The Environment and Competition in Electricity in the USA and the UK: The Impact of Restructuring on CO_2 Emissions

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EXECUTIVE SUMMARY

Over the past quarter century in both the USA and the UK, governments have taken steps to restructure their respective electricity industries, while simultaneously making bold promises with respect to future carbon dioxide emissions reductions. These two phenomena are inextricably linked. In the UK, 90 per cent of the national decrease in CO_2 emissions since 1990 can be accounted for by the electricity sector alone. In the USA, the President's Climate Change Action Plan places the heaviest emphasis on electricity industry initiatives. The critical question which this study strives to address is whether fundamental tensions exist to complicate the simultaneous realisation of these two sets of objectives – those associated with the restructuring of electricity markets and those concerned with carbon dioxide emissions abatement.

Although both countries have historically taken markedly different approaches to electricity industry organisation, legislation and regulation, some generalisations can be made with respect to identifying areas where objectives of increased competition and goals of CO_2 emissions abatement might coincide or conflict. The potential for mutual reinforcement manifests itself in both the likelihood that the free market will ensure environmental protection through innovations such as green pricing programmes, and the possible hastening of producer investment in more efficient, cleaner plants. Restructuring also forces individual firms to bear the brunt of environmental regulatory risk, thereby increasing incentives for private sector abatement efforts. On the other hand, the potential for tension between restructuring regimes and emissions abatement initiatives is great. Changes in generation patterns arising from changes in market conditions and increased competition can include more intensive employment of the lowest cost generators, an increased incentive to extend the use of old, idled and mothballed plants, early retirement of nuclear facilities and increased load factors. Depending on the economics of generation and fuel mix, all of these changes can lead to increased carbon emissions per unit of electricity generated. Increases in costs of capital and discount rates, which occur as a consequence of reallocated economic risk, tend to discourage investment in renewables. Falling consumer prices can serve as a disincentive to energy efficiency improvements. Finally, the changing political economy of regulation that inevitably accompanies industry restructuring is characterised by a stronger, more proactive industry lobby which can serve as a formidable barrier to environmental legislation.

A closer look at the regulatory institutions responsible for implementing environmental legislation which affects electricity generation reveals that insufficient attention has been paid to the changing role of the environmental regulator in the newly structured markets. Consequently, regulators in both countries are ill-equipped to address the need for carbon abatement in a competitive market environment. Recently, the UK government has made attempts to explicitly address the issue of who holds the responsibility for environmental regulation, although the

question of how environmental concerns and competition should be reconciled remains contentious. In the USA, although institutions have been established to mediate between competing economic and environmental industry objectives, these institutions are being rendered obsolete by restructuring, and it has yet to be determined how this void will be filled.

Regulatory complications aside, the UK has been fortunate in that the most economic choice for power generation in the newly privatised industry, gas, also constitutes an environmental improvement on the former fuel of choice, coal. Thus, privatisation led to a 'dash for gas' and a subsequent, dramatic decline in carbon emissions. A recently imposed gas moratorium is expected to slow further gas developments, thus limiting the country's potential to realise further reductions through fuel switching. In terms of renewables development in the UK, restructuring has proved to be a mixed blessing. Privatisation brought both an unprecedented market enablement approach to encouraging renewables development, and increased capital costs, higher required rates of return on investment and higher discount rates which serve to discourage investment in renewables.

The USA has not enjoyed the similar good fortune of having the simple act of restructuring fortuitously lead to a more environmentally sound fuel mix. For various reasons, restructuring has led to increased use of old, polluting coal plants. Renewables are likely to suffer due to regulatory and legislative changes, as well as unfavourable market conditions. Demand side management programmes will also be compromised in more competitive market conditions unless sufficient steps are taken to ensure their continued success.

1. INTRODUCTION[1]

In both the UK and the USA, throughout the 1980s, governments committed to neo-liberalist ideals brought dramatic changes to the real and perceived relationships between the public and private sector. At the heart of this ideology was an opposition in principle to both public sector organisation of the provision of all public goods and government configuration and regulation of the economy. Instead, competition between producers to benefit customers should define the public interest and ensure that it is served. It was precisely this mode of thinking, together with changing economics of electricity generation, technological innovation and, especially in the case of the USA, power industry management problems that led to change. Vertically integrated utility companies supplying power to a captive franchise area became a thing of the past. The Electricity Supply Industry (ESI) became characterised by competition in generation, customer choice, market versus regulated rates and separation of ownership and control of generation, transmission and system operation.

Growing competition and imminent restructuring of the electricity industry has been welcomed by many who expect lower costs, increased efficiency and improved service to all consumers. While these benefits may or may not be observed, there have been concerns that historic support for public service obligations will be lost, as will many of the policy instruments that have been used effectively in the past to encourage industry observation of an environmental ethic. This loss would be particularly lamentable at a time when both the USA and the UK have made bold promises to reduce carbon emissions from electricity generation through technological innovation, improved efficiency programmes and decreased reliance on fossil fuels.

Indeed, the issue of electricity industry sector governance has never been so controversial. As stakeholders in the debate over electricity policy scramble to ensure that the benefits of restructuring are not outweighed by the costs, environmentalists are increasingly seen at the forefront, and for good reason. Throughout much of the discussion, legislation and regulation that have set (ESI) restructuring in motion, there has been disproportionately little talk of environmental impacts and how to compensate for them. In the absence of efforts to account for environmental market externalities, there is no reason to assume a priori that competitive generation markets will operate in the best interest of the environment.

This paper aims to consider the short history of electricity restructuring in the UK and the USA for the purpose of evaluating the extent to which it has hindered efforts to reduce greenhouse emissions, or helped them (either coincidentally, or at some political, social or economic cost). The emphasis will be

[1] Acknowledgements and many thanks are due to the following individuals who offered valuable insights and suggestions: Charles Henderson (Total, UK), Benito Müller and Peter Greenhalgh (OIES), Sir Richard Southwood (Oxford), Duane Chapman (Cornell).

both on the interaction between electricity and environmental policy, and changes wrought by restructuring in the larger context of the political economy of decision making. The research will investigate how the USA and UK have varied their response to electricity market failures and environmental externalities in accordance with their specific institutions, political concerns, resources and pre-dispositions to market intervention.

The USA and the UK were chosen as case studies for this investigation for several reasons. To begin with, electricity restructuring has been underway in some form for over a decade in both countries, making it possible to look at emerging trends over an extended period of time. Secondly, because the two countries have taken distinctly different approaches, a comparative study reveals interesting contrasts and similarities, thereby offering further insight into the nature of the relationship between electricity restructuring efforts and trends in emissions. Finally, the electricity restructuring regimes in these countries are among the most well documented, and thus the necessary data were readily available.

The study begins in Chapter 2 with a chronicle of the past quarter century of electricity restructuring in the USA and the UK. Consideration is given to how high degrees of government intervention in the industry have traditionally been justified, and how many of these justifications have subsequently been invalidated or overruled.

Analysis of the relationship between electricity restructuring and emissions from power generation, which begins in Chapter 3, is arranged systematically within a simple, progressive conceptual model. The model is considered in its most basic stage, namely when it contains two variables only: market restructuring and carbon emissions.

Potential support for and refutation of a positive relationship between liberalisation and emissions is presented. Following a brief survey of the trends in carbon emissions from power generation in the UK and USA since 1970, the symmetries and tensions which exist between economic and political goals underlying market restructuring initiatives, and the environmental and social objectives which underline the need to reduce carbon emissions from generation are characterised.

Neither electricity restructuring nor emissions abatement has taken place in a vacuum. Both phenomena have been subject to and influenced by changes in prices, in levels and patterns of demand, in ideas about resource scarcity and in philosophies regarding optimal resource management. Particularly relevant to the relationship between restructuring and emissions have been the changes in environmental politics in both countries over the last three decades. To interpret practically the relationship between restructuring and emission levels, the changing political economy of environmental issues must be considered. Chapter 4 surveys the past quarter century of environmental politics in the two countries, with explicit emphasis on air quality issues and environmental legislation which have impacted directly on the electricity industry. It also introduces a framework for understanding how change in industry structure – through its effect on the relative political roles

and positions of firms, environmental groups and politicians – can shape policy and thus indirectly affect emissions levels.

New environmental policies or economic legislation do not automatically result in changes on the ground. Societies must establish the roles, priorities, jurisdictions and parameters of effective regulatory institutions before the ideals of market liberalisation or improved environmental quality can be realised. Failure to conceive of and establish efficient regulatory institutions can substantially inhibit the materialisation of economic or environmental ideals. Changes in the institutions have a significant role to play in determining the relationship between market restructuring, environmental political change and levels of carbon emissions. Chapter 5 considers the changing role of the electricity industry regulator. The regulatory institutions that existed prior to restructuring are considered, followed by an assessment of how changes in industry structure and environmental political priorities are shaping new institutions for electricity regulation.

Carbon dioxide emissions from generation present a unique and unprecedented challenge. Unlike other major industry emissions such as NO_x and SO_2, there are no practical means of employing an 'end of the smokestack' approach. Methods of carbon recapture, aside from the planting of trees, have yet to be fully developed. Consequently, three alternative approaches to carbon abatement remain:

(i) Reduce electricity generation. As this implies parallel reductions in economic productivity and prosperity, it is politically unpalatable.

(ii) Reduce the carbon intensity of the fuel mix through fuel switching. Although this can be politically difficult, it is far more feasible than option (i).

(iii) Reduce demand through increased energy efficiency.

Thus, to understand more comprehensively the relationship between market restructuring and carbon emissions abatement, the principal foci of industry decision making which come to bear directly on emission levels – namely generation mix and efficiency programmes – must be considered. The fuel mix variable is considered in detail in Chapter 6, while levels of investment in energy efficiency initiatives are considered in Chapter 7. Both variables are examined with three questions in mind:

(i) To what extent do the political and economic goals associated with restructuring and the environmental goals associated with emissions abatement coincide, such that the most economic choice in terms of sources for power generation or level of investment in energy efficiency is also the most environmentally sound choice?

(ii) To what extent is there tension between economic, political and environmental objectives in terms of choice of fuel mix or investment in energy efficiency?

(iii) To what extent, if any, is the tension between competing objectives resolved in favour of emissions abatement and how can this be achieved?

The main objective of this paper is to assess the implications of ESI restructuring regimes on trends in carbon emissions in the USA and the UK from a political as well as an economic perspective. By looking at how past political decisions have been made and how the political process has been evolving to

accommodate environmental externalities in electricity markets, it is hoped to reach a more thorough understanding of the current position of these two countries, with respect to moving closer to achieving Kyoto promises through changes in the electricity sector.

2. THE RESTRUCTURING OF THE ELECTRICITY INDUSTRY

2.1 THE RISE AND FALL OF THE WELFARE STATE

After the Second World War the role of the state in various socio-economic activities increased steadily in virtually every nation, the industrialised market economies of the USA and the UK being no exception. Both countries, but more notably the UK, witnessed an expansion in the scope of public service and government intervention as the basic elements of the welfare state were put into place. As one author observed, 'the economic revival of Europe and the subsequent boom of the fifties and sixties were ushered in, not by the unfettered operation of the market, but by state planning' (Martin 1993).

By the late 1970s, however, the role of the public sector in providing public goods as well as the role of government in managing the economy, were increasingly subject to neo-liberal attack. The array of weaknesses and complications besetting various public sectors around the world was seized upon by the New Right to substantiate their core ideological position. What unified the New Right was a strong, anti-state bias and a belief that the free market, and the competition it fostered between producers aiming to please customers, was better equipped to define and serve the public interest than the public sector, plagued as it was inevitably with bureaucracy and inefficiency.

In addition to empirical justifications, proponents of privatisation and market liberalisation found *theoretical* justification for their position in neo-classical property rights theory i.e. a lack of private property rights leads to a 'tragedy of the commons' (Clarke and Pitelis 1993); dispersed knowledge theory – i.e. efficient co-ordination and accommodation of innumerable individual decisions made on the basis of widely dispersed and interpreted information – can only be achieved through a market mechanism (Martin 1993); arguments for improved managerial incentives – i.e. private ownership and competitive market forces – subject managers to certain constraints leading them to make the most efficient, innovative and profitable decisions and policies; and more generally, the neo-classical theorem of welfare economics which states that every Pareto efficient allocation of resources can be achieved by allowing the competitive market mechanism to work (Gunn 1997). The link between private property, markets and liberty has also been used as a primary defence of privatisation, insofar as privatisation and deregulation regimes can be convincingly affiliated with larger goals of democracy and a society founded on individual autonomy.

The main aims of the UK and US governments of the 1980s were similar. By increasing reliance on private markets it was assumed that each nation could become more competitive and more efficient while at the same time reducing taxes, deficits and state influence. In addition to shared objectives, the two countries found obstacles and political complications in common. In both cases, as neo-liberal inspired privatisation and liberalisation moved from theory to practice, constraints on textbook restructuring strategies became more apparent as political, economic and social goals came into conflict.

The object of privatising and/or introducing competition into a monopolised industry is to reduce or even obviate the need for government to monitor the cost and quality of the product provided and consequently, to induce more commercial management, remove investment constraints and depoliticise the industry. With regard to the deregulation objective, it seldom proved possible for governments to abrogate control over the restructured industries to the free market. Uncompetitive market environments, unacceptable social outcomes, electoral strategy, concerns about national security, social stability, concern for the natural environment, and so on, have made it necessary for governments to establish detailed regulatory regimes as part of their privatising or restructuring legislation. Thus, although in both the USA and the UK, objectives of increased private investment and commercial management are being achieved, the conspicuous presence of government as a facilitator, enabler and regulator remains.

Privatisation and liberalisation regimes are inherently political processes. Industry restructuring invariably involves a diverse range of vested interests including private businesses, producers, suppliers, consumer groups, social interest groups, politicians, and regulators. The deliberation which ensues and the consensus that emerges is a function of the political culture, institutional arrangements, resource endowments and constellation of established interest groups. However, while economic considerations might signal some directions for change, it is political economy that most significantly determines relative priorities when changes are being made.

2.2 The Natural Monopoly Argument

Traditionally, the generation and supply of electricity has been viewed as a natural monopoly implying high thresholds for investment, technological constraints which constitute barriers to entry, and average costs which fall continuously as output level rises such that cost minimisation can only be achieved through monopoly. The existence of a natural monopoly is generally accepted as sufficient justification for government intervention and regulation, which aims to mimic market discipline in the absence of competition. This can be achieved either through public ownership with some form of parliamentary or ministerial control, as was the case in the UK, or through regulation of a private monopoly, as in the USA.

The transmission and distribution components of ESI continue to be seen as natural monopolies. However, the same cannot be said of generation and supply, where technological and legislative changes have contributed to the erosion of economies of scale, and thus the erosion of a natural monopoly position. Over the past two decades, the economics of electricity generation have changed dramatically with the introduction of new technologies such as high efficiency gas turbines and combined-cycle gas turbines (CCGT). Prior preference for large-scale (often nuclear or coal-fired) generating units which need a capacity of around 1000 MW to exploit economies of scale have been supplanted by a preference for small-scale production facilities which can be brought on line more quickly and cheaply (aero-derivative gas turbines can be efficient at scales as small as 10 MW) (Balzhiser 1996). An added benefit of the new gas technology is that the SO_2, NO_x and CO_2 emission levels are

significantly lower compared to more conventional fossil fuel technologies, which reduces both the costs and risks associated with environmental regulation. Technological advance combined with changes in legislation and patterns of demand has effectively lowered barriers to entry in generation; as natural monopoly conditions erode, pressure mounts on governments to allow private competition in generation.

2.3 The Public Good Rationale

Natural monopoly conditions are by no means the sole justification for government intervention. Governments have exercised ownership or control over the ESI not only in the interest of promoting efficiency and competitive prices in the absence of competition, but also because there are public good characteristics associated with its production and distribution. Because of the complications associated with capturing the full utility value of a public good in market transactions, such goods will usually be under-provided by private markets in the absence of government intervention (Jaccard 1995). In the context of electricity generation and supply, the choice of primary energy sources and generation technologies, risk management, system stability, demand-side management and decisions to invest in energy efficiency and renewables are just a few areas where it is very possible that private electricity generation and supply markets, left to their own devices, will not achieve socially optimal outcomes.

Thus, while the natural monopoly justification for intervention has been renounced as a consequence of real changes in economies of scale, the public good justification for government involvement and regulation has, if anything, increased in significance given growing public concern for environment, equity and sustainability. In spite of this, deregulation and privatisation regimes march forward. There is cause for concern that government intervention in the interest of public welfare, environmental stewardship, energy conservation, and so on is being undermined by the constraints of the free market. Producers and suppliers without regulatory protection from competition are, understandably, unwilling to provide uncompensated social services. This tension between the push for free market liberalisation and the need for market intervention so as to protect the public good and social service obligations will be considered in more detail in Chapter 3.

2.4 Privatisation of the UK Electricity Industry

The UK ESI was nationalised in 1947 with the establishment of the British Electricity Authority, responsible for generation and bulk transmission, while fourteen statutory Area Electricity Boards (AEBs) were charged with distribution and supply. It was hoped that by removing the profit motive, industry management would be able to act in the public interest, so bringing objectives of industry in line with those of the state (Palmer 1997). Support for government management and a restricted public sector did not come exclusively from the Labour Party, but also from successive Conservative administrations before Margaret Thatcher (Massey 1993). It is worth noting, however, that after the establishment of the Central Electricity Generating Board in 1957 which was responsible for both the national

grid and power station operation and construction, there were two unsuccessful attempts (one in 1969 and the other in 1976), to restructure the ESI. Both resulted from a dissatisfaction with the existing industry structure whereby the CEGB, which generated the bulk of industry costs, had little incentive to minimise costs as it enjoyed an inadequately regulated monopoly position (Surrey 1996).

Relationships between the government, parliament and ESI management were never easy. Although price regulation as currently practised was not part of the agenda, industry decisions were intrinsically linked to larger national economic management decisions and prices were increasingly subject to government control. Fortunately, in the decades following nationalisation, with real fuel prices remaining stable and plant efficiencies improving due to technical advances and scale economies, real electricity prices continued to fall, thus negating the need for much in the way of price regulation and creating less cause for conflict. In the 1970s, however, when efficiency improvements plateaued, demand growth fell sharply, and generators were left with surplus capacity and faced with an oil crisis, the ESI came under increasing political and public scrutiny.

2.4.1 The Thatcher Era

Under the government of Margaret Thatcher (1979–90) and John Major (1990–7), every public sector organisation was forced to justify its call on the public purse. The Conservative Party resolved to remove government from the day-to-day sphere of industrial decision making, to depoliticise economic and industrial decisions, to increase private investment and to reduce government spending. Although the 1979 Conservative manifesto did not mention privatisation explicitly, it became a central theme in Thatcher's second election campaign, and by her third term the scale of privatisation was immense. By early 1991, over 50 per cent of the public sector had been transferred to the private sector and 20 per cent of the population were shareholders, compared with 7 per cent in 1979 (Massey 1993).

The 1988 White Paper, *Privatising Electricity,* communicated the government's central belief that greater competition would create downward pressures on prices and ensure that the customer comes first (Cross 1996). The strategy was to separate and regulate those aspects of the industry which were natural monopolies, namely transmission and distribution, while encouraging competition in generation and ultimately supply. Other officially articulated government objectives included reducing government involvement in industry decision making, the widening of share ownership, raising government revenue so as to reduce taxes and public borrowing requirement, and increasing efficiency through competition.

The privatisation of the UK ESI was an inherently political process of mediating between competing objectives and negotiating among antithetically vested interests. What resulted can be understood in the context of the political and economic circumstances in which the new ESI was conceived, and through reference to a complex interaction between political factors. Liberalisation is a dynamic process which continues to evolve, with an ongoing and dynamic agenda of new and continuing political issues (Surrey 1996).

To begin with, there were age-old ties with the domestic coal industry that needed to be addressed before any kind of privatisation could be pushed through. The supply industry over the post-war period had become a vehicle for protectionism of the British domestic fuel market. The protective structure of support for coal, which had already been threatened by the defeat of the National Union of Mineworkers in 1985, was bound to be further imperilled as fuel mix decisions became the responsibility of private profit-seeking companies versus nationalised corporations. Indeed, wrapped up in the government goal of depoliticisation of the ESI was a desire to curb the power of the public sector unions and the labour movement in general, which was rooted in structures of the welfare state. Clearly, a move away from social welfare functions and nationalisation towards the harsher managerial practices and cost minimisation of the competitive market signalled trouble for the coal industry.

In the early stages, however, a more conspicuous conflict of interest was that between the wider share ownership and revenue raising objectives, and the more economic goals of market liberalisation and fostering competition. Although primacy was given in public statements to achieving enhanced competition and efficiency, when these conflicted with the political goals of successfully selling assets and encouraging broad share ownership (closely aligned to an industrial policy which sought to distance government from industrial intervention), the former economic objectives proved secondary (Clarke and Pitelis 1993). This compromising of commitment to competition and deregulation manifested itself in the government's willingness to accept below market prices and failure to split up the industry in a way that would bring about competition. Thus, a politically successful privatisation in terms of wide share ownership and profitability was ensured. It is estimated that an ESI industry with a book value of £45 billion was sold for only £15 billion (*FT Energy Economist*, 1998, vol. 198). Although this emphasis on attracting a diverse group of potential shareholders was rationalised in economic terms by arguing that it would, in the long term, lead to more available capital, the end result was that large stranded costs were borne by the tax payer (Henig et al 1988). What has provoked the most criticism, however, is not the low price tag, but the low level of competition created. The non-nuclear generating capacity that was ultimately sold to shareholders remained in the hands of two very large companies: National Power and PowerGen.

In fairness to the architects of UK ESI privatisation and restructuring, it is important to consider the political climate in which the regime was being negotiated. Clearly the government was aware that leaving 78 per cent of capacity in the hands of two companies while retaining 'golden shares' in both was not in line with the true spirit of New Right liberalism, but as in any political process, compromises had to be made, and vested interests had to be appeased. It was in fact a herculean task to privatise public assets, introduce competition, regulate the remaining natural monopolies and resolve nuclear and coal issues in a remarkably short time (the election was fast approaching), all against considerable opposition. Thus, execution of the British privatisation programme demonstrates a stark reality of economic policy making, namely that economic policies are executed by politicians who must

make decisions that yield the greatest political returns. With hindsight it is possible to find fault with the resulting regime, but it is perhaps unrealistic to have expected more.

On 31 March 1990 the assets of the CEGB were divided between four companies: National Power, PowerGen, Nuclear Electric and the National Grid Company. Although the government had intended to privatise all generation assets, at the eleventh hour nuclear plant was excluded from the sale for fear that investors would shy away from the associated risks. The generation market became semi-competitive composed of the two large companies, a government-owned nuclear company and what would become a growing population of Independent Power Producers (IPPs).

High voltage transmission was the responsibility of the National Grid Company which, as the exclusive holder of a transmission licence, was heavily regulated. Lower voltage distribution was assigned to the twelve Regional Electricity Companies (RECs), who were temporarily assigned an exclusive franchise market of captive customers whose maximum demand was less than 1 MW.

2.4.2 NGC and the RECs

Prior to vesting, the AEBs had been responsible for developing and maintaining efficient, co-ordinated, cost effective and reliable supply systems in their franchise area. Their responsibilities included the promotion of health, safety, welfare and environmental protection. In the newly organised ESI, the AEBs became RECs, monopolistic distributors of electricity in their franchised area. RECs are regulated extensively through Public Electricity Supply (PES) licences which permit them to supply electricity to any premise in their franchise area so long as they fulfil the various licence obligations. Regulation embodied in the licence affects prices charged, access to the distribution grid, generation security standards, promotion of energy efficiency and cross subsidies. All PES licences included an initial obligation to help sustain the market for British coal and government non-fossil fuel orders. There was also an Economic Purchasing Condition which required companies to purchase electricity economically. This was particularly contentious in the early stages of restructuring as it threatened coal's position as the fuel of choice for electricity generation. Finally, the licences require licensees to run separate businesses for their generation, distribution and supply interests, and oblige them to provide open access to their electricity networks for authorised operators or others who apply for use of or connection to the licensee's system. The UK was the first country to require open generation access as a general rule (Yajima 1997).

Most RECs were quick to become generators in the sense that they chose to invest as equity partners in generation projects. Many of the new independent producers entering the market did so with RECs as equity partners offering power purchase contracts. To prevent vertical re-integration between generation, distribution and supply, initial PES licences limited the generation capacity they could acquire to 15 per cent of their sales, although these conditions were relaxed in 1995.

In order to encourage competition in supply, second tier licences were made available to separate supply companies wanting to compete with RECs in the non-franchise areas using the transmission and distribution networks of the NGC and RECs. RECs were also required to obtain second tier licences if they were wanting to supply customers outside their area. Naturally, National Power and PowerGen sought these licences in the interest of vertical integration, but were limited to 7 per cent increase per year in any one franchise area (these limits were lifted in 1993). Second tier licensees were subject to lighter regulation than the first tier PESs.

The competitive market for supply has opened in stages. The original competitive market at vesting was limited to 5000 large industrial and commercial customers, while the rest of the franchise market remained 'captive'. In March 1994, the 50,000 customers whose demand exceeded 100 kW were granted the freedom to choose supplier. Finally, in 1998, retail supply markets were opened up entirely as territorial franchises in electricity supply were abolished.

In this restructured market there remained a need for price control to regulate grid system and connection charges, and to regulate REC transmission charges and supply prices so long as franchise areas remained. The government chose to employ the RPI-X price cap formula, which uses the retail price index to reflect industry costs without reflecting inefficient operation. The RPI is then reduced (or increased, as the case may be), by an expected rate 'X' of increased productivity and efficiency, such that the final price cap is approximated by 'RPI-X'.

The industry regulator is left with the difficult task of determining the appropriate value of X, a highly political process where the regulator, and to some extent the utilities, must grapple with problems of imperfect information. The initial X was set by government at vesting and it was intended that price control conditions would be reviewed by the regulator after a period of five years. This arrangement was intended to offer firms both the incentives to drive down costs and enhance efficiency, and the stability associated with reduced regulatory risk.

A shortcoming of the initial system was that it served as a disincentive to the RECs and the NGC to promote energy efficiency. As originally conceived, price controls were closely linked to the volume of sales versus the number of customers, which created a volume incentive (increases in demand side energy efficiency led to reduced company profits). Adjustments were subsequently made to reduce this anti-efficiency bias. This issue will be dealt with in more detail in Chapter 7.

2.4.3 The Pool

While in the public sector, there had been no cause to develop or employ a contractual framework in order to facilitate business relations between generators, suppliers and customers. In order for the privatised ESI to work, the CEGB's centrally planned merit order system needed to be replaced with a market mechanism. The Electricity Act of 1988 established a legal framework for the ESI, which included a 'power pool', designed to establish a new means of co-ordinating and governing market behaviour. Pool rules are delineated in a 'Pooling and

Settlement' agreement and embodied in the terms of the generator and supplier licensing agreements.

Because of the peculiarities of electricity generation and supply, the pool is arranged as a day ahead market versus a spot market, so as to allow for necessary co-ordination and planning. All licensed generators wanting to supply power the following day submit the details of their plant availability and half hourly bid prices to the National Grid Company by 10 a.m. the preceding day. Plants are dispatched based primarily on offer prices, although other factors including availability and system constraints are also considered. The system marginal price, the largest component of the normal pool price, is largely determined by the operating price of the marginal plant required to meet demand. Generators are paid the offer price of the most expensive station scheduled in any given half hour period. This system has been subject to increasing exploitation with the large generating companies taking advantage of their dominant market position and submitting excessively high bid prices for peak periods, confident that they will be the price setters. In an effort to limit the big generators' ability to influence prices, the industry regulator capped the pool price in 1994 and required the duopolists to divest a total of 6 GW of generation.

To reduce risk of volatile pool prices, producers have used hedging 'contracts for differences' which commit generators to pay the supplier the difference between the pool price and the agreed upon contract price for a certain number of units whenever the pool price exceeds a given price. Hedging has further impeded the development of competition in electricity markets.

At the time of writing, pool arrangements are undergoing a 'review of trading arrangements'. Reform aims to remove market distortions through the formation of a forward market in which customers and suppliers can contract bilaterally, the development of futures and options markets to enable companies to hedge risk, the development of a short-term bilateral market that would operate close to the time that the electricity was needed to allow parties to adjust their contract positions to accommodate changes in supply and demand, and the establishment of a settlement process for imbalances.

UK privatisation was motivated most strongly by a desire to increase commercial decision making, private investment and thus economic efficiency. The intent was to harness market forces wherever possible and to drive production and efficiency improvements through the use of market incentives versus centralised decision making. The privatised ESI was the result of much political debate and deliberation. An oligopolistic generation market, an incrementally competitive supply market, a power pool, a price cap formula approach to price regulation and a system of licensing were among the institutions which constituted the new ESI.

2.5 Deregulating the US Electricity Industry

ESI restructuring in the USA began from a very different position than that of the UK. To begin with, post-war reconstruction was not required on the same scale, which helps to explain why the advances of the welfare state and nationalisation of industrial policy never attained the degree of acceptance or success that they did in

Britain (Massey 1993). Americans have traditionally been more wary about taking private sector organisations into public ownership, preferring instead to curtail private sector activities through statutory regulation. So while the role of the state was never insignificant (Martin 1993), Americans have historically been much more inclined to have the private sector assume nominal management of public goods and services within the public domain. This is not to suggest, however, that there was no privatisation programme – in fact, significant American initiatives followed the British example. The hybrid nature of its public service provision has meant that the main liberalising phenomenon in the USA has *more often* been deregulation than privatisation (Henig et al 1988). Although the activities of privatisation and deregulation are certainly different, the two processes can be considered as separate means of achieving similar ends, namely improved market efficiency, curbs on trade union activity and depoliticisation of industry decisions.

Another important feature distinguishing the British and American liberalisation initiatives stems from the nature of the American political system, wherein sub-national governments are more obliged to accept greater responsibility for their own affairs. This has meant that deregulation has often occurred from the bottom up with local state governments tending to be more active than the national administration in implementing aspects of the liberalisation agenda.

The structure of the American electricity industry prior to any efforts to deregulate was also markedly different to that of the UK ESI prior to vesting. Historically, most electric power had been provided by vertically integrated, private investor-owned monopolies, while remaining electricity sales were carried out by publicly-owned municipal utilities, federal agencies and rural electric co-operatives. The retail rates and local sales of the investor-owned utilities were regulated by Public Utility Commissions (PUCs), while the retail rates and operation of the public utilities were controlled by elected officials, utility governing boards or federal government agencies.[2] A certain percentage of electricity, 7 per cent in 1970, was generated by non-utility generators, consisting primarily of industrial manufacturers who produced electricity for their own use (EIA 1993).

2.5.1 The Beginnings of US Utility Regulation: PUHCA and FPA of 1935

In the first two decades of this century, the number of electric utilities in the USA was declining, primarily because of consolidation and pyramiding of utilities through holding companies. Of the highly leveraged holding companies that survived during the prosperous 1920s, many collapsed following the stock market crash, unable to support their debts. By 1932, three large holding companies controlled half of the electricity generated in the United States.

In 1935, the Federal Trade Commission issued a report which criticised the holding companies for having excessive consumer rates, high debt to equity ratios and increasingly unreliable service. At that time, state regulators had no authority over the holding companies engaged in interstate commerce and federal regulation pertained only to the licensing of hydro-power (Abel & Parker 1998). The

[2] ICF Consulting Group (1997) *New Report on Electricity Restructuring and the Environment*, under the direction of the US EPA. 20 February 1997.

report served as a precursor to the Public Utility Holding Company Act (PUHCA) and the Federal Power Act (FPA) of 1935.

PUHCA established a regime of utility regulation which issued specific and separate powers to the state and federal governments. Trusts were dissolved and all interstate holding companies owning more than 10 per cent of an electric utility were required to register with the Securities and Exchange Commission (SEC) which had the power to break up holding companies or order them to divest assets. State regulatory commissions were charged with regulating intrastate utility activities (including the establishment of retail prices through a hearing process), which has resulted in an ESI today that is as heterogeneous as the states are diverse. Other sections of PUHCA dealt with access to company information, intercompany financial transactions and holding company operations.

