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ENERGY UTILITIES AND COMPETITIVENESS

Edited by
John Fitz Gerald and Justin Johnston



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ENERGY UTILITIES AND COMPETITIVENESS

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***ENERGY UTILITIES AND
COMPETITIVENESS***

Edited by John Fitz Gerald and Justin Johnston

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Chapter I

INTRODUCTION

John Fitz Gerald and Justin Johnston

The importance of energy utilities, both electricity and gas, in a modern economy is often underestimated. It is only when a problem occurs that public attention is, perforce, focused on their operations. However, their central economic role merits more constant and focused interest from policy makers.

Throughout Europe there is a new interest in the operation of energy utilities and close attention is being paid to how they are structured, to the role of competition in ensuring efficient operation, to security of supply, and to the environmental consequences of the way they are operated. The Commission of the European Communities has made some of the running in recent years. However, as in so many other areas, the need to re-examine policy in Ireland stems primarily from our own requirements rather than from any external imperative.

The Energy Policy Research Centre in The Economic and Social Research Institute has now been in operation for over four years. One of the major projects which it has undertaken over that period has been an examination of the issues to be considered in planning the structure of Irish energy utilities for the next century. The results of this research are published as Chapter 2 in this Policy Paper by John Fitz Gerald and Justin Johnston. This contribution considers the special features of the electricity and gas systems in Ireland which must be taken into account in any restructuring programme. The small size of the island economy and the importance of scale economies makes it difficult to introduce competition in the industry. In the light of experience elsewhere, and developments in the industry in Ireland over the last decade, the paper recommends that competition can best be introduced by contracting out many aspects of the business to private companies. Selling off the utilities as they stand would do nothing to improve competition and would, as a result, not enhance the overall competitiveness of the

economy. The authors also recommend the development of an independent regulatory authority covering all energy utilities, and possibly also other utilities, such as telecommunications.

Chapter 3 by Michael McGurnaghan discusses the Northern Ireland experience of electricity privatisation. This experience is of vital importance in considering future developments in the Republic. The isolated nature of the two systems on this island poses similar problems for policy makers on both sides of the border. The potential benefits from linking the two systems in the future provides a further impetus for considering the Northern Ireland experience and the problems that have to be faced in promoting an efficient industry in the two parts of the island.

Chapter 4 by Richard Green shows how the electricity system in Britain has been restructured. The nature of the original privatisation has necessitated a comprehensive approach by the independent regulatory authority to ensure that the benefits of competition are passed through to consumers.

Chapter 5 by Ole Jess Olsen, describes the Nordic experience of introducing competition in electricity. This experience varies considerably from country to country within Scandinavia. Norway has gone further down the road of competition than any other European country and is, as a result, of special interest. However, its reliance on hydro power means that this experience is not fully transferable to other countries. Denmark, by contrast, has maintained its integrated electricity system which relies heavily on interconnection with its Nordic partners, Norway and Sweden, to produce some of the lowest electricity prices within the EU.

These papers were originally presented at a conference on *Energy Utilities and Competitiveness* in the ESRI on 13th February, 1995. While they all focus on how competitive pressures can best be introduced into the energy utility industry, they also highlight the diversity of European experience in this area. Because of the unusual scale of operation in the industry and the accidents of geography and geology each country must develop its own answers. There is no magic formula to promoting competitiveness through restructuring energy utilities in Ireland or elsewhere in Europe.

Chapter 2

RESTRUCTURING IRISH ENERGY UTILITIES

John Fitz Gerald and Justin Johnston

So the economists who wish to submit the production of public goods and services to a regime of free competition are making a mistake which their tone of self-assurance and levity makes all the more serious and inexcusable. They have compromised political science as much as economic science; they have brought confusion into the whole of social science. (Walras)¹

2.1. Introduction

The extreme openness of the Irish economy lends a special significance to the role of competitiveness in promoting growth in output and employment. Experience in the 1980s brought to the fore the importance to the industry and market services sectors of the quality and cost of many public services such as electricity, gas, and telecommunications. At the height of the recession in the mid-1980s Ireland's lack of competitiveness was aggravated by unfavourable trends in the cost of such essential services. While the situation to-day is much more satisfactory, it remains important for the overall health of the economy to ensure that the cost of provision of these services is kept to the absolute minimum. The world is not standing still and the changing environment for energy utilities in Europe is promoting competition and putting pressure on their costs with obvious implications for competitiveness. Recent developments in Northern Ireland further emphasise the need for a reappraisal of the business in the Republic.

The role of competition in promoting the efficient allocation of resources has long played a central role in economic thinking. However, as the quotation from

¹ Walras, L., "The State and the Railways", translated by P. Holmes, republished in *Journal of Public Economics*, 1980.

Walras indicates, perfect competition may not be socially optimal in an industry characterised by increasing returns to scale. With increasing returns to scale monopoly is likely to be more efficient than competition by many small units. This is the case in the instance Walras was considering, railway networks. The energy utilities are notable examples of firms which have developed over time in many European countries as monopolies exploiting the increase in efficiency inherent in the provision of a single transmission network.

A drive to promote competition is apparent throughout the EU and in the developing legislative programme of the Commission. Starting with the promotion of competition through price transparency² in the gas and electricity industries (European Commission, 1992), the Commission followed with a proposal for the promotion of third party access (TPA) to the European gas and electricity networks (European Parliament, 1992). They have also proposed the separation of energy utilities into their different stages of production (unbundling).

In many other industries pressure to cut costs and maintain competitiveness will come from competition. However, the monopoly structure of the industry in Ireland means that government intervention may be required to bring about change. This paper considers what should be the appropriate role for the government in regulating and restructuring energy utilities over the rest of the decade. There are two approaches which may be adopted to the problem of ensuring that energy utilities minimise their cost of operation: the industry may be restructured to increase competition where it is feasible and maximise transparency; where this is not possible the government can regulate the industry to try and ensure that the costs of the monopoly operator are minimised.

In this paper we consider the operations of both BGE and the ESB covering all aspects of the gas and the electricity industries. The functions of energy utilities are broadly divided into four separate stages³: generation of electricity (or production of gas); the transmission throughout the country using a network of wires or pipes; the distribution or delivery from the main transformer stations to the consumers; the sale to consumers over the network involving the metering of consumption. Whereas the transmission and distribution sectors are natural monopolies, elements of the generation and supply businesses are potentially competitive.

The other papers at this conference consider the experience in Northern Ireland, Britain and the Nordic countries. This paper first considers the structure of the industry in Ireland and the possible extent of inefficiency. We then consider how the industry might be restructured to put pressure on all involved to minimise

² This involves the publication of clear rules on the prices charged to different categories of customer.

³ The 1927 Electricity (Supply) Act used this four way classification of the business.

the cost of production subject, of course, to important standards on security of supply and safety. Finally we discuss how the industry, whatever its structure, can best be regulated by the government.

2.2. The Energy Sector in Ireland

Measuring the competitiveness of the energy utilities is not a straightforward task. While the most obvious measure may be the price paid by consumers for the energy actually consumed, this is not necessarily an appropriate measure. First, because of the increasing returns to scale in the industry and the special problems faced supplying a substantial rural market, the ESB and BGE are not directly comparable to utilities operating elsewhere. Second, governments in the different EU countries have adopted different environmental policies which involve raising prices through taxation and regulation to reflect the true cost to society of consuming a "dirty" good such as energy. In these cases the high price reflects the wider costs to society, not inefficiency in production. Third, energy utilities in different countries have been charged with additional objectives such as security of supply and the related support of domestic coal (Germany) or domestic peat (Ireland) industries.

A more appropriate objective for government is the minimisation of the costs of production of energy. This Section first considers how the need to exploit economies of scale in the industry in Ireland has resulted in a highly concentrated monopoly structure. It then considers the cost structure of the industry; to the extent that costs are too high, resulting in "economic rents", there will be a loss of welfare.

Increasing Returns and Monopoly

Energy utilities have developed over time in many European countries as state owned integrated monopolies. In the past the monopoly structure of these industries was justified by the need to improve the performance of energy markets, in particular to exploit the benefits of scale economies. However, the structure of the energy utility industries and the role of the state in managing these industries is now being re-examined.

Underlying recent debate has been a concern that, while the industry's monopoly structure has permitted the exploitation of increasing returns to scale, the government has failed to hold prices to the true marginal cost of production and the industry has not minimised its total cost of production; prices have been higher than necessary to sustain the industry in the long run.⁴ Debate now

⁴ Ideally firms should price at long-run marginal cost. With increasing returns to scale this will not produce enough revenue to cover fixed costs. Fixed costs should ideally be recouped by charges which do not affect consumer behaviour - for example connection charges.

concentrates on the possibility of introducing competition as the market should be more efficient than the state at allocating production where increasing returns to scale are not prevalent.

The structure of the energy utilities in Ireland has evolved over many years in response to government intervention and market forces. Nearly all the generation, transmission and sale of electricity is concentrated in the hands of the ESB and all of the transmission and sale of gas is controlled by BGE. In the case of the ESB its monopoly position goes back more than 60 years reflecting the need to maximise the benefits to be obtained from large scale operation. The BGE monopoly is more recent. Up to the 1980s there were a number of local privately owned monopolies which controlled the supply of gas in individual cities. However, with the introduction of natural gas and the creation of a transmission network in the 1980s, BGE took over all the functions previously handled by independent companies.

The small size of the economy interacting with the exploitation of the scale economies in the industry has resulted in a highly concentrated structure in electricity generation limiting the scope for competition. Currently there are only 15 significant thermal stations and the size distribution of these stations is shown in Table 2.1. This shows that one station, Moneypoint, accounts for over 40 per cent of the power produced and it is essential to the running of the system. As a result, there is currently little scope for developing competition between generating stations, even if there were a change in their ownership.

Table 2.1: *Size Distribution of Thermal Electricity Generating Stations, 1991*

<i>Size of Plant</i>	<i>Number</i>	<i>Units Sent Out</i>	
		<i>Millions</i>	<i>% of Total</i>
Less than or equal to 250	7	963	7.4
Greater than 250 - Less than 1000	4	2,106	16.1
Greater than 1000 - Less than 2000	3	4,586	35.1
Greater than 2000 - Less than 10,000	1	5,393	41.3

The absence of interconnection of the electricity system with other European networks means that the Irish system is unusually small and isolated. There is no possibility of smoothing peaks in demand by drawing electricity from neighbouring systems with different load profiles and there are substantial extra costs due to the need to maintain permanent reserves in the generating system. For example, at all times a reserve equal to the largest generating unit on the system must be ready to take over in case of break-down. These additional burdens reflect the importance

of economies of scale in electricity networks (Helm, 1993). This places the industry at a competitive disadvantage compared to other EU systems.

An interconnector between Northern Ireland (NI) and the Republic was constructed in 1970 but, because of terrorist action, this line has been closed since 1975. However, as a result of recent political developments it is to be re-opened in 1995. The failure to date to integrate the two systems has imposed considerable costs on the two economies (McGurnaghan, 1990) and a major challenge for the future will be how the current systems in the North and the Republic can best be integrated (McGurnaghan, 1994). There are substantial gains to be made from a full integration to form a unified system with centralised decision making on the order in which the output from individual stations will be chosen (despatched).

This process of integration poses obvious problems for the political process; the choice of location for new stations and the choice of redundant stations for closure will obviously have difficult implications, even if the decisions are made on a purely commercial basis. The process of integration also poses legal problems given the divergent path that the industry has taken in the two jurisdictions. The ultimate objective of integration should be a system which ensures the co-ordinated despatch of generating stations to ensure that electricity is always produced at lowest cost.⁵

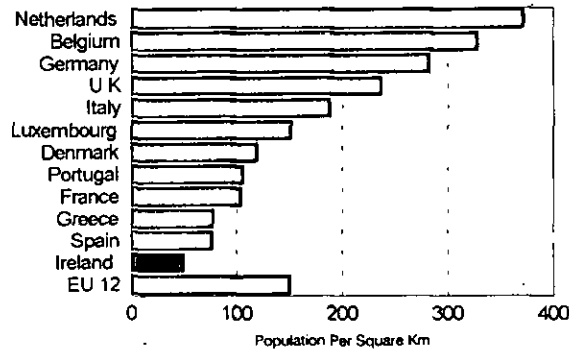
For gas, the installation of an interconnector to Great Britain has ended the isolation of the Irish system. For the next few years, while gas still flows from the Marathon field, this will, at a price, increase the security of the Irish system by providing an alternative source of supply. However, once that field is exhausted Ireland will be once again dependent on a single pipe-line which is vulnerable to accident or failure. The new pipeline gives access to additional sources of gas supply which are essential for the survival of the industry and it also allows the use of additional facilities in the UK, such as temporary storage to cover peak demand. The transmission of gas poses less problems than does that of electricity and there is a lower loss in transmission so that the interconnector will make a significant contribution to ending the isolation of the Irish system. However, security of supply considerations will continue to restrict the potential penetration of gas, in particular in the market for electricity generation.⁶

The small size of the Irish economy and the distribution of the population within the country also affect the energy utilities in their transmission, distribution and supply functions. Ireland is unusual by Northern European standards, not only in the relatively high proportion of the population living in rural areas, but also in

⁵ This involves matching the demand and supply of power second by second by choosing the appropriate generating station to provide the marginal increment in electricity at least cost.

⁶ On site storage of gas and the possibility of switching generation from gas to gas oil at short notice limit the exposure of the economy to any disruption of gas supplies.

Figure 2.1: Population Density



Source: Eurostat, as at 31/12/92.

the dispersion of the population outside villages or small towns. The density of population in Ireland is 51 per km² compared to the EU average of 151, Figure 2.1. This means that the load density (electricity sold) per km² is extremely low. The national load density is approximately 35kW/km² for electricity which drops to an average of 20kW/km² in rural areas of the country. These load densities are about half the levels of other EU countries such as France. This dispersion raises the overall cost of running the system and poses problems in introducing competition.

Economic Rents

In the case of energy utilities the objective of improving the overall competitiveness of the economy focuses attention on the cost of production of electricity and gas. With monopolies the results of the lack of competition may be high production costs due to abnormal profits or *economic rents*, where the normal rate of profit is that which is sufficient to remunerate the capital employed in the industry. The excess profits or economic rents can go to the owner - the government or the private monopolist; they can go to the factors of production - through unduly high prices, such as inflated wage rates, or through a wasteful use of inputs, such as excessive staffing. In monopolies, especially where state owned, it is frequently the case that the economic rent will be captured by the employees rather than by the government. It is also possible that the supplier of materials, such as fuel,⁷ may extract some of the rent.

If the economic rent from over pricing by energy utilities accrued to the government it would be available to reduce other distortionary taxes or to fund additional expenditure. Fitz Gerald and McCoy (1992), suggest that a reduction in taxes on labour funded by a broad energy tax would increase welfare. Thus an

⁷ For example, the price paid for peat in Ireland.

exploitation by the state of its monopoly power as owner of energy utilities could have some offsetting benefits as the economic rent would be broadly similar to a tax on energy. In the case of a private monopolist the situation would be rather similar to that where the economic rent accrues to the employees; the income would be unavailable to the government to reduce economic distortions elsewhere in the economy.

Figure 2.2: *Consumer Electricity Prices*

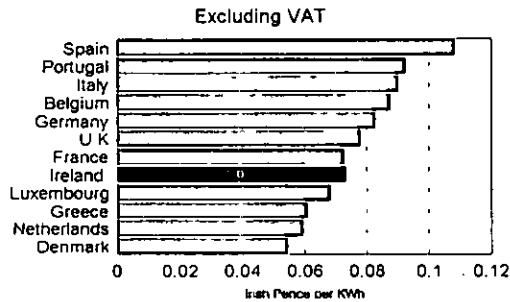
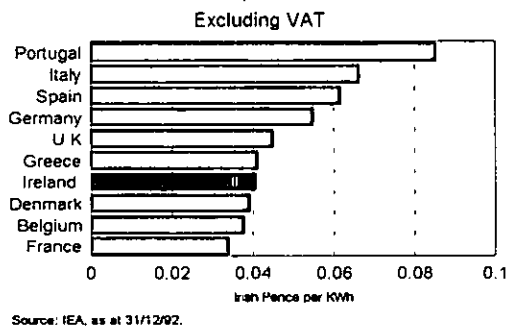


Figure 2.3: *EU Industrial Electricity Prices*

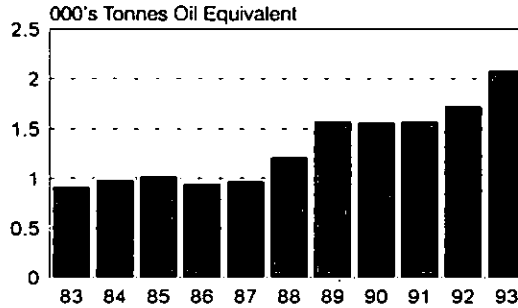


It is difficult to estimate the extent to which economic rents are earned in Irish energy utilities as a result of unduly high production costs (including the cost of capital - profits). As shown in Figure 2.2, in the case of electricity the current price charged to households is quite low by European standards. The price charged to industry is also in the mid range of EU prices (Figure 2.3).

However, as discussed earlier, price comparisons are not a reliable indication of the level of efficiency. There is evidence that the cost structure of the ESB is too high, in particular because of significant overstaffing in different parts of the

enterprise. For example, the ESB themselves manage a gas-fired generating station in Lancashire with far fewer employees than they have in comparable Irish stations. Until the detailed studies undertaken of the cost structure of the industry become available it is not possible to identify the full nature and extent of the economic rents being earned by those working in the industry.

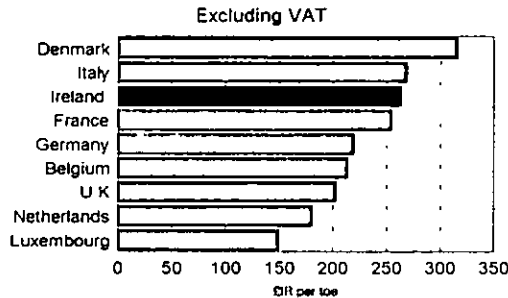
Figure 2.4: *Average Output per BGE Employee*



Source: BGE.

BGE is also a state owned monopoly where there is a possibility that the economic rents may accrue to the employees. In the mid-1980s BGE took over the existing private monopolies which produced and distributed gas in Dublin and Cork. The cost structure of these firms was clearly excessive and, as shown in Figure 2.4, the amount of gas sold per employee has risen dramatically over the past decade showing a major improvement in efficiency. However, this does not allow us to measure whether there is any persisting inefficiency as an increasing proportion of the business has been contracted out reducing the numbers employed directly.

Figure 2.5: *EU Consumer Gas Prices*



Source: IEA, as at 31/12/92.

The case of BGE is slightly different from the ESB in that gas faces much more competition from other fuels in the markets in which it sells. While there are no perfect substitutes for gas, electricity, diesel oil and bottled gas do provide competition in different segments of the market.⁸ Figure 2.5 shows a comparison of the price of gas to households in Ireland compared to the situation in other EU countries. This indicates that Irish prices are not exceptional (though evidence on the price to industry is not readily available). However, the fact that gas has, to date, been available to BGE at a very low price has reduced the pressures on the cost base and it means that the sale price is not a good measure of efficiency. The prospect that BGE will in the near future have to buy gas at UK market prices means that there will be further downward pressure on the rest of the cost base over the rest of the decade.

The evidence suggests that, in practice, the bulk of any economic rent in the ESB has probably accrued to employees serving to improve their welfare at the expense of distortions elsewhere in the economy. The situation in the gas industry is rather different: in the 1970s and the 1980s much of the economic rent was frittered away subsidising NET.⁹ Some of the remainder accrued to the government as a dividend.

Why Worry?

The potential for earning *economic rents* through charging excessive prices is of concern to public policy for four main reasons. First, by charging a higher price than that which is needed to ensure long-run supply the market is getting the wrong signal and firms and individuals will consume a sub-optimal amount of gas or electricity, substituting other fuels and other goods for over-priced energy inputs.¹⁰ Second, it will adversely affect the competitiveness of the economy resulting in a loss of output and employment in the tradable sector as output moves to foreign destinations. Third, the higher price will have an income effect as consumers pay higher prices for electricity. Income will be transferred from consumers to the beneficiaries of the economic rents be they employees, the owners of a private monopoly or the government. Fourth, high prices will affect the distribution of income.

The research evidence suggests that the price elasticity of demand for energy is low in both the industrial and the household sectors (Conniffe and Scott, 1990;

⁸ While electricity also faces competition in certain markets, such as space heating, in others, such as light and power for machinery, there are no close substitutes.

⁹ NET was the state owned fertiliser company which expanded production in the 1970s using cheap gas.

