An analysis of the UK energy market in an age of climate change:

Will adherence to the national emission reduction targets force an increasing reliance on nuclear power?

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Abstract

A number of different greenhouse gases from a variety of sources contribute to the greenhouse effect that is responsible for climate change. A reduction in emissions of these gases would delay and diminish the consequences of climate change. Electricity generation from fossil fuel energy sources is a major contributor to global emissions of carbon dioxide. The threat of climate change is recognised by the United Kingdom's recent Energy White Paper, which establishes the goal of a reduction of carbon dioxide emissions by 60% of 1990 levels by 2050.

A limited number of realistic options exist to reduce carbon emissions from the electricity sector, including efficiency improvements, increased use of renewable energy sources, carbon sequestration plants, and nuclear power.

The analysis in this thesis suggests that reconciling the UK's economic growth projections with the government's plans for carbon abatement will not be easy. The carbon abatement target imposes restrictions on fossil-fuelled electricity generation; renewable energy has practicable limitations; and feasible electricity efficiency improvements are constrained below 2%/yr.

As such, it will be argued that the UK will be unable to meet electricity demand in 2050 without a large scale program of nuclear energy or carbon sequestration. There are compelling arguments favouring investment in new nuclear generating capacity, including cost efficiency, the government's desire for energy diversity, and the fact that nuclear is an established technology, whose risks and potential problems are well known.

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List of Acronyms and Abbreviations

BIPV	Building Integrated Photovoltaics
BNFL	British Nuclear Fuels Ltd.
BTU	British Thermal Unit
BWEA	British Wind Energy Association
capex	Capital expenditure
CC	Carbon Capture
CCGT	Combined Cycle Gas Turbine
CC	Carbon capture and sequestration
CO_2	Carbon dioxide
DCF	Discounted cash flow
DEFRA	Department for Environment, Food and Rural Affairs
DETR	Department for Environment, Transport and the Regions
DTI	Department of Trade and Industry
EIR	Electricity Intensity Ratio
ETS	Emissions trading scheme
FOAK	First-of-a-kind
GDP	Gross domestic product
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
MIT	Massachusetts Institute of Technology
MS	Microsoft
NPV	Net present value
O&M	Operation and maintenance
OECD	Organisation for Economic Co-operation and Development
p	UK pence
PIU	Performance and Innovation Unit
PV	Photovoltaic
T&D	Transmission and distribution
t, kt, Mt	metric tonne, metric kilotonne, metric megatonne
tC, ktC, MtC	metric tonne of carbon, metric kilotonne of carbon, metric megatonne of carbon
therm	(heat) energy equivalent to 100,000 BTU
W, kW, MW, GW, TW	watt, kilowatt, megawatt, gigawatt, terawatt
Wh, kWh, MWh, GWh, TWh	watt-hour, kilowatt-hour, megawatt-hour, gigawatt-hour, terawatt-hour
yr	Year

1. Introduction

Anthropogenic climate change threatens major consequences globally (DTI, 2003a). Already, observed climatic changes have affected both physical and biological systems and evidence indicates that social and economic systems have been affected (IPCC, 2001b). Looking ahead, the Intergovernmental Panel on Climate Change (IPCC) (2001b) expects an increase in climate variability and an increase in the likelihood of extreme events. Further, greenhouse gas emissions in the 21st century could set in motion "large scale, high-impact, non-linear, and potentially abrupt changes in physical and biological systems over the coming decades to millennia" some of which may be irreversible (IPCC, 2001). It is unsurprising therefore, that climate change has been described as one of the greatest challenges of our time (King, 2004).

A number of different greenhouse gases from a variety of sources contribute to the greenhouse effect that is responsible for climate change. A reduction in emissions of these gases would delay and diminish the consequences of climate change (IPCC, 2001b). Electricity generation from fossil fuel energy sources is a major contributor to global emissions of carbon dioxide, a greenhouse gas that contributes significantly to climate change (Ansolabehere et al., 2003).

Fossil fuel energy sources have formed the basis of the world's economy since industrialisation (IPCC, 2001a) and reducing carbon emissions from electricity generation is a significant challenge. This already difficult challenge is complicated by the lack of consensus on whether mitigation is economically efficient (IPCC, 2001c; Schneider and Azar, 2001) and if indeed it is, how best to mitigate the effects of climate change while ensuring sufficient energy for economic growth (Dale et al., 2004; Oxera, 2005).

A limited number of realistic options exist to reduce carbon emissions from the electricity sector:

- Improved efficiency in electricity generation and use;
- Increased proliferation of renewable energy sources such as wind, solar, biomass, and geothermal;
- Carbon capture and sequestration at fossil-fuelled (especially coal) electricity generating plants; and
- Increased use of nuclear power (Ansolabehere et al., 2003).

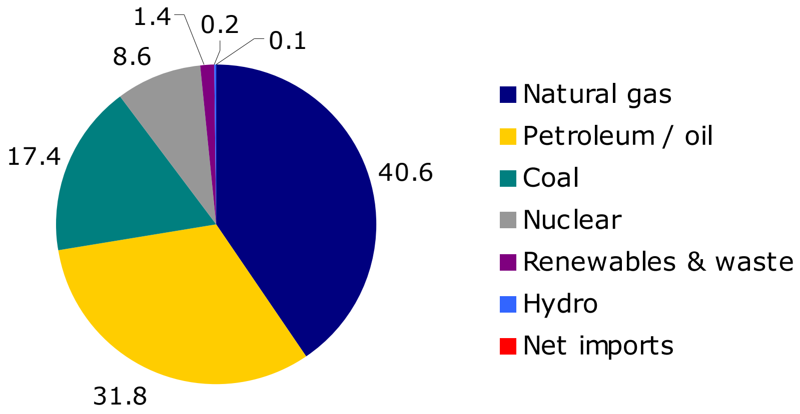
1.1. BACKGROUND AND CONTEXT: THE 60% TARGET

The threat of climate change is recognised by the United Kingdom's recent Energy White Paper, 'Our Energy Future - Creating a Low Carbon Economy', (DTI, 2003a), which establishes four key goals for energy policy:

- to place the UK on a path to reduce carbon dioxide emissions by 60% of 1990 levels by about 2050;
- to maintain the reliability of energy supplies;
- to promote competitive markets and;
- to ensure that every home is adequately and affordably heated.

The aspiration of achieving a 60% reduction in carbon dioxide emissions is an ambitious one. The UK relies heavily on fossil fuel sources of energy - renewable sources of energy provide less than two percent of total energy in the UK, as shown in figure 1.1.

Figure 1.1: UK 2003 primary fuels consumption (%)



Source: DTI Energy Statistics, historic data (Inland consumption of primary fuels and equivalents for energy use, 1970 to 2003 [1]).

Furthermore, electricity consumption in the UK has increased steadily in recent years. Fuel switching from coal to gas has prevented this growth in electricity consumption being accompanied by significant growth in carbon dioxide emissions. However, from 2010 onward, as nuclear power stations begin to close, dependence on fossil fuel sources of electricity is projected to increase and carbon dioxide emissions are forecast to climb (DETR, 2001).

Meeting the carbon dioxide emission reduction target will require significant cuts in carbon emissions from electricity generation. Electricity generation is responsible for 38.1% of emissions in the UK, as shown in figure 1.2. Emission cuts from electricity generation will require both energy efficiency improvements and a significant shift to carbon-free sources of electricity.

[1] http://www.dti.gov.uk/energy/inform/energy_stats/total_energy/index.shtml. Accessed 6 August 2005.

Figure 1.2: UK 2003 emission generation, by sector (%)

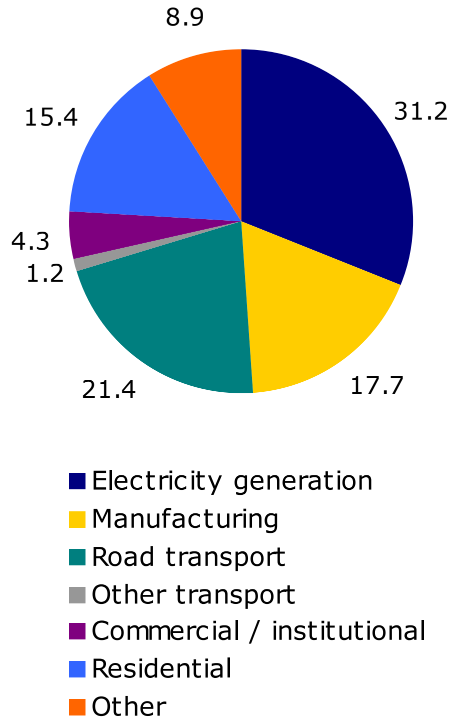
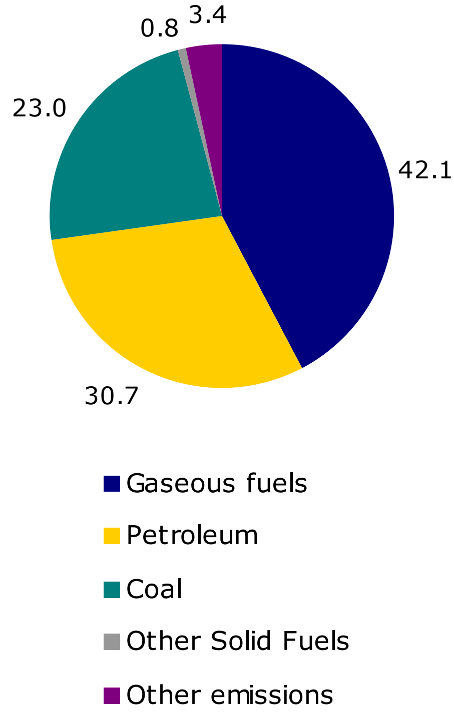


Figure 1.3: UK 2003 emission generation, by fuel type (%)



Source: DEFRA, historic data (Estimated emissions of carbon dioxide (CO2) by UNECE source category, type of fuel and end user: 1970-2003[2])

Despite the importance of carbon-free sources of electricity generation in delivering emission reductions, the Energy White Paper does not set targets for different generating capacities. Rather it sets out a range of policy measures intended to create a market framework that will deliver the stated energy policy goals most effectively.

The policy document ensures a number of support mechanisms for renewable sources of electricity generation. Renewable electricity is defined as that which can be generated from wind power, wave, tidal, solar photovoltaics (PV), hydro generation, geothermal and biomass (energy from forestry or crops). The White Paper suggests that in order to achieve a 60% reduction in carbon emissions by

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[2] http://www.defra.gov.uk/environment/statistics/globatmos/gaemunece.htm. Accessed 6 August 2005.

2050, it is likely that the contribution to electricity generation from renewables will need to be “at least 30% to 40% … and possibly more”.

1.2. RELEVANCE

In the coming decades the UK must confront a number of challenges to ensure secure and affordable energy supplies.

The UK is set to undergo a shift from net exporter to net importer of energy. This has implications for the energy, economic and foreign policy strategies of the UK. The UK’s indigenous energy supplies of coal, gas, oil and nuclear, which together supply 98% of the country’s electricity requirements, are all forecast to decline (DTI, 2003a). By 2020, the UK is expected to import 75% of total primary energy needs (DTI, 2003a).

Much of the UK’s energy infrastructure needs to be updated over the next two decades. Europe’s Large Combustion Plants Directive is expected to either force the modernisation or the closure of a significant number of older coal-fired power plants. In addition, under present retirement plans, only three of the 12 nuclear power plants, which currently provide 23% of the UK’s electricity requirements, will be in operation in 2020. These three plants will produce only 7% of the UK’s electricity requirements. By 2025 it is planned that only one nuclear power plant will remain in operation (DTI, 2003a).

The carbon abatement aspiration embodied in the UK’s Energy White Paper further limits the options available to the UK in fulfilling its electricity requirements. By 2020 it is intended that renewable sources of energy will provide 20% of the nation’s electricity requirements. Over the same time period, nuclear capacity is forecast to decline from providing 23% of the nation’s electricity requirements, to providing just 7%. As a result, the benefits of investment in renewable sources of energy will be offset, in carbon abatement terms, by the decline in nuclear capacity.

It is unclear how the UK intends to meet its self-imposed carbon abatement target. The Renewables Obligation, the central policy mechanism of the UK's renewable energy policy, is intended to bring about an increase in renewable sources of electricity. At present, the Renewables Obligation is underperforming and it is unlikely that the 2020 renewable energy target[3] will be achieved (Mitchell and Connor, 2004). Further, the 2020 renewable energy target is insufficient to put the UK on target to meet its 2050 carbon abatement goal (Oxera, 2005a).

Under current plans, a gap exists between expected electricity demand and supply if the 2050 carbon abatement target is to be met. In order to meet the 2050 carbon abatement target, an additional program of renewable energy, carbon sequestration, energy efficiency or nuclear build will be necessary (Oxera, 2005a).

1.2.1. The nuclear option

The Energy White Paper considers nuclear power an important source of carbon-free electricity. However, it suggests that nuclear power is an unattractive option for new, carbon-free generating capacity due to the current economics and unresolved issues of waste disposal. The possibility of new nuclear build is however kept open, and the White Paper indicates that nuclear build may be necessary if carbon emission targets are to be met.

Nuclear power is not cost competitive with gas or coal in the present economic environment. In liberalised electricity markets, such as that of the UK, private

[3] By 2020 it is intended that renewable sources of energy will provide 20% of the nation's electricity requirements.

investors are deterred by the high capital requirements and the long lead times of nuclear generation. In spite of this, a recent study by Massachusetts Institute of Technology (MIT) (Ansolabehere et al., 2003) suggests that reasonable reductions in capital costs, operation and maintenance costs, and construction time could reduce the gap between the cost of nuclear generation and the cost of generation from fossil fuel sources of electricity. The study further suggests that carbon emission credits could give nuclear power a cost advantage over coal and gas.

Issues of economics aside, the disposal of nuclear waste remains unresolved. While geological disposal of nuclear waste is technically feasible, this has yet to be demonstrated (Ansolabehere et al., 2003). The Energy White Paper states that resolution of the issue of nuclear waste is needed before new nuclear build is commissioned (DTI, 2003a).

Nuclear power is a highly contentious issue of which the public is sceptical (Ansolabehere et al., 2003). The UK government has committed itself to extensive public consultation and the publication of a White Paper on new-build nuclear power before any change to the government's position on nuclear power.

Prime Minister Blair will use his third term in office to underline his commitment to addressing climate change and will turn his attention to national and international energy policy (Tony Blair, in The Economist, 1 January 2005). Speculation in the media suggests Blair intends to initiate a nuclear power plant construction program (The Independent, 8 May 2005). Consequentially, the question of the most effective way to meet the goals of the 2003 Energy White Paper is of particular relevance.

1.3. INTERGENERATIONAL EQUITY AND DISCOUNTING

Discounting allows costs and benefits that occur in different time periods to be compared. The theory of discounting is based on the principle of time preference, i.e. that individuals prefer consumption today to deferred consumption (Kolstad, 2000).