The FPA defines the jurisdictions of federal economic regulation with respect to ESI interstate commerce. The principal responsibility for economic regulation of the ESI at the federal level was conferred upon the Federal Energy Regulatory Commission (FERC), including the governance of system reliability and wholesale rates. Thus, federal regulation was intended to fill the interstate regulatory vacuum that resulted from the states' jurisdiction being confined to instate commerce. PUHCA and FPA of 1935 are direct manifestations of the American philosophy characterised above; when faced with the natural monopoly conditions in the ESI, rather than take the enterprise into public ownership, industry was left in private hands and subjected to statutory surveillance and control.

For the third time since 1935, there is currently a large-scale effort underway to repeal PUHCA on the grounds that its provisions are antiquated, it impedes the transition to competition and its core objective of ensuring that the ESI is adequately regulated has already been achieved. Opponents to reform insist that PUHCA remains relevant in its protection against monopolies and anti-competitive behaviour, and that repeal should wait until it can be incorporated into comprehensive ESI reform legislation.

2.5.2 Sowing the Seeds of Competition: PURPA, 1978

When attempting to understand how the liberalisation of the US ESI unfolded, it is helpful to think of the process as an incremental transition rather than a sudden and distinct transformation of the kind observed in the UK. In some cases, regulators have unwittingly advanced liberalisation by allowing or encouraging activities, unaware of their competitive implications. In other instances, competition has spread in spite of regulators' opposition. In the American federal system, competition in the ESI has been emerging in a somewhat piecemeal fashion, with some states taking bold steps towards opening markets while others hesitate.

The passage of the Public Utility Regulatory Policy Act (PURPA) was the initial catalyst for the opening up of the generation sector to competition (Lee & Darani 1996). The Arab Oil Embargo of 1973 gave rise to higher prices, exacerbated inflation and heightened concern with respect to the nation's energy supply. Born out of this climate of concern was the National Energy Act of 1978, designed to

reduce national dependence on foreign oil, lessen vulnerability to energy supply interruptions and develop alternative energy sources. PURPA was one of the five statutes contained in this Act, and its primary goal was to encourage energy conservation and markets for alternative forms of energy by creating a new, privileged category of generators: qualifying facilities (QFs). Small-scale generators using renewables or cogeneration[3] which satisfied prescribed operating efficiency standards and in whom power companies did not have equity exceeding 50 per cent were eligible. Once a facility achieved QF status, it was guaranteed a market for the electricity it produced. Under section 210 of PURPA, utilities are required to interconnect with and purchase whatever amount of capacity is offered from QFs in their region. Power companies are obliged to purchase electricity from QFs at a rate set by their PUC based on the incremental cost to the utility to purchase or produce the same amount of electricity, referred to as 'avoided cost'. In some states, additional subsidies were provided. PURPA exempted QFs from most regulations faced by the utilities at the federal and state level, in addition to eliminating several procedural and planning problems that had previously served as barriers to entry for small power producers.[4] Section 211 gave FERC limited authority to grant QFs direct access to transmission lines (wholesale wheeling), although only one order was ever issued under this section (Abel & Parker 1998).

Not surprisingly, PURPA's offer of a guaranteed market, together with the tax breaks and minimal regulatory risk, and the emergence of more efficient, small-scale generation technologies, prompted a flood of new projects, particularly in hydro and cogeneration (Arenchild 1996). In addition to PURPA, another Federal Energy Act statute, the Fuel Use Act (1978), prohibited utilities from using gas to fuel new generating technologies. Consequently, QFs were able to take advantage of low gas prices and new CCGT technology. Although FUA was repealed in 1987, by this time small power producers had gained a foothold in the market (Abel & Parker 1998).

Initially, the utilities did not welcome the new competition from non-utility generators (NUGs), although ultimately some found that purchasing from QFs had advantages over constructing new capacity themselves. Throughout the 1970s and early 1980s, cost overruns on the construction of new nuclear facilities and, to some extent, new coal plant had reached the point where regulators acting in the customers' interest could no longer allow these costs to be integrated into the rate base (i.e. regulators did not allow utilities to pass on the full capital costs of expensive new generation plant to the customer). This effectively increased regulatory risk. Consequently, as several authors have pointed out, acquiring new capacity from QFs who were exempt from the bulk of regulatory requirements became an increasingly attractive, low risk alternative for utilities looking to increase capacity.

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[3] Cogeneration is generation that sequentially or simultaneously produces electric energy and other forms of energy such as heat or steam using the same fuel source. PURPA created an enabling environment such that reliance on self generation by industrial and commercial customers using cogeneration was a feasible and competitive alternative to utility supplied electricity.

[4] Public Utilities Regulatory Policies Act of 1978 (Public Law 95-617), Section 2.

In terms of regulatory impact, PURPA represented a shift of responsibility from the federal to state governments. It offered new tools to state regulators and allowed each state broad latitude for implementation. While Congress insisted that each state demonstrate that it had considered the federal goals embodied in PURPA, the state regulatory commissions had final decision-making authority. FERC broadly ruled that a utility was not required to pay more than avoided cost, but it was up to the state to define both 'avoided cost' and the length of QF contracts. Consequently, the real impact of PURPA on utilities and rate payers was determined not at the federal but the state level (Arenchild 1996).

Although early implementation in most states resulted in utilities paying for non-utility generated electricity at prices equal to avoided costs associated with previously planned projects, in most cases QF supply exceeded demand at this price. Utility commissions thus began to establish bidding mechanisms to determine market based rates, so moving one step closer to wholesale competition.

Throughout the early 1980s, when PURPA was first being implemented, there was no growth in the ESI. Net generation declined for the first time since 1945, and high prices together with a sluggish economy resulted in decreasing demand. Many of the long-term avoided cost rates determined by the utility regulators in the late 1970s and early 1980s were based on erroneous forecasts of sharply rising oil prices and swiftly increasing demand. Consequently, by the late 1980s there were QFs who were assured of receiving rates above market prices well into the 1990s. Most avoided cost rates were revised around 1987, at which point applications for QF status began to decline (EIA 1993). The more long-term effects of PURPA have varied from state to state. In general, more investments in renewables occurred in those states where regulators set higher rates of avoided costs and longer contract terms. As some utilities which already had sufficient or surplus capacity were forced to purchase QF generation, many argue that PURPA has effectively increased capital costs of generation and thus, higher costs to consumers.

PURPA is currently being considered for repeal by Congress. Reform proponents argue that it is obsolete, anti-competitive, and that cogenerators and renewables no longer need promotion and protection. Opponents of repeal protest that there remains a need for legislation which promotes conservation and fuel diversity, and that any changes to PURPA should be made within more comprehensive industry restructuring legislation.

Perhaps unwittingly, the architects of PURPA created a new economically and politically powerful interest group, the independent power producers (IPPs), who ultimately began looking for ways to enhance their profits and to sell directly to the retail customer. Increasing pressure from IPPs has been cited as a primary factor in pushing forward electricity industry deregulation in the ESI, together with shrinking economies of scale in generation and the power industry management problems that arose within a regulatory context that led to increased dependence on dispersed power. Rate differences among state utilities have grown as high as 80 per cent between contiguous regions which served as grounds for lobby for competition (Flavin & Lenssen 1994; Yajima 1997; IEA 1996).

2.5.3 Further Endorsement of Competition in the ESI: EPAct (1992) and Order 888 (1995)

In 1992, President George Bush signed the Energy Policy Act (EPAct) which further liberalised the power industry by opening up the transmission grid, deregulating the generation sector and taking the ESI closer to a competitive wholesale electricity market. The Act made it much easier for utility affiliated and unaffiliated power producers wanting to compete along with the QFs to bid to supply power and thus enter the wholesale market. Title 7 of the Act created another new category of power producers, Exempt Wholesale Generators (EWGs). An EWG is an IPP that is engaged exclusively in the business of owning or operating a plant generating electricity for sale at wholesale. EWGs were exempted from PUHCA's corporate and geographical restrictions. Unlike QFs they are not regulated and can charge market based rates, although utilities are not obliged to buy their power. With state authorisation, utilities could designate specific generation facilities as EWGs, thereby terminating their status as rate based facilities.

EPAct's second major provision was to strengthen the authority of FERC to order utilities who owned transmission assets to offer open, non-discriminatory transmission services to all parties as a means of facilitating wholesale transactions and thus competition. This, in essence, constituted a formal indication from Congress that the ESI was heading in the direction of retail competition. While the Act made it clear that FERC's authority to order wheeling did not extend into the retail sector, larger industrial retail customers began to lobby ever harder for the right to bypass the middleman (Joskow 1993). State PUCs also understood EPAct to be a sign of things to come, and many began to re-evaluate their regulatory frameworks in order to prepare for increased competition at the retail level.

On 25 March 1995 FERC issued a Notice of Proposed Rulemaking proposing to allow more competition in the generation sector by bringing an end to utilities' dominance of transmission facilities.[5] In April of the following year, FERC issued two final rules, Order 888 and 889, in an effort to 'remedy undue discrimination in transmission services in interstate commerce and provide an orderly and fair transition to bulk power markets' (Abel & Parker 1998). Order 888 requires transmission owners to file open access non-discriminatory transmission tariffs containing minimum terms, comparable to the terms and conditions they provide to their own generators. The rule also allowed for recovery of stranded or transitional costs which arise because some generation assets will not be competitive in the changed market environment (Jaccard 1995). Order 889 established an information system that gives all users equal access to transmission information. The rule also required utilities to separate their wholesale marketing and transmission operation functions. Although these Orders were significant in terms of eliminating monopoly power over transmission systems and making the generation business more competitive, because 30 per cent of the grid is owned by federal power marketing administrations which are beyond the reach of FERC, the legislation was not all-encompassing.

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[5] FERC Notice of Proposed Rulemaking, docket nos.RM95-8-00, RM94-7-001.

The next logical step would be, of course, to introduce retail competition by allowing generators to sell power directly to customers. There is considerable pressure for retail wheeling in the USA, mainly from large industrial consumers such as energy-intensive industries who are hoping to cut costs.[6] Retail price differences between neighbouring utilities can be as great as 50 per cent, so some industrial customers have a lot to gain (Flavin & Lenssen 1994). At least seventeen states have already enacted legislation providing for retail competition. Leading the way is California where a landmark bill to deregulate the state's $23 billion electricity industry was passed in 1995 including, among other things, provisions for retail wheeling (Yajima 1997). On 31 March 1998, California became the first state to offer consumers choice of electricity providers. It will be some time, however before all states embrace the retail wheeling concept, which is fraught with complications ranging from stranded assets to conflicts with current long-term planning practices of the power sector.

2.5.4 Pending Comprehensive Electricity Restructuring Legislation: S.2287

There is a growing view that an over-arching Federal ESI restructuring bill is needed. As states such as California move forward with retail competition while others stay behind, there is concern that broader questions of transmission policy and system reliability will become unmanageable without a unifying national strategy. As one analyst commented, 'only a federal bill will pre-empt a patchwork quilt of state legislative actions that could turn US electricity restructuring into a regulatory dog's breakfast' (*FT Energy Economist*, April 1998).

Various attempts at a comprehensive restructuring bill have been discussed in Congress and review committees for several years. After scores of workshops, public meetings and hundreds of pages of transcripts, the Clinton administration introduced its long awaited electricity restructuring bill, S.2287, in July 1998. It is, in essence, a Democratic bill, especially in contrast to an earlier and equally comprehensive bill introduced in 1996. With respect to retail wheeling, it includes a flexible mandate which requires all utilities to introduce retail competition by 2003, but allows states and non-regulated utilities to opt out of the competition mandate if it is determined through a public, participatory process that consumers would be better served by an alternative policy. FERC has the authority to regulate the use of transmission lines and to order a utility to divest certain assets if it is found that the utility has excessive market power. PUHCA and PURPA purchase obligations are repealed, although existing contracts will be allowed to run out.

In terms of social policy considerations, the Bill incorporates a number of measures to ensure that certain social concerns and interests are protected. A Federal Renewable Portfolio Standard will be established to guarantee that a minimum level of renewable generation is developed. A $3 billion Public Benefit Fund will be created to match state funds for low income assistance, conservation

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[6] The highest electricity prices in the continental USA can be found in California, New Jersey, New York and New England, precisely the states at the forefront of the restructuring debate.

and energy efficiency programmes, and an interstate trading system for NO_x is called for. Although there was a strong lobby to include measures to meet greenhouse gas emissions abatement targets, it was decided that to do so would drastically reduce the chances that the bill would pass successfully.

Incremental legislative changes over the past two decades or more have wrought dramatic changes on the industry structure. As would be expected, there has been a significant increase in non-utility generators. Throughout the 1970s, NUG capacity in the USA totalled 19 GW and consisted mostly of industrial co-generation. It declined steadily until 1979 when the passage of PURPA, in concert with other economic, regulatory and technological factors, contributed to a 13.9 per cent per year growth rate in NUG capacity between 1985 and 1991, compared with 1 per cent per year for utility capacity increase. By 1991 NUGs were generating 9 per cent of electricity, and in 1992 they added more capacity than utilities (EIA 1993, 1996; Hidy & Spencer 1994). Currently, NUGs account for 10 per cent of US generation, 50 per cent of which is sold to power companies.

Changes have also occurred within the IOUs which since the late 1980s have been involved in wholesale wheeling and have increasingly relied on more purchased power. Prior to formal restructuring, 77 per cent of capacity was owned by the IOUs. As competition increased and IPPs proved very adept at constructing smaller-scale, efficient plant at low cost, the dominant position of the IOUs has changed. Private utilities have had to develop ways to stay competitive. As a group, the IOUs lowered operations and management costs by 22 per cent between 1986 and 1996, mainly through staff reductions. Increasingly, mergers and acquisitions are becoming more commonplace in an attempt to reduce costs and eliminate redundancies: over the past eleven years, 39 IOUs have merged. IOUs are increasingly diversifying into non-utility businesses such as energy service companies, independent power production and so on in an effort to remain viable. Finally, another pervasive trend among the utilities, investor and publicly owned, is a massive sell-off of generating assets. It is said that 20 GW of utility generation has already been sold with an additional 35 GW 'on the auction block' (*FT Energy Economist*, March 1998). As profit margins in generation narrow, large utilities are getting out of the business.

Overall, the Acts and Orders discussed here have played a critical role in the transformation of the US ESI, from an unregulated, vertically integrated, investor owned, monopolised industry to one which is regulated, disintegrated, and increasingly competitive.

3. THE FUNDAMENTAL TENSION

3.1 ENVIRONMENTAL EXTERNALITIES AND THE ELECTRICITY INDUSTRY

Two common justifications for government intervention in the ESI were discussed in the previous chapter. While it was determined that the natural monopoly argument has been eroded by legislative, technological and economic developments, it was suggested that the public good rationale continues to be relevant. Even the most devout libertarians acknowledge that the free market economy has its limitations, and that purely laissez-faire policy will yield unacceptable social outcomes in some contexts.

It was also suggested that the public good rationale for the introduction of regulation or other policy measures is actually increasing in relevance as public concern for current social ills and environmental issues mounts. Since private enterprises often serve to create various negative externalities themselves, it is not unlikely that increased privatisation would exacerbate undesirable outcomes (Haque 1996). Indeed, one of the core hypotheses of this paper is that the erosion of more conventional rationales for government intervention in the ESI is more than offset by the increasing need for intervention on the basis of an emerging environmental externality rationale (Jaccard 1995).

In the perfectly competitive conditions assumed by neo-classical arguments for Pareto efficient resource allocation, markets are complete: no producer or consumer can influence the market price, all participants have access to perfect information, and marginal private cost is equivalent to marginal social cost. When the latter condition is not satisfied, i.e. when a positive or negative effect of some activity is experienced by a third party but is not accounted for in market transactions, an externality is said to exist. The existence of an externality is synonymous with market failure and therefore should be grounds for intervention in markets so as to compensate for that failure.

According to Flavin and Lenssen (1994) electricity generation and distribution constitute one of the world's largest businesses with annual revenues exceeding US$800 billion. Electric utilities are also large users of environmental resources and their emissions increasingly place strain on the absorption capacity of the atmosphere. As a former US Secretary of Energy once commented, 'to say that electricity is "just another commodity" is akin to proposing that "oxygen is just another gas"' (Cavanagh 1996). Electricity generation and use are by no means environmentally benign; on the contrary, they stand as controversial terms in the current environmental debate.

Because depreciation calculations in industry corporate accounts consider physical plant equipment exclusively, the unfettered free market overlooks both the costs of wearing down the natural resource base and the cost of repairing the damage. Over the past two decades, three key negative environmental externalities have come to be associated with electricity generation: coal has been identified as a main culprit for acid rain, the social risks of nuclear power have become painfully

apparent, and the link between fossil fuel generation and global warming has convincingly been demonstrated (Schelling 1998).

In the USA, electric utility plants are among the largest sources of air pollution, accounting for 36 per cent of the nation's CO_2 emissions (and thus 10 per cent of global CO_2 emissions), 33 per cent of NO_x emissions and 72 per cent of SO_2 emissions (Bernow et al 1998; Carlin 1997; EPA 1997). In the UK, the electric utilities contribute approximately 24 per cent of UK CO_2 emissions, 65 per cent of SO_2 emissions and 22 per cent of NO_x (DTI 1998a). All together, electric utilities have accounted for 50 per cent of the world's growth in energy based CO_2 emissions since the 1970s.

3.2 ESI Emissions in the UK

Figure 3.1 shows UK CO_2 emissions from 1970 to 1997. In the early 1970s, UK emissions were high relative to GDP due to a high economic dependence on coal.[7] Following the oil crisis of 1974, economic growth declined while efficiency rates accelerated leading to an overall decline in both energy use and energy-related CO_2 emissions. With oil-shock related concerns ebbing by 1976, energy efficiency rates fell into decline, causing emissions to increase once again. Only after the second oil shock in 1979 did efficiency improvements, and thus emissions reductions resume, enhanced by a permanent decline in heavy industry during the 1979–81 recession. In the mid-1980s, improvement in emission levels due to reductions in energy intensity were compromised as fuel switching away from coal was halted, partly due to reduced oil use for generation. In recent years there has been an overall decrease of 8 per cent in CO_2 emissions (between 1990 and 1997), but an overall increase of 8 per cent in energy consumption. Although the bulk of this decrease can be explained by a large-scale switch from coal to gas in electricity generation, the proportion of generation fired by coal remains high relative to other OECD countries.[8]

Under the 1992 Climate Change Convention, the UK resolved to reduce CO_2 emissions to 1990 levels by 2000, thus offsetting a predicted rise of 10MtC. This target proved relatively easy to achieve, largely on account of the widespread fuel switching in electricity generation from coal to gas, often referred to as the 'dash for gas' (dealt with in more detail in Chapter 6). The Labour government has since set more challenging targets. In Kyoto, the EU accepted a target of an 8 per cent reduction from 1990 levels of CO_2 emissions by 2008–12. In a subsequent meeting of EU environment ministers to determine how the burden would be shared, the UK agreed to reduce greenhouse gases by 12 per cent of 1990 levels by 2008–12, while setting a more challenging domestic target of 20 per cent over the same time period.

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[7] The composition of emissions from electric power plants is partly a function of the completion of the combustion process. In terms of carbon emissions, coal, natural gas and distillate or residual oils are all carbon-hydrogen compounds that produce CO_2 and water vapour when combusted. All fossil fuels are not created equal, however, and carbon emission coefficients will vary according to the properties of the fuel stock. The IPCC's carbon coefficients for coal, oil and natural gas are 25.8 ktC/PJ, 21.1ktC/PJ and 15.3 ktC/PJ respectively (Schipper et al 1996).

[8] The UK is ranked eighth in terms of its proportion of energy needs met by fossil fuels and ninth in terms of the share of its energy needs met by coal (IEA 1998).

This latter target will require the UK to reduce its emissions a full 23 per cent below current 2010 projections (IEA 1998).

The role of the UK ESI in meeting past and future abatement targets cannot be over-emphasised. CO_2 emissions from power stations have decreased by over 25 per cent since 1990 and have accounted for over 90 per cent of the overall decrease in UK emissions. Approximately one-third of this decrease at power stations is attributable to efficiency improvements while the remainder can be explained by the dash for gas and greater emphasis on nuclear output (DTI 1998b). This has effectively offset the rise in emissions from other sectors (Electricity Association 1998). Given the formidable difficulties associated with reducing emissions in transport or manufacturing and industry, it is widely acknowledged that achievement of Labour's 20 per cent target will continue to rely heavily on improvements in the ESI, which has already halved the average CO_2 emissions over the past two decades (Parker 1998). The most recent UK Climate Change Strategy relies heavily on the ESI for the achievement of current targets. Fuel switching in electricity generation will provide 62 per cent of reductions, growth in CHP accounts for 10 per cent and efficiency programmes contribute 13.5 per cent. Thus, the ESI will be expected to achieve over 85 per cent of future CO_2 reductions in the UK.

3.3 ESI Emissions in the USA

The USA has a poor track record with respect to its response to climate change. As the largest coal producer, the second largest oil and natural gas producer, and with an economy dependant on low priced domestic fossil fuels, proactive abatement policies are politically very difficult to support in an American context (Grubb 1990). The United States is the world's greatest energy consuming nation, and its CO_2 emission rates are among the highest in the world, both on a per capita and per unit GDP basis. Transport and electricity each account for one-third of US emissions, the remainder coming from manufacturing, residential and commercial activities.[9]

The USA has signed the 1992 Framework Convention on Climate Change and President Clinton has since reaffirmed America's commitment to reducing greenhouse gas emissions to 7 per cent below 1990 levels. Current projections suggest that a carbon emissions reduction of 390 million tonnes per annum is required just to stabilise US emissions in 2010 at 1990 levels. The Clinton administration has secured over $570 million to fund various research and development projects to help meet this formidable obligation.

The USA has experienced long-term changes similar to the UK in terms of electricity sector emissions, albeit on a different scale. One can make out the footprints of the first and second oil shocks, the recessions of the early 1980s and early 1990s. By 1991, total emissions had returned to 1973 levels, having risen from a low in 1982 to a high in 1989 and falling with the 1991–2 recession. Short-term trends differ significantly from those observed in Britain, however. CO_2 emissions from all fossil-fired generation increased almost 5 per cent from 1995 to 1996, a

[9] Interlaboratory Working Group on Energy Efficient and Low-Carbon Technologies (1998).

one-year increase which exceeds the cumulative increase in emissions from 1990 to 1995. The factors contributing to this increase will be addressed in Chapter 6.

To demonstrate its commitment to the Kyoto targets, the Clinton administration developed its Climate Change Action Plan (CCAP) which comprises 44 programmes in areas such as energy efficiency standards, voluntary abatement agreements and consumer information, which together will contribute to an estimated reduction of 108.6 MMT of greenhouse gas reductions. Similar to UK strategies, the plan places heaviest emphasis on ESI initiatives. Over the long term, the plan seeks to reduce the use of coal and increase the use of natural gas and renewables. In the short tem, the emphasis will be on demand-side strategies that encourage electricity conservation and energy efficiency.

3.4 The Fundamental Tension

Chapter 2 chronicled a continuing phenomenon of expanding liberalisation and deregulation of the electricity industries in the USA and the UK. The previous sections characterised another trend, namely that of governments making ambitious promises on behalf of the ESI to cut back on emissions, requiring electric utilities to play a leading role in the high profile fight against global warming. Considering these two trends together begs the question: is there not a fundamental tension between the desire to deregulate the market and the obligation to legislate protection of long-term public welfare and the environment?

In the current context of electricity restructuring and emissions abatement obligations, this tension has manifested itself as a multi-billion dollar question: can the goals of increased economic efficiency, increased profits, and lower prices associated with market liberalisation, and the goals of increased energy efficiency, decreased fossil fuel generation, decreased emissions associated with environmental legislation be simultaneously realised? Daunting as the question may be, and tempting as it is to hope that a socially acceptable balance will resolve itself, it is important to proactively invest time and money in addressing this problem now, when electricity industries are being restructured, energy policy is being re-evaluated, regulatory institutions are being reoriented and, most importantly, priorities are being renegotiated. It is easier to demand from the outset that emissions reduction takes appropriate precedence over the goals of market liberalisation and to structure markets and regulatory bodies accordingly, than to have to claw back 'the right to pollute' from firms at a later stage.

This implies a further question, namely what constitutes 'appropriate precedence'? Of course, this is a relative and thus political term. As any effort to internalise the external costs of electricity generation and consumption will likely involve higher costs associated with fossil fuel use, there is bound to be tension between firms wanting to be more cost competitive and society needing to be more environmentally conscientious. The manner in which these discordant values clash, the nature of the attempt to resolve the conflict and the value of the compromise that emerges will be largely a function of the prevailing political economy. Chapters 4 to 7 will be devoted to delving into the politics of this problem. The rest of this chapter provides a more rigorous characterisation of why there is such potential for

conflict between the environmental ethic and the free market economy in the context of the electricity industry.

The successful liberalisation of the telephone industry is often used as an example of the types of economic and efficiency gains that can be reaped by 'allowing the market to work'. In the realm of environmental externalities, this analogy falls apart. Telephone poles and microwave towers do not have the same environmental implications as nuclear reactors and coal plants. There is reason to believe that increased competition in electricity markets can and has undermined environmental protection, and therefore, in the context of the ESI, the debate about whether public or private management is best needs to be broadened to include the more significant forces determining the cost of the power system, many of which are environmental in nature (Cohen 1993). If the goal is to structure, regulate and manage the industry in a socially optimal way, the social and environmental dimensions of the various management alternatives must be accorded due weight.

Regulated utilities in both the USA and the UK have, in the past, been responsible for a variety of 'public purpose' programmes. In a regulated monopoly, it is possible for regulators to pursue social and political goals that are paid for by requiring utilities to charge prices for services which are higher or lower than they would be in a competitive market. A key question that arises when confronted by the restructuring process is what will become of public support for energy efficiency, renewable energy, research and development and other important public programmes mandated in a regulated system, but unlikely to survive in the context of a free market? In a competitive environment, there are formidable economic disincentives working against generators and suppliers voluntarily embodying a public service ethos.

The structure of the market itself will not change the level of electricity sector emissions, but the ways in which it changes demand, technology choice, infrastructure patterns and, industry incentives have, and will continue to have, profound effects on the way electricity is produced and consumed, and consequently on the environmental impact (Corry et al 1996). Policy initiatives such as open access transmission and retail wheeling which encourage competition in generation and supply are likely to result in new economic incentives with respect to consumer behaviour and operation and investment in generation. Those changes which could affect changes in overall emission levels are summarised below.

3.4.1 No Tension, Only Mutual Reinforcement

Before endeavouring to characterise various manifestations of the aforementioned 'tension', it is worth considering the arguments of those who suggest that there is no tension to begin with, i.e. that it is possible to shrink government without shrinking away from its social welfare responsibilities, and therefore no need to worry about changes in market conditions exacerbating environmental externality problems (Henig et al 1988). Such arguments typically rely on the distinction between government responsibility and government provision, a definition of monopoly as an inefficient and unresponsive institution, and the portrayal of government regulation

as anti-democratic. In terms of electricity restructuring and its potential deleterious environmental effects, libertarians have three arguments:

First, it has been argued that deregulation in the ESI does not imply deregulation of the environment, and thus there should be no cause for environmental concern. As Schelling (1998) puts it, 'I can see no trend towards massive or even significant deregulatory zeal where externalities are involved.' Furthermore, industry representatives are quick to point out that, on the contrary, environmental regulations have significantly increased (Begley 1997). While this may be true, it does not eliminate the possibility that new market regimes may be altering industry landscapes and incentives, changing firm behaviour, and thereby creating new tensions and problems which present regulatory structures are not designed to cope with.

A second argument, presented by American Congressman Thomas Bliley, among others, insists that, 'the free market, not government regulation, is the way to ensure environmental protection'. To support his claim, he cites the infamous green pricing programmes which offer customers the freedom to choose to pay more for electricity produced from environmentally benign sources. Indeed, pilot retail wheeling programmes indicate that significant numbers of customers say they are willing to pay a green premium, and retail marketers enthusiastically suggest that they anticipate green power will be a profitable way to differentiate their product.

Initial experiments with green electricity and competition in California, however, indicate that green power programmes are not showing all the makings of a panacea. To begin with, many are based on existing utility-owned renewables that are already paid for by ratepayers, i.e. they are not helping to bring any additional renewable capacity on line. Second, green marketers report that recruiting a new customer costs approximately US$100 in marketing, thus increasing per kWh rates by 20 per cent. Finally, in California, 33 per cent of all residential consumers would have to purchase 100 per cent of their electricity from green sources just to maintain current levels of renewable capacity. To date, less than 0.7 per cent have opted to pay green premiums for over 50 per cent of their electricity bill.[10] If California's experience is any indication, green marketing schemes will be insufficient substitutes for government subsidy and regulation.

Finally, it has been suggested that restructuring the industry will actually reduce emissions by hastening investments in newer, cleaner plants. Indeed, in the UK, where electricity restructuring was followed by a rather dramatic decrease in industry emissions, this argument appears to be empirically supported. However, a closer look reveals that this resulted from fortuitous economic and political circumstances which favoured a shift from coal to gas, versus an innate propensity for freer electricity markets to favour emissions abatement. America provides a case in point, where increased liberalisation of markets through the implementation of Order 888 has meant increased emissions as older, under-utilised coal plants are being brought back into production. Furthermore, any emissions abatement that has or will occur as a result of improved supply-side efficiency will potentially be

[10] Public Citizen (1998), *Proposition 9: A Greenlight for Sustainable Energy in California*, September.

offset by other effects of increased competition, including greater consumption due to lower prices, early decommissioning of nuclear plants and changing load factors.

While the arguments that increased competition will, in fact, promote emissions abatement certainly contain elements of truth, these are overshadowed by other, less optimistic considerations which are now discussed.

3.4.2 Changes in Generation Patterns

Future levels of ESI emissions will depend to a large extent on what type of generating units are retired, repowered and constructed, in addition to how the units are dispatched and operated. Decisions made by competitive, profit maximising generators are likely to differ from those of the large, regulated utility owners of the past. To begin with, by reducing barriers to market entry, power suppliers have greater flexibility in seeking lower cost electricity providers. To the extent that the lowest cost generators are fossil fuel plants with high emission levels with surplus capacity, competition will increase the utilisation of these facilities and thus exacerbate pollution problems.

Competitive markets could also increase incentives for electricity suppliers to extend the use of old, idled and mothballed plants through repowering and other life extension investments. Any comparison between the marginal cost of increasing the use of an older, depreciated facility and the cost of constructing a new one will generally favour the former. The fewer new plants that are built, the more demand growth will be met by existing facilities. And to the extent that the older facilities have higher emission levels than new plants that might have been built, net emissions will rise. Certain nuclear facilities which were economically viable in a regulated environment may not be able to compete. It is therefore likely that generators will respond to increased competitive pressures by backing out of high cost nuclear power. To the extent that the void left by the accelerated retirement of nuclear generation is filled by fossil fuel plant, emissions will increase.

Another possible source of emissions increase is greater use of market based, real-time pricing. 'Load factor' is calculated as average load divided by peak load. It has been demonstrated that load factors will increase under retail competition, as suppliers employ new pricing mechanisms to maximise sales opportunities and shift demand to off-peak periods. To the extent that the more inexpensive baseload plants are coal plants, as is largely the case in both the UK and the USA, higher load factors will result in increased emissions (ICF 1997; EPA 1997).

3.4.3 Increased Cost of Capital

Electricity generation is a risky business. Demand may be less than forecast, relative fuel prices may rise unexpectedly and government may impose new and costly regulations. Under the old regimes of public or regulated private monopoly, any unforeseen cost increase could be passed on to the captive customer and thus risk was largely borne by the consumer. To some extent, this created incentives to overbuild, to discount future price volatility or neglect to anticipate regulatory changes (Lee and Darani 1996).

