An Assessment of Carbon Dioxide Abatement and Energy Storage in Methanol

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Abstract

In response to the challenge of climate change and potential energy supply insecurity, the UK Government published a White Paper outlining objectives for a long term energy strategy. The UK Electricity Supply Industry (ESI) must address these energy policy goals of reducing environmental impact while maintaining security of supply and affordability.

The environmental impact of the ESI could be reduced by investing in renewable energy technologies, however, at present, the financial premium of such technologies conflicts with the goal of maintaining affordability. The lower electricity prices currently experienced in the ESI are a result of investment in natural gas generation and it is expected that this investment trend will continue. However, once the domestic North Sea resource is exhausted the United Kingdom will become dependent on imports. Here there is a conflict between low cost energy and security of supply.

This study tests the thesis that energy storage and carbon dioxide (CO_2) abatement in methanol is feasible as a means of meeting the energy policy objectives. Sequestering CO_2 emitted from fossil fuel power stations will allow them to continue to generate electricity. This could maintain the diversity and therefore security in the fuel mix of the ESI. Using intermittent renewable energy to electrolyse water and produce hydrogen offers an energy storage solution that could counter the and alleviates the problems of intermittency on the network.

Analysis of the methanol production process, in terms of the economic requirements, abatement capability and the necessary conditions for its feasibility are set out. To establish the necessary economic and regulatory setting for the methanol process to be feasible an optimal fuel allocation model was constructed. Taking into account factors of CO_2 emissions, security of supply, cost of electricity and economic instruments the model is used to determine how the ESI could achieve the energy policy goals. Results of the feasibility study conclude on how the methanol process can be used to help the ESI meet the energy strategy objectives and describe the necessary economic and regulatory measures required.

Declaration of Originality

I hereby declare that this thesis is my original work except where otherwise stated.

Joanna M Duthie

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This work is dedicated to the memory of Prof Bert Whittington. He is very much missed.

Abbreviations

AGR	Advanced Gas Reactors
BAT	Best Available Technology
BWR	Boiling Water Reactors
CANDU	Canadian Heavy Water reactors
CCA	Climate Change Agreements
CCGT	Combined Cycle Gas Turbine
CCL	Climate Change Levy
CEGB	Central Electricity Generating Board
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
COP	Conference of the Parties
CVM	Contingent Valuation Method
DC	Direct Current
DCF	Discounted Cash Flow
DEFRA	Department for the Environment and Rural Affairs
DIC	Dissolved Inorganic Carbon
DG	Distributed Generation
DMFC	Direct Methanol fuel cell
DNC	Declared Net Capacity
DNO	District Network Operator
DOE	United States Department of Energy
DTI	Department for Trade and Industry
EENS	Expected Energy Not Served
EOR	Enhanced Oil Recovery
EGR	Enhanced Gas Recovery
ESI	Electricity Supply Industry
ETS	Emissions Trading Schemes
EU	European Union
FBC	Fluidised Bed Combustor
FCV	Fuel cell Vehicle
FFL	Fossil Fuel Levy
FGD	Flue Gas Desulphurisation
FOR	Forced Outage Rate
GA	Genetic Algorithm

GHG	Greenhouse gas
GJ	Gigajoule
GtC	Gigatonnes of carbon (10^9 tonnes)
GTCC	Gas Turbine Combined Cycle
GW	Gigawatt
H_2	Hydrogen
HFC	Hydrofluorocarbons
HHV	Higher Heating Value (thermal efficiency basis)
HPR	Holding Period Return
IC	Installed Capacity
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogramme
kW	Kilowatt
kWh	Kilowatt hour
LCPD	Large Combustion Plant Directive
LDZ	Local Distribution Zones
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
LV	Low Voltage
MARR	Minimum Acceptable Rate of Return
MCFC	Molten Carbonate Fuel Cells
MEA	Monoethanolamine
mg	Milligramme
MJ	Megajoule
MPa	Megapascal
MPT	Modern Portfolio Theory
MSW	Municipal Solid Waste
MV	Medium Voltage
MW	Megawatt hours/hour
MWh	Megawatt hour
NETA	New Electricity Trading Arrangements
NFFO	National Grid Company
NGT	National Grid Transco

NIC	National Insurance Contributions
Nm^3	Normal metre^3
NOx	Oxides of nitrogen
NPV	Net Present Value
O&M	Operation and Maintenance
O_2	Oxygen
OCM	On-the-day Commodity Market
OECD	Organisation for Economic Cooperation and Development
OFGEM	Office for Gas and Electricity Markets
OM	Operating Margins
OOP	Object Oriented Programming
OWC	Oscillating Water Column
Pa	Pascal (1 N/m^2)
PEMFC	Proton Exchange Membrane Fuel Cells
PES	Public Electricity Supply
PF	Pulverised Fuel (coal)
PFBC	Pressurised Fluidised Bed Combustor
PFC	Perfluorocarbons
PIU	Performance and Innovation Unit
PN	Physical Notification
ppm	Parts per million
PPP	Pool Purchase Price
PV	Photovoltaic
PWR	Pressurised Water Reactors
R&D	Research and Development
RCEP	Royal Commission on Environmental Pollution
REC	Regional Electricity Company
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
RP	Revealed Preference
SF_6	Sulphur Hexafluoride
SMD	System Maximum Demand
SMP	System Marginal Price
SOFC	Solid Oxide fuel cell
SOx	Oxides of sulphur
SRC	Short Rotation Coppice

SRO	Scottish Renewables Obligation
UK	United Kingdom
UKCS	UK Continental Shelf
UNEP	United Nations Environment Program
VOLL	Value of Lost Load
WMO	World Meteorological Organisation
WTP	Willingness to Pay

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Chapter 1

Introduction

1.1 Thesis Background

An affordable and reliable energy supply is fundamental to the social welfare and economic prosperity of modern nations. The world has enjoyed abundant and cheap supplies of fossil fuels with little regard for the consequences of the energy use or the security of future supply. A greater awareness of the environmental impact of fossil fuel use and the need to maintain secure, reliable and most importantly affordable energy supplies have raised issues of how the future energy supplies should be managed. These features of an energy supply were addressed in a recent Government White Paper, Energy – Our Energy Future[1]. The measures required to achieve these energy policy goals are likely to have a significant impact on the UK Electricity Supply Industry (ESI).

The ESI has changed radically over the last two decades from being a publicly owned monopoly into a deregulated and liberalised private industry. A result of these changes has been the lowering of electricity prices, one of the aims of privatisation. However, the market now is in charge of finding the most cost effective means of supplying power to the nation and embodying the environmental and security factors. The UK Government has committed itself to reducing Greenhouse Gas (GHG) emissions, of which carbon dioxide (CO_2) is the most significant. The ESI contributes around a third of the UK total and is often the focus of major reductions measures. The UK will become a net importer of energy over the next decade and as older plant is decommissioned there is increased awareness of the need to maintain a diverse and secure energy supply. There is, however, no clear way forward to meeting the energy policy goals.

Renewable sources of energy for electricity production are frequently cited as the solution to the continued growth in demand for energy, greater environmental pressures and the problem of dependency on fuel imports. However, there are economic and operational barriers to the widespread integration of renewable electricity generation. The recently published White Paper requires that levels of security and affordability remain high and that will inevitably require the continuation of fossil fuel plant. The removal and storage of carbon dioxide produced from fossil fuel use will also be a means of enabling secure energy supply without adverse effects on the environment.

A novel method of producing methanol from the waste CO_2 and hydrogen produced from the electrolysis of water using renewable energy has been investigated to establish whether it has a part to play in meeting these energy policy goals. The motivation for researching the process of methanol production is that CO_2 emissions need to be lowered if reduction targets are to be met. The ESI is the common focus of such reduction as emissions are frequently from a large point source.

1.2 Aims and Objectives

The previous section presented the background to the changes in the energy industry and in particular the electricity supply industry. The study is expanded in the subsequent chapters to give a full description of the factors behind energy policy development, the means of achieving the policies and the conflicts that will arise.

The work reported tests the *thesis* that: "it is feasible to convert waste carbon dioxide and hydrogen into methanol and the process can be implemented to help achieve the energy policy goals."

The objectives of this study are to:

- Investigate the motivation for the development of a comprehensive UK energy policy
- Propose and evaluate the novel methanol production process from CO_2 and hydrogen and describe its potential to meet the energy policy targets and analyse the potential for the methanol process in terms of its energy storage, and carbon dioxide abatement capability
- Evaluate the alternative options that could be implemented to achieve the policy goals and the potential conflicts arising
- Develop an optimal fuel allocation model to investigate how the ESI can achieve the energy policy objectives up to 2020 and whether the renewable methanol process can make a useful contribution.

1.3 Chapter Summary

Chapter 2 of this report outlines the background to the creation of the UK energy policy. The changes in the ESI since privatisation have led to some positive outcomes of lower electricity prices, lower CO_2 emissions and an increased diversity of energy sources. However, sustaining these positive outcomes will become more difficult. The challenges facing the ESI are described in the context of the conflicts between the energy policy goals.

The methanol production process and the basis for investigation is introduced in Chapter 3. The process requirements and potential are established and its potential contribution to the ESI and energy policy described. The requirements and prerequisites needed for the process to be viable are discussed.

Chapter 4 describes alternative technologies open to the ESI to lower the carbon intensity of the industry. Options included are increasing the efficiency of fossil fuel use, generating energy from non-carbon sources and carbon dioxide mitigation and sequestration techniques.

Chapter 5 describes and evaluates the different methods of analysing the security of the ESI in terms of capacity requirements, fuels choice and price risk, how renewable produced methanol could help these aims.

Chapter 6 discusses how the market can be encouraged to take into account the external environmental costs of electricity generation in order to meet the energy policy goals. The various economic instruments are discussed and compared. The markets for methanol are discussed and how economic instruments can help the economic viability.

Chapter 7 introduces a model that aims to find the optimal fuel allocation for electricity generation in the UK ESI in terms of the energy policy goals, to determine whether there is a need for large scale renewable energy development or carbon dioxide abatement.

Chapter 8 draws together the results of the ESI model, concluding on the suitability of the methanol process as a means of meeting the energy policy goals. Conclusions on how the UK ESI can meet the Energy Policy goals are made and the role of renewably produced ethanol discussed and finally recommendations for areas of further research are outlined in Chapter 9.

Chapter 2

Developing a UK Energy Policy

The UK Electricity Supply Industry (ESI) has undergone radical reform as the publicly owned assets were privatised in the late 1980s. Since then further liberalisation has occurred with the introduction of the New Electricity Trading Arrangements (NETA) in 2001. The policy initiatives introduced over the last few years have aimed to establish open energy markets to deliver energy at competitive prices. As a result of implementing these policies the UK has one of the most competitive energy markets in the world and consumers have benefited from prices following a downward trend. However, the energy policy agenda is now expanding to incorporate further issues relating to the supply of energy such as the environment and energy security.

Until recently there was no significant impetus for developing a fully comprehensive UK Energy Policy. Currently the UK is largely self-sufficient in energy, with a good balance of coal, gas and nuclear generation and ample generating capacity. However, a combination of increasing use of gas in electricity generation, the decommissioning of ageing coal and nuclear plants and with the production of North Sea gas expected to peak in 2005, it will be necessary in the future to rely more heavily on imported fuels. Dependence on imported fuels is not necessarily a negative factor, but more attention is being focussed on security of energy supplies.

The challenges of climate change resulting from increasing levels of greenhouse gases (GHGs) in the atmosphere need to be met. Programs to promote renewable energy sources and energy efficiency have been designed to arrest the increasing levels of carbon dioxide (CO_2) the principal GHG. Despite seeing an overall reduction in anthropogenic CO_2 emissions, in particular from the ESI, since 1990, emissions are predicted to rise again as a result of changes in the fuel mix of the ESI, increase in transport related emissions and an overall increase in the demand for energy.

Maintaining low cost and secure energy supplies at the same time as mitigating environmental impact will require more stringent policies. Consequently, the UK Government has embarked on developing an energy policy to ensure the security and sustainability of future energy supply. This chapter describes the background to the creation of the UK energy policy.

2.1 Electricity Market Reform

Electricity markets within Europe and around the world are being rapidly reformed. After decades of structural rigidity in electricity supply, governments are allowing market forces to play an increasing role in the operation of supply systems and the allocation of investment in new generating capacity. Many countries have already introduced competition into their electricity supply industry, such as the UK, or have plans to do so. The main goal of these changes is to improve the economic performance of electricity supply with the prospect of lower electricity prices, but other goals such as security of supply and environmental protection are equally imperative.

2.1.1 Changes to the Electricity Supply Industry

The UK ESI has changed considerably since its development in the early 20th century. Originally a publicly owned monopoly, a process of deregulation and privatisation has altered the market structure, cost of electricity and balance of generation fuels.

Before privatisation the Central Electricity Generating Board (CEGB) was responsible for all electricity generation within England and Wales and operated the national electricity transmission system. There were twelve area boards that controlled the electricity distribution business, supplying electricity to customers within their specific geographical areas.

The power stations were divided between two large fossil fuelled generators, National Power and PowerGen, and the nuclear capacity to Nuclear Electric. Nuclear Electric was held in public ownership until 1996 when it was privatised and became British Energy.

Each regional electricity company (REC) was given a franchise to supply electricity in their area. Customers with a demand of greater than 100kW were given the opportunity to buy from any supplier. The franchise market was removed in 1998 when all customers could choose their electricity supplier.

The ownership and operation of the transmission system was transferred to the newly created National Grid Company (NGC) which was given the specific remit to facilitate competition. NGC was also given responsibility for administering financial settlements following the trading of electricity in the wholesale market.

In Scotland the vertical integration was maintained with the creation of Scottish Power and Scottish Hydro Electric power companies. Although Scottish Power and Scottish Hydro Electric operate as vertically integrated companies, under the regulatory regime their generation, transmission, distribution and supply activities are each treated as separate businesses. The license requires each company to account separately for each of its businesses, to ensure there is no cross subsidy and that excessive profit is not made from the Use of System charges.

With the assets of the former CEGB privatised the method of electricity trading was also changed. A trading method known as the Pool was introduced. At any one time not all generation is required to meet demand, therefore under Pool operation, each generator submitted an offer for each half hour of the day. A merit order was created with the least expensive given a higher merit order than the more expensive. Once the merit order was established the most expensive generator that was required to meet the demand for that half hour period set the System Marginal Price (SMP). All generators generating for that half hour were paid the SMP.

The actual figure paid to a generator was called the Pool Purchase Price (PPP) and it included a capacity payment in addition to the SMP to try to ensure that there was enough excess capacity to make up any shortfall. It was in this bidding market that it was felt that abuse of market power and price fixing was occurring. The nuclear generators unable to ramp up and down to meet fluctuating demand, bid £0/MWh to ensure that they obtained the highest position on the merit order. It was, however the final bids for each half hour that set the SMP and it was here that market power artificially kept prices high, therefore a policy of further structural changes were implemented.

2.1.2 New Electricity Trading Arrangements

The New Electricity Trading Arrangements (NETA) went "live" in March 2001, replacing the Pool trading arrangements for setting wholesale electricity prices. The motivation for changing the electricity trading arrangements were that prices failed to reflect the falling costs and increased competition that moving from a publicly owned monopoly to privatised systems should have exhibited. NETA was designed to establish a fully competitive market in which supply and demand determined prices.

NETA can be divided into four main areas:

- Forwards and futures market
- Power exchange
- Balancing mechanism
- Settlement

2.1.2.1 Forwards and Futures Market

Suppliers make estimates of their demand based upon contracted loads and sales expectations. They use this information to contract with generators to meet these basic requirements. These bi-lateral trades take place in the forwards and futures markets. There is nothing to prevent contracts being drawn up to cover requirements several years into the future, although in practice deals looking more than a year or two ahead are unlikely.

2.1.2.2 Power Exchange

The Power Exchange operates between 24 and 1 hour before delivery to allow suppliers to make adjustments to account for any discrepancies between contracted supply and the expected demand. They are able to buy or sell electricity within this market to cover any excess or shortfall between their actual position and that covered by the contracts in the

Forwards and Futures market.

Suppliers must declare their positions by making Physical Notifications (PNs), up an hour before physical delivery - this is known as Gate Closure - when a Final Physical Notification (FPN) is submitted. It is on the basis of this FPN that Settlements are undertaken. Alongside PNs, generators and suppliers can also make Balancing Mechanism Offers to help secure the system. It is here that energy purchasers with Load Management or Self Generation abilities can benefit under NETA.

2.1.2.3 Balancing Mechanism

The Balancing Mechanism (BM) is used to ensure that electricity supply meets demand. Under NETA most of the UK's electricity is traded through bilateral contracts ahead of time. As electricity cannot be readily stored and has to be kept in balance on a second by second basis by the National Grid Company (NGC) a balancing mechanism is operated to ensure system security. About 2-3% of electricity bought and sold by NGC is through this mechanism[2]. From Gate Closure to the time of physical delivery, the system operator works to ensure that the system is balanced and secured. NGC can call on the bids made within the Power Exchange to achieve this. Within the BM there is a great potential for demand-side management where large consumers of electricity can be given an incentive or paid to reduce demand at peak demand times.

Generators are out of balance if they cannot provide all the electricity they have been contracted to provide, or they have generated too much. Suppliers are out of balance if they have consumed more electricity than they have contracted for, or they have consumed too little. This means that NGC will face additional costs because it may have to buy or sell electricity at short notice to keep the system in balance. The charges participants face for being out of balance are based on these additional costs.

Modifications and experience have led to significantly reduced price volatility in the balancing mechanism. For instance, the difference between the prices at which participants have to buy electricity from and sell electricity to NGC to balance their positions reduced from £70 per MWh at Go-Live in March 2001 to £17 per MWh in the summer of 2003[3]. There still is the possibility that much higher levels of volatility can occur.

2.1.2.4 Settlement

Settlement is effectively an accounting process. It is here that players in the Balancing Mechanism are forced to pay penalties if their positions were either over or under declared. Ultimately, these penalties have to be paid by consumers. Under NETA reliability and predictability are rewarded. Any generator unable to predict or guarantee output fares less well. This prejudices market access for renewables such as wind or marine based generators.

2.1.3 Results of NETA

The deregulation and liberalisation of the ESI has been successful in terms of lowering the wholesale prices of electricity. The reduced level of regulation does mean that the market needs to be responsible for ensuring security of supply and for incorporating environmental objectives.

Once competition is introduced into the ESI, the framework for undertaking investment decisions changes dramatically. Decision-making shifts from the state to investors and risk bearing shifts from consumers to investors as costs can no longer be automatically passed through to consumers. As a result, investment decisions in a liberalised market are based on profitability. Revenues depend on expected electricity prices while costs depend on the fuel price. Thus, investment activity depends positively on the price of electricity and negatively on the price of fuel.

Electricity prices must reflect the cost of producing electricity. This should mean that prices will fluctuate over time; for example, prices should increase during periods of peak demand when high marginal cost units must operate. The role of financial markets is to fund investments at prices which provide adequate returns, taking into account the risks of the investments. In setting an appropriate price, capital markets need to forecast the return on the investment. The future price of electricity is a key element of this forecast. A much debated question is whether financial markets are able to forecast electricity prices without bias. There is concern that investors may be myopic, basing decisions on current electricity prices alone. Myopic investment could result in investment cycles as high electricity prices would induce investment that would eventually depress electricity prices. This, in turn, could cause investment to stall. Over time, generating capacity could become scarce, again raising electricity prices. These price and investment cycles could be reinforced by the natural variation of electricity demand and prices over the business cycle.

With the reduction in wholesale prices of electricity smaller, less competitive generators have become less profitable and this has resulted in the contribution from smaller generators falling[4]. Lower wholesale prices are one factor but higher fuel costs, especially for Combined Heat and Power (CHP) plants which run on gas, have also contributed. Intermittent or seasonal generators such as wind farms are unable to provide firm power at a given time so are forced to trade within the Balancing Mechanism (BM). Few of the smaller generators actually operate through the BM arrangements as they would be fully exposed to the financial risks of imbalance charges. To limit exposure to imbalance costs consolidation services have been proposed. Consolidation allows smaller generators to operate in NETA through a third party. The groups of generators share the risk of failing to meet or exceeding contracted demand.

A power station can take many years to construct and has a lifetime of up to 30 years. The long lead time means that new generation plant needs to be planned well in advance. There is some criticism of NETA that it has exaggerated "short-termism" in the ESI where companies focus on short term economic gain over longer term security. New Combined Cycle Gas Turbine (CCGT) build accelerated over the 1990s as low gas prices and the short lead times in construction made CCGT an attractive investment. If gas prices were to increase with the inevitable cessation of domestic supply, CCGT may not be such a desirable investment. New technologies such as renewable electricity generation are something the Government has been keen to encourage, however, the cost of renewable electricity remains higher than from conventional fossil fuel sources. This means that renewable resources are unable to compete within NETA without fiscal or regulatory measures such as the Non Fossil Fuel Obligation and Renewables Obligation to assist them.

2.2 Security of Supply

Security of supply refers to the likelihood that energy will be supplied without interruption. A reliable and dependable electricity supply is taken for granted by consumers in developed countries and any disruption to supplies can result in a decrease in economic output and social welfare. Therefore, much attention is placed on ensuring that investment in the electricity industry is maintained so that in the event of a fault, plant outage or market failure, supplies are assured.

To operate a system that is free from disruption, security is approached from two perspectives. In the short term there needs to be sufficient flexibility in generating capacity available in case of plant or facility failure. In the long term, the security of supply depends on the adequacy of investment in terms of providing:

- Enough generating capacity to meet demand;
- An adequate portfolio of technologies to deal with variations in the availability of input fuels; and
- Adequate transmission and distribution networks to transport electricity.

2.2.1 Short Term Reliability

As large scale electricity storage facilities are not yet available electricity must be generated at the instant of its demand. Electricity demand profiles can be accurately predicted in advance (the NGC frequently achieve accuracies of better than +/- 5%[5]) allowing generators to be scheduled to export power when it is needed. To make up any for errors in demand forecasting or the sudden outage of a generator the shortfall in power requirement is met by fast or spinning reserve.

2.2.1.1 Fast Reserve

Fast reserve or spinning reserve can be called upon at very short notice, typically within two minutes notice and must individually be able to deliver at least 50MW and increase power output at a ramp rate of 25MW/minute[6]. In the UK at present the spinning reserve is maintained by pumped storage hydro plants and excess capacity margin in generating plants operating at part load. Demand-side providers can also bid to reduce load by similar amounts, e.g. radio tele-switching of domestic demands in off peak periods.

The approximate level of fast reserve required for a system can be calculated from the largest single unit that is generating plus a smaller amount for any demand discrepancies. Currently in the UK the level of spinning reserve would typically be in the region of 1-1.5 GW[7].

2.2.1.2 Standing Reserve

At certain times of the day the grid operator requires additional power in the form of generation or demand reduction to be able to deal with actual demand being greater than forecast demand and plant outages. This requirement is met from synchronised and non-synchronised sources. This service must be capable of delivery within 20 minutes of instruction and must individually be at least 3MW in size[8].

2.2.1.3 Capacity Margin

If a fault or generator outage persists over a longer period of time (weeks to months) generating capacity can be made up of from generating plant that is not operating but that can be brought online at short notice. The capacity margin is the level of generation in excess of that required to meet the system maximum demand (SMD). The optimum level of capacity margin over the SMD is calculated through comparing the cost of not meeting demand against the cost of holding extra capacity.

Optimal generating capacity for an electricity system is determined by the willingness of consumers to pay for security of supply. If consumers are willing to pay for an extra kilowatt of capacity more than it costs to provide it, it is optimal to invest in this extra kilowatt. If it costs more to expand capacity than the value consumers attach to it, it is optimal not to invest. If neither more nor less investment is needed, then generating capacity is defined to be optimal. Of course, there is no definite way of knowing *a priori* how much capacity would be needed.

Pre-NETA, the value consumers attached to an uninterrupted supply was known as the Value of Lost Load (VOLL) and was defined for each consumer as the monetary value that they attach to the last unit of energy consumed. VOLL measures how much the consumer would be willing to pay in exchange for not having to reduce electricity consumption by one unit. The system VOLL is the VOLL of the consumer with the largest valuation. Estimates of system VOLL range in the order of US $10,000 per MWh (~£6,500 per MWh) in the US[9], but in the UK values in the region of around £2,500 per MWh were used to ensure excess generating capacity was made available[10].

To evaluate the optimal level of capacity margin the probability of there not being sufficient generation to meet demand is evaluated – referred to as the Loss of Load Probability (LOLP) - and the cost of not meeting demand calculated using the VOLL. The investment in margin capacity should continue until it is more expensive to install another unit than to accept a potential loss in not being able to meet demand. In generation systems where the majority of the power is generated from large steam plant (i.e. nuclear, coal, oil etc) a capacity margin of around 22% is judged optimal[11].

Holding additional capacity incurs extra costs to the ESI. Under the Pool trading arrangements capacity margin was rewarded through LOLP payments. These were calculated for each half hour depending on the system marginal prices (SMP) for that half hour, given by:

$$PPP = SMP + LOLP \times (VOLL - SMP) \tag{2.1}$$

where PPP is the Pool Purchase Price, the prices paid to the generation companies. VOLL was agreed on annual basis by all the parties in the Pool.

This practice was abandoned after NETA came online. The ESI had a capacity margin in the region of 28% when NETA was introduced[12], For winter 2003/04 the UK ESI is expected to have a capacity margin of only 11%[13] and interruptions to electricity supply during peak demand are therefore more probable. The reduction in excess capacity is due in part to plant being mothballed in recent years to avoid grid connection charges as marginal costs were greater than the market wholesale price.

Changes in the generation mix, in particular the increased integration of intermittent renewable generators, will have an effect on the LOLP of a system and the necessary capacity to ensure that demand is met.

2.2.2 Security of Fuel Supplies

Another fundamental security of supply issue is the diversity of input fuels to power generation. Other factors being equal, greater diversity tends to decrease the electricity supply industry's vulnerability to price increases in input fuels. The importance attached to diversity varies from country to country, depending on the extent to which a country has indigenous fuel sources and other factors. Research by Stirling[14] highlighted how the low diversity of national electricity depends on the main fuel of the system. Countries with large hydro or nuclear capacity tend to have lower diversity levels than countries with a high dependence on fossil fuels, especially if they are imported. For example, Switzerland and Norway have low diversity in their power systems because of the abundant availability of hydro power.

The security of energy supplies, in particular fossil fuels for electricity generation, is necessary to avoid sudden shortages or price spikes. No energy form, nor source of supply can offer absolute security, so improving security of supply means reducing the likelihood of sudden shortages and having contingency arrangements in place to limit the impact of any which do occur.

After the ESI was privatised, private investors took advantage of the short lead time and low natural gas prices to construct CCGTs. This increase of new CCGT generation displaced the previously dominant coal plant. The trend of investment in gas-fired generation has increased diversity in the UK ESI, as gas was introduced in the portfolio of input fuels. The current fuel mix is however evolving as nuclear stations are decommissioned at the end of their lifetime and stricter emission regulations cause the remaining older coal plant to become uneconomic.

New generation will need to be commissioned to make up the shortfall in generation capacity. Predictions of the future generation fuel mix suggest that gas powered CCGTs will be the dominant technology[15]. Figure 2.1 shows the potential trend in terms of capacity over the next 20 years.

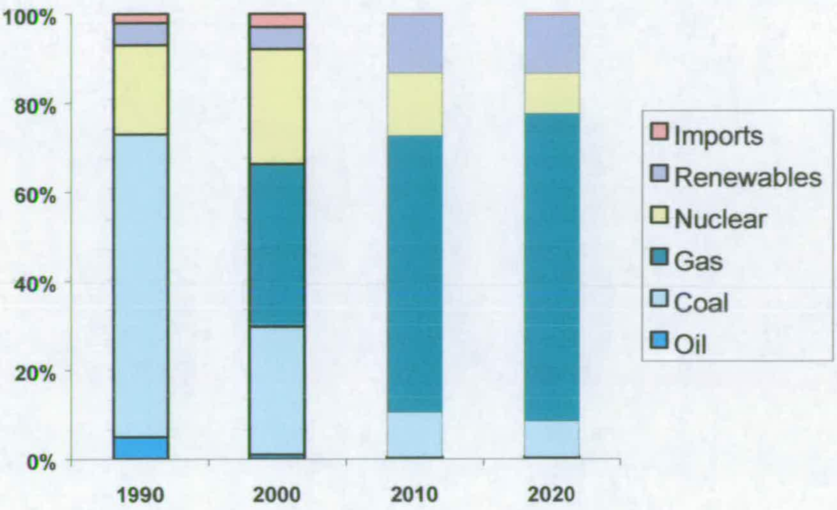

Figure 2.1 - Past and Projected Generator Fuel Share,%[16]

There have been concerns raised over having such a high level of dependency on one type of fuel, especially natural gas. In terms of security of supply, both economic concerns of volatile prices and physical delivery, e.g. facility or transmission failure, have been raised as areas that the UK ESI will need to consider.

2.2.2.1 Import Dependency

The UK has enjoyed a self sufficiency in fuel supplies with the extraction of oil and natural gas from the UK Continental Shelf (UKCS). However predictions of future oil and gas reserves show the field will become less productive over the next decade as the resource runs down. The UKCS is expected to reach peak production by 2005, with the need for the UK to increase imports of energy by 2020. Dependency on fuel imports does not necessarily mean supply insecurity. However, no direct control over supply is undesirable and a greater diversity of energy sources is beneficial to reducing energy supply uncertainty.

A main concern of gas dependency stems from the nations supplying gas or those which through the gas must travel proving to be hostile or unreliable. The UK will firstly become dependent on Norway for the majority of its gas followed by nations further afield such as Russia, Algeria and the Middle Eastern countries. It is impossible to predict whether a gas producing country would restrict supply. An assessment of risks suggests that Russia, for example, would be unlikely to intentionally restrict supply[17]. Firstly as it has been a reliable trade partner for over 20 years. Secondly there are mutual benefits from trade. 20% of European gas comes from Russia and making up 40% of its export revenue. However, Russia has made moves to create a gas cartel with Algeria and Iran. Political instability and the potential of hostile regimes cutting off supply cannot be completely ruled out in today's uncertain times. Also there are problems in terms of the transport of natural gas from Russia to western Europe. The transmission pipelines pass through the Ukraine whose network requires major investment to upgrade the capacity to meet the projected demands[18].

2.2.2.2 Supply Failure

Facility failure can occur at any point in the supply chain and a major disruption in supply has the potential to severely disrupt electricity generation and domestic supply. For the UK the gas supply terminals are the main facilities in which disruption can occur. Out of 8 terminals, only two have the capacity to import from continental Europe, St Fergus in NE Scotland and Bacton in England. These two terminals process 38% and 22% of the UK gas supply respectively. If either of these facilities failed either through natural or deliberate means there would be a significant reduction in UK availability.

There have been a number of gas supply interruptions to customers during 2003. A notable incident occurred on the 17th and 18th June 2003. National Grid Transco† (NGT) undertook a number of localised system balancing actions in order to address a supply deficit in the south of Great Britain. These actions included locational purchases of gas on the On-the-day Commodity Market (OCM). However, these locational actions did not result in sufficient gas to address the localised imbalance. As a result, NGT had to use Operating Margins (OM) gas and to exercise contractual rights to interrupt flows to the Belgian Interconnector and a number of loads on the National Transmission System (NTS) and Local Distribution Zones (LDZs).

Interruption of gas customers during the summer months is unprecedented. Interruptions are a mechanism that NGT can use to offset too great a demand over supply. Consumers on interruptible contracts pay reduced transportation charges to compensate for the risk of losing supply. NGT can only interrupt when demands are above 85% of a 1 in 20 peak day other than to manage transmission constraints. On the 17th and 18th of June a combination of lower terminal capacities and inflexibility in the interconnectors resulted in NGT shutting off demand in order to ensure that the linepack levels (the storage capacity in the pipelines) were maintained.

2.2.3 Future Reliability and Security

Following the Californian Crisis in 2001 and more recently blackouts in North America, London and Italy during the summer of 2003 it is even more apparent that the security of supply of electricity is vital. In terms of generation capacity, there will need to be sufficient capacity to meet demand and make up any shortfall due to unplanned outages or faults. Making sure that this happens is perhaps the greatest challenge as deregulated markets may not be so concerned about such eventualities as maximising short term profit.

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† The National Grid Company and Transco, the gas transmission company, merged in 2003 and was renamed National Grid Transco (NGT). The remit of NGT in terms of the transmission system is identical.

Research by the OECD states that some governments have been concerned that reserve capacity may be at risk in a more competitive market and that ad hoc mechanisms, such as capacity payments, may be required to ensure an adequate reserve capacity[19]. This scenario has happened in the UK with winter capacity levels for 2003/2004 falling to around 11%[20].

Based on current predictions for the winter 2003/2004 electricity demand is expected to be approximately 55.7GW in England and Wales compared with the cold weather corrected value of 54.6GW for the previous year (2002/03). The surplus of generation above average peak winter demand is 6GW an expected margin of approximately 11%. As mentioned earlier, the privatisation of the ESI has led to tightening on the capacity margin of generation, with generators being mothballed to avoid grid connection charges. Of this mothballed plant around 2.8GW could be made available for this winter, but only 0.8 GW is expected to be operational given the challenges involved. This gives a capacity margin of 6.8GW or 12.3%. This margin could be further eroded by a number of factors. Firstly, the demand for electricity could be higher than predicted: NGT predictions show that demand could be 2.2GW higher than average, reducing the capacity surplus to between 3.8 and 4.6GW, between 6.8% and 8.25%. Also, during the winter it can be expected that interconnectors from Scotland and France are not at maximum import. The interconnectors from France and Scotland can import 2.0 and 2.2GW respectively. If total import was reduced to 3GW due to France and Scotland having less excess power to export, the surplus capacity would reduce further to between 2.6 and 3.4GW. Under prolonged cold conditions during the winter months when electricity and gas demand is at its highest, interruptions on gas supply to CCGT generation could be expected. If conditions in the gas market determined that all interruptible CCGTs were interrupted, this would reduce available generation by 8.6GW. 5.9 GW can generate on alternative fuels so under a full interruption there would be a net loss of around 2.7GW.

Each of the scenarios represent the "worst case" risk to electricity security of supply. While each of these scenarios is credible the probability of them all occurring simultaneously is small.

Without any collective decision on how to manage excess capacity, it is up to market forces to determine capacity. This may mean that there is a greater risk of blackouts. During the Energy review by the Performance and Innovation Unit some generators expressed unease at the lack of a capacity mechanism. Innogy, an energy trading company, asserted "a potential weakness of the NETA design is the removal of any form of capacity credit and there is the potential to compromise system security unless pealing and reserve capacity is adequately remunerated"[21].

The liberalisation and deregulation of the ESI is not the only factor that can effect the security of a system. Changes to the fuel mix of a country will also have an effect, not only on the capacity requirements, but also the volatility of electricity prices, if fuels need to be imported from further and further afield. The levels of fast reserve may need to change too, if greater levels of intermittent generators are connected to the system.

Chapter 4 describes the tools and methods available to evaluate the concept of security of supply in the ESI.

2.3 Climate Change

The principal motivation for creating an energy policy, according to the Government, is the increased awareness of the need to mitigate the effects of climate change. There is an increasing body of scientific evidence which states that man-made greenhouse gas emissions are having a perceptible effect on the Earth's climate. The Intergovernmental Panel on Climate Change (IPCC) was jointly established by the World Meteorological Organisation (WMO) and the United Nations Environment Program (UNEP) in 1988 to address the scientific and socio-economic effects of climate change and to advise the Conference of the Parties (COP), the body that drafted the Kyoto Protocol. The Kyoto Protocol is a series of documents outlining the need to reduce greenhouse gas emissions and the responsibility of each nation with the COP.

2.3.1 The Greenhouse Effect

The equilibrium between energy from the sun in the form of visible radiation (sunlight) and the energy constantly being emitted from the surface of the earth to space determines the temperature of the earth. Referring to Figure 2.2, the energy coming in from the sun can pass through the atmosphere almost unchanged and warm the earth, but the infrared radiation emanating from the earth's surface is partly absorbed by some greenhouse gases (GHGs) in the atmosphere and some of it is reflected downwards. This further warms the surface of the earth and the lower atmosphere. The gases that do this naturally are mainly water vapour and carbon dioxide. An analogy is made with the effect of a greenhouse, which allows sunshine to penetrate the glass and keeps the heat in, hence the greenhouse effect.

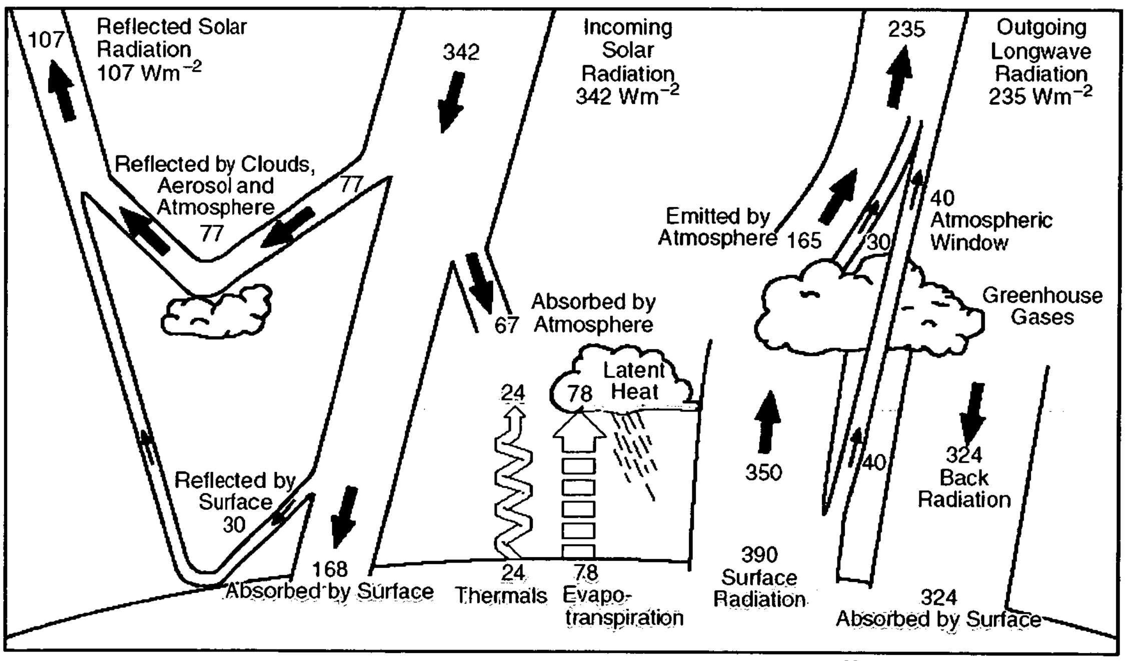

Figure 2.2 – The Earth's Energy Annual Balance[22]

Without this natural greenhouse effect, the earth would be over 30°C cooler and would be too cold to be habitable. The increase in the concentration of GHGs is purported to interfere with the natural Greenhouse Effect, thus causing a greater amount of energy to be reflected back to the earth's surface, i.e. Global Warming.

2.3.1.1 Greenhouse Gases

Of the group of gases that cause the Greenhouse Effect, some occur naturally in the atmosphere and are produced through the natural carbon cycle processes, i.e. water vapour, CO_2, methane and nitrous oxide. Other gases are man-made; hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF6) which arise through a number of industrial processes.

Of the natural GHGs the level of CO_2 is the most important in terms of human impact on the atmosphere. The concentration of GHGs in the atmosphere has risen steadily over the last 250 years as a result of the increased use of fossil fuels since the Industrial Revolution. Research based on analysis of the sediments of lake beds shows that before the industrial era, around the mid 18th Century, CO_2 concentrations were 280±10ppm for several thousand years. It has since risen to 397ppm in 1999. The present atmospheric concentration has not been exceeded in the past 450,000 years and likely not for the last 20 million years[23]. Three quarters of the increase in CO_2 concentration is due to the combustion of fossil fuel with changes in land use responsible for the remainder. This evidence has motivated Governments and policy makers to address the ever increasing levels of CO_2 and other GHGs. The detailed evidence compiled by the IPCC predicts that global temperatures could increase by between 1.4 to 5.8°C over the next 100 years[24].

2.3.2 International Agreements – The Kyoto Protocol

In 1992, the Rio Summit brought together world leaders to address the perceived threat of global climate change. In a later summit in Kyoto in 1997, an outline set of targets to reduce global CO_2 emissions within the Kyoto Protocol was drafted. A policy of *contraction and convergence* was developed which accepts that GHG concentration will increase, but allows less developed countries to produce greater levels of CO_2 and allow them to become more developed. Politically this has not been popular with some countries, for example the United States as it fears economic decline whilst other less developed countries are still allowed to freely emit CO_2. As a result the Kyoto Protocol has yet to be ratified, more than six years since its adoption.

2.3.3 Climate Change and the UK Energy Policy

Through the Kyoto Protocol the UK Government pledged to reduce emissions of the greenhouse gases by 12.5% by the period 2008-2012. The Government, at that time, set an even more ambitious domestic target of a 20% reduction in GHG emissions by the same period. Without the ratification of the Kyoto Protocol these targets are not legally binding. However, they are useful to use as a guide to how reductions in GHGs can be achieved within current markets and economic climate.

The government is confident that the GHG reduction targets will be achieved, however, the influence of CO_2 emissions over the total output remains a critical factor. CO_2 makes up over 85% of the total GHGs emitted from across all UK sectors, Figure 2.3 below shows the CO_2

emissions from the different sectors.

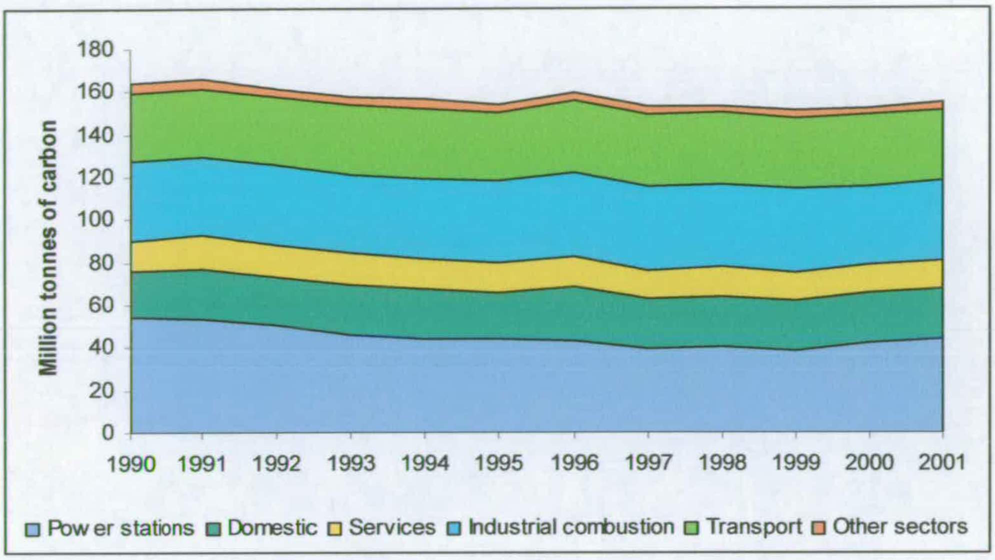

Figure 2.3 - UK CO_2 Emissions by sector (MtC)[25]

Power generation accounts for approximately one third of total CO_2 emissions (Figure 2.3) yet it has been the sector that has contributed the greatest reduction since the Kyoto protocol targets were established. Reductions in CO_2 emissions during the nineties were a result of economic decisions within the ESI rather than environmentally motivated and cannot be used as a marker for further decreases in emissions. The reductions were a result of replacing less economic coal fired generation with the relatively inexpensive CCGT which took advantage of the lower gas prices during the 1990s. Over the same period transport related emissions increased, reducing the total UK CO_2 reduction made by the power sector. Figure 2.4 shows the proportions of different generators used in electricity production and the overall CO_2 emissions for the power sector.