¹⁰ This assumes that the full cost of environmental damage is incorporated into energy prices through an appropriate tax on inputs.

Bradley, Fitz Gerald and Kearney, 1993, and Conniffe, 1993). However, it is likely that at the level of the individual fuel, such as electricity, the elasticity of substitution could be higher. However, even here the evidence suggests that the likely distortions from inappropriate pricing are likely to be low, at least in the short to medium term (Scott, 1980 and Scott, 1991).

A much more important potential benefit from increasing efficiency in the energy utility sector is the likely effect on the competitiveness of the economy. This issue was highlighted in the Culliton report (1992). The effect of reducing the cost of energy will be to reduce the cost base of the tradable sector in Ireland compared to its foreign competitors. This in turn will lead to an increase in investment, output and employment in the sector.

A reduction in energy prices will also clearly benefit consumers. It can be expected that the reduction in consumer prices would, in turn, lead to some moderation in the rate of increase in wage rates reflecting the increase in purchasing power of wages consequent on the reduction in prices. This would further improve the competitive position of the tradable sector.

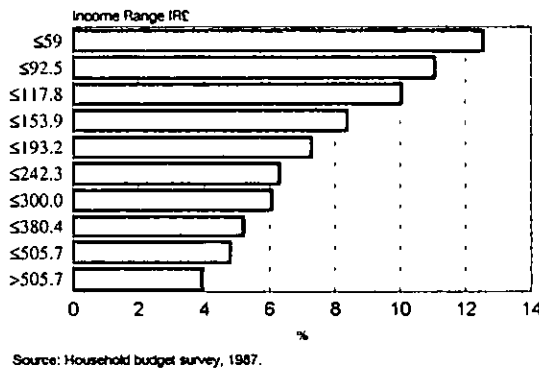
Simulations using the ESRI Medium-Term Model suggest that the initial impact of a cut in costs in energy utilities of, for example, around £100 million, through a reduction in employment of around 3000, would be a net loss of employment in the first year of the reform. However, there would be a major benefit to consumers as the price level would be reduced. In subsequent years the loss in employment in utilities would be offset by increased employment in other sectors of the economy as firms in the tradable sector would take advantage of improved competitiveness to increase output and employment. In the medium term total employment would, at worst, be unchanged and could be somewhat higher than in a *no change* scenario. GNP would be significantly higher than in the *no change* scenario. In the long term it might be hoped that the creation of a more competitive environment in the economy would have effects on other sectors adding to the gains in welfare. In practice, in achieving such a reduction in staffing it is likely that there will be significant restructuring costs. These costs and the time taken to adapt will postpone the eventual economic benefits from increased efficiency.

As shown in Figure 2.6 consumers with low incomes tend to spend a higher proportion of their incomes on electricity and gas than better off households. As a result, a reduction in energy utility prices is also likely to have a progressive effect on the distribution of income.

Of the four channels through which increased efficiency could improve welfare in Ireland the most important is likely to be the effect on the overall competitiveness of the economy. The improvement in efficiency in energy utilities which has taken place over the last 10 years has contributed to the recovery in

economic prospects. Increased efficiency would also have positive income distribution effects. At least in the short to medium term the effects on allocative efficiency are likely to be limited and, while the energy utilities remain in State hands, the albeit limited rent accruing to the government may be assumed to be used to offset other distortions.

Figure 2.6: *Percentage of Expenditure Spent on Energy, by Income Group.*



2.3. Restructuring the Industry

From the point of view of society as a whole whether or not there will be an improvement in welfare from restructuring of the energy industries depends on the extent to which existing *economic rents* are reduced through competition or regulation – will there be an increase in efficiency? In turn this will depend on the balance between the costs of restructuring (contracting costs) and the benefits from the increase in price transparency and competition.

The possibility of improving the efficiency of energy utilities through restructuring can be considered under two broad headings – the level of integration and ownership. The current energy utilities, the ESB and BGE, are highly integrated firms covering all stages of production and sales. The issues to be considered here are the extent to which each of these firms should be broken up into separate companies and, whatever the eventual structure, who should own the resulting firms? To the extent that parts of the business can be producers in competitive markets they can be sold off or contracted out. As discussed in the next Section, all the elements of the business, especially those which are natural monopolies, should be subject to comprehensive regulation by an independent regulatory authority, whoever owns them.

Level of Integration

The unbundling or break up of the energy utilities into a number of new firms covering different stages of the production process may be beneficial if it allows the separation out of the monopoly elements of the business and the introduction of a competitive market for the remainder. The Irish government faces a choice between restructuring the utility industries by splitting up the different stages of production, regulating the natural monopoly stages, or leaving such industries as they are as vertically integrated monopolies, albeit with increased transparency in their accounting procedures. If the latter option is chosen it will still be necessary to regulate them to ensure efficient operation and protect the interests of consumers. The choice between these two options depends on the costs and benefits of integration.

Utilities are highly capital intensive industries and assets tend to be specific and durable (e.g., power stations and transmission systems). Payoffs for new projects may take as long as 15-20 years. To encourage firms to invest in specific assets long term contracts are necessary. However, because future contingencies are hard to describe such contracts may be very costly (if not impossible) to write (Coase, 1937 and Williamson, 1971). This is especially true at the co-ordinated despatch stage (the decision on the order in which generators are to be used). Therefore, any unbundling of the existing vertically integrated energy monopolies will probably involve costs and some loss to society which must be offset against possible gains from increased competition.

The advantage of vertical integration under unified management is that even a monopolist has the incentive to minimise costs, and to ensure that internal transactions between the different stages are conducted efficiently. If an industry is vertically disintegrated, then prices substitute for internal planning and co-ordination, with the regulator influencing these prices. If the prices are incorrect, then decisions may be inefficient. (Green and Newbery, 1993)

The key to the options for restructuring the industry lies in how the market for utilities is operated. At the moment the despatch of electricity (choice of generation station) is determined by the relevant section of the ESB which manages the network using the full range of information available to them on costs and likely demand. The decision on the priority in despatching (using) different generation stations is complex as the cost of a unit of electricity will vary from minute to minute depending on the shape of the load curve and the characteristics of the different generating stations.

In the UK the industry has moved from being organised as an integrated firm to a situation where a number of individual firms decide their own futures and are co-ordinated through a market mechanism - the pool - where electricity is traded between a range of buyers and sellers. There are now signs that the new independent firms are tending to reintegrate through the establishment of long term

contractual agreements. In the Northern Ireland system the role of the market in the UK is currently played by the power procurement section of Northern Ireland Electricity which replaces the many buyers in the UK pool dealing directly with the sellers of electricity.¹¹ Clearly the power procurement function is a monopoly. The choice of model for organising the industry in the Republic of Ireland depends on the empirical evidence as to which one will minimise the costs of co-ordination - ensuring that electricity is produced at least cost over the course of the year and that the optimal level of capacity is available at all times.

However, given the small size of the Irish economy there remains the danger that a rather complicated structure involving vertically separated elements of the existing monopolies could prove difficult and expensive to operate efficiently. The costs involved in operating the UK electricity pool are high and some other approach may be necessary in a small isolated system such as Ireland (Putnam, Hayes and Bartlett, 1993). This suggests that if some other means can be found to introduce competition into parts of the industry it would be best to maintain the current co-ordinated planning model where a single firm or body is responsible for seeing that electricity and gas are made available at minimum cost as and when they are needed.

Whatever method is adopted, if competition is to be possible through new entry into the industry at any stage in the production process it is essential that the rules used in despatching electricity be turned into information which is publicly available on the cost of electricity bought and sold at different times of day (and possibly in different regions). Without such information to drive the market, competition is likely to result in a less efficient use of existing resources than under the current integrated system.

Competition

Faced with the need for increased efficiency in public utilities what is the appropriate response for government? In restructuring the energy utilities a major objective of policy should be to promote competition where returns to scale are constant or decreasing. Competition can be brought about either by a combination of privatisation and new entry¹² or through contracting out a range of services currently undertaken within the monopoly firm.

The approach adopted in the UK has been to privatise the industry and to try and create an environment where the privatised firms compete. An alternative related way of increasing efficiency would be to leave ownership of the assets with the current operators while most of the services and goods used by the utilities could be bought through a competitive tendering process. This latter approach has

¹¹ In due course this arrangement is to be superseded by a pool or market mechanism (Offer, 1993).

¹² Experience from the UK electricity industry suggests that to create competition it is not sufficient to break up a monopoly into two firms (Helm, 1993).

been widely adopted in managing public infrastructure in France (see Lorrain, 1994). Here we consider in turn the two main energy utilities - electricity and gas. We first consider what aspects of the business of the utilities are amenable to competition and we then examine the different ways in which competition might be introduced.

Electricity

The crucial issue to be considered is the extent to which the existing integrated company should be separated into its different business functions - transmission, generation etc. and, whatever the eventual structure, who should own the resulting firms?

In the case of generation, as with the rest of the system, the objective of reorganisation is to minimise or even eliminate economic rents by changing the incentives facing the operators and suppliers of the individual stations. However, even if electricity generation is not a natural monopoly and competition is possible elsewhere in Europe, the small size of the Irish economy may give rise to local monopolies. As discussed above, this is reflected in the size distribution of generating stations with the Moneypoint station commanding a dominant position in the ESB system. The same is true in Northern Ireland where two stations dominate the system. This highlights the potential difficulties in developing competition in a small system such as that of the Republic of Ireland.

As economic rents in generation are most likely to accrue to the employees rather than to the current owner, instead of seeking to change ownership it would be more appropriate to concentrate on changing incentives through contracting out. The extensive use of contracts for providing the different services needed to operate the generation stations, while still leaving ownership in the hands of the state, would help put pressure for increased efficiency in operation. At the very least the maintenance of the stations could be undertaken on a contract basis. A further stage could involve putting the management of stations out to tender, just as the ESB itself has tendered for management contracts in the UK. The contractors would have every incentive to minimise costs while the competition for the contracts would minimise the possibility of excess profits for the contractors. Because the capital costs would still be borne by the ESB, the risks incurred by contractors would be minimised thus making entry into the market easier.

However, it is likely that as well as moving towards a policy of contracting for services in the generation sector, freedom of entry for new operators should also be pursued. With changing technology it is now possible that smaller plants may be economic in certain segments of the market, for example combined heat and power. This opens up the possibility for some competition for production of electricity. However, to allow such a market to develop it will be necessary to

increase transparency in the electricity system as a whole and, in particular, to have a transparent calculation of the costs and benefits of a marginal unit of electricity at different times of day and in different regions.

It is clear that the transmission network is a natural monopoly in Ireland as in the rest of the EU.¹³ The distribution of electricity involves transporting it from the main transmission network to the individual household or industrial or commercial consumer. The management of the transmission system or the despatch function is clearly a monopoly and must remain a central function of the utility which runs the electricity system. Centralised despatch is the key to reaping the benefits of scale from the operation of an integrated system. As discussed above, the cost of developing and running a pool system in Ireland would be unlikely to justify the potential benefits. Therefore to ensure transparency and a free flow of information it is desirable that it remain in government ownership, unlike the situation in Northern Ireland.¹⁴ However there remains the possibility that much of the design, construction and maintenance of the physical infrastructure could be conducted on a contract basis rather than using internal resources. This is the policy which has been adopted by BGE in managing the development of their transmission network. BGE over the last 10 years has undertaken a major shift to contracting out so that the bulk of those now employed in the gas industry are not employees of BGE.¹⁵

The distribution function is also likely to remain a state owned monopoly, though here again the possibility of increased use of contracting out could well introduce serious competition into the sector putting downward pressure on costs.

Finally, the supply of gas and electricity to households involves potentially buying the product from the producers, paying for use of the network, and metering and collecting revenue from consumers. It is theoretically possible to have competition at this level with different suppliers operating over the same network and having different packages of services which they supply to consumers.¹⁶ It is also possible that a single supplier could provide consumers with both gas and electricity (and other utilities) if there were significant economies of

¹³ The one exception to this is the ESB itself which could potentially act as its own distributor of gas, taking it from the BGE transmission network and building its own pipe-line to new gas-fired generation stations.

¹⁴ Unlike Northern Ireland, the constitutional basis of law in the Republic of Ireland makes for a significant difference in operating environment for private and public firms. In the case of private firms the constitutional right to private property might potentially be invoked to limit the flow of information to the regulator whereas this is not possible for semi-state companies (see Convery and Scott, 1990).

¹⁵ Another interesting example of this pattern is Bord na Mona.

¹⁶ For example, one supplier might offer different prices for consumption at different times of the day while another offers a common price. Others might offer interruptible or long-term contracts.

scale in metering (Graham and Marvin, 1994). However, the experience elsewhere on the potential savings to be obtained from such an innovation is unclear. It seems desirable that the possibility of new entrants should be facilitated by accounting changes to ensure increased transparency within the electricity system. It may be that the threat of entry may force a full and timely exploitation by the existing operator of new technology to provide new products.

The other functions of the ESB, retailing and consultancy, are not central to the work of supplying electricity. The consultancy service increasingly operates in a competitive market and it is not clear that it need remain indefinitely in public ownership. A similar argument applies to their retail operations.

Gas

The scope for introducing further competition in gas through unbundling and privatisation is more limited than in electricity. Already, unlike electricity, gas faces competition in most of its main markets from alternative fuels. The network elements of the gas industry are clearly a natural monopoly. However, it is important that the costs of transmission be separately identified. There is already one customer for use of the BGE transmission network the – ESB. If new entry is to be allowed into generation using gas then other new potential users of the transmission system may appear. To allow competition the pricing of the network elements of the gas system should be made as transparent as possible. This is facilitated by the approach of BGE who have sub-contracted the construction of the network through competitive tender allowing a ready identification of the capital costs.

A case could be made for having separate regional distribution companies, as previously existed in Cork and Dublin. However, the benefits of this can probably be obtained more easily by the adoption of transparent accounting procedures allowing the regulator to assess efficiency in the distribution system in different regions. The increasing use by BGE of contractors to build and maintain the distribution network is introducing competition into the provision of this service, helping ensure that costs are minimised.

It is only really in the supply of gas that competition through the entry of multiple enterprises is a theoretical possibility. However, even here it is not clear that new entrants are likely. The concentration on contracting for services and maintenance should put downward pressure on the cost base leaving relatively little scope for economic rents sufficient to attract in new entrants.

Privatisation

Where competition can readily be introduced, either through breaking up and selling an existing enterprise or through new entry, there is a clear case for private

ownership. The issues are more complex in the case of enterprises which are natural monopolies. The key to this question lies in whether a change in ownership will reduce the economic rents inherent in the operation of the monopoly: will it be more efficient and will the benefits of the increased efficiency be passed on to consumers? A secondary issue which is often discussed is the impact of a change in ownership on the public finances.

Privatisation of the natural monopoly elements should only be considered if the value of the natural monopoly to the potential purchaser is greater than the value to the government. The potential for higher profitability of an energy utility in private hands derives partly from the possible additional scope for a privatised firm to equate employees wages to their marginal products,¹⁷ through the reduction of excessive staff levels or from the possibility of shifting the distribution of monopoly rents from suppliers.

The ability of the state to extract this increase in wealth from the privatised monopolist so that welfare is improved, however, will depend on the ability of the regulator to ensure that the monopolist charges a price which is equal to the marginal cost of production (marginal social cost).¹⁸ If the higher value to the private owner derives from a greater exploitation of the monopoly power of the utility then welfare will be disimproved through privatisation.

Another potential advantage of privatisation is that a government may be able to reduce its exposure to risks arising from the large scale investments which the industry involves. A profit maximising private owner should have a strong incentive to control the costs of large investment projects. The price which this reduction in the state's exposure to risk involves is that private owners are likely to have to pay higher interest rates on their borrowing reflecting the higher risks; governments can not go bankrupt whereas private firms, even energy utilities, can. This higher cost of capital must be passed on as higher prices to consumers.

However, this assumes that the government can actually shed the risks involved in major energy utility investment projects by privatisation. The experience in the US and elsewhere is that where private operators have made very unwise investments it has not proved possible for the regulator to insist that the private owner should pay for the consequences of foolhardy decisions; the consequences of the bankruptcy of private utilities have proved too awful to contemplate. As a result consumers have ended up paying the price of both the unwise investment and the higher price paid by the utility for the capital borrowed to undertake that investment.

¹⁷ The firm will maximise profits where the cost of producing an additional unit of output equals the revenue from selling that additional unit of output.

¹⁸ The problem facing the regulator, however, is similar to the principal and agent problem.

If the incidence of the costs arising from unwise investment decisions will fall on the government or the consumer, rather than the private owners or financiers, there is a strong case for direct government involvement in financing and overseeing the construction of power plants or other major energy infrastructure. The government can borrow more cheaply than can the private sector and, depending on the regulatory regime, it may also have greater incentives than the private sector to ensure that the construction is undertaken in an efficient manner. The government's legitimate interest in seeing that costs of construction are minimised can be protected through ownership or else through some special forms of regulation.

A secondary issue to be considered in deciding whether a state monopoly should be privatised is the benefit to the government's finances. In recent years in the UK and elsewhere utilities have been sold off, partly to raise funds for the government. However, many of the arguments on this issue have been ill-informed, viewing all the receipts from the sale of the utility as a net gain of resources to the government. This approach is seriously flawed reflecting the fact that governments rarely publish a balance sheet showing their assets and liabilities (Vickers and Yarrow, 1991).

For a private firm the sale of a subsidiary results in a reduction in the value of the subsidiaries in its balance sheet which is exactly offset by a new asset, the cash receipts from the sale. Similarly, for the government the total assets, if sold for their book value, are identical before and after the sale. Even if all the receipts are applied to paying off existing debt the net worth of the government is not changed by the transaction. Thus arguments for privatisation suggesting that it can allow a reduction in the national debt are a mirage as they are concentrating on only one component of the government's balance sheet. In practice in the UK, to ensure the political success of privatisation, the assets have been sold off for less than their book value.

Other Objectives

It is important that the social and environmental obligations of the energy utilities should be spelt out in detail before restructuring. This will be essential if competition is to be introduced into segments of the industry. If the social and environmental obligations are left unclear this will create uncertainty discouraging future investment. Failure to do so may also result in new distortions in the industry as the industry is liberalised. For example, if the issue of the appropriate level of cross-subsidisation of rural consumers by urban consumers is left unclear, competition could lead to cherry-picking by new entrants choosing to serve only low cost consumers, possibly introducing new distortions in the market.

The case of the peat fired generation stations is another example where policy should be made explicit. Unrestricted competition in electricity generation would rapidly result in the closure of the peat-fired stations. If there is a regional policy objective of providing employment in the relevant areas this would better be achieved by offering an explicit subsidy for such employment which is equal to the current excess burden of maintaining existing stations.¹⁹ This would have the benefit that if a different industry could provide more employment than is currently provided by the peat industry they would be free to do so.

In the case of the environmental regulations an appropriate framework should be designed covering not merely the energy utilities but the rest of the economy. This should preferably involve the conversion of environmental controls into taxes. Where this is not possible emission quotas should be tradable with the quotas being auctioned off by the state at intervals of a few years. Unless there is a market in quotas or there is a common tax rate the environmental controls could act as a serious restraint on new entry.

The possible integration of the two energy systems on this island poses a particular challenge in the area of environmental regulation. Given the different quotas for sulphur dioxide emissions assigned to the two parts of the island the shadow price of the emission quota will differ. Unless trade in quotas is allowed on the island this may give rise to some distortion in the market, making entry easier in one jurisdiction than in another. If the difference in quotas represented a real difference in the absorptive capacity of the atmosphere in the two parts of Ireland then the difference in quotas would have a meaning. However, as the allocation of a quota to Northern Ireland within the UK is itself arbitrary and the allocation of quotas between countries is also fairly arbitrary, this is unlikely to be the case. All this highlights the potential distortions which may arise from a failure to use fiscal instruments to implement environmental policy within the EU.

A final and rather similar issue arises in the case of the implementation of the fuel diversity requirements in a competitive market. Because of the dependence of the gas supply on a single pipe-line it is important that the level of dependence on gas is limited. Already around a quarter of electricity is generated from gas and the scope for further increase is limited. This need to restrict dependence on gas could prevent new entry into the market. While it may never prove necessary to restrict dependence on gas, if it does, to avoid distortions, it may be desirable to treat the limitation on gas usage in a similar manner to the need to limit emissions of pollutants. As with restrictions on emissions, the appropriate response to the fuel diversity requirement may be to sell any gas "quota" by periodic auction and allow

¹⁹ In calculating the excess burden account must be taken of the sunk cost represented by the Bord na Mona debt (Nic Giolla Choille, 1993).

these quotas to be tradable or, alternatively, to tax gas so as to limit its attractiveness.²⁰

2.4. A Regulatory Structure

The purpose of regulation is to try and ensure that, in the absence of competition, the monopolist (private or public) has incentives to minimise costs and to restrict prices to a level at which the capital employed is adequately (but not excessively) remunerated, while ensuring that the level of investment is sufficient and the quality of the product is maintained. Under perfect competition this can be left to market forces. Environmental standards for both monopoly and competitive elements must also be met. Today the Department of Energy effectively fills the role of "regulator" for energy utilities.