Changes wrought by this reallocation of risk are already quite visible, especially in the UK. Utilities are more hesitant to invest in larger facilities and more concerned to diversify generation portfolios and to hedge risk. Increased susceptibility to environmental regulatory risk, provided sufficient risk exists, should result in stronger incentives to weigh the possibility of future emissions restrictions in investment decisions.

Another consequence of risk reallocation has been higher costs of capital. Under competition, generators are no longer guaranteed a fixed rate of return on investments and therefore need a higher expected rate of return on investment and a lower debt to equity ratio to compensate for increased risk. This implies that the annual cost of new generation is higher (further increasing the likelihood that lifetimes of existing plant will be extended).

A second important implication of higher costs of capital is that discount rates are increasing; thus optimisation based on net present value will value near term costs and benefits more than longer-term impacts (ICF 1997). Vertically integrated utilities have worked in the past to minimise costs over a 20–30 year time frame, but competition inevitably implies shorter time horizons. The environment, on the other hand, is fundamentally a long-term concern. The shortening of horizons, together with the increased decentralisation of decision making that comes with competition, causes fundamental problems for traditional means of environmental policy implementation which tend to involve medium- to long-term planning and centralised co-ordination. Investment decisions based on short-term market price signals are also less likely to favour developing renewables technologies, as their long-term sustainability and fuel savings advantages become less valuable relative to the significant initial investment required.

3.4.4 The Changing Political Economy of Regulation

Market liberalisation changes the goals of companies and the means by which they attain them. As competition intensifies, profit margins narrow and firms look for ways of hedging and eliminating risk, the costs of environmental regulation become more of an issue. Consequently, industry's role in opposing environmental regulation has shifted from a reactive to a proactive stance. The industry lobby is much more of a force to be reckoned with, while environmental groups are less able to influence investment decisions in conventional ways as they are no longer centrally co-ordinated by government policy or regulation.

3.4.5 Increased Demand

Several studies of competition and ESI CO_2 emissions in the UK or the USA have come to the conclusion that a significant driver for increasing emissions is increasing electricity demand resulting from decreasing average retail rates (for example see Palmer & Burtaw 1997; Lee 1994; ICF 1997; Joskow 1993). Reductions in retail electricity rates due to competition could produce substantial increases in demand in aggregate, and in the absence of emission caps, this will translate into increased emissions. How governments choose to deal with stranded assets will also have a large impact on rates. To the extent that governments allow utilities to be

compensated for their stranded investments, electricity prices will fall less dramatically.

Figure 3.2 demonstrates the changes in retail price (in 1997 US$) and electricity consumption in household and industry sectors in the UK. Immediately following privatisation, prices to large industrial customers fell while domestic retail prices actually increased due to higher electricity purchase costs and the initial RPI-X price cap for distribution. After this initial tariff increase, prices have fallen in real and nominal terms since 1991. Between 1991 and 1995, largely as a consequence of thermal efficiency improvements and low fuel prices, real prices fell 15 per cent overall for domestic consumers and 21 per cent for moderately large users (excluding VAT).[11] Although prices have fallen significantly, because the pool price has been largely determined by the two biggest generators, they have remained higher than would be expected in competitive conditions. With reform of trading arrangements and the introduction of full retail competition, prices can be expected to fall still further. As the UK Department of Trade and Industry (DTI) estimates that the long-run elasticity of demand is -0.1, this implies that the overall effect of liberalisation on rates of electricity consumption will be small, although lower prices will operate as a disincentive to more efficient energy use.[12]

Figure 3.3 presents electricity price and demand statistics for the USA, measured in 1997 $US and mtoe respectively. Short-run price elasticity of US electricity demand is typically estimated to be between -0.2 and -0.3, while estimates of long-run demand elasticity in the literature vary from -0.5 to -1 (Palmer 1997; ICF 1997; Joskow 1993). Estimates of expected demand increases resulting from increased competition over the next 10–12 years vary from 4 per cent to 12 per cent (ICF 1997; EIA 1998). Residential customers are expected to see the largest price decreases as historically capacity costs were allocated to customer classes based on their peak demand.

Precisely how these increases in demand will translate into increased emissions is difficult to predict on account of uncertainty about future fuel mix, unit dispatch, and also substitution effects. In both countries, much of the increased demand will take the form of customers substituting electricity for other sources of energy, thus pollution avoided by not using a gasoline powered car, for example, must be subtracted from the pollution from the additional electricity use. In industry and manufacturing, however, there might be an incentive to use more electricity and less labour and capital, in which case net emissions from industry will surely increase (Lee and Darani 1996).

Both the US and the UK governments are offering lower consumer prices as the key justification for market liberalisation initiatives. Consequently, the success of these initiatives will be measured, to a large extent, by the degree of price reduction achieved. While acknowledging that the goal of lower retail prices could make it more difficult to meet abatement targets through efficiency measures, both governments have given priority to the economic objectives. It is important to emphasise that the implication of this section is not that inefficiencies and the

[11] See UK Round Table on Sustainable Development (1998a).
[12] ibid.

higher prices which result should be maintained in order to promote conservation. Clearly, environmental policy objectives are better achieved by taxing the efficiently produced good to remove efficiency gains from the consumer and to recycle the revenues back into the economy. Instead, the implication is that the downward pressure which competition exerts on electricity prices should be seen as a source of tension between economic and environmental objectives, and that this tension needs to be addressed by policymakers in some way.

4. THE CHANGING POLITICAL ECONOMY OF RESTRUCTURING: ENVIRONMENTAL POLITICS

4.1 THE IMPORTANCE OF THE POLITICAL MARKETPLACE

Environmental awareness is largely a construct of culture. Global climate change is happening incrementally, it is barely discernible in one's own local environment. The magnitude and complexity of the problem make it intimidating to the point of being alienating. It is hard to feel personally responsible for such a problem, let alone for working towards a solution, unless one is living in a society where it is widely understood that humans are the dominant influence on the global environment and where it has been demonstrated that active personal, collective and political engagement are essential to the resolution of the larger problem. When enough people make the health of the environment a personal priority and, consequently, demand a politics that respects this concern, politicians and regulators will be moved to act accordingly (Osborn 1997). Although governments can play an important role in facilitating involvement and change, the level to which they make an effort to effect increased environmental awareness will be determined largely by who would react and how to their proactive environmental consciousness-raising initiatives.

In order to understand how the recent trends in emissions from electricity generation might be related to trends in market restructuring, it is crucial to take into consideration another significant variable: namely the changing character of the political marketplace, where environmental concern has been making its way up the political agenda. To understand why environmental legislation affecting electricity generation has increasingly been undertaken and how market liberalisation might help or hinder this trend, it is useful to think of the 'political marketplace' in terms of neo-classical micro-economic terms. Rational optimising politicians 'supply' welfare redistributing policy with the objective of maximising political support, measured in votes. Political competition forces politicians to make decisions which equate the marginal demands of competing constituents (see Arenchild 1996 and Stigler 1971).

When applying such a model to air quality legislation that restricts emissions from electricity generation, it appears that the dynamics of collective action should be averse to the passage of environmental statutes. Because the benefits of legislation to reduce ESI emissions (namely those associated with a healthier environment), are widely dispersed over the entire population while the costs tend to be concentrated among a small number of electric power producers, the costs will be much more conspicuous than the benefits. Problems of free ridership, the high transaction costs associated with organising large, widely dispersed groups, and the relatively small and somewhat intangible nature of the benefits accrued to each individual will make it more difficult for environmental groups to organise effectively. Small groups of producers, each facing large costs

should environmental legislation be passed, would be able to organise more easily to outbid the public in the political market for legislation (Farber 1992).

There does come a point where the marginal support gained by delivering policies that favour firms will be outweighed by the marginal support lost from legislating to the detriment of the environment, but the core prediction of interest group theory is that special interests will dominate. One could go further and derive a production possibilities frontier from production functions, the shape and position of which would be a function of the demand and supply conditions for air quality regulation in the 'political economy'. This would illustrate both the dominant influence of the industry lobby in this model, and how politicians must continually respond to changing conditions of the political economy in order to maintain voter support.

A critical downfall of this interest group model of government intervention is that it places undue emphasis on the importance of special interest groups. There are, however, numerous studies which offer empirical evidence to demonstrate how the preferences of the electorate are a critical driver of public decisions and how there exists a high degree of congruence between changes in public opinion and policy response. Indeed, the increase in domestic environmental legislation, mounting environmental regulatory pressure and increasing international collaboration in environmental problem solving can only be attributed to strong public demand.

The implications of this application of public choice theory are that, to the extent that electricity restructuring initiates changes in the political economy of air quality legislation, some of the ground gained in the last two decades of environmental energy policy could be lost. As risks are reallocated to firms, the generation and supply markets become more competitive, and the industry becomes more focused on the bottom line, electricity producers and suppliers will be more apt to lobby fiercely to counter costly legislation. On the other side, as environmental groups lose their seats at the proverbial bargaining table as a consequence of restructuring related changes in regulatory institutions, it will become increasingly difficult for interest groups to counter the growing industry lobby. Environmental taxation and subsidy become more visible in a disintegrated, competitive industry, and thus more vulnerable to public scrutiny. In the next two sections, the emergence of a new environmental agenda in mainstream politics in both the UK and the USA, is briefly chronicled.

4.2 Environmental Politics in the UK

The early 1970s brought what is recognised, in retrospect, to be the initial 'surge' of British and international concern for environmental issues. The UK Royal Commission on Environmental Pollution was established in 1970, followed by the Control of Pollution Act in 1974 which strengthened powers to deal with water, air and noise pollution. Following the quadrupling of oil prices brought on by the first oil crisis, conservation and energy efficiency concerns were catapulted to the top of energy policy agendas, inspiring building regulations, heating and lighting restrictions, and more stringent industry standards.

Much of the enthusiasm generated in the early 1970s had dissipated by the end of the decade. Fears of resource depletion and impending scarcities appeared to have been overstated, and as economic recession set in, environmental issues were pushed aside. The momentum of increased government intervention on behalf of the environment was further thwarted by efforts to roll back the welfare state. Parts of the Control of Pollution Act remained unimplemented and the UK was widely criticised for impeding the progress of Europe as a whole on the environmental front.

By the end of the 1980s, public concern for environmental issues was on the rise again. Membership in environmental groups soared and strong support for the Green Party in the European elections of 1989 demonstrated the political significance of environmental concern. In 1988, the European Council adopted the Large Combustion Plant Directive on the Control of Emissions to the Atmosphere (LCPD), which set EC standards for all new plant in terms of pollutant concentrations of flu gas, in addition to requiring member states to draw up plans for progressive reduction of total NO_x and SO_2 emissions from existing plants. Under the LCPD, Britain was required to achieve a 60 per cent reduction in emissions from 1980 levels of existing large combustion plants by 2003.

In spite of this growing community commitment to mediating the detrimental impacts of electricity generation, the environment played a negligible role in the 1989 Electricity Act. It is likely that, because the Bill was conceived at a time when public concern had been waning for some years, and it had been demonstrated that there was strong public support for privatisation, politicians believed that the political consequences of passing legislation which failed to deal with environmental dimensions of the industry in any detail would not be significantly negative. Indeed, it is clear that the main purpose of the Bill was to set the privatisation programme in motion rather than to attempt to reconcile environmental and economic policy. Although it included vague terms which required industry planners and operators to have regard for the environment, the government defeated a more proactive amendment which would have encouraged suppliers to promote energy efficiency.

The first comprehensive White Paper on the environment (*This Common Inheritance,* published in 1990), aimed to delineate the government's 'green agenda' which included stated positions on global warming and energy efficiency. Among the more political issues addressed were fuel prices, which the government stated could only increase when other nations agreed to do the same, and the private car, which would continue to be welcomed as an enhancement of personal freedom. Although the paper was widely criticised for its toothlessness, it initiated a series of annual papers which has since served as an important means for maintaining direction and continuity to UK environment policy.

Also in 1990, the landmark Environmental Protection Act (EPA) was passed which continues to serve as the principal UK act regulating pollution. Among other things, the EPA introduced a system of Integrated Pollution Control (IPC) for reducing atmospheric emissions; this requires that firms apply to each plant those processes which, without entailing excess costs, achieve the best practicable environmental outcome. It also imposed a statutory duty of environmental

stewardship on both individuals and companies. Included in the EPA was a detailed plan for implementation of the EC LCPD, including SO_2 and NO_x targets and caps for the ESI. The Office of her Majesty's Inspectorate of Pollution (HMIP) was charged with enforcement of the Act.

In 1993, HMIP set emissions limits for electricity generation. The two major generators, National Power and PowerGen, were required to produce proposals to meet LCPD targets. Had the initial 1993 limits been acted upon, all coal plants would have been fitted with fluegas desulphurisation equipment. Arguing that pollution abatement to this extent would be prohibitively expensive, the UK entered negotiations and successfully revised IPC requirements. Also in 1993, the EC published a green paper proposing a community-wide system of civil liability as part of the implementation of the single European market. A scheme combining strict liability with joint compensation was proposed to deter environmental damage, but was rejected by the UK. In 1994 the government signed EC protocols on trans-boundary pollution and imposed a tax on residential fuel which was intended to increase to 17.5 per cent by 1995, although the increase did not pass through Parliament. Parliament also defeated a new Energy Conservation Act, whose modest provisions would have required local authorities to identify ways to reduce domestic consumption (Jones 1995).

The Environment Act of 1995 established the Environment Agency in England and Wales as a more integrated administrative structure for regulation, concerned principally with pollution control, in an effort to consolidate the existing environmental protection and pollution control functions of a number of regulators. The Agency offered and conducted streamlined pollution licensing and control while also performing various consultative, advisory and monitoring functions for the government. The Act created a statutory framework for dealing with environmental contamination, founded on the polluter pays principle. It also gave statutory recognition, for the first time, to sustainable development as an organising goal of law and policy, marking 'the statutory enactment of an idea which has been increasingly promoted in non-statutory material in the (preceding) two years' (Jewell & Steele 1996). 1995 was also the year of the first Conference of the Parties to the Convention on Climate Change, held in Berlin.

In 1996, the Environment Agency negotiated more stringent limits on NO_x and SO_2 emissions, while EU-wide limits for ambient concentrations of the pollutants were set, indicating that further national action with respect to emissions abatement would soon be required. The Labour government elected in 1997 was concerned that taxes on domestic fuels were disproportionately affecting low income households, and so reduced the tax from 8 to 5 per cent. Initial efforts to help cut emissions included raising road fuel duty, increasing landfill tax, and investigating seriously the implementation of a downstream energy tax for industry.

Currently, ESI emissions of major pollutants are subject to regulation by the Environmental Agency, although EU directives play a role. According to the Electricity Association (Environmental Briefing #27, 1998) every major fossil-fuelled power station has had an air quality survey carried out in its vicinity as part of the efforts of the National Environmental Technology Centre to monitor national air

quality. CO_2 is proving to be somewhat problematic within the regulated pollutant control paradigm, both because it is frequently not considered a pollutant within the IPC framework, and because carbon abatement relies primarily on fuel switching and efficiency measures versus 'end of the pipe' solutions.

In terms of UK civil liability for damage to the environment, current UK legislation gives enforcing authorities the ability to recover clean-up costs. Within the EC, however, there are working proposals for a uniform strict liability system based on 'preventative', 'precautionary' and 'polluter pays' principles. The inherent environmental regulatory risks for generators associated with these proposals are considerable.

Four important themes emerge from this brief survey. First, UK environmental legislation has been increasingly influenced by membership of the European Union. In the 1993 Maastricht Treaty, it was agreed that all EU policies should take environmental provisions into account, in the interest of mediating transboundary pollution and promoting the development of an equitable single market. Since then, EU policy has been pushing the UK air quality legislation agenda forward.

Second, efforts have increased to involve the public in the environmental policy-making process, supported by legislation requiring public access to information and participatory consultation before decision making (Osborn 1997). Other legislation, such as labelling regulation, has also been used to make consumers more aware of the environmental impacts of their actions. Achieving environmental objectives will depend, to a large extent, on the personal commitment of individuals, especially with respect to improving energy efficiency. Public participation in the political process of environmental legislation is therefore critical.

A direct result of privatisation and increasing market liberalisation has been an emphasis on building industry liaisons in the context of environmental legislation and on assimilating environmental considerations into commercial decisions as an improvement upon conventional interventionist approaches. Indeed, government has had to develop a more sophisticated approach in the competitive context to accommodate changing industry incentives and institutional infrastructures. The approach has included efforts to carry out joint policy analysis, reach voluntary agreements and involve industry in international environmental agreements. While progress in this vein is encouraging and necessary, there exist, as seen in Chapter 3, prevailing conflicts of interest which are potentially problematic. Jewell and Steele (1996) point out that as a consequence of turning to the regulated sector for solutions, the identification of environmental issues in need of addressing will cease to be a political issue and instead, legislation will address only those issues which appear solvable to commercial interests. There is also the possibility that environmental statutes will be used for rent seeking by the regulated industries themselves. In the generation industry, any environmental legislation designed to reduce emissions will probably have a differing impact across firms due to variations in plant size, fuel type, age and so on. Firms who emit low levels of emissions initially will easily be able to accommodate moderate constraints, while some competitors may find that the cost of compliance will drive them out of business.

A fourth and final trend is the emergence of 'sustainable development' as a guiding objective of the government's environmental policy. The 1994–95 *Report of the House of Lords Select Committee on Sustainable Development* identified the need to 'revise the path of wealth creation and to constrain the parameters of economic decision making by a full and open recognition of the environmental costs of development'.[13] While at face value, government arrogation of the term as a core, guiding principle could be interpreted as a paradigm shift of significant proportion, a closer look suggests otherwise. The term 'sustainability'[14] is an inherently diplomatic word; its overuse having rendered it synonymous with 'everything good'. The 'sustainable development' approach to dealing with the environmental externalities associated with current means of generating economic growth and prosperity, is the most politically attractive (when compared with more drastic measures involving the suppression of further growth in production), because it does not necessarily imply less development. So long as the perceptions of the regulated constituency prevail over the definition of environmental problems and their solutions, 'development' will continue to be the operative word and it will be unlikely that the 'path of wealth creation' will be revised or restrained to any great extent.

This is not meant to downplay the real changes that have occurred in the realm of UK environmental policy and legislation. Green audits, environmental cost/benefit analysis, the identification of Green Ministers in every department and the Round Table on Sustainable Development have all played a role in improving environmental quality. The general consensus is, however, that we are not there yet, and that more radical changes in behaviour and development of effective policy will be needed to meet the environmental objectives of today and challenges of the future.[15]

With regard to the electricity industry in particular, environmental policy is likely to become increasingly political. The industry's market structure and regulatory institutions were designed at a time when the environmental impacts were less of a going concern. Fortuitously, in the early years of privatisation, environmental and economic goals were mutually reinforcing as the 'dash for gas' made economic, as well as environmental sense. With franchise markets remaining until 1998, utilities have had limited means of passing on the costs of new environmental legislation.

Currently, with no franchise markets remaining, utilities must absorb the costs of any future environmental legislation on their own. Concerns for a dying coal industry, domestic energy security and diversity have brought the dash for gas to a halt, which means that the conventional means of carbon abatement, fuel switching, is less of an option. In this current climate of political industrial alliance, popular support and engagement in environmental issues, and narrowing of options for

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[13] *Session 1994-95, HL 72,* as appearing in Jewell and Steele (1996).

[14] The official definition of sustainable development, adopted by UK government bodies, is : 'development that meet the needs of the present without compromising the ability of future generations to meet their own needs'. (UK Round Table on Sustainable Development 1998a).

[15] UK Department of Transport and Industry (1998a); National Academics Policy Advisory Group (NAPAG) (1995); Grubb (1990); Osborn (1997).

carbon abatement, it will be politically challenging to balance the demands of industry (growing louder as competition intensifies), with the demands of a public which is increasingly involved and increasingly adamant that legislation must incorporate an environmental ethic.

4.3 Environmental Politics in the USA

The first attempt of the US Federal government to establish air quality and pollution control standards occurred in 1963 with the establishment of the Clean Air Act. It came at a time when the conflict between those who supported accelerated economic and industrial expansion and those who were more concerned about the pollution effects of such growth was intensifying. Rachel Carson's book, *Silent Spring* (1962), and Paul Erlich's book, *The Population Bomb* (1968), are recognised as being instrumental in heightening public awareness of environmental problems at this time.

Prior to Richard Nixon, American presidents had traditionally dealt with environmental policy at arm's length, delegating affairs to executive branch agencies. Reacting to the upsurge in broad public environmental concern, Nixon signed the National Environmental Policy Act of 1969 and declared the 1970s the 'environmental decade'. Public concern for the environment continued into the early 1980s (it was identified as the second most important problem facing the nation in a 1970 Gallup poll following Earth day), and the government continued to respond. Congress enacted more than twenty major pieces of environmental legislation throughout the early 1970s, including the Clean Air Amendments (CAA), which required utilities to meet air and discharge standards and to adopt designated pollution control strategies.

By the mid-1970s, the rush of environmental legislation slowed considerably. With fears of recession setting in, there was concern that costs of industry compliance with environmental standards were slowing economic growth. The 1973 Arab oil embargo pushed pollution off the agenda for several years as energy conservation took centre stage. Policy response to the crisis included President Carter's windfall profit tax on oil to fund solar research, and the National Energy Act of 1978 which included the Energy Tax Act, the Energy Conservation Act, the Power Plant and Industrial Fuel Use Act and PURPA.

Following the 1979 nuclear meltdown at a power plant on Three Mile Island in Pennsylvania, the public became more acutely aware of the risks associated with nuclear power. Other events which focused attention on environmental contamination included the 1978 media coverage of the severe health effects of land contamination in New York's Love Canal, and the discovery of 17,000 leaking drums of chemicals in Kentucky in 1979. In 1980, the Comprehensive Environmental Response, Compensation and Liability Act (Superfund) was passed.

Ronald Reagan's administration has been credited with destroying any progress that had been made in the area of pollution control. Throughout his eight-year term, he was heavily influenced by pro-business interests urging him to take a more conservative approach to environmental legislation and reduce the scope of federal legislation. His budget cuts, personnel appointments and privatisation

initiatives had a profound effect on the environmental policy of the decade.[16] An interesting consequence of Reagan's neglect of federal environmental stewardship responsibilities was that it prompted other bodies to organise and fill the void. State officials began to combine forces to lobby collectively; groups such as the North East States Concerned for Air Use Management (NESCAUM) were formed, leading to a complete role reversal whereby states acted as policy initiators and legislative architects. Public membership in environmental groups also reached unprecedented highs during this period.

Reagan's successor, fellow conservative George Bush, campaigned under the flag of 'the environmental president'. Indeed, he had no choice but to carry out a 'green' campaign, with 80 per cent of the population agreeing with the statement that 'protecting the environment is so important that regulation and standards cannot be too high and continuing environmental improvements must be made regardless of cost' (Farber 1992). His initial personnel appointments met with mixed reviews: James Watkins, appointed energy secretary, won praise for his commitment to alternative energy and energy efficiency programmes, although he was criticised for failing to put words into action; William Reilly, appointed head of the EPA, successfully incorporated pollution control activities into all realms of EPA work, although his efforts to move forward with international global warming negotiations were thwarted by members of the White House staff.

The 1990 Clean Air Act represented the most far-reaching pollution abatement programme in US history, and perhaps the most significant environmental legislation to affect utilities. It set limits for SO_2 emissions from generation in 2000 at 50 per cent of 1990 levels and established a permit trading programme in an effort to achieve reductions at lowest cost (Hirst et al 1996). Other legislation passed during Bush's term included the Oil Pollution Act of 1990 and the establishment of the President's Commission on Environmental Quality to promote public/private partnerships in the interest of conservation and pollution prevention (Andrews & Govil 1995).

Bush ran the next election on a slightly more conservative platform, where environmental issues took backseat to concerns of job security and economic growth. His opponent, Bill Clinton, ran on a platform which featured, among other things, a promise to reduce carbon emissions to 1990 levels by 2000 (Bush had been widely criticised for not making this promise at the Earth Summit), a promise to set fuel standards, and to increase incentives for energy efficiency. Within a month of being elected, Clinton had established a Council on Environmental Quality, endorsed a Senate Bill that would elevate the EPA to cabinet level status, and was turning his attention to the climate change issue.

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[16] An infamous example of Reagan's consequential political appointments is that of James Watt, founder of a conservative, anti-environment law firm, appointed head of the Department of the Interior. Among Watt's first initiatives was the proposed leasing of $1.3 million acres off the shore of California for oil and gas exploration and an auction of 1.1 billion tonnes of coal in the Power River Basin, intending to replace the department's resource conservation ethic with one of exploitation. Ultimately, Watt became such a liability to Reagan that he was forced to resign.

In 1994, the US Climate Change Action Plan (1994) was released consisting of 44 actions contributing to a net reduction of 108.6 MMT of greenhouse gas reductions. The plan relies heavily on voluntary emissions reductions, but it is hoped that because of the high profile of the voluntary agreements, companies will be willing to participate and unlikely to default so as to reap the benefits associated with positive public relations.

The Administration's 1998 Electricity Restructuring Bill is the product of much controversy, as far as the environment is concerned. The EPA, Northeast state officials and various members of Congress have been campaigning strongly for stringent environmental legislation to be included in the bill, while various industry representatives and members of congress adamantly oppose the joining of restructuring with new environmental mandates (Begley 1997). A key issue was whether the bill should incorporate current targets for carbon reduction into electricity restructuring plans. The FERC chairman argued that to include the global warming agenda in the bill would all but eliminate its chances on Capital Hill; her argument prevailed, and there is no mention in it of capping industry carbon emissions (*FT Energy Economist*, 1998, vol.198). This is not to suggest that the bill relies entirely on market forces to determine environmental outcomes. As mentioned previously, environmental provisions of the act include a renewable portfolio standard, consumer information provisions and a public benefits fund (US Department of Energy 1998).

Both the USA and the UK have undergone similar vacillations in public and political support for environmental issues and action. Both passed landmark air quality legislation in the late 1960s and early 1970s, providing governments with powers to combat pollution problems. In both countries, government policy emphasis shifted to energy conservation following the first oil shock, causing emission rates from power stations to decline significantly as various policies and programmes were implemented. The momentum of the environmental movement slowed in the late 1970s and early 1980s. As recessions came and went, conservative governments arrived with commercial interests in mind and the intention of shrinking government involvement in every realm. By the early 1990s, public concern for the environment had regained its former fervour, this time in a more global context. Problems such as loss of biodiversity, the hole in the ozone layer and the greenhouse effect demanded a new approach to policy making.

Because the electricity industry is such an important contributor to both environmental problems and solutions, it is heavily impacted by changes in environmental politics. Not only is it affected directly by various air quality and environmental liability legislation, but electricity policy itself is shaped, to a considerable extent, by the environmental political climate. From the preceding survey of environmental legislation affecting the industry, together with a brief introduction to interest group and public choice theories of the political marketplace, some valuable insights can be drawn.

Over the past quarter century, environmental legislation affecting electricity generation and supply has increased in scope and scale. Environmental groups and a more aware public, together with international pressure, have demanded that

these legislative changes be made. Thus far, the growth trajectory of environmental legislation affecting the electricity industry has focused mainly on NO_x and SO_x emissions. Only recently have legislators begun to acknowledge the unique character of the CO_2 problem, and legislation to deal with it is only just beginning to emerge. It is impossible to say whether air quality legislation in the electricity industry would have progressed any differently in the absence of market restructuring. What can be said with certainty is that restructuring does alter the political economy of environmental legislation in the context of the electricity markets. It is therefore important that, to the extent that these changes work to thwart the hard won progress of air quality legislation, legislative and regulatory institutions must be altered to accommodate the changed political economy.

5. THE CHANGING INSTITUTIONS OF ELECTRICITY REGULATION

5.1 THE ROLE OF REGULATION IN A 'FREE' MARKET

Electricity market 'liberalisation' and 'deregulation' are invariably paradoxical phenomena, founded as they are upon the ideological understanding that wherever possible, market forces should be harnessed so as to alleviate the need for centralised regulation of industry by government. Because of the remaining natural monopoly element and the social, political, economic and environmental implications of electricity production and consumption, it becomes impossible to divorce decision-making in the industry from the role of the government. Thus, in both the UK and the USA, the question is not *should* the government interfere in the ESI, but *how*?

In the current climate of ESI restructuring, the primary justification for government intervention is to remove distortions so as to allow the market to behave as closely as possible to a free market. Here we are confronted by another fickle term; much depends on what is meant by 'market distortion'. Environmentalists can argue that the market's failure to internalise the climacteric cost of emitting carbon into the atmosphere constitutes a distortion in the economic sense in that it results in a sub-optimal pattern of resource use. Conversely, their libertarian counterparts will contend that the current, unsustainable patterns of energy consumption reflect the natural, undistorted consequences of consumer attitudes and producer's willingness to supply (Grubb 1990). Thus, the 'freedom' of the free market can imply either unfettered in the latter sense of no intervention, or unfettered in the former, more abstract sense of high degrees of intervention so as to ensure that theoretical economic optimums are obtained. The weighty implication of the subjective nature of the term 'free' in this context is that 'the free market' cannot be hailed absolutely as an objective mechanism to which industry decisions can be deferred in good conscience. Society must be integrally involved in defining the parameters and terms of the market, right down to the definition of its state of being 'free'.

Although it is clear that the need for regulation will remain, its nature will change dramatically as competition develops. In essence, market liberalisation represents a regulatory transition from one institutionalised approach to dealing with market failures to another. Restructuring changes not only the market structure, but the character of the many relationships between industry, environmental and economic regulators. As regulated companies come to terms with this new environment, they will learn to optimise their position with respect to its own objectives and those of the regulators. The regulators must undergo a similar learning process, so that they redefine their purpose and discover the most effective means of carrying out their role in a changing business environment (Palmer 1997).

One of the most significant changes, from the perspective of both economic and environmental regulators, is the more complex dynamics of ownership and operation. Generation is driven primarily by competitive forces versus regulatory mandates. There is less direct control of outcomes, and less capacity to plan centrally or over the long term. The actions and decisions of the regulator become

more visible to consumers and shareholders, and it becomes more difficult to appeal, as the government can in a nationalised or private monopoly, to a need to balance wider policy objectives. As discussed in Chapter 3, while regulators of the old monopoly regimes were, to some degree, guided by public service ethics of equity, benevolence and responsibility, these have been largely replaced by pro-market operational criteria of competitiveness, productivity and profitability (Haque 1996).

While the explicit need for changes in the institutions of economic regulation of the ESI was recognised and acted upon in both countries from the very beginning of restructuring initiatives, much less attention has been paid to the fact that the job of environmental regulators is also changing dramatically. It is not just that they need to be sensitive to development of competition, rather, the very existence of competition has rendered many of their former approaches inadequate or obsolete. Conventional approaches which have often involved integrated, centralised, long-term planning in combination with using regulated monopoly sectors as vehicles for taxation and subsidy have been critically undermined by competition. Long-term, centralised plans will be of little use in decentralised, competitive markets. To the extent that governments attempt to apply subsidies and taxes, they will be accused of distorting markets and tilting playing fields, two cardinal sins in the religion of laissez-faire. Market transformation must be seen as a new organising principle for public service programmes if they are to survive in any form in the new environment.

The objective of this chapter is to consider the changing role of the regulator in both the British and American context, and evaluate the extent to which the existing regulatory institutions reflect those changes.

5.2 The Changing Role of the UK Electricity Industry Regulator

Government intervention has been necessary throughout the ESI restructuring process, much more so than with the previously privatised telephone and gas industries. Transitional issues arising in the initial phases (including the commitment to nuclear power, the joint ownership of the grid and the rights to generate granted to the Area Boards), required special regulation so as to facilitate the development of a competitive market (Helm 1989). There are also, of course, natural monopoly elements, as well as safety and environmental features of the ESI which will require regulation on a continuing basis.

