met through licence conditions; environmental concerns can be dealt with by taxes, subsidies or tradable emission permits systems; and technical supply security can be dealt with by market design. Fuel diversity is more difficult to arrange by market-friendly methods, and normally governments impose obligations (on fuel stocks, by non-fossil fuel obligations) or prohibitions (for example, on gas-fired generation in the United Kingdom), most of which distort the market to some degree.

13.4.1 Universal service and consumer protection

Distribution franchises are often defended as a mechanism to ensure equity in the treatment of domestic customers. This tends to be interpreted as ensuring the same price per kWh across the country and cross-subsidizing poorer or vulnerable consumers, particularly where they are required to install more expensive meters. The same debate affects the pricing of access to telephones in many countries, and it is increasingly accepted that tax (or levy) and transfer systems are superior to monopoly franchises. If some category of consumer requires subsidy in order that competitive suppliers will be willing to serve them customers, this is better secured by a levy on all consumers, which can be used to fund such transfers (perhaps via a tax on bottleneck facilities such as transmission or distribution). The alternative, the implicit taxes and transfers of non-cost-reflective tariffs, impedes efficient liberalization.[15]

13.4.2 Environmental protection

The various EU Directives and international protocols on noxious emissions increasingly constrain the behaviour of electricity generators in member states, and will in due course impose heavy costs on accession countries. For example, the Large Combustion Plant Directive of 1988 was driven by the desire of those member states that already faced local environmental pressure to impose comparable costs on their competitors. This Directive has been updated in 88/609/EEC for emission limits of plant coming into operation after 2000. It has been followed by the Directive on Integrated Pollution Prevention and Control (96/61/EC), which applies stringent emissions limits on new plants from October 1999, and existing plants by 2007 at the latest. The latest extension (57/98 of the 1996 Framework Directive 96/62/EC of September 1996) is based on critical loads, rather than economic rationality, and severely constrains country level emissions of SO_2 and NO_X. These emission limits have been largely accepted, and the current debate is primarily about meeting Kyoto targets for greenhouse gas emissions and, as part of this strategy, encouraging the use of renewables for electricity generation.

In November 1997, the Commission published the White Paper *Energy for the Future*: *Renewable Sources of Energy*. In mid-1999, the preparation for a Directive had been postponed indefinitely. In the White Paper, the Commission expressed concern over Europe's energy policy. First, there is an increasing reliance on imports from outside the EU of primary energy sources, mainly oil and gas. Second, conventional primary energy sources produce the greenhouse gas CO_2, which Europe has to reduce under the Kyoto agreement. Both problems can be addressed by promoting the use of indigenous renewable energy sources, such as wind, hydro, biomass, solar, waste and geothermal power, though the Directive fails to state that they can both be met by nuclear power. Renewables are indigenous and thus reduce the reliance on imported energy source as well as being relatively environmentally clean. The explicit goal of the White Paper is to raise the percentage of renewable energy in total electricity supply from the current 6% to 12% by 2010.[17]

The Directive is largely silent on how renewables should be promoted within a liberalized electricity market, though it allows them to have priority dispatch, particularly as additional capacity will inevitably be more costly than conventional technology (otherwise it would not require explicit support). There are two basic methods of supporting renewables that are more or less market-friendly: price rules and quantity rules. Price rules, which come in many variations, are applied in Germany and the United Kingdom. In Germany, the network operators (which are largely integrated with generation) are obliged to accept generation that qualifies as renewable. Effectively, the independent renewable generation capacity is paid a guaranteed price and the renewables run very low risks. The corresponding costs for the network operators are of course passed through to the end-user prices.[18]

The United Kingdom operates a different variation of this approach through the Non Fossil Fuel Obligation (NFFO), as described in Chapter 6 of this Report. Although this was originally intended to ensure the viability of nuclear power, it also promotes renewables and indeed is now solely used for that purpose. The Department of Industry and Trade sets a capacity goal for renewables and, under the NFFO, the public electricity suppliers are obliged to contract for the resulting power. They are, however, centrally compensated for the extra costs of these contracts, thereby avoiding the German problems. The results of the five rounds of tendering to date have been considerable reductions in the cost of contracted renewables, to the point that some are commercially viable without subsidy, though falling conventional fuel costs have made this a moving target.