While conventional approaches to discounting value a gain or loss in the future at less than the same gain or loss today, ethical controversies rage over the applicability of fixed-rate discounting approach to social issues, and indeed to human life (Heinzerling, 2000; Ackerman and Heinzerling, 2002). Certainly it can be argued that no human life should be valued differently from another, regardless of the temporal, or spatial, dimensions involved.

The environmental issues associated with nuclear build have important implications for future generations as nuclear energy has both positive and negative environmental attributes that are important in the long-term. Positive environmental attributes are embodied in its ability to provide large amounts of carbon-free energy in an age of worsening climate change, while negative environmental effects are associated with the decommissioning of nuclear power plants, the storage of nuclear waste and the potential for catastrophic nuclear accidents in the future. As such, the discounting treatment applied to the analysis is of critical importance.

Fixed discount rates are commonly used to find the present value of investments, and in a liberalised electricity market, a fixed discount rate will be used by private investors to evaluate the investment potential of nuclear energy. As nuclear investment decisions will be made by the market, social concerns will play no role in the decision making process and a constant discount rate will ensure risks to future generations are valued to a lesser extent than risks to the present generation.

Recent advances in discounting theory suggest that the correct social discount rate is not a single number, but a value that declines with time (Pearce et al., 2003). This knowledge has important implications for policies concerned with energy and the environment. Certainly the importance of declining discount rates is acknowledged by the UK government – official guidance to Ministries notes the power of time-varying discount rates when evaluating investments and policies with costs and benefits that accrue over more than thirty years hence (HM Treasury, 2003).

Consequentially, this thesis will investigate costs of energy investments using both a constant market discount rate, and the declining social discount rate scheme advocated by HM Treasury in the Green Book.

1.4. RESEARCH GOALS AND QUESTIONS

This thesis limits its investigation to the electricity-generating sector in the UK. It attempts to determine what combination of different generating technologies will allow the UK's electricity sector to reduce carbon dioxide emission by 60% by 2050 at lowest cost. The 60% target was a key feature of the Energy White Paper of 2003, and although it applies to more than just the electricity sector, the electricity sector might be expected to contribute pro rata[4]. More specifically this thesis investigates whether an adherence to both the aspiration of reducing carbon dioxide emissions by 60% by 2050, and to the promotion of competitive energy markets, will force an increasing reliance on nuclear power.

[4] This thesis assumes a 60% reduction in carbon emissions will be required from the electricity sector.

Current literature examining the effect of the UK's emission reduction targets on the structure of the electricity market considers the implications of the policy goals over a shorter timeframe, that is, until 2020 (Pena-Torres and Pearson, 2000; Oxera, 2005). Thus this thesis takes the literature forward by providing an extensive analysis of the implications of the UK's current energy policy on the structure of the electricity market until 2050.

In addition to investigating the electricity mix to meet the UK's electricity requirements in 2050 in the most cost-effective manner, this thesis will investigate how inter-generational equity concerns would alter the electricity mix. Hence, in considering the costs associated with nuclear power, both a time-constant and a time-declining discounting treatment will be applied.

To account for the social cost of carbon emissions, a value for the social cost of carbon will be included when analysis is based on the social rate of time preference. When the analysis is based on market discount rates, a prediction for the cost of carbon on the EU Emissions Trading Scheme (ETS) will be used. Various attempts have been made to estimate the social cost of carbon, i.e. to quantify the damages per tonne of carbon emitted. No similar estimate attempts to quantify the external costs of nuclear power, i.e. the social costs nuclear energy imposes on society beyond decommissioning and waste management costs[5], and hence no value is included for these costs.

Examining the economics of the UK's electricity market over this timeframe, and considering the interaction between energy policy, climate change and inter-generational equity concerns, allows an extensive appraisal, to the fullest extent possible, of the stated goals of the Energy White Paper. Thus, this thesis will

[5] This includes the cost of (potentially irreversible) environmental damage, as well as the effect of a nuclear accident on human health and society.

provide an extensive analysis of the costs of the UK's energy policy to this and future generations.

1.5. STRUCTURE

Before considering the research questions, Chapter 2, will provide an overview of the current electricity market. In particular, a review of existing studies relevant to this thesis, and of the economic and social costs of nuclear power, will be presented. Other carbon abatement options will be examined. Chapter 3 provides the applicable methodological research framework and presents the scenarios used in the research. Results are presented in Chapter 4. Chapter 5 provides a discussion on these results. Chapter 6 concludes by analysing the implications of the results for energy policy in the UK and presents recommendations for achieving the 2050 carbon abatement target at least cost.

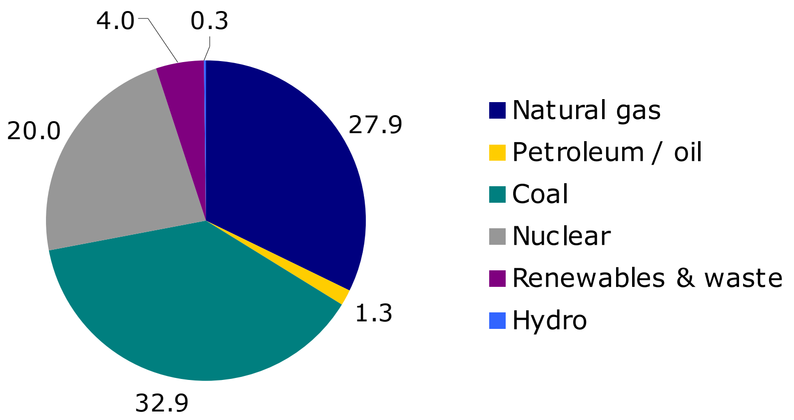
2. Literature Review

This chapter opens with an overview of the UK electricity market and examines the costs associated with coal and gas generation. Recent studies of nuclear economics are considered briefly. An investigation into the economics of carbon abatement options introduced in chapter 1 is presented. This considers both the carbon abatement capabilities and the costs associated with nuclear energy, renewable energy, carbon sequestration and energy efficiency in turn. In respect of nuclear power, an overview of waste management and safety issues is presented. In particular, the current nuclear waste management situation in the UK is examined.

2.1. UK MARKET OVERVIEW

The UK currently relies heavily on fossil fuels for electricity - over 70% of electricity supply is generated from fossil fuel sources. The bulk of the remainder is generated by nuclear power, as is shown by figure 2.1.

Figure 2.1: UK 2003 electricity generation, by fuel type (%)



Source: DTI Energy Statistics (Fuel input for electricity generation[6])

[6] http://www.dti.gov.uk/energy/inform/energy_stats/electricity/index.shtml. Accessed 6 August 2005.

Gas has experienced rapid growth since the electricity supply industry was liberalised in 1990. Combined Cycle Gas Turbines (CCGTs) are seen as offering the best return on investment and are likely to remain the benchmark against which investment in other sources of generation is measured for some time (Oxera, 2005b). Low capital costs, short construction periods and stable fuel prices contribute to this. In the medium term, it is likely that gas will continue to increase its proportion of electricity supply as older coal-fired power stations close and nuclear power stations are decommissioned.

The capital cost of a new CCGT plant has recently been estimated as £270/kW (PIU, 2001; Marsh, 2003). According to Dale at al. (2004), the US Department of Energy expects a modest decline in the capital costs of CCGT plants of 7% by 2020. This is inline with PIU (2001) estimates.

Electricity generators paid an average of 28p per therm[7] for gas in the first quarter of 2005 (DTI, historic data[8]). DTI (2001) predictions indicate average gas prices of 27p/therm toward 2020 are likely.

In contrast to gas, the proportion of electricity supplied by coal is shrinking. Although fuel prices for coal generation are more favourable than fuel prices for gas[9], coal generation is subject to higher capital costs and longer lead times (Marsh, 2003). Integrated Gasification Combined Cycle (IGCC) coal power plants are expected to be the most cost effective option of coal generation in the coming decades (Marsh, 2003). However, at £625/kW, capital costs of IGCCs are

[7] This is equivalent to 0.96p/kWh.

[8] Average prices of fuels purchased by the major UK power producers and of gas at UK delivery points. Available online at: http://www.dti.gov.uk/energy/inform/energy_prices/qepupdate.shtml. Accessed 6 August 2005.

[9] Electricity generators paid £36.4/tonne (0.50p/kWh) in the first quarter of 2005.

significantly higher than capital costs for CCGTs (Marsh, 2003). Coal-fired power plants also have construction periods of between six and ten years - considerably longer than the two years it takes to build a CCGT.

The UK has traditionally exploited indigenous supplies of coal and gas and economically viable indigenous reserves have declined. As a consequence the UK will increasingly depend on imports for its fossil fuel requirements. The 2003 Energy White Paper suggests that this decline in indigenous supplies may increase the UK's vulnerability to price fluctuations but does not necessarily have negative implications for the UK's ability to achieve energy reliability. Diversity of supply is seen as the key to energy reliability to reduce dependence on imports (DTI, 2003a).

In the coming decades the UK faces a further challenge as much of the energy infrastructure in the UK needs updating and substantial new investment is required to maintain generating capacity. According to an Oxera (2005b) estimate, in the absence of new investment 20GW of capacity may be lost by 2020:

- By 2025 only one of the UK's 12 nuclear power plants will remain operational;
- The EU's Clean Combustion Plant Directive will force the closure or upgrading of many coal plants;
- Some gas-fired generating capacity built in the 1990s has been retired (DTI, 2003a).

The government's commitment to mitigating climate change has led to UK participation in the EU ETS forcing the private sector to account for carbon emissions. Estimates from The Carbon Trust (2004) suggest the price of carbon dioxide may rise to €25 per tonne of carbon dioxide[10] post 2012. This is significantly lower than the estimated value of the social cost of carbon in a paper published by HM Treasury and DEFRA, which suggests that a point estimate of £70/tonne of carbon in 2000 prices inflated by £1/tC per year is suitable for use in UK policy design[11] (Clarkson and Deyes, 2002).

2.2. NUCLEAR ENERGY

There is little agreement on which technology provides reliable, carbon-free generation at least cost. Media speculation surrounds the potential role of nuclear power (The Independent, 8 May 2005). Recent studies considering the role of nuclear energy in the future generation mix elicit varied conclusions.

2.2.1. The current situation

Very little new investment has been made into nuclear power in the last decade. New build in China and a single nuclear power station in Finland provide niche exceptions to this observation. At present, the economics of nuclear power do not tempt private investment. The downturn in the fortunes of nuclear power can be attributed to the spread of liberalised electricity markets (MacKerron, 2003).

The only nuclear power plant commissioned in Western Europe in the past decade is currently under construction in Finland. The plant was commissioned by a non-profit electricity utility company that provides power to industrial shareholders at cost. The decision to construct a nuclear power plant was based, in-part, on economic analyses, but influenced by a desire to limit gas imports from Russia and by Finland's Kyoto Protocol commitments (Ansolabehere et al., 2003).

[10] This is equivalent to £4.70 per tonne of carbon.

[11] Note that this figure is currently under review, with a new estimate expected to be announced in September 2005 (Hepburn, pers comm).

In the UK, a nuclear power station was last completed in 1994 and there has been no new nuclear investment since. Presently, 12 nuclear power stations provide 23% of the nation's electricity. However, under current retirement plans only one of these plants will remain in operation in 2025.

Current energy policy in the UK emphasises the importance of planning for the long-term and places climate change mitigation at its core. Despite a commitment to both long-term planning and carbon-free sources of electricity generation, the Energy White Paper provides no support mechanisms for nuclear power. The ostensible reason for this decision is the current economics of nuclear power.

The government recognises that new nuclear build is a highly controversial issue, not least because of the unresolved issues of nuclear waste. The Energy White Paper affirms that extensive public consultation and the publication of a White Paper on new-build nuclear power will be undertaken before any change in the government's current stance on nuclear power. Consequentially, the earliest realistic delivery date for a new nuclear reactor in the UK is around 2020.

2.2.2. Economics of nuclear energy

The MIT study (Ansolabehere et al., 2003) concluded that nuclear power is not currently cost-competitive with coal and gas. However, the study found that plausible reductions in capital costs and construction times could reduce the gap between the costs of nuclear and fossil fuel generation. Further, it was found that if nuclear power benefited directly from a carbon emission credit, or indirectly from a carbon tax on fossil fuel sources of generation, nuclear power could potentially exhibit a cost advantage over coal and gas.

Ansolabehere et al. (2003) acknowledged that concerns over safety, waste and proliferation must be resolved before new nuclear build is commissioned.

MacKerron (2004) argues that until nuclear power is seen as an 'ordinary' technology with regard to these issues, it will not be a serious choice for private investment.

Within the UK, Pena-Torres and Pearson (2000) investigated the market prospects of current nuclear technology and concluded that current technology is unlikely to be able to compete in the liberalised UK marketplace. However, the study did not consider the potential of cost and technology improvements to enhance the competitiveness of nuclear power.

More recently, a study by Oxera (2005b) considered the conditions under which the private sector would finance a fleet of nuclear power plants. Conclusions suggest that a program of nuclear build would require financial support from the government, as the financial risks associated with nuclear build remain unacceptably high to private investors. Like the paper by Pena-Torres and Pearson, and in contrast to the MIT analysis, the Oxera study did not consider the consequences of costs and technology improvements.

The economics of nuclear power have certainly deteriorated in liberalised electricity markets as investment decision-making for electricity generation has shifted away from governments and toward private investors. Although decision-making can be influenced by regulation, and by policy frameworks, ultimately investment decisions are made by private investors who, at present, do not favour investment in nuclear power for a number of reasons:

- Nuclear reactors have prolonged planning and construction time.
- Construction costs of nuclear power plants are uncertain.

- Construction costs account for over 70% of the present value of total generating cost[12] and as a result, total generating costs are sensitive to escalations in construction cost.
- The lower-end of generating cost estimates depend on achieving economies of scale. A construction program involving ten nuclear power plants would be necessary to get costs down to the lowest possible level.
- Investment in nuclear power is influenced by substantial political risk, which is associated with the issues of nuclear waste, safety and public perceptions of safe operation and waste management (MacKerron, 2004; Ansolabehere et al., 2003).

MacKerron (2004) contends that for nuclear power to be seen as a more attractive investment option by private investors, the economics of the nuclear option need to improve, either on the basis of market prices relative to other electricity generating options and/or as a result of government policies in favour of nuclear power or carbon-free electricity.

Private investors are particularly sensitive to lead-in time and construction costs, both of which are discussed below. Construction time is of concern to investors as it determines the period over which a plant cannot generate revenues. Furthermore, the practice of discounting ensures postponed revenues are less important than the more immediate capital expenditures.