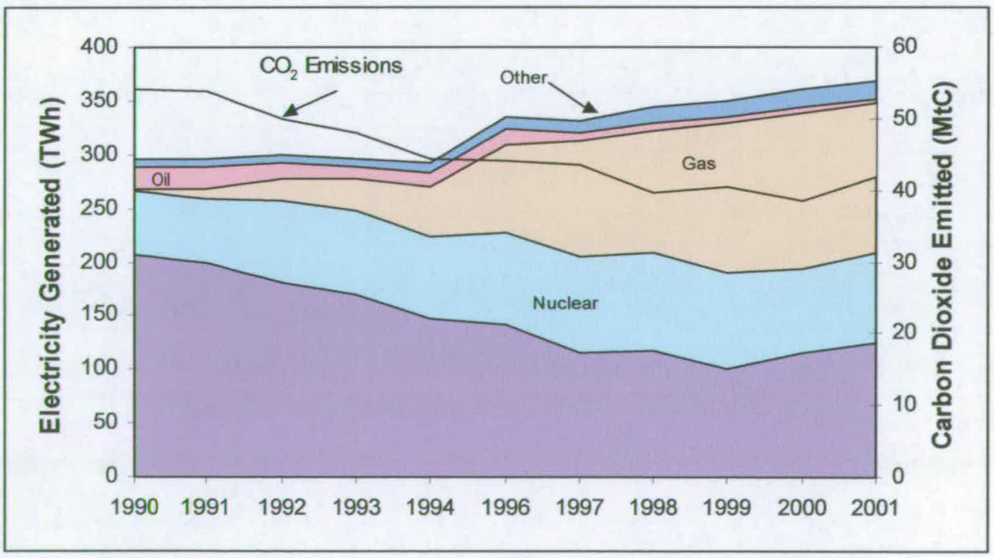

Figure 2.4 – Annual UK Electricity Generation by Fuel Type and Respective CO_2 Emissions[26]

The question remains of what fuel source will be used to replace the aging nuclear and coal fired plant. Currently it is thought that gas will make up the shortfall, yet the issue of security of supply once the UK is no longer self sufficient in natural gas, is raised again. Alternatives include replacing existing nuclear capacity with new nuclear plants. This would benefit the security of the UK ESI electricity supply, however, there is much public opposition to nuclear power. Renewable energy sources such as wind and marine based generation could also be developed at a large enough scale, yet there are problems associated with the higher generation costs in comparison to conventional steam plant.

Research by the Royal Commission on Environmental Pollution (RCEP) made recommendations that the long term goal for the UK is to achieve CO_2 reductions of 60% on 1990 levels by 2050[27]. The higher target proposed by the RCEP was based on international convergence and contraction on a concentration of 550ppm, allowing less developed and energy intensive nations to effectively *catch up* in terms of economic prosperity. For long term high level emissions reductions all sectors will need to contribute, however, in the short term (up to 2020) the power sector is under the greatest pressure to reduce CO_2 output.

2.4 Summary

The deregulation and liberalisation of the UK ESI has resulted in lower electricity prices, a temporary increase in security of supply and reduced carbon dioxide emissions. These results are transient and certainly not guaranteed in the future. The higher investment in gas generation in the future may result in a more volatile ESI when the UK is no longer self sufficient in resources and the markets between electricity and other users become closer.

Chapter 3

Methanol Production from Carbon Dioxide and Hydrogen

The catalytic process for the conversion of carbon dioxide (CO_2) and hydrogen (H_2) into methanol is a proven method of synthesising methanol (3.1).

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \tag{3.1}$$

A novel application of this process is being investigated to incorporate carbon dioxide abatement from fossil-fuel power stations and renewable energy storage. By using renewable energy to produce hydrogen through the electrolysis of water, to then produce methanol from the reaction of CO_2 and H_2, a sustainable, low carbon fuel is created. A simplified diagram of the process is shown in Figure 3.1:

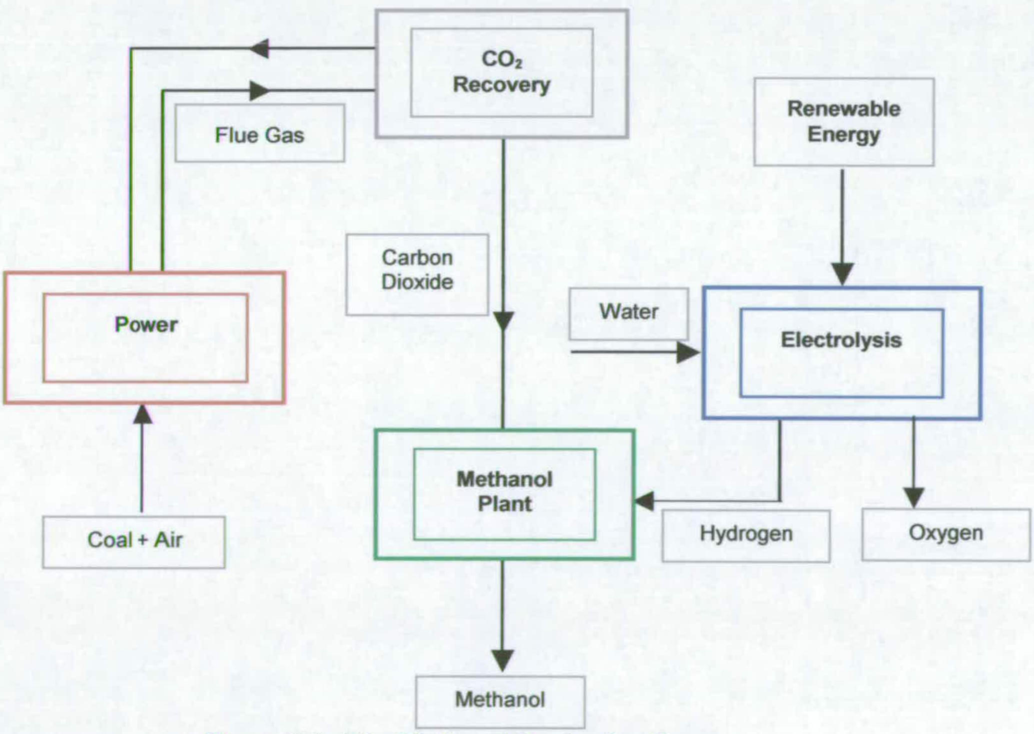

Figure 3.1– The Methanol Production Process

The chapter starts with a description of conventional methanol production techniques. Following sections describe the hydrogen production process, the technological options for CO_2 recovery and electrolysis, and its energy requirements. Results of an economic analysis of the process are explained and the potential contribution the process could make to the UK energy policy goals are established.

3.1 Methanol Production

3.1.1 Conventional Methanol Production

Conventional methanol is produced from the reformation of natural gas. The first step (3.2) is the production of a synthesis gas:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{3.2}$$

The synthesis gas is then passed into another reactor (3.3) where methanol is produced:

$$CO + 2H_2 \rightarrow CH_3OH \tag{3.3}$$

The conventional method requires natural gas as a feedstock and produces carbon dioxide.

3.1.2 The Carnol Cycle

The production of methanol as an agent for CO_2 mitigation is not a novel proposal. One process known as the Carnol cycle uses CO_2 from waste streams of power stations and hydrogen from natural gas to produce methanol[28]. The hydrogen is extracted from the natural gas using a thermal decomposition (3.4) so that pure carbon, rather than CO_2 is produced.

$$CH_4 \rightarrow C + 2H_2 \tag{3.4}$$

The separated carbon can either be stored or sold as a material commodity. The methanol is then produced in a conventional gas phase reactor as in (3.1). A disadvantage of this process is that it requires a source of natural gas. Natural gas is ultimately a finite fossil fuel therefore this process in the long term is not sustainable.

3.1.3 Renewable Methanol Production

The research of this renewable methanol production is based on the thesis outlined in the introduction, i.e. the use of renewable energy to produce the hydrogen to use in the methanol process with the aim of providing a cost effective means of carbon dioxide abatement. This renewable methanol production is a novel application of a proven catalytic conversion of H_2 and CO_2 into methanol and is described in detail in Section 3.4. The results of this investigation are a significant contribution to knowledge in terms of the feasibility and viability of this particular process.

The following sections evaluate the technologies available for the proposed renewable methanol production method and make an assessment of the capability of the process in terms of energy storage capability and CO_2 abatement given and therefore the feasibility and effectiveness of the process to assist in achieving the UK energy policy goals.

3.2 Hydrogen Production

One method of producing hydrogen is through the electrolysis of water. This section describes the theory of water electrolysis and reports on studies of renewable energy storage in hydrogen.

3.2.1 The Electrolysis of Water

When an electric current is forced to pass through an electrolyte or electrolyte solution, chemical reactions take place at the positive (anode) and negative (cathode) terminals. By applying an electric current through water (H_2O) can be dissociated into the diatomic molecules of hydrogen (H_2) and oxygen (O_2) (Figure 3.2).

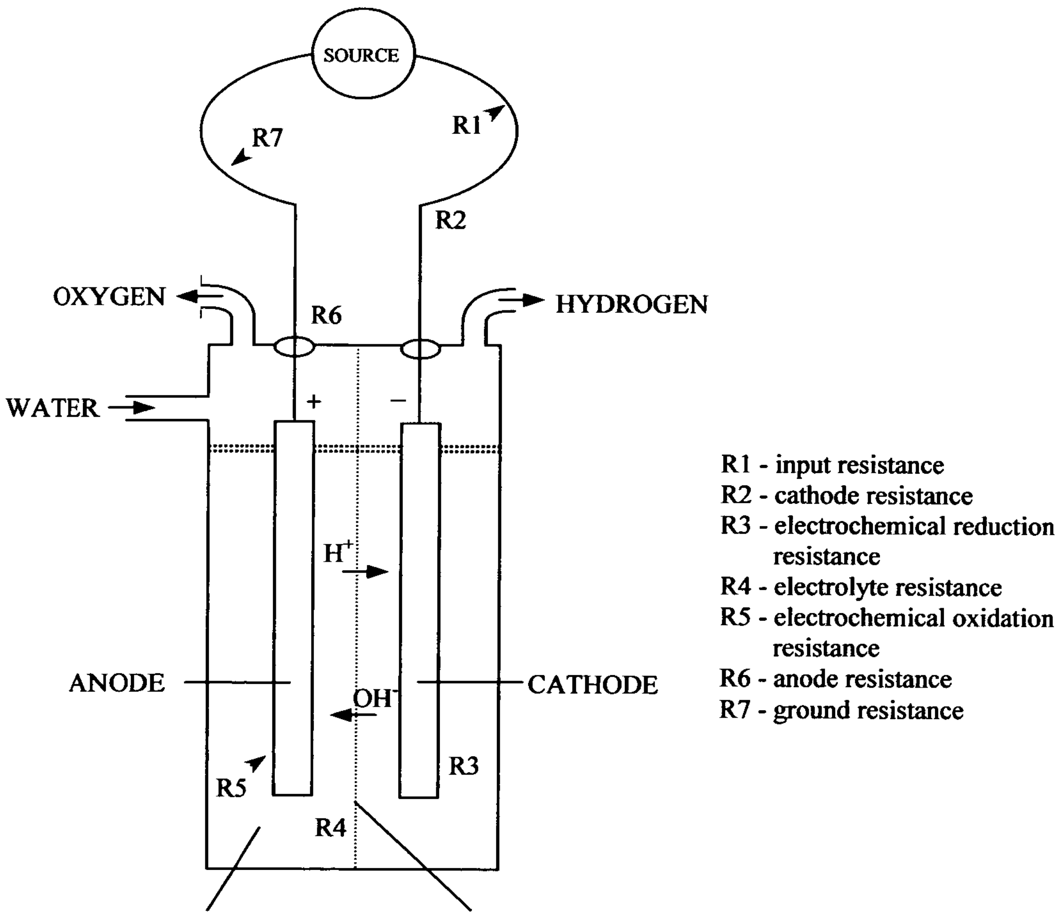

Figure 3.2 – Water Electrolysis[29]

$$2H_2O \rightarrow 2H_2 + O_2 \tag{3.5}$$

Water decomposition through electrolysis is achieved by applying an electric current through an aqueous electrolyte, with hydrogen being produced at the cathode (3.6) and oxygen at the anode (3.7).

$$2H_2O + 2e^- \rightarrow H_2 + 2OH^- \tag{3.6}$$

$$2OH^- \rightarrow \tfrac{1}{2}O_2 + H_2O + 2e^- \tag{3.7}$$

In the ideal case, a voltage of 1.47V applied to water electrolysis cell at 25°C would decompose the water into one mole of hydrogen gas and a half-mole of oxygen gas in their normal diatomic forms, at 100% electrical efficiency. A voltage as low as 1.229V will decompose the water but under these conditions the reaction is endothermic and energy in the form of heat would be absorbed from the surroundings. At voltages higher than 1.47V the water is decomposed and heat is dissipated to the surroundings[30].

To obtain maximum efficiency from the input energy, it is desirable to operate the electrolysis cell at a voltage only slightly above the minimum necessary for the formation of hydrogen and oxygen. Unfortunately under these circumstances very little electric current flows and the actual production rate of the hydrogen measured per cm^2 is very low. If this technique were used for the production of hydrogen, the cells would have to be very large and this more costly. As the voltage is increased the production per unit area of the cells increase but the efficiency decreases. At higher temperatures the voltage necessary for the decomposition of the water decreases so that at a given voltage the production rate increases[31].

Ideally it would be appropriate to operate the electrolysis cell at the highest possible temperature but the vapour pressure of water makes operation more difficult at higher temperatures. At atmospheric pressure water at 100°C is gaseous and therefore the cell and the support components of the cell need to be modified to be able to withstand elevated pressures. Elevating the temperature results in a lowering of resistances represented in Figure 3.2, R3 and R5 (electrochemical reduction and oxidation resistances).

Reducing the other resistances to the lowest possible value increase the overall efficiency of the cell; R1, R2, R6 and R7 are all related to the electrical circuit elements leading into the cell. These resistances can be lowered through selecting materials that are good electrical conductors and making the cell parts of an adequate size.

The resistance R4, the electrolyte resistance, is the only other resistance that can be controlled. Pure water is not a good conductor of water as it has an electrical resistance of $1\times10^6\Omega cm^{-1}$. To increase the conductance of water, a solute that ionises in water is added, typically potassium hydroxide.

3.2.2 Theory of Water Electrolysis

An explanation of the energy requirements of the process makes use of the first law of thermodynamics (3.8):

$$\Delta U = Q - W \tag{3.8}$$

where Q is the heat added to the system and W is the work done by the system and the thermodynamic potentials are as shown in Figure 3.3.

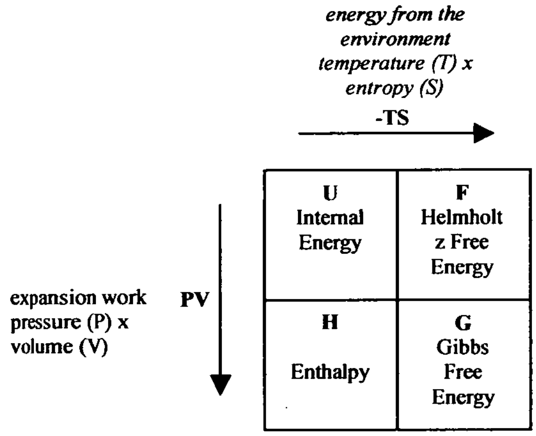

Figure 3.3 – Diagram of the four thermodynamic potentials

U is the internal energy needed to create a *system* (where the *system* refers to the result of a chemical reaction). *F* is the energy needed to create a system minus the energy that can be taken from the environment:

$$F = U - TS \tag{3.9}$$

H is the enthalpy, the energy needed to create a system plus the energy needed to *make room* for the system (i.e. the energy required to allow gases to expand):

$$H = U + PV \tag{3.10}$$

G is the energy needed to create a system plus the energy needed to make space for it minus the energy you can get from the environment:

$$G = U + PV - TS \tag{3.11}$$

The process must provide the energy for the dissociation plus the energy to expand the produced gases. Both of those are included in the change in enthalpy included in Table 3.1.

Quantity	H_2O	H_2	$\frac{1}{2} O_2$	Change
Enthalpy (H)	-285.83 kJ	0	0	$\Delta H = 285.83$ kJ
Entropy (S)	69.91 J/K	130.68 J/K	0.5 x 205.14 J/K	$T\Delta S = 48.7$ kJ

Table 3.1 – Thermodynamic Property Data

At temperature 298K and atmospheric pressure (101.3kPa), the work done (*W*) by the system is:

$$\begin{aligned} W &= P\Delta V \\ W &= (101.3 \times 10^3 Pa)(1.5 moles)(22.4 \times 10^{-3} m^3 / mol)(298K / 273K) \\ W &= 3.715 kJ \end{aligned} \tag{3.12}$$

From equation (3.10), the change in internal energy U is then:

$$\Delta U = \Delta H - P\Delta V = 285.83kJ - 3.72kJ = 282.1kJ \tag{3.13}$$

This change in internal energy must be accompanied by the expansion of the gases produced, so the change in enthalpy represents the necessary energy to accomplish the electrolysis. However, it is not necessary to put in this whole amount in the form of electrical energy. Since the entropy increases in the process of dissociation, the environment 'helps' the process by contributing the amount $T\Delta S$. at temperature T. The amount which must be supplied by the electrical source is actually the change in the Gibbs Free Energy (G):

$$\Delta G = \Delta H - T\Delta S = 285.83kJ - 48.7kJ = 237.1kJ \tag{3.14}$$

This is the amount of energy required to produce one mole of hydrogen and half a mole of oxygen. Converting this value into the electrical energy (kWh) required to produce one kilogram of hydrogen, given there are 500 moles per kg of hydrogen and converting from kJ to kWh:

$$W_{el} = \frac{237 \times 500}{3600} = 32.9kWh/kg \tag{3.15}$$

In practice the ideal the actual energy requirement is greater than the theoretical ideal. The factors which affect the efficiency are the process as follows.

3.2.3 Electrolyser Efficiency

The ideal of amount of energy i.e. the theoretical and lowest value required to produce one mole of hydrogen and half a mole of oxygen from one mole of water is 237.1kJ (3.14) or 32.9kWh (3.15), while the amount of heat generated by the combustion of one mole of hydrogen at 25°C is 285.58 kJ. However, as stated in the previous section that the electrical energy requirement exceeds the ideal voltage as result of resistance losses. Electrolyser efficiencies are currently in the range of 60-75% depending on operating conditions (working pressure and temperature)

The electrolyser in the renewable methanol process will need to be operated under variable electrical supply conditions. Electrolysers can readily accept variable input voltages and even accept energy greater than their rated level for short periods[32] (Section 3.2.4).

In the case of water electrolysis there are also environmental changes to the process that can reduce the energy requirements and increase efficiency (Figure 3.3 and Equation 3.14)). Options include increasing the operating temperature, or by increasing the operating pressure (Equation 3.13).

3.2.3.1 High Temperature Electrolysis

An increase in temperature not only decreases the necessary electrical energy to split the water but also improves the kinetics of the reactions, leading to a more efficient reaction with a faster reaction time. High temperature electrolysis or steam electrolysis is a variation of conventional electrolysis described above. To improve efficiency some of the energy required to split the water is provided through heat energy, reducing the electrical energy required.

The majority of contemporary research is based on the use of waste heat from nuclear power plants to raise the operating temperature and the power plant itself to supply inexpensive electricity[33]. This research has been based predominantly in the US, however in Europe, despite there being discussion of high temperature electrolysis there is little interest in this area now[34].

3.2.3.2 High Pressure Electrolysis

The gases produced through water electrolysis are very pure and should not require further processing therefore it is advantageous to match the electrolysis pressure with that required for further processing or storage. Through special material choice and optimisation high pressure water electrolysers can allow the generation of hydrogen at up to 5MPa[35].

3.2.4 Electrolyser Operation with Renewable Energy

The hydrogen production within this process, by design, has to accept a fluctuating power source derived from renewable energy. This process is expected to use the energy produced from wind generation or a similar variable-output technology (Section 4.3). The technological and operational problems associated with high levels of renewable energy installed capacity are discussed in sections 4.3 and 4.4, however it is still necessary to investigate the operation of electrolysers with fluctuating power.

Ideally the electrolyser would be operated at a constant power at the optimum efficiency. However, in this project the electrolyser is operating as a buffer to the variable power supply. The conversion of electricity to hydrogen as an energy storage medium has been well researched, in particular wind/hydrogen systems where a standalone wind generator is connected to an electrolyser[36, 37]. These studies report that the tolerance of conventional electrolysers to input power fluctuation and the potential for smoothing the output from wind power, are high. Issues relating to the purity of oxygen, at low supply currents, from standard electrolysers were reported. However, as in this study, oxygen was treated as a waste product and vented to the atmosphere.

The conclusion from these studies is that there are no insurmountable problems relating to the variable operation of the electrolysers. Problems can occur in maintaining the pressure but auxiliary energy storage can provide backup in these cases. It was assumed for the basis of this study that variable operation was not a problem. The detailed technical issues relating to operating the electrolyser at variable output are beyond the scope of this study.

3.2.5 Electrolyser Development

As interest in hydrogen production from electrolysis increases due to concerns over the use of fossil fuels, much research interest into the efficiencies of electrolysers is underway. Major development requirements introduced in the preceding sections include the reduction of cell voltages, increase in current density and increase in operating temperature and pressure.

The reduction in the cell voltage of the electrolyser through better anode and cathode alloys is one such area[38]. With a greater increase in research into solid polymer fuel cells[39] or proton exchange membrane (PEM) (the opposite reaction to electrolysis) new techniques of water splitting are being developed. These are currently prohibitively expensive (no figures on the cost are yet being published) as they are still only at the demonstration stage.

3.2.6 Electrolysis By-product Oxygen

A direct result of the hydrogen production through water electrolysis is the production of oxygen. In this project no direct use of the oxygen is required for the methanol process and therefore it can be considered a by-product. However, the purity of the oxygen from electrolysis production is very high and conventional large scale oxygen production is energy intensive and therefore very carbon intensive. Conventional large scale oxygen collection is achieved through extracting it from air. There are three steps to the process: the extreme cooling of air until it becomes liquid; purification of the liquefied air; separating the various components of the liquid by using the different boiling points of each gas. By controlling temperature and pressure, the gases can be separated[40].

This oxygen produced from the electrolysis process could be sold as a high grade oxygen source or alternatively used within the combustion of coal/oil/gas in the power station to improve CO_2 combustion. The full scope of using the oxygen produced is outwith the scope of this project.

3.3 Carbon Dioxide Recovery

The recovery of CO_2 from the flue gas stream of fossil fuel power stations can avoid or reduce CO_2 emissions from the electricity supply industry (ESI) while maintaining the reliability and security that the conventional fossil fuel plants offer to the electricity system.

Carbon dioxide is a stable gas at normal temperatures and pressures. It does form carbonic acid (H_2CO_3) in an aqueous solution and will reduce to carbon monoxide (CO) and oxygen when heated to above 1700°C. However, the removal of CO_2 from a gaseous stream is difficult due to its relative inertness.

Processing techniques for the removal of CO_2 from fossil fuel combustion stream, in particular, are governed by the concentration or partial pressure of the gas to be captured. The concentration of CO_2 in a flue gas stream is low at between 4-14% by volume[41], therefore a large amount of inert gas such as nitrogen needs to be treated. This results in a greater cost penalty as the size of the scrubbing equipment increases.

There are four main methods of recovering CO_2 from the gaseous waste streams:

- Absorption
- Adsorption
- Cryogenic Separation
- Membrane Separation

3.3.1 Absorption

Absorption systems are most common scrubbing systems used to remove CO_2 from a gaseous stream[42]. The CO_2 reacts with a chemical solvent to form a weakly bonded intermediate compound which is then broken down by the application of heat, regenerating the original solvent and producing a CO_2 stream. Typical solvents are amine or carbonate based, such as monoethylamine (MEA), diethanolamine (DEA), ammonia or activated potassium carbonate.

These processes can be used at low CO_2 partial pressures, but the flue gas must be free of acid gases such as sulphur dioxide (SO_2) and nitrous oxides (NO_x), oxygen (O_2), hydrocarbons and particulates. The reason for this is that the amine solvents form stable bonds with other chemicals, reducing regeneration level.

Absorption is the most commonly used CO_2 separation technique attaining high purities and removal rates[43].

3.3.2 Adsorption

Solid adsorption methods employ a physical attraction between the gas and 'active sites' on the solid, whereas solid absorption methods employ a chemical reaction to capture the target gas[44]. There are several adsorption methods used commercially in the process industries that may be applicable for removing CO_2 from power plant flue gases. These employ adsorbent beds of alumina and zeolite molecular sieves.

There are two common methods of regenerating the adsorption beds which release the trapped CO_2. Pressure swing adsorption (PSA) involves lowering the pressure in the vessel contain the saturated adsorption bed until the trapped gases are released. The regeneration cycles are relatively short, typically measured in seconds.

Temperature swing adsorption (TSA) employs a high temperature to remove trapped gases. This regeneration cycle is much slower, measured in hours.

3.3.3 Cryogenic Separation

The CO_2 can be physically separated from other gases by condensation at cryogenic temperature[45]. Other gases that could condense can interfere with the process. For example, methane is difficult to separate from CO_2 but some processes have been developed specially for the methane- CO_2 system. Water also presents problems in cryogenic systems, so the feed gas must be dried before being cooled.

3.3.4 Membrane Separation

There are two types of membrane operations which have the potential for CO_2 removal, gas separation and gas absorption[46].

Gas separation membranes use the physical or chemical interaction between components in a gas mixture with the membrane material causing one component to move faster through the membrane than the other. Gas absorption methods involve membranes being used as contacting device between a gaseous stream and liquid stream. The separation is caused by the presences of an absorption liquid and it is not essential that the membrane has any selectivity.

Membranes use partial pressure as the force for separation and consequently will be most effective at high concentrations and pressure of CO_2. They are not very selective at separating individual components of a gas stream and if low residual CO_2 and/or high CO_2 purity is required, a number of separation stages are required. There is a strong possibility that a combination of processes such as membranes and (MEA) absorption, or cryogenics will be attractive as they would combine the bulk CO_2 removal characteristics of membranes with the ability to remove CO_2 down to low levels.

3.3.5 Comparing Carbon Dioxide Recovery Methods

Processing techniques for the capture of CO_2 are significantly influenced by the concentration or partial pressure of the gas to be captured. For example, at low concentrations such as that applying to the exhaust from a fossil fuel fired turbine, a large amount of inert gas has to be treated which has a significant cost penalty on the size of any downstream scrubbing, heat recovery equipment, etc. However, the quantity of adsorbent or absorbent required is a function of the quantity of CO_2 to be removed, as are the regeneration costs.

The presence of other acid gases and their concentration relative to the amount of CO_2 is likely to be a key factor in determining the optimum CO_2 recovery process. Chemical solvents tend to react with both SOx and NOx to form heat stable salts which are not easily recoverable. This can result in unacceptable solvent losses unless SOx and NOx are removed upstream. SO_2 is generally much more soluble than CO_2 in physical solvents.

Table 3.2 shows a comparison between the different capture methods applied to a typical coal power station.

Capture Technique	Efficiency (%)(1)	Energy Cost (p/kWh)(2)	Cost of CO_2 avoided (£/tonne)(2)	Emission rate of CO_2 (gCO_2 /kWh)
PF+ FGD(3) (base case)	40	3.27	-	829
Membrane	31	5.17	30	194
Membrane &MEA	30	4.98	28	222
Absorption (MEA)	29	4.93	23	116
Cryogenics	n/a	n/a	n/a	n/a
Adsorption PSA	28	7.60	5	57
Adsorption TSA	29	11.93	176	335

(1) Efficiency is defined as the percentage of electrical energy produced from chemical energy consumed
(2) Based on 1995 $US
(3) Pulverised Fuel plus Flue Gas Desulphurisation

Table 3.2 – Typical Data for CO_2 capture – Derived from[47]

Chemical solvents are likely to be preferred for cases with low concentrations or amounts of CO_2 in the combusted gases and do not gain significant advantage by operating at elevated pressure. Whereas, physical solvents are favoured by high pressures and low concentrations of inert gases such as nitrogen. The two chemical absorption processes most commonly applied to remove CO_2 from flue gases are the MEA process and the activated potassium carbonate process.

For the purpose of the feasibility study of the methanol production CO_2 recovery through absorption using MEA was chosen as the most appropriate recovery method, as a compromise between the cost of the solvent and the energy costs.

3.4 Renewable Methanol Production Process Design

The technical design of the renewable methanol production process was undertaken in collaboration with a research team in the department of Chemical Engineering in at the University of Edinburgh. The results of this design were published as a journal paper[48]. A summary of the production process and design choices are presented here.

3.4.1 Flow sheet

Coal is burned in air in a pressurised fluidised bed combustor (PFB) in order to generate pressure and steam for power generation in steam turbines. The pressurised gases from the combustion are passed through a gas turbine and the steam through a steam turbine producing a total power output of 1000MWe.

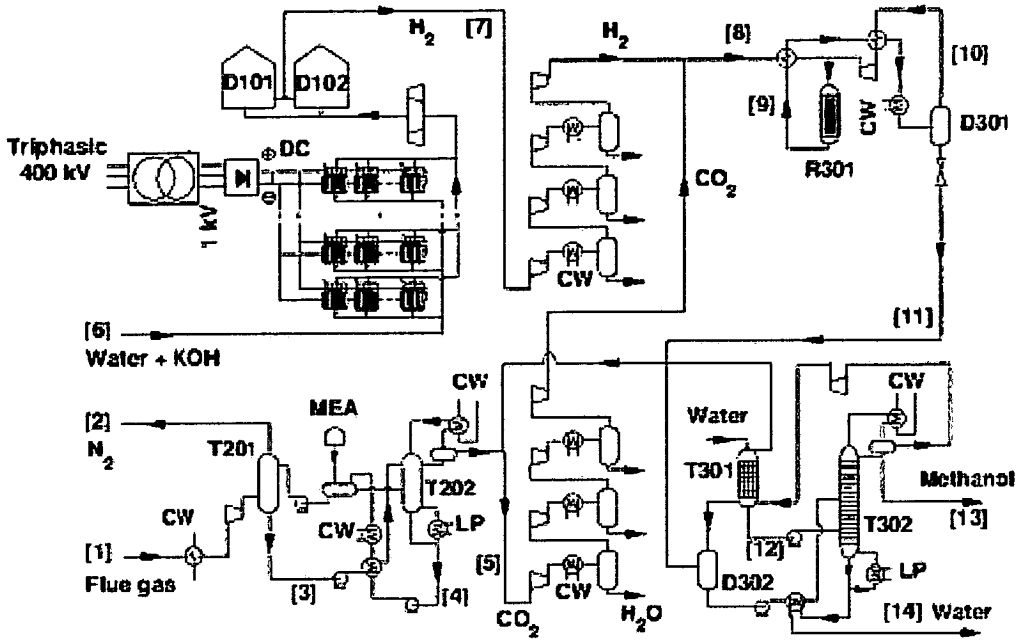

Figure 3.4 – Process Flow Diagram

The flue gas stream [1] is cooled and dehumidified. The flue gas mixture then enters the N_2 separation stage. Here the gas is contacted with MEA (monoethanolamine) in an absorption column [T201] and the CO_2 is absorbed by the MEA forming an intermediate compound [3]. The N_2 [2] is not absorbed and is vented out.

The MEA intermediate compound is fed to a stripping column [T202] where the CO_2 is liberated by heating. The majority of MEA is recycled back to the absorption column and the CO_2 and some of the remaining MEA is cooled and passed to a stripper reflux drum. The CO_2 feed [5] is then cooled further before being passed to the methanol reactor.

In the electrolysis section the plant splits water [6] into H_2 and O_2. The O_2 produced can either be vented or processed further to be sold via pipeline. The H_2 [7] is compressed and cooled and fed to the reactor.

The CO_2 and H_2 are mixed together [8] over a catalyst on Cn/ZuO/Al2O3 oxide to produce methanol and water [9]. The product stream contains methanol, water and any unreacted hydrogen and carbon dioxide. To remove the methanol form this stream the mixture is passed to a distillation column [T302] to remove the methanol and recycle any reactive components back to the reactor.

It should be noted that the hydrogen/oxygen production and CO_2 separation occur at the same site i.e. at the location of the power station. This avoids any energy penalties or financial costs associated with transporting the reagents to the methanol synthesis plant. Although this may appear as if fossil fuelled energy would be used to produce the hydrogen, an equal amount of renewable energy would be injected into the network and it would be as a result of the renewable energy generation that the electrolyser would be activated.

3.4.2 Heat Management

Low pressure steam is necessary to desorb the CO_2 from the MEA and for the distillation of the methanol product. The steam can either be provided from the power plant, through heat integration, resulting in a lowering of efficiency and electrical output (Table 3.2) or through using an external energy source, which is a more expensive option (Table 3.5).

3.4.3 Renewable Electricity Management

As stated in the design specification, the electricity to be used for the electrolysis of water should come from renewable sources. To mimic the variable supply of some renewable electricity generators a varying supply schedule (Table 3.3) was given as the basis for the design project.

Period	Renewable Supply (MW)	Duration (h)	Price (£/MWh)
1	500	4	15
2	100	12	10
3	0	8	-

Table 3.3 – Renewable Energy Supply Schedule

Four options relating to the capacity of the electrolysis unit were investigated:

- Option A - conventional electrolysis uses all the variable renewable power
- Option B – as A but uses constant supply of electricity at off peak level
- Option C – as B but uses high pressure electrolysis to reduce electricity consumption
- Option D – as in B but uses fuel cell plant to offset fossil fuel electricity losses.

These four options were defined to assess the difference in the operation and end cost of the methanol due to the electricity supply profiles (Option A compared to B) and also the result of using more advanced electrolyser technologies (Options C and D).

3.5 Process Specifications

3.5.1 Mass Balances

A summary of the mass balance transfer for the process and different design options are summarised in Table 3.4:

	In (t/day)				Out (t/day)			
Compound	A	B	C	D	A	B	C	D
MEA	0.98	0.47	0.53	0.47	0.98	0.47	0.53	0.47
Water	633	304	345	301	211	101	114	99.3
CO_2	517	246	281	243	95.3	45.8	33.0	0
O_2					555	267	302	264
Methanol					372	178	201	175

Table 3.4 – Mass Balances

3.5.2 CO_2 Abatement

The level of CO_2 from the waste gases sequestered in methanol is limited by the availability of renewable energy and therefore hydrogen. At the level of renewable energy supplied to this process schedule only 3% of the power station's annual 8 million tonnes of CO_2 would be sequestered.

The renewable methanol process sequesters 1.372 tonnes of carbon dioxide in each tonne of methanol produced. The energy required to produce the hydrogen to produce one tonne of methanol is approximately 9 MWh. If the renewable energy were used to displace conventional electricity, using the renewable electricity would save around 3.6 tonnes of CO_2 being emitted to the atmosphere. From this calculation it is clear that using renewable electricity to produce methanol is less effective at lowering emissions than if the electricity could be used conventionally. However, if renewable energy integration and use is limited, there could be 'spare' electricity. Using this extra energy to produce methanol would then avoid further CO_2. It is assumed that this electricity would be available at a very low price.

3.5.3 Energy Efficiency

The energy efficiency balance for the renewable methanol production process is shown in Table 3.5:

	A	B	C	D
Fossil Fuel Electricity Used (kWh/kmol methanol)	10.8	10.8	7.2	0
Renewable Electricity Used (kWh/kmol methanol)	274.5	288.7	255.2	292.8
Conversion Efficiency % (waste heat scenario)	61.9	59.1	67.5	58.4
Conversion Efficiency % (process steam scenario)	54.1	52.0	58.3	51.4

Table 3.5 – Electricity to methanol energy efficiency of the process -

The values of the electrical conversion efficiency (i.e. electrical energy consumed compared with the energy content of methanol produced) of the process in terms of renewable energy to methanol is between 58% and 68% if waste heat from the power station is available. The efficiency is much lower if energy from the power plant needs to be used to produce the low pressure steam.

3.6 Economic Analysis of Renewable Methanol Production

The cost of producing the renewable methanol is the most important aspect for assessing the viability of the process, as it determines whether the process could potentially be profitable. The economic analysis of the methanol production process was separated into three parts.

The first section was the calculation of the capital, fixed and variable operating costs for the process based on the specified renewable energy supply schedule and the design options. Then a model was constructed to extend the economic investigation to investigate different electrolyser operating conditions and supply profiles to establish optimum supply profiles.

3.6.1 Initial Cost Estimates

Initially cost estimates for the four methanol production process options were evaluated during the methanol design project.

As the electrolysis units are of modular design they show little economy of scale. Electrolysers are currently available up to around 1MW. However, using data derived from literature[49,50] the electrolyser capital cost for larger scale units was derived and the following relationship established:

$$C_{el} = aP + bP^{x} \tag{3.16}$$

where P is the maximum rated power of the unit, bP^x is the factor representing the sections such as the rectifiers, pumps and storage facilities, with the exponential factor x, to calculate the economy of scale and aP represents the cost of modular electrolysis units.

The cost estimates for the remaining of the plant were calculated once the hydrogen production volume was established. The chemical process Aspen simulation package was used for the sizing and costing of the remainder of the plant.

Table 3.6 below shows the capital cost expenditure for the four design options.

Process	A	B	C	D
Electrolysis	141	34.7	90.9	34.4
De-NOx capacity	0.107	0.054	0.060	0.054
FGD	2.871	1.368	1.548	1.350
CO2 Recovery	9.36	4.46	5.05	4.40
H2 Compression/Storage	17.6	8.40	9.51	8.28
CO2 compression	4.46	2.13	2.40	2.09
Reactor	2.46	1.17	1.33	1.16
Separation	1.01	0.48	0.54	0.47
Water purification	0.66	0.315	0.356	0.31
Fuel cell plant	-	-	-	54.5
Total	179.6	53.1	111.6	107

Table 3.6 – Capital Cost Expenditure £millions (derived[51])

The fixed operating costs were estimated as 5% of the capital costs and the variable costs for the process were estimated assuming unit costs for steam at 0.593 £/t, cooling water at 0.05 £/t and fossil fuel power at 38 £/MWh (Table 3.7).

Process	A	B	C	D
Renewable Electricity	14.0	6.0	6.0	6.0
Fossil fuel electricity	1.1	0.53	0.4	0
Cooling Water	1.37	0.701	0.752	0.694
LP Steam	3.53	1.68	1.90	1.65
Feed and Chemicals	0.470	0.224	0.254	0.221
Total	20.5	9.13	9.31	8.57

Table 3.7 – Variable operating costs £10^6/year (derived as above)

Finally the effect of selling prices of the methanol on the net present value (NPV) was investigated. Assuming a minimum acceptable rate of return (MARR) of 10%, 35% tax on taxable positive profits, 15% depreciation allowance and a lifetime of the project of 15 years, the minimum selling price of the methanol to achieve a zero NPV after 15 years was calculated (Table 3.8);

	A	B	C	D
Price (£/litre)	0.3720	0.2720	0.3886	0.4224

Table 3.8 – Minimum selling price for methanol as above

3.6.1.1 Conclusions of Initial Economic Costs Analysis

From the initial economic analysis of the four renewable methanol design options, some important factors that influenced the cost of the methanol produced. They were identified as:

- the supply profile of the electricity available;
- the operational capacity of the electrolyser;

- cost of the electricity available.

3.6.2 Process Cost Model

To investigate further the operating regimes of a methanol plant and how this would affect the economics of the process a more detailed analysis was carried out. A process cost model was constructed using data from the initial economic analysis to establish the contribution of each parameter to the cost of methanol. By extending the economic process model, different power supply scenarios could be investigated and the best, but realistic operating scenario could be established.

The model was based on the average unit cost of methanol by estimating the cost of methanol produced in a year divided by annual production.

The cost of producing methanol over a year can be separated into the capital costs of the plant (C_c) multiplied by an annuity factor (α), the cost of the power (C_p), the operating costs (C_{op}) and the annual methanol production (M_{Meth}):

$$C_{Meth} = (\alpha C_C + C_P + C_{OP})/M_{Meth} \tag{3.17}$$

The annuity factor or capital recovery factor is used to calculate the annual payment necessary to pay off an initial sum, in this case the capital costs of the project. It is calculated from the expected interest rate and life span of the project.

3.6.2.1 Capital Costs

The capital costs were separated into electrolyser (C_{EL}), CO_2 separation (C_{CO2}) and methanol synthesis (C_{Meth}) capital costs:

$$C_C = C_{EL} + C_{CO2} + C_{Meth} \tag{3.18}$$

The capital costs of the electrolyser were taken from the estimates in the design project. The scale of the CO_2 and methanol synthesis sections are dependent on the expected continuous hydrogen availability. This was calculated to be the average annual hydrogen production level over a year, M_{H2}, due to the electrolyser unit being run with intermittent electricity supply. The mass of hydrogen produced in a year can be estimated as follows:

$$M_{H2} = \frac{P \cdot T \cdot CF}{E_{H2}/\mu_e} \tag{3.19}$$

where P is the maximum available power, T is the number of hours of operation in a year and CF is the capacity factor of the renewable energy supply, E_{H2} is the ideal energy required to produce one tonne of hydrogen in MWh and μ_e is the electrolyser efficiency. The resultant scale of the carbon dioxide separation and methanol plants are calculated as follows:

$$M_{CO2} = M_{H2} \cdot \left(\frac{m_{CO2}}{\mu_{CO2}} \right) \tag{3.20}$$

$$M_{Meth} = M_{H2} \cdot \left(\frac{m_{Meth}}{\mu_{Meth}} \right) \tag{3.21}$$

Where M_{CO2} and M_{Meth} are the annual levels of carbon dioxide and methanol in the process m_{CO2} and m_{Meth} are the ideal unit quantities of CO_2 needed and methanol produced per unit of hydrogen produced and μ_{CO2} and μ_{Meth} are the conversion efficiencies of the respective processes. The capital costs are assumed to be proportional to the process throughput and exhibit an approximate linear economy of scale, due to the narrow range in capacity:

$$C_{CO2} = c_{CO2} \cdot M_{CO2} \tag{3.22}$$

$$C_{Meth} = c_{Meth} \cdot M_{Meth} \tag{3.23}$$

Where c_{CO2} and c_{Meth} are specific capital costs of the CO_2 and methanol plant sections.

From the previous equations the total capital costs can be estimated and are represented by the flowing equation:

$$C_C = aP + bP^x + \frac{P \cdot CF \cdot T}{E_{H2}/\mu_e \cdot} \left(c_{CO2} \left(\frac{m_{CO2}}{\mu_{CO2}} \right) + c_{Meth} \left(\frac{m_{Meth}}{\mu_{Meth}} \right) \right) \tag{3.24}$$

3.6.2.2 Power Costs

The cost of the power is given by the following expression, where C_e is the cost per MWh of electricity:

$$C_P = C_e \cdot P \cdot T \cdot CF \tag{3.25}$$

3.6.2.3 Operating Costs

The variable operating costs, C_{op}, consist of the cooling water, steam and feed chemicals and vary with the volume of production M_{Meth}, M_{CO2} and M_{H2}. For each section of the process the specific variable cost coefficients have been estimated and are summarised as:

$$C_{OP} = \left(c_{opm} \cdot M_{Meth} \right) + \left(c_{opc} \cdot M_{CO2} \right) + \left(c_{oph} \cdot M_{H2} \right) \tag{3.26}$$

The coefficients c_{om}, c_{oc}, and c_{oh} are the variable operating costs of each plant section.

3.6.2.4 Complete Cost Model

Therefore the total cost of producing methanol per year can be expressed by:

$$C_M = \begin{bmatrix} \alpha\left(aP + bP^x\right) + \dfrac{P \cdot T \cdot CF}{E_{H2}/\mu_e \cdot}\left[c_C\left(\dfrac{m_C}{\mu_C}\right)\left(\alpha + c_{opc}\right) + c_M\left(\dfrac{m_M}{\mu_M}\right)\left(\alpha + c_{opm}\right) + c_{oph}\right] \\ + C_e \cdot P \cdot T \cdot CF \end{bmatrix} \cdot M_M^{-1} \tag{3.27}$$

3.6.2.5 Model Inputs

The product costs of the methanol is determined by the three variable input parameters to the cost model, i.e.:

- the maximum power supplied, P
- the capacity factor of the electrolyser, *CF*, and
- the cost of the electricity, C_e

A number of assumptions relating to these parameters have been made to simplify the analysis.

It was assumed that the maximum renewable power level will be available over the lifetime of the project, as any significant reduction will leave a part of the electrolyser capacity redundant and therefore increase the product cost. Any increase in the maximum supply will not be able to be accommodated unless it can be incorporated through an increase in the electrolyser capacity factor.

The price of the electricity has been taken as an average over the whole time period. In reality however, the cost of the electricity is more likely to vary over time as changes in season and electricity market structure affect the conventional market for renewable electricity.

The range of the variable inputs have been chosen to cover the whole range of possible operational scenarios for the plant. The electrolyser rating has been set between 50MW and 500MW as the lower value has been chosen as the cut-off representing the power coming from one renewable power source, e.g. a single wind farm. The upper cut-off has been chosen a likely maximum rating for a single unit in terms of renewable energy supply and waste heat availability.

The cost of the electricity has been taken over the range of 0.8p/kWh to 2p/kWh. This is a low cost for electricity, however, it was assumed that the electricity would be priced at marginal levels as the electricity would not be sold through the electricity market and therefore be 'spare'. Although newer renewable energy technologies such as wave and offshore wind are still relatively expensive in comparison to conventional generation (>4p/kWh compared with 1.5p/kWh from gas generation), the more technically mature sources such as hydro and on-shore wind are cost competitive. It has been assumed that the power to the methanol process will be priced near to the marginal cost of generation as it is a design specification that only surplus electricity is to be used.