Even if the objective of the regulator is clearly stated (though frequently the regulator may be charged with a range of different objectives), in practice the regulator faces a major problem in obtaining sufficient information to determine what is the appropriate rate of return on capital, what is the appropriate level of investment, what is the appropriate price to charge for the outputs of the monopolist and what is the appropriate price for the monopolist to pay for its inputs. If the industry is restructured and split into its monopoly and competitive elements, the monopolist will have an incentive to minimise the flow of information to the regulator. The control of information is thus a key issue.

The design of a regulatory regime can be specified in such a way that the behaviour of the monopolist (public or private) provides information to the regulator. For example, one obvious way of extracting information is to auction the right to a monopoly. In this case the firms which are likely to be most efficient will bid the highest price telling the regulator that they are the most efficient. (However, this approach has other disadvantages in terms of incentives.)

Where full information is not available to the regulator, decentralising decision making may be more effective: the regulator sets certain simple ground rules and the utility then seeks to maximise profit or minimise costs within the context of the regulatory framework. A variant of this is the break-up of a monopoly into a series of local monopolies in different locations, all with different cost structures. This may allow the regulator to determine where there is waste and inefficiency in individual monopolies. This approach forms the basis of "benchmarking". In practice, there are many dimensions to the problems facing the regulator and

²⁰ This highlights the fact that the fuel diversity requirement conflicts with the environmental need to restrict emissions, especially of carbon dioxide. The fuel diversity requirement may necessitate a higher tax on gas whereas the environmental imperative may favour a lower tax on gas. Obviously if relative prices moved against gas or if new gas were found off Irish shores this potential conflict might be eased in the future.

simple rules, such as auctions of licences, may not result in optimal behaviour by the monopolist.

In designing the regulatory regime there is no obvious or unique set of incentives which will produce an optimal result in terms of maximising social welfare. If, as in the United States, the regulator concentrates on controlling the rate of return on capital employed this can give rise to a number of problems. This regime encourages overcapitalisation – the higher the capital stock the higher the allowable profits. It also provides less incentive to control the cost of major investment in plant, given that the rate of return may be allowed on investment in all plant even if the cost is excessive. To counter this problem the regulator may have to determine what is allowable cost. However, this in turn adds to uncertainty and may further distort decision making (Vickers and Yarrow, 1991).

A different approach has been adopted in the UK where the allowable price is calculated with respect to the price of other products (e.g., the consumer price index) but this may also lead to inappropriate incentives. In this case the incentive to invest will be reduced. In addition, the specification of the appropriate relationship between the growth in energy prices and consumer prices, for example, requires detailed knowledge of the working of the industry and the potential for cost saving. If the price margin is too large the industry may end up being allowed to charge a monopoly price leading to allocative inefficiency (Yarrow, 1992); alternatively mistakes by the regulator could result in too small a margin to remunerate capital. In addition, to the extent that the formula *de facto* allows for a pass through of costs, even small amounts of vertical integration can reduce incentives to put downward pressure on input prices: a higher price for inputs which are produced by the firm itself can be passed through to consumers.

In the UK separate regulatory frameworks have been set up for the different utilities. While each of the industries has special characteristics there are common problems facing regulators of all energy utilities (and of telecommunications). Under these circumstances, given the small size of the country and the limited resources available it may be desirable to have a single regulatory authority to deal with all utilities (including telecommunications), whoever owns them. The experience and problems with one utility may well provide guidance in dealing with the others. It may only be through having a single regulatory authority that this cross-fertilisation can be achieved.

Restructuring in Ireland should aim to increase the flow of information to the regulator. A first prerequisite in restructuring both the ESB and BGE is that the different business activities should be separated for accounting purposes to improve transparency. Even if the utilities are not to be dismantled into their separate business components this stage will be necessary to facilitate adequate

regulation of the continuing monopoly elements (and also because of EU legislation).

There is also the problem that political interference with the regulation process may produce sub-optimal results. Just because ownership is changed or a regulator is introduced gives no guarantee that the resulting regime will produce the desired improvement in welfare. For example, if the regulator controls prices and the regulator is, in turn, amenable to short-term political influence, then the result may be a price below the long run marginal cost. The possibility of such a regime will itself discourage investment. Part of the problem with the current regime is that the Department of Energy has multiple objectives, objectives which shift in priority over time. It is both the major shareholder and the regulator. This has provided a very uncertain regulatory framework.

Any regulatory regime should concentrate on providing a reasonably certain environment for all those engaged in the energy utility industry. To this end it is necessary to spell out the objectives of the regulator and to guarantee the regulatory authority sufficient independence to carry out its task.²¹ Therefore, the regulatory authority needs to be given a simple set of objectives and sufficient independence from political interference which is essential if it is to act successfully. As discussed above, the uncertainty brought about by political interference can prove very costly in an industry as capital intensive as the energy sector. Talking of the UK Helm and Yarrow (1988) say:

the absence of a clear and stable longer-term incentive structures has been one of the most criticised features of control of public enterprise in the UK, and that policy weakness has thus far been perpetuated in the control framework for privately owned utilities.

The availability of information to the regulator on all aspects of the operation of the industry is essential to its success. However, even with good will or legal powers there is still no guarantee that a regulator will be able to obtain and use the information needed to regulate the industry. Many technical issues are involved in designing and implementing an appropriate regulatory regime. It may prove difficult to obtain the expertise needed to staff a regulatory authority. The experts themselves are likely to come from the energy utilities and they may well see their career paths involving a return to the companies which they are regulating, weakening their fortitude and zeal.

In setting up a regulatory authority there is always the danger that some of the monopoly rents may be captured by the authority itself. The huge sums of money involved and the vital role of the regulatory authority make it impossible to give it full independence; it is vital that the regulatory authority itself is subject to audit

²¹ Rather similar issues underlie the discussion on the independence of Central Banks.

and accountable in some sense to the wider public. To avoid undue political interference, while providing some control, it may be desirable to make the regulator directly answerable to the Dail (like the Ombudsman).

5. Conclusions

This paper has considered the reasons why the structure of the current energy utilities – the ESB and BGE – should be reviewed. It argues that the circumstances of the industry in Ireland are rather different from those in the UK or continental Europe because of its isolated status. As a result, the solutions adopted elsewhere may not necessarily be appropriate in Ireland. In particular, there are some elements of energy utility industries in Ireland where, even if competition is possible elsewhere, the small size of the Irish economy gives rise to local monopolies.

We argue that the crucial objective should be to introduce competition into the industry in Ireland *wherever it is realistically possible*. However, it may still be desirable to keep the bulk of the existing physical assets in state ownership while opening up the market to new entrants wherever feasible. In the circumstances in Ireland competition can probably best be introduced in a wide range of areas through contracting out of services such as: the maintenance of gas pipes and generating stations; the construction of new sections of the transmission network; the management of electricity generating stations. Significant progress has already been made with this approach in BGE (and Bord na Mona) and it has the advantage that it can be introduced gradually.

The monopoly elements of the energy utility industry should be subject to comprehensive regulation by an appropriate authority. However, even where competition is possible, regulation will still be necessary to ensure that it actually happens. A single regulatory authority should probably cover all utilities, certainly all energy utilities, to minimise the costs and maximise the efficiency of regulation. The regulator needs a clear set of objectives and an independent status while still being accountable to the public in some broader sense.

A major challenge for the future will be how the current systems in the North and the Republic can best be integrated to the mutual advantage of both parts of the island. This poses obvious problems for the political process. However, it also poses serious legal problems given the divergent path that the industry has taken in the two jurisdictions.

The full resolution of these problems needs further study but the key to success lies in designing a system which both provides for the integrated despatch of electricity and which also maximises the flow of information to the regulator to allow for effective intervention.

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Chapter 3

ELECTRICITY PRIVATISATION: THE NORTHERN IRELAND EXPERIENCE

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The various views and objectives in Northern Ireland concerning competition not only conflict but are often unrealistic, assuring disappointment as competition and its effects are further defined. (Putnam, Hayes and Bartlett, 1993).

3.1. Introduction

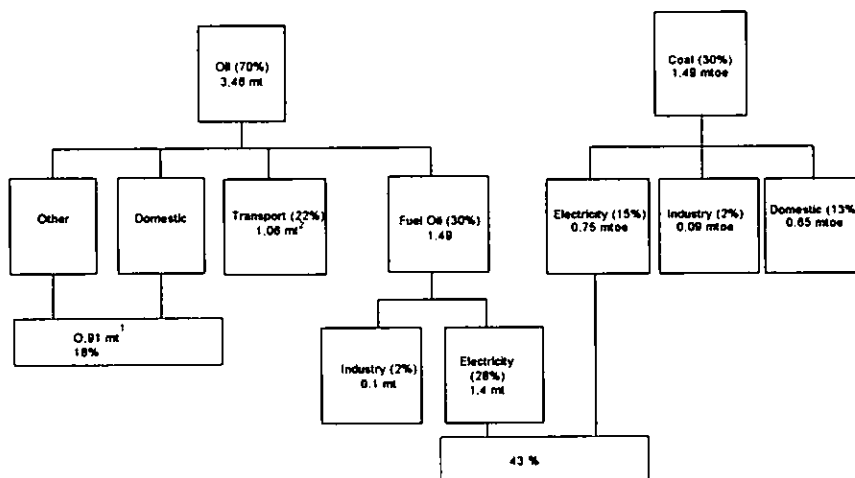
This paper deals primarily with the way privatisation was undertaken in the particular circumstances of the Northern Ireland (NI) electricity industry and its proposed future development. Although a major objective of privatisation was to introduce competition in order to achieve the lowest possible prices and greater choice for customers, the new structure was designed initially to be monopolistic in a number of significant ways because the small size and isolated nature of the system posed special problems. However, provision was made for these arrangements to be changed subsequently to create a more competitive and efficient industry. In that context, there are a number of planned developments involving a wholesale electricity trading system (or Pool) and gas and electricity interconnections with Great Britain (GB), but difficulties surround the ability of these measures to have an effective impact on the current situation for some time. As a result, price regulation assumes a crucial role in replicating a competitive market.

Furthermore, there has been a long-standing commitment by both the British and Irish authorities to restore the electricity interconnector between NI and the Republic of Ireland (ROI) when the security situation permitted. Originally, this link operated from 1970 until 1975 when it was abandoned following a sustained bombing campaign. During this short period, it provided mutual reserve capacity

between the utilities in both jurisdictions. Since then, Northern Ireland Electricity (NIE) and the Electricity Supply Board (ESB) have been isolated from each other and also from any other system, unlike most parts of the European Union (EU) which are interconnected to some extent within the wider objective of developing trans-European energy networks, particularly linking peripheral regions. With the cessation of violence, the NI-ROI interconnector should be reopened by April 1995. Its potential benefits could be significant, but the differing market circumstances in recent years and the respective paths the systems might take in the future makes the longer term effects uncertain.

Including this introduction, the paper is divided into seven sections. As a background, the next section reviews the structural features which prevent the NI electricity system achieving comparable levels of operational efficiency with respect to the industry in GB, and results in relatively higher electricity costs. Section 3 outlines the privatisation objectives and the reorganised structure in NI, particularly how it differs from the privatised utilities in the rest of the United Kingdom (UK). Section 4 examines the future planned developments to promote competition in the generation and supply sectors. A brief review of UK regional electricity price trends over recent years is given in Section 5, followed by an analysis of NI price regulation. Section 6 outlines the potential advantages afforded to both systems from reopening the cross-border interconnector. However, its longer term benefits await further clarification. Section 7 provides a conclusion.

Figure 3.1: *Primary Energy Supplies in Northern Ireland, 1993*



Note: mt = million tonnes; mtoe = million tonnes of oil equivalent; 1 mt = 0.6 mtoe.

1. Includes butane, propane, naphtha, burning oil and gas/diesel oil, excluding derv.

2. Includes aviation spirit, motor spirit, aviation turbine fuel and derv fuel.

3.2. Regional Characteristics

At present, NI has the smallest, isolated electricity system in the EU and is almost totally dependent on two imported fuels, oil and coal, for its energy needs. There is no network gas supply, nuclear, substantial renewable resources or other indigenous fuel sources which have been developed commercially. There are extensive lignite deposits estimated at 1,000 million tonnes but these have not yet been exploited (Northern Ireland Economic Council, 1987). As Figure 3.1 shows, oil provided 70 per cent of primary energy needs in 1993 with electricity generation using 43 per cent of total supplies. As Table 3.1 shows, there are four power stations comprising 23 generating sets (including 5 gas turbines for peak demand) with a maximum installed capacity of 2243 MW, all under contract to NIE. The system is dominated by two stations, Ballylumford and Kilroot, which together account for just under 75 per cent of total system capacity; Belfast West and Coolkeeragh are relatively old and nearing their scheduled retirement dates. With a large proportion of generating capacity oil-firing, the cost of generation has been sensitive to changes in its price.

Table 3.1: Northern Ireland Generation

Power Station (Owner)	Units/Fuel	Capacity MW (Under Contract)	Contract Expiry Dates of Generating Unit Agreements 31 March	Earliest Cancellation Dates 1 November
Ballylumford ¹ (British Gas)	6 Oil 2 Gas Turbines	951 116	2006-2010 2020	2010 2010
Belfast West (Nigen)	5 Coal	240	1997-1998 (120 MW) 1998-1999 (120MW)	1996 1998
Coolkeeragh (Management Employees)	5 Oil 1 Gas Turbine	300 58	2000-2001 (120 MW) 2002-2004 (180 MW) 2020	1998 2000 2000
Kilroot (Nigen)	2 Oil/Coal 2 Gas Turbines	390 on coal 520 on oil 58	2024 2024	2010 2010
Scottish Interconnector (NIE)		240		15 years non-cancellable agreement with Scottish Power

Source: McGurnaghan (1994).

¹ Ballylumford is expected to convert to gas-firing in 1997.

Lacking any established interconnection with an adjacent system, there are economic difficulties inherent in a small "island" system. Generating sets are relatively large which means that there are strict operational constraints and a high reserve requirement for reasons connected with security of supply. For example, there is a so-called "22 per cent" (or "5 set") rule by which no generating set may supply more than around 20 per cent of demand at any time. This means that each power station must be run at some part of every day and so has an effective monopoly over a particular section of the load curve. Also, there must be spinning reserve equal to at least 68 per cent of the generation of the largest set used. System size also means that not all possible economies of scale in generation can be obtained.

Consequently, the amount by which generating capacity exceeds peak demand is relatively large in the NI system. With a maximum demand of approximately 1500 MW, there is currently a system reserve margin of approximately 50 per cent which is much greater than NIE's own relatively high generation security standard of 40 per cent which is considered necessary to secure supply (Offer NI, 1993). In addition, a low population density, approximately half that of the UK level and varying considerably within the region, requires a fairly widely-spread and relatively expensive transmission and distribution network.

In accordance with EU legislation, the UK is committed to reduce progressively emissions of sulphur dioxide (SOX) and oxides of nitrogen (NOX) from power stations and other large combustion plants¹ (European Commission, 1988). As Appendix 1 shows, NI's share of these pollution control limits has been allocated solely to the electricity industry so that there is a SOX "bubble" for the period 1993 to 2003 and a NOX "bubble" for the period 1993-1998 (Department of the Environment for NI, 1994). These apply both on an aggregate and individual plant level, in an increasingly tighter manner, although only the overall target is really relevant.² Given the existing generating fuel mix, compliance with EU and UK emission abatement legislation will have increasingly significant implications for future tariffs because the regulatory regime allows these additional generating costs to be passed to customers (see Section 5).

¹ In accordance with the EC Large Combustion Plants (LCP) Directive, the UK issued its Programme and National Plan (December 1990) for reducing emissions of SOX and NOX from existing LCPs. Measured from a 1980 baseline, the National Plan requires SOX reductions of 20 per cent by 1993, 40 per cent by 1998 and 60 per cent by 2003 with NOX reductions of 15 per cent by 1993 and 30 per cent by 1998.

² With responsibility for central despatch, these ceilings are managed by NIE which can arrange quota-switching as the year progresses to enable least cost generation, provided the aggregate is not breached. This ensures that a particular power station does not cease operating due to having reached its emission limit for that year. Effectively, therefore, the emission limits are not controlled by the generating companies who are also immune financially from the cost of compliance.

As a result, the price of electricity in NI has been typically higher than the GB average (see Table 3.3 and Section 5). In accordance with the Government's current energy strategy of diversifying the generation fuel mix, it is planned to remove some of these system constraints by the construction of a gas pipeline and electricity interconnector with Scotland, due towards the end of the century (assuming the latter proceeds as anticipated³), with 177 MECU allocated under the existing Structural Funds Programme (Department of Economic Development (DED), 1992a; European Commission, 1994). The Ballylumford power station was sold to British Gas on the basis that a gas pipeline link would be built and the plant converted to use natural gas (House of Commons, 1992). This would improve diversification with the generation mix becoming 40 per cent gas, 20 per cent oil and 40 per cent coal. Following the commissioning of the new gas interconnector, it is expected that a natural gas market will develop (NIE, 1994). In addition, the Scottish interconnector would supply sufficient power to meet about 20 per cent of total demand and further diversify the system. However, the costs of these new sources of electricity will tend to increase electricity prices, but it is anticipated that their effects would lead to lower costs in the longer term.

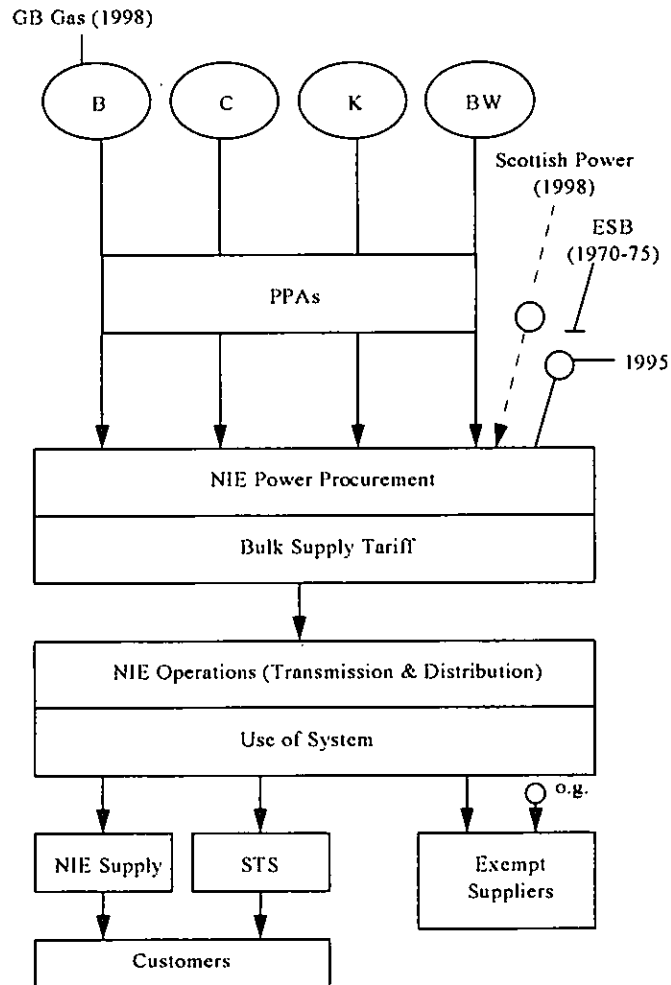
3.3. New Structure

Until vesting, the NI electricity industry was organised as a vertically integrated monopoly. This previous structure was NIE which exercised virtual control over all aspects of the generation, transmission, distribution and supply of electricity in the region.⁴ Although the market was opened in 1987 for independent generation to supply electricity to NIE or directly to customers using the grid network, NIE's integrated generation and distribution operations created effective entry barriers. Furthermore, privatisation was being considered against a background where NIE had been in subsidy some years previously, aligning electricity prices with the highest in England and Wales, and was still formally (until 1990) in a situation where it could continue to be subsidised, if it fell into deficit (McGurnaghan, 1990).