I. Lead-in time. Nuclear generation suffers from a protracted lead-in time, which postpones investor returns. Planning approval is required to build and operate a nuclear power plant on a specific site and requires investors to confront a number

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[12] The MIT study assumes financing of 50:50 debt:equity. Interest on the debt is calculated as 8%, return on equity is calculated at 15%. That implies a discount rate of 11.5%.

of political and regulatory challenges, including local opposition, licensing disputes and discharge requirements.

MacKerron (2004) estimates planning time as two years and construction time as five years. This is optimistic relative to British Energy's (2001) estimate of a ten-year lead-in time. At the other end of the scale, a recent study by Oxera (2005b) estimated a four year construction period and suggested the earliest a new reactor could be made operational was 2015. This implies a two year planning period when the dates for the publication of the white paper on new nuclear build are taken into account[13].

II. Capital costs. Recent applicable data on construction costs of nuclear power plants are sparse. No new nuclear build has commenced in the UK in the past fifteen years and only one in the European OECD in the preceding decade. The problem is compounded as the nuclear industry has a history of not delivering on optimistic cost forecasts. Historically, construction costs have exceeded expectations due to regulatory delays, redesign requirements, and quality control problems.

The cost of construction for Sizewell B, the UK's most recent nuclear plant, was in the region of £3,000/kW in 2000 money including first-of-a-kind (FOAK) costs. Excluding FOAK costs, the construction cost was £2,250/kW resulting in generation at an average cost of around 6p/kWh (PIU, 2001).

This contrasts markedly with the construction costs estimate of £1140/kW for the new Finnish nuclear reactor. Indeed, new designs are expected by the nuclear

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[13] Oxera suggests the earliest a new reactor could be made operational is 2015. As the earliest a White Paper on nuclear new build could appear would be 2008, or more likely, 2009 (MacKerron, 2004), following a separate Government review of nuclear waste which is expected in 2007 (DEFRA, 2001), the Oxera estimate of a four year construction period implies a two year planning period.

industry to deliver electricity at between 2.2p/kWh and 3.0p/kWh. This however has yet to be demonstrated (MacKerron, 2004).

The Performance and Innovation Unit (PIU) (2001) undertook an extensive investigation into the cost of nuclear build in the UK as part of the Energy Review. In submissions to the PIU, British Energy and BNFL predicted that the average cost the Westinghouse AP1000 could generate electricity at was between 2.2p/kWh and 3.0p/kWh. While construction estimates were kept confidential the PIU noted that estimates were better than the best recent estimates from OECD countries, and that estimates of operating availability were questionably high. Considered analysis from the PIU suggested the cost of nuclear generation in 2020 would fall in a range between 2.5 and 4.0p/kWh. This is consistent with construction costs of £1,400-£1,700kW in 2000 money (Ansolabehere et al., 2003).

Oxera (2005a) recently used a construction cost estimate of £1600/kW. This estimate was based on a 1GW reactor. Further allowances of £100 million each were made for FOAK and public enquiry costs, as well as an allowance of 10% for over-run costs. Subsequent reactors were estimated to exhibit cost savings such that the third reactor was estimated at £1200/kW (excluding over-run and public enquiry costs).

The PIU Energy Review (2001) suggests that capital costs of nuclear construction could fall to £690/kW. This is a considerable decline and is dependent on the following assumptions being met:

- Very high operating availability;
- A series build of 10 identical reactors;
- Short construction times;
- Regulatory stability.

III. The discount rate. Until recently in the UK, nuclear investment was heavily subsidised by the government via long-run sales contracts and the underwriting of decommissioning and waste management costs. In liberalised energy markets this is not the case. Additionally, private investors in nuclear power are exposed to further risk due to the uncertain capital costs, electricity prices and new technologies. The rate of return investors expect reflects this risk level. Pena-Torres and Pearson (2000) suggest the return expected by investors is in the region of 10-15%. An Oxera (2005a) study argues that investors expect a return of between 14% and 16%. This argument is supported by the fact that electricity utilities have averaged a capital return of between 7% and 12% in the last 15 years, and the expected risk premium of nuclear investment is between 2% and 4%.

2.2.3. Waste management and safety

While a number of economic concerns hamper nuclear investment, the management and disposal of nuclear waste is perhaps the biggest challenge facing the industry.

The primary goal of any nuclear waste management program must be to reduce the risks of radiation exposure from nuclear waste to an acceptably low level. To achieve this, long-term isolation is necessary, as spent nuclear fuel will remain highly radioactive for many thousands of years. Most countries have a stated preference for the disposal of waste in repositories constructed in rock formations hundreds of meters below the earth’s surface. The scientific community exhibits a high level of confidence about the ability of deep geological exposure to safely isolate nuclear waste from the biosphere for as long as it poses significant risks. However, despite the fact that the first commercial nuclear power station began operating over 40 years ago, no high-level waste repositories are in operation and no country has succeeded in disposing of its high-level nuclear waste (MacKerron, 2004; Ansolabehere et al., 2003).

Within the UK, the decision was taken to reprocess nuclear waste prior to intended geological disposal. Reprocessing has few, if any, benefits, increases the risks of nuclear proliferation and is extremely expensive (Ansolabehere et al., 2003). Indeed, the reprocessing decision is largely responsible for the poor economics of the current British nuclear program (Economist, 2005). The British government recently agreed to supply an initial £2 billion over ten years toward decommissioning and waste management costs, which were supposed to have been met by the financially troubled British Energy (MacKerron, 2004). The issue of nuclear waste management is now officially under review.

The costs of decommissioning current nuclear sites in the UK are high. This is as consequence of construction being undertaken with little thought for the decommissioning process. New nuclear designs by contrast specifically incorporate decommissioning plans and it has been estimated that a realistic value for decommissioning a nuclear power station with two 1GW reactors is of the order of £1 billion (Oxera, 2005b). This assumption is contingent on the issue of nuclear waste management being resolved by the British government.

Waste management is not the only issue that increases the political risks and uncertainties associated with nuclear investment. Concerns exist regarding the safety of the entire nuclear cycle. Three serious reactor accidents[14] and a number of accidents at reprocessing plants have heightened public awareness of the risks associated with nuclear energy (Ansolabehere et al., 2003). Indeed, the public

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[14] Three Mile Island, Harrisburg, Pennsylvania in 1979; Chernobyl in the Soviet Union, 1986; and the Tokaimura Plant, Japan, 1999.

may misconceive the risk of nuclear accident; a survey by Graham (1996) indicates there is a deviation between public assessment of risk and actuarial fact. Nevertheless, MacKerron (2004) argues that issues of public concern, chiefly waste management and safety, must be dealt with to the satisfaction of the wider public to make the nuclear option a more attractive one to investors.

2.3. RENEWABLE ENERGY TECHNOLOGIES

The UK has abundant resources for the generation of renewable electricity. The UK's wind resource is amongst the best in Europe - the accessible wind resource in the UK has been estimated at 15% of the EU wind resource. In addition, the UK has wave resources far superior to that of any other European nation, over half of the European tidal resource and an excellent farming infrastructure that offers significant opportunities for development of biomass electricity (Connor, 2003; Gross, 2004; Elliot, 1996).

The DTI (2000) has estimated both the technical potential[15] and the practicable potential[16] for commercial delivery of renewable energy resources in the UK. The practicable potential is estimated based on assumptions of both technical and non-technical constraints, including technological limitations, space availability, efficiency and uptake (Gross, 2004).

From table 2.1 it is apparent that there is significant technical potential for renewable energy resources to deliver a considerable proportion of the UK's energy requirements. Indeed, current electricity demand in the UK is less than 350TWh per year while the estimated technical potential of offshore wind is

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[15] Technical potential provides an assessment of the useful energy that could be extracted from available resources.

[16] Practicable potential provides an assessment of the useful energy that is likely to be extracted from available resources given both technical and non-technical constraints. This requires assumptions regarding the availability of space (including competing land-use needs), the efficiency and number of conversion devices that may be installed.

almost ten times this amount. The estimated practicable potential of offshore wind is considerably lower than estimated technical potential, however at 100TWh/yr is sufficient to meet almost one third of current electricity demand.

Table 2.1: UK renewable electricity resource in 2025

Technology	***Technical potential (TWh/yr)***	***Practicable potential (TWh/yr)***
Building integrated photovoltaics (BIPV)	250	37
Offshore wind	3000	100
Onshore wind	317	8
Biomass	140	~30
Wave	700	50
Tidal stream	36	1.8
Small hydro	40	3

Note: This table is based primarily on estimates from the DTI (2000). Figures from Bauen (2000) have been used for biomass and from Gross (2004) for offshore wind.

2.3.1. Economics of renewable energy technologies

Renewable energy technologies are highly capital intensive. This is an important economic characteristic that is shared with nuclear power. Whereas roughly 70% of nuclear generating costs are capital-related, the absence of fuel costs contributes to this figure being as high as 90% for some renewables (MacKerron, 2004).

Renewables are however much less dependent on achieving economies of scale than nuclear power. Smaller scale projects ensure quicker construction times and allow investors to earn returns within months of making an investment. This investment characteristic allows the rapid growth and technological learning which is associated with renewable technologies.

The main disadvantage of renewable technologies is that they are intermittent and as a result are unable to be relied upon to balance supply with demand. While the penetration of renewable sources of electricity is low this intermittency is of little consequence, but would become an issue if one form of renewable energy achieved a market share in the region of 30% (Gross, 2004).

Table 2.2 illustrates the current global status of renewable energy technologies with regard to current costs, installed capacity and market growth rates. Although neither PV nor wave energy are likely to be constrained by technological limits in the near future, economic considerations are expected to hinder these technologies. Indeed, due to high costs neither technology is expected to contribute significantly to renewable energy penetration in the UK in the coming decades (Gross, 2004).

Table 2.2: Current global status of leading renewable energy options

Technology	***Current costs (p/kWh)***	***Installed capacity (MWh)***	***Market growth***
PV	20-60	~1200	25% pa
Onshore wind	2-3	~30,000	30% pa
Offshore wind	4-6	~580	240MW of capacity installed in 2004 compared with installation of 90MW in 2003. Growth rate unclear.
Biomass	4-6	~35,000	Unclear
Wave	8	<2	Capacity expected to double through demonstration projects in 2004

Source: BWEA, 2005; Gross, 2004.

The viability of renewable energy is affected by the resource availability and as such is location specific. Whereas wind and biomass technologies exhibit the highest levels of industry maturity on a global scale, within the UK both onshore wind and biomass are constrained from substantial development by institutional barriers relating to planning and land-use. As such it is expected that offshore wind energy will make the largest contribution to electricity from renewable sources in the UK in the medium to long-term (Gross, 2004). In light of this analysis, the costs of offshore wind are considered further.

While the UK has significant resources for the generation of renewable electricity, the penetration of renewable energy will depend on economics. The costs of distributed sources of renewable energy are not limited to capital and operating costs, but must consider the costs imposed by intermittency and by necessary upgrades and extensions to the electricity network. The economics of offshore wind are investigated further below.

I. Capital and operating costs. At present, capital costs for offshore wind are in the region of £850/kW - £1100/kW and exhibit a declining trend (Gross, 2004). In a study on the costs of large-scale wind scenarios in the UK, Dale et al. (2004) used an estimate of £1000/kW for capital expenditure. These capital costs are expected to decline such that by 2020, capital costs will be between 40% and 70% of present costs (Dale et al., 2004). Milborrow (2003) suggests that by 2012 the capital costs of offshore wind could experience a reduction of around 40%. While this may seem optimistic, it is interesting to note that in contrast to nuclear, wind energy has traditionally exceeded cost reduction expectations.

Operation costs for offshore wind have been estimated at £24/kW/yr[17] at present and are expected to decline to £20/kW/yr[18] by 2020 (Dale at al, 2004). These figures seem low however actual costs at the Danish offshore wind farm,

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[17] 0.78p/kWh assuming a capacity factor of 35% and 8760 hours per year.

[18] 0.65p/kWh assuming a capacity factor of 35% and 8760 hours per year.

Middelgrunden, are reportedly around £12/kW/yr[19]. According to Dale et al. (2004), the DTI suggest that a figure of £36/kW/yr[20] may be more appropriate for early installations.

II. Intermittency costs. The intermittent nature of wind energy is expected to be responsible for the largest part of the additional system costs anticipated. Intermittent sources of supply are less valuable in terms of system security due to both capacity and balancing requirements (DTI, 2002). The amount of conventional capacity offset, and thus the marginal contribution of wind per unit of rated power, declines as the installed capacity increases. Additional costs due to system capacity requirements have been estimated between 0.03p/kWh and 0.06p/kWh for wind penetration of 10%, rising significantly to between 0.17p/kWh and 0.20p/kWh for wind penetration of 30% (DTI, 2002; Auer, 2004). Increased penetration of renewable electricity will also impose extra costs due to further requirements on conventional plants to ensure a continuous balance between demand and generation. Estimates indicate that these costs are of the order 0.27p/kWh-0.29p/kWh for wind penetration of 30% (DTI, 2002; Dale et al., 2002).

III. Additional transmission and distribution costs. The location of wind generation will have an important effect on transmission costs. A DTI study (2002) estimated transmission reinforcement costs between £65/kW and £125/kW. Variation is ascribed to the different distribution of wind resources under different scenarios. Dale et al. (2004) use a value of £100/kW as representative of transmission infrastructure costs.

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[19] 0.39p/kWh assuming a capacity factor of 35% and 8760 hours per year.

[20] £1.17p/kWh assuming a capacity factor of 35% and 8760 hours per year.

Costs associated with the connection of dispersed wind generation to the transmission system are not trivial. Dale et al. (2004) approximated these connection costs between £40/kW and £70/kW, and used a value of £50/kW as representative. Once again, variation is attributed to differing assumptions regarding the distribution of wind resources.

Also noteworthy are the costs of connecting and operating renewable generation at the distribution level. These costs have been estimated between £34/kW and £41/kW. Distribution costs would be expected in the lower end of this range for large offshore wind projects as such projects would be more likely to connect at transmission voltage (Dale et al., 2004).

Neither transmission nor distribution costs have a significant impact on overall capital expenditure while construction costs are in the region of £1000/kW. However, the expected 40% decline in capital costs would result in transmission and distribution costs contributing significantly to the overall capital expenditure, i.e. over 40% at current transmission and distribution costs, which are not expected to exhibit the same rapid cost decline as wind (Dale et al., 2000).

2.4. CARBON SEQUESTRATION TECHNOLOGIES

Carbon sequestration, "the capture and secure storage of carbon that would otherwise be emitted to or remain in the atmosphere" (Reichle et al., 1999), has received much attention of late from scientists and policy makers alike. The application of carbon sequestration technologies to power plants has potential to reduce carbon dioxide emissions from the production of electricity by between 80 and 90% (Herzog et al., 2000; Herzog, 2001; Herzog et al., 2002; Tzimas and Peteves, 2005). Although carbon sequestration has significant potential it is subject to a wide range of uncertainties at present, chief among which are concerns over leakage of carbon dioxide from repositories (PIU, 2001).