Table 3.9 below shows the fixed process input parameters to the model used in this analysis.

Process	Parameter	Value
Electrolyser modular factor	a	200
Electrolyser peripherals factor	b	16000
Exponential factor	x	0.60625
Electrolyser Efficiency	μ_{H2}	75%
Capital cost of CO_2 Plant per unit CH_3OH	c_{CO2}	£8.03
Level CO_2 per unit of CH_3OH	m_{CO2}	7.33
CO_2 conversion Efficiency	μ_{CO2}	100%
Variable operating cost per unit CH_3OH	c_{opc}	£32
Capital cost of CH_3OH Plant per unit CH_3OH	c_{Meth}	£2.8
Level CH_3OH per unit of Hydrogen	M_{Meth}	5.33
CH_3OH Conversion Efficiency	M_{Meth}	100%
Variable operating cost per unit CH_3OH	c_{opm}	£19.8
Variable operating cost per unit H_2	c_{oph}	£765

Table 3.9 - Process Model Inputs Parameters

3.6.3 Process Cost Model Results

The sensitivity of the product cost of the methanol was investigated with respect to the variable input parameters. The scenarios were to consider the variation of methanol cost with:

- electrolyser rating
- electrolyser capacity factor
- average cost of electricity

3.6.3.1 Electrolyser Rating

The magnitude of the available power directly determines the electrolyser rating as it is the hydrogen production which acts as a buffer between the intermittent electricity supply and the methanol synthesis. The scale of power available was investigated to establish the sensitivity of the cost of methanol to the scale of the production process. Figure 3.5 shows the cost of methanol for the range of electrolyser ratings at different electrolyser capacity factors.

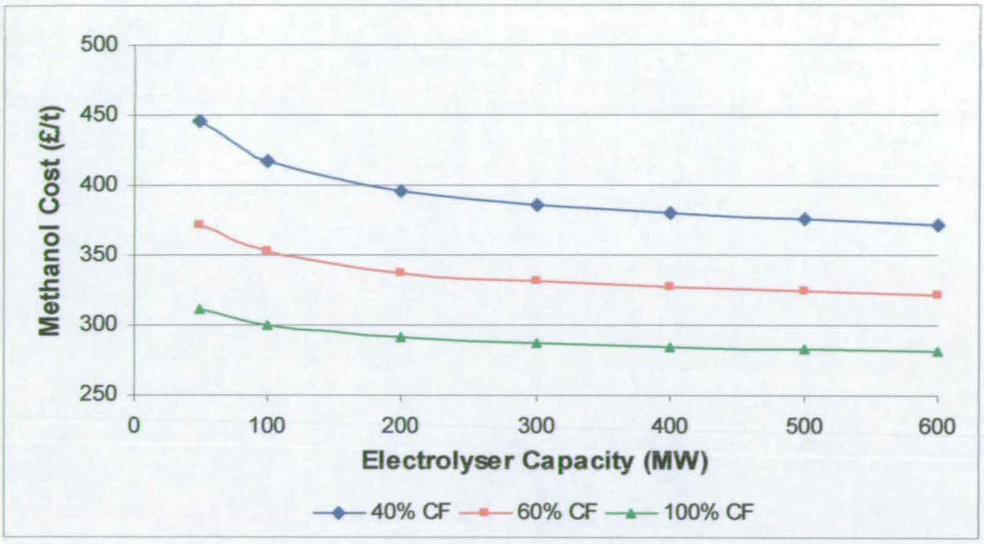

Figure 3.5 – Price of Methanol with Electrolyser Rating (electricity £15/MWh)

The capital cost of the electrolyser dominates the cost of the methanol produced. There is a small economy of scale due to the cost reduction of peripheral equipment (such as pumps and cabling) therefore, there are economic benefits from investing in a larger plant. However, it is important that the capacity factor of the electrolyser is maximised. The cost of the methanol is greatly reduced by over 15% if the capacity factor of the electrolyser is increased from 40% to 60%. This saving is again due to the dominance of the electrolyser capital costs.

3.6.3.2 Electrolyser Capacity Factor

From the previous results it could be seen that the electrolyser capacity factor (CF) is an important factor in the determining the product cost of the methanol. Figure 3.6 shows the cost of the methanol as the electrolyser CF increases.

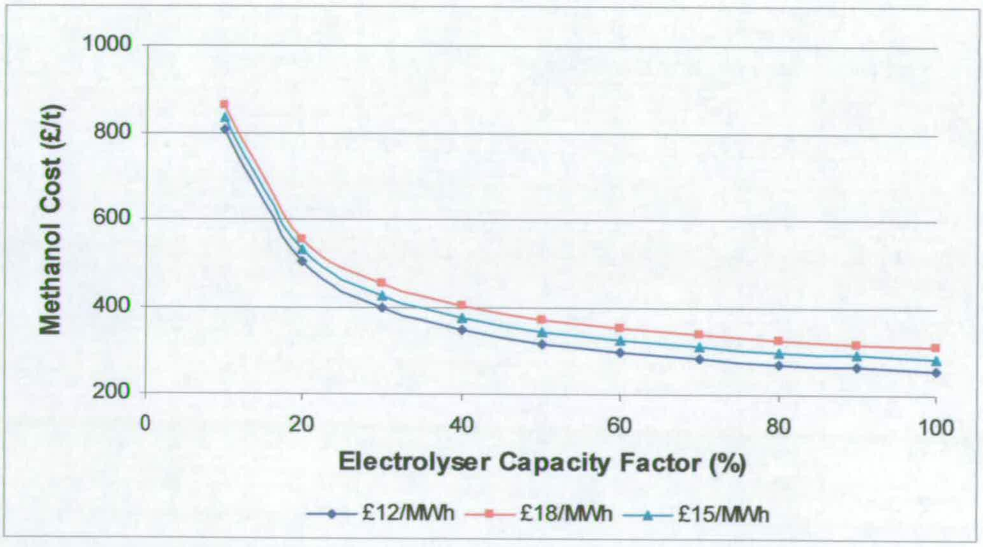

Figure 3.6 - Price of Methanol with Power Capacity Factor (500MW electrolyser)

The cost of the methanol reduces significantly as the CF increases to around 50%, thereafter price reduction is less than 10% for any increase in CF. An appropriate minimum CF would therefore need to be at least 50% - 60% in order to achieve the best economic use of the electrolyser. The electrolyser capacity factor for the first design was 26%. Once the power rating of the electrolyser had been reduced to increase the capacity factor to 66.7% the cost of the methanol was reduced by over 25% to around £300/tonne.

To achieve an overall electricity capacity factor of 60% or more the type and location of the resource would need to be diverse. A wind power installation has a typical declared net capacity (DNC) of 43% in the UK[52] (i.e. the wind farm produces its rated output for 43% of the year). To increase the declared net capacity of a renewable energy supply wind farms would need to be placed across the country to try to take advantage of different weather systems at any one moment in time. Of course, if there is an anti-cyclone over the entire British Isles no output can be expected, even from a group of wind farms at opposite ends of the country. This factor is one reason why variable power supplies may need to be stored in an intermediate media to buffer this variability and uncertainty. This topic is discussed in detail in Chapters 4 and 5.

3.6.3.3 Electricity Cost

Finally the influence of the cost of the electricity was investigated. Figure 3.7 shows the relationship between the energy cost of the product cost of methanol.

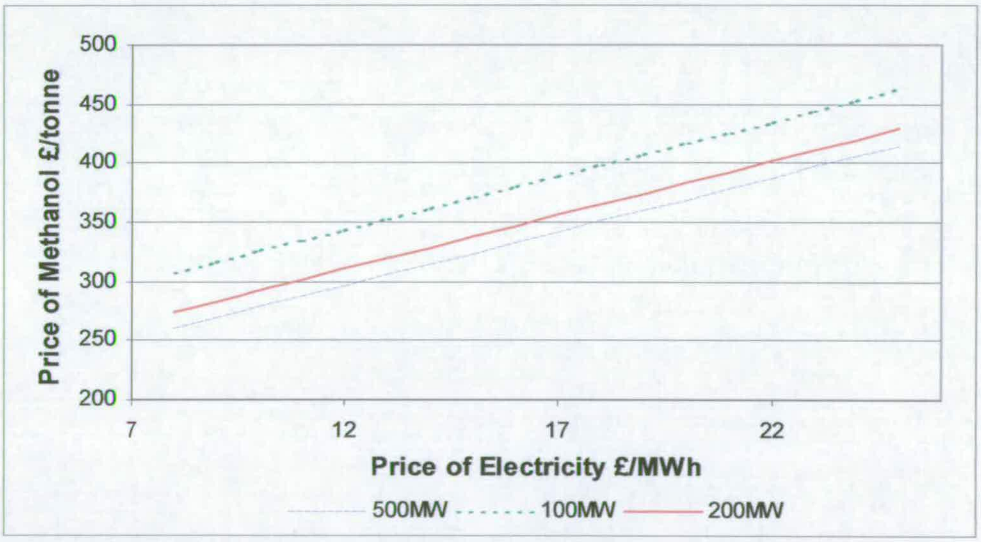

Figure 3.7 - Price of methanol with Price of Electricity (60% capacity factor)

As the electricity requirement for the hydrogen process is very high (~9MWh needed per tonne of methanol) the cost of the electricity is the dominant operating cost. For every increase in the unit cost of electricity of 1p/kWh there is a £9/tonne increase in the cost of methanol. Therefore the cost of the electricity should be kept as low as possible to minimise the cost of the methanol.

3.6.4 Capital Investment Appraisal

The methanol process cost model provided a means for estimating suitable operational criteria in terms of the approximate end cost of the methanol, however, it did not give an accurate representation of whether the process would be able to be profitable. Therefore the NPV analysis of the process was repeated for a range of electricity costs, electrolyser rating and operating regimes.

3.6.4.1 Net Present Value

NPV analysis returns the value of a project to an investor, over and above the opportunity cost of capital to that investor. NPV forecasts the future net flow as capital and discounts them to present values using the investor opportunity cost as the discount rate. NPV can be summarised as:

$$NPV = \sum_{t=1}^{n} \frac{A_t}{(1+r_d)^t} \tag{3.28}$$

where A_t is the net cash flow for period t, r_d is the financial discount rate and t is a specific year of a n year project lifetime. All projects with a positive NPV are accepted as being wealth creating.

NPV calculations were carried out for different operational parameters of the process. To investigate the criteria required for the process to be a viable investment opportunity. It was assumed throughout that the electrolyser had an average capacity factor of 60%. This figure was chosen as a compromise between requiring a high availability of electricity to offset the high capital cost of the electrolyser and the realistic load factor of current renewable energy technologies.

3.6.4.2 Capital Investment Appraisal Results

The renewable methanol is competing against conventional methanol production techniques. Current methanol prices are around £150/t, equivalent to approximately 15-16p/litre[53].

The first graph (Figure 3.8) shows the NPV values for different selling prices of the methanol. The renewable electricity supply was assumed to be an average of £15/MWh.

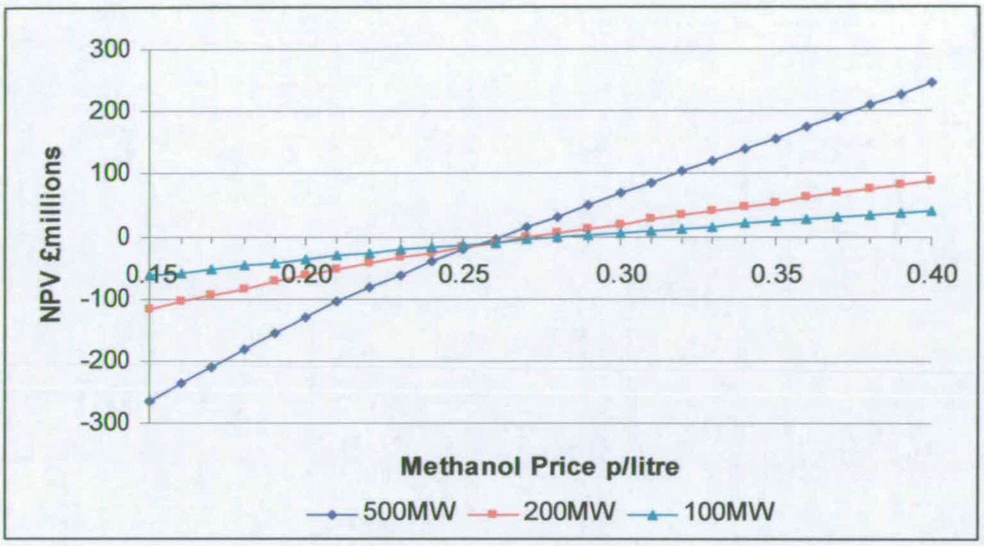

Figure 3.8 - NPV with methanol price

The results show that the renewable methanol process is viable if the methanol can be sold for at least 26p/litre if the electricity supply is an average of £15/MWh. If the average electricity price increases the selling price of methanol would also need to increase. Repeating the NPV calculations, this time investigating the effect of different electricity costs and the selling price of the methanol. It was assumed that the electrolyser capacity was 500MW and the capacity factor 60%.

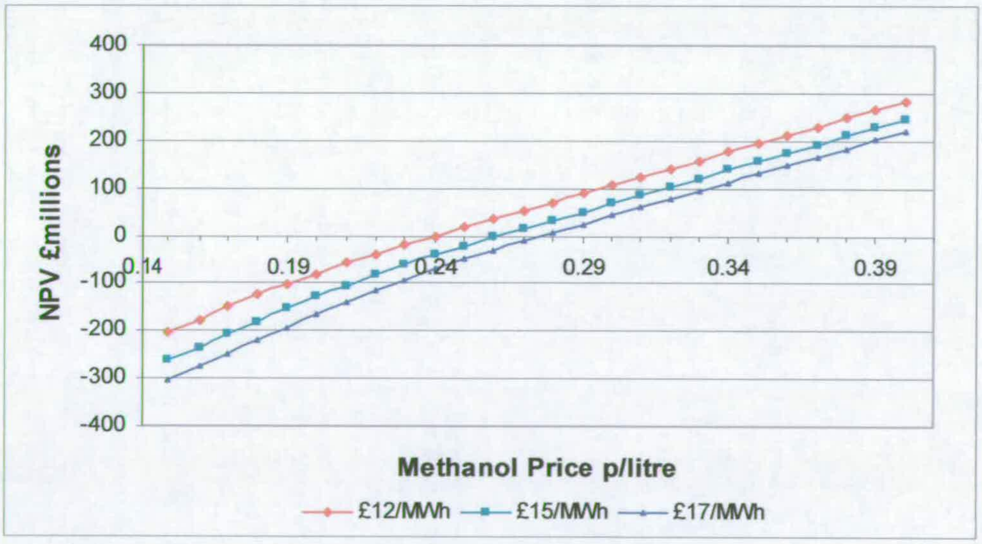

Figure 3.9 – NPV with methanol price

For a 500MW electrolysis unit operating for 60% of the year, a 20% decrease in the electricity price (from £15 to £12/MWh) the break even NPV point lowers to 24p/litre from 26p/litre and 7.5% reduction. It is clear from these result that the cost of the electricity supply dominates the methanol cost.

The renewable methanol process become much more economically viable the lower the average electricity supply cost become. Figure 3.10 shows the effect of the electricity supply cost to the NPV values, assuming the methanol is sold at twice the current rate of 15p/litre.

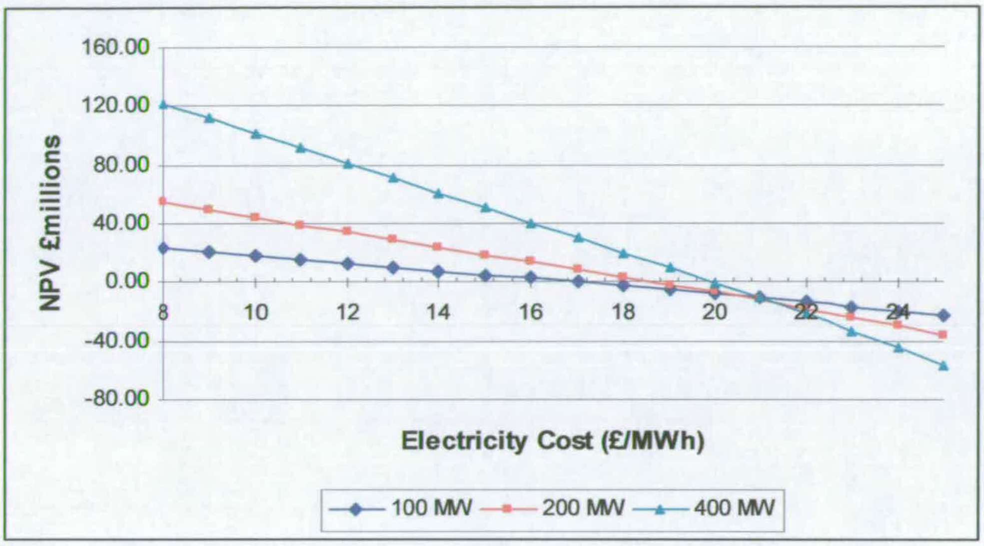

Figure 3.10 – NPV with electricity price (methanol 30p/l, CF 60 %)

3.7 Feasibility of Renewable Methanol

From the results of the economic analysis, it has been shown that renewably produced methanol can be produced for around twice the cost of conventional methanol, given a low cost electricity supply. If the methanol were to be sold on the open market it would be uncompetitive with conventional methanol production techniques. However the process has some important attributes that could alter the market.

Firstly the process sequesters CO_2 that would otherwise be emitted into the atmosphere. As discussed in Chapter 2 the Government is committed to reducing CO_2 emissions. This approach of using waste CO_2 to produce a versatile and sustainable fuel has a capacity to reduce overall CO_2 emissions.

Additionally, the process uses renewable energy. As part of the Government's commitment to CO_2 reduction, renewable electricity generation is being encouraged (Chapter 4). Nonetheless, there are difficulties and limitations to large scale renewable energy integration and this process could offer a viable solution to these problems. However, other carbon dioxide sequestration techniques and low carbon technologies exist that rival the renewable methanol.

With the drive to lowering CO_2 emission, carbon intensive fuels such as coal are less attractive. However, depending on fewer, potentially less secure fuels, is not an ideal situation either. By capturing the CO_2 produced from coal power stations, the environmental targets can be achieved and security of supply maintained. Chapter 5 describes the issues surrounding security of supply and shows how security can be measured and maintained and whether coal is a necessary technology.

Reducing CO_2 emissions and increasing levels of renewable energy into the electricity system through methanol production are only worthwhile once the technical limits of renewable energy integration have been reached. The CO_2 that can be avoided by renewable electricity use directly is greater than the methanol production technique. Therefore there is no carbon benefit with using renewable energy if it has an alternative market. Also, the price paid to renewable energy is much higher than the methanol production technique can afford. If it can be assumed that renewable energy produced that can't be accepted into the network is made available to the methanol production process at a low price, it is here that the renewable methanol production technique could be viable.

The electrical conversion efficiency of the process in terms of renewable energy is between 58% and 68% (Section 3.5.3) depending on the source of the waste heat required for the CO_2 separation. The efficiency is much lower if energy from the power plant needs to be used to create the low pressure steam. Process energy efficiencies therefore could be higher if the CO_2 removal is integrated into the power plant rather than when an existing station is retrofitted with CO_2 separating equipment. The capital costs of the CO_2 separation equipment required around 10% of the total. If the power plant were to have CO_2 separation equipment fitted so as to avoid CO_2, and other pollutants being emitted the methanol production process could make use of a small amount of the separated CO_2. This would improve the efficiency of the methanol process to the higher calculated value of 68%. However, the cost of the methanol would not be reduced by much as the costs of the electricity and capital costs of the electrolyser dominate.

Methanol is a versatile commodity with many uses and the renewably produced methanol is sustainable and carbon neutral. The overall energy efficiency of renewable methanol depends upon its use. If the methanol was to be used for storing electrical energy for conversion back into electricity through a thermal power plant (~30% efficient), the efficiency on the entire process reduces to around 20%. This results in 5 times the level of electrical energy to be stored therefore causing the price of methanol fuelled electricity generation to be up to 5 times the conventional electricity cost.

Methanol can also be used as a vehicle fuel and hydrogen carrier for use in fuel cells. The overall conversion efficiency from the renewable electricity to useful work is also around 20%, the value of the fuel is greater and therefore the poor efficiency may not result in poor economics. Chapter 6 discusses the economics of environmental protection and the economic instruments that could be applied to different applications for the renewably produced methanol to make it a viable technology are discussed.

3.8 Summary

The chapter introduces a novel methanol production method that uses waste CO_2 and hydrogen produced using renewable energy. The production process uses proven and mature technologies and there is little uncertainty of whether it could be constructed and operated.

The renewable methanol process offers a medium for renewable energy storage and carbon dioxide abatement which could improve the security of energy supplies in the UK. However, the process requires high levels of renewable electricity for use in the electrolysis process and the supply profiled of the electricity has a large influence on the final cost of methanol. The conversion efficiency of the electrical energy to methanol is around 50 to 68%. If the methanol is used to generate electricity the overall efficiency drops to around 20%. This means that 5 times the level of electricity needs be stored in the methanol than is created from the electricity generation. This is not a realistic proposition for large scale energy storage. However, other applications for methanol use have higher conversion efficiencies. These are investigated in section 6.3.1.

An economic model was developed to investigate the economic penalties of operating the systems at less than full capacity. Results from this analysis showed that for the process to achieve an acceptable economic operating levels there needs to be electricity supplied at a capacity factor of at least 60% To achieve this, the type and location of the resource needs to be diverse. Once the problem of supply can be overcome the other problems relating variable electricity supply can be overcome.

The methanol production process has limited capability to sequester carbon dioxide: less than 1.4 tonnes CO_2 per tonne of methanol produced. The renewable electricity used in the process (~9MWh) can avoid a larger amount of CO_2 (3.6 tonnes) if used directly rather than converted into hydrogen, therefore there is only a carbon dioxide reduction benefit if the renewable energy would otherwise be wasted.

Chapter 4

Reducing Carbon Dioxide Emissions

Privatisation of the generating assets, liberalisation of the distribution businesses and changes to the trading arrangements have successfully increased competition and lowered electricity prices in the electricity supply industry (ESI). However, of the three main energy policy goals the most challenging to the ESI is the need to reduce carbon dioxide emissions.

The CO_2 reduction targets proposed range from the 12.5% international target to the more ambitious 20% domestic on 1990 levels by 2010. The equates to a reduction of around 20 to 32 million tonnes of carbon (MtC) or 75 to 116MtCO_2. The ESI is often the focus of attention when considering emissions reduction as CO_2 is emitted from large point sources rather than dispersed sources such as transport or agricultural sectors.

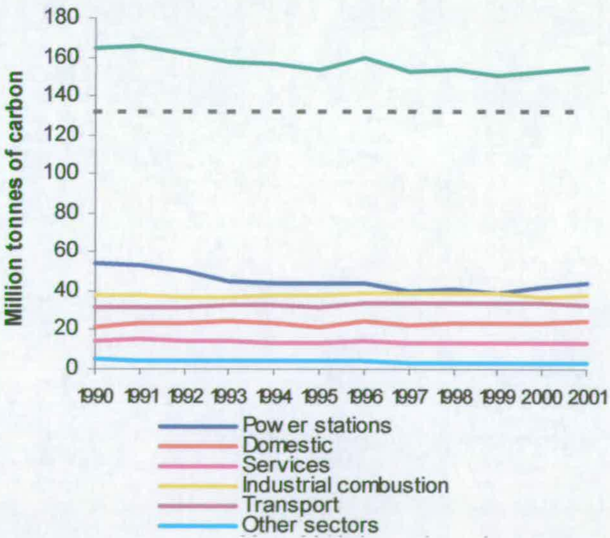

Figure 4.1– UK Carbon Dioxide Emissions source[54]

Power generation contributes only a third of the total UK CO_2 emissions (around 42MtC)[55], yet it has been the sector that has contributed the greatest reduction since 1990 – just under 20% (Figure 4.1). As described in Chapter 2, reductions in CO_2 emissions during the nineties were a result of economic decisions to invest in gas generation over coal generation rather than environmental motivations and cannot be used as a marker for further decreases in emissions.

There are several approaches to reducing atmospheric CO_2 concentration which affect different aspects of the carbon cycle. With respect to the ESI the options to reduce CO_2 emissions fall into three main categories:

- by reducing emissions through fuel switching or increased efficiency in fossil fuel use
- by producing electricity from resources which do not emit CO_2
- by capturing the CO_2 before or after combustion and storing it

4.1 Energy Use and Carbon Dioxide Emissions

The growth in world population and higher standards of living has resulted in an enormous increase in energy use over the last fifty years and a corresponding rise in carbon dioxide emissions. As societies become wealthier an increasing variety and volume of products and services are manufactured and provided. Electrification brings a marked rise in energy consumption as the use of a wide range of appliances becomes available which reflects the convenience of electricity as a form of energy. People want higher levels of illumination, they want their homes and places of work to be warmer in the winter and cooler in the summer. Many coveted activities and possessions are linked to high levels of energy consumption such as larger homes, long haul flights and more powerful cars.

By using fossil fuels more efficiently more energy or useful work can be obtained for the same level of CO_2 emitted. Greater efficiency in terms of CO_2 emissions can be made through substituting a fuel for one with a lower carbon content, e.g. by substituting coal fired plant for gas, through using more efficient electricity generation methods or by using the low grade heat produced during the steam cycle to displace the demand for other heating sources. Figure 4.2 shows the decrease in CO_2 emitted per unit of electricity generated since 1970.

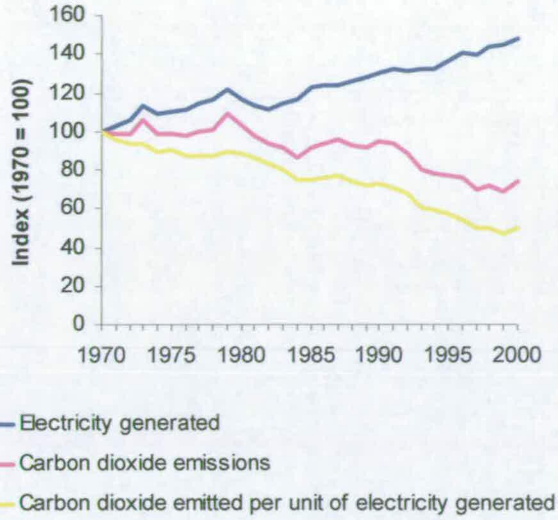

Figure 4.2 - Power station emissions of carbon dioxide, 1970 to 2001[56]

Emissions of CO_2 from power stations have fallen 23% since 1970, whilst electricity generation has risen 52%. CO_2 emissions per unit of electricity generated have halved since 1970, as a result of the switch from coal to gas, improvements associated with the efficiency of power stations and the contribution of nuclear power. The small increase in CO_2 emissions since 1999 is due to the increased use of coal for generating electricity.

4.1.1 Increasing Energy Efficiency

Using energy more efficiently can offer much to energy policy goals. Obviously the lowering of demand may not have a direct effect on greenhouse gas (GHG) emissions as this is dependent on the fuel mix and technologies used to generate the electricity, however, there is scope within the ESI to produce electricity more efficiently in terms of energy produced per unit of carbon released to the atmosphere.

A distinction needs to be made between energy conservation and energy efficiency. The former implies 'making do' with less energy, for example by turning thermostats down and tolerating lower temperatures. The latter is achieved through obtaining more useful heat, light or work for each unit of energy supplied through technological improvements, simply obtaining the same services or level of utility with less energy. Attempts to protect the environment and prevent climate change through pressuring people to make sacrifices in comfort, pleasure and convenience in order to cut energy use are unlikely to be successful.

The domestic household's share of the UK energy consumption is second only to transport. Four fifths of this share is for heating and lighting requirements. Simple steps such as increased insulation, low energy bulbs and efficient heating systems could lower demands in this sector. Low energy light bulbs for example are offered to domestic customers at a discount from several electricity suppliers in the UK. These cost effective options are not being taken up as quickly as may be expected. An explanation for this that households or businesses making the investment decisions do not believe that the efficiency measures are as cost effective as expected[57] or other non-economic factors such as aesthetics deter consumers.

4.1.2 Combined Heat and Power

Beyond a certain point, determined by the law of thermodynamics and the Carnot cycle, the efficiency with which energy can be converted from fossil fuels cannot be further improved unless the low grade heat produced as a by-product of the energy conversion process is used. Combined heat and power plants (CHP) use this low grade heat to provide space and water heating for a local demand. The conversion efficiency of CHP depends upon the heat to power ratio but it can be as high as 70-80%. CHP can be run on a number of fuels, gas and oil being the most common with a number of renewable or waste sourced CHP plants.

CHP is not a new technology. Scandinavia has many long-established CHP district heating systems powered by forest wastes and in the UK industrial and commercial units have also installed them for high-energy processes and loads. In the UK, CHP is still considered an emergent technology in that the installed capacity is still modest at around 4.5GWe[58]. This level is set to increase as a result of a government target to have 10GWe of *good quality* CHP installed by 2010.

The capital costs of domestic CHP are high due to the necessary heat transfer infrastructure that needs to be installed in addition to the power generation unit. These costs are offset through the savings in energy bills but it is one factor holding back the development of CHP in the UK, especially when energy costs are as low as they are at present. A further barrier to CHP has been the regulatory measures put in place to encourage renewables yet none to promote the energy saving and inevitable carbon saving benefit of CHP. The UK has a large untapped potential for CHP and reaching the 10GW target would contribute over 25% of the UK domestic target of a 20% reduction in CO_2 emissions by 2010. If CHP is to make a greater contribution, the following will be needed:

- reform of the electricity network regulations to encourage distributed generation,
- the creation of a CHP obligation, in the same terms of reference as the Renewable Obligation,
- the complete, rather than partial exemption from the climate change levy
- and the inclusion of emissions permits or credit to the UK emissions trading schemes

4.2 Nuclear Power

A range of technologies for electricity generation exist that do not produce CO_2 in large quantities or operate using sustainable fuel sources (i.e. producing no net carbon gain). One of these generation types is nuclear power.

Nuclear power is the generation of electricity using the heat released during fission of atomic nuclei to power the steam cycle. Nuclear power is a well established source of electricity generation producing about 25% of the UK's electricity. Nuclear power is a large-scale power source that produces no greenhouse gases (GHGs), the reduction of which is one the key components of the UK energy policy.

In terms of the UK energy policy it is the decommissioning of current nuclear capacity that is creating problems for the future. Many of the nuclear stations in the UK are reaching the end of their useful life and over the next 20 years all but one plant will be decommissioned. shows the current UK capacity and expected decommissioning date (Table 4.1).

Nuclear Station	Type	Capacity MW	Decommisionng Date
Hinkley Point A	MAGNOX	470	closed 2000
Bradwell	MAGNOX	470	closed 2002
Dungeness B	AGR	1110	2006
Dungeness A	MAGNOX	450	2006
Sizewell A	MAGNOX	420	2006
Calderhall	MAGNOX	168	2006
Oldbury	MAGNOX	434	2008
Chapelcross	MAGNOX	168	2008
Hinkley Point B	AGR	1220	2011
Wylfa	MAGNOX	980	2011
Hartlepool	AGR	2014	2014
Heysham 1	AGR	1150	2014
Heysham 2	AGR	1250	2023
Torness	AGR	1250	2023
Sizewell B	PWR	1188	2035

Table 4.1 - UK Nuclear Capacity[59, 60]

Nuclear power contributes around a quarter of the UK's electricity and this capacity must be replaced. During the government consultation prior to the publication of the energy policy white paper[61] there was a strong lobby to replace the decommissioned nuclear plant with new nuclear capacity, citing emissions reduction and security of supply issues as reasons. Despite the publications of the Energy White Paper the decision on the future of nuclear has yet to be resolved.

The supply of uranium is still plentiful and it can be stored. The energy that can be produced from one tonne of natural uranium exceeds 40 million kWh. This compares to over 16,000 tonnes of coal required to produce the same amount of energy. Nuclear power not only can avoid the release of CO_2 but also provide a certain level of security to electricity supply.

4.2.1 Nuclear Technologies

There are many different types of reactors in nuclear power stations. The differences between types of plant are the coolant and the moderator. Table 4.2 shows the different types of reactors currently in operation.

Reactor	Coolant	Moderator	Fuel Type & Enrichment (%U-235)	Electrical Output (MW)	Thermal Efficiency
PWR	Water	Water	Uranium oxide 1.6% to 4.5%	160 - 1380	32%
BWR	Water	Water	Uranium oxide 1.6% to 4.5%	75 - 1300	32%
MAGNOX	CO_2	Graphite	Metallic natural uranium	50 - 420	27%
AGR	CO_2	Graphite	Uranium oxide 2.7% to 3.4%	600 - 625	41%
CANDU	Heavy Water	Heavy Water	Uranium oxide non-enriched	220 - 935	34%

Table 4.2 – Nuclear generation technologies[62]

Worldwide, 56% of power reactors are PWR (pressurised water reactors), 22% BWR (boiling water reactors) and 6% pressurised heavy water reactors, mostly CANDUs (Canadian D_2O/uranium). The first reactors in the UK built in the 1950s were Magnox plants with research and build focus moving onto advanced gas-cooled reactors (AGRs).

Several new designs are being developed which are simpler, more fuel efficient and cheaper to build and operate. Of these new designs some have evolved from existing designs taking into account the experience gained from their operation over the years and advances in fuel design. Others are not based on existing designs and therefore still require demonstration units to be accepted before commercial construction could begin.

Worldwide there are few nuclear power stations under construction and some have been left partly built. This is mainly due to the resistance from the environmental movement, in particular since the Chernobyl disaster in 1986, but there is also the fact that it is currently not as competitive as other conventional sources of electricity such as gas-powered stations.

4.2.2 Nuclear Wastes

The greatest problem regarding nuclear power is the unresolved issue of the safe, long term disposal of radioactive waste. At the moment there is no firm UK policy with regards to the very long term management of nuclear generation by products. The UK Department for Environment Food and Rural Affairs (DEFRA) initiated a review of nuclear waste management[63] with the aim of reaching a public consensus.

The storage and disposal of nuclear waste is not technically difficult as the Finnish nuclear waste disposal experience shows[64]. Over the last 20 years the Finnish have brought into commission over-ground and underground waste storage facilities for medium and low level wastes. They have also identified a site for the ultimate disposal of the spent fuel which is high level waste and have governmental and community support for this. The progress has been made in terms of a national energy policy that reviewed the needs for electricity over the next few decades. A decision was made to build their 5th nuclear reactor to be located at one of the two existing nuclear plants.

The Finnish experience has addressed the two imperatives of energy policy, that is the security of supply and the environment. They have devised solutions to all aspects of the nuclear waste and have moved on from debate and consultation to action and implementation.

The implication for the UK is that if there is to be a continued contribution for nuclear in future a resolution of the permanent waste facilities issues a essential. Without this resolution other important issues such as public acceptance and investor confidence will be difficult to achieve.

4.2.3 Cost of Nuclear Power

A further disadvantage of nuclear power is the cost of the power generated. One of the main arguments against further nuclear generators is that in the new liberalised markets is that is uncompetitive in comparison to other generation types, in particular gas fired plant. Nuclear generation operates with relatively high fixed costs and low marginal costs when compared to other generators and it has long term liabilities for the decommissioning of nuclear stations. This makes the nuclear industry's revenue stream very susceptible to changes in the prices of electricity.

Published unit costs of nuclear electricity vary depending upon the source of information. Evidence from industry gives costs of new generation of between 2.2-3p/kWh[65]. Analysis from the Performance and Innovation Unit (PIU) estimates costs in the range 2.5-4.0p/kWh in 2020[66], with industry estimates at the lower end of the range. The cost is predicted on the basis of series build, rapid construction, good operating performance and low discount rates.

If nuclear were to qualify for environmental exemptions, the economic situation of nuclear could be made more favourable. It is argued from within the Nuclear Industry that the costs of waste management and decommissioning would be taken into account, with the unit electricity cost reflecting these necessary measures. If the external costs of other generators types were taken into account to ensure that all generators pay to deal with their own waste.

One strength of nuclear power is its insensitivity to increases in fossil fuel prices. Another is its absence of gaseous emissions. Either feature could make nuclear power an entrant in competitive markets if there are substantial changes in fuel prices or environmental policies.

4.3 Renewable Energy

As a part of the UK's climate change policy several statutory measures have been created to encourage the development and integration of renewable energy into the ESI. The Non Fossil Fuel Obligation (NFFO) and corresponding Scottish Renewable Obligation (SRO) were introduced. These measures aimed to encourage a greater share of the UK's electricity to come from renewable sources. Over five rounds during the 1990s, renewable energy developers were asked to submit proposals for renewable energy generation. The additional costs of renewable energy production would be guaranteed for 15 years paid for through the fossil fuel levy (Chapter 6).

Currently, targets for renewable energy integration are set at 10% of UK electricity demand to be met by renewable sources by 2010[67], with a further increase to 40% by 2050[68]. As a short term goal the 10% target is an important step for renewable and alternative energy development. Although renewable energy technologies differ in terms of their level of technical maturity and running cost, it is widely accepted that experience and expertise in the operation, construction and management of such systems play a vital role in the lowering the cost. Furthermore, greater manufacture and operating efficiencies can be achieved over time. There still remain problems associated with renewable energy which must be addressed before large scale renewable energy integration can become a reality.

This section describes the major renewable energy technologies used in electricity generation, their relative costs and maturity, and discusses the barriers to higher renewable energy usage that still remain.

4.3.1 Hydro Power

Hydro power contributed around 1% of the UK's electricity requirements in 2001 and is the most well established of all the renewable technologies[69]. However, the scope for further development of large scale hydro is small. Large-scale hydro power schemes require the construction of dams to create reservoirs, so changing the appearance and ecology of the immediate area.

The scope for further deployment lies in installing new systems and upgrading existing systems. Further exploitation of hydropower is likely to be based on the use of small scale units, including run of river schemes, typically generating tens of kilowatts up to a few megawatts.

4.3.2 Solar Energy

Solar energy is the basis for most of the renewable energy sources. It can also be directly utilised, even in climates such as that enjoyed in the UK. The main ways of using solar energy are:

- Photovoltaic arrays
- Active solar heating
- Solar thermal-electric generation

4.3.2.1 Photovoltaic Arrays

Photovoltaic (PV) arrays convert solar energy directly to electricity in solar cells. The electricity generated is a direct current proportional to incident light levels. For other than the most basic uses, PV cells need to be supported by electronic systems to convert the power to alternating current and to regulate the voltage.

The main applications for PV in the UK are in consumer products (calculators, garden lights) remote professional applications (telecom relay stations, weather and traffic monitoring, navigational aids) and street furniture (parking meters, bus stops, street lighting). These applications are already commercially attractive, but an area of growing interest, is PV integrated into or attached to houses and other buildings. PV will require Government support as its cost is high(> 7p/kWh[70]) in comparison to conventional sources.

4.3.2.2 Active Solar Heating

Active solar heating converts the solar radiation into heat which can be used directly or stored for future use. Active solar heating does not produce electricity but can lower the demand for electricity for heating. Due to the UK climate active solar heating is best suited to low temperature water heating such as hot water heating. Panels fitted to the roof of a structure are used to capture the solar radiation and water passes through them absorbing the heat energy.

4.3.2.3 Solar Thermal-Electric

There have been small research studies to develop solar thermal-electric technology, in which mirrors are used to concentrate the sun's heat to generate steam for electricity generating turbines. The complications of the plant make this unlikely to be a cost-effective way of generating electricity within the foreseeable future in the UK.

Overall solar energy has a small role to play as a power source in the UK, but a significant one. The use of solar panels either PV or solar heating, could help meet the increasing electricity demand, but solar is unlikely ever to contribute more than a few percent of the UK electricity demand.

4.3.3 Biofuels

Biofuels refer to the range of fuels which are derived from plants and the waste from animal husbandry. They include:

- agricultural and forestry residues and by-products
- energy crops
- landfill gas and municipal solid wastes (MSW)

The direct combustion of biofuels or the combustion of the methane gas produced during decomposition of biomass and waste material can be used to produce electrical power. Biomass absorbs carbon dioxide during growth therefore can be considered CO_2 neutral as it balances the CO_2 emitted during combustion.

4.3.3.1 Agricultural and Forestry Residues

The residues and by-products from farming and forestry fall into two main groups: dry materials such as forestry residues, straw and poultry litter; and wet materials such as green agricultural wastes (e.g. root vegetable tops) and farm slurry. The first group can be burned to produce energy. The second group, because of its high water content, is best used to produce a methane-rich biogas via the process of anaerobic digestion.

Current estimates suggest that the availability of agricultural and forestry residues is, in practice, limited. Residues equivalent to 2TWh/year could be available by 2010[71]].

4.3.3.2 Energy Crops

Growing energy crops will be essential if the UK wishes to generate significant quantities of energy from biomass. The crops fall into two categories: perennials such as trees and grasses, and annuals such as oilseeds, cereals and sugar-bearing plants.

Coppiced willow, grown on a 2-4 year rotation, is the most advanced energy crop for northern European conditions. Commonly referred to as Short Rotation Coppice(SRC) the crop is established by planting cuttings at the rate of 10-15,000/ha. One year later, these are cut back close to the ground, which causes them to form multiple shoots, i.e. to coppice. The crop is allowed to grow on for between two and four years and is then harvested by cutting the stems close to ground level. The cut stems themselves form multiple shoots that grow on for a further 2-4 years to become the next harvest. This cycle of harvest and re-growth can be repeated many times. Repeated cutting of the shoots maximises growth rates and ensures that the stems remain thin enough to harvest mechanically at a rapid rate.

A demonstration 10MW wood chipped fuelled plant at Eggborough is using SRC willow from a 45 kilometre radius of the plant. A total of 488 hectares has been planted with willow and this is expected to provide 65-75% of the 43,500 dry tonnes needed pee year[72].

Perennial grasses, such as miscanthus and switchgrass, are also potential energy crops. Their cultivation would result in less of a change for farmers than wood crops as they can be harvested and baled annually using equipment developed for cereals. They have the potential to give a high yield (15-30 dry tonnes pa compared with 10 –15 for SRC[58]) but in the UK they are still at the development stage and deployment is limited to research plots and small trial areas.

The oil from oilseed crops such as rape and soya is used in several EU countries and in the US as a feedstock for producing diesel oil substitutes. Sugar and starch-bearing crops such as beet and cereals can also be fermented to produce ethanol for use as a road fuel[58].

Under the NFFO and SRO contracts electricity production through the gasification of willow such as the Eggborough plant were supported. This achieves a cleaner and more efficient combustion than direct burning. Estimates of the total UK resource depend upon the available land given up from arable farming to the cultivation of energy crops. NFFO contracts were awarded to energy crop projects with a total capacity of 86 MW, and at prices in the range 5.5-8.7p/kWh[73].

4.3.3.3 Landfill Gas and MSW

Landfill gas is produced when the organic component of domestic and industrial wastes decompose. The use of the gas produced as organic wastes decompose has a double benefit. The gas produced contains a high level of methane, a gas that has a far greater global warming potential than the CO_2 produced during combustion and it can provide a continuous supply of fuel for some decades. Landfill gas is produced within one year of tipping and the gas is collected by means of a network of interconnected perforated pipes. Installations can vary in size from 100kW up to 2MW.

The total potential of waste combustion and landfill gas combined is limited by the total amount of waste produced. Although the split between the two sources may be uncertain, the total resource available at economic cost is estimated to be between 2.6 and 3.4% of UK electricity demand in 2010[56].

4.3.4 Wind Energy

The weather which the UK experiences produces one of the largest wind energy resources in Europe. With such favourable conditions, the exploitation of this resource as a sustainable energy supply could help achieve national renewable power and carbon dioxide reduction targets. As a result of investment in research and operating experience, especially in Europe, wind power has become one of the most technically mature renewable energy resources.

Wind turbine generators are designed to convert the kinetic energy of the wind into electricity. A typical wind turbine will start to rotate at a wind speed of around 3-4ms^{-1} known as the *cut-in* speed, depending on the individual turbine design and will increase its rotational speed until it reaches its maximum running speed at which it produces its maximum power. The turbine will continue to produce its rated power until it reaches its cut-out speed. To protect the turbine from damage the wind turbine has a *cut-out* speed of between 17-25ms^{-1}.

4.3.4.1 Onshore Wind

With the exception of hydro power, onshore wind energy is the most mature renewable electricity source. Worldwide there is around 20,000 MW of installed capacity, 75% of this is in Europe. Currently, there is approximately 530MW[74] of installed capacity in the UK. Despite having some of the best resource in Europe growth has been slower than other European countries such as Germany and Spain.