In contrast to the German and UK systems, the Netherlands has adopted a quantity rule (see Drillisch, 1998). To forestall government intervention, the electricity distributors agreed voluntarily to a quota system. Each of the distributors promised to contract for (or itself produce) a fixed percentage share of electricity from renewables.[19] This is compatible with competition among the distributors (retailers), because they simply agreed to take the same percentage of their input from renewables. It is left to the distributors to find the subsequent capacity. Within the intended competitive setting, this sets strong incentives for the distributors to find the cheapest possibility, and this is exactly what a competitive system is supposed to do. The production of renewables will be ‘certificated’ (in units of 10 MWh called ‘groene labels’ or green tickets), and in order to ensure efficient contracting and uniformity of the costs, these certificates are tradable.

The price the Dutch distributors pay for small-scale renewable electricity is set by ministerial decree. This seems unnecessary with a system of tradable certificates, but the government thought it wise to save on transaction costs for small scale production. For larger scale production, the price for renewables will be determined by an agreed contract price for actual production and (possibly) the certificate price. The latter reflects scarcity: if the supply of renewables is short relative to the (prescribed) demand, the certificate price will be relatively high; while if supply is relatively large, the certificate price will be low or may even be negative. It is (potentially) a two-part price and the decentralized market will determine both the price structure and the price level. Moreover, within the competitive setting only cost-efficient suppliers can survive. The only market intervention required is in the setting of the amounts to be contracted.

While from an economic point of view the quantity rule is rather elegant and most compatible with competition (at least within a country), there may be severe compliance problems. Both buyers and sellers have an incentive to agree on 'false' certificates. An independent authority should monitor that the volume of renewables production backing a certificate is actually produced by renewables. It is not yet clear whether this can be ensured, especially if certificates may be traded across borders. Indeed, if international trade in electricity is possible, eligible buyers can avoid paying the higher costs of local green electricity, unless the system is extended (and enforced) Europe-wide, which looks unlikely without EU pressure.

13.5 Visions of the single electricity market

We cannot tell how the electricity market will develop, but we can speculate on what an optimistic and a pessimistic scenario might involve. The optimistic scenario would be one in which transmission tariffs between member states were simple, and related to short-run avoidable cost. In the absence of transmission constraints and especially in off-peak hours, these costs would be extremely small and the spot wholesale prices in different EU countries would be very close. Transmission constraints, more likely in peak periods, would create wedges between low-price exporting regions (probably in Scandinavia during high rainfall seasons) and higher prices in thermal systems to the south. Rapid progress in integrating the transitional economies of Central Europe into the electricity market might make available substantial supplies of low-cost power given the present over-capacity in the region.

With rTPA and open, transparent and non-discriminatory access, traders would arbitrage prices across the EU and drive down retail prices for eligible customers. Medium-sized customers would surely press for eligibility, and as experience with retail competition grows, the pressure would be on to extend access to all consumers. Low wholesale prices may cause some inefficient and polluting plant to close and be replaced by gas, while the economics of new nuclear power stations would look unattractive, allaying the concerns of environmental movements in various countries. Renewables would face fiercer competition and would require more carefully designed market support. The switch to gas would alleviate problems of meeting carbon dioxide targets, while falling electricity prices might allow EU countries to impose sensible VAT rates on energy, possibly allowing lower taxes on labour or capital to the benefit of the rest of the economy.

Allowing entry by new companies into generation risks a rush of entry, which lower wholesale prices might slow down to an acceptable pace. As the industry is unbundled, companies with a comparative advantage in one or other sector of the industry will take over or merge with their counterparts in other countries. Multi-utilities may become increasingly EU-wide, and, as information technology systems reach maturity, trading and transaction costs should fall to the benefit of final consumers.