The 1989 Electricity Regulation Act allocates regulatory responsibilities among several bodies. The Department of Energy retained many of its regulatory powers, while the Secretary of State is authorised to appoint a Director General of Electricity Supply (DGES) to head the Office of Electricity Regulation (OFFER). This is not a political appointment in the ministerial sense, indeed the government specifically sought to create economic regulation at 'arm's length' so as to leave the privatised companies free of government interference. Thus it was important that the agency heads be independent and apolitical. In spite of this, the DGES does have some responsibilities whereby he acts as an advisor to the Secretary of State. The Act also required the establishment of Consumers' Committees within each of the

twelve RECs composed of 10–12 unsalaried members. If disputes arise between the regulators and the regulated firms, or if issues arise that are outside the jurisdiction of the regulator, the Monopolies and Mergers Commission or the Office of Fair Trading may also play a role.

The government retained a certain degree of direct control over the industry. Close links were preserved by means of the government's ownership of 'golden shares' in the privatised companies, in addition to 67 distinct terms laid out in the Act whereby the Secretary of State for energy retains control over the industry.[17] As the powers and operation of OFFER were entirely dependant on the government laying down a regulatory framework and principles, in theory the government could continue to maintain a high degree of control over electricity policy and industry activity.

In the interest of creating an independent and focused organisation, the government laid out clear objectives for OFFER. Utility regulation was largely shaped by the government's main priorities at that time, namely maximising return on investments and promoting competition. Consequently, in delineating the responsibilities of the DGES and OFFER, the primary duties were to promote competition in generation and supply, to ensure that licence holders are able to finance the activities that they have been authorised to carry out, and that all reasonable demands for electricity are satisfied (see Thomas 1994). Other subordinate duties included protecting customers, promoting research and development, protecting public health and safety, and promoting energy efficiency. While OFFER does have a legal duty to take into account the environmental effects of the industry's activities, this is subject to both primary and secondary duties.

The performance of the DGES has largely been judged on the extent to which he has been able to promote competition. In fact, the emphasis on pushing forward the objectives of privatisation and liberalisation on behalf of the government has, to some extent, put the economic regulator in the de facto position of establishing energy policy by default.[18] The regulator has played a central role in the encouragement of investment in CCGT (at a time of excess capacity), the decline of the coal industry, the regulation of pool prices, and the falling of real prices, all in the name of competition (NAPAG 1995). This increasing role of the regulatory offices in defining energy policy, thus blurring the line between regulation and policy, raises important questions. Should the regulatory offices be given more explicit responsibility for issues such as resource development or fuel mix; should a more explicit effort be made to limit OFFER's jurisdiction to overseeing the functioning of

[17] A section of the Act which was later to become a point of controversy was Section 36 which required anyone wanting to construct or operate a generating station in excess of 50MW to obtain consent from the Secretary of State.

[18] The thrust of UK energy policy has shifted from the coal, conservation , security of supply and nuclear focus of the 1970s, to promoting coal and nuclear in early and mid-1980s, to an emphasis on privatisation and market-based decision making in the late 1980s–1990s. As regulatory offices were charged with the duty of promoting competition, and as promotion of competition was virtually synonymous with energy policy, decisions taken by regulatory offices have shaped many of the important energy trends since vesting (OXERA 1996).

the market exclusively, versus the de facto determination of energy policy? (Fells & Lucas 1992)

Similar questions arise with respect to the extent to which OFFER has been or should be responsible for environmental policy objectives. Clearly, economic regulators of the electricity sector are well placed to implement some of them, such as targets for energy efficiency and reduced emissions from generation. With environmental obligations ranking so low on their list of duties, economic regulators have generally regarded the act of balancing economic and environmental issues as being largely the government's responsibility. At the same time, government has made a point of assuming an 'arm's-length independent' position, not wanting to meddle in the policy framework of regulators in the interest of industry autonomy. The Environment Agency is very confined in terms of the extent that it can interfere in the realm of energy policy; its role in the electricity industry is largely restricted to issuing pollution licences. As discussed earlier, the IPC framework is ill-equipped to deal with the carbon question, and interestingly enough, while the EA is required to formally assess the economic costs and benefits of its actions, there is no parallel requirement for the economic regulators to consider the environmental costs and benefits resulting from the exercise of their powers. Because the responsibility of defining and establishing a comprehensive environmental policy for the ESI has not been clearly delegated, no one body is assuming full responsibility and much is slipping through the cracks.

The specific issue of the extent to which the economic role of the electricity regulator should be influenced by environmental and social considerations, and the larger question of the extent to which government should actively define the regulatory framework so as to maintain control over the definition of energy policy, has become the subject of much debate in recent years. It has become clear that a sea change in market structure demands a sea change in any regulatory institution attempting to regulate that market. The debate has induced not only a formal redefinition of the relative roles of the government, the environmental regulator, the economic regulator and the firm, but also a questioning of the fundamental philosophical underpinnings of the British regulatory process.

The British style of political process tends to emphasise executive dominance, Crown prerogative and individual discretion. OFFER, as originally conceived, consciously embodied the British approach in an almost defiant rejection of the American style of utility regulation. In the USA, electricity regulation methodology of the late 1980s reflected the constitutional, democratic nature of American politics with its emphasis on checks and balances, federalism and a separation of powers. American utility regulatory commissions have been intrinsically involved in the activities of their regulatees, with every regulatory decision subject to prescriptive processes involving formal public participation and scrutiny. The UK government made explicit its desire to avoid the interventionist, 'heavy-handed' style of regulation found in America. The appointed DGES, Stephen Littlechild, was anxious to stress initially that he wanted to avoid the pitfalls he had identified in the American system, most noticeably agency capture, and the best way to do this was 'to reduce the contact between the regulator and the industry to a

minimum' (Massey 1993). For this reason, the 'light-handed' RPI-X approach was preferred to the more complex and discretionary rate of return approach used in the USA. Similarly, the 'British style' of environmental regulation has been dominated by administrative discretion and collaboration, resulting in non-transparent, negotiated rule-making.

The resulting economic utility regulatory institution relies heavily on licensing to define regulatory limits, and consequently on the ability and discretion of the choice group of individuals setting the terms of the licences and policing the industry to collect information, interpret it, consider all the pertinent issues and interests and make the correct decisions. Parliamentary scrutiny of the regulated firms is minimal at best, as companies routinely deny access to information on the grounds of commercial confidentiality. The DGES has considerable discretion with few strings attached: there is limited public scrutiny of the licence terms that he establishes, few codes of practice governing his decision-making process, and he is held accountable only to the extent that he makes annual reports to the DTI. When making decisions concerning issues such as fuel choice, environmental policy and security of supply, there is bound to be intense lobbying and political debate. The current system lacks the transparency, public accessibility, accountability, coherence, broad representation and social awareness required to make these decisions.

The government has realised the shortcomings of the current system and has initiated a process of regulatory reform. In March 1998 A Green Paper entitled 'A Fair Deal for Consumers' was released, proposing a new framework for utility regulation. It clarifies that it is the responsibility of government to determine the objective for utility regulation and to establish a clear framework which balances the interests of consumers and shareholders (Sect.1.9, 2.3). The paper recognises that the current framework leaves 'too much discretion for the regulators in social and environmental areas', but argues that market uncertainty would result if the government were to issue mandatory instructions on these issues. Instead, the report proposes that the government should, following extensive consultation, issue statutory guidelines for regulators on social and environmental objectives. Where Ministers wish to implement social or environmental measures with significant financial implications for consumers and/or companies, legal provision should be made. Regulators would thus be placed under a new, secondary duty to have regard to Ministers' guidance on matters of environmental stewardship and social responsibility.

An important object of the paper is the recasting of the regulator's statutory duties such that there is a new primary duty to exercise regulator functions 'in the manner best calculated to protect the interests of consumers in the short and long term' (Section 2.12). This reprioritisation is qualified, however, with the assertion that wherever possible, this should be done by promoting effective competition. The need for improved accountability and transparency is also addressed throughout the paper. The government pledges to open up the regulatory process to wider scrutiny and to make readily available information regarding the decisions of utilities and regulators, and codes of conduct.

It is difficult to tell at this stage to what extent the current process of regulatory reform will adequately accommodate the new challenges associated with restructuring, especially from an environmental standpoint. Regulatory consideration for the environment will remain a secondary duty, and until the government announces what sort of statutory guidance it will provide regulators with concerning environmental obligations, it will be unclear whether this reform will amount to any change at all. The report makes no mention of requiring regulators to consult environmental regulatory agencies, as was suggested by the UK Round Table on Sustainable Development. Nor is there any mention of creating appropriate indicators which better reflect environmental and social dimensions of performance, such that more qualitative progress or failures in these areas could be fed back into the process of economic regulation.[19]

The promise of enhanced transparency and increased potential for constructive popular consultation is also encouraging. It will make it more feasible for a diverse range of interests to secure a seat at the bargaining table. Whether or not this will be a sufficient means of resolving tensions between competing economic and environmental objectives remains to be seen. The paper fails to address the need to introduce a long-term view to the economic regulatory system. Consequently, even though the regulatory process may become more transparent and publicly accessible, the terms and criteria employed in discussion and decision making will continue to discount long-term environmental costs and benefits.

5.2.1 Changing Regulatory Instruments

The changes that come with competition require not only changes in a regulator's role and responsibilities, but also changes in the tools she employs. Not surprisingly, given the central privatisation thrust of energy policy and the increasing tendency to approach environmental policy as a collaborative exercise with industry, the UK government has increasingly expressed interest in the use of market mechanisms to achieve environmental and efficiency goals. In principle, adjusting prices to reflect externalities is more consistent with market liberalisation and can be more cost effective than command and control regulation in achieving targets (EIA 1998).

There are three main instruments available to the government for reducing carbon emissions – namely regulation, voluntary agreements and economic instruments. Regulation in the form of the EU Integrated Pollution Prevention and Control Directive will be implemented in late 1999, aiming to cut emissions from 5000 industrial sites in the UK. As far as domestic legislation is concerned, the government has made clear its belief that regulation is an inefficient means of reducing emissions in competitive market conditions. Although voluntary agreements are particularly attractive in that they depend on the industry's willingness to comply and thus will be unlikely to involve measures that will impair

[19] This was also recommended in the UK Round Table on Sustainable Development's 1998 report.

industry's ability to compete, voluntary agreements alone will not deliver the change that is necessary.[20]

In March 1998, the UK Chancellor of the Exchequer, Gordon Brown, announced that Lord Marshall would lead a task force charged with investigating the use of economic instruments to improve the industrial and commercial use of energy and to help reduce greenhouse gas emissions. The controversial practical implications of an energy tax or a tradable permits scheme makes the negotiation of market based pollution control almost prohibitively tricky.[21] To begin with, energy taxation brings to the surface the ageless tension between efficiency and equity. There is already a serious and well documented problem of fuel poverty in the UK; an energy tax on domestic energy consumption would only exacerbate the problem, which would clearly be a socially unacceptable outcome. The Labour government has already made clear where its priorities are with respect to this issue; in its July 1997 budget the tax on domestic fuel was cut from 8 per cent to 5 per cent, while the gas levy was reduced to 0. Although market responses to an upstream or domestic energy tax may be efficient, if it results in the poorer households shouldering a disproportionate amount of the cost, it will not be a viable option. Although studies have demonstrated that the distributional effects of environmental taxes can be overcome by adjusting transfer payments to compensate lower income groups, any tax or market instrument which could potentially impact on domestic consumers has been ruled out as an option by the taskforce, at least for the time being (Cornwell & Creedy 1997).

Any attempt to internalise the environmental cost of fossil fuel use through taxation or permit trading will invariably come up against formidable political resistance, protesting on the grounds that energy taxation will reduce both the domestic competitiveness of carbon intensive fuels and industries, and the international competitiveness of the economy as a whole. Indeed, it was these fears which defeated the EC's proposal of a mandatory tax in favour of a much weaker policy enabling member states to negotiate their own carbon/energy tax structures (see Cross 1996). If an energy or carbon tax is effectively to reflect the costs of carbon emissions, however, it must affect carbon/energy intensive industries to a greater extent than less intensive ones. Effects can be mediated by recycling some of the tax revenues and lowering other taxes in the economy, but a distributional impact is inevitable.

The Marshall task force made clear its concern that the scheme should not alter the relative competitiveness of firms nor should it affect the position of UK sectors in international markets. Maintaining such a position narrowed the range of options available for consideration. The task force issued its conclusions in November 1998. Lord Marshall endorsed the idea of a downstream tax on the final use of energy by industry and the commercial sector, with rates based on the carbon content of the overall fuel mix. There was no specific recommendation with respect to the level of the tax, although the report did make some effort to correlate tax rates

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[20] *Power UK* (1998), 'Customers and industry divided on environmental curb mechanism', no. 54.

[21] For a discussion see OXERA (1998b).

with abatement levels. It was estimated that a tax bringing in £1bn per year would result in a 1m tonne reduction, or 0.7 per cent of the UK's emissions in 1990, by 2010 (see Houlder 1998). Marshall also urged the government to set up a pilot emissions trading project to prepare the UK for a future international scheme, but noted that because trading schemes would not be able to incorporate small and medium size businesses (who are responsible for 60 per cent of CO_2 emissions from business), he stressed the need for a tax. In order to mediate the effects of the tax on energy-intensive industry, it was recommended that it be recycled in full to business, with some portion devoted to energy efficiency.

5.3 The Changing Role of the US Electricity Industry Regulator

Although restructuring of the electricity industry in the United States has become a major legislative issue, much of it to date has been implemented through the regulatory process. Looking to reduce energy prices and replace regulation with market competition, federal regulators and a growing group of state regulatory commissions are moving wholesale and retail competition forward. Although, in the changing market environment, regulators remain very much in charge of setting the rules and parameters for the industry, their role is changing dramatically.

Retail rates and local retail sales have historically been regulated by state Public Utility Commissions (PUCs), while retail rates and operations of publicly owned facilities are controlled by utility governing boards, elected officials, or agencies of the federal government. Traditional electric utility economic regulation has in the past been characterised by rate of return regulation and cost based rates, whereby retail rates for both public and private utilities have typically been set at the projected cost of service, which included the un-depreciated book value of all assets. Under this system, all utility investment decisions were subject to review after the fact; any prudent expense or investment could thus be recovered through rates or fuel adjustment clauses. As market or demand risk was transferred to the consumer, the system provided strong incentive to avoid under-investment by minimising the utility's exposure to market risk.

Regulators had substantial power under this system. Through their rate making authority and review of utility investment decisions they have been able to influence directly the scope and character of investment. Because utilities had a captive customer base, regulators could encourage or obligate them to administer social policy programmes such as energy efficiency initiatives or renewable energy programmes by allowing utilities to pass on the costs to customers.

5.3.1 Federal Regulation

The US electricity industry is regulated at both the state and the federal level. The Federal Energy Regulatory Commission (FERC) regulates rates, terms and conditions of wholesale electricity sales, as well as the interconnection and wheeling of electricity in interstate commerce and the assurance of stable and reliable service, while the Securities and Exchange Commission (SEC) regulates utilities' corporate structure and business activities under PUHCA.

Federal legislation is premised on the need to fill the regulatory vacuum resulting from the constitutional inability of states to regulate interstate commerce, and as such it is conceived to supplement state regulation. Although FERC cannot, as a federal regulating body, mandate change unilaterally within each state's jurisdictional area, it does have the means to effect nationwide change. For example, in issuing Order 888, FERC effectively initiated wholesale wheeling without overstepping its jurisdictional limits.

Congress holds the constitutional responsibility for enacting legislation to protect the environment. A fragmented congressional committee system, the proliferation of competing interest group lobbies, the inherent political, economic and scientific complexity of environmental issues, and localised re-election pressures tend to leave Congress in legislative gridlock when it comes to environmental policy making, and thus the Environmental Protection Agency (EPA) has often taken the initiative in the development of environmental policy. Established by executive order in 1970, the EPA is an independent agency in the executive branch, headed by an administrator, a deputy and nine assistant administrators, all nominated by the president and confirmed by the senate. The agency is responsible for administering most of the nation's environmental policy, which includes issuing permits, setting and monitoring standards and enforcing federal laws. In terms of its role in the electricity industry, the EPA currently has the authority under the Clean Air Act to establish and enforce pollution control standards for generators in terms of NO_x, SO_2, CO_2 and mercury, and the responsibility to conduct basic research into non-regulatory strategies and technologies for air pollution prevention in the industry. Under the Pollution Prevention Act of 1990, the EPA is required to 'develop and implement a strategy to promote source reduction' of pollution, and under the Global Climate Protection Act of 1987, the President, through the EPA, is responsible for developing a co-ordinated national policy on climate change.

The above statutes, taken together, provide the EPA with considerable authority to address the problems caused by electricity generation. However, just as the UK's IPC framework is unfit to deal with the unique pollutant that is carbon dioxide, the current EPA authorities do not lend themselves to establish market-based national or regional cap-and-trade programmes, which are according to the Congressional Research Service (1998) 'broadly recognised as the ideal way to approach these kinds of pollution problems'. This does not necessarily imply that *more* extensive authority is needed, rather enhanced regulatory authority, designed specifically to deal with a liberalised electricity industry and the market dynamics that go with it. Current CAA provisions for meeting national pollution standards place programme design and implementation into the hands of fifty states. In the case of regional air pollution problems such as acid rain, this is an appropriate arrangement. In the case of CO_2, a non point-source problem where a single federal cap-and-trade programme is more apt to deliver efficient and least-cost solutions, EPA needs to be granted clear federal authority to co-ordinate programmes at a national level.

5.3.2 State Regulation

Traditionally, the main source of environmental and economic utility regulation that occurs is at the state level. While Congress helps by promoting regional solutions, defining jurisdictional boundaries and establishing environmental quality guidelines, it is the states which define how the electricity industry will be regulated within their boundaries. State PUCs consist of three to five commissioners serving for three to five years. Some states elect their commissioners, while others are appointed.

The essential mission of the state regulator is the establishment of retail prices. Because the industry has traditionally been vertically integrated, this has meant that most generation assets have been regulated at the state level. Considerable authority has been vested in all state utility commissions such that they have the capacity to ensure that all utilities in their jurisdiction are providing fair and reasonable consumer rates. PUCs can also regulate various financial activities of electric utilities; in most states, the construction of any major generation, distribution or transmission facility has required the approval of the state PUC.

Utility revenue requirements are set at adversarial public hearings, similar to a civil court hearing and attended by a wide range of interested parties. The central objective of the hearing is to determine the total costs to the utility, including operating expenses, capital costs and an acceptable rate of return, the total amount of money the utility will be permitted to collect, and how the costs will be distributed over residential, commercial and industrial consumer classes. That said, in the process of determining costs and prices, hearings have encompassed the full range of technical, financial, environmental and public interest concerns. Most often, a hearing would be held in response to a request filed by a state utility wanting to increase its rates. Prior to the hearing, the utility prepares evidence to substantiate its request, while other groups such as large companies, commission members, consumer groups, environmentalists and individuals also prepare evidence. The staff of the commission have extensive rights to utility information, as do other hearing participants. To assess utility costs, regulators are empowered to undertake a management audit in order to assess operating procedures and capital investments. The various parties present their evidence and are cross-examined at the hearing. The Commission must make its decision, with justification, within a certain time frame. If it is determined that utilities are failing to operate efficiently, regulators can decree that excessive costs should not be passed on to customers. The considerable regulatory time lag between when a change of circumstances is detected by regulators and when final decisions are made can serve as an incentive to increase efficiency and so bring costs down between reviews and maximise utility profits.

In addition to determining retail rates, PUCs have been empowered to regulate other public and environmental welfare aspects of electricity generation and supply at the state level. Southern states have tended to be more conservative with respect to ascertaining control over utilities, while states such as California and New York have adopted a highly interventionist style.

Under the old regime, utilities could largely ignore the risk that the EPA might introduce more stringent and costly regulation when selecting fuels for new

generating facilities, because they could pass these costs on to the captive customer. There was little incentive to minimise long-term costs or incorporate external social and environmental costs of generation into investment planning decisions. In an effort to correct this, EPAct mandated that all state PUCs develop an integrated resource planning (IRP) approach to planning (Carlin 1997). Key characteristics of this approach include explicit and fair treatment of a wide variety of supply options, consideration of social costs of electricity generation and supply, public participation in the development of utility resource plans and analysis of uncertainties associated with the external implications of different resource options (see Hirst 1994). IRP requires utilities to prove to regulators that, in planning to meet future electricity demand, they have considered all possible supply alternatives – including the construction of new capacity and the purchase of power from IPPs – and demand-side alternatives, including demand-side management (DSM) programmes in which future demand is 'met' in part by reducing energy consumption through programmes promoting efficiency.

The integrated resource plan that is submitted to the PUC by the utility is based on a multi-year demand forecast and consists of a strategy to meet the forecasted demand in a 'least cost' way. The extent to which environmental externalities are included in this 'least cost' assessment depends on the policy of the particular state. The PUC invites input from interested parties such as consumer and environmental groups, and after taking this into consideration, accepts or rejects the plan.

The IRP approach has provided environmental advocates with a means to influence utility investment decisions directly and an opportunity to introduce emerging environmental concerns into future investment strategies prior to formal legislative action. In some states, regulators provide environmental groups with 'intervenor funding' which allows smaller groups to get involved in utility decisions and planning at no cost to themselves. As a consequence of the involvement of environmentalists in IRP programmes, some states have begun to require utilities to estimate the environmental damage that could result from alternative supply-side options and to incorporate these amounts into estimates of production costs. By 1995, seven states had specific monetary values for environmental externalities to be used within the IRP framework (for example, Nevada imposed a penalty of over 4 cents/kWh on coal-fired plants). Internalising externalities in this way affected not only the resource planning decisions (i.e. whether to build a new plant, repower an old one, or postpone capacity additions via DSM), but also system dispatch ordering decisions. Many state PUCs rejected the use of externalities in IRP, often because to include them can be complicated by other related regulations and the divergence between regulated prices and the utilities' marginal costs. There was also the issue of the competitors, IPPs, utilities in neighbouring states and non-electric sectors, such that the economic costs of internalising externalities would be unevenly distributed (Burtaw et al 1996).

IRP has meant good things for renewables and energy efficiency programmes. By obligating utilities to account for the environmental and resource diversity benefits of alternative energy sources, the contribution of renewables to the

electricity generation mix has been encouraged. One survey showed that they had been specifically encouraged through the IRP process in fifteen states, with New York and California explicitly setting aside a portion of purchased capacity for renewables (see Lee & Darani 1996). IRP also encourages competition between electricity and conservation proposals. Similar to renewables, demand-side efficiency programmes cost more in the short term than other supply side options, but can offer more significant long-term economic and environmental benefits. By requiring utilities to consider DSM alternatives and their associated long-term benefits, IRP has led to increased investment in energy efficiency. It is estimated that US spending on efficiency tripled between 1989 and 1993 in response to IRP policies. At an average cost of 2.1 cents/kWh, DSM proved to be, in many circumstances, the most efficient means of meeting future demand (Flavin and Lenssen 1994).

The IRP approach requires regulators to adopt a more prospective and interventionist approach to utility management decisions, taking on the role of 'de-facto partner' in investment decisions. It also involves interest groups and the public to a much greater extent than more traditional modes of regulation. Thus, utility resource management is decided by a wide variety of interests, leading inevitably to choices that are more costly than those which would be selected by a deregulated, competitive market. Opponents of IRP cite heavy-handed regulation and the higher costs and rates that result from a comprehensive IRP process as reason enough to abandon the practice, arguing that highly interventionist regulation and uncompetitive rates are ill-suited to the emerging liberalised markets.

5.3.3 Competition and the PUCs

Although most PUCs have recognised the need to change their approach and objectives in response to market restructuring (a 1996 survey indicated 31 state PUCs were in the process of reorganisation), the magnitude of the required change is only now being realised (Wivick et al 1998). In the past PUCs have depended on stability, control, predictable outputs, centralised long-term planning, a reliance on rate-of-return regulation and an allegiance to a quasi-judicial process of decision making. Now they must quickly adapt to a new regulatory environment characterised by continuous change, competition, decentralised decision making and thus a lack of direct control. Indeed, commissions must radically change their approach or become obsolete.

This is not to deny a role for the PUCs in the changed market environment. As the need for rate-of-return regulation disappears, the need to oversee and monitor utility performance, the conduct of market participants and the structure of the market itself arises. Thus, PUCs must shift their focus from economic regulation to facilitating the creation and efficient operation of competitive markets. In the new environment, economic regulation becomes a matter of ensuring markets are free of monopolisation, price fixing, tying or other anti-competitive behaviour rather than establishing costs and setting retail prices.

Attention to service quality will be a higher priority as competition intensifies and financial regulation obligations diminish. Whereas in the past, mediating between interests was a central objective, as markets become more

competitive and generators, service companies and large users fend for themselves, regulators will increasingly be concerned with attending to the residential customer. Activities such as public education and protecting customers from deception, incomplete information or coercion, once regarded as peripheral, will increase in importance.

There is a real concern amongst PUCs that, in the midst of this complex and taxing transitional period, their budgets and access to resources will be severely reduced. Although the percentage of state budgets devoted to PUCs has remained relatively stable over the past five years, there is concern that state legislators may erroneously assume that competition can serve as a substitute for regulation, and thus regulation can be eliminated. There is also the worry that as the role of the PUC becomes more focused on generic consumer protection and market policing issues, other state agencies with related authorities will compete for resources. Not surprisingly, given the high stakes involved, state legislatures have become increasingly interested in the policies and organisation of their PUCs, which in turn have recognised the need to become more proactive about maintaining good relations with their state legislators and more involved in the policy-making process.

The legislator-regulator relationship with respect to restructuring is an interesting one. While in some states, legislators view deregulation as the 'commission's responsibility', in others there is the implicit understanding that the regulators 'cannot carry the ball over the goal line', while in another 'the restructuring will be done by forging deals based on protection of the incumbent utilities ... the only way regulators will be allowed to be involved will be based upon the extent to which they rule in favour of these powerful forces'.[22] The ability of PUCs to respond successfully to changes in their regulatory environment will be determined, partly by the extent to which state governments involve commissions in the restructuring process and support them as they make their transition.

As the domain of the regulated monopoly shrinks, new forms of 'light-handed' regulation are replacing centrally managed planning of investments and price structures. Environmental considerations are not diminished in importance, but do become more difficult to achieve as restructuring weakens those policies that state regulators have adopted to encourage efficiency and promote renewables. Broader access to electricity transmission can undermine state efforts to encourage generators to reflect social costs in operating decisions, while the introduction of retail wheeling renders IRP unworkable. Electricity suppliers can bypass IRP requirements altogether by operating as independent generators and marketing power directly to large customers or intermediate service companies (Burtaw et al 1996).

The demise of IRP will be especially problematic for those environmental groups that were able to use the process as a means of forging partnerships with utilities and regulators and ensuring environmental considerations play a role in investment decisions. As new processes will likely emphasise incentives and market-

[22] Respectively Susan F. Clark, chairman of the Florida PUC; John B Howe, chairman, Massachusetts PUC and James J. Malachowski, chairman, Rhode Island PUC; all quotations taken from Schuler 1996a)

based approaches to regulation versus central planning and command and control regulation, it will be difficult for environmental groups to have the same degree of influence. The question therefore is not whether IRP can continue in a competitive environment, but whether its goals are compatible with competition. While regulators can continue to subsidise renewables and DSM by imposing a distribution tariff and allocating the revenues to environmental policy programmes, regulators will no longer have the ability to order specific companies to make specific investments. Furthermore, according to Lee and Darani (1996) the means of promoting such programmes will be more explicit and thus more vulnerable to political attack.

Electricity restructuring will affect the many policies that state regulators have devised to deal with power plant emissions. Environmental regulation of utilities at the federal level has increasingly been moving towards incentive based means of enforcing environmental accountability. If the EPA is granted more authority in terms of administering a nationwide cap-and-trade programme, it is possible that increased competition could enhance such programmes. That said, federal programmes often lack some of the accountability, public accessibility and specificity that localised environmental utility regulation offers. If the state level institution of IRP must wither as a casualty of restructuring, another institution must be created to ensure that some of the advances won through the application of IRP are sustained.

So long as unresolved or unrecognised tensions between environmental and economic regulatory priorities persist within regulatory institutions, the task of resolving these tensions on the ground will be more complicated. In both countries, efforts are being made to define new roles and priorities for regulatory institutions which are more appropriate to the emerging, competitive industrial landscape. However, insufficient attention is being paid to the task of meshing together the responsibilities and objectives of economic and environmental regulators.

6. FUEL MIX

In Chapter 2 it was stressed that a change in market structure alone will not necessarily increase or decrease carbon emissions from electricity generation. Subsequent chapters have identified other significant variables affecting emission levels, including the political economy of environmental legislation and the evolution of regulatory institutions, through which changes in market structure could be *translated* into changes in carbon emission trends. But the chain of causal relationships is not yet complete. A stronger industry lobby, higher capital costs, or a regulatory approach rendered obsolete will not spontaneously lead to changes in emission patterns. Instead, these changes affect certain critical industry decisions regarding investments in generation infrastructure and efficiency programmes, which in turn affect emissions.

Future patterns of carbon emissions are a function of the investment decisions made today regarding the type of fuel sources to power the generation facilities of tomorrow. The aim of this chapter is to investigate how the industrial, economic, legislative and regulatory changes wrought by restructuring have affected the fuel mix decisions of electricity producers. The fuel mix trends of the past quarter century in the USA and the UK will be considered in light of concurrent changes in industry market structure, environmental policy and regulatory institutions.

6.1 UK Fossil Fuels

CO_2 emissions from UK power stations have decreased by over 25 per cent in the period 1990–97, despite a 13 per cent increase in electricity demand. Over two-thirds of this decrease can be accounted for by fuel switching from coal to less carbon-intensive gas and nuclear fuels. In terms of overall carbon emissions, it is estimated that 60 per cent of the UK's reduction since 1990 has been achieved through fuel switching in electricity generation.[23]

The electricity industry has the most significant potential for carbon abatement through fuel switching because of its relative flexibility and wide range of non-fossil fuel options. Existing technical opportunities offer tremendous potential for further reduction of carbon emissions from power generation. The policy instruments required to orchestrate such a shift are also relatively simple: special taxes, subsidies, support for research and development and direct intervention can all affect the relative competitiveness of different fuels and generation technologies. There are, however, several factors which can constrain the pace of fuel switching; not least, the nature of past investments in supply and demand infrastructure and technology. Understandably, there will be pressure to use existing capacity, especially if it is relatively new, before investing in new, more efficient capacity. Recent developments in the UK serve to illustrate that the promotion and facilitation

[23] DTI 'Provisional 1997 estimates of carbon dioxide emissions', *Statistical Press Release* P/98/594, 30 July 1998.

of fuel switching can be an extremely contentious issue, both economically and politically (see Grubb 1990).

In the early years of restructuring, not wanting to over-impose on industry decision making, the government restricted its influence in the realm of fuel mix decisions to the Non-Fossil Fuel Order (NFFO) (which required RECs to purchase a given percentage of nuclear and renewables output), coal contracts, and the continuing obligations delineated in the Energy Act of 1976 and the Electricity Act of 1989 (which required companies to seek permission from the Secretary of State before constructing, repowering or operating power stations of any significant size). Thus the question of who burns what was left very much to the generators themselves, although it has been demonstrated that the DGES has had an indirect but not insignificant influence on fuel choice through the exercising of his primary duty to promote competition.

Changes in the UK fuel mix for power generation since 1975 are presented in Figure 6.1, while Figure 6.2 illustrates how predictions of future fossil fuel use in power generation have changed over the past fifteen years. Among the more conspicuous trends made apparent by these figures is the declining role of coal since vesting, and the increasing role of gas.

6.1.1 Coal

For over two centuries, coal has been at the heart of Britain's energy sector. Demand declined steadily throughout the 1950s and 1960s, but stabilised at a level of roughly 35 per cent of total energy demand throughout the 1970s and early 1980s when it reclaimed its dominant position in power generation following the first oil shock. Gas was expensive and in limited supply during this period and thus was not considered seriously for power generation. The relationship between CEGB and British Coal, manifested in part in a Joint Understanding which determined the price structure between the two bodies, helped to secure coal's position in the generation fuel mix (Helm 1989).