As Chart 3.1 shows, the intention to privatise NIE was first announced in July 1988 (Official Report, 1987-88). This extension of the electricity privatisation programme then being formulated within the wider national sphere is worth noting because of the implicit belief that similar benefits would accrue to consumers in NI as those expected to be achieved in GB, regardless of the structure chosen in the light of the industry's special circumstances. These perceived benefits were summed up in the form of six objectives, four contained in the White Paper of

³ Currently, the Scottish interconnector is subject to public inquiries in both NI and Scotland.

⁴ It was also engaged in appliance retailing through a chain of High Street outlets and undertook consultancy and operational work on an international basis.

Figure 3.2: *The NI Electricity System***Generators:**

B: Ballylumford; C: Coolkeeragh; K: Kilroot; BW: Belfast West; ESB: Electricity Supply Board
 PPAs: Power Purchasing Agreements; STS: Second Tier Suppliers; o.g.: own generation.

Source: McCumaghan, 1994.

CHART 3.1: PRIVATISATION OBJECTIVES

(House of Commons, July 1988)

The Government are determined that the benefits from private sector involvement in the electricity supply industry should be available to Northern Ireland consumers as they will be to those in the rest of the United Kingdom.

MAIN OBJECTIVES (White paper of March 1991)

- to introduce, whenever possible, forms of competition which will result in the lowest possible prices for consumers;
- to regulate the electricity supply industry in a way that will protect consumers' interests and maintain security and safety of supply without being unduly intrusive;
- to diversify further the Northern Ireland economy through the introduction of enterprising new participants into the power sector; and
- to promote participation by employees of NIE and by electricity consumers in the ownership of the industry.

FURTHER OBJECTIVES (Department of Economic Development, NI)

- as a result of the flotation of NIE plc, to widen and deepen share ownership, in particular in Northern Ireland, and to establish a modest premium in the immediate aftermarket; and
- to maximise the net proceeds, taking the sales of the generating stations and NIE plc together.

March 1991 which outlined the particular model proposed for NI with a further two set subsequently by the DED, the body responsible for energy policy in NI (DED, 1991). Basically, there were two main aims: to introduce competition, wherever possible, as a means of increasing efficiency to achieve the lowest prices for the benefit of improving consumer welfare and the competitiveness of the economy; to regulate the industry in order to maintain security and reliability of supply.

Various structures were considered and rejected as either being unlikely to meet these objectives or impractical because of the nature of the NI electricity market. The review included: maintaining vertical integration; creating two vertically integrated structures, as in Scotland; establishing a single generating company and a single transmission, distribution and supply company; and, NIE

retaining a major power station with the other stations being owned by independent generators. In the event, the structure chosen as most appropriate for achieving the stated objectives involved separating the generating sector from the rest of the industry, the latter to remain as a single company. Subsequently, NIE's assets were transferred to the private sector through a combination of a trade sale and a public flotation, unlike the industry in GB. During the first stage in April/May 1992, the four power stations were sold by competitive tender, while NIE's remaining assets were reconstituted as a "new" NIE plc (NIE) and floated publicly in June 1993 by means of a fixed price offer.

The organisation of the industry is illustrated in Figure 3.2, the main features of which are as follows:

(i) NIE's principal role is essentially the delivery and sale of electricity. For this purpose, it is divided into a number of core businesses: Power Procurement (PPB) purchases bulk electricity from the generating companies which it re-sells to suppliers at a bulk supply tariff (BST). It is also responsible for the scheduling and despatch of generating sets to ensure security and quality of supply; Operations (T/D) owns and maintains the transmission and distribution network for delivery to customers; and, Supply retails electricity to customers. For these roles, NIE holds the sole, combined Transmission and Public Electricity Supply (PES) licence (DED, 1992b). These businesses are "ring fenced" to prohibit cross-subsidy and each is regulated separately (see Section 5).

(ii) In the generating sector, the power stations operate under independent ownership and a Non-Fossil Fuel Obligation has been introduced to encourage new entrants in renewable generation. The PPB purchases electricity under contract from the generating companies which produce when it instructs: NIE is not permitted to own any generating capacity within its authorised area.

(iii) Retail supply has been opened fully to competition. Other companies can become second-tier suppliers (STS) to compete with NIE Supply for customers. In addition, industrial and commercial consumers with a monthly average demand of 1MW and over may contract directly for the purchase of electricity with the PPB by becoming an exempt self-supplier.

(iv) The principal commercial feature is the Supply Competition Code. This stipulates that the total output of the power stations, with certain limited exceptions, must be bought and sold through the PPB. As Table 3.1 shows, bulk electricity is purchased under a set of long term, power purchasing and generating unit agreements (PPAs). The variation in duration of these contracts reflects the expected economic lifetimes of the generating sets, ranging from late 1997 to 2024. However, the Regulator can cancel a PPA earlier, from late 1996 to 2010, to promote competition in generation and supply (see the next section).

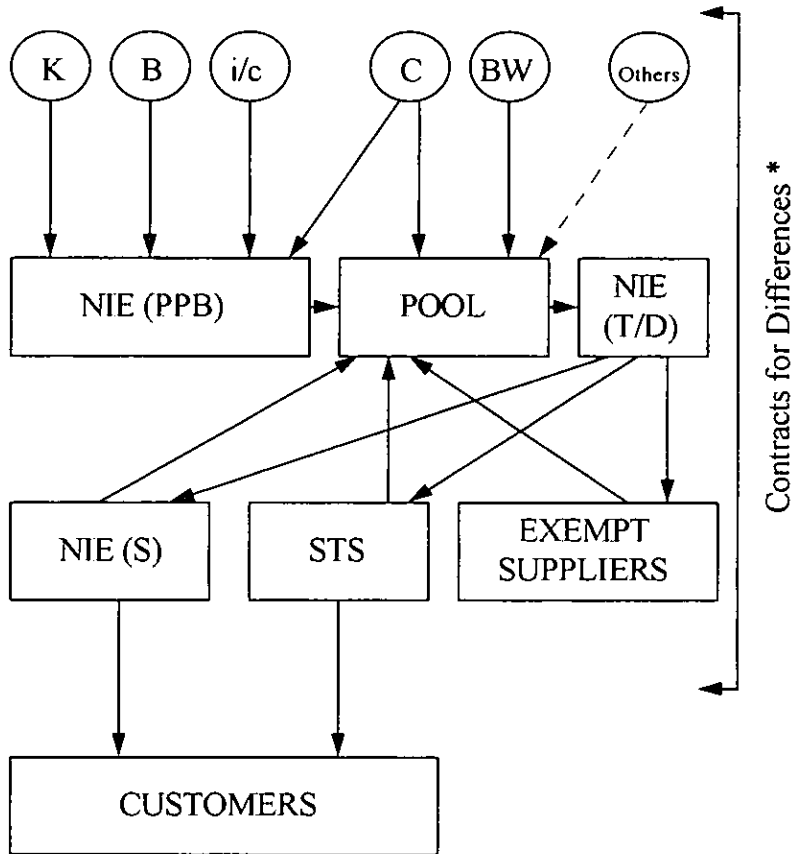
(v) The industry is overseen by the Director General of Electricity Supply for Northern Ireland (the Regulator) and the DED, principally under the Electricity (Northern Ireland) Order 1992 (DED, 1992c). The Regulator is assisted in his duties by the Office of Electricity Regulation for Northern Ireland (Offer NI). The regulatory regime's functions cover three main responsibilities: granting the three types of licence, i.e., Generating, Transmission and PES, and STS; promoting an efficient and competitive industry, where possible; and, price regulation for consumer protection. To assist with the latter task, the Regulator has appointed a Northern Ireland Consumer Committee for Electricity. Finally, the Regulator can refer any matter relating to the activities of operators in the electricity market to the Monopolies and Mergers Commission on public interest grounds.

This structure reflects a number of the features of the electricity industry in GB but with some significant differences (Department of Energy, 1988; Industry Department for Scotland, 1988). First, the division of generation into a number of independent companies and its separation from transmission and distribution is similar to the structure adopted in England and Wales but the change in ownership was more radical in NI. Whereas the fossil generating assets of the Central Electricity Generating Board (CEGB) were transferred to an effective duopoly, National Power and PowerGen, the much smaller NI generating capacity had a greater degree of fragmentation.⁵ In contrast, the small scale of the two Scottish electricity companies meant that each was privatised within an existing vertically integrated structure, although with some redistribution of power stations to give a similar type of plant mix.⁶ The Scottish two-company structure was deemed to have the benefit of "yardstick" competition.

Retail competition has been fully possible in NI from the outset, unlike the Regional Electricity Companies (RECs) in England and Wales which had a mainly franchise market in their respective supply areas (competition being introduced progressively with the franchise abolished by 1998). However, the remainder of the NI electricity industry is more monopolistic as a result of the Supply Competition Code which has allowed the PPB to operate as a legal monopsonist and monopolist in the purchase and sale of wholesale electricity respectively. At the outset, the technical arrangements involved in establishing a competitive wholesale electricity trading system, a Pool, were considered to be impractical in the small NI system and contrary to consumers' interests on the grounds that the cost of setting up this mechanism would be excessive in relation to total unit sales, and thus likely to lead to higher prices. However, an important feature of the

⁵ The CEGB's nuclear and hydro-electric pumped storage capacity was assigned to Nuclear Electric and the National Grid Company respectively.

⁶ As in England and Wales, nuclear generation was assigned to a separate publicly owned company, Scottish Nuclear.

Figure 3.3: *Proposed Northern Ireland Pool*

* Contracts for Differences may be signed between generators and suppliers.

regulatory regime is early cancellation of the PPAs, provided that the Regulator is convinced that a Pool is feasible in Northern Ireland and can be made to operate in a way which will bring benefits to customers. As Table 3.1 shows, the exclusive monopoly given to the PPB in the wholesale generation market could change after 1996 to permit the creation of a Pool. The next section discusses this possibility in the NI context.

3.4. Promoting Competition

Economic theory approaches electricity privatisation from the perspective of improving economic efficiency on the basis of two main principles: (i) productive efficiency which requires that electricity is produced at least cost; (ii) allocative efficiency whereby prices reflect accurately the costs of resources used. In theory, and in the absence of market failures, these conditions will be achieved when competition characterises those activities considered feasible for this purpose.

Generation (producing or importing electricity) is considered to be a competitive activity for two reasons. First, the incentive of merit order giving economic precedence to those power stations producing the cheapest electricity should induce generating companies to compete with each other by keeping their costs as low as possible in order to maximise utilisation. In turn, this will lead to efficiency gains with demand being met at minimum cost and resulting tariffs more closely aligned to costs. Second, the threat of competition from new entrants using the most modern technologies should similarly restrain prices. As a consequence of such competitive pressures, generation is deemed to require relatively little regulation.

In contrast, central despatch and the T/D (or wires) business are presumed to be natural monopolies for which there is no convincing economic argument for replicating an existing set-up. Costs will be minimised and productive efficiency achieved if these activities remain as monopolies, provided that there is non-discriminatory third party access (TPA) to the grid network for suppliers paying price-regulated use of system (UoS) and connection charges. This will facilitate the development of competition between suppliers. In summary, therefore, privatisation allows the potential for promoting competition as far as practical in the generation and supply of electricity, while price regulation ensures against possible exploitation of monopoly power or where the scope for introducing competition is restricted and will need time to emerge. Regulation can be more or less intrusive depending on the degree of competition existing in the industry.

The reality is, however, that the current structure leaves significant constraints on competition, although these are anticipated as existing only during the initial

stages of the privatisation development programme.⁷ In the first instance, as Table 3.1 shows, generation is contractually based. In combination with a largely stable merit order due to a small number of power stations with known costs and efficiencies, there is no competition between the generating companies. Furthermore, the Supply Competition Code gives the PPB a statutory monopoly for the purchase and sale of wholesale electricity. Although there is no customer franchise market and a number of RECs hold licences as STS, very little competition has developed on the retail side. With inputs having to be bought from NIE and a small value added in relation to the final price of electricity, there are limited opportunities to offer alternative contracts. Finally, there is an absence of exempt suppliers as no undertaking has taken up this option yet.

Changing this monopolistic structure by increasing the scope for competition will depend on two major planned developments. First, a Pool is planned when the first PPAs can be cancelled by the Regulator in late 1996 (Offer NI, 1994a). It will be based broadly on the pricing and settlement arrangements in the British Pool, but adapted to the existing NI framework (Coopers and Lybrand, 1994). As Figure 3.3 shows, it will involve the PPB bidding in its existing capacity contracts with a limited amount of independent generation available initially from cancelled contracts to permit competition. Accordingly, 120MW at the old, coal-fired Belfast West plant would be available to compete in a wholesale trading market from 1996, subject to the costs of improvements to meet emission control requirements. (In 1992, this plant delivered 10 per cent of all units required.) As Table 3.1 shows, progressive cancellation of contracts, if and when conditions change, would allow more competition between generators and suppliers to be phased in gradually. Ultimately, the earliest date when the market could be fully opened to competition would be 2010 when the contracts with the two most modern power stations at Kilroot and Ballylumford become cancellable.

This proposal has attracted considerable criticism about its ability to have an effective impact on competition for a considerable time because of the long transitional period, well into the next century, during which most generation would remain under contract (Offer NI, 1993). Also, the small size of the NI market and the limited number of independent bidders has raised concern about the danger of generator oligopoly power and, thus, a NI Pool's viability under competition.⁸ As a result, it is difficult to predict how much competitive pressure may emerge within this new mechanism.

⁷ For a more detailed analysis, see McGurnaghan (1994).

⁸ On the basis of evidence from the British Pool, it has been argued that two dominant generators was not an adequate number for effective competition (Green and Newbery, 1992).

Table 3. 2: *Availability Levels*

<i>Generating Station</i>	<i>Historic Averages to</i>		<i>Achieved by Generating Companies</i>	
	<i>1990-1991</i>		<i>1992-93</i>	<i>1993-94</i>
	%		%	%
Kilroot	71.6 (2 Years)		95.9	94.2
Ballylumford	73.2 (5 Years)		78.1	83.7
Belfast West	79.9 (4 years)		92.8	99.6
Coolkeeragh	73.9 (5 years)		97.6	99.9

Notes: (1) Ballylumford has been undergoing "Plant Life Extension" programme since 1991-92 which has necessitated long periods of non availability. On completion of the programme in 1994, availability is expected to rise.

(2) The contracts with Coolkeeragh require only four out of its five generating units to be available. When the first unit's contract is cancelled in 1998, availability is expected to fall.

Source: Northern Ireland Audit Office.

A further opportunity for introducing competition is expected with the additional generating capacity required, initially in 1998 and again early in the next century, in line with forecast demand and the scheduled retirement dates of the Belfast West and Coolkeeragh stations (accounting for about 25 per cent of existing capacity). However, the first deficit will be met by the additional 240MW of capacity from the anticipated Scottish interconnector, with new potential entrants competing to provide the remainder.⁹ While the Scottish link has strategic importance for generation planning by increasing system reliability and fuel diversification, it would postpone the competitive process until the second tranche of investment was needed.

Also, the arrangements for the Scottish interconnector mean that NIE will be a monopoly purchaser of electricity, at prices linked to the British Pool price, for a 15 year period. In the context of competition, this would restrict TPA until the year 2013. Furthermore, plant modernisation and high levels of availability could provide enough capacity to delay the introduction of more competitive pressure until further into the next century. As Table 3.2 shows, there is already evidence to suggest that the latter has been achieved since privatisation. Beneficially, however,

⁹ There may also be an increase in capacity from non-fossil fuel generation and the NIE-ESB interconnector (see Section 6).

the consequence would be to restrain future upward pressure on tariffs, as the cost of introducing new generating capacity is a major determinant of electricity prices.

In conclusion, it may take a considerable period of time to establish competition to any significant extent. Currently, this means that NIE enjoys a significant degree of market dominance. To prevent any possible exploitation of this position, its core businesses are subject to price regulation. Following a brief review of GB and NI tariff movements over recent years, the relevant price controls are analysed in the following section.

3.5. Regulatory Framework

(a) Price Trends

Electricity prices to all categories of customers in NI have historically been among the most expensive compared with other regions. As discussed in Section 2 above, this is because the provision of electricity has involved inherently higher costs with respect to: relying on oil for the main feedstock supplies; small system size and dispersed population with resulting lower economies of scale; and, the lack of any established interconnection with the greater reserve margin which has to be carried. To mitigate the impact of a large increase in world oil prices, a tariff strategy was adopted in 1981 under which NIE was paid a subsidy to keep its electricity prices in line with the highest prevailing in England and Wales. This tariff link ended in 1990 with electricity privatisation in GB, although subsidisation was not needed after 1986 because of prevailing low oil prices.

Between 1990 and vesting in 1992, electricity prices were set by agreement between NIE and the Government (following consultation with the General Consumer Council for NI¹⁰), restricting tariffs within the rate of inflation. Since privatisation, tariffs have been subject to regulation.

For customers as a whole, electricity pricing arrangements may be considered under two broad categories: a tariff which NIE must offer to almost all customers with a maximum demand less than 1MW; those with a maximum demand exceeding 1MW must take electricity under contract. In relation to the former, Table 3.3 examines movements in comparative prices charged to typical Standard Domestic Tariff customers since April 1989. Over this six year period, NIE's tariff increased by 23.4 per cent, just less than the rate of inflation, most of which took place between 1989/90 and 1992/93, which was a period of relatively high inflation. Overall, its tariff moved from the lower end of the higher range in 1990/91 to become the most expensive in the UK by April 1993. Despite a 1.5 per

¹⁰ The statutory duties of this organisation in relation to electricity matters were transferred to the Northern Ireland Consumer Committee for Electricity at Offer NI.

Table 3.3: *United Kingdom Tariffs, 1989/90 to 1994/95 (p/kWh)*

<i>Company</i>	<i>89/90</i>	<i>90/91</i>	<i>91/92</i>	<i>92/93</i>	<i>93/94</i>	<i>94/95</i>	<i>Increase % 89/90 - 94/95</i>
Eastern	6.84	7.46	8.27	8.52	7.92	8.52	24.6
East Midlands	7.05	7.64	8.5	8.8	8.47	8.47	20.1
London	7.32	8.02	8.94	8.99	8.57	8.56	16.9
Manweb	7.66	8.31	9.19	9.36	8.97	9.18	19.8
Midlands	7.19	7.82	8.67	8.76	8.11	8.25	14.7
Northern	7.26	8.09	9.04	9.29	8.71	9.01	24.1
Norweb	7.08	7.68	8.53	8.6	8.44	7.91	11.7
Seeboard	7.16	7.81	8.66	8.81	8.52	8.28	15.6
Southern	7.06	7.69	8.55	8.74	8.4	8.52	20.7
SWALEC	7.55	8.52	9.42	9.54	9.44	9.44	25.0
SWEB	7.57	8.39	9.27	9.58	9.17	9.33	23.2
Yorkshire	7.32	7.92	8.65	8.79	8.45	8.45	15.4
England/Wales Average	7.26	7.95	8.81	8.98	8.6	8.66	19.3
Scottish-Power	6.74	7.31	7.97	7.98	8.36	8.22	22.0
Scottish-Hydro	6.73	7.33	7.98	8.37	8.21	7.87	16.9
GB average	7.19	7.86	8.69	8.87	8.56	8.57	19.3
NIE	7.65	8.27	9	9.36	9.59	9.44	23.4
RPI Jan 1987=100	114.3	125.1	133.1	138.8	140.6	144.2	26.2
ESB						7.81	

Notes: (1) The above figures are based on published Standard Domestic Tariff Schedules at 1 April each year, comprising a fixed quarterly standing charge and a unit charge. They are exclusive of VAT and assume a typical annual consumption of 3,300kWh. Other tariffs than those shown may be offered to customers and some REC's offer discounts for different payment methods

(2) The figures include all rebates and changes to tariffs announced in 1992/93 and 1993/1994. The 1994/95 prices account for the 8 pounds per customer rebate announced by Seeboard from April 1994 and the 2 per cent and 3.7 per cent discount on unit rates in 1994 by Scottish-Power and Scottish-Hydro respectively.

(3) ESB figure has been adjusted for exchange rates.

Source: Offer NI; Centre for the study of Regulated Industries.

cent tariff reduction subsequently, the present (1994/95) differential is 9 per cent above the GB average and NI remains the highest priced region (together with SWALEC).