An integrated market should lead to greater price stability and predictability, encouraging the development of power exchanges and futures markets. Gas liberalization and the increasing interaction between gas and electricity markets will further encourage futures and derivatives markets, allowing arbitrage between the two fuels. System-wide, cost-benefit analysis for investments in transmission capacity and intelligent methods of financing socially profitable interconnectors should improve security of supply and further integrate the market.

The pessimistic scenario is almost the opposite of these agreeable tendencies. If inter-country transmission tariffs are poorly designed they will discourage trade and protect the local incumbent generators. High wholesale prices in some countries may encourage excess and inefficient entry, hastening the closure of coal mines. The incumbents will resist extensions of customer eligibility as part of their strategy to protect high prices and resist entry, while access to the domestic transmission system will be impeded as each access case is fought through the courts. Mergers and takeovers will increase concentration, horizontally and perhaps by re-introducing vertical integration. The environmental movement will impose costly solutions for renewable power on the electricity industry that will be passed through to domestic households or the larger non-eligible customers (mainly the commercial sector). Accession by Central European countries will be delayed and imports restricted to bilateral swaps with incumbent utilities. Difficult entry conditions into electricity will slow the pace of liberalization in the gas market and sustain continued cartelization of both sectors. In short, very much ‘business as usual’.

13.6 Concluding remarks

Competition and free trade have proved to be formidable engines of economic growth and prosperity. The Electricity Directive has made a significant contribution towards opening up the national electricity markets for competition, and for free trade in electricity in Europe. Yet, the Directive is not all that is needed even if fully implemented in all member states. There remain concerns about the implementation of the Directive in the area of transmission access, where charges are only a part of the terms and conditions of access. There are unresolved issues in how effective functional unbundling will be in achieving the benefits that full legal separation would ensure. There are worries about the way in which member states may use the ability to recover stranded assets as a covert form of state aid, which may distort the market. These will undoubtedly require continued attention by the Commission and by each country’s regulator.

Of the other issues not yet fully resolved, three are particularly important, namely:

- The harmonization of non-tariff conditions for access to the transmission network: If access terms are not open, transparent, non-discriminatory and enforced, trading will be undermined and the benefits of competition and international trade will not materialize to the fullest possible extent.
- The expansion of interconnection facilities: it is a difficult and unresolved problem to ensure that there are efficient and adequate investments in interconnections between different countries or areas covered by different grid owners. There is no obvious body that can take responsibility for identifying the need, allocating the cost responsibility between the participants and drawing up compensation schemes that ensure fair division and cost recovery.
- The design and implementation of a uniform system of cross-border transmission tariffs: we have indicated how a competition and trade-promoting system of cross-border transmission tariffs can be designed. A commonly adopted cross-border transmission tariff, of the type we have suggested or designed in some other way, has to be implemented and enforced within an institutional framework that supports close cooperation and cost-sharing between the TSOs. Such an institutional framework currently does not exist.

We believe that the development of the single market for electricity depends on if, when and how these issues are resolved. Free trade in electricity will reduce the market power of incumbent generators within each national market, lowering prices, increasing efficiency and, finally, benefiting customers. If progress is slow, access for new market participants uncertain and transit charges significant, the single market may only become a club for major generators, producing few benefits to consumers and of little importance for the competitiveness of European industries. If progress, however, is fast so that open access, transparency and non-pancaked cross-border transmission tariffs soon become the characteristics of the European electricity market, there will be a dynamic transformation of Europe's electricity supply industry to the benefit of households and industries.

Notes

1 From the foreword by Christos Papoutsis to the 1999 European Commission document *Opening Up to Choice*: *The Single Electricity Market*.

2 Of course, it is possible that poorly designed and burdensome regulation introduced to manage the various unbundled parts could lead to a more costly and inefficient industry than one under competently managed vertically integrated state ownership. That is just an argument, however, for care in the design of the regulatory system, not an argument against unbundling.