Developing international coal markets, the defeat of the unions in the 1984–85 coal miners' strike, and the relaxation of international energy markets following the oil price collapse in 1986 all served to weaken the position of domestic coal in the generation fuel mix. By the late 1980s, gas and non-fossil fuel sources were posing a serious threat. Faced with import competition, competition from other fuel sources, and increasingly stringent environmental legislation, UK coal production fell by over 60 per cent between 1980 and 1996.

Although government support of the industry had been in decline prior to vesting, as the government set to work defining the structure and nature of the new, privatised electricity industry, it was by no means indifferent to the fate of coal. To begin with, the government was the coal industry's ultimate owner; any negative effects of restructuring on coal revenues would make it more difficult to turn the plan of privatising the industry following electricity restructuring into a reality. Consequently, at vesting the government imposed a series of back-to-back contracts between British Coal, the two main generators and the RECs which obliged generators to maintain pre-privatisation levels of coal use until March 1993. As a

result of these contracts, from 1990–93 domestic coal prices were maintained at levels well above world prices, at the expense of the remaining franchise customers.

When the first round of contracts was due to expire in March 1993, negotiations for further contracts commenced. RECs refused to buy additional volumes of coal-generated electricity above market prices unless they could pass on the costs to their remaining franchise customers. Because the DG was not due to set new retail price caps for REC suppliers until the following summer, the RECs had insufficient information on which to base coal contract negotiations. A compromise was reached and a new round of contracts was put in place for five years, albeit with lower volumes and a dramatically lower price. This second round of contracts continued to limit the scope of the pool price to influence real electricity prices, although the differential between the pool price and the wholesale price was reduced with the new contract terms.

As 1998 approached and the end of the five-year contracts drew near, the industry grew anxious. Its proponents began to argue that coal did not face a level playing field, and that a further advance of gas (and thus, a further contraction of the coal industry), would endanger the security of supply and technical system stability. In November 1997, Energy Minister John Battle offered some solace to the coal industry in a set of measures which included a proposed review of trading arrangements, increased support of clean coal technology development and an order issued to the larger generators to divest redundant coal-fired capacity. These measures proved insufficient to mollify the coal lobby, one of the party's oldest constituencies, and thus the government felt compelled to offer something more substantial. The next month it announced a government review of long-term energy requirements, making special mention of the need to re-evaluate fuel mix in generation (Henderson & Hughes 1998). In addition, a moratorium on gas-fired stations was introduced and an extension of coal contracts with the three main generators until the review was completed.[24]

The results of the review, released in October 1998, included among other things the promotion of new trading arrangements, a divestiture of underused coal-fired stations by the major generators to encourage more intensive use of coal-fired plant, and a temporary restriction on the construction of gas-fired power plant. These measures, however significant, do not signal the end of the problems of the coal industry. Although it continues to contribute 40 per cent of fuel for generation, current use of domestic coal is limited to those power stations that lie in close proximity to the remaining British coal fields, indicating that coal is hard pressed to compete with imported coal and other fuel sources on a cost basis. Generally, the long-term prospects for coal are poor: gas-fired generation is cheaper, and it reduces dramatically the risks associated with future environmental regulation. Natural gas produces approximately half the CO_2 emissions per unit of electricity generated and avoids the need to fit costly flue gas desulphurisation equipment (FGD).

Maintaining coal burn as a medium-term policy runs directly counter to the government's declared objectives with respect to SO_2 and CO_2 emissions abatement. Although the October report contains a promise to increase funding for

[24] *Inside Energy* (1998), 'Sign of Hope for Coal', 16 January 1998.

the development of clean coal technology, any measures to do so at this stage are likely to bring minimal benefit given the industry's other problems. Since the capital costs of FGD equipment are broadly comparable with the cost of investing in a new gas-fired station, while the continuing operation costs are likely to be cheaper for a gas plant than a retrofitted coal plant, it is unlikely to be economical to meet SO_2 emissions standards through clean coal technology. Furthermore, FGD does nothing to address the problem of carbon emissions.

The full environmental impact of the new coal deal will, of course, depend on the magnitude of the increase in coal burn and the type of fuel it displaces. For every 1mt of extra coal that is burned, 2.4 TWh of gas, nuclear or renewables will be displaced. According to OXERA (1998a), switching from gas to coal will thus increase emissions by 54 per cent/TWh (approximately .35mtC/mt), while switching from nuclear or renewables will increase carbon emissions by approximately .65 mtC/mt of coal.

6.1.2 Gas

Even after natural gas was discovered in the North Sea, it was seen by the EC and UK governments, and the state-owned British Gas Corporation, as a premium fuel that was not suitable for bulk burning at power stations. In 1975, an EC directive explicitly banned the use of natural gas for power generation in an attempt to conserve what appeared to be a limited supply. Natural gas distribution was privatised in 1986, and in 1988 the restraints on burning it were dismantled. As Figure 6.1 shows, gas's share of the generation for fuel mix has been steadily increasing since 1990, with its highest rate of increase occurring in 1996/7.

Prior to vesting, it was thought that the main challenge to domestic coal in the newly privatised electricity industry would come from coal imports. Instead, producers were quick to realise that gas technology (spurred on by increased demand in Pacific Rim countries and since then commercially available), was more efficient, cheaper to build, and less environmentally harmful than coal plant. Increased production on the UK continental shelf had resulted in lower gas prices, and new gas plant had become cheaper to operate than coal. Consequently, in the 18 months following privatisation, Britain ordered enough plant to replace 25 per cent of its generation capacity, most of which was coal fired, with CCGT technology.

National Power and PowerGen ordered approximately half of the new gas capacity, in the interest of protecting their market share, moving away from coal dependence and because it was a cheaper way of meeting air quality standards than retrofitting coal plants with FGD equipment. The remainder of the investment in CCGT was made by the independent power producers and the RECs who were looking to reduce their dependence on the two large generators.

As discussed in the previous section, in October 1998 the government released a White Paper, prompted largely by the threat of further coal closures, which mandated, among other things, pool reform and a moratorium on new gas plant. Loss of fuel diversity and a distorted market were cited as the principal justifications for this.

With respect to the fuel diversity argument, the report predicts that by 2003, in the absence of intervention, gas would be supplying 60 per cent of fuel mix, while coal's share would have fallen to a mere 10 per cent (DTI 1998b). The government argues that this encroaching lack of fuel diversity, and thus jeopardisation of fuel security, could be averted by ensuring the correction of those market distortions which are allegedly leading to irrevocable loss of coal mines and coal plants.

As for these market distortions, the review concludes that the comparative costs of new gas plant versus existing coal plant cannot explain the speed and scale of the dash for gas, and that it is the result of a market playing field sloping in gas's favour. It is argued that electricity pricing has thus far been distorted by oligopolistic behaviour; because the price is set by the marginal bidder, and because there are only three companies competing at the mid-load level, large generators have been able to exploit their position as price setters, so keeping pool prices artificially high. The government argues that this has led to an under-utilisation of coal-fired capacity, and the sustained high prices have sheltered new CCGT and contributed significantly to its success. Furthermore, over-capacity of gas in the UK has meant that it has been under-valued, further discriminating against coal.

To correct these identified market distortions, the government intends to reform the pool. Realising that it will take many years before such a reform can effect real change, the government continued a gas moratorium so as to ensure that gas does not continue to undermine coal's position in the interim. The moratorium is designed to block CCGT applications which do not yet have consent under section 36 of the Electricity Act of 1989[25] and Section 14 of the Energy Act of 1976.[26]

Maintenance of a gas moratorium on new plant consents is unlikely to have an immediately perceptible effect on domestic coal demand for power generation. To begin with, there is gas-fired capacity 'in the pipeline' which has already obtained consent and is in various stages of construction. Second, in this new, coal-friendly market environment, there is no guarantee that generators will agree to purchase domestic coal versus imported coal which is cheaper and has a lower sulphur content. Finally, on account of the declining availability of economically workable coal, any short-term gains are unlikely to result in a lasting role for domestic coal in British power generation, indeed it is perplexing how domestic coal, which has been 'discriminated against' by the market's artificially inflated pool prices, will be able to compete in an undiscriminating market where prices will purportedly be lower.

The release of the government paper was met with a fury of protest from all directions. The Parliamentary Select Committee on Trade and Industry came out strongly against the moratorium, when the Chairman, Martin O'Neill, declared that

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[25] This section makes it necessary to obtain consent from the Secretary of State before constructing, extending or operating an electricity generating station above 50MW. He may impose conditions and/or require the applicant to obtain planning permission.

[26] This section requires anyone proposing to establish an oil or natural gas plant in excess of 10 MW to obtain permission from the Secretary of State. The Act gives him power, 'if he thinks it expedient having regard to current energy policies', to direct that a proposal not be carried out, or that it be carried out in accordance with specific directions.

'there are no reasons on grounds of security of supply, or in terms of confidence in long-term availability to resist the growing use of gas'. Within two weeks of the White Paper's release, the IEA was calling for the moratorium to be lifted as soon as possible, suggesting it would cause injurious market distortions. OFFER was equally critical, with the DGES (Steven Littlechild) protesting that the construction of new gas-fired plant to replace coal is a 'rational response to environmental constraints and economic realities', and that the moratorium did not seem justified.[27]

The decision to restrict new gas plant in the interest of promoting coal-burn makes emission targets more costly to achieve. The imposition of the moratorium is a clear example of tension between competing objectives being resolved to the detriment of the environment. Interestingly, this is not so much a case of tension between economic and environmental goals, but rather a case of contemporary political pressures about the future of the domestic coal industry overriding the environmental goal of emissions abatement, and economic goals of efficiency and unfettered competition.

6.2 UK Non-Fossil Fuels

Figures 6.3 and 6.4 reveal the trends in non-fossil fuel use for power generation since 1975, and the changing predictions for the future use of non-fossil fuels in generation. Nuclear is by far the most dominant non-fossil fuel used (although predictions with respect to its future role have become more conservative over the past fifteen years), and the role of renewables, however negligible, has been increasing.

6.2.1 Nuclear

In 1956, the UK became the first country in the world to generate electricity from a large-scale nuclear power station. Although nuclear generation has expanded steadily since its inception, projections of the magnitude at which it will ultimately operate have been dramatically scaled down. As in most countries, the UK programme has been fraught with problems from the outset. It had initially focused on an advanced gas-cooled reactor design which proved to be an economic and technical disaster. In 1979, the government turned to a Pressurised Water Reactor design (PWR), still clinging to the hope that its investment in nuclear generation would prove lucrative and worthwhile. Chernobyl in 1986, low oil and gas prices, the defeat of the coal unions in 1985, planning delays and a series of investigations highlighting the decommissioning liabilities, demand forecasting mistakes and inherent riskiness of the nuclear programme meant that by 1989, there was still only one PWR reactor under construction (see Grubb 1990; NAPAG 1993).

Privatisation and industry restructuring dealt a blow to the government's core energy policy of nuclear expansion. Higher rates of return on capital, shorter capital write-off periods and the reallocation of risk, made the nuclear programme a very unattractive investment. Initially, the government had wanted to include nuclear assets in the privatisation programme, but it soon became clear that with the costs of fuel reprocessing, accident insurance, decommissioning and commercial

[27] See *Power UK*, 'Offer blasts de facto moratorium', 26 August 1998, no. 54.

production all accounted for, nuclear liabilities were too great to be carried by the private sector. Nuclear plants were thus withdrawn from the privatisation sale, and a new public company, Nuclear Electric, was hastily created. To ensure that the company could cover costs, a Fossil Fuel Levy (FFL) was imposed as a 10 per cent surcharge on every electricity bill.[28] The levy was calculated so as to provide income to Nuclear Electric for eight years (the EC prohibited the subsidy from being imposed indefinitely).

The future of nuclear power generation in the UK remains unclear. On the one hand, in a competitive generation market without long-term contracts or vertical integration, the investment risks associated with new nuclear projects are too high for the private sector to bear in the absence of some sort of government insurance. Attempting to push for a large-scale revival would be economically difficult, politically unpalatable and probably impossible. While it is possible that new reactor designs and international safeguards could minimise risk to a certain extent, considerable economic, social and environmental risk would remain.

In August 1998, the government signed an agreement alongside the other fourteen nations which comprise the Convention on Pollution Prevention in the Northeast Atlantic. This has significant implications for the nuclear sector. In order to meet its radioactive discharge reduction requirements, the government is set to close all its older stations by 2010, and it is likely that this will start as early as 2001 to smooth the decommissioning and fuel reprocessing processes.[29] Ironically, this move comes at a time when the government is increasing coal-burn and striving to meet ambitious carbon emission reduction targets.

Of course, nuclear power contributes substantially to the limitation of greenhouse gas emissions. There are at present no plans to construct new plants in the UK, and whether or not nuclear has a role to play in meeting future targets is a contentious issue. From a practical point of view, it has been estimated by Grubb (1990) that the nuclear option is up to seven times more expensive per unit of carbon saved than efficiency improvements. That said, several studies have indicated that efficiency improvements alone cannot bring carbon emissions anywhere near the targeted levels. The DTI and British Energy are among those suggesting that it will be 'virtually impossible' to meet UK Kyoto targets without a substantial contribution from nuclear energy.[30] Such declarations have, however, come under fierce attack by environmental groups who insist that new nuclear capacity is not needed to meet targets, and that the answer lies instead in less polluting, more efficient, renewable forms of energy.

6.2.2 Renewables

Fuel switching to renewable energy sources offers the multiple benefits of acid-gas abatement, increased technical diversity (and thus increased energy security), resource conservation and carbon abatement. Renewables are the only supply-side

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[28] For details see Leach (1991); Helm (1989); Massey (1993).
[29] See *Power UK* ,'Magnoxes set to shut by 2010', 26 August 1998, no 54.
[30] See *Inside Energy*, 'Policy announcement-damp squib or lasting solution', 3 July 1998.

option for carbon abatement, aside from high-tech carbon storage, that comes without the high risks associated with nuclear power.

The UK government has estimated that domestic, accessible, renewable resources (defined as technologies capable of producing electricity for less than 10p/kWh (1992)) could meet the UK's current electricity demand three times over. Although the country is too far north to have significant solar power potential and is without significant geothermal aquifers, it has some of the best wind and wave energy sources in the world. More than two-thirds of Britain is classified in the top two wind speed categories of the European Wind Resource Atlas, and total offshore wind resources alone are estimated to be of the same scale as total electricity demand. Other important renewable resources include energy crops, municipal and industrial waste combustion, landfill gas, conventional forestry and agricultural wastes and hydro.

Unfortunately, those resources with the greatest technical potential also tend to bring the greatest economic risk. High costs, long construction times, technical risk and market uncertainty render large-scale off-shore wind and tidal projects unfeasible as purely commercial ventures in a competitive market with a short-term investment horizon, unless fossil fuel prices increase significantly. Leach (1991) and Grubb (1990) argue, however, that they constitute the key to meeting energy diversity, security and environmental objectives simultaneously. That said, major government commitment would be required for their development, the likes of which is probably impossible in the current political climate.

Indeed, there are a number of major obstacles to having renewable sources make large-scale contributions to the UK's power generation fuel mix. There are technical problems associated with siting, reliability, and power availability that fluctuates with natural cycles. Formidable institutional barriers are embodied in the conventional financial, legal and planning structures of the industry, and finally, renewable technologies tend to be more capital intensive. Because the 'fuel' used by renewable energy technology does not cost anything, the bulk of the total costs for construction and operation are paid up front. High discount rates and short contract lengths do not favour such investments.

The UK renewables programme prior to privatisation was limited to research, development and demonstration initiatives. In the mid-1970s, the emphasis was on wave power, followed by wind, geothermal and solar. Beginning in 1978, the emphasis shifted to wind, with the CEGB taking some tentative steps to invest in small wind power after having been criticised for its predilection for large non-renewable plants. In 1982, the Government Advisory Council on R&D for Fuel and Power undertook a major review to assess the potential of various renewable technologies in Britain which led to decreased emphasis on wave power and increased emphasis on geothermal and tidal (Surrey 1996). Figure 6.5 shows data on government budgets for non-fossil fuel research and development in the UK.

Under the 1983 Energy Terms Act, electricity boards were obliged to buy electricity from IPPs, but at 70 per cent of the rate paid to CEGB. Thus, renewable schemes could sell their electricity if they were connected to the grid, but at low prices. This arrangement meant that only a few renewables projects were developed,

namely those large wind and tidal projects developed by the CEGB. Under public sector conditions, however, very long-term contracts were the norm, as were low rates of return (see Elliot 1992).

In the earliest discussions of electricity privatisation, it was recognised that it was politically, environmentally and economically advisable to include some means to ensure the continuing contribution of non-fossil fuel sources. The 1988 paper outlining the government's restructuring plans made explicit the goal of ensuring that 15–20 per cent of electricity was provided by such sources. Although the government's concern was primarily nuclear, there were widespread hopes that the reform of the electricity industry would favour at least some renewable energy technologies. In 1988, the then Secretary of State for Energy, Michael Spicer, declared that the 'privatisation of the electricity supply industry should boost the commercial prospects for these (renewable) technologies as the free market is established' (quoted in Elliot 1992). As vesting day drew closer, however, it became clear that, given the state of development of renewable technologies, the provisions protecting coal and nuclear and the high rate of return demanded by private financiers, renewables would not survive the unfettering of market forces in the short term. Thus, the case for government intervention was clear.

The government made clear from the beginning that it was strongly opposed to offering financial incentives for renewables, and insisted that support should be limited to the financing of initial research. Over time, however, it was forced to temper this competitive market approach. Consequently, the Electricity Act of 1989 offered support for renewables through an unprecedented market enablement approach: the Non-Fossil Fuel Order (NFFO). The NFFO is an output subsidy which guarantees a premium price for those renewable electricity generation technology projects that are successful in their application for a contract under the programme. Sections 32 and 33 of the Act empower the Secretary of State to order the RECs to arrange to secure specified amounts of generating capacity from specified renewable sources. The RECs deal collectively with a Non-Fossil Fuel Purchasing Agency to sign contracts with the renewables-based generators. Initially, the orders were intended to fulfil a government goal of 1500 MW declared net capacity of renewables by 2000.

Recognising the higher costs associated with purchasing from renewable generators, the government generated revenues to cover costs through the imposition of a fossil fuel levy, a statutory charge built in to the bills of consumers, which distributed costs across almost all users. The revenues are paid out to the RECs according to the additional costs they incur in meeting their NFFO obligations. Applicants applying to the NFFO do not receive any capital grant, but are guaranteed a premium price per kWh upon winning an NFFO contract to supply.

The NFFO originated as a mechanism to guarantee a market for nuclear power exclusively in the new market conditions. It was only after strenuous lobbying that the government set up a protected quota of 600 MW for renewables, to be filled in stages by 2000. The order stipulated that all applicants had to be able to offer power at a per kWh cost of 6p or less. Under the initial assumption of a 15 to 20 year contract term, many producers could satisfy this requirement and the

government received more applications for its first renewables order than anticipated.

Before contracts could be negotiated, however, RECs began demanding shorter, more flexible contracts, and more importantly, the EC began to protest that the fossil fuel levy was in conflict with the EC's 'fair competition' rules. As nuclear power would obtain the lion's share of the non-fossil fuel tariff, the whole mechanism was perceived by the EC to be a 'nuclear tax'; that renewables would also benefit was incidental. The UK was able to negotiate a compromise wherein the levy was permitted on the grounds that it would be terminated in 1998. This eight-year limit had disastrous implications for many renewables projects which could not meet the 6p/kWh cap if capital costs could not be spread over twenty years.

Since 1990 there have been five non-fossil fuel orders, the fifth issued in September 1998. Tables 6.1 and 6.2 present data from the first four orders.

A number of logistical changes have been made since NFFO-1. In NFFO-2, the government decided to set six different bands in order to ensure that as each technology was approaching commercial viability it was given access to the market, without having to compete directly against more mature renewable technologies for a contract. In NFFO-3, the eight-year funding limit was abandoned, but this led to over-subscription, which meant that 380 applicants spent a lot of time and money preparing unsuccessful bids. NFFO-4 set more stringent and thus discriminating price caps, underlining the goal of bringing down renewable prices to converge with market prices. The recently announced NFFO-5 is the first to be issued by the Labour government and places considerably less emphasis on market convergence. At the time of writing, 408 projects with a capacity of 2579 MW were competing to be included in the order, with contracts anticipated to be fifteen years in length for five technology bands.[31]

The government has set a target of 10 per cent of electricity demand to be met with renewables by 2010, stating that this would contribute savings of up to 5.4 MtC in 2010, in addition to reductions realised through NFFO arrangements currently 'in the pipeline'.[32] Assuming that demand will increase at 1 per cent per year, renewables capacity will need to be 8300 MW in 2010 to meet the target – nearly ten times current levels.[33] This would imply a programme of 500 MW per year for the next ten years. The DGES has publicly argued that the cost of achieving the target is prohibitively expensive, suggesting that it will be somewhere between £11 and 15 billion which would necessitate a levy rate of 6–8 per cent over the next fifteen years (currently, the rate is 0.9 per cent). It is worth noting, that even if this target is reached, the total share of carbon free technology in 2010 would still be less than present levels due to nuclear retirements.

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[31] The bands are expected to be: landfill gas, municipal and industrial waste, municipal and industrial waste with combined heat and power, small-scale hydro and wind power.

[32] *Inside Energy*, 6 November 1998

[33] *Power UK*, 'OFFER queries cost of government's renewable target', September 1998, no. 55.

Table 6.1: Status of NFFO Orders as of June 1998

	Projects Contracted		*Projects Generating*		*Projects Terminated*		*Projects to Commission*		*Completion Rates*	
	No.	*MW*	*No.*	*MW*	*No.*	*MW*	*No.*	*MW*	*No.*	*MW*
NFFO-1	75	152	61	141	14	7.6	0	0	81%	93%
NFFO-2	122	472	82	173	40	298	0	0	67%	37%
NFFO-3	141	627	56	163	2	2	83	461	40%	26%
NFFO-4	195	843	8	14	0	0	187	829	4%	2%
Total	533	2094	207	490	56	308	270	1290	39%	23%

Source: OFFER (1998a)

Table 6.2: Fossil Fuel Levy: 1990–98

Year	*Total (£m)*	*Nuclear (£m)*	*Renewables (£m)*	*% allocated to Renewables*
1990/1	1175	1175	0	0
1991/2	1324	1311	13	1
1992/3	1348	1322	26	2
1993/4	1234	1166	68	5.5
1994/5	1205	1109	96	8
1995/6	1105	1010	95	8.5
1997/8	279	143	136	49

Source: Mitchell (1997)

Although the future of renewables remains uncertain, what is clear is that there is no likelihood of the government meeting its target through operation of the free market alone. There is no choice but to continue to use some form of NFFO mechanism, and to an unprecedented extent.

Figure 6.5 clearly demonstrates that, since vesting, the government has cut back significantly on its investment in renewables research and development. This can be attributed to the belief that the renewables technologies themselves are now well understood, their relative potential has been comprehensively assessed, and that money is better spent on market-based support such as NFFO orders.

This change in research emphasis and changes in industry structure are difficult to separate. It was the conclusion of the Watt Committee that 'new institutional and financial factors would seem to positively harm the prospects of increasing the proportion of electricity supplied by renewable sources' (quoted in Elliot 1992). There is no denying that institutional and strategic uncertainties, costly and short-term contract conditions and high levels of risk have not complemented

well the competitive position of renewables in restructured markets. Furthermore, the fact that renewables were tied to nuclear via the NFFO arrangement proved to be fatal to many renewable candidates, at least initially. In retrospect it appears that, while the advent of the NFFO levy as part of the privatisation regime has stimulated some projects that would not otherwise have gone ahead, in general privatisation arrangements have hindered as much as helped renewables.

It is difficult, perhaps impossible, to predict how renewables would have developed over the past ten years in the absence of restructuring. There were practically no generation projects apart from hydro and limited wind and tidal prior to privatisation. However, considering the increased public concern for energy issues and the growing momentum behind environmental legislation over the past decade (a phenomenon quite independent of restructuring), it seems fair to say the increase in political support for renewables development, of which the NFFO is a result, is more a function of changes in the environmental political economy than changes in the electricity market. Considering the financial character of renewable investments, renewables might have fared better if this increased political commitment had been manifested in a less market-oriented programme of intervention. Undoubtedly, the more novel, large-scale sources such as offshore wind and tidal power would have fared better in a programme that did not rely on the market to dictate which technology options were worthy of support. (Despite their potential, both are denied a technology band under the NFFO on the grounds of short-term economic non-viability).

The introduction of supply competition and new wholesale trading arrangements will create a host of complications for future renewables orders. At present, only the Public Electricity Suppliers have an obligation to fulfil orders, with no corresponding obligation imposed on other suppliers. As retail competition unfolds, PESs in their present form will no longer exist, making it prohibitively difficult to impose NFFO obligations. Furthermore, under the current system, pool prices are used as a reference for reimbursing suppliers and for the cost of each project. Under the proposed reform of trading arrangements, there will no longer be such a price. These and other problems will require significant revision of the current NFFO system.

The UK has constituted a special and fortuitous case with respect to converging environmental, political and economic objectives in electricity restructuring. Fortunately, in the newly privatised industry, gas was the more economic and the more environmental choice. The economic appeal of gas meant that many of the potential deleterious environmental effects of increased competition (such as repowering or increased dispatch of old, polluting plants), did not occur. While the coal contracts ensured that a certain proportion of the base load was coal-fired, overall increased competition promoted environmentally friendly fuel switching. Of course, with the expiration of the 1998 contracts and the recent gas moratorium, a fundamental tension between environmental and economic/political objectives regarding the use of coal versus gas has surfaced. To some extent, this tension has been addressed at the expense of carbon abatement objectives, although it remains to be seen how the issue will ultimately be resolved.

As it happened, privatisation did not lead to early retirement of nuclear plant, although it played a part in bringing an ambitious national nuclear programme to an end. Perhaps ironically, it is environmental considerations that will ultimately lead to early retirements, thus placing heightened pressure on other means of reducing carbon emissions.

Where tensions have plagued the regime from the outset is in the realm of renewables. Increased capital costs, higher required rate of return on investments, higher discount rates, and an affinity for market-based schemes versus direct government investment have contributed to the chronic under-exploitation of tremendous renewable potential. Although the government has acknowledged the incongruity between the nature of the free market and the needs of developing renewables, its response (the NFFO) has been overly concerned with remaining true to the mantras of market competition and light-handed intervention. With the introduction of competition in supply, the entire NFFO mechanism requires reform. If the government is to meet either its renewable or its Kyoto target, it will have to be more brazen about placing environmental objectives ahead of economic and political ones.

6.3 US FOSSIL FUELS

A study of trends in CO_2 emissions per unit of GDP (Schipper et al 1996) found that in the USA, fuel mix was one of the most important variables in terms of accounting for changing emissions trends over the past quarter century, followed by energy efficiency. Of the 135 MtC carbon reduction expected from the American utility sector – equal to 35 per cent of the total Kyoto target – over 70 per cent comes from retirement of coal plants, repowering of coal plants with gas, and carbon ordered dispatching of the utility system. The remaining 41 million comes from increased contributions of renewables to the fuel mix, nuclear power extensions and power plant efficiency improvements.[34] Indeed, there is unanimous consent that in the American context, as in the British, the most promising way to 'decarbonise' energy is to switch to a less carbon-intensive fuel mix. The extent to which this occurs will depend on which generating units are retired, repowered and constructed in the years to come, as well as on how these units are operated. As this section will show, deregulation of electricity markets is substantially affecting the fuel-related decisions of American power suppliers and producers.

6.3.1 Coal

As shown in Figure 6.6, coal has been the fuel of choice in the electric utility industry for many years, fuelling more than 50 per cent of generation since 1980, and representing over 85 per cent of all domestic coal consumption. Figure 6.7 indicates that it will remain the dominant choice over the next few years. Coal is the only fuel which has consistently increased its contribution to the mix since 1975, achieving an overall increase of 53 per cent, albeit erratically. It has also consistently been the least expensive fossil fuel per unit of electricity yield, with

[34] Interlaboratory Working Group on Energy Efficiency and Low Carbon Technologies (1998).

prices in constant decline for the past eleven years. The recent continued downward trend has been attributed to improved efficiency in coal production and transportation, excess production capacity and the expiration, renegotiation and buy-outs of older high-priced contracts. Although increase in coal use had begun to slow around 1988, the rate of growth has recently sped up, not only because of low prices, but also due to the decline in nuclear generation. Sales of large gas-fired units to non-utilities have also meant that gas generation has dropped significantly (in California, July 1998 levels of gas-fired generation had dropped 57 per cent below 1997 levels), and coal has been the fuel of choice to fill the void.[35]

6.3.2 Gas

The recent history of gas use in American electricity generation is markedly different from that of the UK. Gas consumption for power generation in America peaked in 1980, at a time when it was forbidden to UK generators. Use of gas by the electricity industry declined throughout the 1980s, reaching a low in 1986. Despite being hailed by the Bush administration and the environmental community as the fuel of choice, and despite the increasing popularity of gas among the IPPs, new coal capacity grew faster in the late 1980s and early 1990s, largely due to the low cost and low price volatility of coal. Improvements in gas generation technologies and falling gas prices led to increased consumption in 1992, since when it has been the preferred source of energy for most new generating capacity. It is anticipated that utilities will add four times as much gas and oil capacity as coal capacity between 1994 and 2003 (see Hirst et al 1996).

6.3.3 Wholesale Competition and the Fossil Fuel Mix

Because competition has been incrementally and asymmetrically introduced to the American utility market, the impacts of restructuring on fuel mix have been less dramatic than in Britain. PURPA encouraged fuel switching to some degree in 1978 by eliminating market barriers to smaller qualifying facilities using renewables or cogeneration. EPAct, in allowing utilities to purchase power for distribution to retail customers from wholesale generators, made it possible for the IPPs to expand their share of the wholesale power market, thus indirectly encouraging natural gas (the preferred fuel among independent producers). Until this point, however, no acute tension between competing environmental, political and economic goals had surfaced as a result of competition as far as fossil fuel mix was concerned.

This changed dramatically with the introduction of FERC 1995 Order 888 which required utilities to provide open, non-discriminatory access to transmission and distribution facilities, so increasing the intensity of competition in wholesale generation. In order to understand why increased competition in the US electricity market has had negative environmental implications, it is important to highlight some distinct features of the US fossil fuel-powered, wholesale generation market.

1.Coal is cheap. In the UK, due to the predominance of older, expensive to operate coal plants, new gas-fired plant often proved to be more economical to build and

[35] IEA, *Electric Power Monthly-October 1998; Electric Power Annual 1997; Energy Policies of IEA Countries,* 1975–1998.

operate than the old coal plants were to run. Quite the opposite is true in many areas of the USA, where the existing and substantially amortised fossil fuel and nuclear generation base is much cheaper in the short term as compared with new gas-fired technology – provided that environmental costs are not taken into consideration. Figure 6.8 presents data on the related fuel costs for electricity generation in the USA. If trends continue as expected, the bulk of the existing coal fleet is likely to remain economically competitive relative to new candidates for entry, even when compliance costs with 1990 CAAA are included. The effect of Order 888 was to provide utility and non-utility generators greater flexibility in seeking the lowest cost electricity. Because the lowest cost generators are generally the high-emitting coal-fired plants, the increased competition borne out of open access to transmission, in the absence of more stringent environmental regulation, increases utilisation of high emission facilities (Bernow et al 1998).

2. Disparities in Environmental Standards Compliance Requirements. A factor which exacerbates the cost discrepancies between plants is the different emission limits imposed by various states for Clean Air Act compliance, and the differences in regulatory treatment of new versus old facilities. When newer emission standards were imposed under the CAA, older power plants, particularly those in the Midwest and Southeast, were 'grandfathered' in, giving them an unfair cost advantage over newer units. Although this has more direct implications for regional NO_x and SO_x emission levels, uneven emissions control does give the old plants an unfair cost advantage over the newer, more efficient plants The disparities in emissions performance across different generating facilities and states, and the implicit subsidies associated with that disparity, increase the chances that competition will encourage older polluting facilities to gain a larger market share unless further controls are put into place.