In the case of large users of electricity, a similar analysis is limited by contract prices and commercially confidential information (Offer NI, 1994b). Prior to privatisation, it was acknowledged that large users were paying prices some 20 per cent higher than their counterparts in GB (House of Commons, 1991). Since then, NIE has moved towards more cost reflective pricing which resulted in quite significant increases in electricity charges to this category, although transitional relief has been given to phase in the full impact. While the actual size of the price differential between large users in NI and GB has been a matter of debate, the Regulator estimated it to have been in the order of 5-10 per cent on average during 1993/94, although there was a wide range of variation (Offer NI, 1995).¹¹

(b) Price Controls

Electricity tariffs and contracts in NI are based on a set of three inter-related price control formulae. These cover each of the components determining the final price of electricity – the BST, UoS and supply charges – which account for approximately 60,¹² 33 and 7 per cent respectively. Figure 3.4 summarises the equations specifying NIE's allowed tariff increases which are contained in its composite Transmission and PES licence. The price controls are aimed at replicating a competitive market, thus avoiding a possible abuse of market power. As the BST will need to be changed with the establishment of the Pool, the Regulator can formally revise the price controls after March 1997.

The equations are broadly similar to the regulatory regime which protects electricity customers elsewhere in the UK. In this respect, the factors included relate to changes in the rate of inflation and efficiency savings which can reasonably be expected to be achieved and passed on to consumers (Centre for the Study of Regulated Industries, 1992). However, there is a unique point of difference in the NI framework where the purpose is to regulate NIE's total revenue, and thus its profits, by providing an incentive to control its costs. The following subdivisions provide an account of how the price controls apply to NIE.¹³

¹¹ Comparisons depended on rebates under the NI load management scheme, the fuel cost adjustment mechanism and the transitional relief schemes.

¹² For certain large users, this could represent 70-80 per cent.

¹³ For a further analysis, see Brennan (1994).

Figure 3.4: *Electricity Price Regulation in Northern Ireland**(a) Bulk Supply Tariff*

$$M_{\text{BS}} = (1-r) A_t + rB_t + C_t + D_t + K_t$$

Where:

M_{BS} = the maximum average charge per unit sold

$$r = 0.1$$

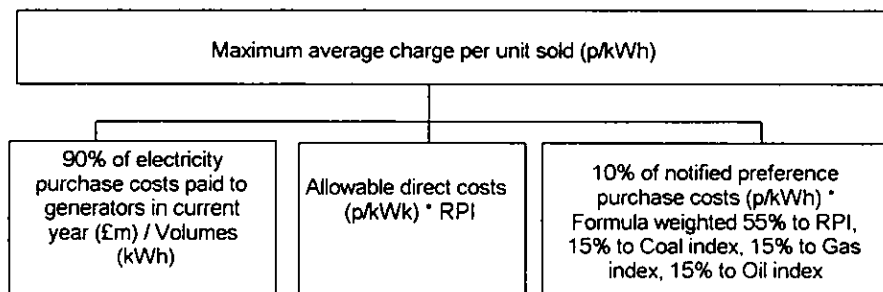
A = actual purchase costs per unit sold

B = reference yardstick of fuel costs per unit sold

C = power procurement administration

D = power procurement excluded costs per unit sold

K = a correction factor per unit sold for under or over charging in the previous year (applies to all the formulae).

*(b) Use of System Charge*

$$M_{\text{US}} = hF_t + (1-h)V_tQ_t - T_t + K_t$$

Where:

M_{US} = the maximum allowable revenue

$$h = 0.75$$

F = a fixed component

VQ = a variable component relating to the volume of units carried

T = an adjustment for electricity losses in the network

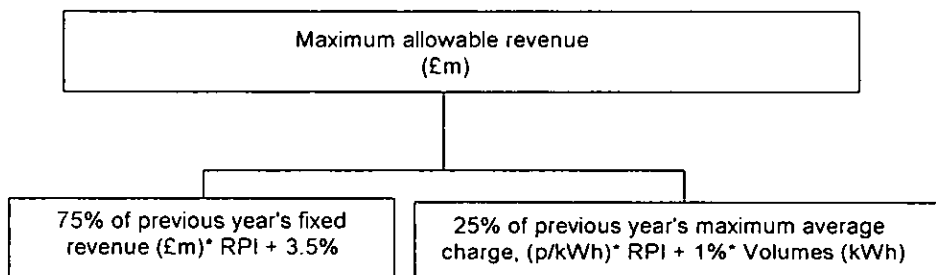


Figure 3. 4 / continued

(c) Supply Charge

$$M_s = G + U + S + K$$

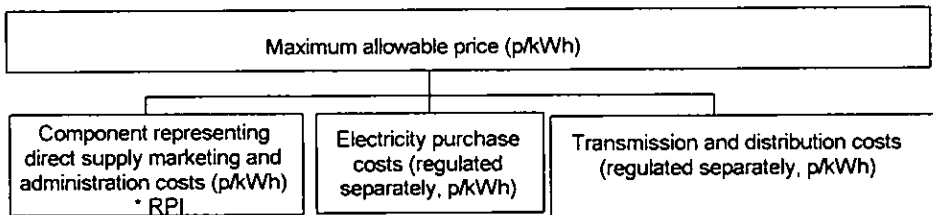
Where:

M_s = the maximum average charge per unit supplied

G = the electricity purchase costs from power procurement per unit supplied

U = the allowed payment for use of system per unit supplied

S = the direct cost per unit of supplying customers



Source: Department of Economic Development (1992b).

BST:

The BST equation restricts the amount of the costs incurred by the PPB in purchasing wholesale electricity which can be passed through and, hence, the price at which bulk electricity is re-sold to suppliers. The vast majority of these power purchase costs are contracted payments made to the generating companies under the PPAs for availability in the year ahead and to cover the fuel costs of producing electricity, together with other contracted services.¹⁴ As the prices at which the generators sell power to the PPB are pre-determined under the conditions of sale of the power stations as part of the privatisation process, they are effectively outside the remit of the Regulator and thus not subject to regulatory control, provided that the generators adhere to the conditions set out in the PPAs. Notwithstanding, the PPB is required to purchase as economically as possible to achieve the least cost of generation.

¹⁴ The availability payment is compensation for keeping the power stations or individual generating sets ready for immediate use and also covers the provision of spinning reserve plus a profit element for the generators. The energy payment is calculated with reference to indices of prevailing world prices for oil and coal and the £/\$ exchange rate and is subject to monthly adjustment.

For this purpose, a maximum average charge per unit of bulk electricity sold (M_B) is set in each year with NIE given a financial incentive by means of an "r" coefficient to purchase generation economically, within the constraints of the PPAs and the standards of supply which it must maintain.¹⁵ Set originally at a value of 0.1, "r" permits 90 per cent of actual unit purchase costs (A_i) to be a full-cost pass through, but ties the remainder to 10 per cent of a unit level of reference purchase costs (B_i). This latter amount, which is allowed to be passed on, is derived by a composite index proxying movements in the price of three fuels – heavy fuel oil,¹⁶ gas and coal – together with the RPI, all against a base year notified value, determined by DED under advice from its consultants. While no information is available on the nature of indexation chosen, it may have been assumed that the general price index and international fuel indices would move in line with electricity prices over time. It may be thought also that the equal weighting given to each of the fuels reflected some optimal generating plant mix.

If the PPB can reduce its actual purchase costs and outperform this yardstick mechanism so that rA_i is less than rB_i , it may keep the profit.¹⁷ The rest of the variables in the formula include the PPB's operating costs (C_i) which are passed through in line with the rate of inflation together with excluded costs (D_i) which are classified as being outside its control and, therefore, are permitted to be passed on in full.¹⁸ Based on forecast maximum permissible revenue, there is a correction factor (K_i) which adjusts the unit price for any divergence resulting from under- or over-charging in the previous year (included in all three equations).

UoS:

The UoS charge is for the delivery of electricity through the transmission and distribution network. Although this element accounts for around one-third of the final price of electricity, the wires business is the most important commercial part of NIE's overall activities because it provides the overwhelming majority of its operating profits. This price control is different to that imposed on either the RECs

¹⁵ These are the generation security planning standard (relating to capacity) and the operating security standard (relating to spinning reserve) which act as a counterweight to "r".

¹⁶ The HFO variable is related to both high (3%) and low (1%) sulphur oil. The formula directs more of the higher cost (1%) fuel to be used up to 1995/96 in recognition of the need to comply with progressively more stringent emission levels. Thereafter, the constraint is relaxed.

¹⁷ However, the level of profit/loss on the B term is capped each year at +/- £4 millions in 1992/93 prices, increased annually at the RPI.

¹⁸ Excluded power purchase costs are predominantly related to the Land Bank and need the Regulator's approval.

in England and Wales or the two Scottish electricity companies where there is a price cap which imposes a maximum average revenue per unit transmitted and distributed. In contrast to GB, the control on NIE is designed as a combination of elements of a revenue cap¹⁹ and a price cap. This "cap and collar" method means that the T/D income is less sensitive to the number of units delivered across the network.

As Figure 3.4 shows, the maximum allowable revenue each year (M_D) is determined by a fixed element (F)²⁰ which accounts for 75 per cent of the total with a variable element (V, Q) contributing the remaining 25 per cent. The former permits the previous year's fixed income to grow in real terms by 3.5 per cent annually, i.e., regardless of the total number of units actually transported across the network: this constitutes the revenue cap effect. The remainder of permitted revenue is determined by allowing the UoS unit charge to increase in real terms by 1 per cent annually multiplied by the number of units carried, i.e., quantity related: this is the price cap effect. The choice of the RPI factors in F and V were set at the outset to reflect the expected rate of growth of electricity sales over the five year period to the next regulatory review. In the event of the actual growth rate being greater than forecast leading to the maximum allowable revenue limit being exceeded, and vice versa, NIE would have to readjust the following year's tariffs, bearing in mind the size of any over- or under-recovery. The equation also contains an adjustment factor (T) giving NIE an incentive to reduce transmission losses. Any savings on a target level may be added to the maximum revenue and retained.²¹

Effectively, therefore, the greater part of permissible T/D revenue is independent of volume growth which prevents this major source of NIE's total profits from being highly sensitive to units sold. Given that the control is not due to be reviewed formally until 1997, it provides NIE with a secure and stable income and a degree of regulatory protection in its essential business. Presumably, permitting a significant real increase in annual revenue recognises the need to upgrade the network in coming years with the resulting capital costs involved. Furthermore, to the extent that it removes an incentive to push sales by setting a maximum limit on total allowable revenue, it may be presumed to be a mechanism by which the DED attempted to promote the efficient use of electricity.

¹⁹ This is the usual practice in US utility regulation.

²⁰ This was set originally in 1992/93 at £129.63 millions.

²¹ The allowed rate of electrical losses is set at 10.5 per cent of units transmitted, as a result of which NIE increased M_D by £917,690 due to savings made in 1993/94.

Supply charge:

Strictly speaking, the supply control equation covers the total price of electricity retailed to final users by setting a maximum average tariff per unit sold (M_s). Accordingly, its role is essentially a passing through of the already regulated costs of upstream activities, i.e., generation purchase (G_i) and transmission and distribution (U_i) costs. In addition, it determines the revenue allowed to cover the cost of NIE Supply's activities (S_i) and, hence, the supply charge to cover mainly billing and metering of customers and administrative costs. The control ensures that this charge does not change by more than the rate of inflation. Given the diversity of the retail market, the allowed component price further reflects the different categories of customer between those with a maximum demand of under 1MW and larger users.

3.6. North-South Interconnection

There are a number of capacity and trading benefits to a small, isolated system which can be achieved through interconnection with an adjacent utility (Scott and McGurnaghan, 1981). With respect to both NIE and ESB, it would contribute to ending their energy isolation and take advantage of economies of scale and increased reliability of supply. Furthermore, access to other grid networks and enlarged markets is in line with the wider objective of developing and reinforcing trans-European energy networks, particularly linking peripheral regions with more central areas of the EU.

Originally, the interconnector agreement was between two vertically integrated nationalised systems, each characterised by centrally planned investment and statutory monopoly power over its respective customer base. During the short time it operated, the link worked on the principle of equal benefits, realised mainly in the form of providing mutual reserve capacity between both systems. In the intervening period, however, the market framework has changed so that re-instatement will occur within significantly different circumstances. Whereas ESB has continued to function as a public sector, vertically integrated monopoly, NIE has been privatised and its activities must be conducted essentially on a market-orientated basis. In this context, NIE's licence requires it to have regard to economic purchasing and stipulates that transactions must be "at the best effective price reasonably obtainable having regard to the resources available". In the light of this condition, its policy towards any future trading relationship should be to attempt to maximise its share of profit from the interconnector, a potentially conflicting rationale to the previous concept of equal sharing of benefits.

Nevertheless, the basis for restoring the interconnector is the premise that it will be mutually beneficial. In the short run, interconnection is estimated to realise savings, as previously, in the form of improved overall reliability of each system

by providing mutual support during temporary shortfalls on either system together with trading benefits. However, the actual level of possible benefits would be small since the capacity of the present interconnector sets a limit to the amount of reserve capacity which would be rendered dispensable and, hence, total plant savings. With a turnover of around £480 millions in 1994, it is estimated that short run savings for NIE could amount to approximately £1.5 millions per annum, £1 million from a reduction in spinning reserve required and the remainder from the possibility of trading on the margin. Similar forms of benefits should accrue to ESB.

In the longer term, the potential economic benefits could be more substantial. If the interconnector became well-established, it could open up the possibility of an increased trading relationship and enlarged transfer capability with the prospect of a more integrated electricity sector evolving. Co-operation in terms of planning future generating capacity would realise significant economic benefits to customers in both areas from cost savings both of a capital nature and from economies of scale. For example, total generation capacity in a more combined system need be less while the installation of a more economic set size is made possible. Furthermore, should insufficient capacity be available in the ROI to meet increasing demand, the necessary plant could be available in NI to meet this need. For that purpose, the NI Pool is intended to provide an incentive to provide additional capacity when a high enough price prevails. Ultimately, there is the potential for demand to be matched with supply, regardless of ownership.

However, greater integration of both electricity markets has to be viewed with caution because it is difficult to predict the respective paths the systems may take, and so the nature of any future market framework. Accordingly, longer-term benefits will depend on several important factors, which remain uncertain presently. These are as follows:

First, in theory, competitive pricing of exports and imports in a Pool system should give an overall efficiency gain, in the sense of creating a greater economic surplus. The distribution of this welfare impact will, however, be different between producers and consumers in both areas. Should ESB remain as the monoposony buyer of power and thus the only pool participant from the ROI with whom trade was possible while the major part of generation in NI was contracted to NIE, as at present, and it continued to dominate both sides of the Pool, the scope for competitive pricing, and thus increased trading opportunities, would be lessened.

Second, both areas are subject to different emission reduction targets. In the case of NI, this applies in an increasingly stringent manner while, in contrast, the ROI would not appear to be as constrained (Weyman-Jones, 1994). Consequently, the respective pollution control targets would need a mechanism to fit into a more integrated supply system, possibly involving the trading of emission entitlements.

Given current practice in NI, however, it is difficult to envisage that the authorities responsible for implementing environmental legislation would be receptive to a quota-switching arrangement which might result in breaching aggregate limits.

Third, assuming the Scottish interconnector is commissioned in 1998, it would be complementary to the cross-border link. From the ROI's viewpoint, it could be presumed that it would be advantageous to gain access to the GB pool via NI. This might not be possible, however, as NIE has 15 year rights. Given the concern about expected upward pressure on tariffs, it might be assumed that NIE would be influenced by economic circumstance to retain the benefit of cheaper GB Pool electricity, when available, mainly for NI customers.

Finally and most critically, basing capacity planning strategy in any irrevocable manner on the integrity of the link could be risky were it to result in one system becoming substantially more dependent on the other. Unless there is certain confidence surrounding the security situation in the longer term, that area without sufficient independent generating capacity might face a major energy crisis at a later date.

In summary, cross-border co-operation in the supply of electricity has been experienced and, while operational, was reasonably successful. Further development with a view to achieving a more combined system could realise potential, longer term benefits. Given the difficulties in forecasting the many relevant economic and political variables, however, these remain extremely uncertain and make it difficult to draw firm conclusions about the prospects for any significant integration of the electricity markets between both jurisdictions. Accordingly, quantification awaits future clarification.

3.7. Conclusion

This paper has considered the experience of electricity privatisation in the particular circumstances of NI. Privatisation was undertaken in the Government's belief that similar benefits to those achieved in GB would come to consumers in NI. In the short period to date, privatisation has not resulted in its main objective of achieving competition. That possibility is anticipated at a future time.

However, serious reservations must exist concerning the ability of future planned developments to have an effective impact on the situation for some considerable time. From the point of view of improving consumer welfare as a whole, the benefits of electricity privatisation will depend ultimately on demonstrably lower prices whether through increased competition or regulation. As the quotation at the beginning indicates, however, it may not be possible to meet everybody's expectations of what competition may deliver.

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Appendix1 Maximum Permitted Emission Levels for Power Stations In Northern Ireland in Accordance with the United Kingdom Plan Dated 20 December 1990 for Reducing Emissions from Large Combustion Plants.
 (a) SULPHUR DIOXIDE (TONNES) (b) OXIDES OF NITROGEN (TONNES)

Year	Coolkeeragh	Kilroot	Ballylumford	Belfast West	Northern Ireland Total
1993 (a)	2580	21000	51400	5020	80000
(b)	520	8650	7430	3400	20000
1994 (a)	6200	14000	44600	10200	75000
(b)	700	7100	7100	5100	20000
1995 (a)	7000	14000	37800	10200	69000
(b)	700	7100	7100	5100	20000
1996 (a)	1700	13600	38600	10200	64000
(b)	700	7100	7100	5100	20000
1997 (a)	2900	13500	34100	7500	58000
(b)	700	7600	7700	4000	20000
1998 (a)	5600	13600	31300	2500	53000
(b)	700	8400	8400	2500	20000
1999 (a)	5900	13300	29800	Nil	49000
2000 (a)	2100	13000	39000	Nil	46000
2001 (a)	1500	12600	27900	Nil	42000
2002 (a)	900	12900	25200	Nil	39000
2003 (a)	500	12400	22100	Nil	35000

Source: Department of the Environment for Northern Ireland (1994).

Chapter 4

COMPETITION IN THE BRITISH ELECTRICITY INDUSTRY

Richard Green, Office of Electricity Regulation

The changes to the British electricity industry have rightly attracted a lot of attention. I am presently working at the Office of Electricity Regulation, which has the task of overseeing the electricity industry in England and Wales and in Scotland. There is a separate Office of Electricity Regulation for Northern Ireland, which is responsible for developments in that province. Since Northern Ireland is the subject of another paper at this conference, I will not refer to it. The bulk of the paper will be concerned with what has happened in England and Wales, but I will also have a few comments about Scotland, where the industry has a different structure.

When discussing the electricity industry, it is helpful to break it down into stages, starting with generation. In England and Wales, coal-fired stations accounted for 80 per cent of the electricity generated in the late 1980s – most of the rest came from nuclear power. Over the last few years, nuclear has increased its share to about one quarter, and the share of coal-fired electricity has shrunk to just over half, as new gas-fired stations have been commissioned. More gas-fired capacity is under construction, and so its share, presently about one-seventh, is due to rise further. About one-tenth of the electricity used in England and Wales is imported from France and Scotland.

The next stage in the industry is high-voltage transmission, moving electricity from the power station to local distribution networks. The third stage, distribution, takes the power to consumers at lower voltages. Until a few years ago, I would have stopped there, because the distributor was also the company which dealt with the consumer. Since 1990, however, selling electricity to end-users has become a fourth distinct stage of the industry, known as supply. The supplier has to agree terms with the consumer, collect payment for the

electricity, and then use the money to pay for generating, transmitting, and distributing it.

For a domestic consumer, generation accounts for about half of the total bill, transmission one-twentieth, and distribution about a quarter. The supplier's own costs are also a relatively small proportion of the bill. Finally, the fossil fuel levy, presently 10 per cent, is added to the bill. Most of the levy is used to cover nuclear liabilities, for fuel reprocessing and station decommissioning, which had been incurred, but not provided for, before vesting day. The remainder is used to support renewable generation – wind power, waste burning, and so on.

Very large consumers pay much less (in proportion) for distribution, since they typically take their electricity at higher voltages, causing fewer costs. Accordingly, generation charges make up more than two-thirds of the typical bill. Since many of the supplier's costs are fixed, regardless of the number of units taken, the supplier's charges will only be a tiny proportion of the total bill.

In most cases, the supplier is the distributor who owns the wires which deliver the electricity, but the distributor has to allow other companies to use its wires if they wish to supply consumers in its area. You do not need to own a distribution system to become an electricity supplier – all you really need is an office, a healthy credit rating, and a supply licence, issued by Offer. With a few small-scale exemptions, everyone involved in the electricity industry has to have a licence, and the licences contain provisions to allow Offer to carry out its legal duties. There are quite a few of these, but they can be summarised as protecting consumers and promoting competition.