3 Another argument for nTPA is that it may be hard to ensure that a formulaic approach to setting regulated tariffs makes them all properly cost-reflective, and it may be that a combination of nTPA and rTPA can deal with this, where the entrant or supplier has a right to the terms of rTPA, but can be offered different terms (which would have to be at least as

attractive) by the TSO – perhaps requiring a different combination of fixed and variable charges, for example, where the new terms are closer to (marginal) cost. This would not be desirable without ownership separation, as it would be open to abuse and discrimination. The alternative in which the TSO proposes revised terms to the regulator may achieve the same result but more slowly.

4 There have been concerns where privatized distribution companies have been taken over in aggressive bidding from state-owned electricity companies with access to low cost *de facto* publicly guaranteed finance, though of course the consumers in the host country can then enjoy the financial risk undertaken by another set of tax payers abroad.

5 For simplicity, we limit the discussion to organization of the supply side of the market for physical deliveries. The arguments are straightforwardly extended to the case in which consumers are participating actively in the market for physical deliveries ('demand-side bidding').

6 These bids may be subject to regulation. For example, in Argentina, generator bids are monitored and compared against (assessments of) actual costs.

7 In Norway, the TSO also requires that the short-term contracts market (operated by Nord Pool) is split into different geographical regions when a bottleneck problem is expected. In Sweden, the TSO runs a 'buyback' market to relieve transmission constraints. See Chapter 7 on the Nordic electricity industry for further discussion.

8 With optimal centralized dispatch, transmission tariffs of course have no role to play for short-run, cost-efficient generation, as transmission losses and constraints can be accounted for in the dispatch order; and energy-related tariffs may therefore be set equal for all participants. (To the extent that consumers adjust their short-run pattern of consumption according to prices – this may be the case, for example, with large consumers on hourly meters – transmission tariffs should be set optimally to allow for efficient consumption decisions.) Yet, if the merit order takes into account transmission constraints, but not transmission losses, transmission tariffs have a role to play. Then the argument for centralized dispatch loses some of its appeal.

9 The experience of the Nordic countries is of little use in this respect, as very little investment has taken place since the market reforms were introduced. Few other countries have sufficiently long histories of market-based competition to provide useful lessons on long-term issues.

10 Though at each periodic review, the allowable revenue is related to the capital base, which would be increased and take the form of higher systems charges for remaining users.

11 The problem arises if generation pays a capacity charge proportional to DNC (that is, total capacity) while customers only pay on net demand at the peak. It might be overcome if the capacity charge is paid on net sales (or net purchases) at the peak. In short, whether or not the allocation between customers and generators matters depends on whether they are treated completely symmetrically or not. Embedded generation raises subtle issues of the option value of retaining the right to take the full demand from the grid if the embedded generator fails, which may not be adequately charged for if only net demands are charged.

12 One of the issues to resolve in both approaches is how and whom to charge for costly countervailing measures taken by the TSO to achieve feasibility between commercial transactions and the physical properties of the transmission system.

13 Market splitting means that prices on each side of the transmission contract diverge, splitting the markets into zoned sub-markets, as in Norway.

14 According to simulation results reported in Haubrich et al. (1999) there is only a weak relation between the average air distance between source and sink and the average changes in transmission losses. For individual transactions, however, no such relation could be detected. Thus the cost-reflectivity of distance dependent transmission prices can be seriously questioned.

15 Auctions to establish the least-cost way of meeting such public service obligations may reduce the cost, though they might reduce consumer choice for those being subsidized.

16 There is a worrying relaxation of the earlier requirement of BATNEEC (Best available techniques *not entailing excessive costs*) to BAT (Best available techniques), though these apparently must take account of costs and advantages. There is an industry growing up of presenting estimates of the benefits of reducing emissions, which normally starts from extremely large numbers of deaths caused by pollutants, each of which can be multiplied by a very large number for the value of a statistical life saved. Others compute the QALYS (quality adjusted life years saved) and come up with numbers that may be smaller by a factor of 10:100. Cost-benefit analysis, while better than environmental prejudice, is still an unreliable instrument in this area.