3. Economic Appeal of Extending the Use of Old Plants. As compared with the UK, American generation infrastructure is exceptionally old. The first reason for this is simply that American utilities were installing much more advanced equipment 30–40 years ago, and thus these older plants are able to achieve efficiencies close to what is expected of more modern installations. Secondly, American utilities were too optimistic in their demand forecasts in the mid-1960s–1970s, and constructed far more capacity than was needed. There has been little new capacity ordered since 1980, aside from that built by IPPs and QFs under PURPA. So far, the alternative of retiring an old plant to make room for a new one continues to be unattractive. It has been widely predicted that competition in the USA, instead of catalysing a dash to construct new, less-polluting plant as occurred in the UK, will continue to increase incentives to avoid incremental capital investments and extend the use of existing, low cost, coal-fired plants. Indeed, the 1995 open access legislation has not only served to extend the use of old operating coal plants, but also to revive those which had been moth-balled or retired (ICF 1997).

The aforementioned concerns – the low cost of coal, the implicit subsidy which old coal plants receive as a consequence of the grandfathering principle inherent in CAA policy, the tendency to extend the life of old coal plants – would be of little importance if polluting coal plants, prior to the issuing of Order 888, were

being used to their full capacity. In fact, a 1995 comparative analysis of emissions and cost characteristics of three major American power systems found that the one in the Midwest was characterised by substantially higher emissions of NO_x, SO_2 and CO_2 per unit of electricity than the systems in the Northeast and mid-Atlantic. Furthermore, it was estimated that the Midwest system could generate 60 million additional MWh for 3 cents per kWh or less, while in the Northeast (where total power supply in a typical year is less than 120 MWh), there was a limited capacity to generate more power at competitive prices (NESCAUM 1998). Not surprisingly, in the national arena, power companies in the Midwest are the biggest supporters of restructuring, whereas those in the Northeast are calling for a cautious approach (see Begley 1997).

Following FERC's announcement of the proposed rulemaking for Order 888, several environmental groups, north-eastern state commissions and utility companies protested that open transmission access would lead to a flood of cheap Midwestern coal-generated electricity into the high cost markets of the mid-Atlantic and Northeast, taking away market share from the costly but cleaner generating plants there. At that time, Midwestern coal plants were operating at utilisation rates in the low sixties, and there was concern that even a moderate increase would have a substantial impact on emissions.

FERC was required to conduct a thorough Environmental Impact Assessment (EIA) of the possible effects of Order 888, with a major emphasis on NO_x emissions. Carbon emissions were also considered, but SO_2 emissions were omitted from the analysis because they had effectively been capped by the CAAA (1990). Because of the uncertainties associated with projecting fuel prices, electricity demand, the economics of increasing transmission capacity, and the potential for increased performance from older coal plants, a number of alternative cases were considered, in the context of a utility forecasting model, in an effort to examine the potential impacts of the rule.

FERC published the conclusions of the assessment in April 1996, concluding that the Order 'poses no threat to the environment and promises substantial economic benefits'. [36] The key findings from all cases studied were that emissions are expected to increase over the next twenty years with or without open access, and that any increase that might occur as a consequence of open access would be negligible as compared to the increases that will result from increased demand and nuclear plant retirement. The assessment stressed that the proposed rule in no way hinders the enforcement of the CAA by the EPA. It drew attention to the well-established regulatory framework for air quality that already existed within the EPA, and concluded that there was no need for FERC to alter the Order or impose its own mitigation measures in the rule (US DOE 1996).

Although the EPA supported immediate implementation of the rule, it did refer the Order to the President's Council on Environmental Quality (CEQ) in May 1996 on the grounds that the rule could, under certain circumstances, have deleterious affects on air quality (NESCAUM 1998). In June, the CEQ concluded that

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[36] FERC (1996), 'FERC Issues Final Environmental Impact Statement on Open Access Rule',*FERC News Release,* Docket No RM95-8-000, 12 April 1996.

the rule should proceed, but with significant mitigation action. EPA agreed to take all available action under the CAA to limit NO_x emissions, and FERC was obliged to act should EPA efforts fall short.

The CEQ's verdict by no means satisfied all concerned parties. In particular, the Centre for Clean Air Policy and NESCAUM continued to find fault with both the FERC study and a later one by the IEA commissioned to review the FERC assessment. (The IEA study had arrived at results very similar to the FERC EIA). The concerned groups offered two major criticisms. The first had to do with the failure to assess the impacts of the order against a true 'no action' base case. Secondly, critics point out that, in concluding that open access would have little or no environmental impact, FERC makes the assumption that transmission prices, but not capacity, would change substantially in response to open access. Consequently, FERC was able to assume that transmission constraints would seriously restrict power flowing between regions to less than 5 per cent of overall generation up to 2005. As the Order explicitly requires that transmission owning utilities expand transmission systems as necessary to accommodate requests for further access, such an assumption was immediately suspect. It is also reasonable to assume that there will be an increased incentive to expand transmission infrastructure as wholesale competition increases demand for existing facilities. Furthermore, research conducted by NESCAUM in 1996 indicated that in fact, FERC had underestimated the ability of the *existing* transmission system to accommodate power flows between systems.

Less than five years after the order came into effect, it is early to assess the full impact of the order, but the initial effects can be identified. Between 1995 and 1996, several Midwestern electric power companies increased their short-term wholesale electricity sales substantially, some by as much as 84 per cent. In addition generation substantially increased at the companies' highest polluting coal-fired plants (NRDC 1998). Data on nationwide electricity generation indicates (NESCAUM 1998) that there was an increase of 83 million MWh in coal-fired generation and a decrease of 44 million MWh in gas-fired generation between 1995 and 1996. Contrary to FERC assertions, the existing transmission infrastructure was easily able to support a substantial increase in the flow of power from the Midwest to the eastern states (NRDC 1998).

6.3.4. Retail Competition and the Fossil Fuel Mix

In March 1998, California became the first state to introduce retail competition, and many, if not most states are preparing to follow suit. The driving force behind this competition comes from the large industrial customers, particularly the energy-intensive industries, who are hoping to cut production costs. Without adequate environmental safeguards, retail competition will further exacerbate the industry's air quality impacts.

In the absence of retail wheeling, utilities have a virtual monopoly over the provision of electricity. In exchange, the utility assumes the obligation to provide reliable service at reasonable rates. Retail competition implies a decentralisation of decision making. Consumers decide from whom they purchase power, and

investment decisions are triggered not by regulators, but by thousands of short-term power transactions that make up a dynamic market.

Perhaps the most troubling implication of retail wheeling is the demise of the IRP process of utility regulation. In a competitive retail market, PUCs can no longer require utilities to consider environmental and social costs when comparing options for power supply. Under the new system, utilities are simply responsible for maintaining wires; they have little planning function and no incentive to invest in customer-owned efficiency options. The service companies who do exist to act as middlemen between generators and customers have little incentive to invest in anything that costs even slightly more than the least expensive power plant. Thus, in a regime where customers are free to find the lowest cost supplier, it becomes very difficult for a PUC to ensure that social and environmental obligations are met.

It is debatable whether the substantial costs of retail competition, namely the fatal undermining of current regulatory structures and industry incentives which facilitate the realisation of environmental and social objectives, will in fact be outweighed by the benefits, namely the negligible reductions in overall supply costs, and thus prices. Another, more direct source of environmental impact comes with greater use of real-time pricing. It is estimated that retail deregulation will lead to an increase in load factor of 2.5 per cent as consumers respond to new pricing mechanisms by shifting their demand from peak hours, when electricity is more expensive, to non-peak hours. As a consequence of the economics and composition of the US generation mix, oil- and gas-fired generation is most likely to be the marginal source of generation in peak times, while coal will be more likely to be the marginal source, as the base load, in off-peak times. Consequently, higher load factors, as a result of retail competition, will result in higher carbon emissions in the American context (ICF 1997).

6.4 US Non-Fossil Fuels

6.4.1 Nuclear

Nuclear power has gone from being the smallest major source for energy generation in the USA to the second largest since 1975 (see Figure 6.6). This can be attributed to large plant construction programmes during the 1960s and 1970s when it was anticipated that nuclear would be the generation technology of the future. While the nuclear industry currently accounts for approximately 20 per cent of the generation fuel mix, its share is expected to decline as competition in generation intensifies. In a competitive market, owners of nuclear plant will find it difficult to afford any major maintenance investment (i.e., in excess of $100 million), as such improvements can no longer be included in the rate base and amortised over twenty years. When faced with such an investment requirement, utilities will probably respond by retiring nuclear plants early.

The potential impact of early nuclear retirement on carbon emissions is substantial. A study by Lee and Darani (1996) suggests that if 6000 MW of nuclear capacity is prematurely retired, this would result in 14–28 million tonnes of CO_2 emissions, depending on what fuel was substituted, which is equal to 5–10 per cent

of current US reduction targets. In another study (Palmer and Burtaw 1997) which models carbon emission increases as a function of transmission expansion rates, demand increases and early retirement of nuclear, it was found that if power imports from under-utilised coal plants in other regions are used largely or exclusively to displace existing nuclear generation in importing regions, national carbon emissions could increase by over 130 $MtCO_2$.

How states choose to resolve the stranded cost issue will have important implications for the nuclear industry. California was the first state to allow utilities to recover stranded costs over a transition period in exchange for them opening up their service territory to competition (see Roberts 1998). Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric are receiving a US$28B bail-out which will subsidise the future operation of California's nuclear plants, allowing them to run longer and secure a larger market share than they otherwise would. The policy position taken in the Administration's comprehensive electricity bill is that 'Federal policy should encourage the States to provide for stranded costs ... At the same time, the authority of the States ... should be preserved' (EIA 1998). With the government and utilities in favour of stranded cost recovery, it is likely that current nuclear capacity will be protected to some extent from the pressures of competition, thus moderating the acceleration of nuclear plant retirement.

6.4.2 US Renewables

In the United States, where energy consumption per capita and per unit GDP are among the highest of IEA countries, low carbon energy supply options are critical if the goals of continued economic growth and reduced carbon emissions are to be simultaneously realised. The USA is the largest user of non-hydro renewable energy among IEA countries; 2.3 per cent of electricity was generated from non-hydro renewables in 1996, with a further 9.6 per cent from hydro-power. Biomass and waste together account for over 70 per cent of the renewable supply, with geothermal taking most of the remainder (IEA 1998b). Much of the support for renewables comes from California, where 16 per cent of biomass, 94 per cent of geothermal, 99 per cent of solar power and 97 per cent of wind power generation in the United States can be found. In fact, California's current renewables capacity represents a significant fraction of the total, worldwide non-hydro renewables generation (see Wiser et al 1998).

Figure 6.9 depicts the trends in use of renewables for power generation since 1990 while Figure 6.10 shows predictions for 2000. Non-hydro renewables have remained virtually untapped by electric utilities, whereas renewable fuels collectively produced the second largest share of non-utility capacity in the manufacturing sector of the economy. The proportion of non-hydro renewable electricity has dropped slightly over recent years, reflecting small drops in wind and geothermal capacity, although it has been observed that this trend is reversing. According to Burnow et al (1998), wind power has become one of the most cost-effective renewable electricity technologies today, achieving costs as low as 4–5 cents/kWh. The dominant non-hydro renewable fuels for electricity generation continue to be biomass and waste. It is expected that electricity generation from

municipal solid waste (MSW) will grow faster between 1998 and 2010 than from any other renewable source. This could ultimately be hindered, however, by a Supreme Court ruling that the ash from MSW generation be treated as a hazardous waste (IEA 1998b).

To a large extent, the American non-hydro renewable electricity generation industry of today finds its beginnings in the 1970s when oil shocks, soaring energy prices and widespread public concern for air quality and pollution prompted a socio-political questioning of the nation's fossil fuel dependence. To stimulate the development of renewables, the Federal government offered generous tax incentives and invested heavily in research and development – research appropriations reached US$18.5 million by 1980 (Zucchet 1997). PURPA has also played a critical role in the promotion of renewables generation by guaranteeing markets, simplifying contracts and eliminating procedural and planning complexities. Thanks to PURPA, QF capacity makes up one-third of California Edison's utility capacity; California's QF contracts were particularly favourable, offering ten years of fixed avoided energy payments which now exceed 9 cents/kWh (Wiser et al 1998). There is reason to believe, however, that advancement of renewables under PURPA is coming to an end. Several legislative motions are circulating which aim to repeal the act, as well as FERC rulings in favour of utilities unhappy with mandated QF rates which limit the use of above avoided cost rates to promote renewables generation. Both could severely affect the commercial viability of the renewable electricity industry.

The Energy Policy Act (1992) has furthered the cause of renewables by providing incentive payments, investment credits and tax breaks to certain renewable technologies. In addition, the 1993 Climate Change Action Plan included a clause which directly endorsed an IRP approach to renewable promotion.

6.4.3 Competition and Renewables in the USA

Deregulation of electricity markets promises to substantially affect the continuing development and commercialisation of renewables. On a positive note, there are ways in which increased competition could feasibly enhance the progress of renewables in generation. To begin with, increased access to the transmission grid, provided it comes at a reasonable cost, could increase market access for more remote renewables sources, and for sources such as wind and solar which are often available at times that coincide with peak demand (Begley 1997). Assuming that the risk of future environmental regulation is real, a reallocation of risk could increase producers' willingness to pay more for renewables capacity in an effort to hedge risk. Finally, market surveys suggest that an element of the consumer population is willing to pay a premium for 'green' renewable energy. This demand can be tapped as competitive power suppliers look for ways to differentiate their product.

On the other hand, there is reason to believe that market deregulation puts past successes and future potentials of the American renewables industry in jeopardy. As competition brings prices down and markets seek out the lowest cost producers, prices paid to renewable producers are likely to be considerably less than those paid to QFs under PURPA. Despite their social, environmental and long-term benefits, non-hydro renewable energy applications continue to be more expensive

than conventional sources. Table 6.3 presents the comparative, total levelised costs of power generation from competing power sources.

Table 6.3: Levelised Costs of Electricity Generation (1995 Mills/kWh)

Technology	*Capacity Factor*	*Capital Costs*	*Operation & Mainten..*	*Fuel Costs*	*O&M + Fuel*	*Total Costs*
Coal	70	25.30	5.61	14.88	20.49	45.79
Gas Combined Cycle	70	7.43	4.82	20.37	25.19	32.63
Gas Combustion Turbine	30	13.76	4.63	41.04	45.67	59.44
Biomass	80	36.25	9.55	15.16	24.71	60.97
Wind	27	26.79	11.53	0	11.53	41.29
Solar Thermal	33	91.28	8.97	0	8.97	100.25
Solar Photovoltaic	24	143.68	3.11	0	3.11	146.78

Source: Bohi and Montgomery (1997)

The total cost of various power source options is typically the most important criterion when deciding between alternative means of expanding capacity, while variable (operations, maintenance and fuel) costs are most critical in determining dispatch order. Thus, while solar technology is extremely competitive in terms of variable costs, high capital costs act as a strong deterrent to investors. Although the total cost of wind power appears to be cheaper than coal and gas combustion turbine technologies, technical limitations associated with wind power generation are such that it cannot be seen as a substitute for more conventional power sources. While coal boilers and gas combined-cycle units are used to supply base load, wind technology is intermittent and non-dispatchable, requiring additional back-up technology, usually gas, to fill the gaps when wind is not available. These limitations operatively reduce the value of wind energy relative to coal and gas, hence making the cost of integrating wind technology into the power system more costly

The economics of renewable technology, and more specifically, the high ratio of capital to variable costs, serve to handicap renewables in a competitive market characterised by short-term investment horizons, high costs of capital and high discount rates. Without an assured revenue base to pay for long-term contracts, utilities cannot afford technologies that are not cost effective in the short run. In the absence of government intervention, renewables will be squeezed out of the market.

Renewables research and development programmes, which have been integral to the cultivation and fostering of the current renewables industry, have suffered significantly since the opening up of markets in 1995. Following a period of strong support in the 1970s, funding for renewables R&D declined throughout the 1980s when public support for environmental concerns in general was waning. Appropriations began to increase again in 1990, achieving a peak rate of increase in 1994. Since 1995, research budgets have experienced rapid decline.

The Department of Energy is responsible for overseeing federal research on renewable energy technologies. The National Renewable Energy Laboratory (NREL) is responsible for managing the majority of DOE renewables contracts, and in turn subcontracts to industry to support the majority of development activities. The DOE has recently been threatened with diminution or even liquidation through the DOE Abolishment Act (H.R. 1933) and H.R. 3415 which seeks to repeal the gasoline tax and recover the revenues through DOE budget cuts. The NREL faces its own problems as it grapples with severe budget cutbacks, including a reduction of 30 per cent ($113 million) in 1996. The government has rationalised the cutbacks by suggesting that industry will pick up the slack, and consequently the NREL is now expected to find 50 per cent of its funding in the corporate sector. Private companies, however, are dealing with their own downsizing as they prepare for increased competition and have little incentive to spend money developing technologies which would offer common benefit to all generators. Furthermore, according to Schuler (1996) the NREL's inability to predict funding makes it difficult to establish credibility and working relationships with industry partners.

Finally, the decentralisation of industry decision-making and increased competition will render many existing renewables policies inappropriate or non-viable. While some will remain – there is no reason that EPAct tax credits or state funded renewable subsidies should have to change – other programmes, such as resource-specific set-asides and environmental adders applied exclusively in the decision-making processes of regulated utilities, will be terminated. Opportunities to use state or federal authority to shape the generation choices of utilities will disappear, and thus the IRP approach (which not only served to promote investment in renewables, but also helped to incorporate environmentalists in the decision making and agenda setting process), will no longer be viable.

With core renewables policy programmes rendered obsolete, a regulatory void is created, and the question becomes, how to fill it? There are those who would argue that there is no void to fill. In a paper commissioned by the Natural Gas Supply Association, it is argued that competitive restructuring will 'eliminate many of the distortions of past economic regulation', thus removing the rationale for programmes to promote renewable energy. The report insists that 'if renewable energy is not a cost-competitive option for reducing emissions, then there is no environmental justification for promoting renewable energy', concluding that a free market approach provides all the incentives needed to make the right investment decisions (Bohi and Montgomery 1997). The problem with this line of argument is that it fails to acknowledge the un-internalised public goods and social costs associated with environmental impact, research and development and fuel diversity, problems of imperfect information and free readership which impair the market's ability to allocate resources optimally; and existing price distortions related to an unequal tax treatment and subsidies to fossil fuel and nuclear generation (Wiser and Pickle 1997). While the introduction of market discipline to the electricity industry promises many things, complete alleviation of those market failures which work to the detriment of renewables development is not one of them. Thus, the justification for intervention remains.

A variety of policy options exist for supporting renewables in restructured markets by improving their cost-effectiveness, financing research into technical improvements, furthering their diffusion into the market and helping to overcome the various short-term barriers they face. Policy discussions in the USA have tended to focus on three main supply-side support mechanisms, namely a renewables portfolio standard, funding of programmes through a distribution surcharge and green purchasing programmes. Of the ten states that have enacted restructuring legislation in 1998, eight had included an RPS or Systems Benefits Charge in order to support renewables (IEA 1998b).

The renewable portfolio standard (RPS) was first introduced by the American Wind Association and has been included in the Administration's new restructuring bill, mandating all electricity sellers to cover 5.5 per cent of their sales from non-hydro renewable sources by 2010. The RPS is set to expire in 2015 when it is expected that renewables will be firmly established in the market. The proposal also includes a cap to hold costs below a specified ceiling. To meet the purchase requirement, retail suppliers can either construct and operate their own renewable capacity, purchase credits from independent renewable energy facilities, or purchase credit from a private credit market. Because credits are tradable, renewables will command the same price nationally, equal to the marginal above-market cost of renewable energy. The premium is paid by all customers on a cents/kWh basis.

Because transmission and distribution elements of the power system remain natural monopolies, states will continue to have jurisdiction over the delivery of electricity to consumers, who will find it difficult and costly to bypass the use of local distribution facilities. Thus, there remains a non-bypassable means of taxing consumers without discriminating against any supplier or generator, enabling states to impose a systems surcharge in order to raise funds to finance renewables support.

A third alternative, and perhaps the most attractive to those wishing to remain true to free market competition ideals, is to rely on green marketing as a means of renewables support. The limitations of this approach have already been discussed in Chapter 3. Since green pricing programmes have just begun, it is too early to draw any conclusions about the capacity of the American market to encourage renewables development.

Several states have begun enacting legislation and initiating new approaches to renewables support in response to changing market conditions. Arizona has issued a solar portfolio standard through a regulatory order versus through restructuring legislation. Montana provides a 35 per cent tax credit on investment in wind energy (see Mastaitis and Weissman 1998). As the leader in both renewable development and electricity restructuring, California has since 1994 been debating how and to what extent renewables should be supported in a restructured market. Ultimately, a distribution surcharge was imposed, intended to raise $500 million between 1998 and March 2002. $100 million of this is available on a customer incentive plan to encourage green marketing.[37]

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[37] *Public Citizen*, 'A Green Light for Sustainable Energy in California', September 1998.

To be sure, the tensions between the goals of increased market penetration by renewables, and economic goals of deregulation, competition, low prices and economic efficiency are many. Renewable generation costs more in the short term. Forcing suppliers to include a renewables component in their generation contract mix will necessarily raise consumer prices, and thus it is perceived to promote economically inefficient means of meeting demand. Furthermore, government intervention through the RPS or distribution benefits charge is seen by some to 'introduce static distortions into an otherwise adaptive and competitive market', while at the same time denying consumers the freedom to choose between generation sources (Bohi and Montgomery 1997).

A consideration of the political economy of renewable energy in the USA reiterates the need for compromise, prudence and forethought in energy policy making. To the extent that the government is able to maintain a long-term perspective in its policy making, renewables could benefit from stable, effective policies. Each state will need to make its own decisions about how to intervene on behalf of renewables, what level of support is necessary and/or acceptable, what types of renewable technologies should be eligible for support and how to divide support between new and existing renewables facilities. In order to be politically palatable, legislators will need to demonstrate that new policies are competitively neutral and provide some means of cost containment.

6.5 Competition and Fuel Mix in the USA: Final Observations

The USA will have a more difficult problem than the UK in terms of reconciling economic, political and environmental objectives as competitive electricity markets develop. At least in the short to medium term, the most economic fuel choice for power generation will rarely coincide with the most environmentally sound choice. Unless states become radically more proactive about internalising the external costs associated with power generation, coal will continue to be the fuel of choice over the next few years. This is largely a result of low, non-volatile price, the grandfathering of old coal plants under the CAA, and the capacity of such plants in the mid-west to step up production in order to expand their market share in the Northeast and mid-Atlantic. Retail competition will bring increased load factors, and thus increased emissions as coal constitutes a substantial proportion of the base load.

The deleterious impact of increased competition on carbon abatement efforts through fuel choice is further exacerbated by the implications of competition on pre-existing regulatory institutions. First PURPA, which has been instrumental in the promotion of renewable generation, is being officially censured by FERC on the grounds that it is incompatible with the competitive environment. Even more troubling is the demise of IRP, an effective means of allowing social concerns directly to influence industry conduct which has evolved over recent years in many different state contexts. Although the IRP approach was far from perfect, it did offer a means of both incorporating external costs of industry decisions and offering a wide range of interest groups a seat at the management table. As a direct result of IRP, the inherent value of renewables as a viable alternative in the long run was gaining

recognition. Whether or not a more market oriented mechanism can be developed to achieve the same ends remains to be seen.

The extent to which fundamental tensions between environmental and economic objectives are resolved in favour of the former has been disappointing. The FERC EIA of Order 888 is a case in point. Although it is commendable that an EIA was carried out, and while measures were put in place to ensure that air quality impacts of the order are being monitored, the fact remains that the conclusions were founded on an erroneous assumption, and the actual environmental impact of the order has been demonstratively negative. Perhaps most telling and significant is the administration's unwillingness to include proactive carbon abatement measures in the Comprehensive Electricity Act, for fear that this would doom the bill to failure.

7. ENERGY EFFICIENCY

The theoretical justification for market reform in both the USA and the UK is that free markets deliver more efficient outcomes. These improvements are largely born out of reductions in capacity surplus, more efficient use of transmission and distribution systems, more efficient market pricing and improved project management. While there is no doubt that liberalisation will give rise to more efficient outcomes, productive, allocative and dynamic 'efficiency' in this sense are narrowly defined in terms which emphasise short-term monetary gains and expenditure, while de-emphasising long-term social and environmental costs and benefits. Consequently, the concept of efficiency as put forward in the endorsement of liberalisation is distinctly different from, and in some cases antithetic to, improving *energy* efficiency, which relates to achieving the same quality and level of some end-use of energy while using a lower energy input.

Helping consumers to use energy more efficiently can be the most cost-effective way to accommodate increased demand for energy end-use. Energy efficiency programmes can be seen as another means of meeting demand, similar to power plants, and can be used to avoid, delay or moderate the need for further system investments. Programmes can lower customer costs and increase customer satisfaction with the service, attributes which become more important as competition in supply matures. Energy efficiency improvements can also have profound environmental benefits. In defining a strategy to meet their respective carbon abatement targets, both the USA and the UK have placed considerable emphasis on improving energy efficiency, recognising that it is one of the few low-cost approaches to emissions reduction.

In the preceding chapter, fuel mix was presented as an intermediate variable in the relationship between changes in electricity market structure and changes in CO_2 emissions trends. Energy efficiency constitutes a second, significant, intermediate variable in this conceptual model. Increased competition, stronger industrial lobbies, changing environmental and economic regulatory institutions will all serve to hinder or help various approaches to achieving energy efficiency, which will in turn serve to exacerbate or ameliorate the carbon emissions problem.

7.1 ENERGY EFFICIENCY IN THE UK

It has become increasingly clear that the quickest, easiest way of limiting carbon emissions from energy generation without sacrificing economic productivity or living standards is to increase levels of energy efficiency and thus make each unit go further. In an October 1997 meeting of the Environment, Transport and Regional Affairs Select Committee, John Prescott, the current deputy Prime Minister and Transport Minister, identified energy efficiency as a key means of meeting the UK's 20 per cent domestic target, and indicated that utility regulation would be an important vehicle for promoting efficiency improvements.

The UK is widely recognised as a nation with vast stores of unexploited potential for energy efficiency improvements. Technical estimates suggest that the

UK has the capacity to reduce its energy use by 20–25 per cent (not including the transport sector) with minimal disturbance (see for example Jones 1995; Fells and Woolhouse 1994). The Energy Efficiency Office estimates that UK households are wasting £6.5 billion annually and that cost-effective energy efficiency measures such as improved home insulation could reduce CO_2 emissions associated with dwellings by 25 per cent.

Energy related concerns of the early 1970s brought energy conservation and efficiency issues to the political forefront. Before that time, although fuel suppliers had a statutory requirement to promote efficiency among their consumers, in fact producers did not see it as their responsibility to carry out any such obligation. The oil shock of 1973, however, prompted a host of new Labour policy initiatives to promote energy conservation and efficiency which effectively mobilised electricity suppliers to co-operate with government efforts. Public concern for dwindling resources persisted into the late 1970s, and thus there was widespread acceptance of energy conservation promotion as a legitimate government activity.

In 1979, a newly elected Conservative government pledging to uphold market principles brought an abrupt end to Labour's energy efficiency policy measures. The fall in oil prices that same year allowed governments to cut expenditures in energy efficiency programmes and still see an improvement in production per unit of energy costs. In contrast to the 1970s, when the belief that energy sources were running out forced governments to demand that firms and industry do their part, in the 1980s firms were largely excused so as not to interfere with their ability to compete.

Funding for energy efficiency programmes and agencies, although modest by European standards, did rise slightly in the mid-1980s, including a 40 per cent increase in the budget of the Energy Efficiency Office (EEO) in the Department of Energy between 1983 and 1987 (Leach 1991). In 1987, with the arrival of a new energy minister whose top priority was preparing the utilities for privatisation, projects were cut, budgets slashed, and efficiency played a negligible role in the formulation of the Electricity Act. The budget of the EEO fell more than 50 per cent from 1987–90, precisely the time when environmental and climatic concerns were on the upswing.

At the time of vesting, the need to increase levels of investment in efficiency could not be ignored and thus another wrench was thrown in the works of a government who would have ideally liked to abrogate its intervention in the industry more absolutely. As in the cases of renewables and air quality concerns, questions arose about the extent to which the government should intervene in the restructured market in the interest of providing a public good. Once again, the justification for intervention was largely a function of the extent to which the market failed to deliver the optimal amount of the good.

In the case of energy efficiency, the ability of the unfettered market to optimally exploit cost-effective opportunities to save energy is severely restricted. Scores of studies have identified a particularly large 'efficiency gap' in the UK; that is to say that there are widespread opportunities to invest profitably in cost-effective

efficiency measures which are not being pursued, indicating that the market is failing to allocate resources efficiently.

To begin with, there is the standard problem of imperfect information, such that consumers at all levels of the market are insufficiently informed about the variety of options and the benefits associated with energy efficiency measures. Supply and demand side organisational problems also lead to inefficient use of energy and electricity. Suppliers, particularly in the competitive market, have had little incentive to encourage consumers to use less of their product. On the demand side, corporate decision making tends to separate current and capital spending. Different forms of accounting and decision making can apply when comparing capital costs with incremental energy savings such that the common inclination is to postpone capital expenditures until absolutely necessary, even if investing today in energy efficiency measures could save money in the long term. A similar dilemma of divorced responsibility is manifested in the domestic sector, in the form of landlord/tenant relationships.

A third problem arises from investment priorities. Even in energy-intensive industry, energy efficiency is traditionally categorised as non-core business (Fells and Woolhouse 1994). In the domestic sector, many people view the electricity bill as a necessary and peripheral expenditure, and thus assign energy efficiency a low priority as compared to other investment options. Consequently, even those energy efficiency investments which are available on short payback periods in the domestic sector go largely unnoticed. For example, it is estimated that it will take over 200 years before low energy light bulbs, which last ten times longer than the conventional type, will have penetrated 90 per cent of the market (see Energy Savings Trust 1998 website). Other factors which serve as disincentives to investment in energy efficiency include lack of available capital (particularly among low income consumers), the failure of the market to reflect the full social cost of energy consumption and the tariff structures of the energy suppliers (Thomas 1994).

When increased competition and falling energy prices are added to the variety of market imperfections contributing to the sub-optimal exploitation of efficiency opportunities, the efficiency gap becomes that much more difficult to bridge. That is why, as electricity privatisation was in the process of being introduced, there was much speculation about how pre-privatisation levels of energy efficiency activity would be maintained.

7.1.1 Post-Privatisation Energy Efficiency Programmes

As part of the government's response to the 1992 Earth Summit in Rio, the Energy Savings Trust (EST) was established in collaboration with the energy companies as a non-profit company whose central aim was to identify, promote and manage energy efficiency schemes in the UK. It was hoped that through programmes encouraging energy efficiency, 2.5 MtC could be saved by 2000 at a cost of £1.5 billion. The idea of the EST had actually been developed in 1989, but abandoned. In 1991, following the privatisation of the gas industry, the concept of an 'E factor' was devised as a way to raise money from gas users in order to finance energy conservation. Questions arose as to whether British Gas could be trusted to use the E-factor

revenues for energy efficiency programmes exclusively, prompting the idea of creating an independent body to manage the funds. Thus the EST idea was resurrected; as initially conceived, it was to be a small, low cost agency created to manage the E-factor funds.

As it was preparing to open, however, the secretary of energy asked the chairman of British Gas to delay the announcement of the gas funded EST and discuss the possibility of broadening the mandate of the organisation to include the electricity industry. Consequently, when the EST was finally set up there were three guarantors: British Gas, the government and the RECs. With the government unable to contribute funds, British Gas (whose customers had funded the entire establishment and development of the institution) feeling it had made a disproportionately large contribution to the partnership, and the RECs unhappy about not being consulted on the idea, this coalition was less than consummate (Jones 1995).