Wind power has benefited greatly from the NFFO and SRO orders and cost of generation has reduced from around 4.8p/kWh during the third round of NFFO to 2.88p/kWh during the fifth round[75]. However, many NFFO and SRO projects have failed to be developed.

The difficulty in the commissioning of NFFO wind projects is blamed on the complexity facing developers when applying for planning permission. Opposition from local residents over visual impact and noise pollution, though often over exaggerated, is preventing many of the wind projects from proceeding. The government must intervene and provide stronger guidance for local authority and also try to raise awareness of the environmental benefits of such schemes, in order to attain a higher success rate.

4.3.4.2 Offshore Wind

To overcome the problems of local residents complaining about visual impact etc, developing wind farms offshore seems to provide a solution. The development of offshore wind farms is receiving the most attention as a way of reaching the UK government's 10% renewable energy target. Offshore wind farms are an adaptation of onshore wind farms. The turbines are conceptually similar but they must maintain higher levels of reliability and be able to withstand less favourable conditions given the difficulty of accessibility for maintenance.

The move to offshore wind farms began with demonstration projects in Denmark, Holland and Sweden. Five were constructed between 1991 and 1997, the first at Vindeby in Denmark. The capacity of installed offshore wind power schemes in Europe now totals approximately 80MW, 3.8MW of which is in the UK, near Blyth[76].

4.3.5 Tidal Stream

Tidal streams are high velocity sea currents created by the periodic movement of the tides. These tidal streams are often magnified by local topographical features such as headlands, inlets to inland lakes, and straits and it is the capture of the energy in these tidal streams that is converted into electricity.

A variety of tidal stream energy conversion devices are currently being proposed or are under development. The most commonly used concept involves a water turbine similar to a wind turbine with a under sea cable to a land-based grid connection[77].

The technology is currently at the demonstration stage with a 150kW prototype of a tidal stream converter *Stingray* successfully installed and recovered by the Engineering Business in the Yell Sound near Shetland in 2002[78]. The Engineering Business are now in the process of making estimates for the construction and installation of a 5MW system.

4.3.6 Wave Energy

Wave energy is a concentrated form of solar energy where winds generated by the differential heating of the earth pass over oceans, transferring some of their energy to the water in the form of waves. This energy transfer can create a wave power level of 70kW per metre of crest length. This figure rises to an average of 170kW/metre of crest length during the winter, and to more than 1MW/metre of crest length during storms.

Wave energy converters extract and convert this energy into a useful form. The conversion usually makes use of either mechanical motion or fluid pressure, and there are numerous techniques for achieving it, e.g. oscillating water/air columns, hinged rafts, gyroscopic/hydraulic devices. The mechanical energy is then converted to electrical power using a generator. Direct drive generators, in which the motion of the wave is converted directly to electrical power, are now being considered.

Wave energy converters can be deployed either on the shoreline or in the deeper waters offshore. The shoreline resource potential is much smaller than the offshore potential. This is because there are few specific sites that meet the requirements for useful energy capture.

East-facing sites in the UK are unsuitable because of the limited energy associated with easterly winds, while bottom friction reduces power levels where the water depth is less than 80 metres. As a result, the inshore resource is typically less than one quarter of the deepwater resource.

Many different wave energy devices have been, and continue to be, proposed, and there is no consensus on the best approach or any certainty that this has yet been identified. While it is clear that wave power devices can be made to work, it has not yet been demonstrated that they can be made to work cost-effectively, with economically attractive prices for the electricity generated.

The UK has one of the best wave power resources in Europe and three projects have been awarded contracts under the third SRO, the first Renewables Order to be open to wave power[79]. Although the prices to be paid for the electricity from these three projects are commercially confidential, they are quoted as being higher than the cap price under the new Renewables Obligation, though not substantially so. However, these prices are well below the bid prices for UK wind power in the first round of the Non Fossil Fuel Obligation (NFFO) for England and Wales. They are also comparable with predicted electricity costs from the first offshore wind farms although, admittedly, the UK has a much greater experience of wind turbines, derived from their widespread use onshore.

The first of the SRO projects is now operational. This is the LIMPET device, a 500kW shoreline oscillating water column (OWC) deployed by Wavegen in Inverness on the Scottish island of Islay in November 2000[80].

In the second project, Ocean Power Delivery based in Edinburgh is developing *Pelamis*, a semi-submerged articulated device. At the time of writing this project is still ongoing, with the mooring for the 750kW full scale prototype being laid[81]. The *Pelamis* will be the first deep water, grid connected trial of a wave energy converter in the world.

The third SRO contract is for the Swedish wave power company called Seapower International. Their concept is called Floating Wave Power Vessel and will be installed in the waters of Shetland. The vessel is rated at 1.5MW and is expected to generate 5.2 GWh per year[82].

These three projects will generate a vast amount of valuable information which will improve the industry's understanding of the commercial prospects for these particular devices in the

UK, and of the key development issues facing wave power.

4.4 Renewable Energy in the UK

The UK is fortunate to have extensive renewable energy resource Table 4.3 shows the current status of renewable energy technologies in the UK, the current technical and commercial maturity and the potential contribution each technology has to be developed by 2010.

Technology		Current Output (GWh/year)	Estimated Gross Potential (TWh/year)	Potential Contribution to 2010	Technical Maturity	Commercial Maturity	Cost p/kWh
Hydro	large	4,584	7	1	5	5	na
	small	204		2	5	5	4.5 - 6.0
Solar	PV	5	19	1	4	3	6.0 - 7.0
Biofuels	landfill gas	2,679	283	3	4	4	2.7 - 6.5
	energy crops	870	187	3	3	3	3.7 - 8.6
Wind	onshore	1,251	318	4	4	4	2.9
	offshore	5	100	3	2	2	5.5
Tidal		0	40	2	5	5	3.4 - 6
Wave		0.05	700	1	1	1	na

Potential Contribution: 1 – Small potential 2 – Moderate potential 3 – High Potential 4 – Excellent Potential

Technical Maturity: 1- Experimental 2 - Demonstration 3 - Major improvement expected 4 - Minor improvements expected 5 - Little scope for improvement
Commercial Maturity: 1- Experimental 2 - Demonstration 3 – Initial commercialisation 4 - <10 years commercial 5 - >10 years commercial

Table 4.3- UK renewable Energy Utilisation and Resource[5770]

Yet there are a number of barriers that exist preventing the widespread integration of renewable electricity plants in the UK:

- Insufficient support for renewables
- Problems of network integration
- Problem of transmitting power to demand centres
- Issue of intermittency and generation scheduling

4.4.1 Support for Renewable Energy

Renewable energy and its development can be a contentious subject. Many renewable energy technologies require financial assistance to compete within the ESI. The disparity in cost between conventional generation and renewable resources was partly addressed through the NFFO and SRO schemes, with many technologies such as wind power bidding at lower prices in later rounds.

In addition to financial support the process of gaining planning permission for renewable installations, especially onshore wind farms is proving a barrier to its development. Opposition from local residents over visual impact and noise pollution, though often over exaggerated, is preventing many of the wind farms and other projects from going ahead. The government will need to intervene and provide stronger guidance for local authority and also try to raise awareness of the environmental benefits of such schemes, in order to attain a higher success rate.

Government targets for the increased exploitation of renewable energy have been set at 10% of the UK energy demand by 2010, approximately 35TWh per year. To meet these targets 65% of the NFFO contracts awarded so far would need to be commissioned. The commissioning success rate of these projects has been much lower than this. Of the 672 MW of projects in the third NFFO round only 237 MW have been commissioned which is a success of less than 40%.

NFFO and SRO have now been succeeded by the Renewable Obligation and Renewable Obligation Scotland as a mechanism for supporting the development and deployment of renewable electricity devices. Chapter 6 describes the policy and economic issues surrounding electricity generation and environmental objectives.

4.4.2 Connecting Renewable Energy

Historically, power systems developed from local generation supplying local demand to interconnected centrally controlled generation and dispatch. Large steam power stations (>50MW) are connected by the transmission network to demand centres feeding lower voltage distribution networks. The system operates effectively and reliably with fluctuating but known demand profiles being met by the coordination of many individual power stations and reserve and emergency plant being available in the case of faults occurring.

Generating units powered by renewable sources are generally much smaller (<50MW) than conventional fossil fuelled and nuclear plants. As a result of their size and also the geographical requirements of some renewable sources, the generators are connected to the lower voltage distribution network rather than the high voltage transmission network.

The result of connecting distributed generation units to the distribution network is creating a host of problems for the integration of renewable energy and is probably the key factor which must be overcome in order to achieve the high levels of renewable plants required to meet renewables targets.

Renewable resources are usually located in areas of low population density and consequently low energy demand. Currently, distribution networks are designed to transfer power from the higher voltage transmission networks to lower voltage demand centres, with the power demand reducing at nodes along a distribution line. Therefore, both real (P) and reactive power (Q) flows are generally from the higher to lower voltage levels. A schematic for such a system is shown in Figure 4.3.

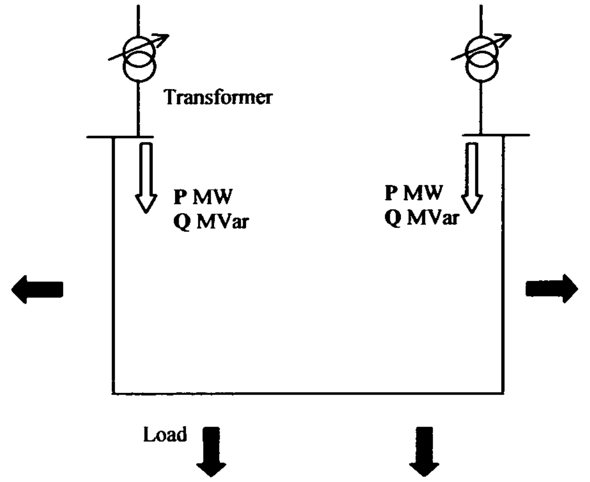

Figure 4.3 - Schematic of Conventional Distribution System

However with a significant level of connected distributed generation on the distribution lines the power flows may reverse and the distribution line is no longer a passive circuit supplying loads but an active system with power flows determined by generation as well as demand loads. An illustrative example is shown in Figure 4.4

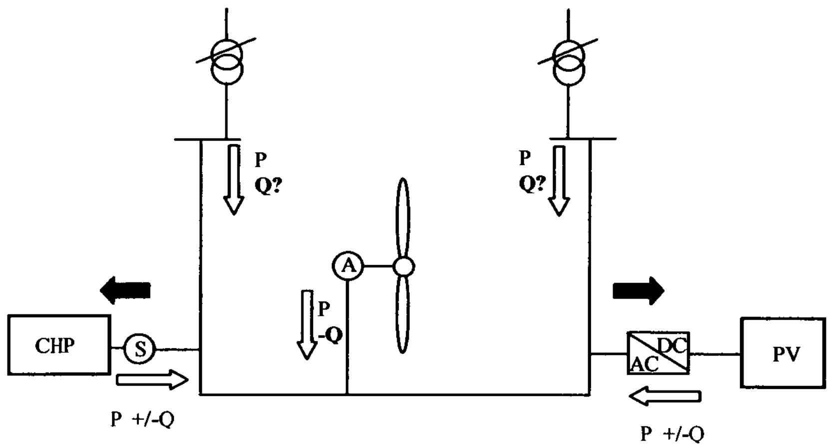

Figure 4.4 - Schematic of Distribution System with Distributed Generation

The Combined Heat and Power (CHP) plant with the synchronous generator, *S*, will export real power when the electrical load of the premises falls below that of the generator, but it may absorb or export reactive power depending on the setting of the excitation system of the generator. The wind turbine will export real power but requires a source of reactive power to magnetise its induction or asynchronous generator, *A*. The voltage source converter of the PV system will export real power at a set power factor but may introduce harmonic currents. Therefore the power flows through the circuit may be in either direction depending on the real and reactive network loads and generator output in the network.

Changes in real and reactive power flows in a distribution system caused by distributed generation has important technical and economic implications for the power system. Currently most attention is paid to the immediate technical challenges of connecting and operating distributed generation on the distribution network. Many countries have developed standards and practices to ensure distributed generation does not impinge on the quality of supply offered to other customers[83].

As levels of distributed generation are still very low and detailed system studies are undertaken to ensure that quality of supply is not affected, many distributed generators are treated as a negative load.

4.4.3 Technical Impacts of Distributed Generation

The technical impacts of distributed generator on the distribution systems are far reaching and can significantly alter the operation of a network. The following sections give on overview of some of the greatest technical barriers to distributed generation integration.

4.4.3.1 Network Voltage Changes

There is a statutory obligation placed on every distribution network operator (DNO) to supply its customers at a voltage within specified limits. This requirement determines the design and cost of the distribution circuits and therefore systems have been developed to maximise the use of the distribution network. Figure 4.5 shows a radial distribution feeder and a typical voltage profile along the feeder of such a system.

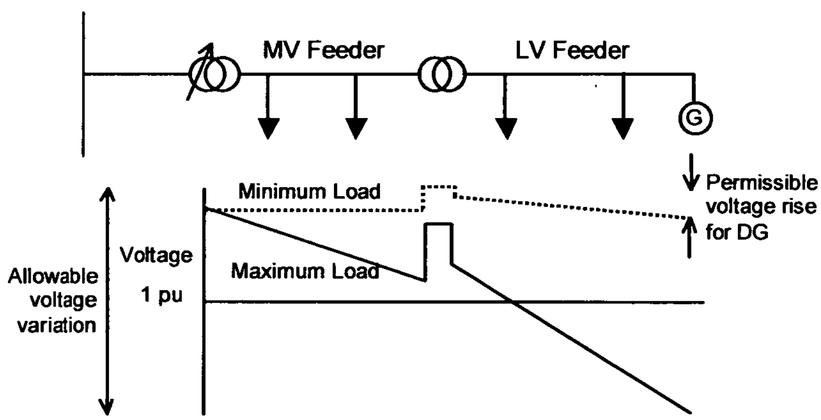

Figure 4.5 - Voltage variation along a radial feeder

The transformer between the medium voltage (MV) and low voltage (LV) lines has been set so that during times of maximum load the most remote customer will receive an acceptable voltage. During minimum load the voltage received by customer is just below the maximum allowed. If a generator is connected at the end of the distribution feeder power flows in the line will change, affecting the voltage profile. The *worst case* scenario is when the customer load on the network is at a minimum and the power generated flows back up the line.

It is sometimes possible to limit the voltage rise by reversing the flow of reactive power along the line by either using an induction generator or by under-exciting a synchronous machine and operating at a leading power factor. However, this is generally only effective on MV lines meaning only very small generators can be connected to LV circuits. Table 4.4 shows some of the design rules of connecting distributed generator to different locations in the distribution circuit.

Network Location	Maximum Capacity of Distributed Generator
on 400V network	50 kVA
at 400V busbars	200 - 250 kVA
on 11kV network	2 - 3 MVA
at 11kV busbars	8 MVA
on 15kV or 20kV network & busbars	6.5 - 10 MVA
on 63 to 90kV network	10 - 40 MVA

Table 4.4 - Design Rule Indicators for Distributed Generation Connection[79]

4.4.3.2 Increase in Network Fault Levels

Distributed generators, either induction or synchronous machines, will contribute to the network fault level, although their behaviours under fault conditions differ. In urban areas where fault levels almost reach switchgear ratings, there is little scope for distributed generation integration without the upgrading of protection equipment. Upgrading switchgear for distribution systems can be very expensive and currently in the UK the cost burden would be transferred to the generator.

4.4.3.3 Power Quality

Power quality is reduced by transient voltage variations and harmonic distortion of the voltage. Depending on the location and type of generator, distributed generation can either decrease or increase the quality of the voltage on the distribution network. Any disturbance on the public electricity supply (PES) network may result in annoyance to customers connected to the system or result in damage to equipment forming part of or connected to the system. In order to minimise the risk of such annoyance or damage occurring the Distribution Code stipulates limits for the levels of harmonic distortion, voltage fluctuations and voltage imbalance that may be tolerated[84].

Distributed generation can cause transient voltage variations on the network if relatively large current change during connection and disconnection of the generation occur. The magnitude of the current transients can be limited by careful design of the distributed generation plant. Power conditioning equipment can also be incorporated to overcome these effects, though at a cost.

4.4.3.4 Protection

Generation protection is fairly well understood yet the impact of a faulty generator on a network is more difficult to analyse and manage. The UK Electricity Association publishes recommendation documents referring to the connection of distributed generation, for example G59[85] and G75[86]. The protection required is intended primarily to protect consumers, supply authority personnel and the grid system by preventing the connection of distributed generation to weak networks.

Loss of mains protection is required to disconnect an distributed generator if the grid supply is interrupted in any way. Loss of mains and its detection is unacceptable due to *islanding* where, after a fault, a section of the network remains live. This is illustrated in figure below[87].

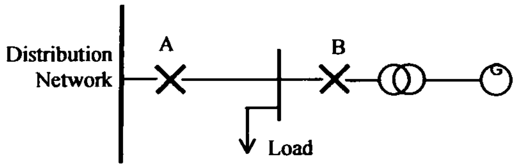

Figure 4.6- Schematic of Islanding Problem

If circuit breaker A opens there may be insufficient fault current to trip generator circuit breaker B. In this case the generator may be able to continue supplying the load. If the output of the generator is able to match the real and reactive load requirements there will be no change in the voltage or frequency of the *islanded* section. It would be very difficult to detected whether the circuit breaker is open or not by analysing local measurements.

4.4.3.5 Stability

The previous sections that have described the effects connecting distributed generation to distribution networks can have. Looking more towards the network as a whole, the issue of stability and distributed generation become apparent.

Stability comes about from high volumes of kinetic and thermal energy provided by steam plant being stored in the centre of the network. If large amounts of distributed generation are connected to a system with widespread frequency and voltage variations the problem of stability becomes greater. With inappropriate settings of protection equipment, if the grid frequency were to fall as in the case of the loss of a large generator, under-frequency relays would trip the distributed generates and further reduce the local capacity of system. This would allow the frequency to fall further and potentially the grid to collapse. Such a drastic occurrence is unlikely to happen in a robust and well interconnected system such as the UK, however, this must still be considered if large amounts of distributed generators were to be connected in weaker, more remote areas.

4.4.4 Network Operation

The electricity network has evolved to deliver power from large scale remote plants to consumers. The networks is made up of a number of high voltage transmission lines that carry power over hundreds or thousands of miles to the distribution networks. Increased levels of distributed generation that meet local demand will result in the power flows in the transmission network that change and the potential impact of renewable energy on the transmission system spans economic, technical and operational issues.

In a similar manner to the distribution system, distributed generation will affect power flows in the national transmission system. Referring back to the levels of renewable energy required to meet the government targets, if this were to be met by wind power alone over 10GW of capacity would need to be installed. Although this is a slightly unrealistic scenario, as there are other renewable sources that can make a useful contribution, currently only wind power and potentially wave generation have sufficient resource to meet a significant proportion of the energy demand in the UK The figure is high as the target relates to energy supplied not power capacity and as wind power is intermittent with a low declared net capacity (DNC) of around 0.3 to 0.36[88][57]. Intermittent or variable distributed generation can displace conventional on an MW basis but cannot provide firm capacity.

Figure 4.7 shows the UK–wide transmission network. From the diagram is can be seen that in the southern areas of the country there is a extensive network of high voltage lines, where the demand for electricity is greatest. Moving north up the country the system becomes less dense and the transmission network become more radial as it reaches the north of Scotland.

Figure 4.7 - UK Transmission Network and Power Stations[89]

Like the distribution network, the transmission network must operate under both steady state and fault conditions to ensure quality and security of supply. A high level of security of supply is achieved by the provision of sufficient redundancy of circuits and components[90]. This ensures that supplies are maintained under all reasonably predictable occurrences of plant breakdown or weather induced failure, for all system demands.

To meet this requirement, the transmission system is planned and operated to withstand the sudden loss or withdrawal from service of any transmission circuit without loss of supply or an unacceptable deviation of voltage or frequency. This assumes an intact system with no pre-existing circuit outages.

The amount of power that can be transferred over a group of transmission circuits between one area and another is limited by a number of factors. These factors include the thermal rating of the individual circuits and the way in which the power transfer is shared between them. The 'firm' thermal capability (i.e. the capability after the loss of any one or any two circuits) is generally less than the sum of the individual capacities of the remaining circuits to the extent that the load is not shared pro rata by the remaining circuits.

In certain cases, considerations other than the thermal capability of transmission plant may determine the effective power system capability. These considerations relate to the system electrodynamic performance and are defined in terms of transient stability and steady state (or dynamic) stability. Maintenance of voltage profiles and the control of reactive power flows may also impose other constraints on the system capability.

4.4.4.1 Connecting renewables

As mentioned in Section 4.4.4.1, the level of distributed renewable generation is low enough for it to be considered as a negative load rather than as a generator. As renewable energy installations increase in number and size, technical and operational constraints will need to be overcome:

- Intermittency
- Transmission network constraints

4.4.4.2 Operating with Renewables

As electricity cannot currently be easily stored in significant amounts, centrally controlled power balancing is required. Increasing levels of renewable energy could add costs to the running of the balancing system. The increase of these costs will depend on the proportion of the generation which is intermittent (wind, wave or solar), predictable (tidal) and flexible (biomass and waste combustion) and on the types of generation displaced. Intermittent generation will incur greater costs as the action must be taken to ensure that the system can react to unpredicted fluctuations.

As wind and wave powered generation is most likely to be expanded on a large scale, flexibility must be included in the system to compensate for the potential fluctuations. Means of achieving this readiness are:

- Keeping additional thermal capacity connected as spinning reserve

- Obtaining flexibility in supply and demand in terms of other generators or from demand side management

The central question frequently raised is the cost of backup supplies for the scenario when the intermittent generators cannot generate or their output is low. A study was commissioned for the energy policy consultation by the PIU regarding the costs of intermittent generators[91]. Currently, levels of intermittent generators are low enough to have negligible effect on the operation of the system as they are lower than the normal fluctuation is demand across the UK.

At some point, however, the levels of intermittent generation will start to impact on the operation of the system. The percentage capacity at which point this will occur is unclear. Different studies (shown in brackets below) have stipulated levels at which operational issues could arise. In summary [87]:

- at around 10% of intermittent energy integration it may be necessary to reject a small amount of energy – (CEGB, 1990)

- intermittent output not to exceed 30% of instantaneous demand (ESB, 1990)

- potential change in one hour not to exceed 3% of peak demand (NGC, 1999)

These studies show is that there is no clear limit to renewable energy integration, but informed ESI opinion asserts that problems will occur once installed capacity reaches around 15-20% of system maximum demand[92]. Regardless of the level at which the effects of intermittent power becomes a technical problem in terms of supply quality and there will still be costs associated with any potential fluctuations due to the requirement of holding additional plant as fast reserve.

Only one study published results on this cost increase due to intermittency of renewables (based on wind generation). As a rough estimate, for wind integration levels below 5% the system costs would be negligible. Up to 10% costs may start to rise by an estimated 0.1p/kWh and up to 20% by an estimated 0.2p/kWh[93]. These results are investigated in Chapter 8.

4.4.4.3 Transmission Constraints

The majority of the wind and wave energy resource lies in Scotland and the North West area of the UK. This unfortunately is also the area with the lowest population density in the UK and therefore lowest electricity demand. The electricity network in the area was designed to utilise the hydro-electric resource and ensure that communities had an electricity supply.

Currently these transmission lines are unable to accept any more generation due to power flows approaching thermal limits and boundary constraints. Studies by Scottish and Southern Energy who operate the transmission network in the north of Scotland indicate there is no transfer capacity across the North to South export constraint boundary to the Scottish Power region in southern Scotland. This restriction does not apply throughout the year but can occur when the existing generation and/or load patterns vary within predictable seasonal conditions. To increase the transfer capacity on this route by 150 MW would require an estimated £81million of reinforcement. To accommodate the projected renewable generation in the north and west of the system, reinforcement of the West 132kV route will be required at an estimated cost of £130 million[94].

The boundary constraints are not restricted to the Scottish network. There is also currently a export limit on the Scotland/England interconnector, which was recently upgraded to 2200MW. It cannot however export this level of electricity as there is no excess capacity in the Vale of York transmission lines.

There is no simple solution to the transmission constraints problem. Upgrading the transmission network is extremely expensive and with renewable energy already at a higher cost, renewable energy projects would become prohibitively expensive, if the costs were passed to developers directly or through charging. The transmission issues working group (TIWG) were commissioned to undertake a study to investigate the cost to the entire UK network to accept high levels of renewable energy. Results estimate the upgrade costs would be £520 million to accept 2GW of renewable power, £1.2 billion for 4GW and £1.5 billion for 6GW[95].

4.4.5 Summary

As the proportion of electricity supplied by renewable energy sources increases the intermittent nature of some of these sources will create problems for matching electricity supply and demand. If the UK is to rely more on these variable sources, then extra reserve generating capacity will be needed or alternatively new energy storage facilities or energy carriers will be needed. This may be an area where hydrogen energy may provide a solution. Section 4.6 introduces the Hydrogen Economy.

4.5 CO_2 Capture and Storage

The reduction of CO_2 emitted to the atmosphere can be achieved by capturing the CO_2 at the point of combustion and then storing it long term. Carbon sequestration options that are being considered can be split into:

- Atmospheric removal of CO_2, e.g. vegetation or ocean surface enrichment.
- Capture and storage at the point of combustion.

Storage options include aquifers, depleted underground reservoirs and unmineable coal beds and in the deep ocean. These options are best applied to large point sources of carbon dioxide, such as the releases from fossil fuel power generation.

Atmospheric options can be used to offset CO_2 production by any source including smaller and dispersed sources that are not amenable to end-of-pipe capture technologies.

4.5.1 Atmospheric removal

4.5.1.1 CO_2 Abatement in Vegetation

One of the most commonly proposed means of reducing CO_2 levels in the atmosphere is through growing vegetation to offset emissions. Biological processes driven by photosynthesis cycle more CO_2 through the atmosphere than is currently emitted through the combustion of fossil fuels[96]. Although the majority of this activity is through the algae in the oceans humankind has control of almost half of the primary photosynthetic productivity of the planet through agriculture and forestry. Better management of these natural and manmade carbon sinks could result in reduction of CO_2 levels in the atmosphere. However, the size of these reductions is open to debate. By planting forests and vegetation CO_2 would be absorbed, however the storage time depends on the use of the forests. If the forest is used in a sustainable process such as paper production where forests are replaced once they are felled, net atmospheric carbon levels will reduce. However, if the trees die naturally some of the carbon is held in the soil, but the rest will be released back to the atmosphere during decomposition, negating any carbon benefit. It is interesting to note that agricultural practices are responsible for 36% of anthropogenic CO_2 emissions in Scotland, around 11% of the UK total[97]. Land management techniques and soil cultivation could have a significant although small contribution to make in the overall carbon emissions picture.

The amount of CO_2 that can be sequestered through vegetation and forestry is finite in size and duration. Furthermore the CO_2 mitigation capability of forestry is small in comparison to ever increasing CO_2 emissions. Estimates from the IPCC[98] of potential global CO_2 removal state that 60 - 87 Giga tonnes of Carbon (GtC) (equivalent to 12-15% of projected emissions up to 2050) could be achieved through reduced deforestation and enhanced vegetation in tropical countries and further world wide forestation.

The report from the RCEP suggested that 25% of necessary reductions in CO_2 could be made by 2050, however, this would require considerable political will and there would be little potential for increasing CO_2 reductions thereafter. Also as the vegetation must be maintained for a long periods to have any benefit in terms of reduced carbon emissions, future pressures on land use could result in areas being cleared for development resulting in a loss of the carbon benefit.

For forestry/vegetation to have any impact on net CO_2 emissions large areas, including those areas already deforested, must be planted. To store the equivalent CO_2 emitted from a 500 MWe coal fired power station would require a region of 1400 km^2 to be maintained for several hundred years[99], equivalent to the area of central Scotland.

Rather than attempt to offset CO_2 emissions through vegetation planting the use of natural resources for fuel may be more effective. The use of biomass such as short rotation coppice, agricultural wastes and forestry residues can be used to produce electrical power in a closed emission loop. Any CO_2 emitted is stored in the next generation of vegetation as the CO_2 is absorbed through photosynthesis.

The cost of sequestering carbon in vegetation depends entirely upon the opportunity cost of the land. A study of the costs of forestation concluded with widely varying results. The mitigation costs through forestry can be quite modest, £0.07 - £14/tonne Carbon (tC) in some tropical developing countries, and £14 - £70/tC in developed countries[100].

4.5.1.2 Ocean Surface Enrichment

Exchanges of carbon dioxide between the atmosphere and the oceans in the carbon cycle have resulted in about 40% of the excess CO_2 being absorbed since industrialisation. The rate of uptake is determined by the solubility of CO_2 in the surface layer of the ocean, the amount of carbon contributed to the biological productivity and the rate of mixing between the layers of the ocean. By increasing biological productivity of the surface layer, the transfer of carbon can be increased to the deep ocean resulting in an increase in the carbon absorbed by the surface. The limiting factor in biological productivity is thought to be the availability of certain elements in the surface layers, these being iron (especially in the southern oceans) and nitrogen. Experiments have confirmed the theory of *fertilising* the ocean surface to increase CO_2 uptake by sprinkling it with iron particles although it has yet to be confirmed that the process can be scaled up and successfully repeated[101].

There are concerns regarding the environmental impact of tampering with the biological productivity of the ocean surface. The ecology and biodiversity may not be so effected if the natural surface layer to deep ocean transfer is bypassed and the CO_2 transferred directly to the deep ocean.

4.5.2 CO_2 Capture and Sequestration

The traditional solution to pollution problems is to fit equipment to a flue gas stack or other outlet and remove the pollutant before it reaches the atmosphere so that it can be disposed of in some other manner. An example is the flue gas desulphurisation of the waste flue gas stream from some coal fired power stations. It is also possible to remove carbon dioxide from waste gas streams for it then to be stored preventing its release.

4.5.2.1 Geological Storage

There are several options open for the geological storage of large amounts of CO_2. One option is to inject CO_2 into underground geological strata which could naturally hold large volumes of CO_2. The most suitable methods involve storing the CO_2 in depleted oil and gas fields, saline aquifers or unmineable coal beds. The capacity for such geological storage is estimated to be vast (>250GtC in the UK). The oil industry has experience of using CO_2 to enhance the proportion of oil in a field[102]. This is known as Enhanced Oil Recovery (EOR).

Enhanced Gas Recovery (EGR) is a process that uses CO_2 injected into coal beds to extract the trapped methane (natural gas). The process involves injecting the CO_2 into a coal seam where the CO_2 is absorbed into the pore matrix, displacing the methane. As with EOR, EGR has the benefit of producing a fuel that can be used to offset the cost of the CO_2 storage.

The first environmentally motivated example of disposing of CO_2 in geological formation is in the Sleipner gas field. The Norwegian company Statoil is operating a demonstration project that separates out CO_2 mixed in the extracted natural gas and pumps the CO_2 back into the vacated strata.

4.5.2.2 Deep Ocean Storage

As stated in the previous section the oceans could naturally store a vast amount of CO_2, far greater than terrestrial and atmospheric reservoirs. Discharging CO_2 directly into the deep ocean would accelerate the natural process of CO_2 absorption by the ocean. The process has yet to be confirmed as a viable option as research is still ongoing to explore the environmental, technical and economic issues.

CO_2 is much more soluble in seawater then in fresh water because of the high pH of seawater. The CO_2 mostly forms into the bicarbonate ion (>90%), carbonic acid and carbonate ions, collectively referred to as Dissolved Inorganic Carbon (DIC).

The relatively warm ocean surface areas are saturated with CO_2 but it is the colder deep waters that have the potential to store large amounts of CO_2. The solubility of CO_2 in the deep waters is twice that of the surface yet the concentration of DICs is only 12% higher. The DIC content of the oceans (38 000 GtC) would be little changed even if all the carbon of all the known fossil fuel reserves (~4 000 GtC) were to be stored there[103].

The use of the ocean to dispose of waste materials obviously raises concerns over environmental impact. With regards to the potential disposal of CO_2 in the ocean the main issues relate to the change in the acidity of the seawater. A study into the change in pH in the vicinity of a release stream of liquid CO_2 found that the pH would reduce by approximately one unit which would impact marine life in the area[104].

There are also legal and political barriers to the disposal of CO_2 in the oceans, such as the London Convention, whose 1996 protocol prohibits the dumping of all except "approved" wastes in the sea. The UN convention on the Law of the Seas puts an obligation on coastal states to control and regulate waste discharges. Furthermore, a strict application of the precautionary principle prevents the operation of an environmental option being implemented until its impact has been fully quantified. This will be a significant constraint on the sequestration of CO_2 in the ocean, not least because of the complexity of biodiversity and daily and seasonal migration patterns.

Combining the problem of the legal and environmental constraints the problem of finding suitable sites for CO_2 injection could remain. The location of suitable sites depends on several technical and economic factors. Sites need to be deep enough (>1000m) yet close enough to the shore to minimise the cost of transporting the CO_2 to the injection site. Suitable locations that have been identified for pilot studies include off the cost of Hawaii, Puerto Rico and the Philippines[105]. Despite the potential setbacks many research studies are ongoing[106] which are aiming to accurately map the costs and benefits of ocean disposal.

4.5.2.3 The Potential for CO_2 Sequestration

CO_2 sequestration is an ambitious way of disposing of large amounts of carbon dioxide. In terms of UK potential there is a modest resource for long term storage in vegetation, the oceans or in geological formations. Table 4.5 shows the status and resource of CO_2 sequestration in the UK.

Technology	Status	Certainty of Storage	Constraints	UK resource	Sequestration/ Capture Costs (£/tC)
Forestry	Mature	Medium – depends on land use	Land availability	small	50 - 80
Ocean Surface Sequestration	Experimental	Uncertain – long term effectiveness unknown	Environmental Considerations	large	3 - 37
CO_2 Capture	Demonstration	-	-	large	18 - 70
Geological Storage	Demonstration	Medium – risk of leakage	Offshore sites only	modest	2.3 – 6.8
EOR/EGR	Mature	Medium – risk of leakage	Offshore sites only	modest	1.4 – 6.9
Deep Ocean Storage	Experimental	Uncertain	Environmental Considerations	large	2.3 – 6.8

Table 4.5 - CO_2 Sequestration Options [107,108,109,110]

The potential for CO_2 sequestration over the next 20 years is likely to be limited by the cost. The costs of capture and sequestration options vary greatly. However, in the longer term it should be ruled out as an option for achieving the climate change targets, especially as it would allow more polluting fuels such as coal to continue being used, therefore helping the security of energy supplies.

4.6 The Hydrogen Economy

One of the main arguments for using more renewable energy technologies to produce electricity and increasing energy efficiency is that fossil fuels are finite in the medium term. Although there is no consensus of how much fossil fuel resource remains or when we will run out of oil and other natural resources, alternatives are being investigated. Hydrogen is frequently cited as the "fuel of the future" as a clean and abundant replacement for fossil fuels[111,112]. Hydrogen energy systems could provide viable, sustainable options for meeting the future energy demands.

Following the energy crisis in the early 1970s the International Energy Agency (IEA) was established to facilitate collaboration for the economic development, energy security, environmental protection and well being of its members[113]. As part of this, the IEA launched the Production and Utilization of Hydrogen Program known as the Hydrogen Agreement in 1977, to advance hydrogen production, storage and end use technologies and to accelerate the acceptance and utilisation of hydrogen.

The motivation for the development of a hydrogen energy system is its versatility. Hydrogen can be used in all energy sectors, it can provide energy storage and it can be infinitely sustainable. Hydrogen is abundant in the world, found combined in hydrocarbons and water. There are still a number of issues surrounding the use of hydrogen that are still under research for its introduction as a fuel. Hydrogen is very difficult to contain as it is a low density gas. This creates problems regarding the transport, storage and use of hydrogen as an energy carrier. With this comes the higher cost of hydrogen in comparison to current conventional fuels and this in turn creates barriers to the transition towards a hydrogen economy.

The following sections describe how hydrogen can be used as an energy carrier, the methods of its production and the issue surrounding the transportation and storage of hydrogen that need to be overcome for it to be a viable fuel.

4.6.1 Using Hydrogen

Hydrogen can not only be used in any application where fossil fuels are used, i.e. in combustion engines and turbines, but also electrochemical fuels cells. If used in conventional combustion applications, emissions of NO_x occur due to the high temperature reactions of oxygen and nitrogen in the air. However, when used in fuels cells only water vapour is produced as a by-product. In contrast conventional fossil fuels used in transport and power generation, such as petrol and natural gas or coal, contain carbon compounds along with other impurities such as sulphur which form polluting gases. The benefit of using hydrogen is that less pollution is created, especially at the point of use, if sourced from renewables.

4.6.1.1 Fuel Cells

Fuel cells are electrochemical energy conversion devices similar to batteries, however, as the fuel is constantly supplied they do not run down and a constant flow of electrons is available. Fuel cells are powered from pure hydrogen or hydrogen rich fuels such as coal, natural gas and methanol. By conversion of chemical energy directly into electrical energy, fuel cells avoid the low cycle efficiencies inherent in the indirect conversion (combustion) of fuels in conventional thermal power generation, typically >50% in comparison to combustion efficiencies of around 25-35%.

4.6.1.2 Fuel Cell Operation

In principle, a fuel cell operates like a battery. Unlike a battery, however, a fuel cell does not run down or require recharging. It will produce energy in the form of electricity and heat as long as fuel is supplied. A fuel cell (Figure 4.8) consists of two electrodes sandwiched around an electrolyte.

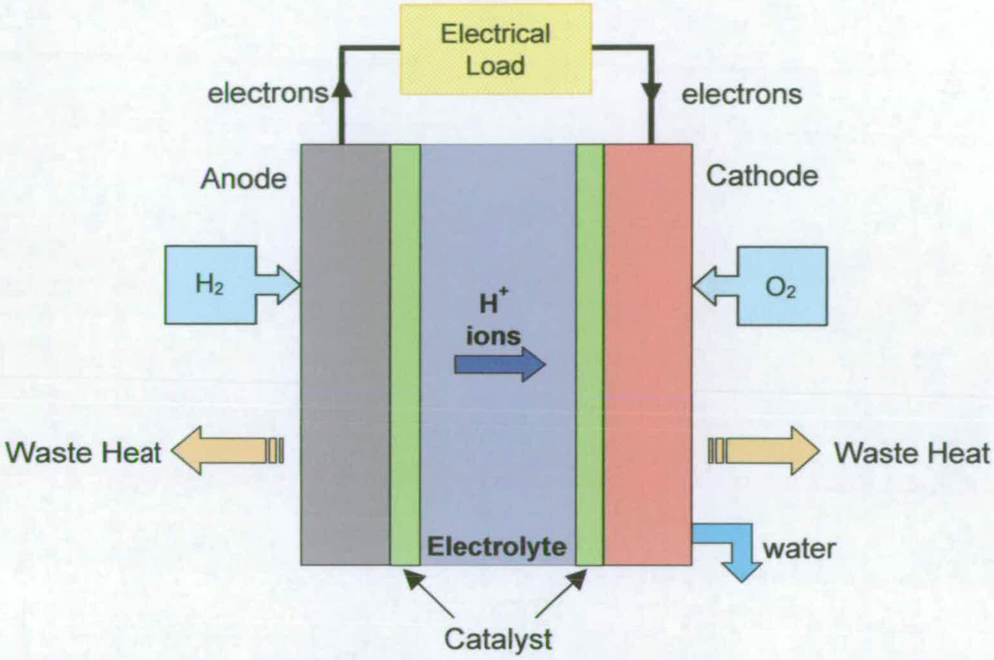

Figure 4.8 – Fuel Cell Schematic

Oxygen passes over one electrode and hydrogen over the other, generating electricity, water and heat. Hydrogen fuel is fed into the anode of the fuel cell. Oxygen or air enters the fuel cell through the cathode. Encouraged by a catalyst, the hydrogen atom splits into a proton and an electron, which take different paths to the cathode. The proton passes through the electrolyte. The electrons create a separate current that may be utilised before they return to the cathode, to be joined with the hydrogen and oxygen as a molecule of water.

The voltage produced by a single fuel cell is not very large (around 0.6V), but when connected in series within a stack the available voltage becomes much larger. The current rating of a fuel cell is related to its surface area. Since they are constructed in modules or stacks, fuel cells can have a power rating from as little as 50W up to 100kW.

4.6.1.3 Types of Fuel Cells

There are several different types of fuel cell technology, differentiated by the fuel used, operating temperature and electrolyte. The most common fuel for fuel cells is pure hydrogen. Fuels cells can also operate with hydrocarbons as fuels.

Phosphoric Acid is the electrolyte in the most commercially developed type of fuel cell. It is already being used in such diverse arenas as hospitals, hotels and utility power plants[114]. Phosphoric acid fuel cells generate electricity at higher than 40% efficiency. These fuel cells also can be used in larger vehicles, such as buses and trains but are particularly suited to stationary applications.

Proton Exchange Membrane Fuel Cells (PEMFCs) work with a polymer electrolyte in the form of a thin, permeable sheet and the proton (charge carrier) is a hydrogen ion. This membrane is small and light, and works at relatively low temperatures, approximately 80 °C and can have a high power density. PEMFCs can vary their output quickly to meet shifts in power demand and are suited for applications where quick start-up is required. They are the primary candidates for fuel cell powered cars and potentially for much smaller applications such as replacements for rechargeable batteries in laptop computers and mobile phones[115].

Molten carbonate fuel cells (MCFC) promise high fuel-to-electricity efficiencies and the ability to consume coal-based fuels MCFCs and are being used to provide power and heat for a number of industrial processes in Germany. Several 200kW MCFCs were installed by a subsidiary of DaimlerChrysler during 2003[116]. Units of 2MW have been built, but designs exist for units of 50 and 100MW[117].

The Solid Oxide fuel cell (SOFC) could be used in large, high-power applications including industrial and large-scale central electricity generating stations. Some developers also see solid oxide use in motor vehicles. A solid oxide system usually uses a hard ceramic material instead of a liquid electrolyte, allowing operating temperatures to reach 720°C. Power generating efficiencies could reach as much as 60%[118].

Alkaline fuel cells (AFC), long used by NASA on space missions, can achieve power-generating efficiencies of up to 70%. AFCs operate on compressed hydrogen and oxygen and use a solution of potassium hydroxide in water as their electrolyte. Temperatures inside alkali cells are around 150 to 200°C[119]. Until recently they were considered too costly for commercial applications, with gold and platinum required for the anode and cathode, but several companies are examining ways to reduce costs and improve operating flexibility.

The Direct Methanol fuel cell (DMFC) is similar to the PEMFC in that the electrolyte is a polymer and the charge carrier is the hydrogen ion. However, the liquid methanol used is oxidised in the presence of water at the anode generating CO_2, hydrogen ions and the electrons that travel through the external circuit as the electric output of the fuel cell. The hydrogen ions travel through the electrolyte and react with oxygen from the air and the electrons from the external circuit to form water at the anode completing the circuit. There are problems including the lower electrochemical activity of methanol as compared to hydrogen, giving rise to lower cell voltages and therefore efficiencies[120].

4.6.1.4 Fuel Cell Costs

As with all emerging technologies, the costs of many fuel cells are still prohibitively high for widespread use, from \$1,000 to \$100,000/kW[121]. Many are still custom made and economies of mass production and manufacturing experience have not yet been achieved. For fuel cells to be used in mobile applications their cost would have to be less then \$100/kW. The membrane electrodes assemblies, with their precious metal and polymer layers, currently dominate the cost of the fuel cell[122].

4.6.2 Hydrogen Production

If fuel cells are to be used as a replacement for combustion engines in cars or as large scale electrical power sources, hydrogen must be produced in large quantities. Hydrogen is not a true fuel, rather an energy carrier like electricity. Unlike other primary energy carriers such as coal, oil and gas, hydrogen needs to be extracted from other chemicals. Hydrogen is found in all hydrocarbons (H_xC_y), for example coal, oils and biomass and most abundantly, in water (H_2O).

Over 500 billion cubic metres of hydrogen are produced each year, for use in a wide variety of processes. More than 99% of this hydrogen is produced from fossil fuels, primarily natural gas, with chemical production and renewable energy sources (hydropower in Canada, Iceland and Norway) accounting for the rest[123].

4.6.2.1 Reformation of Hydrocarbons

Currently, the primary large-scale hydrogen production method is through steam reformation of natural gas. To separate the hydrogen from the carbon in natural gas (mainly methane CH_4) the natural gas is mixed with high temperature steam under pressure with a catalyst present (4.1). This produces carbon monoxide (CO) and hydrogen (H_2):

$$CH_4 + H_2O \rightarrow 3H_2 + CO \tag{4.1}$$

A second water shift reaction is then applied to produce more hydrogen and carbon dioxide (4.2):

$$H_2O + CO \rightarrow H_2 + CO_2 \tag{4.2}$$

The benefit of steam reformation of natural gas is that it is inexpensive given the low cost of natural gas currently. There are a number of disadvantages if using natural gas to produce hydrogen however. The process releases CO_2 as part of the reforming process. Additionally the future security of supply and cost of natural gas is an area of concern, especially for the UK.