17 The potential to use renewables is obviously the largest with electricity production. The White Paper projects that 12% of total energy consumption corresponds to 23.5% of electricity production, compared to 14.3% in 1995 (of which about half is large-scale hydro, which may raise other kinds of environmental concern.) This would correspond to an increase in renewables generation of 338 TWh. The main contributors are expected to be wind and biomass; the latter in CHP plant, though in the United Kingdom, burning waste appears to be the cheapest option. This releases CO_2, which might be sequestered if buried (though there are then problems with methane emissions) and can be polluting, but the original source of the carbon is often from renewable sources such as wood.

18 One problem is that the northern network operators are at a disadvantage, because the northern coastal area is a good source for wind energy and consequently the supply of wind energy is rather large in the north, raising costs compared to the southern operators. In a monopolized world, this is hardly a problem, but in a competitive setting, it disturbs the level playing field (for the supply of electricity) between market players. Some other way of recovering these subsidies will be required in a completely liberalized market, and even if the franchise remains, the costs will inequitably be borne under the present system.

19 Nationwide, the goal is to increase the share of renewables from 3% in 2000 to 10% in 2020. This is considerably below the goal of the EU White Paper, but the Netherlands has hardly any hydro-power.

Glossary

Units

kV	kilovolt (1000 volts)
kWh, TWh	kilowatt hour, terrawatt hour = 1 000 000 000 (1 billion) kWh
kW, MW, GW	kilowatt, megawatt = 1000 kW, gigawatt = 1000 MW
watt	A unit of electrical power

Acronyms and technical terms

AGR: Advanced gas-cooled reactor (nuclear), the generation design prior to *PWRs*. Most nuclear generation in the United Kingdom is by AGRs.

Amsterdam Power Exchange: Financial power pool in Amsterdam, active since May 1999.

Ancillary services: Services that are required for the security and stability of the transmission system. See *uplift*.

Association Agreement – Verbändevereinbarung: Agreement on access charges under nTPA in Germany; negotiated among selected representatives of the industry.

Availability: In respect of a generating station, the ratio (usually expressed as a percentage) of the net amount of electricity that a generating station is capable of producing in any given period (usually one year) to the net amount of electricity it could produce in that period if it were operating at its net output capacity. The availability of generating stations is affected by a number of factors, including the incidence and duration of breakdowns and the need for overhaul and maintenance. In respect of a transmission system, availability is the ratio (also usually expressed as a percentage) of the time, in hours, for which the relevant equipment was available to perform its normal function in a given year to the total number of hours in that year.

Base load: The lowest load continuously supplied by an electrical power system over a period of time. A base-load generating set is one which under normal operating conditions would run continuously.

Base-load, non-base-load, mid-merit and peak-load generation: Base-load generation is that used to meet the continuous demand even at its lowest level. Non-base-load generation is brought in progressively as demand increases. Peak-load generation is used to satisfy short period of maximum demand. Mid-merit generation is that which falls between base-load and peak-load.

Black start capability: The ability of certain power stations to start up without external electricity suppliers. System operators must ensure that sufficient amounts of this capability exist in the event of plant failure.

Bundeskartellamt: German federal antitrust agency.

Capacity payments: In the United Kingdom, the difference between *SMP* and *PPP*. Capacity payments reflect the probability of supply being lost (*LOLP*) by reason of available generation being insufficient to meet demand, and the *VOLL*.

CCGT: Combined cycle gas turbine, gas-fired electricity plant with low minimum efficient scale.

CEGB: Central Electricity Generating Board, former state-owned monopoly enterprise in the United Kingdom.

CHP: Combined heat and power plants.

CNSE: Comisión Nacional del Sistema Eléctrico, the Spanish electricity regulator.

CO_2: Carbon dioxide.

Co-generators: Co-generators can simultaneously generate electricity and steam. The steam is used locally, and the electricity may be used by local customers, sold through the pool, or both.