Often, our role is protecting consumers through promoting competition. The new industry structure, which was announced in 1988 and implemented on March 31 1990 – Vesting Day – introduced competition to the industry wherever it would be practicable. The Central Electricity Generating Board (CEGB) was split into four parts, and three new generating companies started to compete with each other, and with the pumped storage stations owned by the fourth part, the National Grid Company. Entry into generation has also been liberalised, and a dozen major stations, and many small ones, have come into the industry.

Competition in supply is being introduced in stages. At first, only the 5,000 largest consumers, with maximum demands of more than 1 MW, were allowed to choose their supplier. They consume about 30 per cent of the electricity supplied in England and Wales. Since April 1994, another 45,000 customers with a maximum demand of more than 100 kW have joined the competitive market, which now covers half the electricity supplied. In April 1998, every consumer should have the right to choose their own supplier – people are already working to make sure that this will happen.

Transmission and distribution are natural monopolies. A single company – the National Grid Company – is responsible for transmission across the whole of England and Wales, while there are twelve regional electricity companies (RECs), each of which is responsible for distribution in part of the country. It would be senseless to create a second network of wires, and since competition is impossible, regulation is needed to ensure that consumers are protected. Offer also regulates the overall tariffs paid by small consumers, since these consumers cannot choose their suppliers yet. The price controls allow the suppliers to pass through the costs of generation, transmission and distribution, and contain an element for the supply business' own costs and profits. Offer does not regulate the overall prices paid by large consumers in the competitive market.

The REC is bound to offer its system to all licensed suppliers on the same terms, and this non-discriminatory access makes competition in supply possible – if you do not need to use your own wires to supply a customer, it becomes a contestable activity.

Similarly, the National Grid Company (NGC) has a licence obligation to facilitate competition, and has to offer non-discriminatory access to its system to all potential generators. That does not mean that all generators should pay the same prices – it is quite proper that the prices they pay should reflect the costs which they impose on the system. There is more generation than demand in the north of England, and more demand than generation in the south. If a new station is built in the south, it will reduce the amount of electricity that has to be imported from the north, and NGC's costs should be lower than if the station had been built further north. NGC's charges reflect this, so that generators in the north have to pay more, and new stations face an incentive to locate in areas which reduce the grid's costs. NGC has kept Offer fully informed about these charges, for it is important that the regional differentials reflect costs – differentials which were too high or too low would discriminate against some users.

The cost differentials can be measured in several ways, although they give the same answer in the long run. In Chile, for example, a very detailed law requires the industry to calculate the short-run costs of transmission for every point on the network, and to set charges equal to these costs, together with a mark-up (or mark-down) to ensure that the transmission system earns enough revenue to cover its overall costs. In England and Wales, NGC calculates medium-run costs for each region, an approach which gives less detail, but more stability in its charges.

The biggest changes to the way in which the industry is organised concern generation. In the past, the CEBG drew up an internal merit order, listing its stations in order of increasing cost, and then ensured that the stations with the lowest costs were operated most intensively, to minimise the overall cost of

meeting demand. This internal procedure has been replaced by a market mechanism – the Pool.

The Pool is not a true "spot market", but a day ahead market, because generators (and customers) must be given time to plan ahead. The Pool calculates prices and operating schedules based on the most accurate predictions available, and has a mechanism for reconciling the differences between the predicted schedule and the out-turn.

It is the only physical market in electricity. It is impossible to tell which consumer's demand is met by the electricity from a particular power station, and so large-scale bilateral trading would be impossibly complex to monitor. A few small stations do sell their output bilaterally, but all large stations have to sell their output to the Pool, and suppliers buy from it. In that way, you only need to monitor the electricity put on to the system, and the amount taken off, and the market need not worry about the pattern of flows on the system.

Every day, the Pool receives bids from each large power station, reporting their availability during the following day, and the minimum prices at which they are prepared to generate. It then uses this information to calculate the least-cost operating schedule which will meet the demand predicted for the next day. Much of the software used was inherited from the CEGB's merit order system, but bid prices are now used instead of the CEGB's cost estimates.

For each half-hour, the Pool can identify the most expensive station which is in normal operation, and the price which it has asked for becomes the system marginal price, paid for every unit of energy generated according to the Pool's day-ahead operating schedule. A system like this, in which your bid affects whether you run, but will not have much impact on the price you are paid (since for most of the time that you are called, more expensive stations will be running as well, and the price is set by their bids) gives small companies the right incentive to ask for a price which is equal to their avoidable costs. A large company, however, might ask higher prices for some of its stations, even if they are less likely to run as a result, because this will push up the prices earned by the company's other stations, which continue to run.

Argentina has an electricity pool in which each station's bids are regulated, and required to equal its marginal fuel cost. That is one way of ensuring that no company can abuse market power. The approach in England and Wales, however, has been to make competition work. If the market is competitive enough, companies will bid at the level of their avoidable costs without any need for regulation.

The second part of the Pool price is known as the capacity element. In order to meet the highest demands, we need to have some power stations which only run for a few hours a year, and could not cover their fixed costs if they were only paid

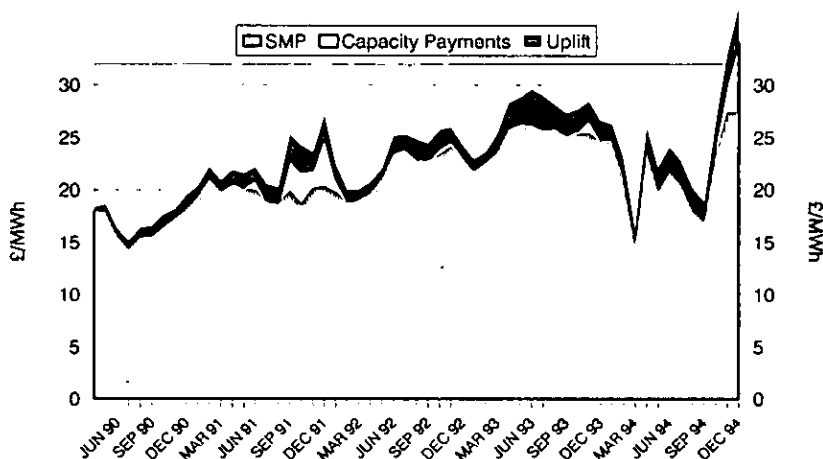
for running at those times. The capacity element is the product of the risk of a power cut, the loss of load probability, and the cost of a power cut, the value of lost load. It measures the value of additional capacity – the chance that it will be needed to avoid a power cut, times the costs that will be saved if it does so. If there is a lot of spare capacity on the system, the capacity payments will be small, and generators may find it profitable to close some of their less efficient stations, which are no longer needed. If there is little spare capacity, generators should expect to earn enough from capacity payments to cover the cost of keeping their old stations open, keeping the system in balance.

In practice, stations will not generate as predicted a day in advance, for the level of demand may be different, some stations may become unavailable, and some may not be able to run at full load because of constraints on the transmission system. All the output which was not predicted in the day-ahead schedule is paid for at the bid prices of the stations involved, and the total cost of this is added to the Pool price in a charge known as uplift. Many of the costs involved can be influenced by the way in which the transmission system is operated, and so NGC presently shares the cost of uplift, to give it a financial incentive to minimise the cost of the system.

Prices in the Pool were expected to be volatile, and have been – it is part of their role, to signal information on the balance between supply and demand. Contracts for differences can provide financial stability, without masking the price messages, by committing traders to make side payments based on the Pool price. When the Pool price is high, the seller (typically a generator) would have to give a rebate to the buyer (typically a supplier), while if the Pool price is low, the buyer gives the seller some extra income. The net effect of trading through the Pool and holding a contract is to make the net payments much more predictable, and so far, most of the trades through the Pool have been backed by contracts. When you hear that one company has sold electricity to another, what it has actually sold is a contract for differences. The actual electricity still has to be sold through the Pool, even though the total payments between the companies no longer depend on the Pool price. Despite that, because Pool prices are so visible – they are published in the *Financial Times* every day – they have received most of the attention.

Figure 4.1 shows monthly average Pool prices since the Pool was set up. For much of the period, there was an upwards trend, and Offer has held a number of enquiries into Pool prices. The reports have raised several issues concerned with the workings of the Pool, and some changes have been implemented as a result. The overall level of prices has always attracted the most attention, however.

At first, the avoidable costs of the two major generators were above their average revenues from the Pool, and on that basis, it was difficult to object to

Figure 4.1: *Average Pool Price by Component*

increases in bid prices from their initial levels. By the middle of 1993, however, average Pool revenues exceeded the avoidable costs of the two major generators.

Over the longer term, a competitive market price would need to cover the cost of building new plant or refurbishing old plant, as well as the cost of maintaining or operating it. This level may well be above the demand weighted Pool price to date. In contrast, competitive market prices in the short term would reflect more closely the avoidable costs of producing electricity, and the extent of capacity on the system in relation to demand. They could, for example, be as low as to enable generators to cover only their one year avoidable costs.

Pool prices were above that level at the beginning of 1994, and National Power and PowerGen agreed to reduce them for the next two years (1994/5 and 1995/6). They undertook to bid into the Pool in such a way that annual average Pool price would in normal circumstances reasonably be expected not to exceed 2.46 p/kWh time weighted and 2.61 p/kWh demand weighted (in 1994/5 prices).

The Director General obtained these undertakings because experience had suggested that the extent of competition had not been sufficient to restrain National Power and PowerGen if they wished to increase prices. The two companies were given plant accounting for 78 per cent of pre-vesting output in England and Wales, including all the coal- and oil-fired plant. Their overall market shares have since fallen, to about 60 per cent, following an increase in output from Nuclear Electric, and entry by new companies which have built combined cycle gas turbine stations.

More nuclear and gas-fired capacity is due on stream, and so National Power and PowerGen's market share can be expected to fall somewhat further.

This new entry has until recently been almost entirely geared to running baseload, however. This means that competition to run in the non-baseload section of the load curve is still limited almost entirely to the two major generators. The outputs of Nuclear Electric, the independent Combined Cycle Gas Turbines (CCGTs) and the interconnectors are practically constant throughout the day. It is the plant owned by National Power and PowerGen that accounts for almost all the variation in output over the day.

The System Marginal Price (SMP), the largest component of Pool price, is equal to the bid of the marginal plant. Nearly 90 per cent of the time, it is set by a station owned by National Power or PowerGen. The increased output of Nuclear Electric and the interconnectors, and the new entry by independents, have changed the market shares of baseload output, but have so far had little or no impact on market shares for the non-baseload part of the load curve.

The increased competition for baseload running may put increased competitive pressure on plant running mid-merit and at peak, but National Power and PowerGen are competing only with each other for a critical part of the load curve.

This is why the Director General wanted to introduce more competition in the generation market, particularly in certain parts of it, more quickly than would otherwise occur. In February 1994, he proposed that the two major generators should sell or dispose of 6,000 MW of coal- or oil-fired plant by December 1995, and they undertook to do so. This would double the present extent of independent generation. The undertakings were explicitly designed to introduce more independent competitors, able to challenge the ability of the two major generators to increase prices, with the aim of bringing about an industry that would not be vulnerable to the exercise of market power.

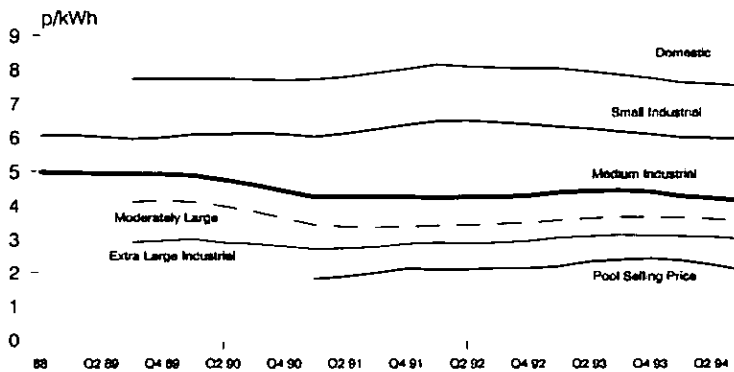
While Offer has had to give its attention to the problems experienced with competition in generation, there have also been successes. A significant amount of new entry has taken place, despite the doubts of some people who wondered before vesting if any companies would want to enter the market. RECs have been involved in all but one of the dozen large "independent" stations, but they had outside partners for ten of these. The first generation of projects were all supported by long-term contracts which matched their debt repayments, fuel supplies, and electricity sales. This greatly reduces the risks faced by the station's owner.

These stations were following a model created in the United States, where utilities have been required to buy from independent power producers, where these offer the best terms, since a law enacted in 1978. Since most American power companies are vertically integrated, the independent producers would find it

difficult to sell their power to anyone other than the host utility, and needed long term contracts for their own security. Effectively, there is competition to obtain the contract, which then governs the operation of the plant. Some parts of the US system are now experimenting with common carriage in transmission and with greater competition in generation.

Two recently announced CCGT projects have taken a different approach, however. One has long-term contracts, but most of the output has been taken by IVO from Finland and Tomen Corporation from Japan, which are investing and buying the contracts on a "merchant basis", taking the full risks of selling at whatever prices subsequently obtain in the Pool and the contracts market. Eastern Group, the owner of the other project, has indicated that it is not committing its supply business to long-term purchases of Contracts for Differences (CfDs) but instead envisages that its generation business will sell contracts for differences into the competitive market. These projects seem to represent a further development of a more competitive market in generation.

Figure 4.2: *Real (1990) Electricity Prices in*



Four Quarter Moving Averages Deflated by the Retail Prices Index

A competitive market is not an end in itself, of course, but a means for ensuring that a product is delivered to consumers at the right price. Government surveys allow us to track electricity prices for industrial customers, shown in Figure 4.2. The size categories do not correspond exactly to the ones used by the electricity industry – some of the "small sites" have a maximum demand of more than 100 kW, and became free to choose their supplier from April 1994, while the others are still in the RECs' franchise. Similarly, some of the

"medium sites" have a maximum demand of more than 1 MW, and were in the competitive market from its beginning in April 1990, while the others remained in the franchise market until last April.

The introduction of competition in the 1 MW market led to significant initial reductions for most large customers, typically about 15 per cent but in some cases up to 25 per cent. Even despite subsequent price increases, prices in real terms to most large customers were still over 10 per cent lower in 1993/94 than in 1989/90.

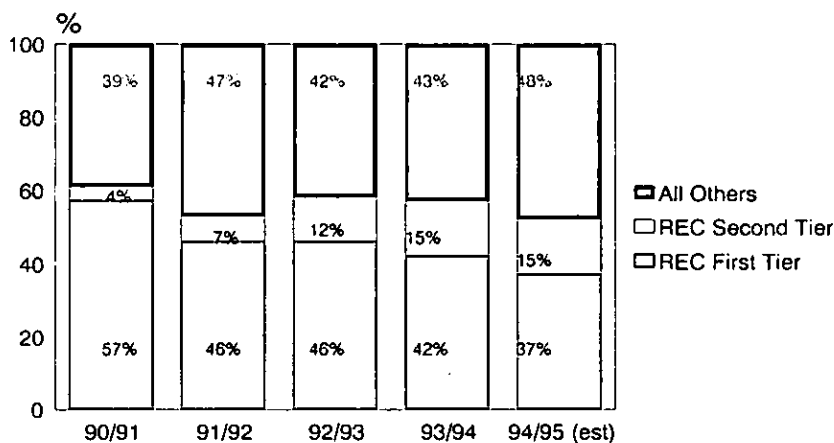
Some of the very largest customers have experienced significant price increases over this period, at least in nominal terms. To a large extent this reflected a withdrawal of the special terms which they enjoyed before Vesting. In real terms, prices to these customers were about 3 per cent higher in 1993/94 than in 1989/90, but the most recent survey data suggests that the average price in the year to September had returned to its level at Vesting.

For franchise customers in England and Wales, including domestic and small commercial and industrial customers, the price controls and contractual arrangements put in place at Vesting envisaged an initial increase in electricity prices of about 3 per cent in real terms followed by prices held constant in real terms until April 1993. Prices to franchise electricity customers did increase, a little later than planned, but fell in 1993/94, typically by 2-3 per cent.

Customers in the 100 kW market, newly exposed to competition, reported price reductions of around 10 per cent from April 1994 compared with prices they had previously paid. All of their suppliers announced either price freezes or price reductions for remaining franchise customers for 1994/95. In real terms, franchise prices in England and Wales are 4½ per cent lower than before Vesting. They should fall further, as the tighter distribution price control announced last summer takes effect.

Market shares can provide another guide to the state of competition, and Offer conducts annual surveys on suppliers' shares of the competitive market, shown in Figure 4.3. The figures here are broken down into REC first tier (supplying in their own area) and REC second tier (supplying in another area). The third segment, called "generators", is dominated by National Power and PowerGen, but includes the two Scottish Companies, Nuclear Electric, and a few independent suppliers. Even in the first year, second-tier suppliers took more than two-fifths of the market, measured by output, and this has grown to more than three-fifths. Not all RECs are active in second tier supply, but those which are have taken an increasing share of the market. The figures shown here exclude the newly liberalised 100 kW market, where about a quarter of consumers have changed their supplier.

That experience, and the experience of other utilities where competition has been introduced, suggests that all groups of customers, including domestic

Figure 4.3: *Market Shares in the Over 1MW Market: Consumption*

customers will wish to take advantage of the opportunities to exercise choice. Offer has recently issued a statement on the issues surrounding the competitive electricity market from 1998, when the RECs' exclusive franchise disappears. The arrangements, which must be capable of satisfactory implementation by 1998, should protect the interests of all customers and encourage new entrants during the transition to fully effective competition. They should also be cost-effective and in particular minimise costs and inconvenience to customers seeking second-tier supply.

At present, second-tier customers require half-hourly metering, so that their suppliers can settle their accounts in the Pool. This approach is likely to be costly for domestic customers, and for a transitional period at least, an alternative arrangement is required. An alternative is to use load profiling, which calculates bills on the basis of typical consumption patterns between less frequent meter readings. This would seem to minimise costs and inconvenience and be conducive to effective competition, although there are numerous details to be resolved. We hope that it will be possible to test the arrangements with small-scale trials before 1998.

Although most of the attention paid to the British electricity industry has concentrated on the vertically separated structure in England and Wales, Offer is also responsible for regulating vertically integrated companies, in Scotland. The industry in Scotland had been vertically integrated since the 1950s, and the government decided to introduce competition on top of the existing structure. As

far as possible, however, the industry's regulation follows the same lines as in England and Wales.

Scottish Power and Scottish Hydro-Electric, the two public electricity suppliers in Scotland, therefore have to make their transmission and distribution systems available to third parties, just as the RECs do, at regulated tariffs. The overall prices paid by small consumers, who cannot change their supplier until 1998, are also regulated.

The main difference is in the way in which generation is treated. In England and Wales, generation costs are passed through to consumers, but this would not give consumers sufficient protection in a vertically integrated company. Instead, the Scottish companies will be allowed to charge the average cost incurred by RECs in England and Wales in their electricity purchases, which relates the control to market prices. At present, they use a weighted average of the RECs' costs and a straight price cap.

Although large customers are free to change their supplier, only about one in twenty has done so. This may indicate that they are happy with their present supplier. In a contestable market, the threat of competition is effective in protecting consumers' interests and entry is not required to bring prices down. Certainly, average prices to large consumers fell by a quarter, in real terms, in the two years following vesting.

Nevertheless, some companies have told Offer that second-tier suppliers in Scotland find it difficult to secure generation from Scottish Power and Scottish Hydro-Electric on terms which are as favourable as those offered to their own supply businesses. The Director-General has said that it may well be appropriate to put in place arrangements to prohibit the companies from selling to their own supply businesses on terms which are more favourable than those which they offer to other suppliers. It may be more difficult to make competition work in a market which is largely vertically integrated, but Offer is determined to do so.

There are many aspects of Offer's work which I have not covered, such as dealing with consumer complaints, and arbitrating certain disputes between companies. However, I hope I have shown you how the industry works, and how Offer's approach – competition where it is possible, and regulation where it is not – has helped to make it work better.

Parts of the text of this paper are drawn from publications by Offer, including:

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Chapter 5

COMPETITION IN THE NORDIC ELECTRICITY INDUSTRY

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5.1. Introduction

The focus of this paper is on the major transition of the electricity supply industry that is now taking place in the Nordic countries. In Europe, Britain started reforming its industry in 1990. Norway followed the year after. Sweden and Finland will soon join the group of reform countries. The European Commission presented a first draft directive on limited competition in the Union in late 1991 and has since been elaborating on the final version.