At present there is only one commercial application of carbon dioxide storage worldwide. The Sleipner Project injects 1 million tonnes of carbon dioxide into a saline aquifer below the North Sea per year (Tzimas and Peteves, 2005).

2.4.1. Economics of carbon sequestration technologies

The economics of carbon sequestration are vital to its viability. Carbon sequestration will result in an additional charge to the electricity produced from plants at which carbon sequestration is applied. This additional charge has the ability to alter the attractiveness of carbon-neutral energy sources.

I. Capital costs. Significant investment for technological development and infrastructure is necessary for a large scale carbon sequestration project. Construction of carbon dioxide capture facilities, pipelines and injection wells compel increased capital costs.

A study by Marsh (2003) for the DTI estimated the capital costs for carbon dioxide capture from a new IGCC plant as £850/kW, and as £510/kW from a new GTCC plant. These numbers exclude capital costs for the construction of pipelines and carbon dioxide injection facilities. More recently, Tzimas and Peteves (2005) estimate capital costs as £1310/kW for a new IGCC plant with carbon capture capabilities, and £690/kW[21] for a new GTCC plant with carbon capture capabilities. Carbon capture, transport and injection technologies also impose additional operating costs[22]. In addition, high power requirements of sequestration technologies enforce a penalty on power plant efficiency (Marsh, 2003).

[21] This implies a cost of carbon dioxide abatement of £62/tC, and is based on the cost of generation from plants built in 2020. Other assumptions: carbon dioxide emissions from CCGT – 0.37kg/kWh; carbon emissions from CCGT CC – 0.06kg/kWh (Marsh, 2003). The high cost of abatement reflects the conservative assumptions for capital cost used which are in line with the recent paper by Tzimas and Peteves (2005).

[22] Marsh (2003) has estimated additional plant operating costs for capture from IGCC and GTCC plants as 0.3p/kWh and 0.4p/kWh respectively. Operating costs associated with transport have been estimated as £5.7/t CO_2 and with injection as £1/t CO_2, i.e. £1.6/tC and £0.23/tC respectively.

2.5. ELECTRICITY EFFICIENCY

Improvements in the efficiency with which electricity is converted and used has the potential to make a large contribution to a carbon abatement strategy at low or negative cost (IPPC, 2001c; Blok, 2005; PIU, 2001; DETR, 2001).

Electricity use in the UK, corrected for economic growth, has fallen by an average of 1.18% per year in the preceding decade. This improvement in electricity efficiency amounts to 10% over the period and is due to technological progress. However, in absolute terms electricity consumption has grown by 27% during this time due to growth in economic output. Under a business-as-usual assumption, based on the improvement rates of electricity efficiency over the past decade, electricity consumption is expected to increase by 21% to 2020 and by 66% to 2050.

There is considerable debate about what rate of efficiency improvements can be realised. In theory, annual rates of 2% or more are achievable, however, in practice, it is seldom that rates of above 1% per year are attained (Blok, 2005). It has been estimated that the current potential for cost effective improvements in electricity efficiency is in the region of 26% of total electricity demand (PIU, 2001; DETR, 2001). The associated net cost savings are estimated at £7.5 billion (PIU, 2001).

A number of barriers complicate the design and implementation of electricity efficiency policy measures, as well as the prediction of the timing and effect of these measures.

Electricity efficiency is a fast-moving and dynamic process. Blok (2005) considers efficiency improvements in specific energy use of 5% per year possible (Blok, 2005). However, efficiency improvements to electric equipment are seldom implemented without encouragement from policy. Moreover, the policy process is at best slow-moving; often it is stationary. It may take many years for agreement to be reached on a single, static electricity efficiency standard (Blok, 2005). In addition, while electricity use is increasingly dispersed over a variety of appliances, the policy process tends to focus its efforts on a single appliance.

Further, electricity users do not seek to optimise the economic efficiency with which they use electricity as electricity costs are often a small percentage of total costs for households and commercial business alike. Electricity intensive industry and fuel poor households provide an exception to this rule. Nevertheless, the majority of electricity users are indifferent to electricity efficiency savings (PIU, 2001). What is more, many electricity efficiency improvements can only be implemented upon capital replacement. Thus, it may take a significant period before the full potential of efficiency savings are realised. Accurate forecasting of this phenomenon is difficult.

Notwithstanding these barriers, the rate of electricity efficiency improvements, are contingent on political will, policy ambition, the policy instruments used and the vigour with which they are implemented. Consequentially, when considering the potential of electricity efficiency measures to reduce demand for electricity, it is prudent to consider different efficiency improvement scenarios to account for these variables.

3. Methodology

In order to gain an idea of the future significance of nuclear power in the UK, this thesis makes use of a computer model written in MS Excel. The model calculates the expected profitability and thus the subsidy requirements of different electricity mix scenarios. To achieve this, the model first determines both electricity demand and the carbon emissions limit from electricity generation in 2050. A number of sensible electricity mix scenarios, that meet both the electricity supply and the carbon emission targets, are then constructed. The model then determines the present value, in 2005, of each scenario.

This section begins with a summary of the key assumptions on which the model is based. A detailed overview of the electricity mix scenarios used is then presented. Finally, a discussion of the discounting schemes employed to determine the present value of generated profits is presented. The following section presents the results of the analysis.

3.1. KEY ASSUMPTIONS

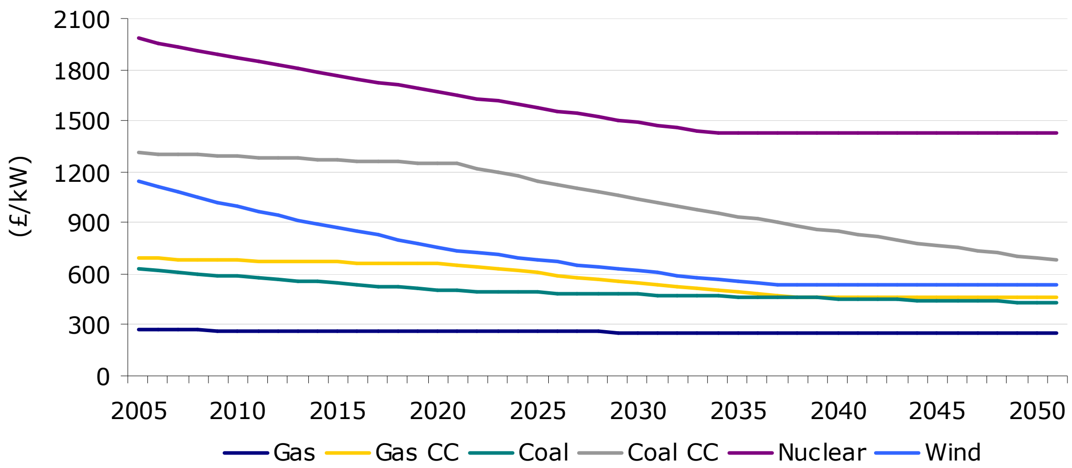
The electricity price forecast model, which is at the core of this thesis, required a number of assumptions regarding available technology and associated costs. The analysis assumes that in future, six different types of electricity generating technology will be constructed. These are CCGT plants, IGCC coal power plants, nuclear power plants, offshore wind power plants and CCGT and IGCC coal power plants with added carbon capture capabilities.

This selection reflects the expectation that new coal and gas power plants will use the latest available technology in order to maximise the electricity output/emissions ratio, as well as to achieve economic sustainability. Further, the model includes offshore wind power as the only form of renewable energy for the reasons outlined in section 2.3.

The cost structure of all power plants is assumed to consist of the following four cost elements: capital expenditure, operation and maintenance ('O&M'), fuel (except for wind) and the cost of carbon (except for wind and nuclear). For nuclear power plants, there is also a cost for decommissioning after the plant is closed down.

Capital expenditure, which includes all start-up costs, largely planning and construction, is expected to show the most variation. Variation in capital expenditure with time is shown in figure 3.1:

Figure 3.1: Capital expenditure, 2004-2050 (£/kW)



Nuclear capital expenditure is significantly above the capital costs of all other technologies modelled. Capital costs for nuclear energy are based on estimates by Oxera (2005b). Thus, capital expenditure for the construction of the first nuclear plant is estimated at £1,600/kW, decreasing to £1,200kW from the third plant onward. Additional costs are included as follows: £100 million each for FOAK[23] and

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[23] Only applicable to the first nuclear power plant built.

public enquiry costs, and an allowance of 10% for over-run costs. Thus, capital expenditure for nuclear energy is estimated at £1,980/kW initially, decreasing to £1,430/kW in the long-term.

These cost estimates are conservative. The current nuclear reactor in Finland is being built on fixed-price contract of £1140/kW. Further, the PIU Energy Review (2001) indicates that capital expenditure for current nuclear technology is in the region of £1,400-£1,700/kW and that capital expenditure may decrease to £690/kW in the long-run.

For offshore wind turbines, the 2004 capital expenditure is set at £1,140/kW. This number is based on Dale et al. (2000) and includes £1,000/kW for the plant itself and £140/kW for necessary transmission and distribution ('T&D') investments. Dale forecast the costs of wind turbines to fall to £600/kW by 2020 and to £400/kW in the long-run, with the cost of T&D remaining constant.

CCGT gas plants are a relatively mature technology, and no major cost savings are expected. The PIU (2001) indicates current capital expenditure is £270/kW. Capital expenditure is expected to decrease to £250/kW in the long-run (PIU, 2001).

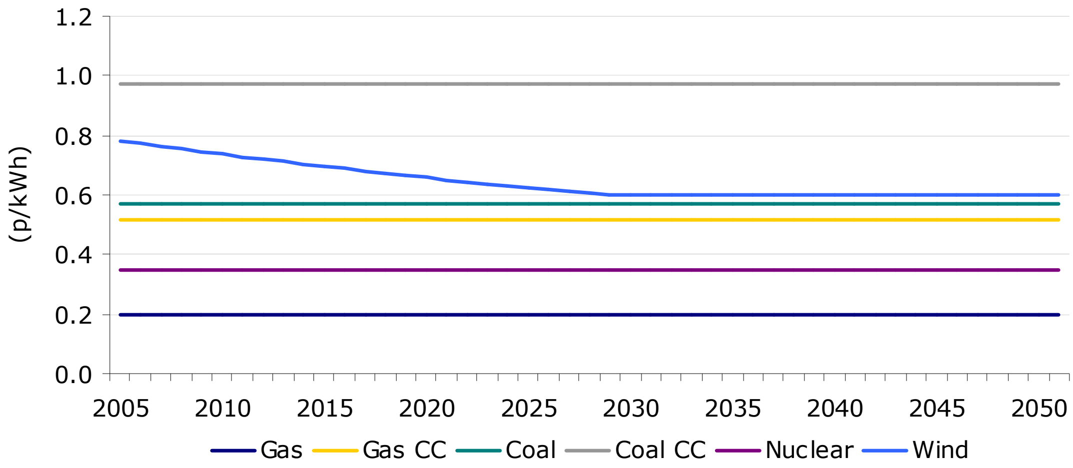
No reliable forecasts are available for CCGT plants with carbon capture capabilities. Capital costs are assumed to be £690/kW (Tzimas and Peteves, 2005). The assumptions made for the model are that initial cost savings are very low, i.e. of the order of 5% between 2004 and 2020. This assumption is based on limited experience with the technology and thus limited technological learning and cost savings. It is assumed that once the technology is established, i.e. after 2020, significant cost savings are possible, and that the costs of the capture plant (but not of the power generating plant) decline by 50%. Thus the lower limit for CCGT with capture is £460/kW.

IGCC coal plants are a relatively new technology for which Marsh (2003) gives current capital expenditure as £625/kW. The DTI (2001) has further indicated that a 20% reduction by 2020 is feasible, reducing capital expenditure to £500/kW. No forecasts are available for cost reduction after 2020, but the model assumes a 50% reduction in the long-term over the 2004 level, which is conservative given the higher expected reduction for other new technologies, i.e. offshore wind and nuclear.

For IGCC plants with carbon capture capabilities, Tzimas and Peteves (2005) estimate capital expenditure as £1310/kW. No forecasts are available, but based on the same assumptions used for gas carbon capture plants, a reduction to £655/kW is considered feasible in the long-run.

As shown in figure 3.2, the O&M costs are less variable than capital expenditure.

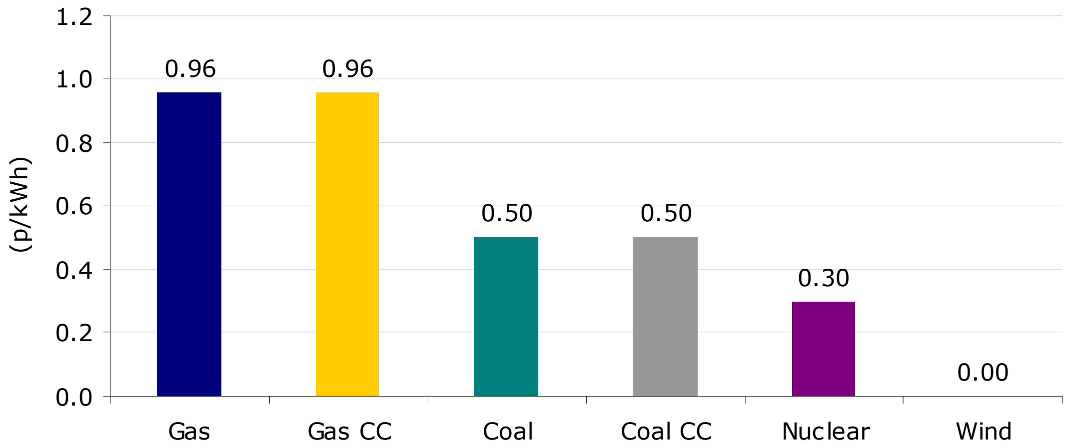
Figure 3.2: Operation & Maintenance costs, 2004-2050 (p/kWh)



The only O&M costs expected to decrease are those of wind farms (Dale et al., 2004). The anticipated decrease is based on the expectation of larger wind farms and thus higher operating efficiency. All other O&M costs are based on reports by Marsh (2003) for the DTI, and Oxera (2005, for nuclear), reflect the complexity of the plant in question and are not expected to change significantly.

Fuel costs are assumed to remain constant over time. Fuel prices are affected by many uncertainties and an attempt to quantify these uncertainties is beyond the scope of this thesis. The current levels are summarised in figure 3.3:

Figure 3.3: Fuel costs, 2004-2050 (p/kWh)



Source: DTI, historic data (Average prices of fuels purchased by the major UK power producers and of gas at UK delivery points[24]); Oxera, 2005b.