Contract for Differences (*CfDs*): CfDs are contracts negotiated between the generators and suppliers in which the parties allocate among themselves the risk of variability in prices otherwise associated with the purchase and sale of electricity through the pool.

Contract-path (or transaction-path) principle: Method to determine the use of the (transmission) network by deducing a fictional path from the contract; usually a straight line between the point of injection and the point of delivery.

CR: Concentration ratio.

CRE: Commission de Regulation de l'Electricite, the French electricity regulator.

Demand-profiling: Statistical method to approximate individual time-of-use, if time-of-use metering is not feasible.

Demarcation contracts: Long-term contracts (typically found in Germany before liberalization), which demarcated/closed the service areas.

Dispatch: The process by which the system operator instructs generators to operate their generating plant.

Dispatch centre: The part of a transmission or distribution system control centre that contains the display and control devices used by dispatchers to monitor and to control the power system.

Dispatching: The operating control of an integrated electric system involving operations such as:

- The assignment of load to specific generating station(s) and other sources of supply to effect the most reliable and economical supply as the total of the area loads rises or falls.
- The coordination of operations with maintenance of high voltage lines, substations, and equipment.
- The operation of principal tie lines and switching.
- The scheduling of energy transactions with connecting electric utilities.

DNC: Declared net capacity.

EdF: Electricité de France.

Electrical reserve: The capability in excess of that required to carry the system load.

EMF: Electro-magnetic field.

EnWG – Energiewirtschaftsgesetz: Energy Act of 29 April 1999 in Germany.

ESI: Electricity supply industry.

Essential-facilities doctrine: Antitrust requirement to allow access to essential facilities under certain conditions.

EVU – Elektrizitätsverbundunternehmen: Used to label the major electricity producers in Germany (in particular, EnBW, RWE, VEBA, VIAG).

FFL: Fossil fuel levy, a levy imposed on licensed suppliers in the United Kingdom under the 1989 Electricity Act to compensate electricity suppliers for the additional costs incurred as a result of satisfying any *NFFO*.

FGD: Flue gas desulphurization.

Fossil fuel: Coal, coal products, lignite, natural gases, crude liquid petroleum or petroleum products.

GWB – Gesetz gegen Wettbewerbsbeschränkungen: Competition Act in Germany.

HFO: Heavy fuel oil.

Information-disclosure: Regulatory requirement to disclose predetermined pieces of information.

Installed capacity: The highest level of output, measured at the main alternator terminals, which a generating station or generating set is designed to be able to maintain indefinitely without causing damage to the plant.

IPPs: Independent power producers. In the United Kingdom, defined as a generator other than a privatized generator or *REC*. They may be partly owned by, or have power purchase agreements (*PPAs*) with, RECs.

KAV – Konzessionsabgaben Verordnung 1992: Federal decree in Germany, that arranges the concession fees for the right-of-(public)-way (*Wegerechte*).

kWh: Kilowatt hour. A rate of consumption of energy, 1 kWh being one hour's consumption at a constant rate of 1 kW (1000 watts).

Load factor: The ratio (expressed as a percentage) of the average demand (for example, in MW) to the peak demand.

LOLP: Loss of load probability. See *capacity payments*.

Loop flow: The unscheduled power that flows inadvertently across a power system that is caused by power taking the path of least resistance from generation to load instead of flowing across a particular schedule or contract transmission path.

Margin: The difference between the net system generating capability and system maximum load requirements, including net schedule transfers with other systems.

MLE – Marco Legal Estate: Spanish electricity regulations, 1997.

NCA: Norwegian Competition Authority (Konkurransetilsynet).

NFFO: Non-Fossil Fuel Obligation.

Net output capacity: In relation to a generating station or generating set, the installed capacity of the generating station or generating set less the power that is consumed by the plant associated with the generating station or generating set.

NO_X: Nitrogen oxides.

nTPA: Negotiated third party access.

NVE: Norwegian Water Resource and Energy Administration.

Offer: The Office of Electricity Regulation (in the United Kingdom).