4.6.2.2 Water Electrolysis

As described in Chapter 3 hydrogen can also be produced using electricity to break down the bond between hydrogen and oxygen in water (4.3).

$$2H_2O \rightarrow 2H_2 + O_2 \tag{4.3}$$

Under ideal conditions the energy required to liberate 1kg of hydrogen from water is 33kWh. Results from the renewable methanol design showed that the actual electricity required to electrolyse water is higher at around 45kWh per kg.

Using renewable energy to produce hydrogen would create a sustainable and non-carbon emitting energy carrier unlike hydrogen production from natural gas, from which per kg of hydrogen produced, 5.5kg of carbon dioxide is released.

4.6.3 Transportation and Storage of Hydrogen

Depending on the application of hydrogen use there are issues regarding the transportation and storage of hydrogen. Hydrogen can be stored in similar ways to natural gas, either under compression or in a liquefied state. A key difference from natural gas is that hydrogen has a much lower energy density so, for the same amount of energy stored in a given space, hydrogen must be compressed much more. In compressed form, hydrogen can be handled in a similar way to compressed natural gas with some technical modifications. For example, the design of the compressor seals need to allow for the smaller hydrogen molecule. Hydrogen is compressed and stored in cylinders at pressures typically 200 to 300 bar, but potentially as high as 700 bar. Even so, large volume tanks are required for storage of hydrogen gas.

For storage as liquid, hydrogen's much lower liquefaction temperature (-253°C) means that more energy must be used in the liquefying process than for liquefying natural gas. Liquid hydrogen must also be stored in heavily insulated vessels to prevent excessive losses through evaporation.

Large quantities of hydrogen could be stored in underground reservoirs, for example depleted oil or gas fields, in the same way as natural gas. Good sites for this are strata of porous rock bounded by a cap-rock, impermeable to gas. Alternatively, underground salt caverns can be hollowed out using water as is carried out for natural gas.

More novel methods of hydrogen storage are currently under investigation. Hydrogen can be adsorbed into activated carbon surfaces in the same way as natural gas, or reacted with metallic mixtures, to produce a metal hydride. Such metal compounds are potentially capable of storing large amounts of hydrogen in a simpler form than using compression or liquefaction, but at present they are heavy and expensive; storage capacities are only about 4% by weight.

4.6.3.1 Transportation of hydrogen

Depending on the quantities required, hydrogen can be transported by road tanker or pipeline. The use of large-scale hydrogen pipelines has been practiced for more than 50 years. Conventional mild steel pipelines in the Ruhr district of Germany have carried hydrogen between producers and consumers since 1938 without safety problems[124].

Other countries also have extensive pipelines – there is a 170km system in Northern France and a total of some 1500km in Europe as a whole; North America has at least 700km. Existing hydrogen pipelines are broadly comparable to the small-scale local pipelines now used for natural gas, being 25-30cm in diameter and operating at pressures of 10-20 bar, though pressures of up to 100 bar have been used without difficulty.

A large-scale hydrogen network could be similar to an existing natural gas network, though costs would be incurred to cover the different materials and specialised designs for pumping stations required. Although hydrogen gas has a lower energy density than natural gas, it is also less viscous, but suitable modifications could allow approximately the same amount of energy to be piped in similar volumes of pipeline.

Costs for transporting hydrogen vary widely according to the method used. One study has suggested that the levelised cost for pipe and compressor stations transporting pure hydrogen could be similar to that for natural gas[125][83]. Other studies have produced figures between 1.5 and 3 times the natural gas costs[126]. The cost of delivery has been assessed as 1$/GJ (~ £0.7/GJ) for distances of 500km[127]. Using conventional methods, such as road tankers, for moderate quantities the cost can be as high as $20/GJ (£14/GJ)[128].

Depending on the end use of hydrogen, it has been suggested that rather than transport the hydrogen in its pure form, the transportation of compounds of hydrogen such as natural gas or methanol would be more economical. For example, if smaller quantities were required for refilling a H_2 powered vehicle – on site reformers or electrolysers could be used. This would remove the need for large-scale storage of hydrogen. The more familiar liquid fuel media such as liquefied petroleum gas (LPG) or methanol are less likely to provoke a negative response from consumers.

4.6.4 The Transition to a Hydrogen Economy

As can be seen from the discussion the Hydrogen Economy can offer many environmental and energy security benefits, however, the transition from the current oil based economy will not be straightforward.

Encouraging environmentally and socially beneficial technologies has not been hugely successful in the developed world so far. Examples include the slow uptake of energy efficient light bulbs – despite being more expensive than conventional light bulbs, they use up to 80% less power and last longer. Reasons for this are varied, however, the issue of cost remains the most critical. Unless the next best technology has a price acceptable to the consumer, few will volunteer to shoulder the higher costs.

A further barrier is the unfamiliarity of how the new technology will work. In terms of the Hydrogen Economy, there may need to be changes in the way that consumers handle fuel, especially in the transport sector. Hydrogen filling stations that have been built so far have strict safety procedures that need to be adhered to that may deter a normal consumer. Despite the risks attached to the dispensing of petrol and diesel into passenger cars, few consumers think twice about the risks of petrol explosion. Yet some of the perceived risks associated with hydrogen and its flammability are much higher than in reality.

The main constraint to widespread hydrogen use is cost. The world still enjoys cheap and abundant sources of fossil fuels used in the majority of energy applications. Table 4.6 shows the costs of different fuels that can be used in the transport sector.

Fuel		Cost £/GJ
Hydrogen	Natural gas reformation	6 -9
	Coal/biomass reformation	7 -12
	Water electrolysis	12 -57
Petrol	No tax	6.5 – 7.4
	Including tax	18 - 21
Natural Gas		2 – 2.5
Methanol	Natural Gas Reformation	11.5
	Renewably produced	23

Table 4.6 - Comparison of Fuel Costs[129, 130, 131]

In terms of cost per unit energy hydrogen produced from natural gas is comparable with petrol and natural gas. If the hydrogen were to be reformed from methanol the energy costs increase. In pure economic terms, hydrogen from renewable source either directly from electrolysis or from the reformation of renewably produced methanol is not competitive with current fuels. Changes in the cost and supply of conventional fuels in the future could make renewably produced hydrogen or methanol more attractive.

The unresolved issues of storage and distribution of hydrogen would also be reflected in the cost. Hydrogen is a low density gas with a very low boiling temperature and therefore needs to be stored either as a compressed gas or liquefied to avoid having very large storage facilities. Methanol as a hydrogen carrier would remove the problems and associated energy requirements of the compression of hydrogen, but losses in the conversion (around 15%) would be incurred. The conversion of hydrocarbons into heat, electricity and motive power are mature technologies, with years of operational experience. Fuel cells, however, are still a developing technology and cannot yet compete in a free market. Currently the cost of energy is very low as there are abundant supplies. In the future when supplies of fossil fuels become limited, the *cost* of fossil fuel energy will increase and the *value* of renewable energy sources will increase accordingly. It is this situation that emerging fuel technologies such as hydrogen and renewable methanol will become viable.

4.7 Summary

There are many options available to the ESI in terms of reducing or offsetting CO_2 released into the atmosphere, through managing different sections of the carbon cycle. Low or zero carbon electricity generation technologies avoid the production of CO_2. These technologies include nuclear power and the wide variety of renewable energy sources. Nuclear power is a large scale electricity generator, however, there is public opposition to its development due to concerns over increased radioactivity and waste disposal. Renewable energy sources are varied and the UK is fortunate to have a significant resource in particular wind and marine sources. However, the renewable energy resources are dispersed, often far from the electricity demand centres and depending on the technology, intermittent and unpredictable. It is generally believed that intermittent renewable sources face a technical limit due to stability of around 20% of installed capacity, restricting their potential electricity contribution. After this level of 20% is exceeded, energy storage technologies would be required to counter the effects of the intermittent generation on the network.

CO_2 capture and sequestration methods offer possibilities for reducing CO_2 levels, both before and after its release into the atmosphere. These technologies would enable the continued use of fossil fuelled electricity generation without the concern over CO_2 emissions. However, these methods and technologies make electricity generation more expensive than at present. A balance would need to be established between the cost of the CO_2 abatement against the benefit of continued use of secure and reliable fuels.

The proposal of using hydrogen as a energy carrier, replacing fossil fuels offers the potential to have a sustainable and low carbon economy. Benefits of such a fuel economy are that dependency on imported fuel could be reduced if the hydrogen were produced from renewable methods such as water electrolysis. Also hydrogen itself produces no pollutants at the point of use, therefore has no detrimental effect on the environment. Currently the technologies of the hydrogen economy, e.g. fuel cells, are still at the demonstration stage and the abundant and cheap supplies of fossil fuels make the hydrogen economy uneconomic at present. But changes in the cost and supply of fossil fuels and greater pressure to reduce CO_2 emissions could change this situation.

The following chapters show methods of how the factors of security of supply and environmental protection can be measured and accounted for in the ESI. Economic instruments are evaluated that can be employed to adjust the behaviour of the ESI to produce particular security of supply and environmental outcomes.

Chapter 5

Security of Supply in the Electricity Supply Industry

The security of supply provided by the electricity supply industry (ESI) is a fundamental aspect of the economy and this has been shown even more clearly as a result of recent events that have resulted in power outages. During the summer of 2003 a number of key events relevant to security of supply occurred.

- On 14 August 50 million people across the north-eastern United States and southern Canada were left without electricity for approximately 25 hours[132].

- On 28 August, a sequence of events led to the loss of electricity supply to some 410,000 customers in South London and parts of Kent[133].

- France and Italy experienced shortages of generating capacity, and on 28 September, Italy was hit by its most serious power cut in decades. Over 50 million consumers lost supplies[134].

Each of these incidents had different causes: the North American event involved an uncontrolled, cascading blackout currently caused by an unusual series of transmission faults, in the UK the powercut was due to underrated protection and switchgear equipment[135]. The events France and Italy in 2003 were a result of a combination of insufficient generation capacity and high international energy transfer[136]. In 1999/2000 California experienced a series of forced electricity supply restrictions also as a result of insufficient generation capacity[137].

The result of these electricity supply outages has been the increase in awareness of the social and economic impacts of lost supply. However, a balance needs to be established which allows for affordable electricity supply whilst ensuring that shortages or price fluctuations are kept to a minimum.

Research by the OECD[138] states that some governments are concerned that reserve capacity may be at risk in a more competitive electricity market and that ad hoc mechanisms, such as capacity payments, might be needed to ensure an adequate reserve capacity. The principal argument against the need for such mechanisms is that prices in a competitive market should reflect the value to the buyer of reserve capacity, as well as any other component of security. In particular, contracts between providers and buyers of electricity should include the characteristics of the security of supply to be provided and the penalties for failing to deliver.

This suggests that there are natural market mechanisms that can provide sufficient incentives to invest in reserve capacity. Such market mechanisms may either be set up by the regulators or by the market players themselves. If, despite these natural market mechanisms, there is concern about future reserve capacity, or if policy makers want an explicit market for capacity, there are a number of policy tools available, including capacity payments. However, at least for as long as some generators enjoy market power, capacity payments carry some disadvantages and may result in significant market distortions.

The UK ESI has a capacity margin in the region of 28% if all installed generators are considered. This is seen as an excessive requirement by the regulator OFGEM even in terms of insuring against loss of generation[139]. The increased competition between generating companies due to NETA has caused some companies to mothball plant to save money and may also cause the ultimate closure of some of this plant as there is no longer a capacity payment scheme such as existed under the Pool.

The current ESI is made up from large steam generation which has high availability levels (>85%). If large scale integration of renewables were to occur the system loss of load probability (LOLP) would be increased and therefore the system's capacity margin would need to be adjusted.

This chapter describes the investigation and evaluation of two methods of assessing the security of electricity generation in an ESI. The first deals with the LOLP and generation capacity and the probability of there not being enough generation to meet demand. The second method is a technique based on investment theory used investment theory to analyse the price volatility of fuel used for electricity generation.

5.1 Measuring Reliability

There is a problem when it comes to measuring the reliability of an electricity system. This is a result of the continuously changing demand for electricity and the random events that can affect generation and transmission systems. In terms of the reliability of the generation system meeting the demand there are two methods of establishing reliability.

5.1.1 Reserve Margin

In its simplest form, the reliability of an ESI is calculated from the installed capacity and expected system maximum demand:

$$RESERVE\ MARGIN\% = \frac{IC - SMD}{IC} \tag{5.1}$$

Where IC is the installed generating capacity of a system and SMD is the system maximum demand. Using reserve margin as a measure of reliability is limited however, as is does not take into account the type, age or condition of the generating assets.

5.1.2 Loss of Load Probability

A more meaningful measure of reliability does take into account the features of the generators. In the UK, pre-privatisation, the cost of not meeting demand was calculated in terms of the Loss of Load Probability (LOLP)[140]. The LOLP was developed in the late 1940s in the United States to assist the decision of determining the right level of reserve capacity[141].

The LOLP is a function of time varying demand and generation availability. Using probability theory the probability of *r* generators not being available from within a population of *n* generators is given by:

$$P(r) = \frac{n!}{r!(n-r)!} \cdot q^r \cdot (1-q)^{n-r} \tag{5.2}$$

Where q = the unit outage rate and $P(r)$ = probability of *r* units being unavailable. For example, Table 5.1 shows the probabilities that an particular number of generating units from a group will be unavailable with a forced outage rate (FOR) of 5%. The FOR is defined as the fraction of the year that the generator is unavailable to generate.

Units Out	Probability of number of units out x10^{-6}								
	1	2	3	5	10	20	50	100	150
0	950000	902500	857375	203627	315125	377354	202487	31161	33596
1	50000	95000	135375	21434	74635	188677	261101	81182	14102
2		2500	7125	1128	10475	59582	219875	139576	33616
3			125	30	965	13328	135975	178145	70823
4					61	2245	65841	180018	108843
5					3	295	25990	150015	138441
6						31	8598	106026	149891
7						3	2432	64871	141016
8							597	34901	11710
9							129	16716	86901
10							25	7198	58211
11							4	2810	35488
12							1	1001	19828
13								327	10212
14								99	4873
15								28	2164
16								7	898
17								2	349
18									128
19									44
20									14
21									4
22									1

Table 5.1 - Probability of simultaneous groups of generators failing

Therefore, from a group of 20 like generators the probability of more than 3 of them being out simultaneously is 0.059. This does not mean that the actual number of days a year that more than 3 will be out is 0.059 x 365 = 21 days, this is the average rate which outages of more than three units will occur.

If the generators in a group not the same or have a different size it is necessary to calculate for each capacity rather for the number of units out. An example probability array is shown in table to illustrate

No.	MW	Prob.	No.	MW	Prob.	No.	MW	Prob.	No.	MW	Prob.	No.	MW	Prob.
3 150 MW Units separately			3 220 MW Units separately											
			0	0	0.857375	1	220	0.135375	2	440	0.007125	3	660	0.000125
			Combined Groups											
0	0	0.857375	0	0	0.735092	0	220	0.116067	0	440	0.006109	0	660	0.000107
1	150	0.135375	1	150	0.116067	1	370	0.018326	1	590	0.000965	1	810	0.000017
2	300	0.007125	2	300	0.006109	2	520	0.000965	2	740	0.000051	2	960	0.000001
3	450	0.000125	3	450	0.000107	3	670	0.000017	3	890	0.000001	3	1110	-

Table 5.2 – Array for combining outage probabilities

The process is completed by arranging the individual probabilities in order of capacity as in Table 5.3:

MW Capacity	Probability of Outage
0	0.735092
150	0. 116067
220	0. 116067
300	0. 006109
370	0. 018326
440	0. 006109
450	0. 000107
520	0. 000965
660	0. 000107
670	0.000017
740	0.000051
810	0.000017
890	0.000001

Table 5.3 – Probability of Outages

The probability of outages exceeding reserve margin can be determined. In this example there are 6 generators with a total installed capacity of 1110MW. If the system maximum demand (SMD) is 670MW, there is a reserve margin of 440MW. Using a system demand profile (Figure 5.1), the period of time that there could be insufficient generation to meet demand can be established.

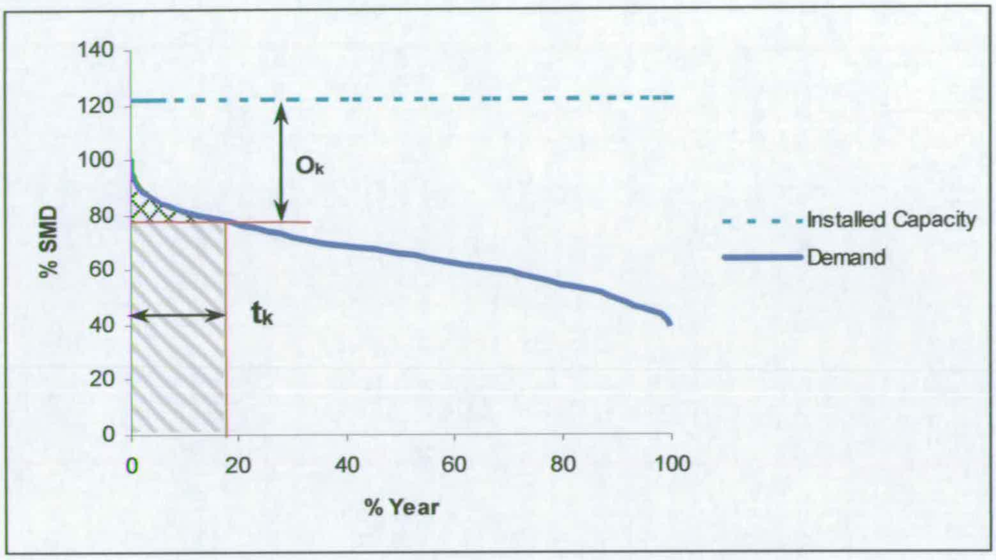

Figure 5.1 – Load duration curve for example system

From this graph for each capacity outage drop (O_k) the correspond length of time (t_k) this would effect supply is established. The sum of the time of each outage and the probability of the outage is the LOLP (Table 5.4).

Capacity Outage Ok	Time of Outage tk	Probability of Outage pk	pk* tk
440	0.00	0. 006109	0
450	0.005	0. 000107	<0.000001
520	0.029	0. 000965	0.000027
660	0.419	0. 000107	0.000044
670	0.491	0. 000017	0.000008
740	0.816	0. 000051	0.000042
810	0.950	0. 000017	0.000016
890	0.005	0. 000001	<0.000001
Loss of Load Probability			0.000137

Table 5.4- Calculation of Loss of Load Probability

The LOLP can be represented either as a percentage – in the example this would be 0.01% - or as the number of hours per year – 0.000137*8760 = 1.2. Alternatively the Expected Energy Not Served (EENS) can be calculated. The double hatched area in Figure 5.1 is proportional to the energy (EENS) which would be lost as a result of a capacity outage O_k if it were to last throughout the period t_k. This can be calculated by multiplying the LOLP by the annual energy demand.

The main use of the LOLP or EENS values is to calculate the optimal level of capacity margin. An LOLP of 0.03% was the optimum reliability that was used pre-privatisation and it is still the benchmark figure used in reliability assessments[142].

Assuming an average plant outage rate of 15% per annum, the margin required to achieve an LOLP of 0.01% is 22.5%. Figure 5.2 shows the LOLP against the capacity margin for different levels of generation availability.

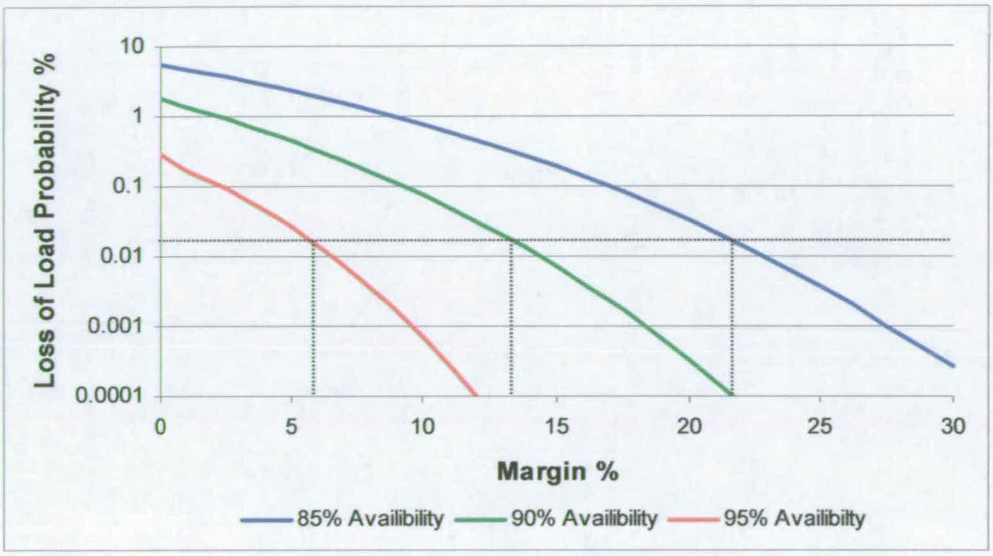

Figure 5.2 – LOLP against margin

The LOLP is very sensitive to changes in plant availability and capacity margin. An improvement in the annual availability of a group of generators from 85% to 90% means that an acceptable LOLP value can be achieved with 10% less capacity margin than if the generators had an availability of 85%.

The LOLP is also a function of the size of the system being studied, that is the number of generators in the system. The graph above assumes that there are 100 generators in an ESI – comparable to the England and Wales ESI. LOLP calculation can show the benefit of increasing the pooling of generation resources. For example, Scotland currently has an SMD of approximately 6GW and an installed capacity of 10GW. This equates to a capacity margin of 40%. However, the LOLP for the Scottish system not including the potential transfer of power across the interconnector is 0.03%. The LOLP value is comparable to that of the rest of the UK but almost twice as much excess capacity is required to achieve this. This is due to the smaller number of generator in the system. The smaller the group the higher the LOLP In reality Scotland currently exports 1500MW to England with the interconnector upgrade increasing this to 2200MW in the next few years.

5.2 LOLP and Intermittent Generation

Until recently the effect of intermittent generator in a system has not been a great concern. However, with renewable electricity being actively encouraged there may come a time when this variable and unpredictable output of wind may become an issue. Intermittent resources such as wind generation have a relatively low availability, therefore adding renewables to the generation mix will effect the LOLP (Figure 5.3).

For a system with an SMD of 50GW (the SMD for England and Wales is 57GW) to provide 10% of the required energy by wind energy would require at least 11.4GW of installed capacity. The assumed availability of wind generation is 43%. This is the figure used to calculate the declared net capacity of wind – a generous value as this does not take into account turbine failure. Assuming a FOR of 15% and 10% the LOLP of the system against the capacity margin with an installed capacity of wind generation of 11.4GW is shown in Figure 1.13.

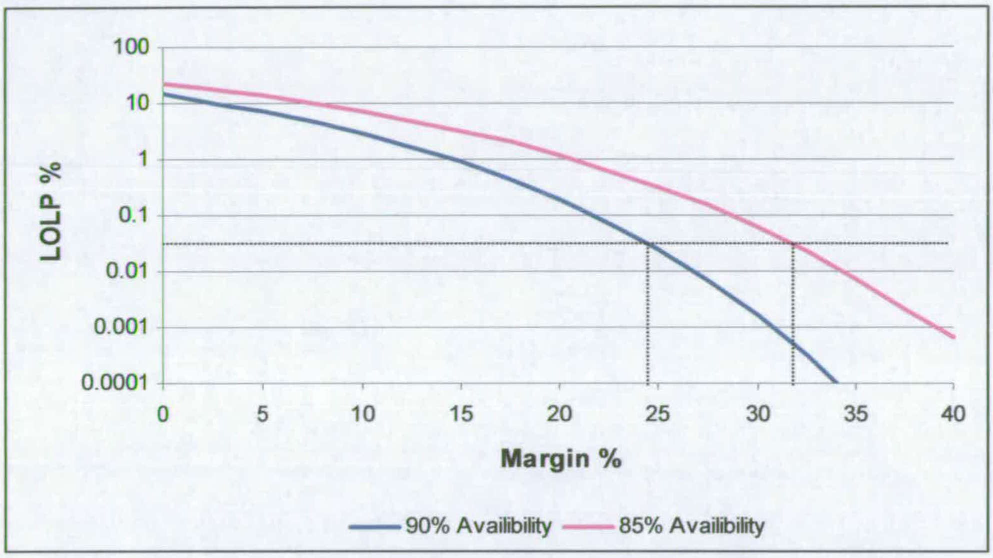

Figure 5.3 - LOLP with 10% energy from wind

It can be seen comparing Figure 5.2 and Figure 5.3 that an increase in wind energy integration will require excess thermal capacity to be held to ensure that a suitable level of security is maintained. Assuming optimistically that all other non-wind generation has an availability of 90%, 10% of extra capacity margin is required to carry the 10% renewable energy supply and maintain the LOLP.

This probabilistic analysis of capacity requirements with high levels of renewable energy shows that to sustain the current levels of security of electricity supply, wind energy development cannot displace conventional generation capacity; it can only displace incremental energy delivered. Therefore existing plant levels must be maintained.

A decision must be made on whether the value of having such a high level of wind energy is worth the extra cost of holding reserve generation capacity. The next section discusses the effect of price risk on the ESI. Chapter 6 discusses the external costs of electricity generation and methods of internalising those costs using regulation and economic instruments.

5.3 Electricity Generation Portfolio Selection

Investors have long sought to reduce their exposure to the ups and downs of the financial market by holding a diverse mix of investments, confirming the conventional wisdom of *don't put all your eggs in one basket*. Diversification of a portfolio of options reduces the impact that a sudden unexpected event on the value of a single option has on the whole portfolio.

The benefits of diversification apply as much to the Electricity Supply Industry (ESI) as financial investments. In the ESI, the security of supply coupled with the stable cost of electricity is a principal economic driver. The privatisation of the UK ESI now means that electricity companies need to make a profit and keep shareholders happy as well as provide an essential service. The balance between the cost of electricity and exposure to price changes could become more difficult to maintain as new investments in generating plant are required and the anticipated increase in gas fired generation occurs.

In the UK current reservations of policy makers about relying on imported fuels resulting in the cessation of fuel supplies can be taken as over pessimistic. There are significant capacities of fossil fuels world-wide and within economic distance of the EU and UK[143]. As the UK moves away from being self sufficient in energy new supplies from Europe and further afield will be discovered. It is very unlikely that the UK will be cut off from its supply as it is as much in the interest of supplying countries to maintain their supply to the market. If the supply can be assured the price cannot. As the European gas market expands and becomes further deregulated, there is the risk of greater exposure to price volatility.

The short-run elasticity of electricity is such that price changes tend not to be reflected in a change in demand[144]. In the long term, however, electricity intensive industries and the effect of price increases in the domestic market can have significant effects on the economy. The management of the price risk resulting from the uncertainty of fuel imports can be used to decide upon a portfolio of fuel mix so that unexpected events do not have an overwhelming effect on the security or volatility of price in the electricity supply industry.

5.4 Modern Portfolio Theory

Through the examination of expected return, variance and covariance of a group of assets, Markowitz[145] devised a method of constructing an efficient portfolio which maximizes the expected return for a given level of risk, known as Modern Portfolio Theory (MPT). The theory is based on the fact that while an individual asset may be risky with a high variance, the covariance of returns from a group of assets will insulate a portfolio from fluctuations thus creating portfolios with higher returns but little or no added risk.

Portfolio theory relates the expected return of a portfolio, $E(r_p)$, to the total portfolio risk, σ_p, defined as the standard deviation of past returns. Using a simple two asset portfolio, the expected return is the weighted average of the individual returns of the two securities.

$$E(r_p) = X_1 E(r_1) + X_2 E(r_2) \tag{5.3}$$

Where $E(r_p)$ is the expected portfolio return, X_1 and X_2 are the proportions of the two assets and $E(r_1)$ and $E(r_2)$ are the expected returns of the two assets.

Portfolio risk σ_p (5.4) is also a weighted average of the two assets, but is moderated by the correlation coefficient between the two returns.

$$\sigma_p = \sqrt{X_1^2\sigma_1^2 + X_2^2\sigma_2^2 + 2X_1X_2\rho_{12}\sigma_1\sigma_2} \tag{5.4}$$

Where ρ_{12} is the correlation coefficient between the returns of the two assets.

Financial theory use a measure of relative risk rather than absolute risk to avoid distortion in the MPT analysis. The reasoning for this is that an asset with a high price may have a larger variance than a lower priced asset simply because of its magnitude. Therefore the standard deviation (risk) of the Holding Period Returns (HPRs) are used.

A HPR over a period is calculated from:

$$r_t = \frac{EV_t - BV_t}{BV_t} \tag{5.5}$$

Where EV is the price at the start of period t and BV is the value and the end of period t.

5.4.1 The Portfolio Effect

The goal of maximizing return while minimizing risk or variance produces a set of *efficient portfolios* from which an optimal portfolio can be chosen, given a defined level of risk aversion. A correctly designed portfolio exhibits a portfolio effect – the reduction of risk through diversification. Diversification occurs whenever the returns of two or more securities are less than perfectly correlated i.e. $\rho_{12} < 1$.

To illustrate the portfolio effect graphs were produced using Excel. To confirm that the calculations were correct data from Awerbuch[146] is used. To establish the points on the graphs, the expected return and portfolio risk were calculated for portfolios of different proportions of stock A and B. Each tick mark along the line represents a 5% change in the portfolio proportions. Figure 5.4 illustrates the portfolio effect of two assets.

A

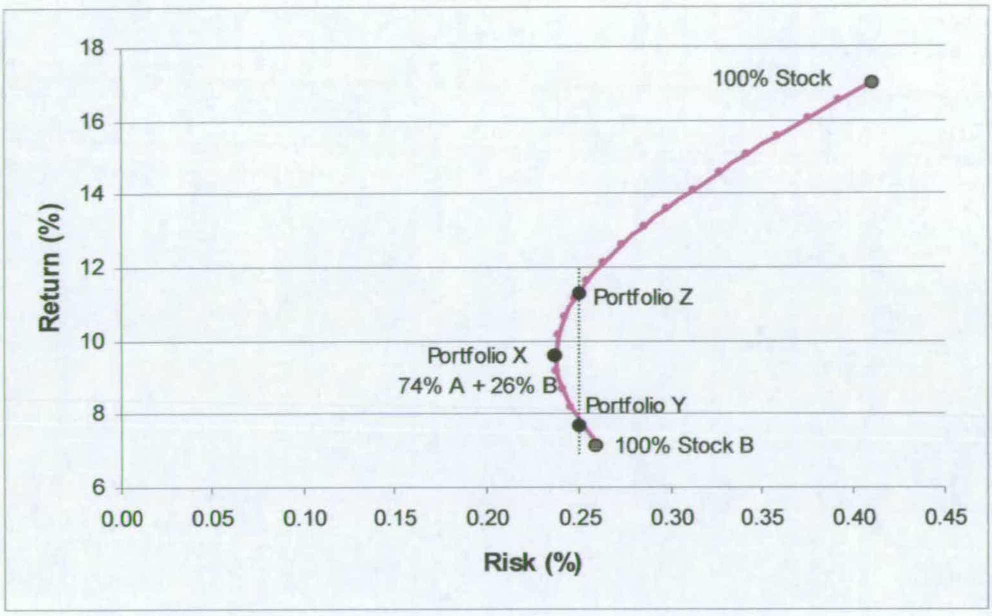

Figure 5.4 - Risk Return Curve for 2 Asset Portfolio

A portfolio consisting entirely of stock A has an expected return of 17% with a risk or standard deviation (SD) on historic returns of 0.41. Stock B is less risky with an expected return of 7.2% and an SD of 0.26. Starting with a portfolio consisting of 100% of stock B and increasing amounts of stock A the portfolio risk decreases to a minimum at point X. This seems at first counter intuitive as stock A has a higher risk. The initial reduction in the risk is a result of the correlation between the two assets. If the assets have a correlation of less than one, the variation in the two stocks will cancel each other out. From a risk reward perspective, holding only stock B makes little sense as a lower risk and higher level of return can be achieved from holding a proportion of stock A.

Given two risky assets it is not possible to prescribe a single optimal portfolio rather a range of options which lie on the efficient frontier. A portfolio is inefficient when it is possible to obtain a higher expected or average return with no greater variability of return, or obtain greater certainty of return with no less average or expected return. Investors will choose a risk return combination based on their own preferences and aversion to risk. More risk averse investor would choose portfolio X whereas more adventurous investors would perhaps choose portfolio Z.

5.4.2 Correlation Coefficients

The portfolio effect is dependent on the correlation between the standard deviation of the assets held. Figure 5.5 shows the portfolio effect of two assets with different correlation coefficients. If the correlation coefficient ρ is equal to 1, the line of various proportions of assets is a straight line as there is no damping effect. If ρ is lower, say around 0.5, a risk lower than either of the other assets can be achieved. The perfect situation would be if the assets had a correlation coefficient of –1. This can effectively create a risk free investment.

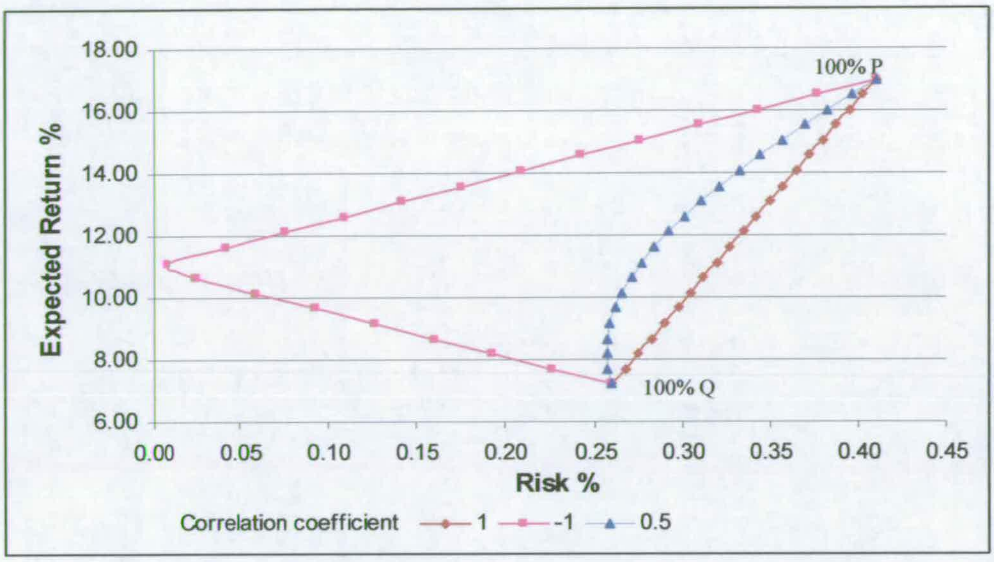

Figure 5.5 – Portfolio effect with varying correlation coefficients

5.4.3 Adding Risk-Free Assets

Adding a risk-free asset to the AB stock mix produces further interesting results. In financial portfolios, risk-free assets would consist of governments bonds or perhaps just having money sitting is a fixed interest savings account. The term risk-free is however, misleading as even fixed interest savings accounts or government bonds can incur some level of risk. Interest rates can change or liquidating assets before maturity can incur an element of risk. The accurate terminology regarding bonds etc is that they are zero-beta† assets to distinguish the fact they are not truly free of risk.

Figure 5.6 shows the effect of adding a risk-free asset with a return of 5% to the AB mix. The risk-return curve for the combinations of A and B remains unchanged from Figure 5.4. The new element is the straight line which represents adding increments of the risk-free asset.

† Beta is an index used to measure systematic risk. Assets with a beta value greater than 1 tend to amplify the movements in the financial markets. Values between 0 and 1 move with the market but do not fluctuate as much. Zero-beta assets reflect the zero variance and hence zero covariance with the market portfolio.

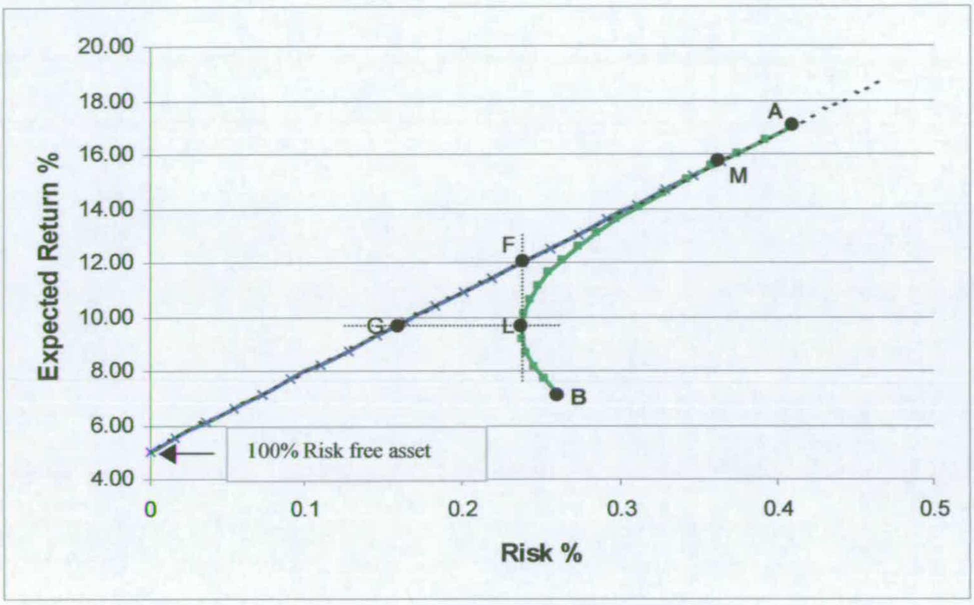

Figure 5.6 - Risk free and risky assets

The tangent point M between the straight line and the AB risk return curve is now the optimal portfolio for stocks A and B. The tangent at the point M is calculated by optimising the equation known as Sharpe's Ratio:

$$Q = \frac{E(r_p) - r_f}{\sigma_p} \tag{5.6}$$

Where $E(r_p)$ is the expected portfolio return, r_f is the expected return of the risk free asset and σ_p is the portfolio risk. In this example, point M represents 87% of stock A and 13% of stock B.

By examining the effect that adding risk-free assets to the portfolio, it can be seen that a greater return can be achieved at the same risk level. For example, point F, which includes risk-free asset, has the same risk as point L on the AB asset curve. This illustrates that by including lower yielding, but less risky assets, a portfolio with the same risk can be created, in this case 0.23%, but with an increase in the expected return from 10% to 12%. The same expected return can be achieved at a lower risk level shown by points G and L. Point G is at 45% of the risk free asset and 55% of A and B at point M.

5.5 Multiple Asset Portfolios

Portfolio selection with two assets can be easily extended to more assets. The return on a portfolio is simply the proportion of each asset multiplied by the expected return for that asset:

$$E(r_p) = \sum_{j=1}^{N} X_j E(r_j) \tag{5.7}$$

The variance of the portfolio for multiple assets is:

$$\sigma_p^2 = \sum_{j=1}^{N} X_j^2 \sigma_j^2 + \sum_{j=1}^{N} \sum_{i=1}^{N} X_j X_i \rho_{ij} \sigma_j \sigma_i \tag{5.8}$$

5.5.1 The Efficient Frontier

The line optimal portfolio for multiple assets is called the efficient frontier. Figure 5.7 shows the risk return lines between two of three assets. The line to the left of these is the efficient frontier. The Efficient frontier exhibits lower risk for a given level of return than any combination of just two assets.

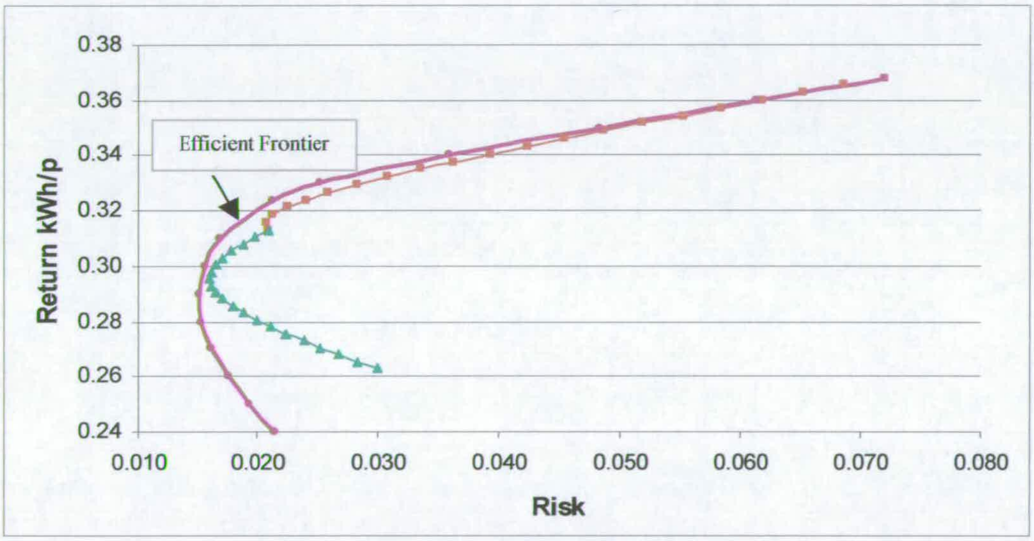

Figure 5.7 - Efficient Frontier

The calculation of the efficient frontier for multiple assets portfolios requires the use of an optimising method. To calculate the efficient frontier an optimising function in *Excel* called *Solver* was used. For each level of expected return the lowest risk value was established.

5.6 Applying MPT to the Fuel Mix of the ESI

This section discusses how the research into security of supply and how to quantify it using MPT was extended to evaluate the ESI in terms of price volatility. An assumption was made at the outset that the relationships derived from financial portfolios could be applied to portfolios of generating assets. In the case of generating assets, market and historical cost and price risk data can be defined as analogous to those used for financial markets, i.e. risk is measured in terms of the historic variation and co-variation of the fuel costs of different types of generation considered. The technologies are defined by their fuel as in the conventional plant such as coal, gas and oil and renewable plant such as wind.

Analogous to the treatment of financial assets whose expected return is measured in terms of output or yield divided by an input or cost, generating costs of energy are converted into return by inverting them. The return on a generating assets is in terms of kWh/p[147, 148].

5.6.1 Limitations of MPT Application for Generating Portfolios

There are some caveats relating to applying MPT to generating assets. Standard assumption are that there exist perfect markets for trading assets, implying low transaction costs, perfect information exists about the assets and that returns are normally distributed. Despite these limitations, MPT is often applied to tangible, non-financial assets such as generation choice and energy supply[149].

5.6.1.1 Indivisibility of Assets

MPT analysis is based on the premise that assets are infinitely divisible. Using MPT in generating models assumes that for large systems or national generating portfolios the indivisibility of a generating station becomes less significant. Since total capacity of a large ESI is much greater than an individual generating unit, one unit may represent less than 1% of the system. In generation portfolio analysis an accuracy of greater than 1% is not essential therefore the requirement that generators are infinitely divisible can be ignored.

5.6.1.2 Normal Distribution of Holding Period Returns

MPT assumes that the risk of fuel prices is normally distributed. It is not certain whether fossil fuel prices follow a normal distribution. Research in this area states that fuel prices are commonly modelled as *random walks* that imply that price changes are at least independent from each other[150].

5.6.1.3 Perfectly Fungible Assets

Portfolio assets must be perfectly fungible: their value must depend only on the amount, timing and certainty of expected cash flows. This may not always hold for generating assets where issues such as location and fuel availability may influence selection. For example, a gas line may enhance the "amount, timing and certainty" of cash flows only if a gas plant is constructed rather than a coal plant. Technology choice may further influence asset value to the extent that electrical grid connection costs may differ for different technologies.

5.6.1.4 The Past as a Guide to the Future

Portfolio theory uses the past as a guide to the future and this has created much debate on its validity in terms of assessing generating portfolios. A paper by Stirling[151] criticised the use of mean-variance portfolio analysis on the grounds that fuel price movements have no patterns. Stirling proposed that ignorance over risk or uncertainty dominates investment decisions, where risk is defined as where a probability density function that can be meaningfully defined over a range of possible outcome and uncertainty in where there exists no basis for the assignment of probabilities. Ignorance is defined as when there is no basis for the assignment of neither probabilities of an outcome nor the definition of the outcome itself.