The cost of carbon is a cost factor of increasing relevance for coal and gas powered plants. Forecasts from The Carbon Trust (2004) for the market price of carbon traded under the EU ETS are included when analysis uses market discount rates. This forecast sees the price increase from a current level of €5/tonne of carbon dioxide to €25/tonne of carbon dioxide in 2013. The price is forecast to remain flat post-2013. When analysis is based on the social rate of time preference, Clarkson and Deyes' (2002) estimate of the social cost of carbon is incorporated. Thus a value of £74/tonne of carbon is included to represent the social cost of carbon in 2005. This value is inflated by £1/tC per year.

[24] Available online at: http://www.dti.gov.uk/energy/inform/energy_prices/qepupdate.shtml. Accessed: 6 August 2005.

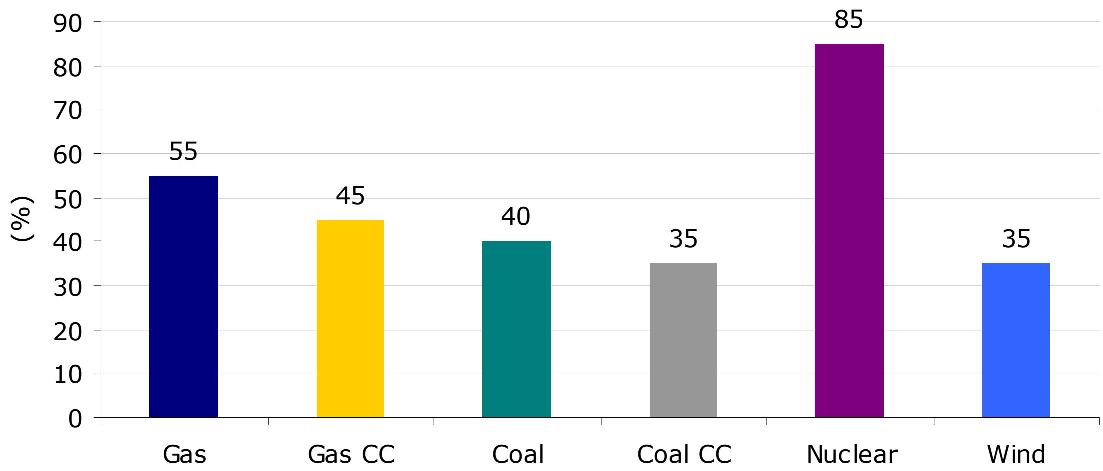
As nuclear power plants need decommissioning at the end of their operating life, this cost item has been included in the model. Oxera (2005b) estimates the net present value of decommissioning costs in the final operating year of a nuclear plant as £500/kW. This value has been used for the model.

3.2. OTHER ASSUMPTIONS

The economics of the different technologies modelled are influenced by capacity utilisation and carbon emissions, as well as costs.

Capacity utilisation varies significantly by technology reflecting technical aspects and resource availability. Resource availability is of particular importance for wind energy. In this regard, nuclear power plants have a clear advantage over other technologies (see figure 3.4), and as a consequence less nuclear capacity is required to ensure electricity demand is met.

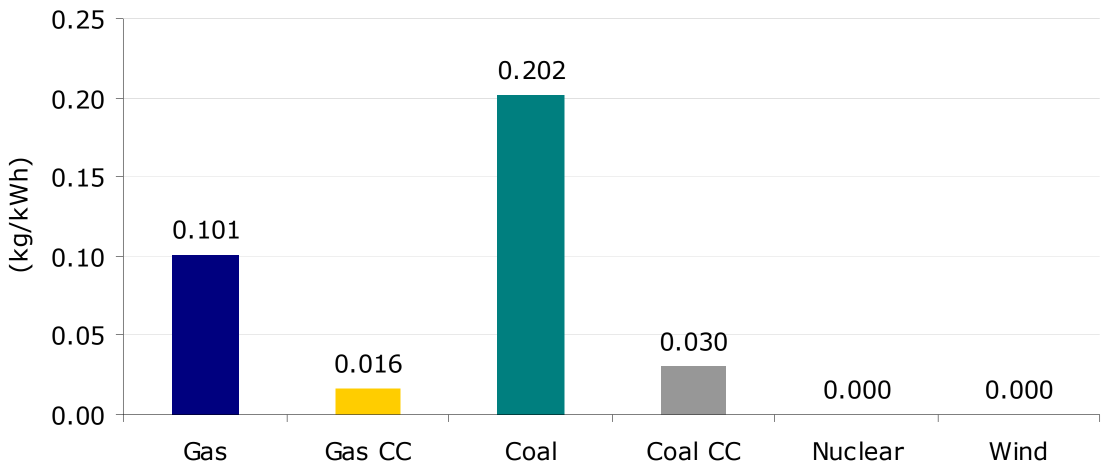
Figure 3.4: Capacity factors, by technology (%)



Source: Dale et al., 2004; DTI, 2002; Marsh, 2003; MIT, 2003.

Of fundamental importance in determining the degree to which individual technologies can be used without violating the 60% reduction target are carbon emissions relative to electrical output. Nuclear and wind are at an obvious advantage, in this regard, but coal and gas plants are very attractive when carbon capture technologies are applied (see figure 3.5).

Figure 3.5: Carbon emissions, by technology (kg/kWh)



Source: Marsh, 2003.

3.3. SCENARIO CONSTRUCTION

The model considers eight different scenarios grouped into two sets of four. The first group considers an electricity demand base case in which electricity efficiency improvements are forecast under a business-as-usual assumption. The second group considers a more optimistic lower electricity demand situation that is as a result of electricity efficiency improvements. The four scenarios in each demand group differ in the way that wind, nuclear and carbon sequestration are used to meet the 2050 supply target without violating the carbon emissions limit.

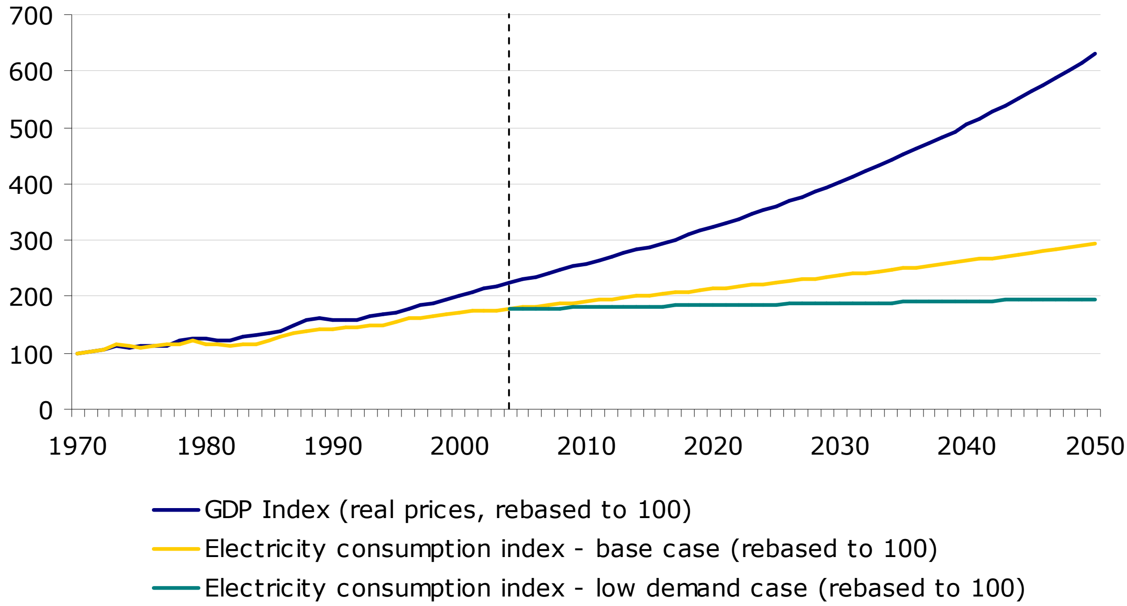
3.3.1. Electricity Demand

The base case envisages an electricity demand of 563TWh in 2050, while the lower demand case is based on a demand of 377TWh. To forecast demand in 2050, electricity demand is considered a function of GDP and electricity intensity such that economic growth is expected to increase demand for electricity, while improved electricity efficiency will result in decreased demand.

In the model, it is assumed that GDP will grow at 2.5% for the next 5 years, before levelling out at a long-term growth rate of 2.25%. These assumptions result in a doubling of GDP over the next 35 years, and are in line with forecasts by HM Treasury (2003).

Economic output is linked to electricity consumption via the Electricity Intensity Ratio (EIR), which is the ratio of electricity consumption and GDP. The EIR has decreased steadily in the past, reflecting continuous improvements in electricity efficiency. Over the past 30 years the average EIR improvement has been 0.65% per year. This has grown to an average increase in efficiency of 1.16% over the past decade. This improvement of 1.16% is the assumption used for the base case electricity demand scenario and yields an electricity demand of 563TWh in 2050. For the lower demand case an annual increase in electricity efficiency of 2% is assumed, based on more optimistic forecasts (Blok, 2005). The resulting 2050 electricity demand is 377TWh, reflecting only a very slight increase over current levels, as shown in figure 3.6:

Figure 3.6: GDP and electricity demand forecast (rebased to 100)



Source: Office of Statistics, historic data (Primary energy consumption, gross domestic product, the energy ratio[25])

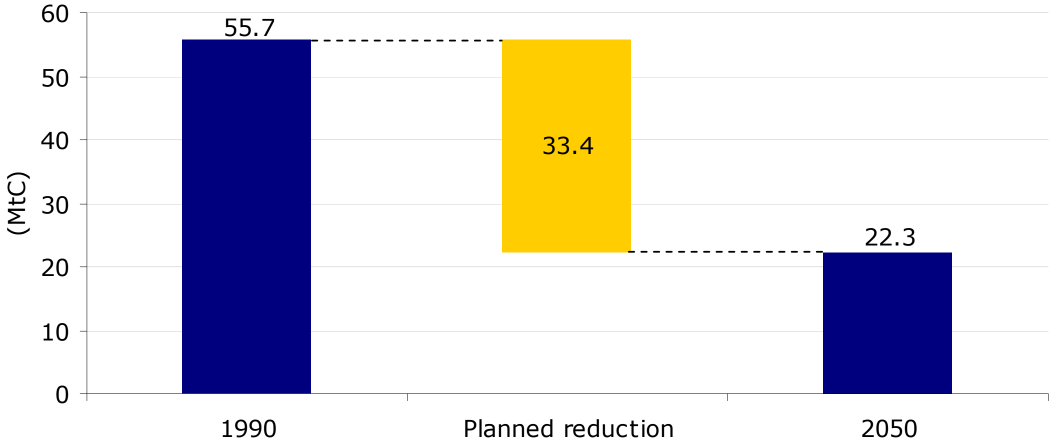
3.3.2. The Emissions Limit

In all scenarios coal and gas are assumed to generate as much electricity as possible without violating the 2050 emissions limit. To determine the 2050 carbon emissions limit it has been assumed that the 60% target will be applied to the economy and its sub-sectors, the electricity sector included, in equal proportion. As such, the 2050 emissions limit is determined as 22.3MtC/yr. This number is 60% of the carbon emissions from the electricity sector in 1990, 56.7MtC (DEFRA, historic data[26]). The 60% reduction consequently amounts to 33.4MtC, as shown in figure 3.7:

[25] Available online at: http://www.dti.gov.uk/energy/inform/energy_stats/total_energy/index.shtml. Accessed 6 August 2005

[26] Estimated emissions of carbon dioxide by UNECE source category, type of fuel and end user: 1970-2003. Available online at: http://www.defra.gov.uk/environment/statistics/globatmos/gaemunece.htm. Accessed 6 August 2005

Figure 3.7: Planned reduction in carbon emissions by electricity sector (MtC)



Source: DEFRA, historic data (Estimated emissions of carbon dioxide by UNECE source category, type of fuel and end user: 1970-2003)

I. Gas and coal generation. In all scenarios gas and coal are assumed to operate in a 2:1 ratio. This assumption reflects the superior attractiveness of gas, but also the important role of coal generation in diversifying the electricity mix (DTI, 2003a). Given this ratio, and the relative emissions to output ratios shown in figure 3.5, the maximum output from gas and coal generating plants, in the absence of carbon capture, can be determined as follows:

Needed values:

S_g = Gas supply

S_c = Coal supply

Given values:

EL = Emissions limit = 22.3MtC, as shown in figure 3.7

S_g/S_c = 2:1

e_g = emissions to output ratio for gas = 0.101kg/kWh

e_c = emissions to output ratio for coal = 0.202kg/kWh

$$EL = e_g S_g + e_c S_c \qquad (1)$$

$$\frac{S_g}{S_c} = 2 \quad \text{thus} \quad S_g = 2S_c \qquad (2)$$

Substituting (2) into (1):

$$S_c = \frac{EL}{2e_g + e_c} \qquad (3)$$

Inserting the known values into (3) it follows that coal can supply up to 55TWh in 2050, and given e_c, this will result in 11.1Mt of carbon emissions. It follows from (2) that gas can supply up to 110TWh, which, given e_g, also generates 11.1Mt of carbon emissions.

Thus, in the absence of carbon capture, gas and coal can supply 166TWh of electricity in 2050, whilst jointly generating 22.3MtC, and achieving the 60% emission reduction target. Under the business-as-usual assumption, this is equivalent to 29.4% of electricity demand in 2050, 563TWh, and 43.9% of electricity demand, 377TWh, in the lower demand case.

Under both the business-as-usual and the lower electricity demand situation, gas and coal alone are unable to meet the 60% target and simultaneously satisfy electricity demand. Substantial scope remains for other technologies.

3.3.3. Construction schedules

To facilitate the analysis, it is assumed that the capacity required in 2050 will be built in four ten-year intervals starting in 2010, with a quarter of the capacity needed in 2050 built in each construction phase. The construction mix in each period reflects the final electricity mix in 2050. An underlying assumption has been made that, for a technology to be reliable on a large scale in 2050, investment in the technology is required for a significant period of time.

The construction schedules ignore the phasing out of current generating capacity. Precise matching of new capacity requirements with the phasing out of existing power plants goes beyond the scope of this thesis. However, it is assumed that an even distribution of new capacity over a 40 year period approximates the requirements of both new demand and phasing out of existing capacity. It is further assumed that all current power plants will be out of service by 2050. The model does not include the cost of replacing any capacity post-2050, but given the long discounting period it is unlikely that such costs would impact in a significant fashion on present investment decisions.