Ofgas: The Office of Gas Regulation (in the United Kingdom).

Ofgem: The Office of Gas and Electricity Markets (in the United Kingdom).

Outage: The withdrawal from service or non-availability of a generating set, or any part of a transmission or distribution system, for a period of time.

Orimulsion: An emulsion of bitumen and water. Orimulsion is a trademark of Bitumenas, Orinoco, SA of Venezuela.

PES: Public Electricity Supply.

Postage stamp: Charge for use of the network, which is independent of distance.

Power: The rate (expressed in kilowatts) of generating, transferring, or using energy.

- *Apparent*: The power (both real and reactive) proportional to the mathematical product of the volts and amperes of a circuit. This product generally is divided by 1 million and designated in megavoltamperes.
- *Reactive*: The portion of apparent power that does not do work. It is measured in Megavars. Reactive power must be supplied to most types of magnetic

equipment, such as motors. It is supplied by generators or by electrostatic equipment, such as capacitors.

PPA: Power purchase agreement. Long-term contracts securing the capacity and output of power stations.

PPP: Pool Purchase Price, the price generators receive for power in the UK pool.

PSP: Pool Selling Price, the price purchasers pay for power from the UK pool.

Pumped storage power: A power station which uses electricity to pump water into a high holding reservoir. The water can be released to turn turbines to generate electricity on short notice in order to meet sudden increases in demand.

PWR: Pressurized water reactor (nuclear). The most recent commercial reactor design operating in the United Kingdom. Sizewell B is the only nuclear power station using PWR technology.

REC: Regional electricity company.

RPI: Retail price index, the general index of UK retail prices published by the Office of National Statistics each month.

rTPA: Regulated third party access.

Second-tier supply: Supply to non-franchise customers.

Simultaneity factor: Also called the coincidence factor, this expresses the probability that different loads on a network are simultaneous.

SO_2: Sulphur dioxide.

SMP: System marginal price, the highest offered price for any generation set scheduled by the UK pool to run before system constraints are taken into account.

Spinning reserve: The generation capacity which has the status of generating sets in which the turbines are spinning and able to generate more electricity in response to system needs.

System security: The ability of a system to continue to meet demand, following an abnormal occurrence, without overloading any component part of that system.

System stability: The stability of a power system is characterized principally by the maintenance and frequency, voltage and power transfer within limits. It is also dependent on the design and operation of the transmission system, the response of generating sets to disturbances and the availability of reactive power.

Thermal efficiency: The efficiency with which heat energy contained in a primary fuel is converted into electrical energy. The thermal efficiency of a generating station is the ratio (usually expressed as a percentage) of the electrical energy supplied by the generating station (net of electricity consumed by the generating station) to the total heat energy contained in the primary fuel consumed.

Time-of-use metering: Metering of electricity consumption at the precise time of use, rather than over some period of time.

Time-weighted Pool Price: The time-weighted pool price for a given period is the average price over the period, obtained by summing the price for each half-hour slot and dividing the sum by the number of half-hour slots. It is the price a generator would receive from the pool over a period of time if its output was constant.

TSO: Transmission system operator.

UCPTE: Union for the Coordination of the Production and Transmission of Electricity.

UCTE: Union for the Coordination of the Transmission of Electricity (successor to UCPTE).

Uplift: The difference between *PPP* and *PSP*, the cost associated with operating the transmission system in the United Kingdom so that the National Grid Company complies with its statutory and licence duties.

Use of system charges: Charges made on suppliers for the use of distribution systems.

VOLL: Value of lost load. See *capacity payments*.

Voltage: The potential difference or 'electrical pressure' that forces an electrical current to flow within a circuit is measured and expressed in volts (V). As the load on an electrical circuit fluctuates, so the voltage can fluctuate.

Voltage control: The maintenance by the system operator of the voltage within prescribed bounds.

Wheeling: The use of the transmission facilities, in contracts referred to as transmission services, of one system to transmit power of and for another system.

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Index