It can be argued that a sudden event like an Enron bankruptcy, or major technological failure may have unpredictable consequences on future fuel prices. Portfolio risk however includes the random fluctuations of individual portfolio components which have a wide variety of historic causes. Therefore it must be assumed that the historic fuel prices include such random events mean that they can be used as a reasonable range of expectations for the future.

5.6.2 MPT Input Data

The fuel price data for the fossil fuels in the analysis has been taken from DTI quarterly statistics over the last ten years. The graph below shows the prices of coal, gas and oil from 1993 to the first quarter of 2003.

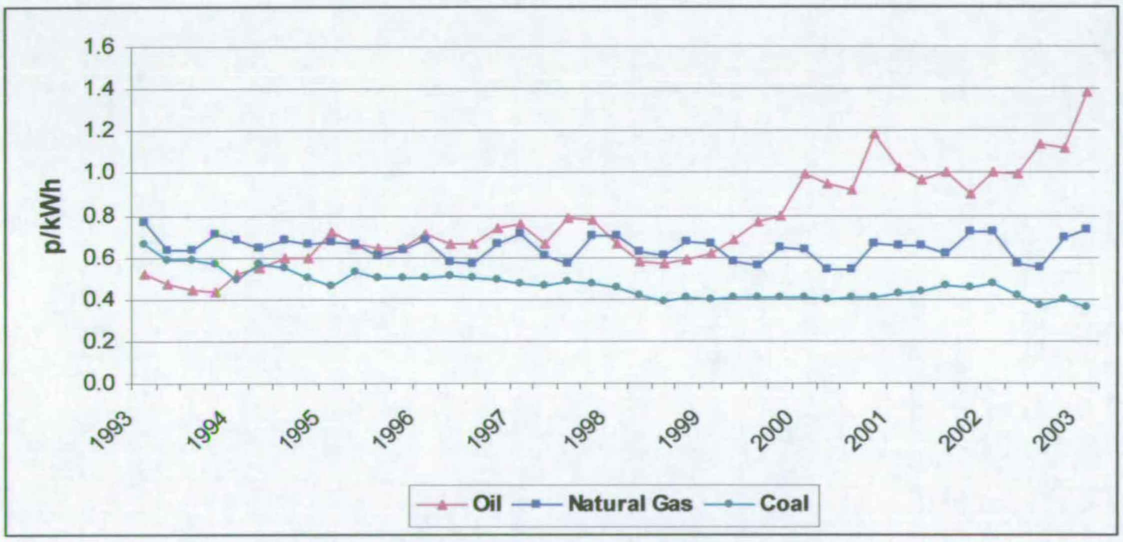

Figure 5.8– Quarterly Fossil Fuel Prices[152]

The fuel prices for each quarter were used to calculate the HPRs of each fuel. Then the standard deviation of the HPRs could then be calculated to estimate the fuel price risk.

The price variance is calculated from the standard deviation of the HPRs of the fuel prices using the Excel function *STDEV( )*. The values are then scaled with respect to the fuel cost to represent the variance of the price per kWh for each fuel. Table 5.5 shows the costs per kWh for each type of conventional generation and the percentage contribution from fuel costs.

Costs p/kWh	*Coal*	*Oil*	*Gas*	*Nuclear*
Investment	1.50	1.50	0.85	2.50
Fuel	1.20	4.61	1.57	0.30
O&M	0.50	0.50	0.30	1.00
Busbar Cost	3.20	6.61	2.72	3.80
%fuel cost	0.38	0.70	0.58	0.08

Table 5.5– Generator Cost Data (derived[153154])

From the values in Table 5.5 the expected return or kWh/p values were calculated. Table 5.6 summarises the MPT input data for conventional generation.

MPT Input Data	Coal	Oil	Gas	Nuclear
Return kWh/p	0.313	0.151	0.368	0.263
Price Variance	0.021	0.073	0.072	0.030

Table 5.6 – MPT Input data

The covariance of the fuel with respect to each other is also calculated from the HPR of the different fuels. Using Excel function *COVAR( )*. The table below shows the covariance of the main fuels.

	Coal	Oil	Gas	Nuclear
Coal	-	-0.036	0.184	-0.130
Oil	-0.036	-	0.170	-0.370
Gas	0.184	0.170	-	-0.270

Table 5.7 - Correlation Coefficients of Fuels(derived[155, 156])

5.6.3 MPT Results

Using the DTI data in Table 5.5 and Table 5.6, the risk/returns curves for pairs of fuels were calculated as shown in Figure 5.9. It is more apparent how holding a portfolio of generating assets with different fuel supplies can result in higher returns and lower risk such as a points on the coal-nuclear line.

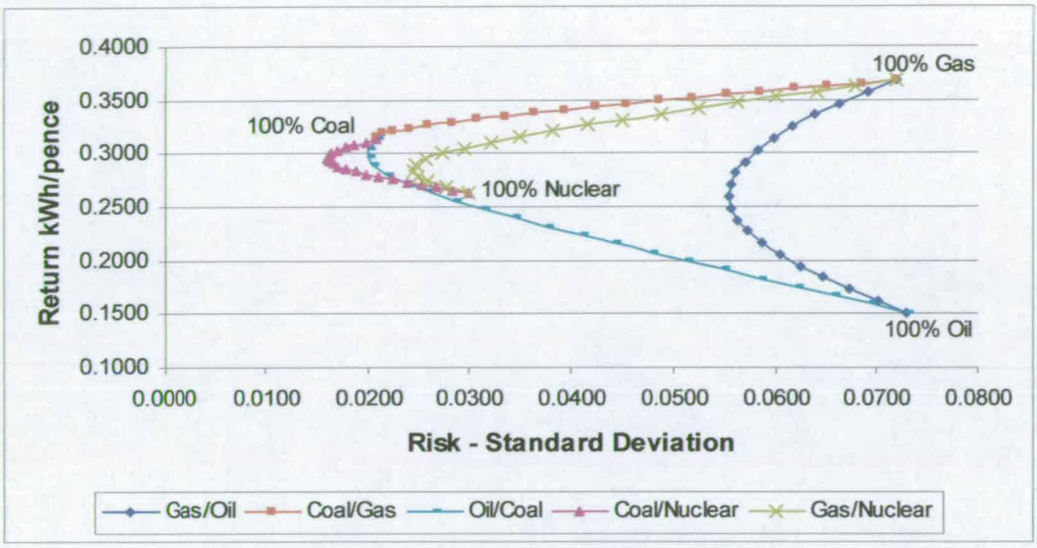

Figure 5.9– Portfolio Risk Return Curve

Zooming in on the upper section of the curves and including the efficient frontier is can be seen in Figure 5.10 how holding more than two generator types can still further reduce risk while maintaining levels of return.

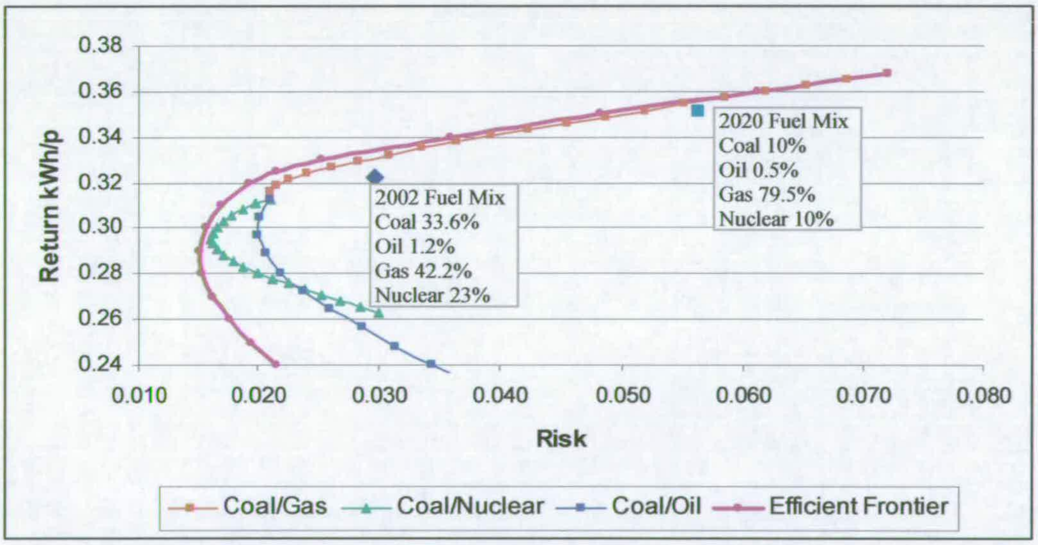

Figure 5.10– Efficient Frontier of UK Generating Assets

Marked on the graph are the points of the current UK generating portfolio and the one of the predicted possible fuel mixes in 2020[157]. By plotting on the risk/return graph the results for the two different fuel mixes it can be seen that fuel prices may be more volatile in 2020 compared with 2002. The return or profit for the ESI would also be greater in the 2020 portfolio.

These graphs are based on historical figures and movements in prices. The move away from a domestic gas resource might cause the gas prices to become more volatile, increasing the risk to the investor.

Including renewable energy into the fuel mix can lower the risk of price fluctuations of a portfolio without adversely affecting the return. Renewable energy return cost is calculated from the Renewables Obligation‡ buyout cost plus the cheapest conventional electricity. In this case it is 3p/kWh plus 2.72p/kWh. This gives a return of 0.174kWh/p.

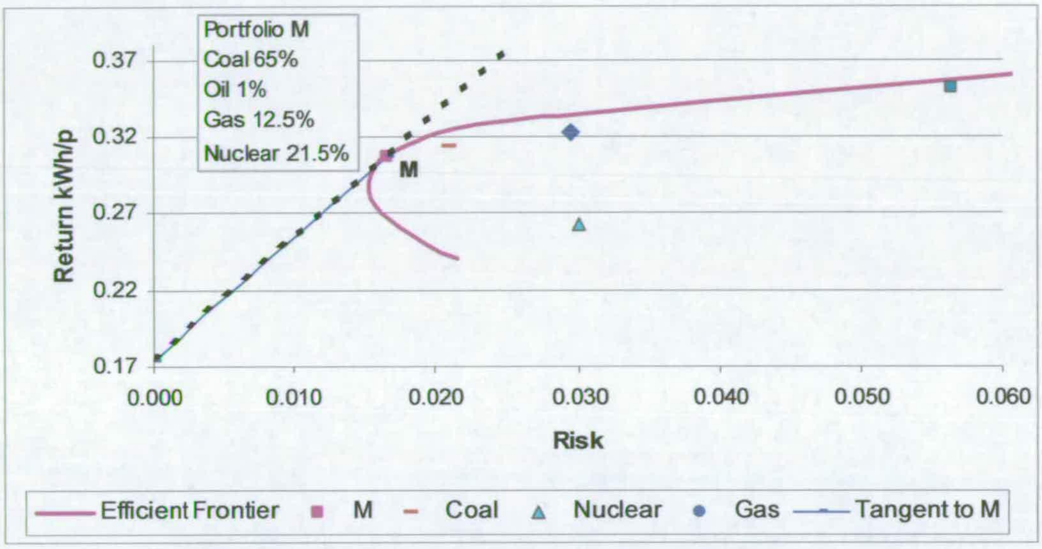

Figure 5.11- Efficient Frontier and Sharpe's Ratio Tangent

Point M on the efficient frontier is the point where Sharpe's ratio is maximised. A portfolio of mix M plus the renewable risk free asset gives the optimum risk and return. Each tick mark on the tangent line represents a 5% change between the risk free asset and the mix of assets M. In relation to the UK ESI the optimum fuel mix calculated from Sharpe's Ratio equation is made of predominantly coal (65%) and nuclear (21.%) with smaller contributions from gas (12.5%) and oil (1%). There results are counterintuitive. The predicted fuel mix for 2020 is based on market decisions and expected fuel prices in the future and gas is the favoured fuel. Using MPT, however, gives results that give preference to coal over gas.

It should be understood that MPT analysis does not result in a right or wrong answer, but offers a method of analysing the risk of a particular generation investment choice. It may be deemed acceptable in the future by policy makers and the ESI that a higher level of price volatility is acceptable if electricity prices are low.

Portfolio M is also much more like the fuel mixes the UK had during the early 1990s before gas investment increased. It was the move to gas generation from coal that led to a significant decrease in the carbon dioxide emission from the power sector.

The inclusion of an intermittent renewable such as wind power will increase the LOLP resulting in the need for extra capacity to ensure a acceptable reliability level. Through the

‡ The Renewables Obligation replaced NFFO and SRO in 2002 and it is described in more detail in chapter 5.

MPT analysis, the addition of a generator without fuel risks decreases the overall portfolio risk whilst keeping the return on the portfolio up. Therefore a balance needs to be established between objectives that want to maintain profits and objectives that want to see a decreased in carbon dioxide emissions and the increase in renewable energy penetration.

5.7 Summary

The security of electricity supply is one of the key issues of the UK Government's energy policy objectives. Other polices are to increase renewable energy generation and lower carbon dioxide emissions within the power sector. This chapter described how two different quantitative methods of evaluating the security of supply within the ESI were developed; and how, by using these methods for analysing security of supply of the ESI, the problem of achieving a compromise between economic and environmental objectives can be seen more clearly.

The first method, LOLP, was developed from a concept originally developed to evaluate thermal generation reserve requirements. This analysis was extended to include the effects of new renewable generation that has little or no influence on the security of supply of the current and future ESI. The LOLP analysis of generation capacity requirements with high levels of intermittent renewable energy showed that extra generation capacity will be needed to ensure that security levels are maintained and this will certainly incur a cost burden.

By applying MPT techniques to evaluate the efficiency of potential fuel mixes in the ESI, portfolios of lower cost or risk can be designed. The results of the analysis shows that the inclusion of fixed cost renewables to the portfolio reduce risk levels. This is an advantageous scenario as the potential uncertainty of future fuel prices increases as domestic supplies are exhausted and the UK becomes more dependent on imports.

There is, however, no definite right or wrong answer in terms of generation investment. Investment decisions in the future may be based on many factors not just economics, but also environmental issues and taking into account long term supply issues. In terms of generation investment in the UK over the next 15 to 20 years, the methods outlined in this chapter will be useful in assessing efficacy of a particular fuel mix to the energy policy goals.

Chapter 6

Regulation and Economic Instruments for Achieving the UK Energy Policy

It is accepted that gaining a benefit involves a cost and everyday decisions are made on whether the benefit gained is justified by the cost. However, in many situations the full social or environmental cost is excluded from the market price. These external costs are created from the impact of pollution or degradation of visual amenity. Electricity generation creates numerous external costs that are not included in the price of electricity, for example, the costs of militating against the effects of global warming. Yet to achieve convergence on the energy policy objectives of environmental performance, ensuring security of supply and maintaining affordability, these external costs may need to be accounted for.

Privatised industries are generally driven by the aim of maximising profits and minimising costs, therefore polices and legislative measures are usually required to influence the behaviour of private firms if the outcome of investment decisions would otherwise oppose environmental protection. A variety of approaches may be employed to control and reduce the environmental impacts associated with the generation and use of electricity, including:

- direct regulation;
- voluntary measures; and
- economic instruments.

This chapter describes the regulatory measures and economic instruments that have been and could be implemented to influence changes in behaviour towards the energy policy objectives, and describes the potential consequences for the electricity supply industry (ESI). The effects of these policies and instruments on the economic viability of the renewably produced methanol are also established.

6.1 External Cost Theory

Economics is often described as the study of how to allocate limited resources when faced with unlimited wants; and markets serve to organise this resource allocation[158]. Markets use prices to communicate the wants and limits to bring about coordinated and efficient economic decisions. Markets can be considered a real place to buy and sell goods or as a virtual tool for the exchange of goods and services. Market trading creates wealth through voluntary exchange of scarce resources when resources move from low-value to high-value uses. Markets are also effective communication channels. They use prices to reflect the wants and limits of a diffuse and diverse society so as to bring about coordinated economic decisions in the most efficient manner. The ESI is a good example of a market where consumers purchase *useful* electricity from providers who transmit it from *less useful* generation sites, who in turn generate power from *less useful* coal, gas or nuclear energy.

Markets can also fail. Markets fail when private means contradict the social ends of an efficient allocation of resources. When dealing with environmental resources that cut across nations and generations, the conditions under which markets work do not necessarily hold up.

Market failure comes about when property rights cannot be clearly defined. Markets fail when property rights cannot be transferred freely, others cannot be excluded from using the good or when rights to use the good cannot be protected. With market failure, free exchange does not lead to the socially optimal outcome because either too much of a bad effect or result such as pollution is produced or too little of a beneficial effect such as open space becomes available. Since everyone *owns* the right to clean air, no one individual owns the right and it is impossible for a market to exist.

6.1.1 Externalities

Externalities are a classic example of the consequences of market failure. An externality exists when a market participant does not bear all the costs or receive all the benefits of their action. An externality exists when the market price or cost does not reflect or excludes social impact, cost or benefit. Therefore a polluter who adversely affects the air quality is not bearing the costs of people deprived of clean air and therefore can effectively ignore these costs. Within the area of environmental economics, the inclusion of external costs in the market price of goods is seen to balance the private and social costs.

6.1.2 Types of Externalities

The previous section has focussed predominantly on the externalities of pollution from fuel cycle or processes. However, externalities range much further than just air, water land pollution. The table below shows an example of the range of externalities associated with a coal power generation station.

Category	Burden	Impact	Damage Cost/Scale	Range	Cost to Mitigate
Working Emissions	CO_2	Climate	L	G	L
	SO_2	Environment	L	T	L
	NO_2	Environment	L	T	L
	Particulates	Health	M	Lo	L
	Wastes	Environment	M	Lo	M
	Radiation	Health	S	Lo	L
Visual	Presence	Aesthetics	L	Lo	L
	Pollution	Air quality	L	R	L
Noise	C, O and M	Acoustic	M	Lo	M
	Operation	EMI on RF	S	Lo	L
Land	Presence	Sterilisation	M	Lo	L
	C, O and M	Erosion	M	Lo	L
	Fuel Extraction	Stability	M	Lo	L
Local Ecology	C, O and M	Flora	L	Lo	L
	C, O and M	Fauna	L	Lo	L
Health and Safety	C, O and M	Occupational	M	Lo	S
	C, O and M	Public	M	Lo	S
	Major accident	Society	S	Lo	S
	Major accident	Environment	M	R	M
Decommissioning		Environment	M	Lo	L

Key: C, O and M – Construction, Operation and Maintenance;
L – Large M – Medium S – Small
G – Global T – Transboundary R – Regional Lo - Local

Table 6.1 - Externalities of Coal Generation[159]

Once the externalities have been identified and their individual damage, range and cost to mitigate have been estimated the work to quantify the overall cost of the externalities can begin.

6.1.3 Methods for Quantifying Externalities

In terms of externalities there exists two categories of resource usage:

- User value
- Non-user value or existence value

Within the user value category there is both direct and indirect use. Direct use is when an agent physically experiences the commodity in question, for example when a farmer loses farmland to flooding and thus losing the benefit of growing crops. Indirect use exists when the agent is indirectly affected by the use of a commodity. Continuing the previous example, the loss of the crop a consumer who wished to purchase that crop.

Non-user or existence values occur when there is no discernible link from the good to the agent. An example could be the protection of wildlife by those who receive no identifiable benefit from its existence.

Environmental valuation methods can be categorised into:

- Stated preference methods

- Revealed preference methods
- Production function approaches

6.1.3.1 Stated Preference Methods

Stated preference approaches to environmental valuation include the following methods:

- Contingent valuation
- Choice experiments
- Contingent ranking

These methods have the common feature in that they are all based on surveys which the public are directly questioned about their willingness to pay (WTP) for certain hypothetical changes in environmental quality.

Contingent Valuation Method (CVM) is the most commonly stated preference approach. CVM has been widely adopted in numerous environmental costing projects across the world[160]. The method in principle is simple, given the absence of a value for an environmental good due to the absence of a market, CVM asks respondents how they would behave if a market did exist. For example, a question might be 'what is the maximum you would be willing to pay for an improvement in water quality to go ahead?' The important aspect of CVM is that respondents are asked what their WTP or willingness to accept compensation (WTAC) would be for a hypothetical increase or decrease in environmental quality.

Critics of CVM highlight that CVM questions ask respondents what they *would* do which may be different from what they *actually* do. Free riding, in practice, would result in the CVM value being incorrect. Also, respondents may overstate their WTP if they believe that the change may happen if they believe their answer is not linked to what they would be charged.

The other two methods of stated preference approach use bundles of attributes of an environmental good. For choice experiments the value of any environmental good is broken down into attributes, including cost and then different bundles of attributes are assessed against each other. Contingent ranking works in a similar way but a respondent would be asked to rank the attribute in order of preference for protection. By analysing the ranking the WTP for changes in a particular environmental commodity.

6.1.3.2 Revealed Preference Methods

In revealed preference (RP) approaches, the analyst tries to infer the value people place on environmental goods from their behaviour in markets for related goods. The major difference between stated preference and RP methods is that RP is based on actual behaviour rather than intentions. Two principal types of RP are:

- Hedonic pricing model
- Travel cost model

Hedonic pricing relates to the measurable increase or decrease in an individual's resources due to a change in the attributes of a good. For example, hedonic pricing is often applied to house prices and the change in the value of a property as a result in a change in environmental good. The travel cost method has been widely used in the USA in context of planning and management of outdoor recreation in national parks. Changes in the behaviour of tourists to a particular national park can be used to estimate how much value a tourist or group of tourists have on a particular environmental good, such as fishing or forestry.

Some renewable electricity generation technologies may incur an external cost under the revealed preference valuation method. There is some public opposition to onshore wind farms in particular in the Highlands of Scotland. Here some local people believe that tourists would find visiting an area with a wind farm development less attractive and the local economy would suffer as a result of loss of tourist related income.

6.1.3.3 Production Function Methods

In production function approaches the environment in typically valued as an input to the production of some market value or good. Changes in the quality or quantity of an environmental good are evaluated by estimating the implications of this change for its output. This class of methods include dose response models which are used to study the impacts of pollution on market The dose response function relates a *dose* of some kind for example pollution to the *response* and therefore a monetary cost can be attributed.

Dose response methods can be used to analyse the health impacts of pollution as a dose or concentration of that pollutant for example can be compared against the increase in certain respiratory illnesses reported at the time of a high concentration.

6.1.4 Externalities in Electricity Generation - ExternE

The generation and use of electricity produces great economic and social benefits yet at a significant environmental and societal cost. The environmental costs include airborne pollution, wastes and visual impact and social costs of for example acid rain damaging agriculture and climate change causing flooding etc. Traditionally the price paid for electricity is based on the fuel, generation, transmission and distribution costs and the external costs are ignored.

The ExternE project is a research project by the European Commission[161] which has attempted to use a consistent *bottom-up* methodology to evaluate the external costs associated with different fuel cycles. The European Commission launched the project in collaboration with the US Department of Energy in 1991 and since then a series of reports detailing the results of the external cost studies have been published.

6.1.4.1 ExternE Methodology

The external cost methods were carried out for each fuel using a bottom-up approach. A novel approach called impact pathway was developed for the ExternE project. Emissions and other types of burden such as risk of accident are quantified and followed through to impact assessment and valuation. The approach thus provided a way of quantifying externalities.

The impact pathway included both stated preference approaches (namely CVM) and dose response approaches to fully evaluate the different impacts under consideration (Table 6.2).

6.1.4.2 Externalities of Electricity Generation Fuel Cycles

Table 6.2 shows the potential external costs values for fuel cycles in the UK using the ExternE estimation methodology.

	Coal	Oil	Gas	Nuclear	Wind	Biomass
Public Health	1.66	1.40	0.23	0.15	0.06	0.33
Occupational Health	0.06	0.02	0.01	0.01	0.02	0.00
Crops	0.06	0.02	0.01	0.00	0.00	0.01
Materials	0.05	0.03	0.00	0.00	0.00	0.00
Noise	0.01	0.01	0.00	0.00	0.00	0.01
Global Warming	2.02	1.47	0.91	0.03	0.02	0.03
Total	3.85	2.95	1.16	0.18	0.10	0.39

Table 6.2 - External Costs of Electricity Generation p/kWh

6.2 Economic Instruments

Where it is felt the market is unable to deliver satisfactory results in terms of environmental impact or pollution emissions, intervention through the use of market based approaches known as economic instruments can be used. Economic instruments can be implemented in several different forms:

- Subsidies
- Green taxes
- Emissions Trading

Over recent decades the UK ESI has had experience of a number of economic instruments designed to implement specific goals.

6.2.1 Direct Regulation

Direct regulation or *command and control* approaches operate by setting out technological or performance based standards that must be adhered to, otherwise penalties are incurred. Environmentalists have preferred this method of improving environmental performance as its legalism by regulation is perceived to provide the security of environmental certainty.

Benefits of direct regulation include the effectiveness of meeting targets and ensuring pollution thresholds are not exceeded. Disadvantages of direct regulation are that there is little flexibility and revisions in target can be slow to achieve. There is also a high cost of monitoring to ensure compliance and there is no incentive to continue pollution reductions beyond target level.

6.2.1.1 The Large Combustion Plants Directive

From decisions made within the European Union the UK has had to incorporate several directives regarding the environment over the last few decades that affect the ESI in the UK. One which has had a significant impact on the ESI is the Large Combustion Plants Directive (LPCD). The LPCD[162] applies to *existing* combustion plants, i.e. those in operation before 1987, with a electrical output greater than 50 MW. The LCPD aims to reduce acidification, ground level ozone, and particles throughout Europe by controlling emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x), and dust (particulate matter) from large combustion plants (LCPs). These plants include power stations, petroleum refineries, steelworks, and other industrial processes.

The LCPD reduces emissions through stipulating that combustion plants must meet the Emission Limit Values (ELVs) supplied in the LCPD. Member States can choose to meet the obligations by either:

- Complying with ELVs for SO_2, NO_x, and dust for each plant; or
- Operating within a *National Plan*

The UK has chosen to operate within a National Plan[163] where emissions from LCPs are expressed as total emission *bubbles* for each pollutant. Emissions bubbles are calculated by calculating the emissions from each *existing* LCPs and adding them up. A national emission reduction plan must reduce the total annual emissions of NO_x, SO_2 and dust from existing plants to the levels that would have been achieved by applying the ELV described in the Table 6.3 below, to the existing plants.

Fuel	Plant Size (MW_{th})	NO_x mg/Nm³	SO_2 mg/Nm³	Dust mg/Nm³
Solid fuel[(1)]	50 – 100	500	200	50
	100 – 300	500	200	50
	>300	600[(2)]	200	100
Liquid Fuel	50 – 100	450	850	50
	100 – 300	450	400-200[(3)]	50
	>300	400[(2)]	200	50
Gaseous Fuel	50 – 100	300	35	5
	100 – 300	200	35	5
	>300		35	5

(1) Includes all types of coal and biomass
(2) Applies to units > 500MW
(3) Decreases linearly

Table 6.3- LCPD Emissions Value Limits[164]

The advantage of this plan is that emissions reduction will apply to the entire UK bubble so that plants which are more able to lower NO_x, SO_2 and dust levels can offset plant where it is more difficult or expensive.

For new LCPs the Directive stipulates that "Member States shall take appropriate measures to ensure that all licences for the construction or... the operation of new plants...contain conditions relating to compliance with the emission limit value[165]. Where the emission limit values above cannot be met due to the characteristics of the fuel (for example with the burning of coal), desulphurisation must be implemented. For smaller plants with a rated thermal input of less than or equal to 100 MW at least 60 % desulphurisation must be achieved. For the largest plants greater than 500 MW a desulphurisation rate of at least 92 % is applied.

Under the LCPD coal fuelled electricity generation will be penalised as it contains high levels of sulphur and produces large amounts of NO_x, SO_2 and dust. This will mean that coal could be removed from the fuel mix unless more expensive flue gas desulphurisation equipment and low NO_x burners are fitted. This resulted in coal plants being closed down and replaced with *cleaner* gas, meaning the fuel mix of the ESI could move towards a higher dependency on gas. In this case, direct regulation helps solve the environmental problems related to gaseous emissions but could create a more severe security of supply problem.

6.2.2 Subsidies

Subsidies are traditionally used by Governments to alter the market economics in order to achieve a particular goal. A drawback of subsidies is that if they are used long term in the electricity market they can create distortions where, for example, the subsidised technology will be used at the expense of more efficient or sustainable technologies. In the short term, however, subsides can play an important role in the development of new technologies. The Non Fossil Fuel Obligation (NFFO) and associated programmes (i.e. Scottish Renewables Obligation and NFFO Northern Ireland) is a good example of the use of subsides to influence the electricity market.

6.2.2.1 The Non Fossil Fuel Obligation

When the ESI was privatised in 1990 there was the problem of how to deal with the nuclear capacity. Private investors appeared to be unwilling to take on the financial risks of having to manage nuclear waste and cover decommissioning and waste storage costs. Unable to sell the UK nuclear power capacity, the government instead sought to finance it in a way that would complement the market system and not conflict with the European Union's prohibition against subsidising forms of energy other than renewables. The government solved this by selling the fossil fuelled plants but imposing on the new formed Regional Electricity Companies (RECs) an obligation to buy non-fossil fuelled energy. If the non-fossil energy cost more than fossil-derived electricity, a tax, called the Fossil Fuel Levy (FFL), imposed on fossil fuel derived electricity would make up the difference. The European Commission approved this subsidy of "non-fossil" electricity for eight years; the initial subsidies terminated at the end of 1998.

This system came to be known as the Non-Fossil Fuel Obligation (NFFO). Although initially designed to support nuclear energy, it has stimulated the rapid growth of renewable electricity. Since 1990, the price of renewable energy purchased by the RECs has fallen markedly - although it is not clear whether the NFFO itself is the cause or if instead market developments and subsidies in other nations have brought down industry prices worldwide.

Through five NFFO "orders" placed the fifth was the largest, with almost 1.2GW of renewable energy projects contracted. The average price of electricity was only 2.71p/kWh in comparison with an average of 4.35 p/kWh from NFFO-3in 1994[166]. The rate of the FFL was set by OFGEM each year, and currently stands at 0.3% of the cost of fossil fuel electricity supplied.

6.2.2.2 Renewables Obligation

With the ending of the support for renewables through the NFFO orders, the UK government needed to establish a mechanism to support renewable energy technologies to achieve renewable energy target of 10% of electricity supplied by 2010. A policy initiative known as the Renewables Obligation (RO) was introduced in October 2001. The RO is a number of instruments including setting renewable levels through Renewables Obligation Certificates (ROCs) and capital grants to assist development. It requires all licensed electricity suppliers in England and Wales to supply a specific proportion of their electricity from renewable sources, with a Renewables Obligation Scotland mirroring the targets. Each supplier will have to obtain a target proportion of their sales from renewable sources, or prove that someone else has done so on their behalf.

ROCs are issued to accredited renewable energy generators, and they can be sold separately to the electricity to which they relate. This allows for open trading of certificates, and allows those who have exceeded their Obligation requirements to sell to those suppliers who have been unable to purchase enough renewable energy generated electricity. Individual suppliers can also choose to "buy out" their Obligation commitment if they are unable to purchase renewable electricity or ROCs or if the price of renewable electricity is too high . The buy-out price is currently set at £30.51 per MWh. Revenues from the buy-out process are recycled to those suppliers who have demonstrated compliance by presenting ROCs to OFGEM.

In addition to the ROCs the new policy incorporates capital grants schemes to encourage offshore wind and energy-crop projects. The reason for the additional support for offshore wind and for energy crops is that unlike onshore wind, hydro and waste schemes, they are not fully competitive with conventional generation. It is believed that wave and photovoltaics are too immature technologies to play a significant role in meeting the 2010 target and therefore are also excluded from this scheme[167].

6.2.2.3 The Results of Subsidies

In an attempt to evaluate the success of subsidies it is useful to look back on the legacy of the NFFO/SRO programs. The NFFO can be considered a success in stimulating some research and development in renewable energy. Success to date can be traced to three key factors. Firstly, awards were made in rounds over time from 1990 to 1998. This allowed the technologies time to mature, with each round incorporating improvements from lessons learned in earlier phases.

Secondly, NFFO contracts are awarded as a result of a competitive bidding process within technology bands so that a landfill gas project is considered against other landfill gas projects. This has allowed each technology to progress at an appropriate pace rather than forcing it to compete against dissimilar technologies. In addition, it allows the development of altogether new bands or technologies, such as gasification of animal waste.

Thirdly, NFFO contracts were granted with long enough payment periods to allow reasonable financing of projects. Although NFFO-1 and NFFO-2 had contracts until the end of 1998, NFFO-3, NFFO-4 and NFFO-5 have 15-year contracts with 5-year grace periods, allowing projects to develop without time pressure.

The result of these strategies has been a steady decline in the cost of renewable electricity and increased competitiveness. In NFFO-4, for example, winning bids were awarded an average price of 3.46 p/kWh from 840 MW of projects. It is higher than the projected selling price of around 2.5 p/kWh of new combined-cycle gas turbines (CCGT). By NFFO-5, however, the average price for winning bids had dropped again, this time reaching a new low of 2.71 p/kWh.

A weakness of the NFFO orders are in that contracting a renewable energy development has not necessarily meant that the project has been constructed and commissioned. Some projects, especially wind power projects have had difficulty in obtaining planning consent. The last three rounds (NFFO-3 to NFFO-5) 2,647 MW was contracted However, only a third of the projects have been commissioned[168]. This problem of projects not proceeding to completion has not been solved with the introduction of ROCs. There are still no clear planning guidelines for local authorities and many renewable projects, especially wind farms, are receiving significant negative responses from local residents.

6.2.3 Green Taxes

The economist Alfred Pigou first suggested the an effective solution to pollution problems was to add a tax onto the market price of a polluting process or product. This Pigovian tax or green tax would be set to the external cost of damage suffered by those effected by the pollution[169], i.e. the marginal cost would be set to marginal benefit. By setting the price of social damage and applying that price as a tax on the polluter, the idea is that it is possible, through the market, to solve the environmental problems.

Green taxes exhibit what is known as a *double dividend.* A double dividend exists for example when a green tax both reduces the amount of pollution emitted and when revenue raised can be used to offset a distortionary tax elsewhere. A distortionary tax is a tax on something which society wants to encourage such as work or investing such as income tax. If green taxes can be used to reduce pollution and reduce income tax, for example, society benefits twice with the same economic instrument.

In principle, a choice will be influenced by the green tax. In relation to the ESI a tax on CO_2 emissions could encourage electricity suppliers to purchase from cleaner renewable or nuclear power stations rather from CO_2 emitting coal or gas depending on the levels of the tax. A generator will continue to produce electricity and pay the tax as long as the incremental benefits outweigh the additional costs, i.e. there is still a market for the electricity produced at that price. Once the green tax exceeds the incremental benefits, the generator would cease production.

6.2.3.1 Climate Change Levy

The climate change levy is a tax on the use of energy in industry, commerce and the public sector, and forms a key part of the Government's overall Climate Change Programme. The levy, it is hoped, will play a major role in helping the UK to meet its targets for reducing greenhouse gas emissions. The reforms are intended to promote energy efficiency, encourage employment opportunities and stimulate investment in new technologies.

The Government took into account recommendations that any tax needed to be designed in a way that protected the competitiveness of UK firms. The CCL entails no increase in the tax burden on industry as a whole and no net gain for the public finances as the levy is offset against cuts in employers' National Insurance Contributions (NICs). Revenues from the levy are being returned to the non-domestic sector, through a cut in the rate of employers' NICs of 0.3%. Businesses will also benefit from schemes aimed at promoting energy efficiency and stimulating the take-up of renewable sources of energy, e.g. solar and wind power. The rate of the CCL is shown is Table 6.4.

Fuel	Rate of levy
Electricity	0.43 p/kWh
Natural Gas	0.15 p/kWh
Coal and lignite Coke and semi coke of coal or lignite Petroleum coke	1.17 p/kilogram
LPG	0.96 p/kilogram

Table 6.4 - Rates of climate change levy on fuel

Exemptions to the levy include renewable energy sources and good quality CHP. Nuclear power, despite producing no CO_2 emissions, is not exempt from the levy. The Government also recognised the need for special consideration to be given to the position of *energy intensive* industries given their energy usage, the requirements of the Integrated Pollution Prevention and Control regime and their exposure to international competition.

Consequently, the Government has provided an 80% discount from the levy for those sectors that agree targets for improving their energy efficiency or reducing carbon emissions known as Climate Change Agreements (CCAs). Energy intensive users are those that operate a Part A process listed in Schedule 1 to the Pollution Prevention and Control (England and Wales) Regulations 2000[170], i.e.:

- Combustion activities
- Gasification, Liquefaction and Refining Activities
- Production and Processing of Metals
- Cement Production

The basic purpose of the IPPC regime is to introduce a more integrated approach to controlling pollution from industrial sources. It aims to achieve: "a high level of protection of the environment taken as a whole by, in particular, preventing or, where that is not practicable, reducing emissions into the air, water and land".

The main way of achieving this is to be by determining and enforcing permit conditions based on best available techniques (BAT). BAT are defined as "the most effective and advanced stage in the development of activities and their methods of operation which indicates the practical suitability of particular techniques for providing in principle the basis for emission limit values designed to prevent and, where that is not practicable, generally to reduce emissions and the impact on the environment as a whole". IPPC applies to specified installations both existing and new requiring each operator to obtain a permit from the regulator, either the Environment Agency or the local authority.

6.2.3.2 Effects of Green Taxes

Results of the CCL and associated CCA have been positive to date. Compared to the energy used in the baseline years, overall 221 PJ less energy was consumed in the 2002 period. This is equivalent to 4.3 million tonnes of carbon or 15.8 million tonnes of carbon dioxide[171]. Another important factor is that energy is achieving a higher profile within companies and businesses. Chief executives and finance directors are alert to the additional costs to their energy and to the importance of ensuring they meet their targets and maintain their levy reductions.

However, green taxes have historically been used to raise small levels of revenue rather than induce big changes in behaviour. Taxes have been set too low to encourage greater use of pollution abatement techniques or environmental protection[172]. The CCL does not discriminate between the different levels of CO_2 produced from different fuel types and is more a levy on energy use than a carbon tax.

If a true tax on the CO_2 output of electricity generation was applied renewable and nuclear electricity generators would benefit, but again coal fired power plants and to a lesser extent gas power plants would be penalised. The tax would have the effect of increasing overall electricity prices but may not encourage energy efficiency.

6.2.4 Emissions Trading

An alternative to setting a Pigovian tax is to set the quantity of the environmental commodity under consideration and allow the trading of the good on the open market. The idea for tradable permits for environmental protection was independently developed in the 1960s by T Crocker and J Dale[173] Emissions trading or Tradable Pollution Permits (TPPs) are a means of placing an economic value on an otherwise external environmental or social cost. TPPs create a market in which polluters are allowed to trade limited pollution rights. Permits may be sold by firms which have emissions levels below the allotted allowance and other firms can then use them to offset emissions above permit levels.

6.2.4.1 US Sulphur Dioxide Tradable Pollution Permits

The USA has the most extensive experience of using TPP markets to control pollution[174]. The initial moves towards the use of TPPs came in the 1970s when conflicts arose between the national targets for clean air and economic growth in polluting industries in states which were in violation of these national targets. Policy initiatives such as offsets and banking were brought together under the Emissions Trading Program in 1986. This resulted in limited emissions trading in emissions credit from 7 pollutants in 247 control regions across the USA..

In 1992, amendments to the Clean Air Act paved the way towards a national TPP market for sulphur dioxide emissions from power stations. The aim was to reduce emissions by 50% of existing levels. The market began in 1995 and 110 of the largest power stations were allocated permits based on historical emissions and then allowed to trade. In 2000 a further 800 power stations were brought into the market.

Total emissions fell by more than the target in its first phase as companies banked permits for future use. The increased volume of trading, reduction transaction costs and falling abatement costs caused the initial price of a permit to fall from $1000/tonne to $100/tonne. The falling abatement costs were a result of suppliers of the equipment cutting their costs in response to there being an alternative.

The cost savings of the sulphur trading program have been estimated at up to 50% of what the costs would have been if direct regulation had been employed. Also the total costs of the program seem to be substantially less then the benefits which include the avoided damage to health, ecosystems and recreation activities.

6.2.4.2 UK Emissions Trading Scheme

The UK emissions trading scheme is the world's first economy-wide greenhouse gas emissions trading scheme. 31 organisations or *direct participants* in the scheme have voluntarily taken on a legally binding obligation to reduce their emissions against 1998-2000 levels, with the aim of delivering around 4 million tonnes of additional CO_2 equivalent emission reductions by 2006.

Within a 'cap and trade' trading scheme, participants take on targets requiring them to reduce their emissions to a capped level. Each participant then receives allowances equal in number to its cap. Because it does not matter geographically where emissions reductions are made within the trading scheme, participants have three choices. They can:

- meet their cap by reducing their own emissions;
- reduce their emissions *below* their cap and sell or bank the excess allowances; or
- let their emissions remain *above* their cap, and buy allowances from other participants.

When demonstrating compliance, every single participant must hold allowances at least equal in number to its quantity of emissions. The result is that the total quantity of emissions across the scheme will have been reduced to the sum of the capped levels.

A participant's decision to buy, sell or bank allowances depends on how its costs of reducing emissions compare with those of other participants in the scheme. All individual decisions to buy, sell or bank lead to a market price for allowances being established (the price at which demand for allowances equals supply). The market price reflects the marginal cost of reducing emissions across the whole scheme and so sends a clear signal about the cost of complying with targets. All participants have a direct incentive to innovate and invest in new technologies to reduce their costs of complying with targets. A participant reducing its costs relative to other participants opens up the possibility of gains from trade.

6.2.4.3 Electricity Generators and the UK ETS

During the consultation phase of the UK ETS the Government recognised that there are many difficult issues to be addressed within the electricity generation sector and that the inclusion of the generators in an emissions trading scheme could impact on the various types of generation in different ways.

The involvement of electricity generation activities in the domestic trading scheme will need to be on a basis that is consistent with the Government's wider energy policy. Although electricity generation activities were not able to participate in trading from the outset of the domestic scheme, the Government considers that electricity generation activities could well have a significant role to play in trading in the future.

There are a number of difficult technical issues that will need to be resolved to develop a system that can successfully include both downstream energy users and upstream energy producers. In particular, it is important to avoid double accounting of emissions reductions.

Double accounting would occur if emissions reductions arising from reduced energy demand were credited to both the energy producer and the energy user.

There is a need to make sure that emissions reductions credited to energy users accurately reflect the actual emissions reductions that have been achieved. Discrepancies would arise if the actual fuel mix used in electricity generation departed significantly from that assumed in the calculation of emissions reductions downstream.

Currently under the UK ETS direct participants enter any indirect emissions from their use of electricity or heat into the scheme with a CO_2 emissions factor of 0.43kg CO_2/kWh. The Government has proposed that trading of ROCs should be allowed for energy suppliers with a renewable energy obligation. Where individual suppliers over-achieve their obligations, they will be able to convert their overachievement to credits measured in CO_2-equivalent and trade them under the rules of the scheme. For the purposes of the scheme, it will be assumed that electricity from renewable sources displaces fossil-fuel based generation at a fixed factor. The factor used for converting ROCs will be the same as that used for renewable energy by the Agreements and the Reporting Guidelines i.e. 0.43 kg CO_2/kWh.

6.2.4.4 Results of the UK ETS

As the UK ETS is still a fairly new market and the scope is still limited to voluntary participation, it is impossible to gauge its success at this stage. However, if the UK ETS follows the same path as the US Sulphur ETS, it offers a cost effective means of reducing CO_2 emission from the industrial and commercial sectors. The current exclusion of the power generation sector means that an average rate of CO_2 emitted from electricity generation is being used. Therefore there is little incentive for CO_2 emissions from the power generation sector to be reduced. The exception to this is the sale of ROCs to the firms within the ETS.

6.3 Implications for the Methanol Production Process

The results of the economic analysis of the methanol production process (chapter 3) show that the process is not competitive compared to conventionally produced methanol unless there is some form of external regulatory or financial support.

6.3.1 The Market for Methanol

Methanol is a versatile chemical and the future demand for methanol is reliant on the expansion of three sectors:

- Conventional chemical use
- Conventional fuel use
- Fuel cell use

6.3.1.1 Conventional Chemical Demand

Methanol has been a widely use chemical since the 1800s and current uses of methanol include as a feedstock for a variety of organic chemicals, the largest being for the production formaldehyde, acetic acid and methyl tertiary butyl ether (MTBE), a vehicle fuel additive. Other applications are as a solvent in paint strippers, plastics and car windscreen washer fluid[175].

Currently in the US the manufacture of MTBE for the use in *clean* reformulated gasoline holds 25% of the methanol market. MTBE became very popular in the early 1990's due to the US Clean Air Act Amendments (CAAA) and it is this federal regulation that is solely responsible for the demand for MTBE. MTBE has been attributed to improving air quality as a fuel additive; MTBE is a clean octane component, an octane booster and a lead replacement.