The model does however include the costs of replacing new capacity that phases out before 2050. This is the case for all plants built in 2010, with the exception of nuclear which does not require replacement before 2057, as well as for wind farms built in 2020. The phasing out of newly built capacity is summarised in table 3.1:

Table 3.1: Phasing out of newly built capacity

	Construction year				
Technology	**2010**	**2020**	**2030**	**2040**	**Comments**
CCGT	2042	2052	2062	2072	replace first generation in 2040
CCGT (CC)	2042	2052	2062	2072	replace first generation in 2040
IGCC	2046	2056	2066	2076	replace first generation in 2040
IGCC (CC)	2046	2056	2066	2076	replace first generation in 2040
Nuclear	2057	2067	2077	2087	no replacement needed before 2057
Wind	2031	2041	2051	2061	replace first generation in 2030, second in 2040

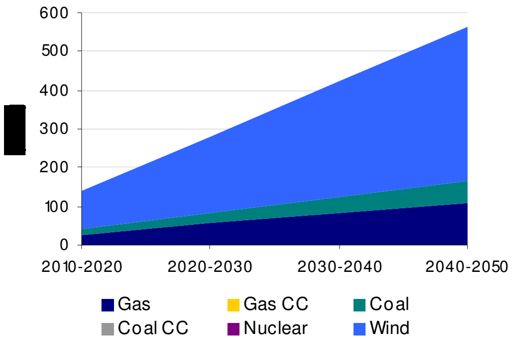
3.4. SCENARIO OVERVIEW

The scenarios used in the model illustrate how the gap between electricity demand, and supply by traditional fossil fuel generating technologies, can be filled by carbon-free generating capacity.

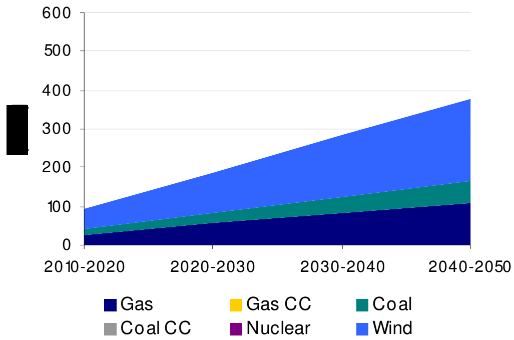
Scenarios 1 and 5. Scenarios 1 and 5 assume that the entire supply shortfall can be covered by wind. The two scenarios differ only in the overall demand, and therefore in the amount of electricity supplied by wind, as shown in figure 3.8:

Figure 3.8: Cumulative new electricity supply, 2010-2050 (TWh), 1/5

Scenario 1



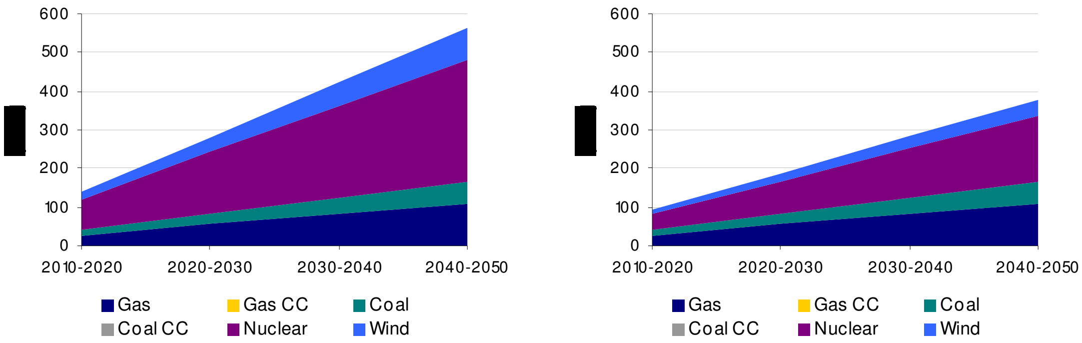
Scenario 5



II. Scenarios 2 and 6. Scenarios 2 and 6 consider significant investment in nuclear power. However, as wind energy is expected regardless of investment in nuclear power, nuclear only covers 80% of the supply shortfall in these scenarios. The two scenarios vary only in the overall electricity demand in 2050, as can be seen in figure 3.9:

Figure 3.9: Cumulative new electricity supply, 2010-2050 (TWh), 2/6

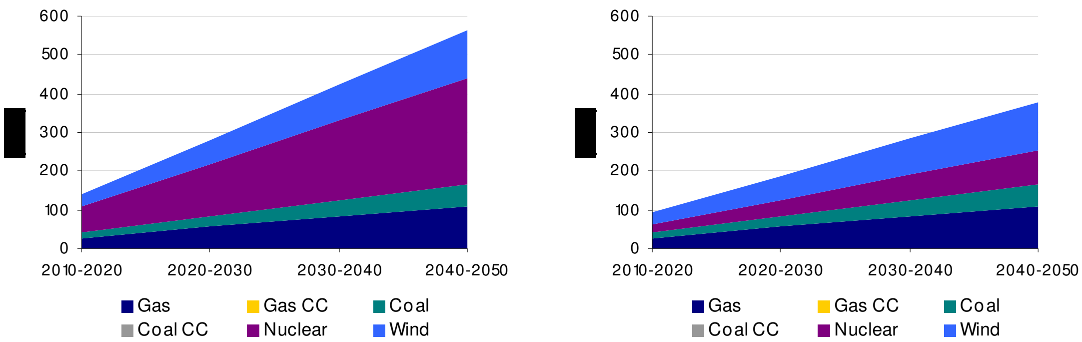
Scenario 2 Scenario 6



III. Scenarios 3 and 7. These two scenarios model a more realistic wind option than represented by scenarios 1 and 5. As highlighted in section 2.3., a realistic upper limit for wind power generation in the UK in 2025 is 100TWh annually. No equivalent estimate exist for 2050, but a generous 25% improvement assumption[27] yields an annual limit of 125TWh/yr. Scenarios 3 and 7 assume wind power supplies this upper limit in 2050, and that nuclear power supplies any shortfall. As a consequence of these assumptions, scenario 3 does not differ substantially from scenario 2. However, the impact of the assumptions is more starkly illustrated by the differences between scenarios 6 and 7, as shown in figure 3.10:

Figure 3.10: Cumulative new electricity supply, 2010-2050 (TWh), 3/7

Scenario 3 Scenario 7



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[27] Practicable potential is also influenced by space availability, efficiency and uptake; hence the 25% improvement assumes significant improvement in one of these areas.

IV. Scenarios 4 and 8. In the final two scenarios, wind is again modelled to supply up to a realistic limit of 125TWh/yr. However, scenarios 4 and 8 assume significant investment in carbon sequestration technologies rather than in nuclear power. The ratio of gas to coal is held at 2:1. The model computes the percentage share of electricity supplied by plants with carbon sequestration capabilities in order to meet both the electricity demand and the carbon emissions target. This procedure is illustrated in table 3.2:

Table 3.2: Calculation of supply shares in carbon capture scenarios

	Scenario 4	**Scenario 8**
2050 demand (TWh)	563	377
Less: wind supply (TWh)	125	125
Needed from coal and gas (TWh)	438	252
Gas to coal ratio	2:1	2:1
Gas supply (TWh)	292	168
Coal supply (TWh)	146	84
Share of carbon capture in coal and gas	73.6%	40.7%
Gas supply – traditional (TWh)	77	100
Gas supply – with carbon capture (TWh)	215	69
Coal supply – traditional (TWh)	39	50
Coal supply – with carbon capture (TWh)	108	34
Gas emissions – traditional (MtC)	7.77	10.07
Gas emissions – with carbon capture (MtC)	3.52	1.12
Coal emissions – traditional (MtC)	7.77	10.07
Coal emissions – with carbon capture (MtC)	3.22	1.03
Total emissions (MtC)	22.3	22.3

The critical element in the above analysis is the share of carbon capture in coal and gas output. This is calculated in the following manner:

Given values:

EL = Emissions limit

S_c = total supplied by coal

S_g = total supplied by gas

e_{ct} = emissions to output ratio, traditional coal

e_{ccc} = emissions to output ratio, coal with carbon capture

e_{gt} = emissions to output ratio, traditional gas

e_{gcc} = emissions to output ratio, gas with carbon capture

Needed value:

s_{cc} = share of carbon capture in overall coal and gas supply

The total emissions output can be set equal to EL and is the sum of all the emissions generated by the four different technologies:

$$EL = e_{ct} S_c (1 - s_{cc}) + e_{ccc} S_c s_{cc} + e_{gt} S_g (1 - s_{cc}) + e_{gcc} S_g s_{cc} \qquad (4)$$

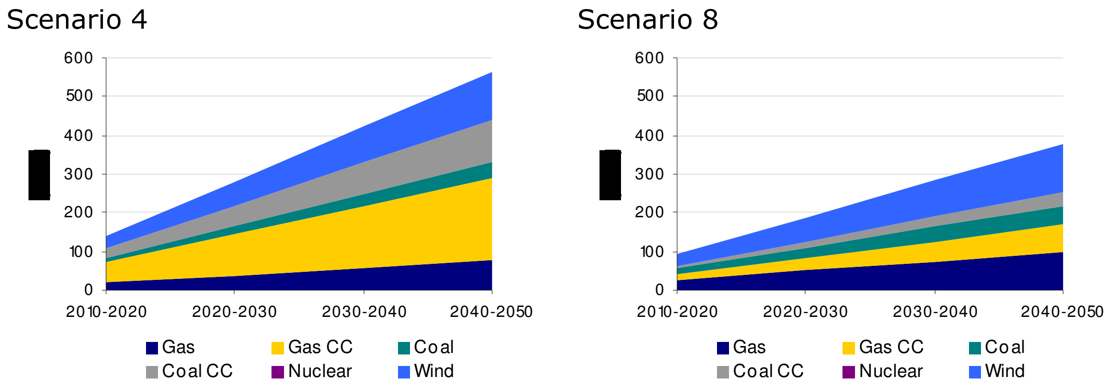
(4) can be simplified and solved for s_{cc}:

$$s_{cc} = \frac{(e_{gt} S_g + e_{ct} S_c) - EL}{(e_{gt} - e_{gcc}) S_g + (e_{ct} - e_{ccc}) S_c} \qquad (5)$$

Substituting all known values into (5) yields the share of carbon capture in overall coal and gas supply: 73.6% for scenario 4 and 40.7% for scenario 8.

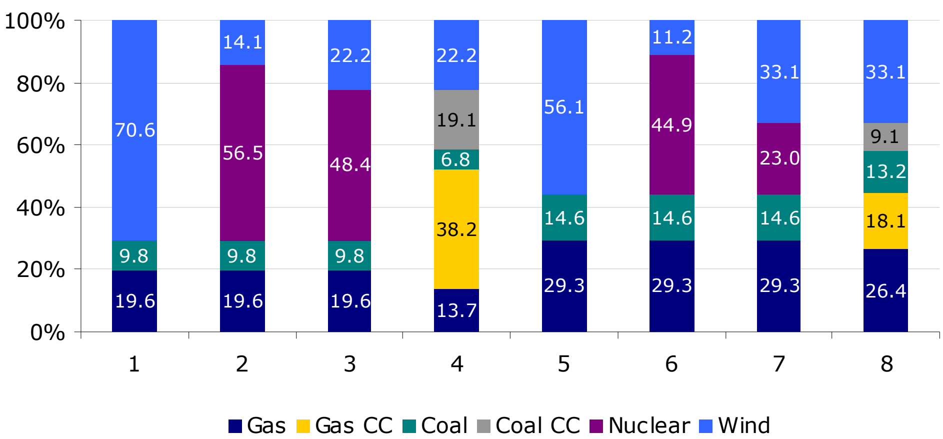
Consequently, the two scenarios differ in the way that carbon sequestration is used and also in the impact of wind supply, as shown in figure 3.11:

Figure 3.11: Cumulative new electricity supply, 2010-2050 (TWh), 4/8



V. Scenario summary. To summarise, the eight scenarios are compared in figure 3.12, which illustrates the relative shares of the different generating technologies by scenario. Most interesting for the analysis in subsequent sections are scenarios 3 and 7, in which coal, gas and wind supply electricity up to their maximum, as determined by the emissions reduction target in the case of the fossil fuel generating technologies and by technological limitations in the case of wind. It is thus apparent that these three technologies alone are insufficient to meet future electricity demand - indeed, even in the lower demand case, in the absence of additional generating capacity, a supply gap of almost 30% exists which is filled by nuclear generation.

Figure 3.12: 2005 supply shares, by scenario (%)



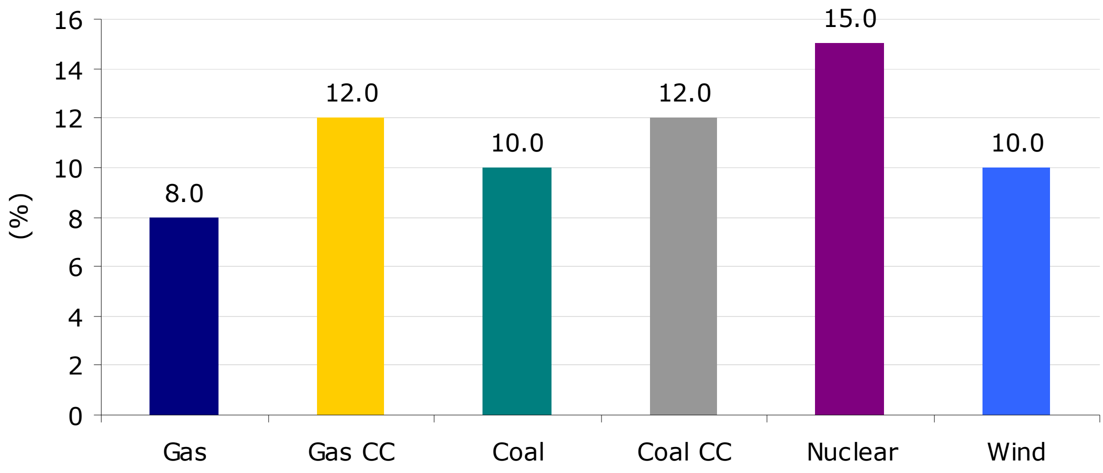
3.5. DISCOUNTING

Two different discounting methods are used in the model. The first method uses a traditional fixed discount rate that reflects the risk of the technology concerned. The second method uses a declining social discount rate, as proposed in the Green Book by HM Treasury, and gives more weight to future cash flows.

I. Fixed rate discounting. Private investors use a fixed discount rate, which reflects the risk of an investment, in evaluating investment potential. Thus, electricity generation technologies that subject investors to lower risks are analysed with lower discount rates. Generation technologies are considered risky if cost over-runs are possible, the relevant technology is untried, large capital requirements are required, projects have long lead- and life-times, and there is potential for environmental disasters.

Of the technologies analysed in this thesis, CCGT plants are the least risky, as CCGT is a mature technology that keeps these risks acceptably low. At the other extreme is nuclear power. As the technology for a new generation of nuclear power plants is untested there is potential for cost over-runs. Further, large capital requirements are necessary thus the market considers nuclear power inflexible. The long lead- and life-times of nuclear energy requires long-term assumptions about electricity requirements – an additional risk. Finally, nuclear power plants have the potential to cause significant environmental harm. A nuclear investment thus has to offer significantly higher returns than a CCGT plant to compensate investors for the additional risk. This extra profit requirement is an important factor in determining the overall profitability of a technology. Figure 3.13 shows the discount rates used for the different technologies, and reflects their expected risk:

Figure 3.13: Fixed rate method discount rates, by technology (%)



Oxera (2005b) quote the average expected return for a utility company as 8-12% annually. This is reflected in the discount rates used in the model. Gas, as the safest of the six technologies, is discounted at the lower end of the range, i.e. at 8%. Carbon capture plants on the other hand have a significant element of risk embodied in uncertain technology and are therefore discounted at the upper end of the range at 12%. Coal and wind are considered to represent an average risk. Nuclear is discounted at 15%, reflecting the extra-ordinary risks involved.