The approaches of the Commission and of the individual countries are different. There is, however, a difference in terms of their radicalism rather than in terms of their basic philosophy. In both approaches a distinction between the generation and supply of electricity, on the one hand, and network services (transmission and distribution), on the other, is central. Like most other industries, generation and supply should be regulated by allowing competition, whereas transmission and distribution are still considered natural monopolies and should be regulated as such. To ensure that competition will be "workable", it is necessary to separate competitive activities from monopoly activities and to assign the network operators with common carrier obligations ("third part access" in the European jargon).

The British and the Nordic reforms differ with respect to their political background. The British reform started with privatisation which was never a real issue in the preparation of the Nordic reforms (the reform proposals were presented by Social Democratic governments).

In the next section, the Scandinavian electricity industry is introduced with respect to production, consumption, performance and regulation. The third section

is devoted to a presentation of the reforms in Norway, Sweden and Finland. The main emphasis will be on Norway which so far is the only country that has implemented a fully competitive market. Sweden and Finland will only be discussed with respect to issues where their reforms differ from the Norwegian case.

In contrast to the other Nordic countries, Denmark is reluctant about introducing competition in the electricity industry. The Danish electricity industry is presented in more detail in section four. The possible consequences of introducing competition in Denmark are discussed in the final section. The conclusion is that the Danish electricity industry should have good possibilities of survival on an open Northern European market. Major changes of the present Danish regulatory system will, however, be necessary.

5.2. The Nordic Electricity Industry

The electricity industry has, in many respects, developed the same organisational structure in the three Nordic countries that have now decided to introduce competition. To begin with, the industry was organised on a local basis. Supply of electricity was either established by large energy-intensive enterprises for their own purposes or by municipalities in towns and cities. As the large enterprises were often placed in the countryside, they started to supply the local (regional) community as well.

The state also participated, primarily by developing the large hydro-power installations that earlier this century became an important power source. Around the Second World War, the state-owned power administrations became responsible for establishing a nationally integrated power industry. They constructed the missing transmission lines for the national grid and became the leaders of the clubs of large producers, opening up the possibility of cost-minimising exchanges of power.

Today, the state-owned power companies (*Statkraft* in Norway, *Vattenfall* in Sweden and *Imatran Voima* in Finland) control about 25-50 per cent of power generation and the main part of the transmission grid. The remaining part of generation is divided between large manufacturing enterprises and municipal energy administrations in the large cities.

The organisational development of the Danish electricity industry was different. It was either organised by municipalities or (outside the cities) by consumer co-operatives. There was no hydro-power to motivate large-scale integration. After the Second World War the system has gradually become much more concentrated by mergers and co-operation and is now organised into two regional power associations (more details will be given in Section 5.4.1).

Different natural endowments and different organisational histories have resulted in large differences among the four Nordic countries regarding production technology and market concentration. Market concentration is highest in Denmark and Sweden (Herfindahl's index is 0.45 and 0.32 respectively), lowest in Norway (Herfindahl's index is 0.07) and with Finland in between (Herfindahl's index is 0.17).

Power is *generated* from different technologies in the four countries (see Table 5.1). All the Norwegian power supply comes from hydro-power; the Swedish supply is divided equally between hydro-power and nuclear power; Denmark is supplied by conventional (coal) condensing power and combined heat and power (CHP); Finland has a bit of everything.

Table 5.1: *The Composition of Generating Capacity and Power Supply in the Four Nordic Countries, 1993*

	<i>Denmark</i>		<i>Norway</i>		<i>Sweden</i>		<i>Finland</i>	
	<i>Capacity (GW)</i>	<i>Production (TWh)</i>	<i>Capacity (GW)</i>	<i>Production (TWh)</i>	<i>Capacity (GW)</i>	<i>Production (TWh)</i>	<i>Capacity (GW)</i>	<i>Production (TWh)</i>
Hydro-power			27.0	119.7	16.5	73.3	2.8	13.5
Nuclear power					10.0	58.9	2.3	18.8
Condensing power	3.5	30.5	0.1	0.1	2.8	0.5	3.6	7.3
Extraction-condensing power ¹	5.1							
Combined heat and power (back pressure)	0.9	0.5	0.2	0.3	3.6	8.0	4.7	18.6
Other (wind turbines)	0.5	1.0			1.9	0.2	0.9	0.0
Total	10.0	32.0	27.3	120.1	34.8	140.9	14.3	58.1
Imports		6.3		0.7		8.0		7.9 ²
Exports		5.1 ³		8.5		8.6		0.4

¹ Most large generating sets in Denmark use this technology for combined production of heat and power (see Section 5.4.2 for more details).

² Including imports from Russia.

³ Including exports to Germany.

Source: Nordel, *Annual Report 1993*, and Elsam, *Udbygningskriterier og omkostningsstruktur*, 1994.

These differences make power exchanges very beneficial (e.g., exchanges between producers of condensing power and producers of hydro-power). Since the 1960s, the four countries have exploited this possibility through the Nordic power pool (*Nordel*). It was organised directly by the large generating companies (before the reforms, these companies were also responsible for the transmission lines) in the four countries and have resulted in relatively large exchanges of power. Since then, the participants in this Nordic club are supposed to have enough capacity for their own supply this means that transactions are mostly based on short-term excess capacity.

The generating companies sell a part of their production directly to final customers (often energy-intensive industries). The rest is sold to local distributors, that are mainly owned by municipalities or regional authorities. There are more than one hundred of such *distributing* utilities in each country.

Patterns of *consumption* are different. Finland, Norway and Sweden have many large, energy-intensive industries (metallurgy, paper and pulp) that use electricity in their production. Electricity is also used as a main source of heating by households and business firms. The three countries therefore consume relatively large quantities of electricity per inhabitant. Denmark has only a few energy-intensive industries and primarily uses other forms of heating, resulting in much lower electricity consumption per inhabitant (see Table 5.2).

Table 5.2: *Consumption of Electricity in 1993 (in GWh)*

	<i>Denmark</i>	<i>Norway</i>	<i>Sweden</i>	<i>Finland</i>
Industry	9,817	42,005	49,452	34,180
Transport	200	680	2,400	450
Services and households	21,081	52,357	72,814	28,100
Total ¹	31,098	95,042	124,666	62,730
Per inhabitant (in kWh)	6,387	23,984	15,214	12,929

¹ Net of transmission and distribution losses.

Source: Nordel, *Annual Report 1993*.

In a European context, the Nordic electricity industry performs well. This is reflected in both lower *prices* than elsewhere (see Table 5.3) and high quality (constant frequency and voltage, few outages). The good performance can be explained by a combination of natural endowments (large resources of hydro-power), exploitation of beneficial exchanges between different technologies (inside each country as well as through the *Nordel*) and control against misuses of monopoly status.

Before the reforms, *regulation* of the electricity supply industry was organised differently in the four Nordic countries. Political control was most direct in Norway. Until recently the state-owned power administration did not have a separate identity, but was part of the ministry. Its prices were approved by Parliament. In Sweden and Finland, the state-owned power industries were organised as enterprises with a separate identity. In all three countries, the state sector has had an important role as price leader for wholesale power. This role has, among other things, been used to favour large energy-intensive industries by providing them with cheap power (price discrimination is most extended in Norway). Denmark is different from the other three countries as the state never participated directly in the electricity supply industry.

Table 5.3: *A Comparison of European Electricity Prices (in ECU/kWh, as at January 1, 1993, Excluding Taxes. UNIPEDÉ)¹*

<i>Country</i>	<i>Household 3 500 kWh</i>	<i>Industry 2 500 MWh</i>
<i>Nordic Countries</i>		
Denmark	0.06	0.05
Sweden (Stockholm)	0.06	0.05
Norway (Oslo)	0.05	0.05
Finland (Helsinki)	0.06	0.05
<i>European Union</i>		
Germany	0.120	0.100
France	0.106	0.080
Netherlands (PEN)	0.090	0.060
Belgium	0.110	0.090
Italy	0.168	0.090
Spain	0.140	0.090
Portugal	0.140	0.110
Ireland	0.090	0.080
England	(London) 0.111	(South) 0.075

¹ Average prices (tariffs) in ECU per kWh (and exchange rates) as at January 1, 1993, excluding taxes.

Source: UNIPEDÉ, Economics and Tariffs Study Committee, *Prices of Electricity as at January 1, 1993*.

The distributing utilities possess(ed) regional or local monopolies of supply. In Norway and Sweden, these monopolies are defined in concessions issued by the state authorities. In Denmark and Finland, they are provided by local authorities. Until the present reforms of the electricity supply industry, Finland has been the most liberal of the four countries. According to the present Finnish electricity act, competition is legal in both generation and transmission. In practice, however, the Finnish industry is controlled by a club of large producers with regional monopolies of supply.

There has been some *price control* by public authorities in all four countries, both by state authorities and local authorities. The applied price principles have not been sophisticated and public control not severe. In Denmark, the electric utilities have referred their tariffs to a special agency under the Monopolies and Mergers Commission. This agency has only intervened in those cases where a tariff was considered to violate the applied price principles (see Section 5.4.3). In the other three countries, there have been no general price control. The controlling agency (usually the Energy Agency) has evaluated concrete cases of complaint on an *ad hoc* basis.

5.3. *Introducing Reforms*

5.3.1. The Norwegian Reform

Norway was the first Nordic country to reform its industry. Its main motivation came from internal concerns about economic inefficiencies in the form of over capacity and a distorted price structure. The reformers were high ranking civil servants in the Norwegian Ministry of Energy who gained general political backing from the leading political parties. They also received important intellectual support from the academic community, where the economists had for a long time criticised the organisation of the electricity supply industry as being inefficient (see Hope, Rud and Singh, 1995).

The reform was defined in a new electricity act approved by the Norwegian Parliament in 1990 and put into practice in 1991. The main provisions stipulated in the new act are the following:

1. Third party access (TPA) for all customers (not temporarily restricted to large customers as in the United Kingdom). Every customer in Norway can make a contract to purchase electricity from every producer or wholesaler in the country.
2. The distributing utilities need a concession from the Energy Agency that provides them with a net monopoly for their area (other companies are not allowed to construct competing networks). Obligations are asymmetrically defined: The distributing utilities have an obligation to supply all

customers in their concessionary area, but these are not obliged to buy electricity from the local distributor.

3. If a customer uses his/her right to purchase electricity from another company, the local distributor must accept that and can only charge the customer for network costs and for administrative costs (e.g., separate metering). These tariffs should be cost-based and are controlled by the Ministry. The price of electricity (the energy supply), however, is free. It is supposed to be controlled by market forces.
4. Many Norwegian electric utilities are vertically integrated (they both generate and distribute power). To avoid cross-subsidisation, utilities with an area concession for distribution are obliged to keep separate accounts for their network and supply activities (so-called "unbundling").

The new law has been followed by a number of additional organisational measures to secure effective competition:

1. The state-owned power company has been separated into a generating company (*Statkraft*) and a transmission company (*Statnett*). The former is supposed to compete on equal terms with other suppliers, whereas the transmission company has been assigned the overall responsibility for the quality of the national electricity supply (like the *National Grid Company* in the United Kingdom). Neither the two state-owned companies nor the many utilities owned by local or regional authorities has been privatised. The purpose of the Norwegian reform was to improve the performance of the electricity supply industry by introducing competition. Privatisation was never an important political issue in the discussions of the reform.
2. Since 1971, the large producers had organised a spot market (*the Norwegian Power Pool*) for exchanges of occasional power. It has now been opened for other actors (primarily large purchasers and brokers in electricity).¹ In Norway it is not obligatory to use the power pool as it is in the United Kingdom. The price-determining mechanism is also different.² About 20 per cent of the total power supply in Norway is traded by the pool. The rest is traded directly by contracts between producers (wholesalers) and buyers of electricity. It has, however, become more

¹ It is organised as a subsidiary of the state-owned transmission company (*Statnett Marked*) with a board of directors appointed by the users of the pool.

² The basic unit for market clearing and settlement is the hour. Normally, only six price sections are being issued per day. They are determined in advance by the pool administrator. The market participants state their supply and demand in the form of a number of price-quantity combinations for each price section. This information is then being aggregated by the pool administrator, deriving supply and demand schedules and determining the equilibrium price for each price section (see Hope, Rud and Singh, 1995).

common for contracts to include clauses that relate the contract price to the pool price (see Andersen, *et al.*, 1994).

3. Ideally, the choice of electricity supplier by a customer (which could be a household, an industrial firm or a local distributing utility) should only be influenced by the price and supply conditions offered by competing suppliers. In practice, this choice can be strongly influenced by different transport and transaction costs (buying electricity from a non-adjacent supplier requires negotiations with the owners of the networks in-between). To reduce such costs, and thereby approach the ideal situation, a point tariff system that covers the whole national territory has been introduced. The tariff refers to the point where the supplier or customer is connected to a network, and it covers all relevant costs (it includes for instance payments from the owner of the local network for being connected to the superior regional and national networks).³

Competition in the Norwegian reform considers only internal transactions. Foreign trade is still subject to certain restrictions such as the amount of power that can be exported each year. Foreign power companies have access to the power pool but not on equal terms with Norwegian companies. The background for this restriction is fear of increasing power prices for the large energy-intensive industries. It was a political precondition of the reform that these industries should continue to be favoured by low prices.

So far, the main results of the Norwegian reform are lower prices for those groups (in particular business firms) that before were not favoured by price discrimination. Some utilities have been threatened by bankruptcy. Both effects were to be expected in the short run: because many utilities had constructed too much and too expensive new capacity in the years preceding the reform; and because the practice of price discriminations was common.

5.3.2. The Swedish and Finnish Proposals

Sweden and Finland have prepared proposals for reforms of their electricity supply industry. In most aspects these reforms are similar to the Norwegian reform. The Swedish proposal was transformed into a new electricity act that was presented to Parliament in Spring 1994 and planned to be implemented from January 1995 (see Swedish Government, 1994). However, the general election in September and the subsequent change of government resulted in a postponement of the new law. It is, however, not likely that this will end with the law being cancelled.

³ The variable parts of the new transmission tariff are constructed to reflect time and location specific loads and congestions (see Statnett, 1993).

During the preparations of the Swedish reform it was suggested to exempt the distributing utilities from their obligation of supply (included in the Norwegian electricity act). The new Swedish (general) competition law (from 1993) was expected to provide the necessary powers to avoid exploitation of electricity consumers. Doubts about this provision of the proposed electricity law and its consequences for electricity prices in thinly populated areas have served as the main excuse for postponing the law. Most likely, an obligation to supply such customers and some control of the prices they are charged will be included in the revised act.

In Sweden, there is no wish to restrict foreign trade as in Norway. One problem, however, will be the very concentrated generating sector (the two largest generators control 50 and 25 per cent of production respectively). Without measures to decrease concentration, the outcome can very well be monopolistic pricing (see Bergman and Andersson, 1995). One option will be to separate the state-owned power company, Vattenfall, into two or more independent companies. Another option will be to integrate the Swedish market with the Norwegian market (this option is very much advocated by the new transmission company, *Svenska Kraftnät*, that wishes to participate in the joint organisation of a Norwegian-Swedish power pool).

So far the proposal for the Finnish reform has not been transformed into a new electricity act. It is expected to be presented to Parliament this year and to be enacted in 1996. It will probably be less restrictive regarding the network (transmission and distribution) monopoly than the Norwegian and Swedish reforms (see Rännäri, 1995; and Finnish Government, 1993). There will be no restrictions on foreign trade (Finland is in contrast to Norway and Sweden a net importer of power).

Because of the reforms, the Norwegian and the Swedish electricity industries have started to construct cables to the Continent and to negotiate long-term contracts with continental companies (in particular in Germany and The Netherlands).

5.4. *The Danish Electricity Industry*

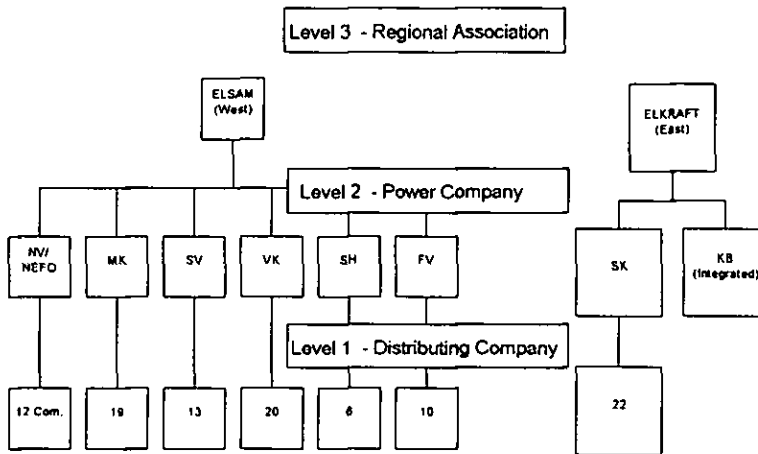
5.4.1. Organisation

The Danish electricity supply industry consists of two vertically integrated regional systems. About ninety distributing utilities of widely different sizes own nine generating companies⁴ that co-operate in two regional associations (see Figure 5.1). The latter are responsible for fuel purchases, central dispatch and

⁴ One utility, the Copenhagen Power Company (Københavns Belysningsvæsen), is vertically integrated.

international trade. The two regional associations have hitherto not been connected, but a cable has now been decided. All electric utilities except one are municipal enterprises or consumer co-operatives (and the exception is a joint stock company owned by municipalities).

Figure 5.1: *The Organisational Structure of the Danish Electricity Supply Industry*



Each generating company has its own area of supply. The distributing utilities in the area will buy all their power from this company, which they own. The distributing utilities are exclusively serving a franchise market. They are obliged to serve all demand (up to the capacity of the installations at the customers' premises) and the customers cannot make contracts with alternative suppliers.

The two regional systems are organised as tight pools with economic dispatch. It means that the power stations are being dispatched by the regional centre according to a merit order that reflects increasing variable (energy) costs. As the Danish system is almost exclusively fuel-based (coal⁵), the energy efficiency of the power plant is a main determinant of variable costs (new plant is more efficient than old plant). Electricity is being imported from the hydro-power and nuclear power systems in Norway and Sweden, whenever available at a lower cost than self-generation.⁶

⁵ The furnaces of the large generation sets can burn different qualities of coal and can easily be shifted to oil; a few of them also to gas. Most of the decentralised CHP-plant is gas-fired.

⁶ In some years up to 40 per cent of the Danish electricity consumption is imported.

Most power plants are located close to the consumption centres and the quality of the transmission and distribution networks is high. Because of that transport costs are relatively low and only under very exceptional circumstances will network constraints be relevant.

5.4.2. *Technology and Costs*

Danish power generation is nearly exclusively based on thermal capacity (see Table 5.1).⁷ Since the 1970s, coal has been the dominating fuel. Because of environmental restrictions, gas and biomass are likely to substitute a part of the coal in the future. There are three major types of steam turbines in the present Danish power system:

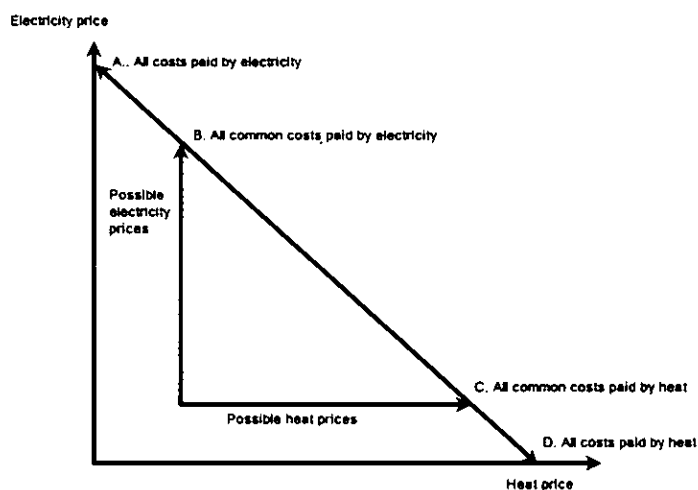
1. Condensing units without co-generation (primarily older generating sets).
2. Back-pressure units producing power and heat in a fixed relationship imposed by the technical lay-out of the turbine (used by small combined heat and power (CHP) generating sets).
3. Extraction-condensing units, which allow both condensing and back-pressure mode production in a flexible combination of power and heat (used by all newer large CHP-generating sets)

Co-generation has become very important during the recent decade. Since 1981 all new large units have been located near the large urban centres with a district heating grid. After the new Heat Act of 1990 it was made obligatory for all district heating systems to substitute their heat boilers by back-pressure units. It means that the future generating system will be dominated to an even larger degree than the present by CHP-capacity.