The EU does not have a single obligatory regulation that defines gasoline quality at present. However, a set of conclusions included in the European Parliament directive for fuel quality state that from 2000 steps need to be taken to limit the use of aromatics in new fuels. As this will affect the refining blending pool, European refiners will need to use MTBE to produce the required octane grade[176].

MTBE has been banned in California due to fears about water contamination. As the concerns which surround MTBE are not from the end use of the fuel rather its storage in underground tanks that is the cause of the problems, the banning of the fuel in California is seen by some as premature and somewhat misguided[177,178].

As a feedstock chemical, renewably produced methanol at around 30p/litre is uncompetitive unless the price of conventional methanol (currently around 16p/litre[179]) increases.

6.3.1.2 Conventional Fuel

In the US methanol has also been used as a fuel in a small number of specially adapted vehicles since the mid sixties as either pure methanol M100 (100% methanol) or as a mixture with gasoline M85 (85% methanol)[180]. The introduction of these flexible fuel vehicles (FFVs) was primarily to reduce the US dependency on crude oil but also based on their ability to reduce related traffic emissions. However, there has been limited success in their widespread introduction mainly due to the restricted infrastructure caused by the high cost of the fuel and the reluctance of gasoline stations to carry the cost of conversion to methanol[181]. The cost of implementing a methanol-refuelling infrastructure is between £36,000 and £45,000 for upgrading an existing station with new facilities and £20,000 to £50,000 to displace infrastructure used for petrol or diesel[182].

If these barriers to methanol as a conventional vehicle fuel were overcome renewably produced methanol could be competitive given a favourable tax regime. Table 6.5 shows the cost per litre and equivalent cost per litre for the major vehicle fuels and methanol.

Fuel	Price (p/litre)	Gasoline Equivalent (p/litre)
Gasoline (excl. tax)	18	18
Gasoline (incl tax)	72	72
Diesel (excl. tax)	20	17.2
Diesel (incl tax)	74	65.4
Conventional Methanol	16	31.5
Renewable Methanol	30	60

Table 6.5 – Comparison of Vehicle Fuel Prices at September 2003[183][184]

Tax revenue from the sale of motor spirit (gasoline) and diesel for transport exceeds £26 billion a year. If the tax on petrol and diesel was lowered by 2 pence from 54 pence per litre, the drop in revenue would be approximately £1 billion. If the government were willing to forego the tax revenue by substituting motor spirit with M85 made from renewable methanol, the equivalent cost to the Government per tonne of CO_2 avoided would be almost £3,500 per tonne CO_2 (derived from[185]). As this is an extremely high cost for avoiding CO_2 it is unlikely that the Government would support more than a small volume of methanol fuelled vehicles on the road.

6.3.1.3 Fuel Cell Demand

A more positive development is that of the interest in fuel cells for vehicle applications with major car companies all investing in prototype fuel cell vehicles. As discussed in Chapter 4, the hydrogen economy is seen to be the replacement for our current oil economy. However, the problems of handling hydrogen make it more difficult to implement. The use of methanol as a hydrogen carrier may make the transition to the hydrogen economy easier, especially for vehicle fuels.

In terms of vehicle manufacturers a decision to invest in pure hydrogen infrastructure or methanol has not been resolved, but DaimlerChrysler, Toyota and GM have all suggested that methanol may be an acceptable compromise as the intermediate hydrogen carrier[186].

Although exact numbers of vehicles can only be estimated at this time, research projects carried out in the late 1990s predicted that 100 million fuel cell vehicles (FCVs) will be on the road by 2015[187], consuming approximately 120 billion litres of methanol a year or 3 times the current world capacity. However, as these predictions of fuel cell vehicle commercialisation expected FCVs to be on the road by 2004, the 2015 target is unlikely.

As described in Chapter 3 electrical to chemical efficiency of the renewable methanol process is around 55 – 65%. If the methanol is used in a fuel cell, efficiencies of around 50 - 70% are expected (chapter 4). Therefore overall electricity to electricity efficiency will range from 27 to 45% for fuel cells. The efficiency will be much lower for combustion of methanol –

around 20%. This will mean that the cost will be 3 to 5 times greater. However, the benefits of the renewable methanol process in terms of helping increase renewable energy integration, producing a sustainable and low carbon fuel and maintaining security of supply may outweigh the costs.

6.3.1.4 Possible Role of Methanol in Future Energy Scenarios

Under future energy scenarios the "environmentally friendly" aspect of the renewable methanol fuel may justify the higher cost. The renewable methanol process incorporates CO_2 storage, renewable energy storage and provides a sustainable energy source. Therefore the future energy scenario that would include this renewable methanol process one or more of several factors will need to occur.

Firstly the Government must be willing to forgo tax revenue. As mentioned earlier a reduction of 2p per litre on conventional fuels will reduce the revenue to the Treasury by £1 billion. In this scenario the Government would need to balance the cost to the economy in terms of fuel shortages. The cost of pre tax gasoline would need to triple in cost to reach the cost level of methanol.

As described in Chapter 5 the security of supply is a concern within the energy policy. Given favourable economic instruments for CO_2 abatement and maintaining security of supply the renewable methanol production process could be used to help achieve the energy policy goals by:

- Reducing overall CO_2 emissions and
- Increasing the levels of renewable energy in the UK system and
- Keeping more secure fuels within the fuel mix of the ESI.

The attributes of reducing CO_2 emissions and increasing levels of renewable energy in the system through methanol production are only valuable once the technical limits of 20% of installed renewable energy capacity have been reached. The CO_2 that can be avoided by renewable electricity use directly is greater than the methanol production technique. Therefore there is no carbon benefit with using renewable energy if it has an alternative market. Also the price paid to renewable energy is much higher than the methanol production technique can afford. If it can be assumed that renewable energy produced that can't be accepted into the network is made available to the methanol production process at a low price it is here that the renewable methanol production technique could be viable.

To establish whether high levels of renewable energy are required for the ESI to achieve the policy objectives or whether coal will be needed to maintain security of supply despite the associated CO_2 emissions an optimal fuel allocation model was designed to evaluate all the external and internal costs of electricity generation and to evaluate the optimal least cost option of achieving the energy policy goals.

6.4 Summary

The UK energy policy goals have been set to maintain a secure and affordable electricity supply while taking into account the environmental impact of its use and production. The estimation of the external costs of the fuels cycles in electricity generation show that the effects of climate change are the greatest contributing factor. It is generally understood that the market will not deliver on the environmental objectives of lowering CO_2 and other pollutants without placing a value on the environment.

Direct regulation, for example the LCPD, is a means of forcing a particular response but it has been shown that this may not produce the most economically efficient outcome. Subsidies can be used to encourage the development of a particular technology or sustain another as in the NFFO. But in the long term this is not an ideal solution as this carries a financial burden and it may discourage long term innovation.

Emissions trading schemes such as the US sulphur dioxide program provide a market for environmental protection so that firms have to the choice whether to invest in abatement technologies or pay for additional permits. This scheme rewards successful players.

The mechanisms set up so far in the UK for environmental protection have not been designed with specific CO_2 reduction from the ESI in mind. The ROCs will continue the work on from the NFFO in subsidising renewable energy development and maintain an impetus for continued investment in renewable energy development and generation. Although there is no direct CO_2 tax the government has effectively put a price on CO_2 through the CCL and the value of ROCs in the UK ETS of £10 per tonne[†]. If this tax were imposed on the different types of generation it would result in less investment in coal unless there were another benefit (such as security of supply) for this to happen.

As described in the previous chapter the security of supply is also an important issue within the energy policy. This chapter has pointed to a scenario that has high levels of low carbon technologies, yet as described in chapter 4 these technologies have technical and economic disadvantages.

Given favourable economic instruments for CO_2 abatement and maintaining security of supply the renewable methanol production process could be used to help achieve the energy policy goals by:

- reducing overall CO_2 emissions and
- increasing the levels of renewable energy in the UK system and

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[†] 0.43p/kWh CCL value divided by 0.43kg/kWh ROC CO_2 value

- keeping more secure fuels within the fuel mix of the ESI.

The attributes of reducing CO_2 emissions and increasing levels of renewable energy in the system through methanol production are only valuable once the technical limits of 20% of installed renewable energy capacity have been reached. The CO_2 that can be avoided by renewable electricity use directly is greater than the methanol production technique. Therefore there is no carbon benefit with using renewable energy if it has an alternative market. Also the price paid for renewable energy is much higher than the methanol production technique can afford. If it can be assumed that renewable energy produced that can't be accepted into the network is made available to the methanol production process at a low price it is here that the renewable methanol production technique could be viable.

To establish whether high levels of renewable energy are required for the ESI to achieve the policy objectives or whether coal will be needed to maintain security of supply despite the associated CO_2 emissions an optimal fuel allocation model has been designed to evaluate all the external and internal costs of electricity generation and to evaluate the optimal least cost option of achieving the energy policy goals.

Chapter 7

Optimal Fuel Allocation Model for the ESI

To evaluate the viability of the renewable methanol production process, an optimal fuel allocation model was constructed to establish the least-cost options given a set of policy criteria (e.g. carbon dioxide emissions limits) and restrictions (e.g. a minimum of energy generated from renewables). In a privatised market investment in electricity generation capacity is usually assessed in terms of cost with the least-cost generating option generally being developed in response to meet future demands in electricity. If the environmental performance and security of supply issues are introduced in the investment planning decisions the external costs will need to be included in the economic evaluation.

The aim of the optimal fuel allocation model is to evaluate the least-cost generating option for a set of constraints, for example, CO_2 emissions, expected electricity cost and price risk level. There have been many discussions on the conflicts that the energy policy raises in terms of the fuel mix of the ESI, but none yet have attempted to include all the factors that affect attempting to meet the energy policy objectives. For example, to establish whether high levels of renewable energy are required for the ESI to achieve the policy objectives or whether coal will be needed to maintain security of supply despite the associated CO_2 emissions an optimal fuel allocation model was designed to evaluate all the external and internal costs of electricity generation and to evaluate the optimal least cost option of achieving the energy policy goals. The renewably produced methanol could be a means of storing large amounts of renewable energy and therefore if levels of renewable energy greater than the technical limits were needed, there then the renewable methanol might have a contribution to make to the energy policy goals.

This chapter describes the method and implementation of optimising the fuel mix.

7.1 Modelling the ESI Fuel Mix

As described in the previous chapters the renewable methanol production process only has a purpose once renewable energy can no longer be accepted into the electricity network; either for operational or economic reasons. It is therefore necessary to determine whether the UK ESI can achieve the energy policy goal of reducing carbon dioxide emissions, ensuring security of supply and maintaining affordability within currently available electricity generation technologies or whether novel technologies such as methanol production are needed.

7.2 Genetic Algorithms

Genetic programming is based on the Darwinian principle of reproduction and survival of the fittest and uses genetic operations such as crossover and mutation. John Holland's pioneering Adaptation in Natural and Artificial Systems[188] described how an analogy of the evolutionary process can be applied to solving mathematical problems and engineering optimisation problems using what is now called the Genetic Algorithm (GA). The genetic algorithm attempts to find the best solution to a problem by pseudo-genetically breeding a population of individuals over a series of generations. In the genetic algorithm, each individual in the population represents a candidate solution.

The terminology of genetic programming is borrowed from biology. The main components are genes and chromosomes. A gene represents a single parameter of a solution. A data structure which holds a string of task parameters, or genes is called a chromosome. This may be stored, for example, as a binary bit-string, or an array of integers.

To use a genetic algorithm, a solution to the problem must be able to be represented as a *chromosome*. The genetic algorithm then creates a population of chromosomes each a potential solution. Each chromosome is the assessed by the fitness function to ascertain how good a solution it is. Through the process of evaluating the fittest chromosomes and by disregarding the less fit chromosome, the genetic operators, mutation and crossover, can be applied over successive generations in order to attempt to improve on previous generations, by copying fit genetic material into next generations.

Unlike standard hill climbing optimisation, a GA creates a population of chromosomes which all are potential solutions and then by applying genetic operators such as the best solutions are found and bad solutions are discarded. In general, genetic algorithms are better than gradient search methods if your search space has many local optima. GAs overcome the inherent limitations of hill climbing (becoming stuck in local optima) by virtue of not being restricted to a single search path and using the mechanism of mutation to allow 'escape' from local optima. However, GAs are computationally demanding, although this is less of a problem nowadays especially with the advent of parallel and distributed computing.

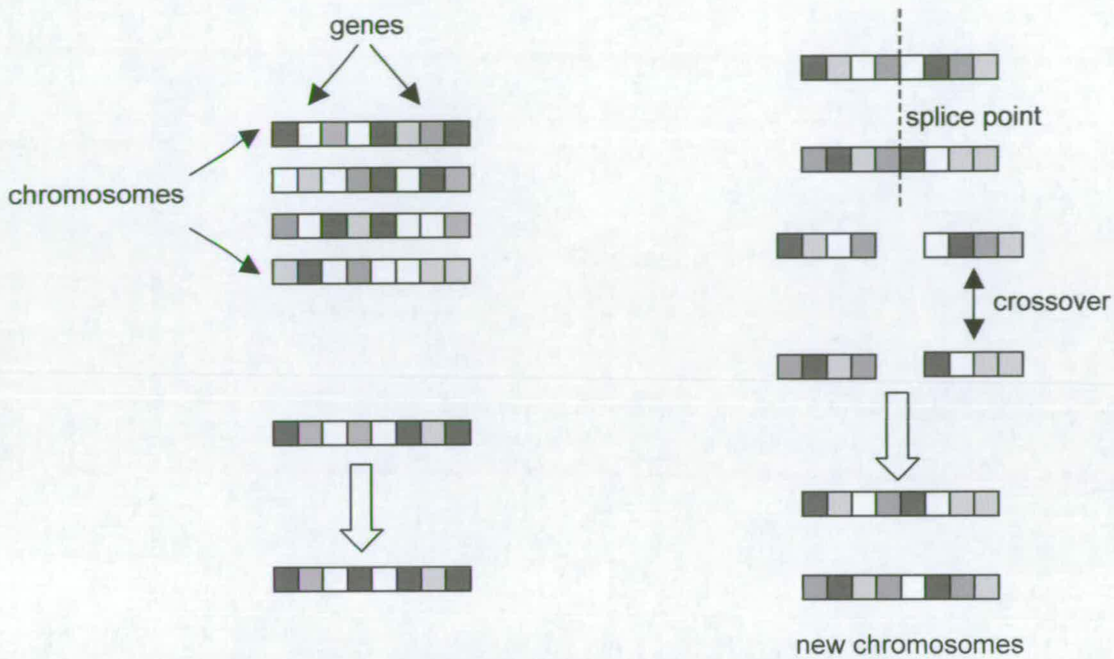

Figure 7.1 – Illustration of a genetic algorithm operations

The three most important aspects of using genetic algorithms are:

(1) The definition of the objective function,

(2) The definition and implementation of the genetic representation, and

(3) The definition and implementation of the genetic operators.

Each individual must represent a complete solution to the problem being optimised.

7.3 The Electricity Supply Industry Genetic Algorithm

To optimise the fuel mix of an ESI the chromosome was made up of genes each containing an integer representing the number of a particular type of generator.

X_1	X_2	X_3	X_4	X_5	X_6

Figure 7.2 - Representation of a GA Chromosome

Where X_n represents the number of a type of generator.

7.3.1 The ESIGA Fitness Function

The aim of the fitness function is to return a low value if the chromosome provide a good solution or a high value if the chromosomes is not suitable. Figure 7.3 shows the process of evaluating a chromosome.

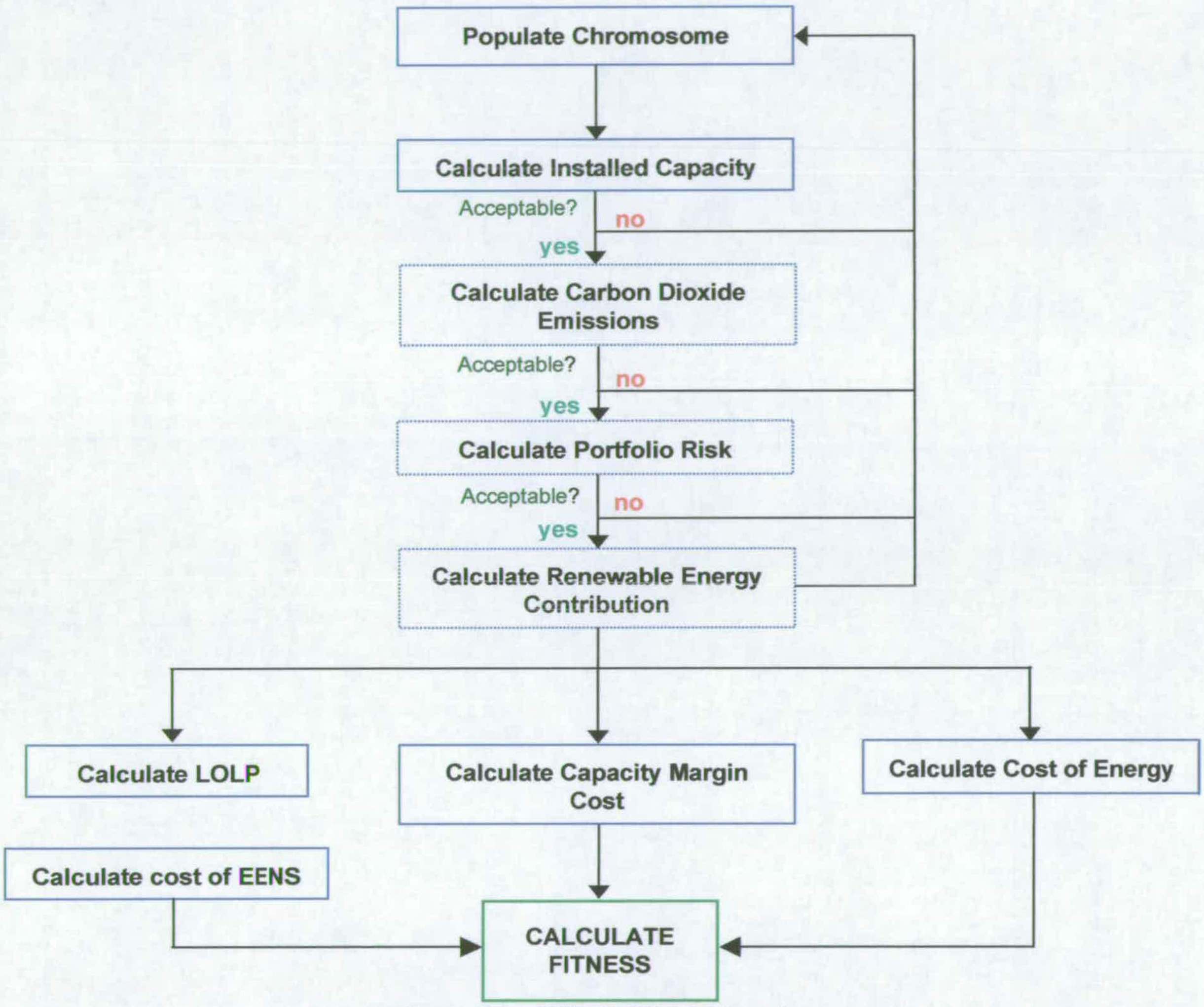

Figure 7.3 – ESIGA Fitness function

The ESIGA evaluates the fitness of a chromosome in two distinct ways. Firstly, the chromosome is tested to ensure that some basic attributes are met, the first is whether there is sufficient capacity in the solution to cover the system maximum demand (SMD). Then tests to check if other aspects of the fuel mix, such as the renewable energy provision, CO_2 emissions and portfolio risk level are satisfied.

Once these tests have been carried out, if required, the cost of providing electricity from the particular fuel mix is calculated. This cost is made of the cost of generators the electricity, the cost of expected energy not served (EENS) and the cost of capacity margin.

7.3.1.1 Installed Capacity

The first test applied to the chromosome is whether it holds generators of sufficient capacity to meet the electricity demand of the system.

$$installed\ \ capacity = \sum_{1}^{i} C_i n_i \tag{7.1}$$

where C_i is the capacity of generator i and n_i is the number of instances of generator i.

If the installed capacity of the generators does not meet the system maximum demand (SMD) the fitness value is given a very high value so that it will be deemed unfit and not reproduce. The same process is applied if the installed capacity was significantly greater than the SMD defined by an external SMD factor. The reason for allowing the installed capacity to be so much greater then the SMD was to ensure that fuel mixes which contain high levels of renewable plant are not excluded from further evaluation. As renewable energy has a much lower declared net capacity than other conventional thermal generators a much higher installed capacity was needed to ensure that further calculations could be made.

7.3.1.2 Loss of Load Probability

As described in Chapter 5 the LOLP is a probabilistic method of evaluating the security of electricity generation. To make the LOLP more meaningful it is represented in the fitness function as a cost to the system for potential loss of load.

The LOLP cost (7.2) is calculated in terms of expected energy not served (EENS) multiplied by the value of lost load (VOLL).

$$EENS = LOLP \times VOLL \times Annual\ \ Energy\ \ Demand \tag{7.2}$$

The calculation of the LOLP requires many hundreds of probability calculations. During the development of the ESIGA is was found that it was this operation of the fitness function which took up the most computational time. As a GA needs to evolve through hundreds of generations, with chromosome breeding and mutation, it is best to ensure that the calculations for the fitness function are as streamlined as possible.

7.3.1.3 Capacity Margin Cost

The capacity margin costs is the cost associated with holding extra generation within the system which is not usually required to generate over the year. This extra marginal capacity provides a certain level of security, but it carries a cost burden. The capacity margin cost for the system was calculated by adding up the capital and fixed costs per year for the generation not required to generate.

7.3.1.4 Modern Portfolio Theory and Power Generation Choices

As described in Chapter 5 Modern Portfolio Theory (MPT) can be used to evaluate the expected return and risk of a portfolio of generating assets. As there is no right or wrong answer in MPT calculations, analysis using MPT is used to establish the risk return and define a boundary where the return or risk are unacceptable to the investor. Figure 7.4 shows the flow diagram of the optimal portfolio in terms of risk and return.

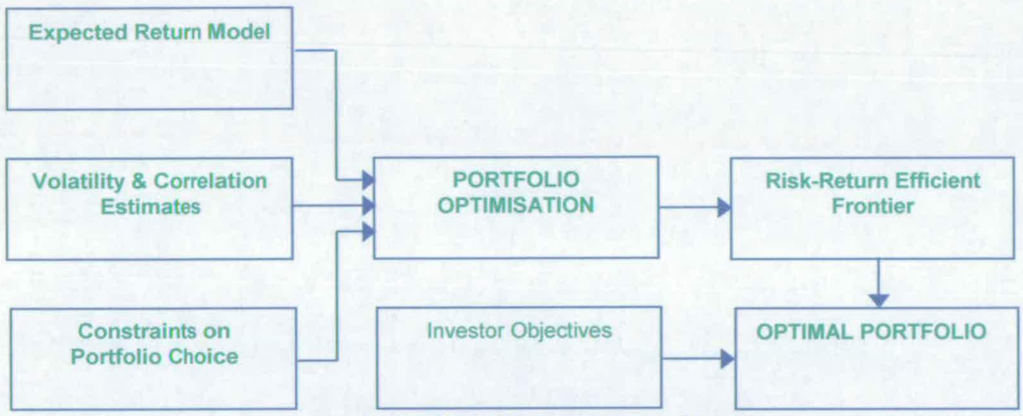

Figure 7.4- The MPT Investment Process

Using the values of risk from the calculations shown in Chapter 4, low, medium and high aversion of risk levels could be included in the fitness function. That is if the risk level of a portfolio exceeded the level of risk the ESI was willing to accept the chromosome was given a high fitness value, thus ensuring the chromosomes would not be selected for breeding in the next generation.

7.3.1.5 Carbon Dioxide Emissions

The levels of CO_2 emissions of the ESI is one of the key environmental factors for the future. Currently the levies and tax on electricity generation do not discriminate between fossil generators and their relative CO_2 output and the climate change levy does not always take into account whether a generator emits CO_2 or not.

The ESIGA was designed so that different types of economic instruments could be applied to the fuel mix. In terms of establishing CO_2 reductions the CO_2 emissions were calculated and if the level was too high the chromosome failed. Tests can also include a CO_2 tax or levy which effect the generator with CO_2 emissions.

7.3.1.6 Electricity Unit Cost

The cost of generating a unit of electricity is calculated from all the generators that are needed to meet the electricity demand in £/MWh. If economic instruments are applied to the system such as a carbon tax or renewables subsidy, the price per MWh for a generator will change.

The total cost of generating was calculated for use in the fitness function.

7.3.1.7 Chromosome Fitness

In line with least cost planning the fittest chromosome is that with the lowest total cost once other constraints (such as price risk or CO_2 output) are applied.

7.3.2 ESIGA Implementation

C++ is a popular programming language which implements software by modelling the state and behaviour of real world objects as specific data types. This programming methodology is therefore known as object oriented programming (OOP). OOP allows the user to program, and therefore *think*, more in terms of objects from the problem domain being modelled rather than upon the mechanics of the programming language itself.

ESIGA implements the following classes which describe objects required to model objects from the optimal fuel allocation problem.

7.3.2.1 Class generator

The class *generator* is a representation of an electricity generating unit in the ESI. It has the following attributes:

Class Generator Attributes	Description
Capacity	The capacity of a generator is the maximum electrical output for that unit in MW.
Maximum capacity	The maximum capacity of a generator is defined as the percentage of the SMD it can contribute to. For example, a generator may not be able to provide 100% of the UK electricity demand due to fuel import restrictions.
Carbon dioxide produced	This is the carbon dioxide produced in tonnes per MWh of electricity generated.
Availability rate	This is the value of the annual availability of a particular generator.
Merit Order	The merit order of a generator describes its priority to generate. For example, nuclear power stations are not suited to load following therefore they usually hold a high merit order position i.e. they generate all the time as a base load. Oil generation on the other had can be ramped up and down and therefore may hold a lower merit order position.
Fuel cost	This holds the fuel cost per MWh of electricity generated.
Capital cost	This holds the value of the annual capital and fixed costs for a generator.
Whether it is renewable or not	Certain aspects of the GA fitness are conditional on whether a generator is renewable or not. This attribute indicates this.

Table 7.1 – Class *Generator* Attributes

7.3.2.2 Class probability

The probability class provides a convenient means of accessing any function associated with calculating probabilities. The class provides the following functions:

Class Probability Attributes	
getFailure	This function given a number of generator in the system and the availability rate of these generator calculates the overall probability of failure for a particular number of these generator not being available. The returned value is used by the Loss of Load Probability calculation.

Table 7.2 – Class *Probability* Attributes

7.3.2.3 Class duration

The duration class provide a convenient means of accessing any function associated with the annual energy demand profile. The class provides the following functions:

Class Duration Functions	Description
getFromFile	This function reads in a data file containing the load duration curve data. The input file is describe in pairs of numbers, one is the percentage of the SMD with a corresponding percentage of the year this demand occurs.
getLoadDuration	Given a percentage of SMD this function returns the percentage of the year for which the demand is required.
yearEnergy	This function calculates the annual yearly electricity demand from the SMD and the area under the load duration curve.

Table 7.3 – Class *Duration* Attributes

7.3.2.4 Class chromosome

The chromosome class contains the functions and attributes required to create, evaluate and breed a solution within the GA framework. The Chromosome class contains the following attributes

Class Chromosome Attributes and Functions	Description
geneSequence	The gene sequence is a vector (or array) of integers representing the number of each type of generator within the current system.
getFitness	This function evaluates the overall fitness of the gene sequence. The evaluation takes in to account the factors described in Section 7.3.1
breed	Given two chromosomes as parents this function picks a random point on the gene sequence and splices the two sequences together creating two new offspring. Each gene within the offspring has a chance of mutating. The chance of a mutation occurring is defined as system constant. If mutation does occur then the current gene is replaced by a completely new random value.

Table 7.4 – Class *Chromosome* Attributes

7.4 The ESIGA Input Data

The generator cost data used in the ESIGA was derived from power station construction data published by the International Energy Agency (IEA) based on new build generation projects around the world in the late 1990s[189]. The fuel costs were calculated from the efficiency of each generator type and the fuel price in the last quarter of 2002. In practice, generator operators negotiate fuel supply contracts for month or years ahead. This can mean that fuels may be available at a different price to the published beach price.

Attribute (p/kWh)	Gas	Coal	Oil	Nuclear	New Coal	Renewables
Investment	0.85	1.50	1.50	2.50	2.00	4.8
Fuel	1.57	1.20	4.61	0.30	2.80	0.0
O&M	0.30	0.50	0.50	1.00	0.50	-
Total Cost	2.72	3.20	6.61	3.80	5.30	4.80

Table 7.5 - Generator Cost Data[181]

The capacity of each type of generator was based on an average size for that type of generator. In reality generator can be built in a wide range of output capacities however, for ease of calculation the unit size for each generator were kept the same. The reliability of the generators was set at 85%, a figure commonly used in reliability studies[190].

The power generation costs data agreed with published cost estimates from other sources, for example from Department for Trade and Industry (DTI) prices and the Royal Commission on Environmental Pollution publications[191][192].

It was assumed that the renewable energy contribution would be from unpredictable sources such as wind. There are other renewable generation technologies that are predictable but the largest renewable energy resources in the UK are from unpredictable sources therefore they have been used in this study. To simulate the probable large scale wind farms the renewable energy unit was assumed to be 100MW in capacity.

The ESIGA uses a system that has a systems maximum demand (SMD) of 50 GW. This is comparable with the SMD of England and Wales. A smaller system SMD was used to improve on the speed of the ESIGA calculation without risking the accuracy of the results.

7.4.1 ESIGA Output Format

The fittest chromosome and therefore the optimal fuel allocation for a scenario is shown as a series of integers where each represents a number of generator in the systems. The sequence is the same as the merit order, i.e. [4][5][6][7] represents: 4 wind farms, 5 nuclear generators, 6 gas generators and 7 coal generators. This information is followed by the value of the fitness, and the component parts of the fitness value (cost of electricity, LOLP cost and capacity margin costs).

Chapter 8

ESIGA Simulation Results

For the renewably produced methanol process to be viable several factors must be satisfied. Firstly, there must be a requirement to reduce CO_2 emissions beyond targets that conventional generation can meet and secondly, there must be a demand for renewable energy that exceeds the technical limits of renewable energy integration.

To investigate the results of least cost planning with different polices and targets based on the energy policy objectives, a series of scenarios were implemented using the electricity supply industry genetic algorithm (ESIGA). The scenarios were defined by applying different targets on the fuel mix result such as minimum renewable energy contribution and carbon emissions limits and by applying economic instruments for example, carbon tax. The scenarios placed restrictions or boundaries on the fuel mix with solutions failing these restriction or criteria being regarded as unfit.

8.1 Unconstrained Market Scenario

The first scenario run on the ESIGA was an investigation of the optimal fuel mix given no other constraints on the market or fuel supplies. The aim of this scenario was to investigate the ideal ESI fuel mix in 2020. The predicted generator installed capacity was not included so as not to influence the results.

In the unconstrained scenario, there was no restriction on how much energy a particular generator could provide to the system, thus disregarding fuel supply and security constraints, and there was no limit on the CO_2 output from the ESI .

The generator input data used is shown in Table 8.1

Generator Type	Renewable?	Capacity	Reliability q	Availability	CO_2 t/MWh	Fuel Cost £/MWh	Capital Costs £millions
Wind	1	100	0.70	0.30	0.0	0.0	12.7
Nuclear	0	1000	0.15	0.85	0.0	3.0	260.0
Gas	0	350	0.15	0.85	0.8	15.7	30.0
Coal	0	500	0.15	0.85	1.2	12.0	74.5
New Coal	0	500	0.15	0.85	0.2	28.0	81.9

Table 8.1 – Generator Input Data (derived [181])

8.1.1 Results of Unconstrained Scenario

Given the generator data above the ESIGA returned 174 gas generators and 1 wind generator as the optimum solution. The table below gives an example of the output data from the ESIGA.

Fittest Chromosome	Installed Capacity MW	Fitness Value	Margin (% of SMD)	LOLP %	Power Cost (total £)	Power Cost (£/MWh)	CO_2 Emissions (Mt)
[1] [0] [174] [0] [0]	61,000	9.96501×10^9	22.0	0.01	9.3389×10^9	32.25	117.6

Table 8.2 – Results of Unconstrained ESIGA run

The result of the ESIGA returning a gas dominant fuel mix is not unexpected as the gas generation has the lowest running cost and lowest fixed costs. Therefore, given the gas prices assumed (based on current values) it is the least cost fuel mix.

The inclusion of one wind farm unit of 100MW is explained by the improvement in reliability with the lowering of the LOLP. Table 8.3 shows the fitness, and fitness function attributes of the chromosome and surrounding options.

Chromosome	Fitness	LOLP Cost	Margin Capacity Cost	Power Cost
[1] [0] [174] [0]	9.965×10^9	0.085×10^9	0.540×10^9	9.339×10^9
[0] [0] [174] [0]	9.967×10^9	0.089×10^9	0.540×10^9	9.338×10^9
[0] [0] [175] [0]	9.970×10^9	0.062×10^9	0.570×10^9	9.338×10^9

Table 8.3 – Breakdown of Chromosome Fitness

The inclusion of a wind farm in the fittest chromosome improves the security of the system by lowering the associated LOLP cost (the cost of losing the electricity supply). The system with 175 gas generators has a much lower LOLP (0.0086% compared to 0.011% of the fittest chromosome) and therefore lower LOLP cost, but this benefit is counteracted by the additional marginal capacity requirement and associated cost.

8.2 Renewable Energy Contribution Targets

Central to the UK energy policy, the government is aiming for the contribution of renewable energy to meet 10% of electricity demand by 2010 and 20% by 2020[193]. It is not yet fully understood what effect high levels of intermittent and unpredictable generation will have on the security of the system. Technical and operational limits of intermittent renewable energy are quoted to be around 20% of SMD before stability issues arise. To investigate the impact of intermittent renewable energy on the security of the system, the ESIGA was set up with minimum renewable contribution constraints forcing the renewable energy contribution above this 20% level. This minimum renewable energy constraint is applied as an absolute 'unfitness', if the target is not met, simulating the direct regulation approach.

The generator input data used was the same as shown in Table 8.1. The fitness function also had a constraint on the minimum renewable energy contribution calculated as a percentage of annual electricity demand in MWh..

8.2.1 Results of Renewable Energy Contribution Scenario

The results of the renewable energy contribution scenarios are shown in Figure 8.1.

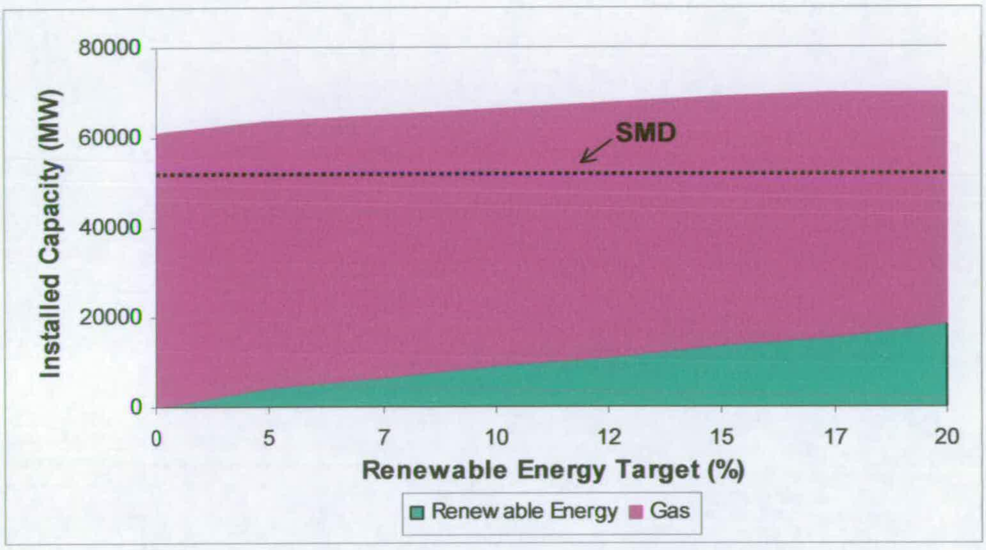

Figure 8.1 – Optimal Fuel Mix with minimum renewable energy targets

With no renewable energy contribution target the results of the ESIGA returned the same values as the unconstrained scenario. The fuel mix of the ESI would not contain any renewable energy component if it were not for external financial support and the direct regulation target. The installed capacity at this point is 61MW, a capacity margin of 22%.

As the level of renewable energy increases the total installed capacity of the system increases, yet the margin capacity (i.e. the capacity held to maintain security of supply) stays the same. The security of generation is maintained by the gas generation. This is because adding a unit to a system will only ever improve the security of the system by lowering the LOLP. However with adding renewable generation, the contribution to lowering the LOLP or their load carrying capability is much less than conventional generation. The results of this scenario show that unpredictable intermittent generation cannot displace conventional generation if security of supply is to be maintained. The overall installed capacity of the system increases as a result.

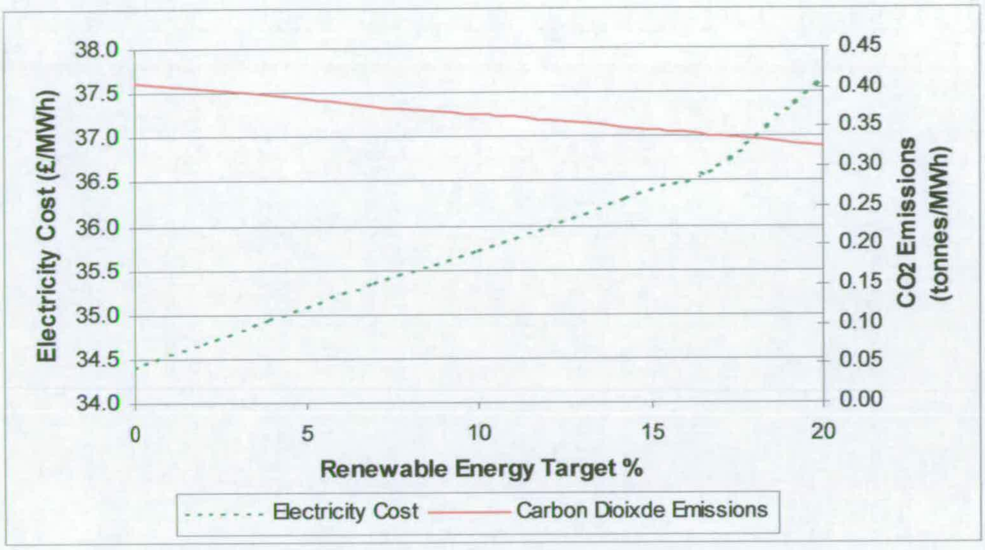

Figure 8.2 - Cost of Electricity and CO_2 emissions

The average cost of electricity (Figure 8.2) increased as the renewable generation level increased, however, this is as a result of the higher cost of the renewable generation, not as a result of extra margin capacity. After the renewable energy level exceeded 15% of energy supplied the security of the system was reduced. The LOLP of the system increased from 0.01% to 0.055%. This increase of the LOLP occurred because the cost of increasing the capacity margin was greater than the costs associated with electricity outages (LOLP cost). The ESIGA optimised in favour of lower cost and a higher risk over higher costs.

The consequence of the security limit of high level of intermittent renewables is that the 10% energy target cannot be met with intermittent sources such as wind. To ensure renewable energy supplies 10% of total demand, a generation capacity of over 20% of SMD needs to be installed. There are other renewable technologies that can contribute to the energy supply, for example, hydro, energy from waste schemes and biomass technologies, however their contribution is limited either by resource or generation cost. The problem arises if there is the need or demand to have a greater supply of energy from renewable sources. Wind and marine power have the greatest resource and are the only potential large scale renewable resources available for the UK.

The carbon dioxide emissions from a system made of renewable and gas generation are lower than current levels (Figure 8.2). In 2001 the UK ESI contributed an estimated 160 million tonnes of CO_2 ($MtCO_2$) to the total UK emissions, equivalent to an average of 0.43 tonnes/MWh. If all electricity were generated from gas CCGTs the average emission would be around 0.4 tonnes/MWh, a decrease of almost 10% on current levels. With the increased level of renewable energy the CO_2 emissions per MWh (tCO_2/MWh) decreases from 0.37 tCO_2/MWh at 10% renewable energy supply to around 0.32 tCO_2/MWh when renewable energy makes up 20% of the energy supply.

With an average of 0.37tCO_2/MWh the UK CO_2 ESI emissions would be reduced by 20% or by almost 30% if average emissions were reduced to 0.32 tCO_2/MWh. In terms of the total emissions in the UK this is equivalent to around a 8 to 10% reduction in CO_2 emissions, assuming no changes in the other sectors. This is sufficient to meet the UK's 2010 emissions target, however, the ESI would not be able to contribute to more reductions without external support or regulation. Also the gas/renewable system may not be feasible in terms of the risk of relying on one fuel.

8.3 Applying Fuel Supply Constraints.

From the previous discussion it would be an ideal situation for the ESI to consist of predominantly gas generation as it is the lowest cost option and theoretically provides a secure (in terms of LOLP), lower CO_2 emissions. However, from the discussions regarding security of supply, it not an ideal situation to have too great a reliance on one form of fuel. As the second scenario showed, renewable energy cannot be relied upon to provide any firm capacity therefore if gas cannot be the only fuel, a means of finding the optimal fuel mix needs to be included.

To investigate the best mix to reduce supply and fuel price risk the principles of modern portfolio theory (MPT) are applied to the fitness function. As described in Chapter 5 the variance and covariance of the fuel prices were calculated from the quarterly fuel prices over the period from 1990 to 2002. The variance represent the price risk associated with each fuel type. A high variance may results in volatile electricity prices whereas a low variance prices are likely to be more stable.

	Coal	Oil	Gas	Nuclear
Coal	0.021	-0.036	0.184	-0.130
Oil	-0.036	0.073	0.170	-0.370
Gas	0.184	0.170	0.072	-0.270
Nuclear	-0.130	-0.370	-0.270	0.030
New Coal	0.021	-0.036	0.184	-0.130
Renewables	0.000	0.000	0.000	0.000

Table 8.4 - Variance and Co-variances of Fuel Prices

The generation cost and capacity data remained unchanged. Renewables account for 20% of the installed capacity.

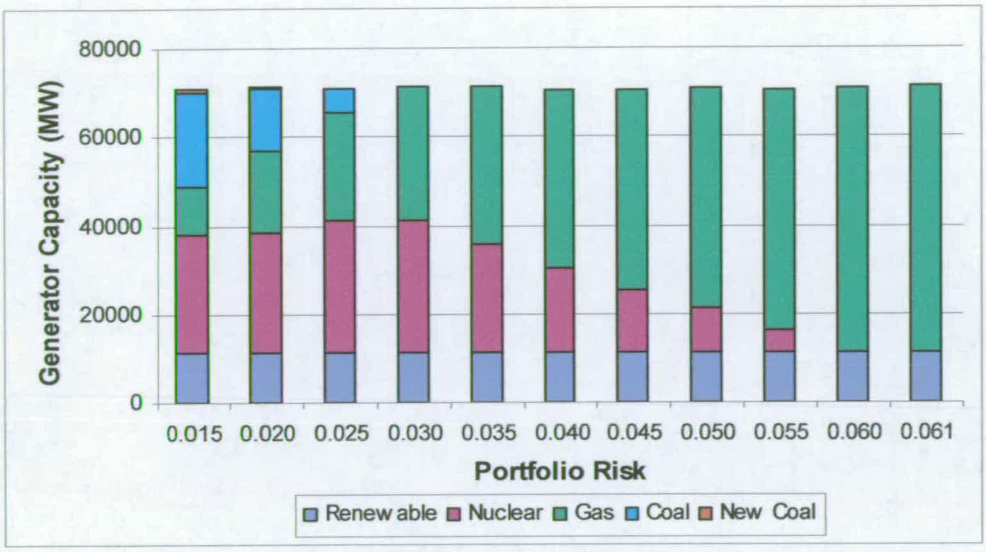

Figure 8.3 – Fuel mix with portfolio risk

Figure 8.3 shows the result of the ESIGA with limits to the variance or risk of the portfolio. Gas is the least cost fuel for electricity generations but it has exhibited a higher variance to other generators. At low variance limits (~0.015) the fuel mix is a balance of renewable, nuclear, gas and coal with a small amount of new coal. As the variance limit is increased coal generation is replaced by gas generation. The nuclear contribution provides a limit to the variance but as the variance limit is further increased the cheaper gas option increases, displacing the more expensive nuclear.