These discount rates are used to discount all cash flows relating to a project from the day of its initiation, i.e. the first day of planning, to the last day of operation. Once the net present value of a project at initiation is determined, this value is discounted back to 2005 at a discount rate of 10%. This is the average return of a utility company and as such is deemed applicable to any money not yet committed to any specific project.

II. Green Book Method. As discussed in the introduction, advances in discounting theory indicate that the correct social discount rate is a value that declines with time (Pearce et al., 2003; Groom et al., 2005). Indeed, projects that are discounted with a single discount rate give considerably less weight to future costs and benefits.

To correct for such anomalies, official guidance to Ministries from HM Treasury (2003), advocates the use of low and declining discount rates for evaluating long-term investments. This guidance sets the discount rate at 3.5% for the first 30 years of a project. For the next 45 years, it is set at 3%. Afterwards, it declines further, but is no longer relevant for this analysis. This discounting treatment requires risk to be dealt with before discounting takes place. Thus expected costs can be lowered and expected benefits increased by reducing risk and uncertainty through risk management before the risk-free rate recommended by the Green Book is applied. As such, conservative assumptions of costs and benefits are appropriate for use with this discounting scheme.

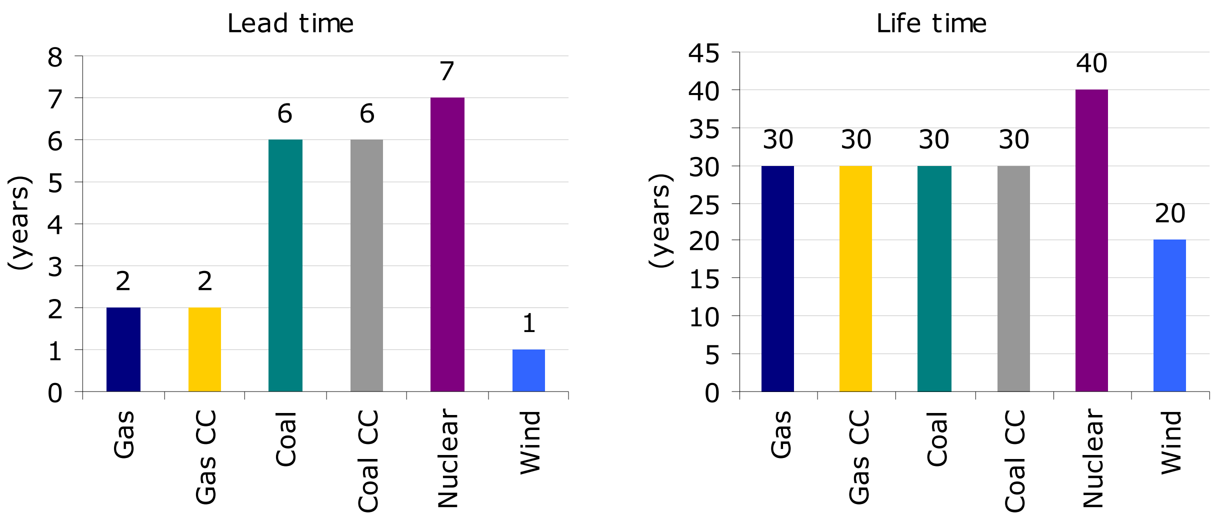
The use of a declining discount rate scheme has two important consequences for the analysis of the future electricity mix.

First, a unified rate is used for all technologies. Thus nuclear energy is no longer penalised by a high discount rate. The investment risk of nuclear generation is accounted for by the use of conservative assumptions and an allowance for cost over-runs.

Second, declining interest rates increase the impact of future cash flows. As most negative cash flows involved in power generation occur in early periods, i.e. during the planning and construction phase and profits are generated in later periods, the effect of declining discount rates is increased profitability. Hence, the longer the lead-time, the later a technology reaches its profitable phase, and the more likely its profitability will improve as a result of lower discount rates. Similarly, projects with long lifetimes are likely to benefit from low discount rates due to distant positive cash flows, which become more significant using a declining-rate scheme.

Figure 3.14 shows that, relative to other generating technologies, nuclear power plants have the longest lead- and life-times. Wind has the shortest. Consequently, nuclear benefits to a greater degree than wind from low and declining discount rates.

Figure 3.14: Lead and life time, by technology (years)



Source: Dale et al., 2004; MacKerron, 2004, Whittington and Bellhouse, 2000.

3.6. PROFITABILITY

In order to compare the profitability of the various technologies and scenarios modelled, a wholesale electricity price of 3p/kWh is assumed. This price is used in analysis by Oxera (2005b) as a long-term average wholesale electricity price and is consistent with a gas price of 28p/therm.

The assumption of a wholesale price for electricity allows the calculation of expected profits or losses from different generating technologies. These are then discounted to 2005 for comparison. In the absence of government subsidies it can be expected that investors will only pursue those projects that, based on the traditional discounting method, offer positive net present values. To the extent that a scenario generates a negative net present value, it can be argued that this reflects the size of the government subsidy required to make it attractive.

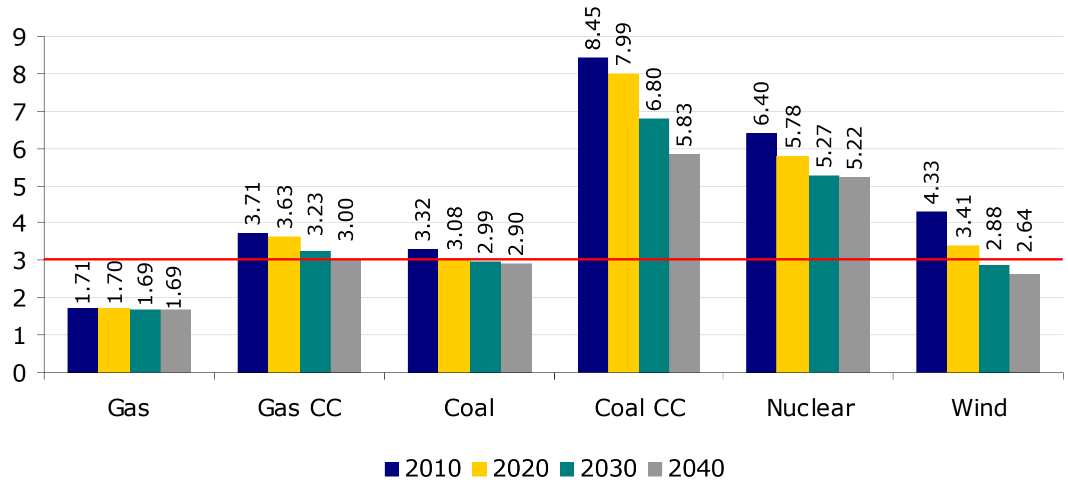
4. Results

This section presents the results of the discounting exercise carried out by the model described in the previous section. First, the costs of the different technologies are compared. The expected economic performance of the eight scenarios is then evaluated in terms of expected profitability, expressed as net present value ('NPV') in 2005. Negative NPVs are used to quantify the amount of government support, either in form of direct subsidies or in form of risk guarantees, needed to make a scenario feasible.

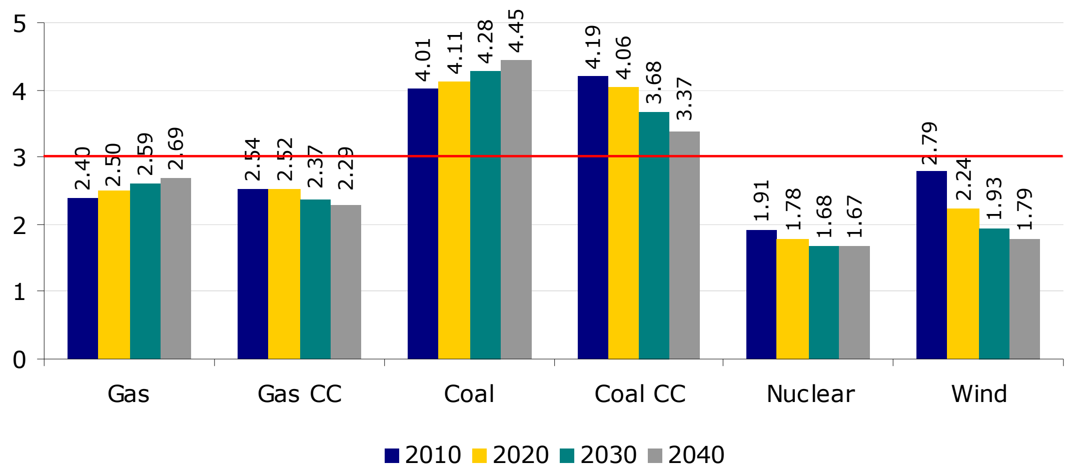
4.1. TECHNOLOGY COMPARISON

Figure 4.1: Cost, by technology (p/kWh)

Fixed rate method



Green Book method



Note: Cost defined as the price in pence per kWh that yields a NPV of zero

The costs of the six different technologies evaluated are summarised in figure 4.1 in terms of pence per kilowatt hour. The figure shows the electricity price that is required to generate a net present value of zero for each technology. Thus, it reflects not only the costs of capital expenditure, O&M, fuel and carbon, but also the risk associated with each technology.

Costs for plants initiated in 2010, 2020, 2030 and 2040 are shown. As discussed in the previous section, capital expenditure costs in particular, are expected to decrease with technological learning. Consequentially, plants of all technologies built benefit from lower costs with time under the market method.

As becomes apparent from figure 4.1, under the market method, only CCGT power plants are able to generate electricity in 2010 at costs that are below the assumed price level. Despite significant cost savings, this does not change in 2020. Further analysis reveals that due to continuous cost savings, wind turbines built in 2030 will be able to generate electricity profitably, at costs of 2.88p/kWh. Similarly, in 2050 IGCC plants will generate electricity profitably, at costs of 2.90p/kWh. However, neither nuclear plants nor plants with carbon capture ability are expected to become profitable technologies if the wholesale electricity price remains at 3p/kWh.

Of the technologies that are likely to be needed to fill the supply gap left by traditional fossil fuel generating capacity and wind, gas plants with carbon capture technology are the cheapest option, followed by nuclear and coal plants with carbon capture technology.

The outcome changes significantly when the declining discount rate scheme recommended by HM Treasury, and the social cost of carbon recommended by DEFRA, are used. Under this treatment, all technologies except traditional gas and coal, which increase due to the application of the social cost of carbon, become considerably cheaper. Further, technologies discounted at higher discount rates under the market method benefit the most.

Consequentially, nuclear is the biggest beneficiary under the social cost method, in which low, declining discount rates are used and the social cost of carbon is included. Indeed, nuclear is not only profitable but becomes the cheapest technology[28]. All technologies except traditional coal and coal with carbon capture technology are profitable when Green Book discounting is used.

These results should be interpreted with caution. The rationale for using declining discount rates is to give more weight to the costs and benefits experienced by future generations. However, potential environmental costs are difficult to quantify. In particular, the costs of climate change and externalities associated with nuclear power pose a challenge. While the model includes the social cost of carbon, climate change has the potential to cause irreversible damage to ecosystems that is impossible to quantify in monetary terms. In respect of nuclear energy, the inestimable societal costs nuclear energy has the potential to impose[29] remain external to the model. Thus, the results of the analysis based on the Green Book discount rates have the potential to mislead as some, but not all, social costs have been included.

When the market discount rate is used, the risk associated with potential environmental liabilities is accounted for by the risk premium required by investors in nuclear energy. Hence, nuclear is more costly under a market evaluation. The method advocated by the Treasury Green Book only accounts for

[28] This is the case even if the social cost of carbon is omitted.

[29] That is, the effect of nuclear catastrophe on human health and society, and on the environment.

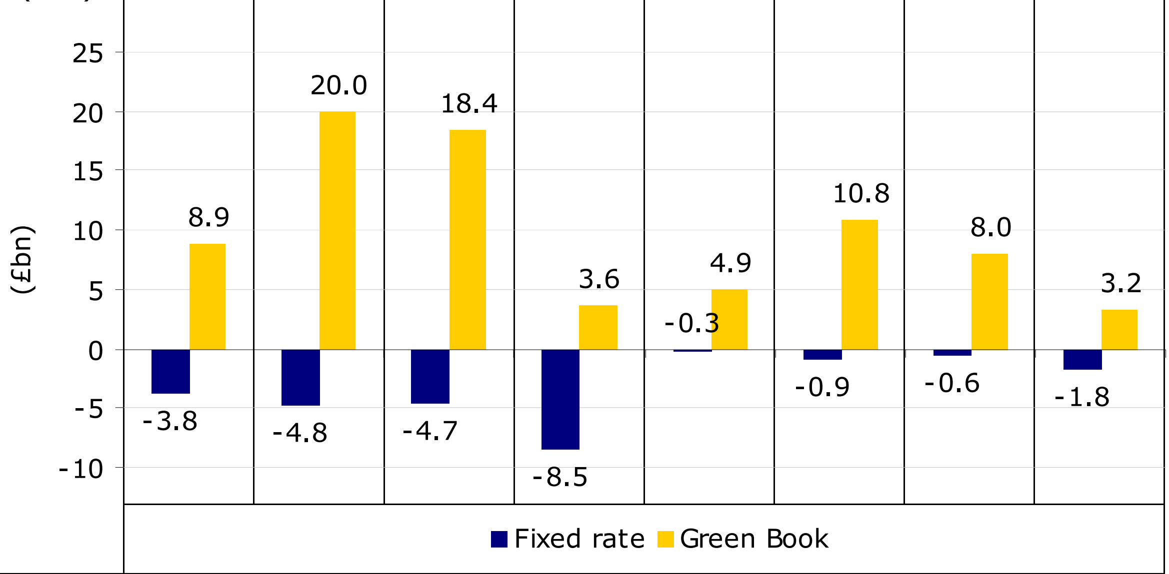
such risk if it can be quantified in the form of future cash flows. While the analysis of nuclear economics in this thesis includes an estimate for decommissioning and waste management costs, such costs are difficult to assess.

4.2. SCENARIO COMPARISON

The technology prices discussed above determine the profitability of the different scenarios analysed. The net present values of the various scenarios are summarised in table 4.1. For ease of comparison, key demand and supply parameters are given as well.