When deciding how energy efficiency investment should be encouraged and maintained in a privatised industry, the DGES was not favourably disposed to the E-factor idea, and decided instead to allow the RECs to raise £1 per customer to fund energy efficiency programmes which need not be administered through the EST. In section 41 of the Electricity Act, the DGES is required to set Standards of Performance (SoP) for the RECs to promote energy efficiency through programmes financed by the £1 levy. The first of these were set in March 1994 as part of the supply price control. The standards were set as targets, expressed in GWh of energy saved, for each REC. The DGES then developed a framework under which RECs could select projects to meet requirements, stipulating that all projects must have been initiated by March 1998. The standards encouraged companies to undertake a variety of approaches, with cavity wall insulation and low energy lighting projects among the most popular choices. Although the majority of projects have been developed by the RECs themselves, the Trust has been responsible for assessing each project before it is implemented and after it is complete. The standards also included important cost-effectiveness criteria which projects were required to meet. The Trust advised that projects should not cost more than 4p/kWh saved, 3.4p/kWh in the case of home insulation. In 1998, it was estimated that the average cost per kWh saved through these programmes is 1.68p (OFFER 1998b).

An allowed tariff of £1 per franchise customer, per year for four years was estimated in 1994 to be worth £155 million. The REC requirements were set at a level which would require an overall expenditure approximately equal to the tariff revenues, based on assumptions about cost effectiveness, external funding and the predicted programme mix. The introduction of this tariff helps to account for the sudden drop in direct government funding of research and development beginning in 1994, as the government had effectively legislated itself out of efficiency programme support. Although the tariff revenues, together with remaining government funding, represent an improvement upon research budgets of the early 1990s, the budget remains modest as compared to the 10 per cent NFFO which raised £1.3 billion for the nuclear industry in 1992/3 alone. It has also been argued (Jones 1995) that the

SoP approach is less efficient than more direct government intervention, i.e. that pounds get lost in extra layers of administration and logistics.

By 1998, the SoP scheme had delivered a saving of approximately 0.15 mtC per year (IEA 1998). While this is commendable, with a domestic abatement target which will require a total reduction of well over 30 mtC by 2010, it is not good enough. Clearly, if such a target is to be achieved, the energy efficiency programme has to be vastly expanded.

Upon the expiration of the first round of SoPs in 1998, the DGES conducted a consultation to explore the possibility of continuing to support energy efficiency through the SoP approach. While environmentalists and consumer groups strongly supported the idea, the RECs were more concerned that the programme would be incompatible with supply competition. The DGES concluded in a 1998 report that until full competition in supply had developed, there was a case for continuing the standards over a transitional period. Wanting to ensure that market competition did not adversely affect standards, the DGES made clear that under the new standards, those 'first tier' suppliers who were obliged to participate in the programme could not use their energy efficiency services to defend or extend market share. The programme will be funded in a similar manner, imposing a tariff on consumers served by first tier suppliers. The size of the tariff will be determined by assuming, among other things, that less than 5 per cent of customers will switch to second tier suppliers during the transition period. The new standards programme will emphasise insulation, lighting and appliances programmes (see OFFER 1998b for details).

The fact that the programme is intended as transitory is significant. In his report, the DGES suggests that as the competitive supply market develops, competing suppliers will strive to offer customers energy services, energy efficiency packages, new pricing structures and so on. 'Competition in supply can therefore assist below 100 kW customers to become better informed of the potential for energy efficiency.' The implication, clearly, is that the DGES is hoping that a well functioning market will soon eliminate the need for public programmes to promote efficiency. Indeed, it is often suggested that as the scope for cost reduction falls and firms look for other ways of distinguishing their product, other foci might develop, including the supply of energy efficiency either directly or through energy service companies. Energy efficiency services are thus a potential marketing tool which suppliers will be able to employ, under supply competition, to differentiate their service (Corry et al 1996).

Although it is possible that market incentives might exist to encourage energy management assistance to large commercial and industrial supply contract customers, the transaction costs associated with targeting the household markets will probably render residential programmes prohibitively expensive. (A 1990 study concluded 30 per cent of UK CO_2 emissions come from buildings in the domestic sector. Further research suggests that as the domestic sector is the area with the greatest potential for savings, it is important that it not be excluded!) (see Shorrock and Henderson 1990). While public efficiency programmes have traditionally been founded upon environmental and social considerations, market driven efficiency

initiatives will be founded upon the profit motive and thus are unlikely to benefit poorer domestic consumers.

In addition to the SoP programme, an important change was made to the price control formula in 1995 in the interest of removing disincentives to energy efficiency. The problem was formally identified in a 1994 review of price controls, where it was noted that the system at that time provided an artificial incentive to companies to sell more units. Because the price control system based its assessment of allowed supply business revenue entirely on the number of units sold (in spite of the fact that a significant part of costs are independent of this number), there was an artificial incentive to sell more units so as to earn a higher allowed revenue. Realising that this ran counter to energy efficiency objectives, in 1995 a new price formula was introduced in an effort to decouple the dependence of price on sales. The weight of the 'units sold' variable in the revenue driver of the price control was reduced from 100 per cent to 50 per cent, with the remaining 50 per cent related to number of customers supplied.

While this chapter has thus far focused primarily on those energy efficiency initiatives which relate directly to the new market arrangements, it is important to note that a number of government initiatives that have not been mentioned actively help to promote the efficient use of energy. Responsibility for government energy efficiency programmes lies with the Energy, Environment and Waste Directorate within the Department of Environment, Transport and the Regions (DETR). Major DETR programmes include the Energy Efficiency Best Practise Programme, established in 1989, which serves as a nationally recognised knowledge base on energy efficiency. The programme is in charge of preparing strategies with the key sectors of the economy, in collaboration with users and representative organisations. The Home Energy Efficiency Scheme provides energy advice and grants for investments in energy efficiency to low income households. Other programmes include the capital receipts initiative which offers grants to local authorities to refurbish buildings, local energy advice centres and market transformation activities. The new government initiated a review of current programmes in 1997. It is anticipated by the IEA (1998) that current programmes will continue, in addition to new initiatives being introduced which emphasise collaboration with the private sector through voluntary programmes and grants.

7.1.2 Characterising the Tension Between Economic and Energy Efficiency in the UK

With improvements in energy efficiency widely seen as the most obvious and effective response to the global warming problem, and with decreasing opportunities to meet abatement targets unproblematically and apolitically through fuel switching, it becomes increasingly important to put sufficient energy efficiency policies in place. Encouraging demand-side energy efficiency promises to become increasingly difficult under potentially falling energy prices, and in increasingly competitive markets where competing firms become more sensitive to interventionist policies. Furthermore, as the line distinguishing first and second tier suppliers begins to

blur, current means of raising revenue to support efficiency programmes will be deemed inappropriate.

To a certain degree, objectives of increased competition and deregulation and objectives of increasing efficient use of energy are mutually reinforcing. To the extent that competition in supply gives rise to a market for service companies offering energy efficiency programmes, economic and energy efficiency will go hand in hand. Competition in both generation and supply will also encourage further supply-side efficiency improvements. Many such improvements will serve to strengthen carbon abatement efforts, such as low cost transformers promoted by the DGES through his controls on capital expenditures at the NGC and, over the long term, the adoption of more efficient generation technology by producers looking to cut fuel costs.

Another approach to supply-side efficiency, which is strongly endorsed by governments and industry alike, is improving load management. Essentially, this involves bringing costs down by spreading demand more evenly across the day, reducing operating costs for peak load plants and potentially avoiding the need to construct excess capacity. As supply competition develops, real time pricing mechanisms are evolving such that large customers can respond to prices by shedding load at peak times, thus transferring load from peak to non-peak hours. As discussed earlier, decreasing the load factor can in fact impact negatively on the environment in cases where a carbon intensive fuel fires the base load. Thus, it is possible to enhance efficiency at the expense of carbon abatement goals!

Perhaps the most obvious tension between economic goals and objectives of improved efficiency manifests itself in the pricing dilemma, whereby increased economic efficiency delivers lower consumer prices which serve to discourage more efficient use of energy. A more subtle, but perhaps more significant tension lies between the political implications of efficiency and competition respectively. The efficiency gap in the UK is a product of a broad range of market failures and limitations: imperfect information, organisational problems, divorced responsibility, consumer discounting of efficiency benefits, and socio-environmental externalities. To fill such a gap, direct intervention is needed, but in the restructured markets, where competition tends to be omnipotent, direct government intervention is avoided wherever possible. Although it has been suggested that assigning obligations of promoting efficiency to natural monopoly distributors would be more acceptable, as they have no direct contact with customers, nor do they make decisions about how to satisfy future demand for production, they are not well placed to undertake demand-side management programmes.

Since vesting, the government has acknowledged the need to intervene on behalf of energy efficiency and has acted on it, but only so far as the 'no regrets' principle would allow. Provided efficiency programmes met cost-effective criteria (which do not yet fully account for externalised social benefits), did not inhibit firms' ability to compete, and could be covered by tariff revenues, they have gone ahead. Commendable progress has been made. If the efficiency gap is to be addressed so as to enable efficiency improvements to contribute substantially to meeting carbon emissions targets, greater regulation and expenditure will be required to push

investment where the free and imperfect energy markets would not normally lead (Grubb 1990). (It is estimated that a comprehensive demand-side management programme would cost £500 million annually, almost thirteen times current average annual tariff revenues, only 2 per cent of total gas and electricity turnover; see Corry et al 1996).

7.2 Energy Efficiency in the USA

Demand-side energy efficiency programmes in the USA are commonly referred to collectively as 'demand-side management' (DSM). The primary objective of most utility DSM programmes has traditionally been to defer the need to create new capacity and reduce the use of fossil fuels. Generally, DSM programmes influence usage through either reducing the aggregate level of electricity use through promoting efficiency, or shifting the customers' use from peak to off-peak times. Both approaches involve influencing customers' decisions on how and when to use electricity.

A variety of programmes fall into the DSM category. Information programmes including brochure mailings, labelling programmes and energy audits were especially popular in the 1980s. In residential programmes, the utility would conduct an audit, arrange for the installation of energy saving equipment and provide a loan, rebate or subsidy to help finance the capital costs of the efficiency improvement (Sioshansi 1995). Later, utility programmes began focusing on market transformation initiatives which seek to enhance the market for a particular service or technology so that more efficient practices become more widespread. This implies lasting changes which affect not only the targeted consumer group, but other customers who might later take advantage of the improved and available technology (Keating 1996). Finally, load management programmes have sought to reduce electricity use during peak hours, typically through direct load control of residential equipment or from peak control rates applied to industrial and large commercial customers (Gellings 1996).

Prior to the 1973 oil embargo and the subsequent 'energy crises', DSM was something of a non-issue in a country where electricity was abundant and relatively cheap, and at a time when the environmental costs of electricity generation were not widely known. With the oil crisis, however, came sharp increases in fuel prices accompanied by high inflation and high interest rates. Consequently, the costs of using and producing electricity increased, as did concern about the security of future supplies and demand for energy conservation and efficiency. Regulators and policy makers in a number of states passed regulations requiring utilities to engage in conservation and load management programmes. Utilities were generally receptive to these new obligations as the need for improved efficiency was self evident and there were cost effective and painless means of improving efficiency readily available. For example, many business offices did not have light switches in every room at that time, and by simply installing switches, lights could be turned off in rooms not in use to save electricity (Sioshansi 1995).

In the late 1970s and early 1980s, utilities responded to forecasts of continued load growth with newly constructed capacity. When the price of oil and

natural gas prices fell, however, and load growth turned out to be slower than expected, many utilities were left with excess capacity. Readily available opportunities for energy efficiency had become slightly harder to find, and the pressure to suppress load growth had all but disappeared. In this changed environment, utilities began to lose revenues, at least in the short run, as a consequence of their DSM obligations, and thus began to begrudge their energy conservation responsibilities. PUCs soon realised that if utilities were going to continue to pursue demand-side management opportunities on behalf of their customers, regulatory intervention was required to ensure that utilities not only recovered the lost revenues and costs associated with implementing DSM programmes, but were also offered incentives to compensate them for their time and trouble. California was first to introduce a programme in 1989 whereby state regulators allowed investor owned utilities to retain a pre-determined percentage of the savings attributable to DSM programmes as profit for investors. Other states soon followed and it became possible in some cases to make more money selling less kWhs. Although regulatory-driven, 'incentivised' DSM was not without problems, it did help to promote the further development of DSM throughout the early 1990s. By the time utility funding and participation were at their peak in the early 1990s, both programmes and evaluation methods had improved significantly.

It is difficult to measure precisely the progress and impacts of DSM programmes as this involves speculating about what end-use demand patterns would have looked like had the programmes not been implemented, or vice versa. That said, monitoring and evaluation of DSM has improved such that progress assessments can be made on the basis of cost-effectiveness, efficiency improvements, and so on. Clearly, there was a dramatic increase in utility investment in DSM since it was incentivised in many states around 1989. Expenditures rose from US$872 million (0.5per cent of revenues) in 1989 to over US$2.7 billion (1.5 per cent of revenues) in 1993, when approximately 33 per cent of utilities reported having DSM programmes (see Hirst 1994; Gellings 1996; Lee and Darani 1996). In 1994 there were modest reductions in expenditures which were attributed to the fact that interest in restructuring was accelerating rapidly. Since that time, DSM spending has continued to decline as industry participants search for ways to cut costs and remain competitive. In 1996, ten large and 40 small utilities discontinued DSM programmes or programme monitoring, while expenditures declined 21 per cent.

In 1989, DSM programmes resulted in a 0.6 per cent decrease in total electricity consumption. From 1989 to 1993, energy savings grew steadily, with a cumulative amount of savings reaching 150 billion kWh. By 1993, savings were equivalent to 1.6 per cent of annual electricity sales and 6.8 per cent of summer peak demand. In 1994, incremental energy savings decreased by 8.4 per cent, and still further in 1995. Incremental savings rose slightly again in 1996.

While a certain proportion of the large variety of DSM projects that have been undertaken were cost ineffective, the average cost of programmes has been less than the equivalent costs for new capacity. According to one study (Hirst et al 1996), utility expenditures on energy efficiency programmes in 1993 resulted in a cost per

unit of conserved energy (CCE) of US$.03/kWh, assuming that the measures installed in the last ten years and savings are discounted at a real rate of 5 per cent. In general, recent evaluations indicate that typical DSM programmes cost US$0.025–$US0.035/kWh, with a total resource cost of US$0.03–US$0.08/kWh (including customer contributions to purchase and installation), although costs reported are as low as US$0.014/kWh(TRC) and as high as US$0.14/kWh(TRC) (Nadel and Geller 1996). It is interesting to compare these costs with the full levelised cost of operating a gas-fired combined-cycle plant, which was estimated (Gellings 1996) to be approximately US$0.043/kWh. In general, commercial and industrial programmes tend to be more cost effective because of lower transaction costs.

7.2.1 Characterising the Tension Between Economic and Energy Efficiency in the USA

Although considerable efficiency improvements have been made as a result of DSM efforts on the part of utilities and regulators, the efficiency gap persists. Several studies have indicated that there is tremendous potential to improve upon efficient use of electricity use in the USA. The Electric Power Research Institute estimated a technical potential of 24–44 per cent of electricity use, while the Alliance to Save Energy identified cost-effective opportunities to cut electricity use by 22 per cent between 1991 and 2000. Indeed, the utilities' very ability to achieve results through DSM programmes attests that formidable market barriers obstruct efficiency improvements which are highly cost effective. Problems relating to imperfect information, irrational consumer discount rates, prices which do not reflect the true long-run cost, organisational and institutional inefficiencies and so on, give rise to these market failures.

Increased competition and the regulatory uncertainty which characterises a period of restructuring, bring dramatic changes to utility planning. The nature of the relationships, costs, reward structures and incentives in the electricity industry have changed inexorably. Consequently, DSM as it has been practised is not consistent with increasing competition and decreasing direct regulation and thus the nature of energy efficiency programmes are bound to change. Whether or not these changes will lead to increased rates of energy efficiency improvement will depend on how tensions between new market conditions and old approaches to encouraging efficient use of energy are reconciled.

As in the UK, there is much talk of ways in which market restructuring can reinforce energy efficiency objectives. One central hypothesis is that, as competition increases and it becomes too difficult to compete on price alone, utilities will incorporate energy efficiency programmes into their line of business so as to improve customer service. Utilities will of course be looking to increase participant contribution to programme costs and thus the emphasis will likely be on programmes which emphasise partnership between a utility and its larger customers.

Especially for large commercial and industrial customers who tend to embody more cost-effective DSM opportunities, DSM could become part of a strategy

to provide enhanced value and thus competitive service. The extent to which 'for profit' utility DSM offers efficiency gains comparable to 'ratepayer based' DSM will largely depend on the utility's ability to lower the costs of DSM and its inclination to be more customer driven (Nadel and Geller 1996).

Another source of synergy between efficiency and economic objectives is manifested in the reallocation of environmental regulatory risk that invariably accompanies the deregulation of the generation market and can make DSM investments more attractive to utilities. There is much uncertainty regarding environmental utility regulation, particularly potential regulations to deal with global warming. Possible new regulations could substantially increase the costs of electricity production, especially considering that CO_2 is currently unregulated. As our understanding of the ramifications of continued CO_2 emissions and the threat of global climate change improves, the probability of CO_2 being the focus of future regulation increases. Furthermore, to the extent that carbon emissions rise as a result of restructuring, more stringent environmental regulation of the pollutant becomes ever more likely. Thus utilities will want to continue DSM programmes voluntarily to reduce the risk of future CO_2 regulation. In 1996, at least 38 utilities had voluntarily agreed to reduce emissions under the Climate Change Action Plan.

Finally, a third area where market and energy efficiency objectives could potentially coincide is load management, which will naturally improve with the introduction of time-of-use pricing, real-time pricing, and other flexible pricing systems associated with retail competition. In the American context, however, better load management will mean increased carbon emissions, at least in the short term.

While the aforementioned aspects of competitive markets serve to promote continued utility involvement in DSM and improved energy efficiency, there remain some critical areas of tension:

1. Heightened pressure to keep production costs competitive. With the exception of those DSM programmes for which participating customers are willing to pay full cost, with retail competition looming, the last thing utilities want to do is increase revenue requirements. On the contrary, many utilities are actively looking for quick cost savings in an attempt to demonstrate to shareholders, regulators and retail customers that they are determined to keep prices down. Although there are much more important factors contributing to utility production costs, such as excess capacity, these costs are sunk whereas DSM costs are at the margin and therefore easily trimmed off. Consequently, current scaling back of DSM expenditure is likely to continue as utilities become more concerned with load building than energy saving. As one author comments: 'If utilities were going to live or die solely by how low they could drive the short-term commodity price of electricity, they would have every reason to resist investment to reduce pollution or help customers save electricity' (Ralph Cavanagh of the Natural Resources Defense Fund, quoted in Lee and Darani 1996).

Indeed, a utility planner facing a surplus of short-term capacity and a short planning horizon is not going to look favourably upon DSM, a long-term resource with substantial up-front costs.

2. *Lower and more flexible avoided costs.* In addition to the increased pressures of retail competition to keep prices low, lower avoided costs serve to deter utility investment in DSM. Because many regions have excess generating capacity, avoided costs for the next few years are expected to be only slightly above the variable operating cost of power plants. Higher reserve margins will probably persist for a prolonged period as utilities increasingly offer real-time pricing. Furthermore, the flexibility advantages of DSM (because of its small 'unit' size and potentially shorter lead-time) are becoming relatively less as power supplies become more competitive. To the extent that wholesale competition lowers production costs, avoided costs will decline, implying that fewer DSM programmes can be justified on the basis of being less expensive and more flexible than other supply alternatives. As current surplus capacity is absorbed by future growth over the long term, avoided costs will rise and DSM programmes will become more cost effective.

3. *Rate impacts of DSM.* In a competitive generation market, it is in the producer's interest to sell more generation services at higher prices. Energy efficiency programmes which reduce consumer demand can place downward pressure on prices which can reduce utility profits. In an IEA report (1996), utilities and regulators cited the rate impacts of energy efficiency programmes as a reason for reducing savings targets. Given that generation revenues in a competitive market will be recovered at market prices versus on a cost-of-service basis, utilities will become much more concerned with the potential revenue losses associated with DSM.

4. *Decreased integration.* There seems to be general consensus that integrated utilities represent an obsolete industrial form, and that the utility of the future will be a distribution entity regulated by a PUC, whilst generation is separated from distribution and customer service. In the new institutional framework, utilities will have limited customer contact and will play a limited role in the determination of the mix of supply and demand-side resources employed to meet the demands of their service territory. This loss of integration raises concerns with respect to DSM programmes. The utility has traditionally been in a unique position to identify conservation opportunities for their customer base as a whole and pursue them by offering to pay a large fraction of the costs. There is surely something to be said for vertical integration when it comes to pursuing energy efficiency for the energy system as a whole. It has been argued that generation resource portfolio management exhibits natural monopoly characteristics, and just as multiple decision-makers could not operate a transmission system reliably, a myriad of individual market-directed decisions will not effectively ensure the optimal mix of resources at the lowest long-term costs.

5. *The loss of franchise area.* As regulated monopolies, utilities have in the past been granted a monopoly franchise within a given geographic area. Under this system, utilities operated in a relatively stable environment, which allowed for long-term resource planning. It also made it possible to cross-subsidise between consumer classes by distributing the costs of efficiency programmes across all ratepayers.

Under retail wheeling, the utilities' franchise areas disappear and customers are granted the right to choose their own supplier. Traditional cost-of-

service regulation gives way to competitive, market-based pricing and there will be no guarantees to the utility with respect to covering costs of DSM programmes. Understandably, in the absence of guaranteed returns, utilities will be hesitant to implement DSM programmes. If the programmes fail to appeal to their customers, or if programme benefits are distributed too thinly over time or consumer population such that they cannot be adequately capitalised upon by the utility, shareholders will be penalised.

6. The demise of IRP. Much of the success of DSM programmes throughout the 1980s and into the 90s is due to the existence of an IRP framework which mandated states to ensure that supply-side and DSM resources were fairly compared, and that those DSM measures which were more cost-effective relative to supply-side measures be implemented. By 1996, approximately half of state PUCs were actively seeking to reduce disincentives to utility investment in DSM through the IRP approach. US experience with that approach has revealed that utility-orchestrated research and development of energy services can identify and act upon cost-effective and environmentally beneficial DSM opportunities which would otherwise have been overlooked by consumers (Jaccard 1995).

That IRP and thus, to a large extent, DSM will be rendered obsolete with the arrival of supply competition is acknowledged by retail wheeling advocates. In March 1992 the executive director of the Electricity Consumers Resource Council counted among the virtues of retail wheeling its ability to 'strip away' the 'masquerade of least cost service.' He made specific reference to energy efficiency programmes as superfluous 'bells and whistles' which will be rendered 'impotent' by retail wheeling (see Cohen 1993). Although this is perhaps an extreme example, in general the restructuring rhetoric does not acknowledge that short-term markets might not be the best choice for a decision-making mechanism directing DSM investment. In the likely event that the IRP framework is dismantled, utility DSM will be substantially reduced and a process of governance which has fostered partnerships between utilities, environmentalists and other concerned interest groups, will disappear.

Taking into consideration the market failures and inherent tensions identified above, there appears to be a strong case for policy intervention in electricity markets in the interest of ensuring that optimal levels of investment in energy efficiency are achieved. In the near term, during a complex period of transition, the fate of DSM should not be left to the market to decide. Rather, the future of energy efficiency initiatives must lie with the state regulators who continue to shoulder the responsibility for long-term planning for their constituents. Ensuring that shareholders earn sufficient profit to keep the utilities operating will of course be a prime concern, but PUCs which have historically supported DSM are likely to continue to do so to the extent that it is possible in a competitive and 'deregulated' environment (Keating 1996). The problem, of course, is that if true competition is allowed the market forces will dominate, and the regulator's influence will diminish over time.

As in the UK, however, regulated monopoly segments of the industry will remain, i.e. distribution and transmission, and thus it is possible to design a non-

bypassable means of generating revenues to finance DSM programmes. Revenues could either be paid to distribution utilities for delivering efficiency improvements, or alternatively, state organisations could be established explicitly to operate DSM programmes. The Administration's comprehensive restructuring bill calls for the creation of a $3 billion Public Benefits Fund (PBF) to be matched by states and used for energy efficiency programmes, technology research and consumer education. It is estimated by the Department of Energy that resulting efficiency gains, together with increases in efficiency derived from market driven services and programmes, will reduce electricity demand by 2 per cent in 2010. According to Keating (1996) it is expected that programmes for market transformation, shared savings and customer retention are the ones most likely to be encouraged by regulators and tolerated by utilities.

Undoubtedly, the future of traditional DSM programmes is limited. Their costs and benefits, their rate impacts, changing industry incentives and evolving regulatory institutions will mean that DSM ten years from now will look quite different. To reinforce a re-occurring theme, none of the tensions identified here are impossible to overcome. If existing ratepayer subsidised DSM programmes do fall victim to the restructured market, this would be because society has chosen different priorities.

8. CONCLUSION

Even the most devout champions of the free market will concede that the absolute unfettering of electricity markets can produce outcomes that are not socially optimal. Consequently, electricity market regimes must incorporate some form of regulation so as to correct for the market imperfections which do exist and to deal with other policy objectives which are best administered from within the electricity sector. This paper endeavours to assess the extent to which the types of regulation that are being implemented in the context of newly restructured electricity markets adequately address those market failures and social policy obligations that have implications for climate change. Speaking specifically in terms of the environmental costs of electricity generation, it is concluded that insufficient regulatory institutions and policy measures are in place to ensure that environmental costs are accounted for and socially optimal levels of CO_2 abatement are achieved.

The question is no longer whether electricity markets should be restructured, but how and how quickly. There are benefits to be won through this process, particularly in the realm of short-term economic efficiency, and it is on these grounds that the current course of policy action is justified. That said, there is much work left to do in terms of ensuring that competitive markets operate in a way that is socially acceptable. The critical first step towards encouraging emissions abatement in the newly structured electricity sector is to understand precisely how increasing competition in wholesale and retail electricity markets discourages CO_2 emissions abatement.

Throughout this paper, the ways in which free market competition hinders further emissions abatement are spoken of in terms of 'tensions'. The tensions which are identified are a product of two factors. First and foremost, tension comes from the simple fact that the environmental consequences of electricity generation, CO_2 emissions in particular, represent an environmental externality. Conventional accounting practices fail to account for these environmental costs. Consequently, when electricity industry decisions become more strongly influenced by private sector concerns of profit margins, low production costs and controlled risk, production alternatives made inherently valuable by their ecological advantages are more susceptible to being discriminated against on the grounds of their failure to maximise short-term monetary profits. Secondly, conventional approaches to dealing with externalities in general and pollution in particular tend to involve centralised decision-making and moderate to high levels of government intervention. Tension between laissez-faire approaches to facilitating market efficiency through competition and more regimented approaches to reaching socially optimal levels of pollution though regulation, arises when action on behalf of pollution control is perceived to compromise or complicate the market's ability to bring about efficient economic outcomes. Although these two sources of tension are inextricably linked, the latter is more concerned with patterns of resource exploitation which yield socially optimal outcomes, and the former is concerned with the actual definition of 'social optimum' and 'value'.

It is worth reiterating that these tensions are not insoluble. Accounting practices can be adjusted to include the depletion of the earth's resources and the costs of interfering with ecological processes in industry management decision making. Air quality standards and natural resource depletion rates can be enforced in ways that are more compatible with market forces and the dynamics of industry competition. Neither adjustment, however, has proved apolitical or unproblematic. Both the UK and US governments have been reluctant to take responsibility for reprioritising policy. Consequently, the determination and enforcement of environmental standards has been deferred to the industry regulators who have neither the authority nor the incentive to place environmental priorities over short-term monetary ones.

In both countries, significant progress has been made in creating market-based means of achieving social policy objectives. The NFFO, the renewables portfolio standard, environmental adders, energy taxes are all examples of market-based innovations which are more compatible with increasingly competitive wholesale and retail electricity markets than more traditional command and control approaches. There are limits to how much these new mechanisms can achieve, however, so long as governments continue to neglect the need for a definite reorientation of priorities.

It seems highly unlikely that either country will be able to meet its respective domestic targets for CO_2 reduction under the current electricity industry regime. Without rapid advances in carbon recapture technology, the principal means of reducing carbon emissions from electricity generation will continue to be fuel switching and increased efficiency. Under current industry conditions, there exist inadequate incentives for firms to invest in less carbon intensive generation or efficiency improvements. If the targets are to be met, changes need to be initiated from outside the private sector.

The potential negative implications of electricity restructuring for patterns of carbon emissions from generation are not inconsequential, and inadequate attention is being paid to ensuring that institutions are established to compensate for these negative incentives. Changes must be made to ensure that the costs of increasing atmospheric carbon concentrations are accounted for in industry transactions. Individual firms cannot be expected to take the initiative, and thus the onus is on government to find ways to mandate all firms to accept responsibility.

In light of the changes wrought by restructuring on the political economy of industry legislation, it will be increasingly difficult to devise transparent, politically palatable ways of internalising environmental costs of electricity generation. Thus far, market mechanisms and voluntary agreements have been unable to deliver socially optimal generation fuel mix or electricity consumption patterns. Although more direct means of dealing with pollution externalities are not ideally compatible with emerging competitive markets, such approaches to regulating emissions should not be dismissed simply on these grounds. A more interventionist approach to exploiting potential for energy efficiency improvements or supporting renewables development is necessary. Constraints on free market activity may be a price that

has to be paid for the mediation of long-term consequences of carbon intensive fuel mix and inefficient energy use.