Production costs of electricity from CHP-units will depend on the cost-sharing between heat and power. For rational actors the cost allocation rule cannot result in costs that are higher than the stand-alone costs of each product. Stand-alone costs for thermal power are equal to the costs of condensing production (B in Figure 5.2) and for district heating they are equal to the costs of a heat-only boiler (point C). The relevant cost of power generation will be in the interval between these two extremes (this "bargaining line" is BC in Figure 5.2).

In Table 5.4 the technical parameters of two large and one small CHP-plants are presented. They all represent technologies that are being commissioned in Denmark in these years.

⁷ The non-thermal capacity consists mainly of wind turbines.

Figure 5.2: *Cost Sharing Between Heat and Power*Table 5.4: *Technical Data and Production Costs for Three CHP-units*

Fuel	250-500 MW Extraction-condensing		50-100 MW Back-pressure
	Coal	Gas (Comb.cycle)	Gas (Comb.cycle)
Electricity/ heat ratio, C_m	0.65	1.10	1.05
Electricity loss ratio, C_v	0.15	0.17	-
Total efficiency, η_m	0.88	0.91	0.90
Electric efficiency, η_p	0.45	0.55	-
Investments costs (mill. DKK/kWh)	6.94	5.37	6.44
Operation and maintenance in per cent of investments cost	3	2	3

Source: Grohnheit and Olsen, 1994.

5.4.3. Regulation and Performance

The Danish electric utilities are strongly regulated. New plant is subject to prior approval by ministerial as well as by local authorities. The authorities do not limit their role to a discussion of the proposals made by the industry. Because of raising environmental ambitions during the last decade, the Ministry of Energy has

tried to enforce specific capacity choices on the electric utilities. Examples are wind turbines, small local CHP-units and the use of gas and biofuels instead of coal.

The power generators are subject to regulations to reduce emissions of SO_2 , NO_x and CO_2 . Recently, it has been made obligatory for the electric utilities to prepare plans for *Demand Side Management* and *Integrated Resource Planning*.

Part of the regulations are specified in public laws. Another part is included in agreements between the Government and representatives of the industry (most often the regional associations). Danish administrative practice has a long tradition of such co-operative (corporative) arrangements. Examples are agreements according to which the utilities agree to build a specified amount of wind turbines and small local CHP-plant. Another example is the regulation of emissions of SO_2 and NO_x . The Government has after negotiations with the electricity supply industry specified quotas for the total emissions. How to reach the agreed target is, however, up to internal decisions by the industry (it can install FGD-equipment or switch to fuels with lower emissions).

The electric utilities are also subject to price control. Tariffs should be calculated according to a set of rules issued by the state authorities in co-operation with the Association of Electric Utilities and referred to the Electricity Price Board (under the competition authorities). Tariffs are, however, not subject to prior approval. Utilities are supposed to break even: surpluses (deficits) in one year mean price reductions (increases) in the following year. New plant is financed by a mark-up on rates during the period of construction (including the years immediately before and after).

The co-operative (corporative) administrative tradition is also reflected in the composition of the price board. The members are appointed by the Minister, but most of them as representatives of the electric utilities and their customers. Decisions are usually based on consensus and implemented in co-operation with the Association of Electric Utilities.

The dominant pricing rule is "cost of service" (including depreciation and interest charges). There has been a tendency in the post-war period towards more simple tariffs, the rationale of which are lower average energy costs and higher metering costs. Therefore, most tariffs are simple two-part tariffs with a fixed element covering administrative costs and a variable element covering all the rest (mainly purchases of power and distribution). Peak load pricing is common for wholesale to distributing utilities and large customers and is now being opened as an option for other groups of customers.

As the Danish electricity supply industry is increasingly a CHP-system, the allocation of the common generating costs between heat and power is important. So far, the benefits from joint production of heat and power have been assigned to

the heat customers. It means that electricity customers pay the generating costs of condensing power (see Figure 5.2).

5.5. *The Consequences of Introducing Competition in Denmark*

Low production costs, cost-based tariffs and a tradition for exploiting advantages of foreign trade all together indicates a Danish industry with a strong initial position on a competitive European market.

Despite that, the introduction of competition in the electricity supply industry has few supporters in Denmark. The industry is against it. Consumers will find few incentives from a comparison of their prices with the prices in most other European countries. The politicians fear that an open market can be a threat to national energy policies. Therefore, changes can only be initiated by pressures from external actors.

5.5.1. Organisational Consequences

The Danish electricity industry will have no difficulties adapting to the formal organisational requirements included in the proposed EU-directive (limited third party access and unbundling of accounts). Adaptation will only require that the generators separate their accounts for generation and transmission. The distributing utilities own the generators and are by tradition strongly integrated with them. With one exception (see Figure 5.1), however, generation and distribution are separated in different firms.

The many limitations and the lack of facilitating arrangements in the proposed EU-directive do not make it a powerful device for introducing competition in the Union. More relevant for the Danish utilities, therefore, is the outcome of the Nordic reforms. The Nordic organisation of co-operation, *Nordel*, is already adapting its membership⁸ and rules to the new conditions. An extension of the Norwegian spot market to include Sweden and Finland, which is now being proposed, will work in the same direction. The new transmission lines between the Nordic countries and Germany, which are either under construction or are being discussed, will facilitate integration with the Continent as well and thereby increase competition for access to the cheap resources of hydro-power in Norway and Sweden (Germany is a high-cost country). To continue to have access to these resources, Denmark must adapt and give the producers in the other Nordic countries access to its market.

The concrete organisational responses of the Danish industry will be determined by the dynamics of this Northern European market:

⁸ The two new transmission companies in Norway and Sweden, Statnett and Svenska Kraftnät, have been included.

1. The present tendency towards further *concentration* of both generation and distribution will be continued. The ties upholding vertical integration will not be loosened and only the minimum requirements of vertical separation stipulated in the EU-provisions (unbundling of accounts) will be implemented. Under these assumptions, the main differences from today will therefore be the new mechanisms for exchanging power across national borders and the adaptation of contracts and tariff structures to prevent by-pass.
2. *Vertical* and *horizontal* disintegration will be the result of the many new conflicts caused by the opening of a competitive market for electricity. The distributing utilities will exploit the possibilities of alternative suppliers and will separate from the generating companies. The co-operation among the latter in the regional associations will dissolve. Some concentration will take place to reach the necessary "minimum scale of efficiency" of the new European electricity market (3-5 generating companies and 15-20 distributing utilities are left).

The organisational dynamics determining whether the integrated or the disintegrated future will be realised depends very much on the competitiveness of Danish CHP-power. If it turns out to be competitive, the distributing utilities will have few incentives to find alternative suppliers, and vice versa, if it turns out not to be competitive. Therefore, the competitiveness of CHP-production is crucial for the organisational outcome. I will deal with that problem in the next section.

5.5.2. Is Danish CHP Competitive?

Different power generating technologies are characterised by different cost profiles (e.g., concerning the ratio between fixed and variable costs). The nationally closed markets for power have also allowed very different costs for the same technology to occur. In a recent report from the Swedish Energy Agency (*Nutek*, 1993), the reported costs of the same (new) generating technology varied in some cases with more than 100 per cent among different European countries. Such cost differences have several sources: protection of national industries (coal mines and manufacturers of generating equipment), exploitation of monopoly, cost inefficiencies due to organisational slack, and locational advantages (Danish power plants are coast-based and therefore do not need expensive cooling towers).

Fuel and generating equipment are internationally traded goods. Therefore, it is reasonable to expect cost differences for fuel-based generating technologies to disappear in an open market. Subsidies will disappear (or be paid directly to the coal mines) and existing inefficiencies will be squeezed away.

It is important to distinguish between the *short* and the *long run*. With the present prices there is too much capacity in Northern Europe. Therefore, it is

likely that prices in a period after the opening of the market will decrease (eventually to the variable costs of the marginal technology). Such price cuts will stimulate demand. An increase in demand is also likely to come from exogenous sources (population increases and higher standards of living). Demand growth and an increasing need of replacements will cause prices to go up in the longer run (eventually to a level where the construction of new capacity will become profitable).

Table 5.5: *Generating Costs of New Capacity (US mills per kWh)¹*

	<i>Nuclear</i>	<i>Coal (electricity only)</i>	<i>Natural Gas (electricity only)</i>
Germany	51.4	79.1	
UK	48.4-51.6	46.8-51.6	45.2
Denmark		35.1	35.1-37.4
Finland	30.1	35	35.3

¹ 5 per cent discount rate.

Source: Nutek, 1993.

Some price differences will, however, persist due to transport costs and limitations on transmission capacity. A continuation of market imperfections can, of course, also be the cause of price differences.

The competing technologies are presented in Table 5.6. *Nuclear power* has low marginal costs (0.06-0.07 DKK per kWh). As it is costly to change the load, nuclear power will be used as base load and will not be the price-setting technology under normal conditions. For political reasons it is not very likely that new nuclear capacity will be constructed in Germany and Sweden.⁹ In Denmark and Norway, nuclear technology is not on the agenda at all.

Hydro-power (with a water reservoir) is the most flexible generating technology. It can be stopped and started quickly and with little direct cost. Generators will therefore prefer to produce when demand and prices are high. In such periods, however, technologies with higher variable costs such as condensing power will determine the price (hydro-power will be intramarginal). Direct variable costs are extremely low, 0.01-0.02 DKK per kWh. It can be argued, however, that opportunity costs are higher for a hydro plant with a water reservoir, because of the possibility of storing the water and selling it at another time. Amundsen *et al.* (1993) quote an average value of 0.06 DKK per kWh.¹⁰

⁹ Nuclear power is still a politically realistic option in Finland.

¹⁰ The water value is based on expectations of future values of precipitation, demand, output and prices. It is therefore debatable if an "average water value" is a meaningful concept at all.

The availability of new low-cost hydro-power resources is very limited in the Nordic countries (additionally 10 TWh can be exploited annually in Norway to a unit cost in the range of 0.18-0.22 DKK per kWh and less in Sweden and Finland).

Thermal (condensing) power (coal and in increasing measure gas) is likely to become the marginal, price-setting technology most of the time on a Northern European market with competition. It is also the technology that is likely to be constructed to cover an increase in demand. This is the case for Denmark, Finland and Germany, but it can be relevant in the future for Norway and Sweden as well (because new hydro-power is more expensive than new thermal power and because Sweden politically is committed to substitute its nuclear capacity before 2010). As all countries will have access to the same technology, I assume similar cost characteristics as for the Danish plants presented in Table 5.4 (and very different from the unit cost reported in Table 5.5).¹¹

Table 5.6: *Short- and Long-term Marginal Costs of Different Technologies for Power Production (DKK/kWh, 1990-prices)**

	Low Fuel Cost ¹		High Fuel Cost ²	
	Short term	Long term	Short term	Long term
Small local gas-fired CHP	0.08	0.19	0.12	0.24
Central coal-fired CHP	0.06	0.19	0.07	0.21
Central gas-fired CHP	0.07	0.15	0.12	0.2
Coal condensing	0.12	0.24	0.14	0.28
Central gas condensing	0.12	0.19	0.19	0.28
Nuclear (France and Finland) ³	0.06	0.22		
Nuclear (Germany) ³	0.07	0.36		
Hydro (direct variable cost)	0.02	0.18		
Hydro (water value)	0.06	0.22		

* 5200 annual hours of production for all technologies, 5% interest.

¹ 12.43 DKK/GJ for coal and 16.29 DKK/GJ for gas.

² 16.29 DKK/GJ for coal and 29.22 DKK/GJ for gas.

³ Source: OECD Nuclear Energy Agency/International Energy Agency, *Projected Costs of Generating Electricity. Update 1992*, Paris 1993.

The supply costs to the Danish market will include transmission costs. For new capacity, these have been calculated to 0.04-0.05 DKK per kWh (including

¹¹ As most German thermal plant will be placed inland and therefore requires more expensive cooling, this represents a conservative assumption with respect to the competitiveness of Danish producers.

transmission losses, and under the assumption of an annual use of 8,000 hours, see Bjorvatn and Bjorndalen, 1993) from Norway to Denmark. Similar costs can be assumed for transmission from Sweden to West Denmark and from Germany to East Denmark. Transmission costs are negligible from Sweden to East Denmark and from Germany to West Denmark.

What are the prospects for Danish CHP on a future open market in Northern Europe with these technologies? It appears from Table 5.6 that CHP has lower or similar (short-term) marginal costs as most of the competing technologies. The only exception will be hydro-power (and nuclear power if the alternative is to decrease the load). In such situations, however, transmission costs will provide the Danish market with some protection. The Danish CHP-technologies are competitive in a long-term perspective, when the relevant alternative for the competing technologies is to construct new capacity and transport power to Denmark.

Amundsen *et al.* (1993 and 1994) have developed two equilibrium models for the study of prices, output and trade on an integrated (North-Central¹²) European market for power. One model analyses the short-term perspective whereas the other deals with the long-term perspective.

The long-term model (Amundsen *et al.*, 1993) determines national consumption and volume trade in electricity in year 2000 based on existing and newly constructed transmission lines. The model takes account of existing production capacity in the various regions and calculates the optimal expansion of new production capacity. Calculations are based on the assumption of efficiency in production, free trade in electricity and the possibility of constructing new transmission lines. The resulting equilibrium prices are reported in Table 5.7.

The price in Denmark will be 0.25 DKK per kWh under the assumptions of free competition of the model (which includes average precipitation in Norway). This is similar to the unit cost of new coal condensing capacity and above the unit cost of new CHP-capacity in Denmark.

The other model (Amundsen *et al.*, 1994) calculates time-differentiated equilibrium prices under the assumption of existing generating and transmission capacity. The time periods are: summer day, summer night, winter day and winter night (see Table 5.8). The over-capacity mentioned above is reflected in lower equilibrium prices than in the long-run model.

Most of the resulting prices on the Danish market are above the short-term marginal costs of CHP reported in Table 5.6 (under the assumption of high fuel costs, the price on a summer night will be lower than the marginal costs of the two gas-fired CHP-plants). The calculated price differences among the four periods are

¹² The Norwegian models include more countries than discussed here. The Benelux countries, France and the UK are included in Amundsen *et al.* (1993), whereas Italy, Austria and Switzerland are also included in Amundsen *et al.* (1994).

not large. This reflects, among other things, the modifying influence of hydro-power that is not exposed to the same peak load problems as thermal production capacity.

Table 5.7: *Calculated Prices^{*} in year 2000 on a Northern European Competitive Market for Power (DDK/kWh)*

	<i>Initial situation without competition (1988-data)</i>	<i>Free competition (year 2000)</i>	<i>CO₂-tax (10\$ per barrel oil) (year 2000)</i>	<i>Norwegian exports restricted to 10 TWh annually (year 2000)</i>
Norway	0.20	0.20	0.21	0.17
Sweden	0.21	0.21	0.22	0.21
Finland	0.23	0.23	0.23	0.23
Denmark	0.31	0.25	0.22	0.30
West Germany	0.32	0.27	0.25	0.31

* Wholesale prices excluding transmission costs

Source: Amundsen *et al.*, 1993.

Table 5.8: *Time Differentiated Prices on a Northern European Competitive Market for Power (DDK/kWh)*

<i>Period</i>	<i>Summer day</i>	<i>Summer night</i>	<i>Winter day</i>	<i>Winter night</i>
<i>Per cent of year¹</i>	31	13	39	17
Norway	0.11	0.11	0.11	0.11
Sweden	0.11	0.11	0.11	0.11
Finland	0.11	0.11	0.11	0.11
Denmark	0.13	0.11	0.15	0.11
West Germany	0.14	0.08	0.16	0.11

¹ Varies a bit among the five countries.

Source: Own calculations from Amundsen *et al.* (1994)

5.5.3. Regulatory Problems

The analysis of production costs and market prices on an open Northern European power market tells us that Danish CHP-producers will have good possibilities to compete and thereby survive. It also tells us that Danish consumers can expect lower prices in the short run, and prices that are not so different from the present tariffs in the long run.

The Danish utilities often mention the constraints created by the different time profiles of electricity and heat load as a problem of CHP in an open market. They have added some flexibility to the system by using extraction-condensing plant and heat storing facilities. In my opinion, access to a large and open market will create further flexibility to the system. Along with its own distributing companies, power can now be sold on the external market, either on the spot market or on long-term contracts with other utilities and customers. Contract terms can be determined to suit each individual case. It should therefore not be too difficult for the regional associations to design contracts that can match the attempts of by-pass.¹³

The exploitation of these possibilities, however, presupposes an adaptation of the Danish regulatory system to the conditions of a competitive market. As in most other countries, the present regulations have been designed for vertically integrated monopolies with exclusive rights. Without changes serious problems will be the result under competitive conditions. This is the case with both sections of public regulation: monopoly and environment.

(a) Regulation of monopoly:

The generators are supposed to compete in production and supply with other companies. The present system where all utilities are required to break even and new plant is financed by mark-ups on the power price during the period of construction is not viable under competition. There should be no direct price control of generators under competitive conditions and they should finance their plant as under normal business conditions.

In Section 2 the Danish industry was characterised as the most concentrated of the Nordic electricity industries. Despite that, I do not consider it necessary to dissolve the present co-operation in the two regional associations. These associations are relatively small compared to the potential competitors in the surrounding countries. Forced separation could result in economic units that will not be viable under future competitive conditions. Further, a high degree of concentration on the domestic market is not likely to result in monopolistic domination because of the large transmission capacity that connects Denmark with its neighbouring countries. In particular, the existence of low cost producers in Norway and Sweden will make the market contestable.

The distributing utilities will continue as regulated monopolies. Their tariffs must remain under public control that makes it possible to continue with the present financial regime. There are, however, reasons why this is not a good idea. Under competitive conditions the scope of regulation will be enlarged. Third party

¹³ One of the generators in the Eastern part of Denmark, SK, has recently concluded a contract on exchange of ownership with the Swedish state-owned generator, Vattenfall. Ownership in some of Vattenfall's hydro power plants will be exchanged for ownership in a planned extraction-condensing plant in the Copenhagen area to be constructed by SK.

access requires that competing suppliers are treated equally for access to networks and customers. The distributing utilities are no longer dealing with a single power supplier and they are no longer the only supplier for their customers. It is also among the objectives of the regulatory authorities to prevent vertically integrated companies from cross-subsidisation by transferring resources from monopoly to competitive activities.

(b) *Environmental regulations:*

Such regulations have either been introduced by public law or are the result of negotiations between the Danish Government and the two regional associations; or a combination of both. Examples of negotiated regulations are: the obligation of the two regional associations to construct a certain amount of wind turbines and small local CHP-plant; and the obligation to use straw and gas as a fuel in some of the central power plants. Examples of a combined solution are the quotas for SO₂- and NO_x-emissions the implementation of which is administered by the industry.

Under the conditions of an open market, the power generators cannot be expected to accept obligations that are not extended to their competitors and thereby will harm their position. Environmental regulations must be implemented as: common obligations for all power suppliers (e.g., to use certain fuels or to keep emissions within specified limits); direct subsidies (to the favoured fuels and power producing technologies); or as obligations for the transmission and distributing utilities (to give dispatch priority to the favoured alternatives).

It should be added that certain policy instruments such as duties and tradable permits are well suited to work with competition. Preferably, they should be introduced on a super-national level to cover the whole market for power.

5.6. *Conclusion*

The Nordic countries are very electricity intensive and their prices are lower than in other European countries. Nordic co-operation has allowed beneficial exchanges of power among different technologies.

Three Nordic countries are now introducing major reforms of their electricity supply industry. With the exception of privatisation, these changes are as radical as those included in the UK reform from 1990. They will create access for all groups of customers to competing suppliers.

Norway was first to reform its electricity industry and has already gained experience that can be useful for other countries. However, the Norwegian power supply is unique because of its exclusive use of hydro-power and because of the large number of producers. The other Nordic countries (and other European countries as well) will start with a much higher degree of concentration of their

power supply. Increased Nordic co-operation is an obvious measure if one wishes to avoid monopolistic dominance of domestic markets.

Denmark is different. It is much less electricity intensive than the three other Nordic countries and has (partly) a different organisational tradition. The country is, however, an active participant in the Nordic co-operation from which it has received considerable benefit.

The international trend favouring competition in electricity supply has been met with reluctance by the industry and by the political authorities. In the paper, I argue that this attitude is not justified by poor economic performance. The Danish electricity production, that is becoming more and more dominated by combined heat and power (CHP), should be competitive on a Northern European market for power. Such a market will also open new possibilities for the CHP-generators for beneficial exchanges.

These conclusions, however, presuppose major changes of the present Danish regulatory system that relies on agreements between industry and authorities. Such relationships must be replaced by more arm's length arrangements. This applies to both monopoly and environmental regulations.

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