Table 4.1: 2005 NPV, by scenario (£bn)

	Scenarios							
	1	***2***	***3***	***4***	***5***	***6***	***7***	***8***
Energy demand (TWh, 2050)	Base case 563				Lower demand case 377			
2005 NPV (£bn)								



2050 supply (%)	1	2	3	4	5	6	7	8
Gas	19.6	19.6	19.6	13.7	29.3	29.3	29.3	26.4
Gas CC				38.2				18.1
Coal	9.8	9.8	9.8	6.8	14.6	14.6	14.6	13.2
Coal CC				19.1				9.1
Nuclear		56.5	48.4			44.9	23.0	
Wind	70.6	14.1	22.2	22.2	56.1	11.2	33.1	33.1

The first key insight is that none of the eight scenarios generate a positive net present value when using the fixed discount rate method. Thus, either the assumed wholesale price of 3p/kWh is too low, or government intervention will be necessary in order to achieve the emissions reduction target in 2050.

The need for government support is minimised in scenarios 1 and 5, which rely on wind energy to a degree that is improbable[30]. Further analysis reveals that those scenarios that rely heavily on nuclear power require less government support than the carbon capture scenarios.

This seems counter-intuitive as nuclear is not the cheapest option on a per kWh basis. The apparently contradictory result is caused by a peculiarity of discounting. Indeed, while the high discount rate of nuclear drives up the price at which a nuclear power plant can break even, it also discounts any losses generated by a nuclear plant at a higher rate.

Thus, while nuclear energy is more expensive than, for example, wind, and as a consequence generates greater losses at a wholesale electricity price of 3p/kWh, these losses are discounted at a higher rate and resultantly, are lower in present value terms. This results because the same risk/return preferences of investors are assumed in both financing and operating electricity projects.

Under the declining discount rate scheme, all eight scenarios are NPV positive, and therefore economically feasible. The two scenarios relying most heavily on nuclear are economically the most attractive. This is a consequence of the low price per kilowatt-hour for nuclear under the Green Book discount rate scheme.

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[30] Both these scenarios require more generation from wind than is practicable, i.e. more than 125TWh of wind generation.

It is however highly unlikely that the discount rates recommended by HM Treasury would be utilised in assessing privately financed electricity investment without government support to reduce the risks to investors. This could be achieved by a government offer to finance packages at the discount rates set out in the Treasury Green Book, and would result in the taxpayer carrying the risk in excess of discount rates recommended by the Treasury, should costs exceed expectations or benefits disappoint.

5. Discussion

The results of the model indicate that the British government has some difficult choices to make if it is to meet the 2050 carbon emissions target. The limits imposed on coal and gas generation by the 2050 target, together with the limit imposed on renewable energy generation by its practicable potential, necessitate massive energy efficiency savings if the 2050 target is to be met without a large-scale nuclear energy or carbon sequestration program. Indeed, in order to achieve this, demand must be contracted to 1995 levels[31].

The possibility for improvements in the efficiency with which electricity is generated and used is not unlimited (Blok, 2005). There are serious questions about the ability of efficiency improvements to contract demand to the levels necessary to rule out the need for a large-scale project of either nuclear energy or carbon sequestration.

The energy efficiency scenario used assumed efficiency savings of 2% per year. Blok (2005) suggests year-on-year efficiency savings of this level are possible but rarely achieved. Hence, the efficiency improvements assumed are considered optimistic and it is improbable that sustained efficiency improvements beyond this level will be achieved[32].

The prospects for renewable energy sources are limited by what is practicable. DTI (2000) estimates for 2025 indicate that the practicable limit to generation by wind (both off-shore and on-shore) is 108TWh/yr, whereas all current renewable

[31] Assuming a 2:1 ratio of gas:coal, gas can provide a maximum of 110TWh/yr, coal can provide a maximum of 55TWh/yr and wind is limited by a practicable potential of 125TWh/yr. This amounts to 290TWh/yr, which is equivalent to the electricity demand in 1995.

[32] To contract demand to 1995 levels, a yearly electricity efficiency improvement of 2.5% is needed – significantly above both the 1.7% achieved in the last decade and the 2.0% Blok (2005) considers possible but unlikely.

energy technologies have a practicable limit of 230TWh/yr (see table 2.1). These estimates can only be approximations - the practicable potential of certain renewable energy technologies may increase while that of others may never be met - however they are indicative of renewable energy potential in the UK.

If the UK could achieve electricity efficiency savings of 2% per year until 2050 and realise the practicable potential suggested by the DTI (2000) in wind (both offshore and onshore), biomass, BIPV, wave, tidal and small hydro[33], notwithstanding uneconomic generating costs and ignoring any extra generation requirements due to intermittency, the electricity demand in 2050 could be met.

At present, this scenario seems impossibly optimistic.

- The Renewables Obligation is underperforming and is unlikely to achieve its objectives (Mitchell and Connor, 2004).
- The goals of the Renewables Obligation are insufficient to put the UK on track to reduce carbon emissions by 60% by 2050, especially in the face of declining nuclear contribution to the electricity mix and growth in electricity demand (Oxera, 2005b)
- The costs of wind generation, considered the most promising renewable energy technology, increases significantly as wind penetration approaches 30% (Dale et al., 2004) - this cost increase is difficult to model and not included in the analysis in this thesis.

[33] The costs of renewable technologies other than offshore wind have not been assessed. In the case of onshore wind, due to limited practicable potential of 8TWh/yr – the majority of the growth in wind to 2050 is expected to be offshore. In the case of all other renewable energy technologies this is due to prohibitive costs.

As a consequence of practicable limitations on electricity efficiency improvements and renewable energy penetration, either a large scale carbon sequestration or a nuclear energy program will be necessary to meet both future energy requirements and the 2050 carbon abatement target[34].

The economic analysis completed indicates that scenarios that rely on nuclear power to meet the shortfall from traditional fossil fuel generation and wind energy require less government support than scenarios that rely on carbon capture.

The argument for nuclear is advanced as a carbon sequestration strategy increases the nation's dependence on imported fossil fuels, while a strategy of nuclear energy goes some way to meeting the UK government's stated requirement for energy diversity (DTI, 2003). The value of this cannot be quantified in an economic sense however it is undoubtedly a factor that weighs in favour of nuclear energy.

Carbon sequestration is similar to nuclear energy in that a large-scale project involving considerable investment is necessary for implementation. Unlike nuclear energy however, carbon sequestration is an unknown quantity. Only one carbon sequestration project operates worldwide (Tzimas and Peteves, 2005). Widespread deployment of carbon capture, transport and injection infrastructure carries unknown economic risks and significant scientific and technological challenges.

For the reasons discussed above, all else being equal, nuclear power is an

[34] This thesis has assumed that the UK government will either support a large scale program of nuclear energy or a large-scale program of carbon sequestration, but not a combination of the two, as cost reductions are dependent on economies of scale.

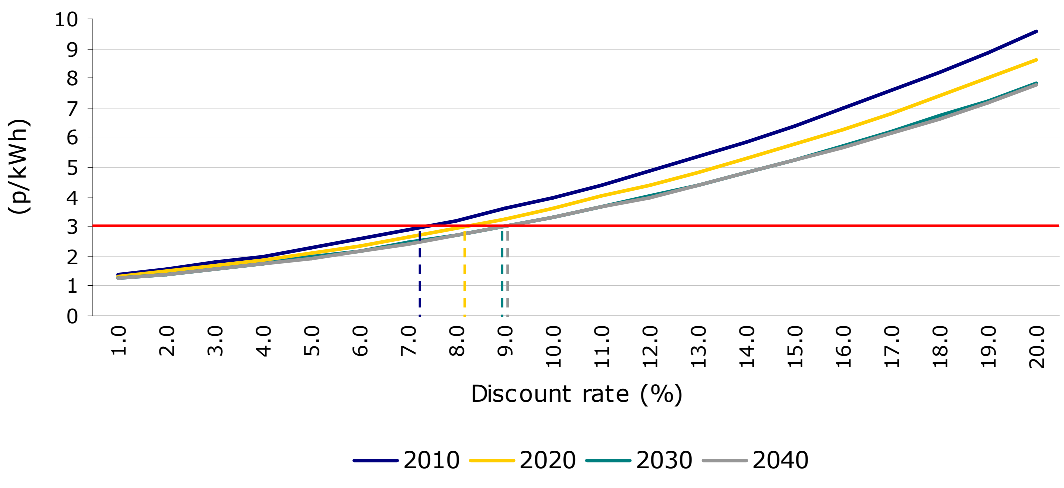
attractive option in the transition to a low carbon economy. However two important constraints exist.

- The risk premium required by the private sector for nuclear investment results in unprofitable generation at a wholesale electricity price of 3p/kWh – a nuclear plant built in 2020 would generate electricity at a cost of 5.8p/kWh.
- The issue of nuclear waste is unresolved.

Risk has a dramatic effect on the cost of nuclear generation. This is well illustrated by the example of the new Finnish rector, which is being built on a fixed-priced contract by the French company, Areva. Areva is partially owned by the French government, and as such, French tax-payers bear the risk of cost over-runs. This arrangement has enabled the private consortium, TVO[35], which financed the Finnish reactor to use a low, 5% discount rate to do so.

The effect of the discount rate on profitability is shown in figure 5.1, which illustrates that nuclear power stations built in the UK in 2020 could be financed profitably at a discount rate of 8%.

Figure 5.1: Nuclear cost, by construction year and discount rate (p/kWh)



[35] One of TVO's six shareholders is the government owned utility company, Fortum.

The risk premium required for nuclear investment is a consequence of uncertainties surrounding new nuclear technologies, the possibility of cost over-runs and the dependence of the wholesale electricity price on the price of gas, i.e. price sensitivity (Oxera, 2005b). Indeed, if the nuclear waste issue can be resolved to the extent that privately financed nuclear build is desirable, government support for nuclear investment must address these uncertainties.

I. Uncertain new technologies. While new nuclear technologies are predicted, by the nuclear industry, to be able to supply electricity very cheaply, these designs have yet to be built anywhere in the world (PIU, 2001). The private sector, which considers the risk of investment in nuclear relative to investment in gas, requires a greater return on investment to bear this technology-related risk.

The government on the other hand must consider the social cost of carbon and the imperative to reduce carbon dioxide emissions. As such, it is required to choose between two uncertain technologies if it is to meet its own emission reduction target while supplying sufficient electricity for economic growth. Hence, the risk profile faced by the government is markedly different from that faced by private investors and government intervention in favour of either nuclear energy or carbon sequestration is necessary for the 2050 target to be met.

II. Cost over-runs. A second generation of nuclear reactors could be expected to suffer less from cost over-runs. However, cost over-runs have been a feature of nuclear power in the UK and elsewhere to date. Consequently, this thesis has been conservative in the assumptions made regarding the costs of nuclear energy – upper estimates of costs have consistently been used. Further, a 10% allowance for cost over-runs has been made.

Uncertainties over costs continue to affect potential nuclear investment regardless of cautious estimates - the private sector requires a risk premium to finance a project on the scale of a nuclear power plant if the possibility for cost over-runs exists. If the UK government decides nuclear energy is to be part of a solution to carbon abatement, the risk of cost over-runs must be addressed by government. This can be done either through a cost guarantee or by a government-owned company building the plants on a fixed-priced bid.

Cost over-runs are not restricted to nuclear investment and could be expected to afflict a large-scale carbon sequestration project. As such, similar measures would be needed to reduce the risk of investment in a carbon sequestration project and encourage private sector involvement.

III. Price sensitivity. As a consequence of the low cost of gas generation in the liberalised market, the price of electricity is dependent on the price of gas. Part of the risk associated with nuclear investment is concerned with gas prices, and thus electricity prices, falling. The realised price of electricity is of particular risk to nuclear investors due to the long lead- and lifetimes of the nuclear power plants, although this risk is also present in a large-scale carbon sequestration project.

Private investors will require assurances that investment in a nuclear power plant will not result in an unprofitable source of generation several years hence due to a fall in gas prices. In this regard, government could prevent gas prices falling below a price floor by using either a carbon tax, or a 'smart' import tariff that is dependent on the price of gas[36].

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[36] That is, an import tariff that acts to ensure a minimum price but is absent at gas prices above this minimum level.

However, a government decision to support nuclear new build will consider more than just economics. Ultimately, government may decide that supporting nuclear investment carries too much political risk, in which case commitment to carbon abatement will suffer, and the 2050 target will almost certainly fall by the wayside.

6. Conclusion

Uncertainty is inherent in any study which attempts to predict the future. This thesis required assumptions regarding, among other factors, energy efficiency improvement rates and the practicable potential of renewable energy sources. In either case, significant deviation from the numbers used, would affect the results of the model in a relevant manner. However, the best case scenario (i.e. high energy efficiency savings and high penetration of wind energy) results in a 23% short-fall in supply in the absence of a nuclear energy or carbon sequestration program. Thus, significant changes to either or both of these numbers (in the same direction) would be required to alter the conclusion that either nuclear energy or carbon sequestration will be required to achieve the 2050 target.

Further study regarding the practicable potentials of renewable energy technologies past 2025 is necessary. Decisions regarding the generating mix are long-term decisions, and full information in this regard is essential.

It must be noted, that an economic analysis of the sort undertaken for this thesis has limitations in accounting for social costs. Indeed, it is impossible for the social cost of carbon included in the analysis to account for the worst consequences of climate change, such as irreversible damage to the climate system and ecosystems. Similarly, certain societal costs nuclear energy has the potential to impose[37] remain external to the model.

These limitations notwithstanding, the analysis suggests that reconciling the UK's economic growth projections with the government's plans for carbon abatement

[37] That is, the effect of nuclear catastrophe on human health and society, and on the environment.

will not be easy.

- The carbon abatement target imposes restrictions on fossil-fuelled electricity generation;
- Renewable energy has practicable limitations;
- Feasible electricity efficiency improvements are constrained below 2%/yr.

As such, the UK will be unable to meet electricity demand in 2050 without a large scale program of nuclear energy or carbon sequestration. There are compelling arguments for investment in new nuclear generating capacity:

- Nuclear energy is more cost effective than a carbon sequestration program (involving both gas and coal sequestration), although both would require government subsidy.
- A large-scale nuclear power program supports the government's desire for energy diversity, while a carbon sequestration program requires increased dependence on imported fossil fuels.
- Nuclear energy has benefited from much technological learning. Carbon sequestration, by contrast, is untried on the scale necessary to meet the predicted shortfall.

However, management of nuclear waste is a major weakness in the case for nuclear. In the UK, the issue of nuclear waste is under review, and resolution of the matter is necessary before any nuclear new build is undertaken. Consequentially, whether the UK's national emission reduction targets will force an increasing reliance on nuclear power depends on satisfactory resolution of the nuclear waste issue.

The analysis presented in this thesis suggests that an environmental toll will be paid for electricity usage in the UK over the next fifty years. Whether that toll will be in carbon emissions or nuclear waste is a decision for the country's politicians.

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