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Figure 3.1: US CO2 Emissions From PowerStations1970-1997

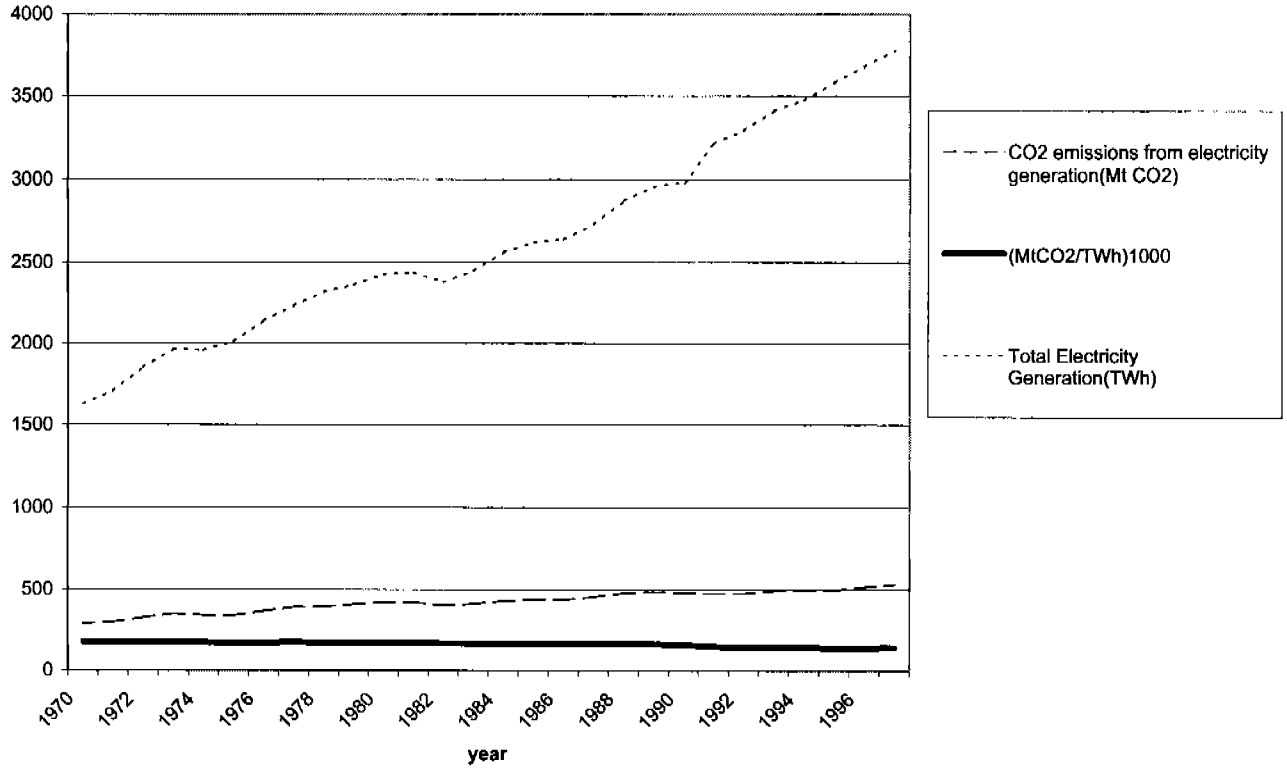


Figure 3.2 UK Electricity Demand and Prices:1978-1996

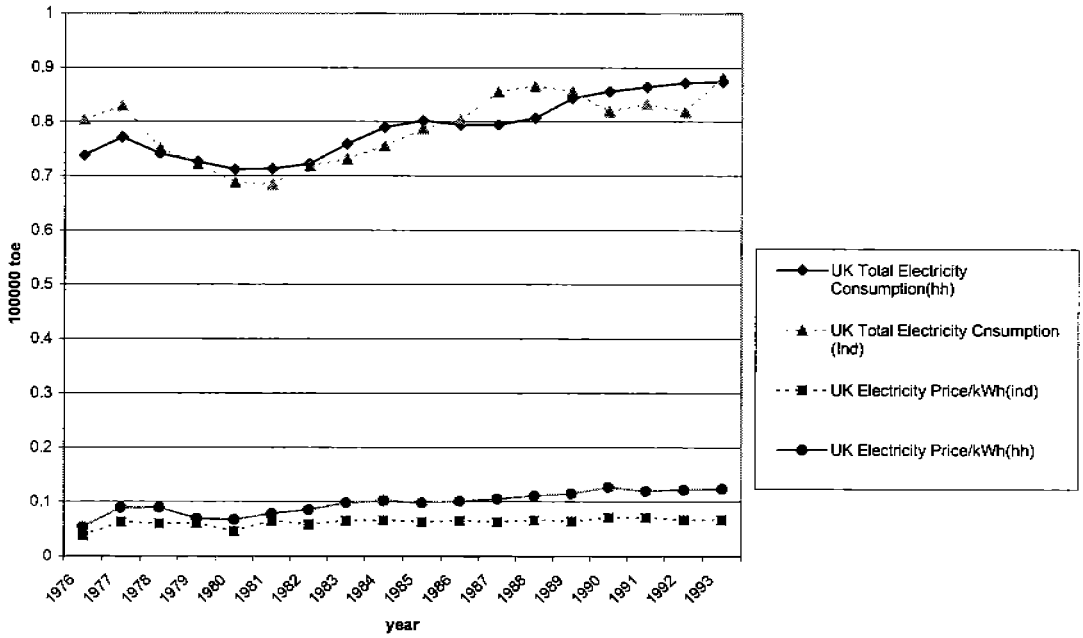
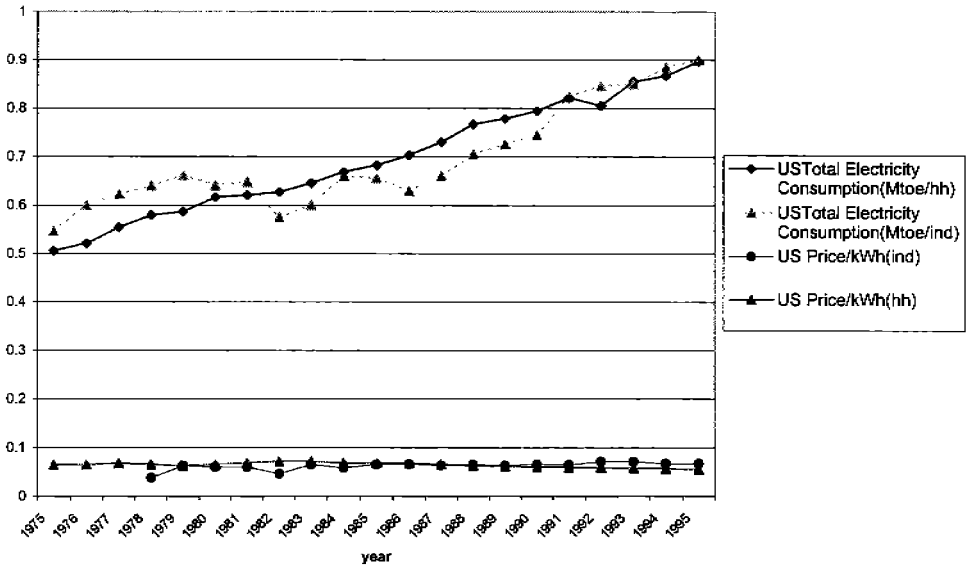


Figure 3.3 US Electricity Demand and Prices 1975-1996



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[i] Data taken from IEA Statistics Series(1980-1998)*Energy Prices and Taxes* and *Oil, Gas and Electricity* OECD

Figure 6.1 : Fuel Input for UK Electricity Generation:1975-1997

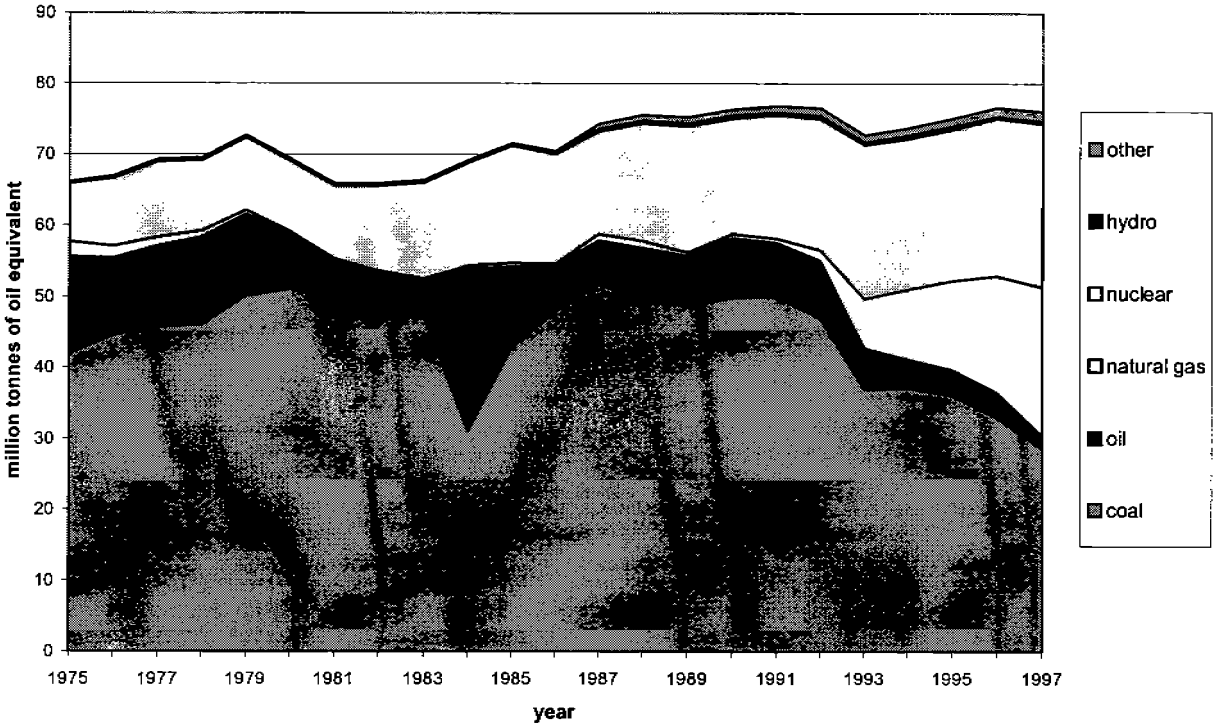


Figure 6.2: IEA Predictions for UK Fuel Mix for Electricity Generation 2000: Fossil Fuels

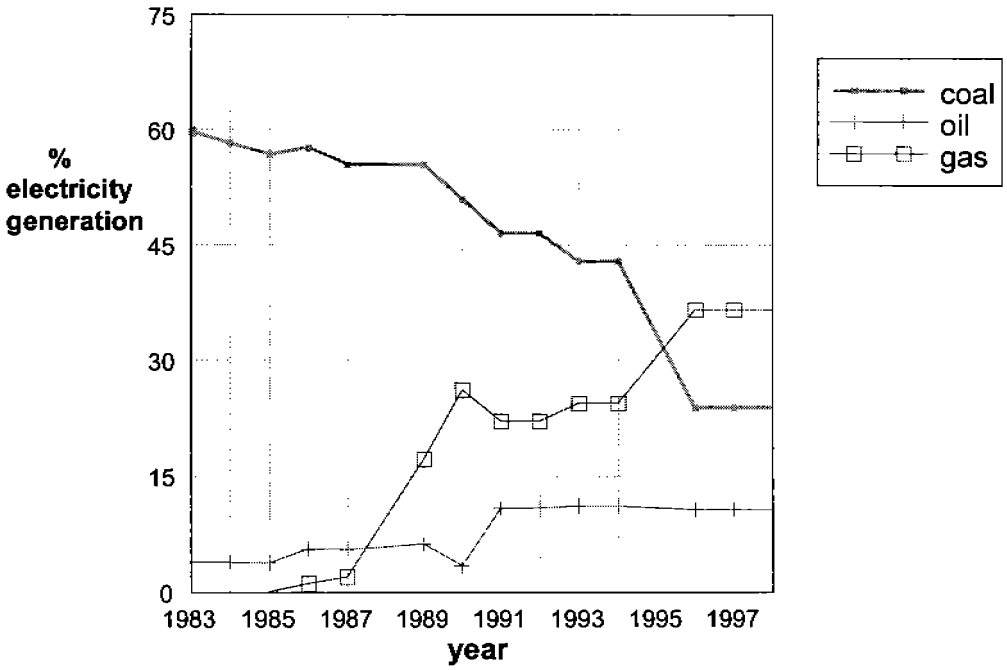
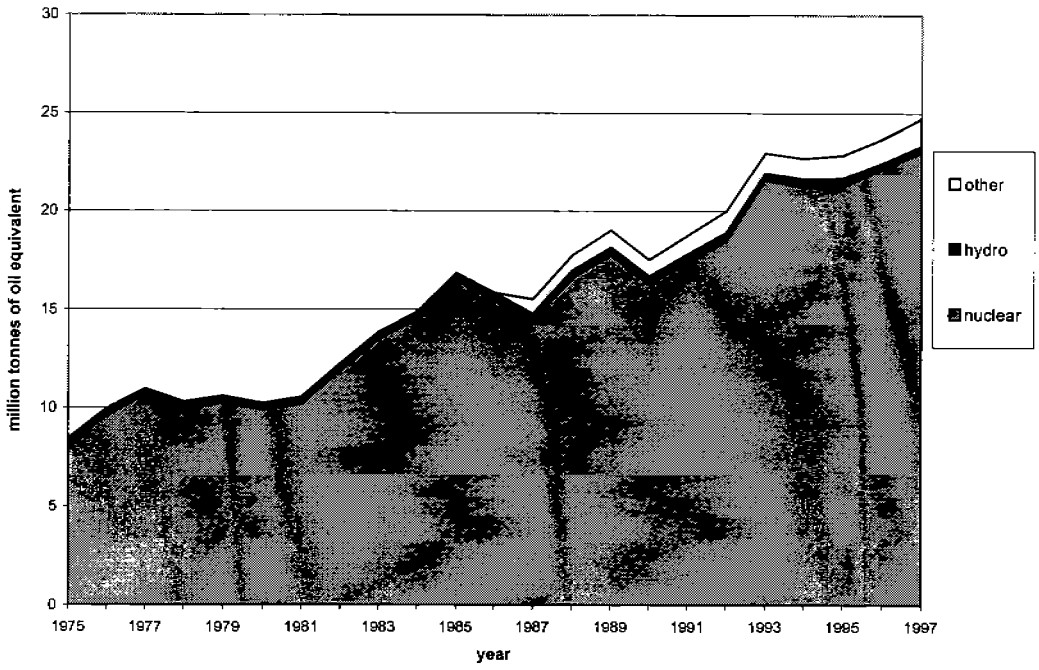


Figure 6.3 : Non-Fossil Fuel Inputs for UK Electricity Generation: 1975-1997



6.4 IEA Predictions for UK Fuel Mix for Electricity Generation 2000:Non Fossil Fuel

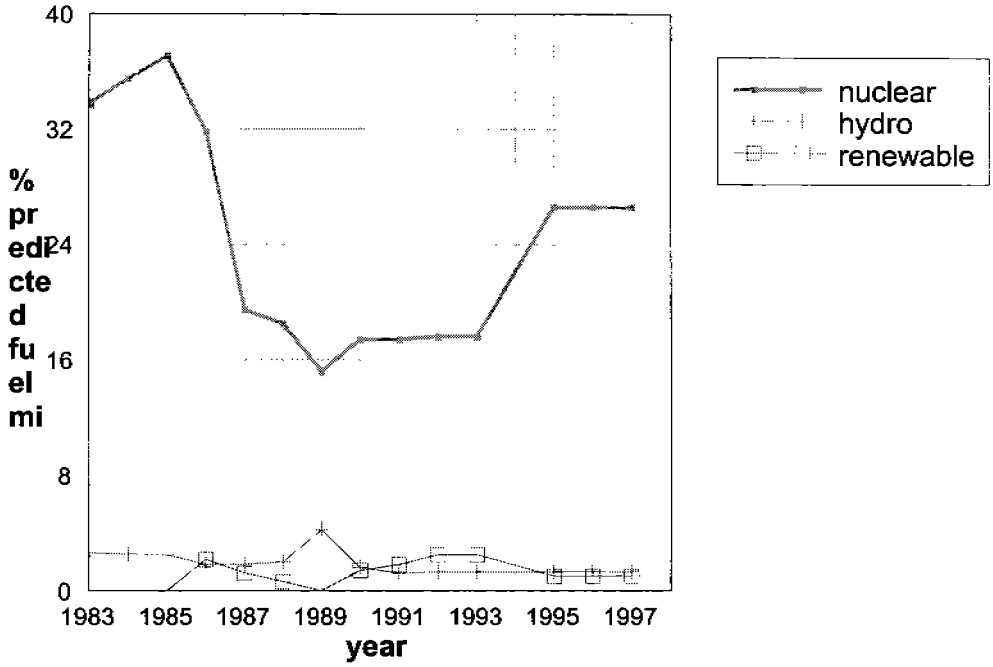
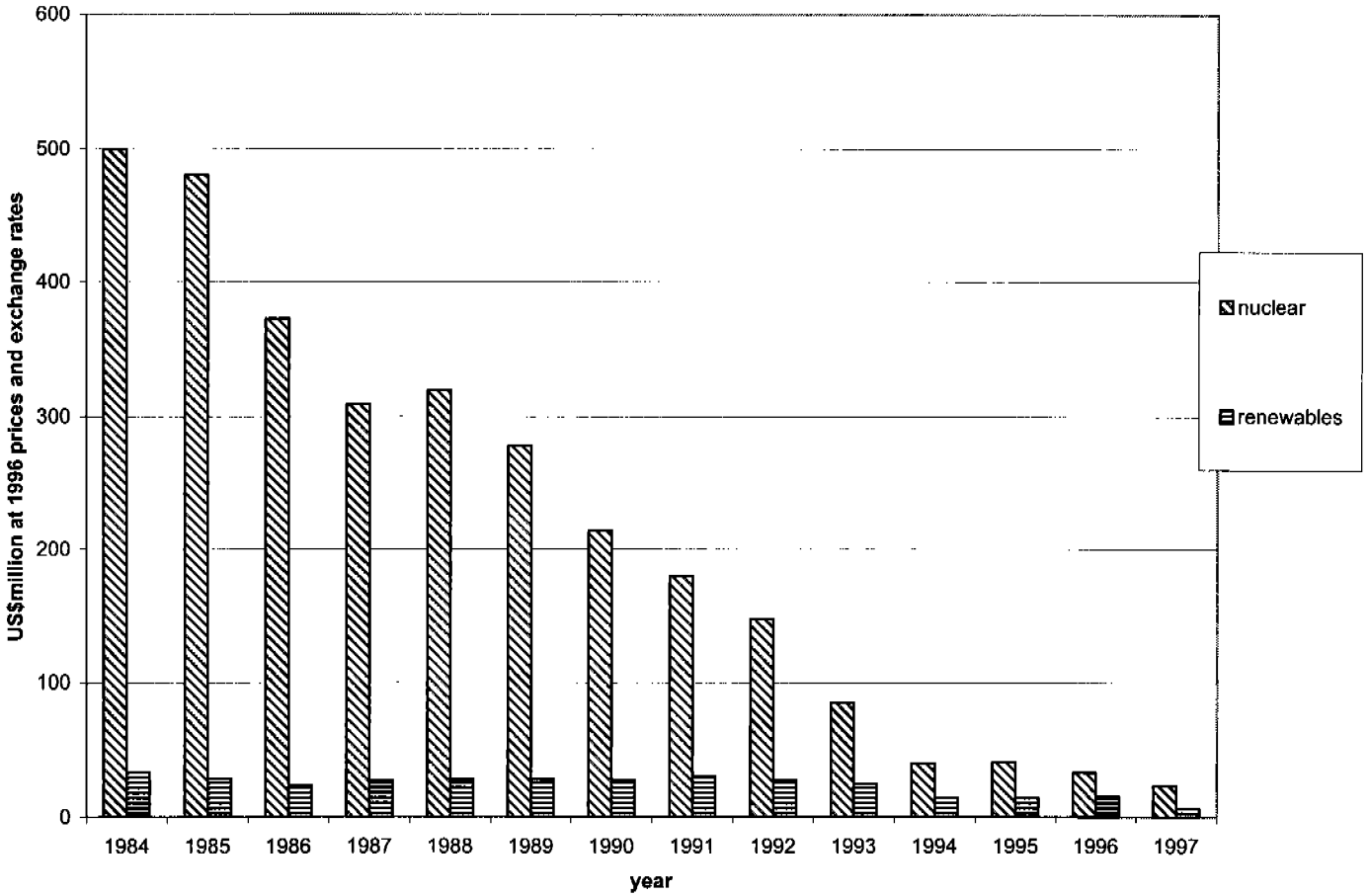


Figure 6.5: UK Government Budgets for Research and Development in Nuclear and Renewables: 1984-1997



Data taken from IEA(1996) *Energy Policies of IEA Countries, 1997 Review* and IEA(1998), *Energy Policies of IEA Countries, 1998 Review,* OECD, Paris.

Nuclear research and development includes conventional nuclear, nuclear breeders and nuclear fusion.

Figure 6.6 : US Fuel Mix for Electricity generation:1975-1998

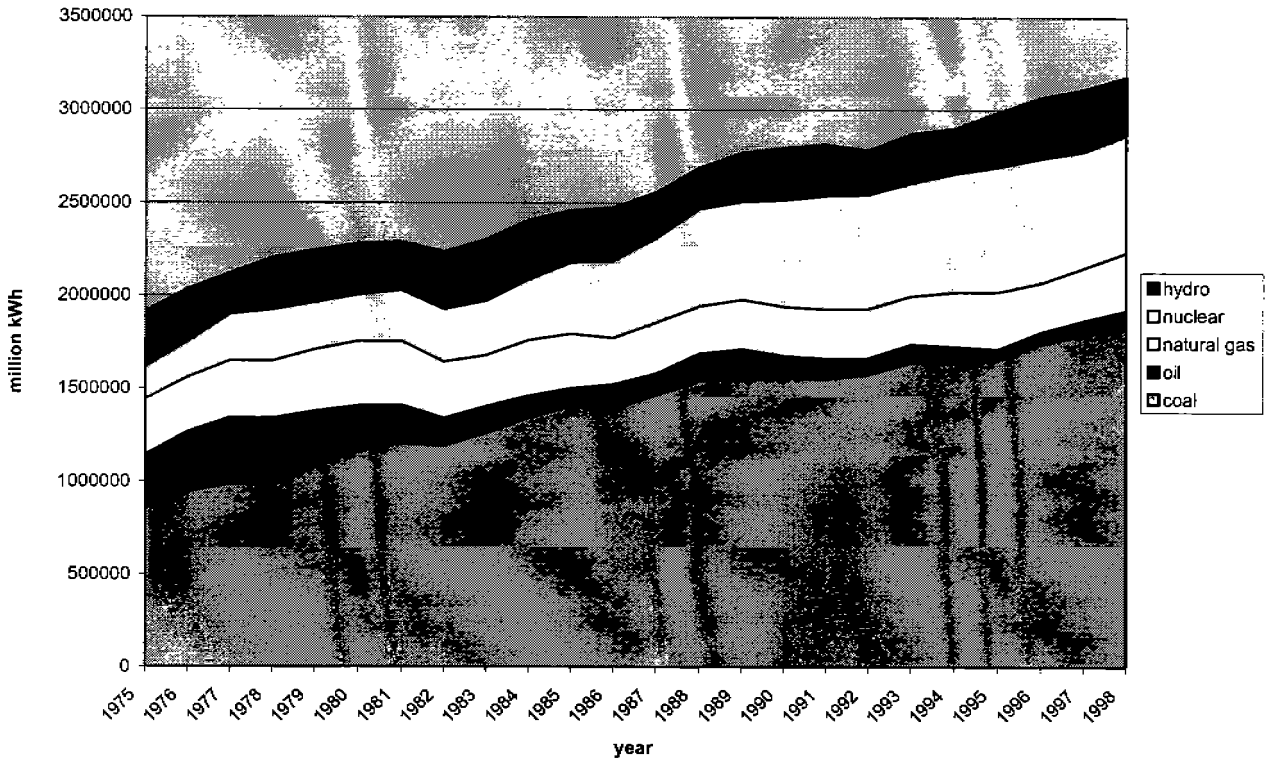


Figure 6.7: IEA Predictions for US Generation Mix 2000: Fossil Fuels

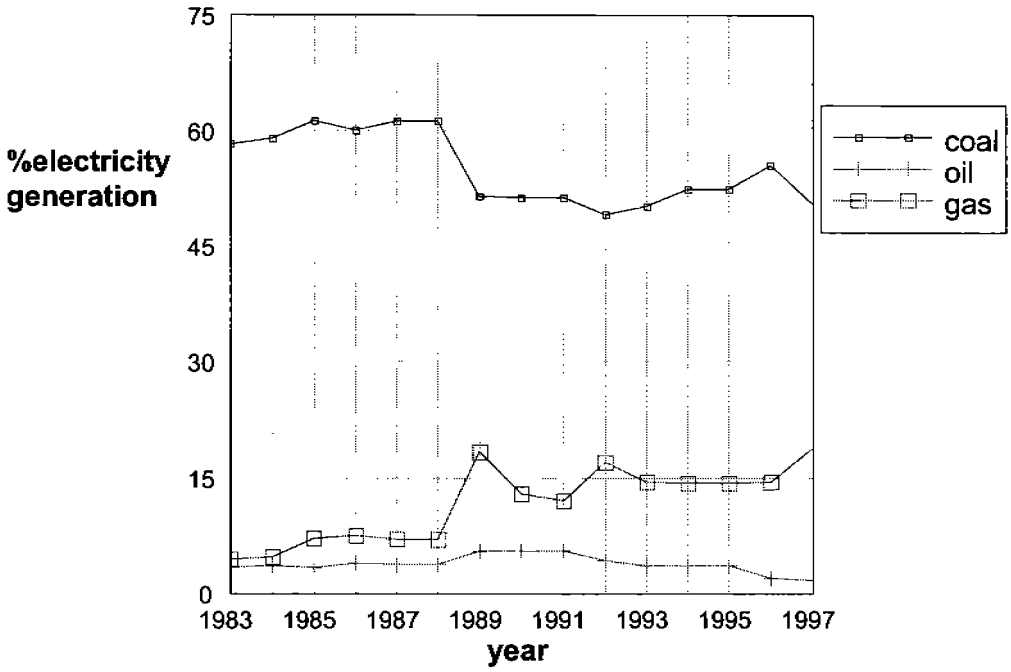
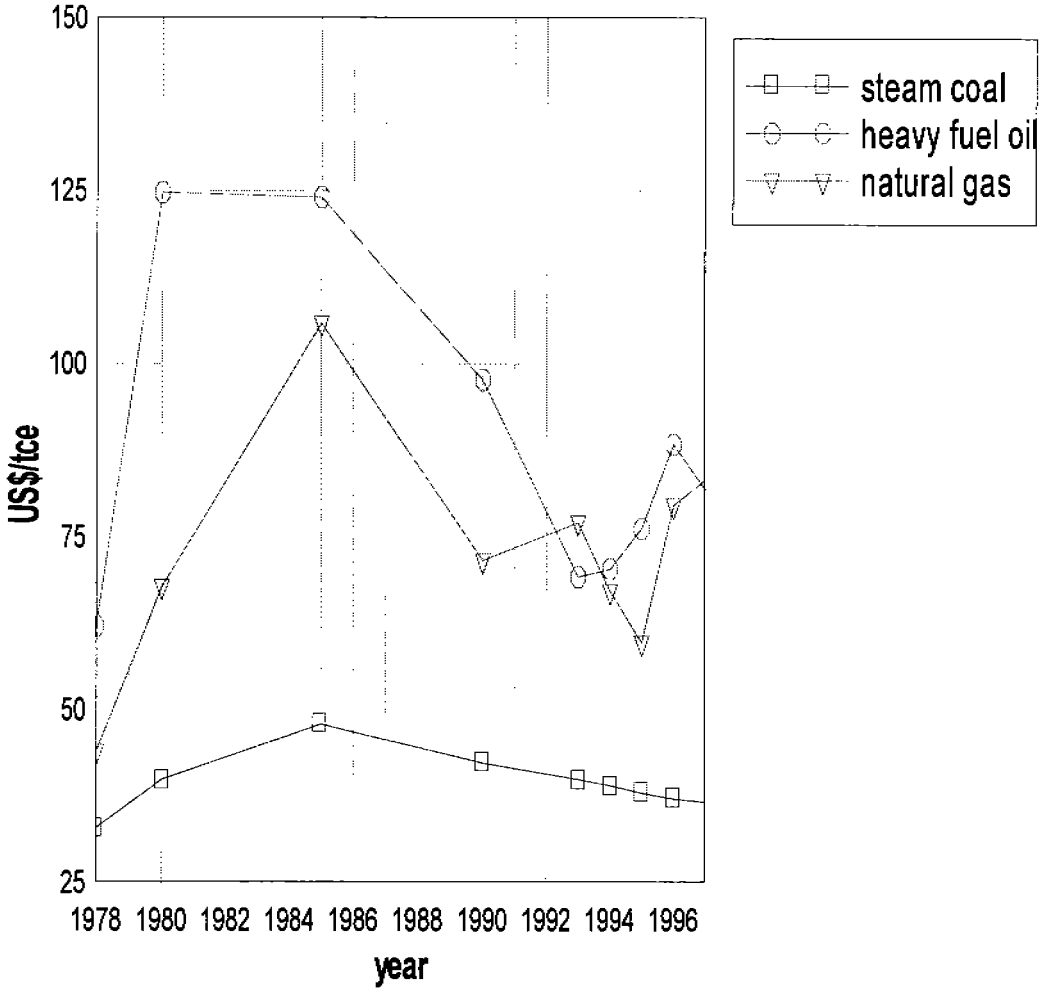


Figure 6.8: US Fuel Prices for Electricity Generation[1]



[1] Data taken from IEA(1998)*Coal Information 1997*, OECD

Figure 6.9 Renewables Generation in the USA: 1990-2000[1]

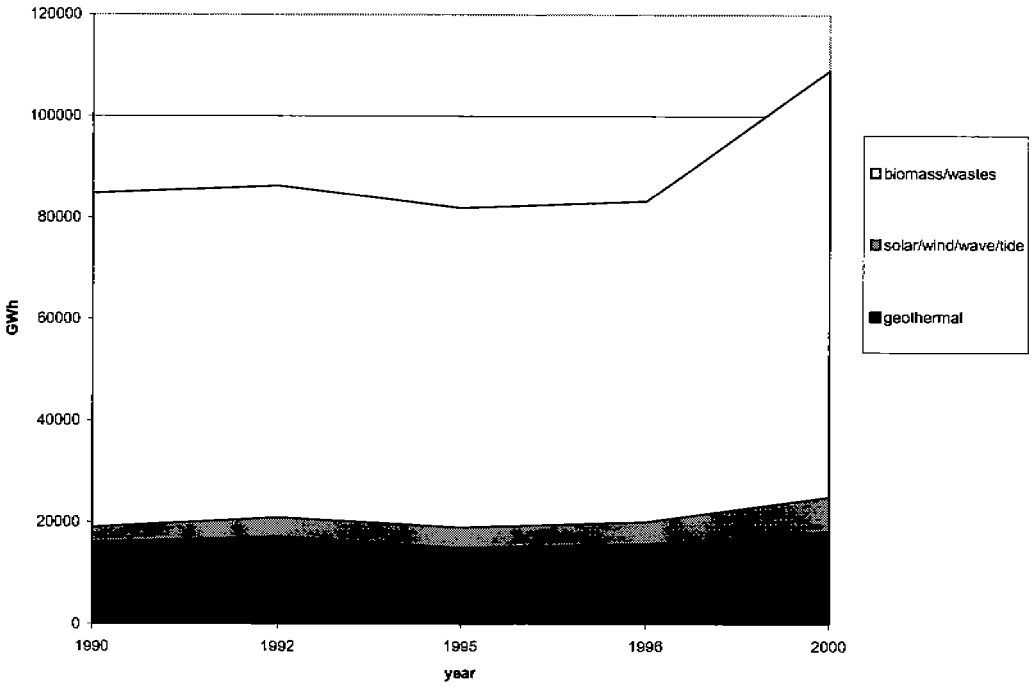
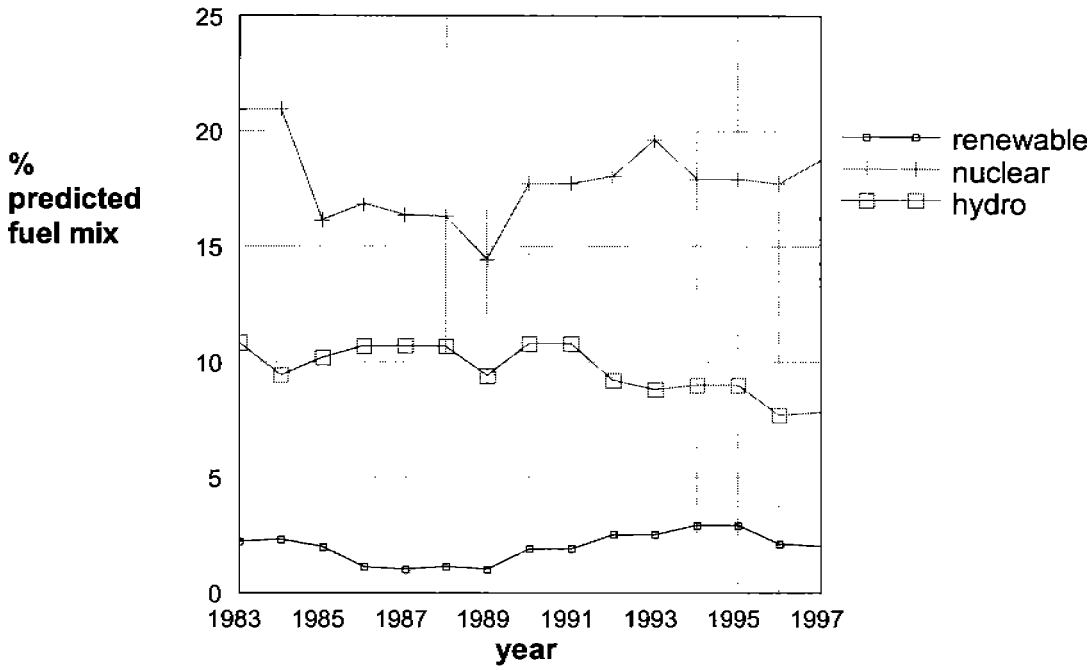


Figure 6.10 IEA Predictions for US Fuel Mix for Electricity Generation 2000:Non-Fossil Fuels



[1] IEA Website

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