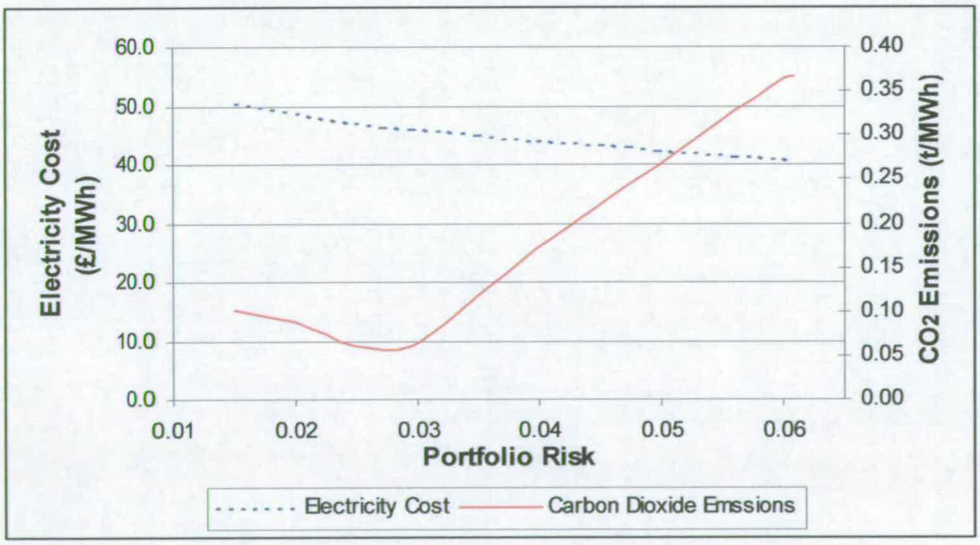

Figure 8.4 - Cost and CO_2 emissions

From Figure 8.4 the results show that a low risk and low CO_2 emissions can be achieved but only with a higher electricity cost. The lowest point on the CO_2 curve is the fuel mix with the highest nuclear capacity. Nuclear is both a non carbon technology and has a relatively low price risk. However, it is more expensive. The electricity costs are higher than when the risk was set to zero in the fitness function as the generator with the lower price risk are more expensive than the gas generation. This simulation assumes that gas prices remain the same over the next 15 years despite having a higher price risk.

If the ESI were to exhibit a very low price risk level, this would need to be achieved through direct regulation or taxation on gas generation. As Figure 8.4 shows, the market would favour the relatively low cost gas option, which incurs a high price risk. If the ESI is to reach a steady-state low risk fuel mix a 'nuclear obligation' in the same framework as the renewables obligation or non-fossil fuel obligation would be required. Alternatively, capacity payments would need to be re-introduced to encourage generators to maintain there units despite them only providing security backup. This would encourage investment in coal or nuclear that would otherwise not happen as lower cost options exist.

8.4 Effects of Carbon Taxes on the ESI

To investigate the effect of levying a carbon tax on electricity generation, the ESIGA was run with a tax of £10 per tonne of CO_2 applied. The effect of this tax on the optimal fuel mix was evaluated from increasing levels of portfolio risk i.e. allowing increasing contributions of gas generation into the system. Figure 8.5 show the optimal fuel mixes for different risk levels.

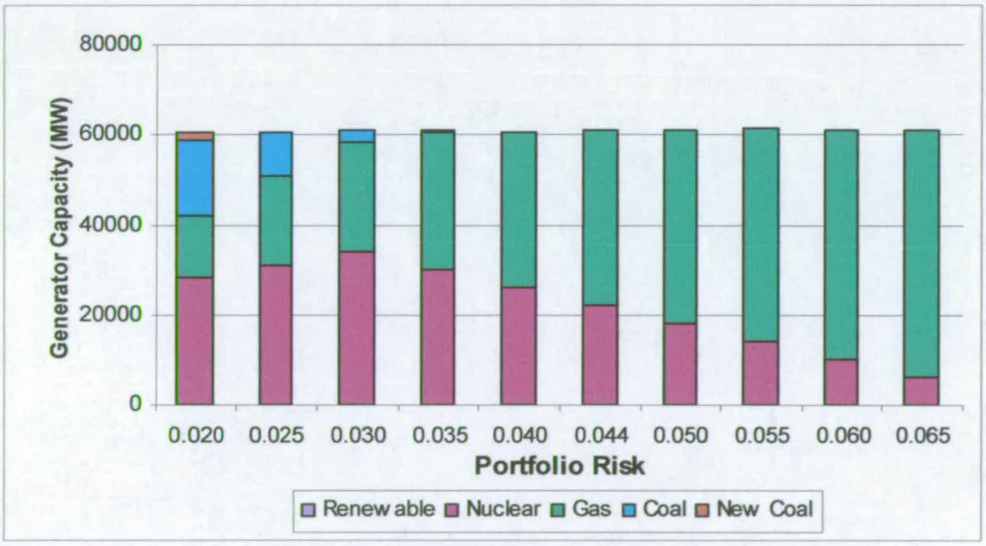

Figure 8.5 - Optimal Fuel mix with £10 CO_2 tax

Without the minimum renewable energy constraint applied to the systems it is interesting to note that renewable energy is not included in the optimal fuel mixes with a carbon tax applied. The ESIGA results favoured the better security and reliability of nuclear over the intermittent renewables. The costs for this system were higher due to the added cost of the tax being included. Figure 8.6 shows the cost and CO_2 emission for the fuel mixes.

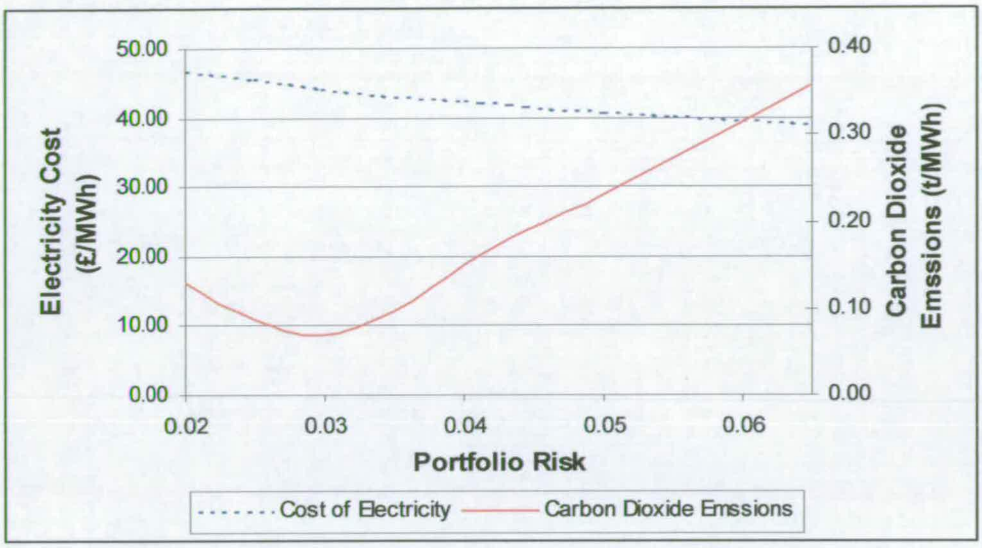

Figure 8.6 – Cost/Emissions Graphs for £10 tax no renewable energy target

It is interesting to note that the CO_2 emissions reach the lowest point when the portfolio risk is limited to 3%. This mix contain 55% nuclear, 40% gas and 5% coal. With this fuel mix the minimum CO_2 emissions drop to 0.07tCO_2/MWh, equivalent to a total of 20MtCO_2 a drop of 140MtCO_2 from the ESI. This drop in CO_2 emissions would be enough to meet the Government target of a 20% reduction in GHGs.

The low carbon dioxide emissions, however, come at a price. To achieve the low level of emissions would cost £45/MWh in comparison to £34/MWh for a gas dominant ESI. The fuel mix would also need external intervention to achieve such a market make up.

The carbon tax is needed to make nuclear more attractive financially and the limit on the variance by a direct regulation mechanism helps by reducing the contribution that gas generation can make to the system.

Another problem relating to the system is the high level of nuclear generation. It is the closure and decommissioning of the current UK nuclear capacity that will create a shortfall over the next decade. Despite the benefits nuclear can offer in terms of low CO_2 emissions and a high level of security of supply and reliability, there is still public opposition to its development.

If it is the case that nuclear is not a option that an be considered due to public concerns, alternative technologies will be needed that can provide low CO_2 emissions but secure energy. This is the potential market for new coal generators with CO_2 separation equipment. New coal generation offers the same security that conventional coal has, i.e. fuel storage capabilities, relatively low price fluctuations and large reliable generating station. The new coal technologies are low carbon.

Figure 8.7 shows the results of the carbon tax scenarios where nuclear is excluded from the fuel mix and the portfolio risk is limited to 4.5%.

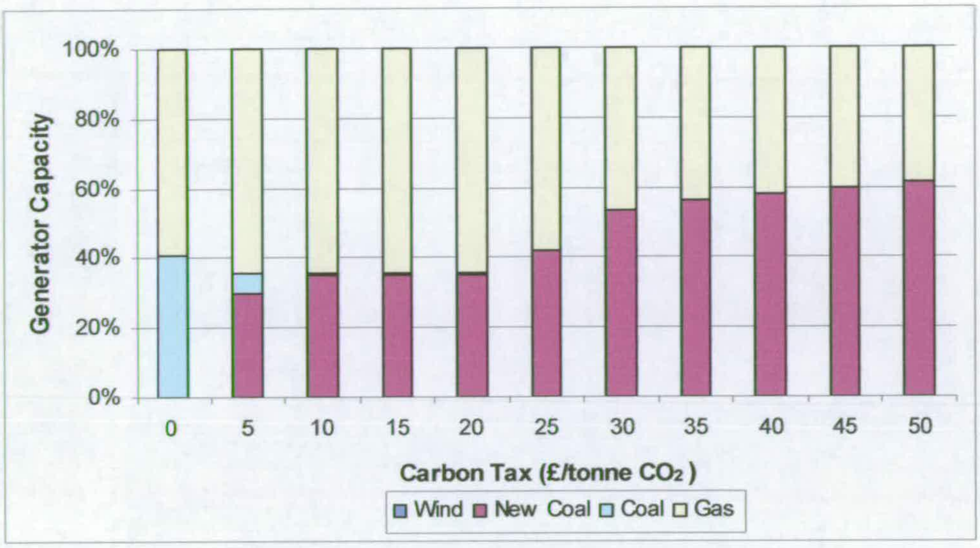

Figure 8.7 – Fuel mix carbon tax and no nuclear

At low levels of carbon tax coal and gas make up the fuel mix. As the tax increases conventional coal becomes too expensive and the capacity is replaced by new coal. The gas is limited by the restriction on the portfolio risk level.

Figure 8.8 shows the cost and CO_2 emissions from the different fuel mixes. The electricity cost rises as a result of the carbon tax and the increases in cost of the generation.

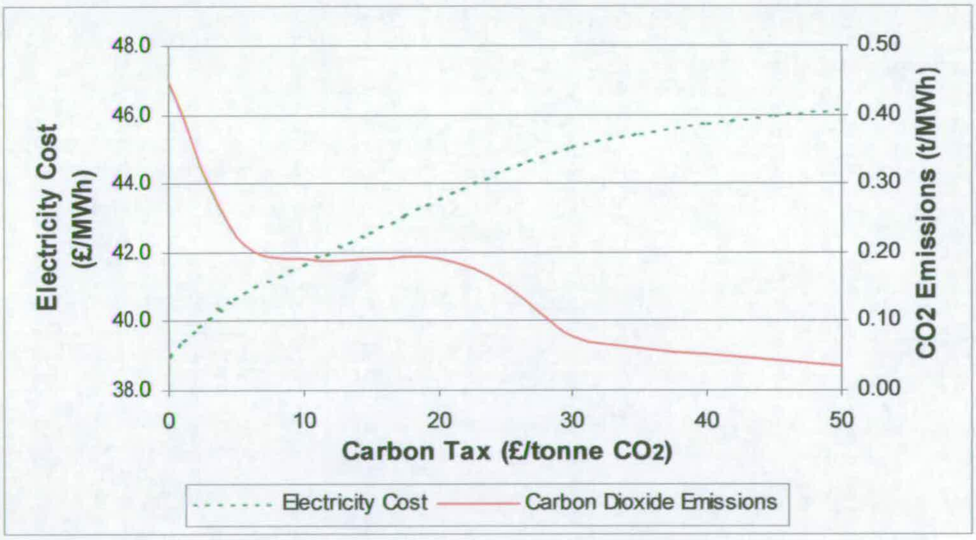

Figure 8.8 – Carbon tax and electricity costs

The use of a carbon tax may not be the most effective mechanism for encouraging investment in low carbon technologies. The inefficiency of applying a carbon tax can be seen in the CO_2 emissions curve. There is a drop in emissions when the tax is first levied, but once the tax reaches £10/tCO_2 the level of CO_2 emitted remains constant until the tax reaches £20/tCO_2 and the next low carbon technology becomes economic.

The issue of what to do with the CO_2 once it has been captured still remains. In the short term the CO_2 could be used in enhanced oil and gas recovery in the North Sea oil and gas fields, as the least cost option for large disposal, as discussed in Chapter 4. The renewable methanol production technique can only sequester a relatively small amount of CO_2, depending on the renewable energy supply, and therefore cannot contribute significantly to storing the CO_2 emissions from the ESI.

8.5 Setting Carbon Targets

Under the Kyoto protocol the UK Government pledged to reduce CO_2 emissions by 12.5% by the period 2008-2012. At that time an even more ambitious domestic target was set of a 20% reduction in CO_2 emissions by the same period. Most of the reductions in CO_2 the UK has achieved over the last decade has come from changes in the fuel mix in the ESI, a drop from 212MtCO_2 in 1990 to 153MtCO_2 in 2001. As a result there may be a greater pressure for the national targets to be met from reductions in the power sector. Table 8.5 shows the required emissions reductions to meet the 12.5% and 20% reductions targets.

CO_2 Reduction Target	CO_2 Reduction (MtCO_2)	Average CO_2 Emissions per MWh (tonnes)
0% (1990 ESI Emissions level)	0	0.73
-12.5% of ESI total	19.2	0.64
-20% of ESI total	30.6	0.58
-12.5% of 1990 UK total	80.8	0.35
-20% of 1990 UK total	124.8	0.24

Table 8.5 – Emissions reduction required to meet 2010 targets

The average emissions from the ESI currently stands around 0.5tCO_2/MWh which is a reduction of greater than 20% since 1990.

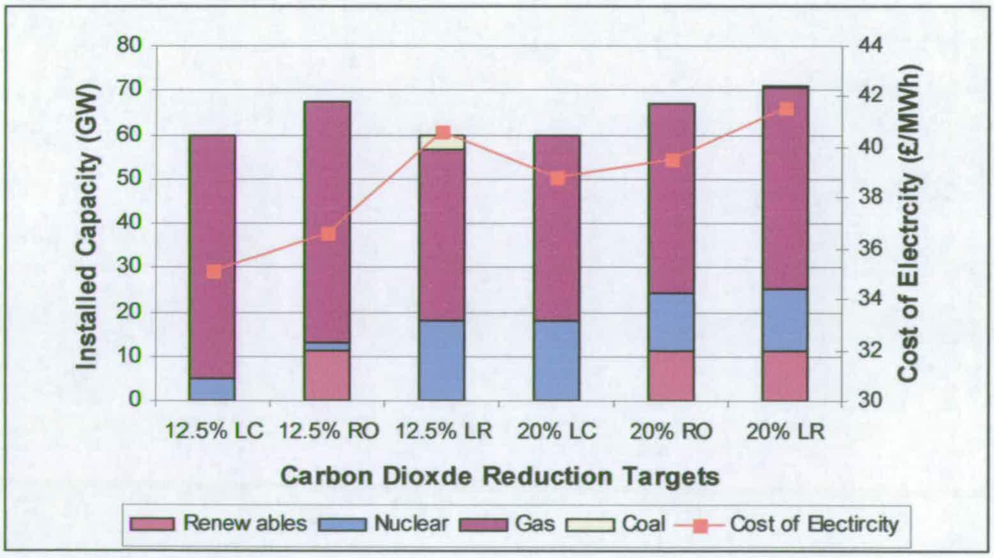

Figure 8.9 - Fuel mixes for 12.5% and 20% carbon targets with least cost (LC), with renewable obligation (RO) and with low risk (LR) scenarios

Figure 8.9 shows the ESIGA optimal fuel mixes for the ESI to achieve a UK wide reduction in CO_2 emissions. The least cost (LC) options do not include any renewables as the cost of installing nuclear is lower in terms both the £/MWh cost and the lower LOLP cost. With the renewables obligations (RO) target included in the 12.5% target the contribution by nuclear decreases, yet the overall installed capacity increases to accommodate the renewables. The low risk (LR) option includes a small number of coal generators to lower the overall price risk of the system. The displacement of gas by coal increases the average cost by 10%. The CO_2 emissions remain lower however, as the coal generation principally provides capacity for security and would not usually be used for electricity generation. With the 20% reduction targets the fuel mixes follow a similar trend however, the contribution by nuclear is greater. However, the cost increases by over 30% as the objectives of low CO_2 emissions and increased security are included into the scenarios.

8.6 Investment Implications for the ESI

The aim of these simulations was to establish the least cost fuel mix for electricity generation in 2020. The results of these scenario analyses shows that the targets for CO_2 reduction and continued security of supply are possible, however, some generation units can take many years to plan and build, up to 7 - 10 years for nuclear generation. Therefore for a particular mix of generation to be in place by 2020, investment decisions will need to be made much earlier.

In May 2003 the UK had a generation installed capacity of over 70GW. Figure 8.10 shows the percentage installed capacity from the main generator types.

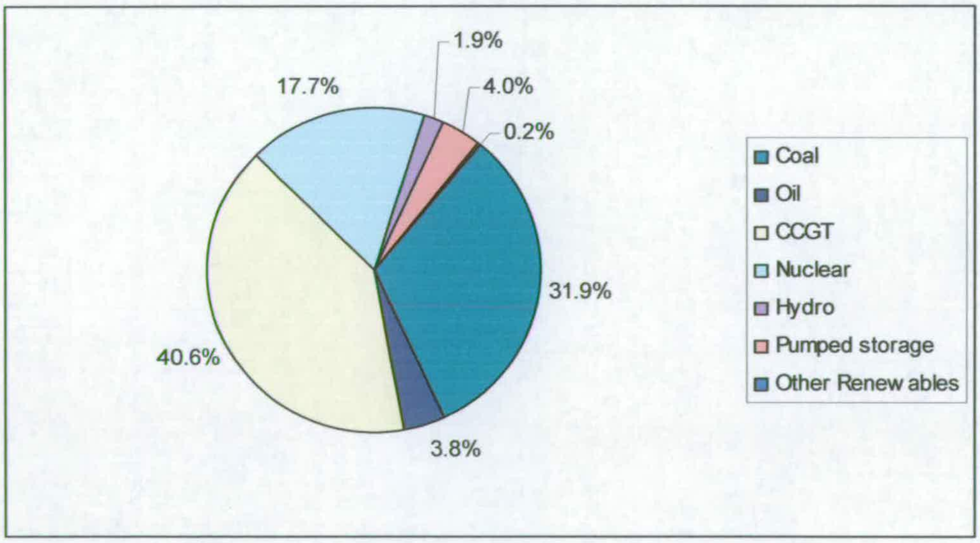

Figure 8.10 – UK ESI Generator Installed Capacity

Over the next 15 years, approximately a half of the current installed generation capacity will be decommissioned in the case of nuclear or closed due to emissions restrictions in the case of coal. This will mean that 35 GW of generation capacity will need to be constructed to ensure that demand is met. Figure 8.11 shows the estimated installed capacity for 2020.

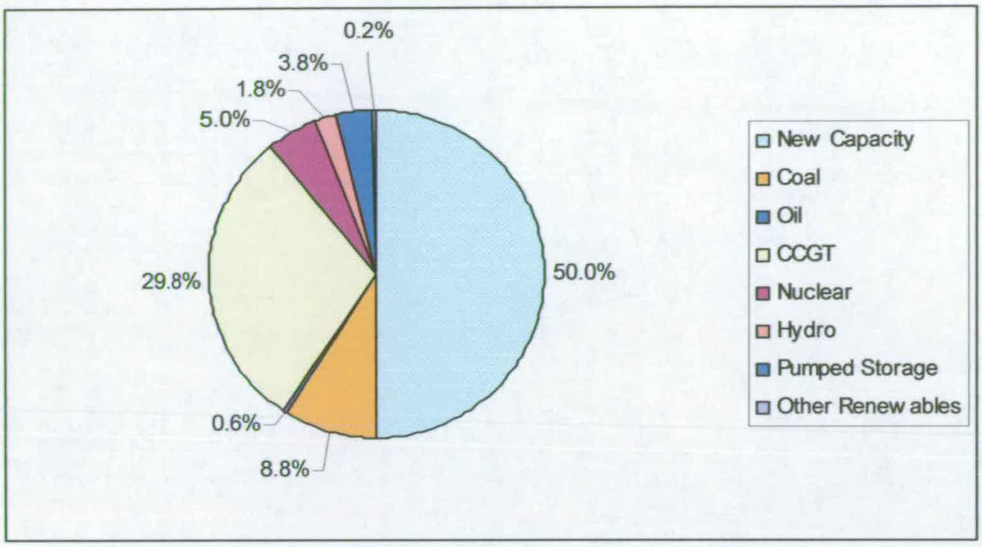

Figure 8.11 - Generation Installed Capacity in 2020[194]

If the contribution from intermittent renewables is increased to 20% of installed capacity and CCGT makes up the remaining of the capacity shortfall a scenario similar to the 12.5% renewables obligation could be achieved. However, if greater cuts in CO_2 emissions are required, investment in nuclear will be needed or if that is not acceptable, investment in the more expensive, less mature new, clean coal technologies will be required.

The implication for investment by the ESI is that if current nuclear capacity is to be replaced with new nuclear generation, the planning and construction process will need to begin soon. Solutions to the public opposition and waste disposal problem will need to be found and some form of nuclear obligation may be needed to guarantee investment.

8.7 Summary

In terms of meeting the energy policy goals of 2020 there are a number of investment options open to the ESI. If there is no concern about relying on high levels of fuel import dependency the lowest cost option for the ESI is to replace the aging nuclear and coal capacity with gas generation. This would create an ESI with CO_2 emissions around 10% lower than 2002 levels and almost 20% lower than 1990 levels. The high use of gas is currently also the lowest cost option but it carries the highest price risk. The higher price risk means that gas prices could fluctuate possibly causing higher electricity prices.

The Government objective of increasing renewable energy use to 20% by 2020 is theoretically a good idea in term of lowering carbon emissions. However, the security of the system suffers as the LOLP increases and the extra margin required to keep it low is too expensive to justify the extra generating units. There is an increase in the cost of electricity due to renewable energy technologies being more expensive, however, there is an improvement in the portfolio risk with the inclusion of renewable energy into the system. A barrier to this target is the current quoted technical limit of 20% of intermittent renewables in the system. This limit means that only around 7% to 10% of energy can be from intermittent renewables if this capacity is provided by wind generation. If marine based power sources become more cost effective over the next 15 years, and they exhibit higher levels of reliability a greater proportion of renewable energy could be accepted. There would still be a cost premium and support in the form of financial incentives required to ensure investment occurred.

The investigation of the optimal fuel mix when the price risk tolerance is low shows that there is an increase in the use of coal and nuclear, as these electricity generators have lower price risk levels. However, this can also cause an increase in the level of CO_2 emitted. This can be rectified by the use of carbon taxes, however, it can be an inefficient and expensive means of reducing total emissions. As in the case of renewable energy support, nuclear may again require assistance if it is to be developed again. The public opposition to nuclear may mean that no new reactors are constructed. If this occurs there must be the choice of whether to invest further in gas CCGT plant to make up the shortfall or invest in new technologies such as new coal generation, which captures CO_2 emissions from the waste stream.

A clear result from the investigation of the fuel mix options for reducing carbon dioxide emissions is that very low emissions can be achieved without high levels of renewable energy. The consequence of this is that there is unlikely to be any significant level of spare renewable energy that could be used in the methanol production process.

Chapter 9

Conclusions

This chapter draws together the key findings in the feasibility study of producing methanol from renewable energy and waste carbon dioxide (CO_2). The principle objectives of this study are summarised as follows:

- The investigation of the main drivers for the development of a comprehensive UK energy policy.
- The evaluation of a novel methanol production process from CO_2 and hydrogen, in terms of its energy storage and carbon dioxide abatement capability
- The investigation of alternative options that could be implemented to achieve the policy goals and any potential conflicts arising
- The development of an optimal fuel allocation model to investigate how the electricity supply industry (ESI) can achieve the energy policy objectives up to 2020 and whether the renewable methanol process can make a useful contribution.

9.1 The UK Energy Policy

The liberalisation and deregulation of the UK ESI has resulted in lower electricity prices, an increase in the security of supply and lower carbon dioxide emissions. However, this situation is a result of market led investment in combined cycle gas turbines (CCGTs) and the results cannot be extended indefinitely without negative impacts occurring. The trend in investment in gas generation may also result in more volatile electricity prices for the ESI when the UK becomes a net importer of gas.

The publication of a White Paper on an energy policy for the UK outlined the objectives for the development of an environmentally benign, secure and competitive energy supply. It was asserted that the competitiveness should be maintained and that the market should be able to choose the most profitable options.

9.1.1 Renewable Methanol Production

A method of producing methanol from renewable energy and waste CO_2 was proposed as a potential enabling technology that could result in the increase in the utilisation of renewable energy and lower CO_2 emissions, both objectives of the Government's energy policy. At the outset, the advantages of this production method of methanol were that it would be used as a buffer to intermittent and variable renewable power sources, the CO_2 abatement would allow fossil fuelled power stations to continue generating without the related emissions and that a versatile and sustainable fuel would be created.

Results of the investigation of the renewable methanol production method showed that it offered a method of storing renewable energy, however, the economics of the process were dependant on the renewable energy supply profile. High levels of very low cost renewable energy would be required to produce sufficient hydrogen to make the process economically viable. A supply of 500MW with a load factor of at least 60% for less than £15/MWh was required for the methanol to be priced at even twice the conventional methanol price of 16p/litre.

Additionally, the carbon dioxide abatement capability of the methanol process was found to be limited. The level of CO_2 avoided by the methanol production was found to be less than a third of that which could be avoided if the renewable energy were used directly as electricity. Therefore, there is no benefit in using the renewable energy to produce methanol in terms of CO_2 emissions unless the renewable energy could not otherwise be used.

Despite the apparent drawbacks to the process, alternative technologies to lower CO_2 emissions also have advantages and disadvantages. Research into the alternative techniques for a low carbon economy is required to make a clear judgement on the feasibility of the renewable methanol process.

9.1.2 Low Carbon Technologies for the ESI

There are many options available to the ESI in terms of reducing or offsetting CO_2. Electricity can be generated from sources that produce little or no CO_2 emissions such as nuclear power and renewable energy sources. Unfortunately nuclear power is not a popular generation technology due to public concerns over safety of the long term storage of high level nuclear waste.

The use of renewable energy is also a potential solution to avoiding CO_2 emissions and lowering dependency on fossil fuels. However, the largest mature resource in the UK, wind power, is intermittent and unpredictable. This means that there is a limit of around 20% of installed capacity before technical problems such as stability and security of the the system are incurred. After this level energy storage technologies would be required to counter the effects of the intermittent generation on the network.

Other methods of reducing CO_2 emissions include its capture and sequestration either before or after its release into the atmosphere. These technologies enable the continued use of fossil fuelled electricity generation with reduced concerns over CO_2 emissions. A drawback of these technologies is that these methods make electricity generation more expensive.

The proposal of using hydrogen as an energy carrier and replacing fossil fuels offers the potential to have a sustainable, low carbon economy. The benefits of such a fuel economy are that dependencies on imported fuel could be reduced if the hydrogen were produced from renewable methods such as water electrolysis. Currently the technologies of the hydrogen economy, for example fuel cells, are still at the demonstration stage and the abundant and cheap supplies of fossil fuels make the hydrogen economy uneconomic at present. Changes in the cost and supply of fossil fuels and greater pressure to reduce CO_2 emissions could change this situation.

All these low carbon technologies and techniques can offer a low carbon economy, yet like the renewable methanol production method, they are more expensive than current electricity generation.

9.2 Achieving Energy Policy Objectives

To evaluate the benefits of the renewable methanol process and alternatives for lowering CO_2 emissions in the ESI, a means of comparing the benefit of particular technologies against the cost of using them was developed. For significant reductions in CO_2 emissions to occur the external cost factors of environmental damage and security of supply issues, relating to the fuel cycle, in particular electricity generation needs to be taken into account in order to evaluate these options.

9.2.1 Security of Supply

The concept of security of electricity supply is a difficult issue to quantify. Two methods for establishing measures of security of supply were investigated to establish suitable fuel mixes for the ESI.

The calculation of the Loss of Load Probability (LOLP) for an ESI was traditionally used to calculate capacity payments to ensure that sufficient reserve generation was made available. In a system made up of predominantly thermal generation the optimal level of capacity margin to achieve the best level of LOLP (~0.1%) is 20%. An investigation of the effects of increasing the level of less reliable electricity generation into a system showed that renewable energy has no load carrying capability. This means it cannot be relied upon to meet demand. Therefore, extra generation capacity would be required to ensure security levels are maintained.

Modern portfolio Theory (MPT) techniques used to evaluate the efficiency of potential fuel mixes in the ESI, showed that the inclusion of renewables in the portfolio lower price risk levels. This is an advantageous scenario as the potential uncertainty of future fuel prices increase as domestic supplies are exhausted and the UK becomes more dependant on imports.

By using quantitative methods for analysing security of supply of the ESI the problem of achieving a compromise between economic and environmental objectives could be identified and results used to balance the compromise between the opposing objectives of security and competitiveness.

9.2.2 Policies, Regulation and Economic Instruments

Externalities are defined as the costs of pollution, visual impact and other non-market commodities that must be accounted for if the energy policy objectives are to be achieved. It is generally understood that the market will not deliver on environmental objectives of lowering CO_2 and other pollutants without placing a value on the pollutants or through fulfilling direct regulation requirements.

Direct regulation, for example the Large Combustion Plant Directive (LCPD), is a means of forcing a particular response but it has been shown that this may not produce the most economically efficient outcome. Subsidies can be used to encourage the development of a particular technology or sustain another as in the Non Fossil Fuel Obligation (NFFO)., but in the long term this may not be an ideal solution as it carries a financial burden and may discourage long term innovation.

Emissions trading schemes such as the US sulphur dioxide program and the UK carbon trading scheme provide a market for environmental protection so that firms have to the choice whether to invest in abatement technologies or pay for additional permits.

The mechanisms set up so far in the UK for environmental protection have not been designed with specific CO_2 reduction from the ESI in mind. The renewables obligation (RO) will continue the work of the NFFO in subsidising renewable energy development and maintain an impetus for continued investment in renewable energy development and generation.

Given favourable economic instruments for CO_2 abatement and maintaining security of supply the renewable methanol production process could be used to help achieve the energy policy goals by reducing CO_2 emissions, increasing the levels of renewable energy in the UK system and helping keep more secure fuels within the fuel mix of the ESI.

However, reducing CO_2 emissions and increasing levels of renewable energy in the ESI through methanol production is only viable once the technical and operational limits of renewable energy integration in the network have been reached and intermediate energy storage in required. The levels of CO_2 emissions that can be avoided by renewable electricity use directly is greater than the methanol production technique. Therefore there is no carbon benefit with using renewable electricity if it can displace thermal generation.

9.2.3 Optimising the ESI Fuel Mix

To establish whether high levels of renewable energy are required for the ESI to achieve the policy objectives or whether fossil fuels will be needed to maintain security of supply, despite the associated CO_2 emissions an optimal fuel allocation model was designed to evaluate all the external and internal costs of electricity generation and to evaluate the optimal least cost option of achieving the energy policy goals. The model incorporated the different factors of environmental impact, security of supply and cost.

The key results of the ESI model (ESIGA) were that there is no motivation for increasing renewable energy levels above their technical limits of 20% up to 2020, as there is sufficient scope in choice for meeting the energy policy objectives of reducing CO_2 and maintaining security of supply with less expensive and more reliable technologies. It was shown that economic instruments such as carbon tax can influence investment decisions, but their efficacy is limited by the choice of low carbon technologies.

It was also shown that a high level of intermittent renewable energy has a detrimental effect on the security of the system. The reliability of the system is sacrificed as the cost of maintaining sufficient reserve capacity increases.

Regarding the problems relating generation investment over the next 15 years, if the nuclear capacity is not replaced by new nuclear generation, over the next decade the levels of CO_2 from the ESI will rise.

9.3 Recommendations for Further Work

9.3.1 Renewable Energy Supply Profiles

There have been many studies relating to the physical renewable energy resource, however, if large scale integration of renewable energy is to occur, energy storage will be required. From the results of investigating the renewable methanol production process, the load factor of the renewable energy supply was very important in terms of evaluating the economics of the process. The level of energy storage required to enable the best use of large scale renewable resources and the potential impact of demand side measures on the need for energy storage could be investigated. As this is applicable to any energy storage medium, research into the supply profiles of integrated renewable energy could be extremely useful.

9.3.2 Quantifying Security of Supply

Two different methods of establishing security of supply were used to evaluate fuel mix options for the ESI. One was a probabilistic method of estimating optimal generation capacity, the second a measure of price risk exposure. As the security of supply is a key issues in investment decisions, further research into other techniques of quantifying security of supply could be an interesting and useful project.

9.3.3 Cross Sector Analysis

For the hydrogen economy to be successfully introduced and operated the power and transport sector will possibly become more integrated as the demand for a sustainable hydrogen source increases. An investigation of the link between the power sector and transport through the hydrogen economy is an area that could be considered, as the ESI would need to adapt to the new demands on electricity supply and generation.

9.4 General Conclusions

The aim of this research was to test the thesis that methanol from waste CO_2 and renewable energy would be a cost effective technology to help achieve the UK energy policy goals in the medium term to 2020. The renewable methanol production process is an effective energy storage medium and it has potential to store intermittent renewable energy. However, the process cannot offer the same level of CO_2 emissions reductions as renewable electricity supplied directly to the network. Therefore, only renewable electricity in excess of what can be absorbed by the network before stability and operational problems arise should be used.

To ascertain whether such a level of renewable energy would be required to meet the energy policy objectives to 2020, an optimal fuel allocation model (ESIGA) was constructed to analyse the effectiveness of different generator fuel types in terms of emissions, security and reliability of supply and cost. Results from the ESIGA showed that emissions reduction targets could be achieved with renewable energy only with some additional support. Therefore it would be unlikely that the high levels of renewable energy required to supply the methanol process would be constructed by 2020, making the methanol process unviable.

The renewable methanol process should not be discounted despite not being viable in the short term. In the longer term as fuel supply issues become more uncertain or when fuel prices increase significantly the methanol process could then offer a sustainable, low carbon versatile fuel.

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Appendix I – Published Papers

J. M. Duthie and H. W. Whittington
Securing Renewable Energy Supplies Through Carbon Dioxide Storage in Methanol.
IEEE Power Engineering Section Summer Meeting, Chicago, 2002, pp 145 – 150.

D. Mignard, M. Sahibzada, J.M. Duthie and H. W. Whittington
Methanol synthesis from flue-gas CO_2 and renewable electricity: a feasibility study.
International Journal of Hydrogen Energy, vol. 28 (4), 2003, pp455 – 464.

Securing Renewable Energy Supplies Through Carbon Dioxide Storage in Methanol

J. M. Duthie and H. W. Whittington

***Abstract*—Renewable energy will undoubtedly be required to make a significant contribution to electricity supply in the future as fossil fuel reserves are depleted and concerns about the environment increase. The inherent sustainability and low carbon dioxide (CO_2) emissions of renewable energy technologies additionally provide the necessary features of a future energy policy goals, however, there are a number of technical and operational problems limiting large scale integration into the conventional electricity network.**

The most abundant renewable energy resources come from intermittent, often unpredictable and non-despatchable sources such as wind, solar and wave. The integration of such variable power sources into the electricity grid network make the control of strict voltage and frequency limits and the security of supply through reserve capacity management difficult.

To secure the contribution of renewables in future electricity supply a novel method of storing renewable energy through electrolytic hydrogen production converted into methanol incorporating CO_2 sequestration is being proposed. This method provides a solution to the integration problems through absorbing the variable out put, producing a readily storable and transportable fuel and further contributing to carbon dioxide emissions reductions.

Index Terms—Energy conversion, Energy storage, Hydrogen economy.

I. Introduction

The economic prosperity of a nation is directly linked to abundant and secure supplies of energy. To maintain this wealth and success it will be imperative to ensure that fuel supplies can be provided in the future, and as our dependency on fossil fuels will inevitably need to be reduced.

Furthermore, rising amounts of greenhouse gases (GHGs), such as carbon dioxide (produced through the combustion of fossil fuels), in the Earth's atmosphere contribute to the risk of enhancing the natural greenhouse effect, leading to changes in climate. The extent of these changes and likely impact are not yet fully understood, nevertheless, it is widely accepted that, at some stage, a limit on these man-made emissions will be needed. Many renewable energy technologies emit little or no carbon dioxide (CO_2) and therefore provide a means of producing electricity without further contributing to the greenhouse effect.

Significant changes in the Electricity Supply Industry (ESI) will be required to accommodate these energy policy goals if renewable energy is to be a major power contributor. These changes will not only be in the fuel mix of the ESI but also in the infrastructure and operation of the electricity network

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II. Current Power System Operation

Typically, within the ESI, electricity is generated at large stations (>100MW) such as coal, gas and nuclear and the power is supplied through an interconnected transmission network. This system, operating under coordinated central control, allows for changes in demand to be met by generation capability or standby reserves, irrespective of the location.

Small increases in demand can be readily absorbed by the network through the inherent inertia of the rotating plant. If demand further increases, spinning reserve or part loaded generation can be brought on line. Over greater time periods of 8-12 hours, steam plant can be started up from cold to serve the demand. Load profiles can be accurately predicted (+/-5% in the case of the UK National Grid Company) and therefore plant can be scheduled to go on and offline well in advance.

III. Renewable Energy

The UK and especially Scotland enjoys extensive renewable energy resources, especially wind and wave energy, many times greater than the maximum electricity demand. Table 1 shows results of resource studies into the potential renewable energy contribution. The *generation capacity* is the total renewable energy that could be exploited for a given technology with no restrictions due to connection or operational limits. The *realistic capacity* is the maximum level of each technology that could be accepted once connection and operational limits are taken into account. For comparison the total UK demand is around 80GW with 390TWh supplied each year[1].

Unlike conventional generation, renewable electricity generators tend to be less than 100MW and are linked to the distribution network to lower connection costs and also due to the remoteness of much of the resource. Few of these small stations are under any central control as monitoring distribution networks is generally unnecessary.

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TABLE I
RENEWABLE ENERGY RESOURCES AND TECHNOLOGIES IN THE UK

Renewable Energy Technology	Wind		Hydro		Energy Crops/Biofuels	Wave	Tidal
	Onshore	Offshore	Large	Small			
Existing UK Capacity (GW)	0.36	0.004	1.4	0.035	0.008	0.0005	0
Generation Capacity (GW)	11.5	25	0	0.3	0.8	14	7.5
Realistic Capacity (GW)	3	2.5	0	0.3	0.8	3	0.4
Predictability	Low	Medium	High	High	High	Medium	High
Constrainable	No	No	Yes	Yes	Yes	No	No

Source: Garrad Hassan, 2001

A. Operational Problems of Renewable

In a modern Electricity Supply Industry there are three essential features:

- electrical power has to be produced at the time of demand
- the power must be supplied within strict standards governing voltage and frequency,
- the security of the supply is extremely important

Industrialized nations depends upon power supplied at rated frequency and voltage, free from surges, harmonics and interruptions.

Stability problems of electrical systems will arise when intermittent generators, especially at light load, supply a significant proportion of system demand. Informed opinion asserts that the upper limits of intermittent sources would be around 15-20% of total system demand before instability issues become a risk[2].

This operational limit related to the power output and not the energy output which is not widely appreciated. Wind installations, for example, typically produce only 25-45% of the rated capacity in a year, yet there will be times at which most turbines will be operating a 100% of rated output power. Therefore, the network needs to be designed to operate safely at these times even though these conditions may only occur on a few occasions.

Advocates of wind energy often refer to the Danish system as an example of successful large-scale integration of intermittent generation. In Denmark, around 14% of the electricity demand is produced from wind energy and is still growing. However, the energy sector has already complained about the problems regarding stability in the network for some time, resulting in the Danish Energy Minister eventually admitting that there is a problem[3].

Currently Eltra, the Danish transmission company, is forced to accept all the power produced by not only the wind farms but also the decentralized combined heat and power units. This results in the conventional thermal units being required to follow customer demand less wind generation, a mode in which they weren't designed to operate. The thermal units run at less than optimal efficiency and are often to be kept in "spinning reserve" consuming fuel but producing no useful output.

To ensure the security of supply there already needs to be a certain level of reserve generation in place to cover the possibility of a sudden loss of generation. This level of reserve capacity cannot be provided by intermittent renewables which require a significant level of additional reserve generation.

B. Connecting Renewable Technologies to the Network

As much of the renewable technologies were connected to the distribution networks this immediately places a restriction on the level of integration that can be accepted. Distribution networks are designed to transmit power from the bulk supply point down to the customer and were not designed to accept active and uncontrollable power at the end of radial feeders. Generation embedded in this way will eventually lead to the need for larger switchgear and protection systems.

In Scotland, the transmission network was designed to provide electricity supplies to the most remote parts of the country while taking advantage of the hydro resource in the highlands. The system was designed with little spare capacity to keep costs down. Fig. 1. shows the transmission system in Scotland: it can be seen the majority of network development is in the central belt and East of the country, the location of the principal demand centres. However, the majority of wind and wave resources are located in the north and west.

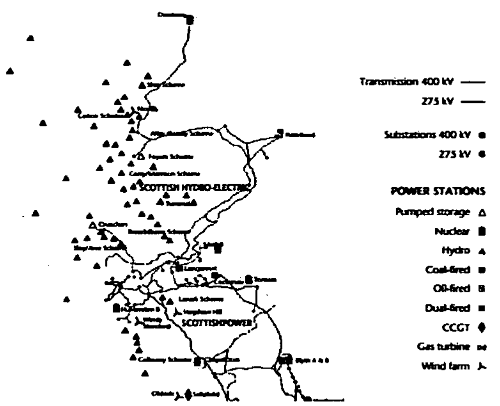

Fig. 1 – Transmission Network and Key Generation sites in Scotland

The transmission lines down the east of the country are reaching their operational capacity. Scotland with 40% over-capacity in generation is a net export of electricity south, but due to planning constraints and the high cost no new transmission lines and towers are likely to be constructed

IV. Solutions for Renewable Energy Integration

To resolve the problems of connecting large amounts of variable and largely unpredictable renewable electricity to remote areas of the network, an alternative means of storing and transporting the energy will be needed as conventional transmission systems are unsuitable.

The important features of an alternative energy medium are that the conversion process is:

- capable of accepting intermittent and largely unpredictable power
- storable and transportable
- efficient

Battery technologies could be used to store the energy but the problem of transmission and distribution capacity limits are not resolved.

By converting the electricity into an alternative medium it can be transported without requiring transmission network upgrades in addition to greater ease of storage.

In this work, the conversion of renewable electricity into methanol has been investigated as such an alternative energy medium.

V. Methanol Production Process

The methanol production process (1) is a catalytic reaction of carbon dioxide and hydrogen:

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \qquad (1)$$

The proposed methanol production method uses carbon dioxide separated from the flue gas stream from a fossil-fuel power station and then purified to remove oxides of nitrogen and sulphur. The hydrogen is produced from the electrolysis of water using renewable electricity so as to avoid the production of CO_2.

A. Carbon Dioxide Separation

Using the carbon dioxide emissions from a fossil-fuelled power station was chosen for two principal reasons. Firstly, there is a high concentration of CO_2 emitted, approximately 8 million tonnes a year from a typical 1000MW coal fired plant. Secondly, there is also the motivation to reduce emissions and clean up the flue gases and as a result of the CO_2 purification the acidic gases such as sulphur dioxide are removed and disposed of.

For the purposes of the design evaluation, a CO_2 separation process using monoethalamine (MEA), a solvent, has be chosen as the preferred capture method. The CO_2 is absorbed by the MEA forming an intermediate compound. Pure CO_2 is then liberated by heating allowing the MEA to be recycled.

Other techniques for CO_2 removal are under development, for example, pressure swing adsorption and membrane separation. However, these techniques are more costly and less technically mature than the MEA option, although they offer the potential of greater efficiencies in the future.

B. Hydrogen Production

Water electrolysis involves the catalytic decomposition of an electrolyte, typically potassium hydroxide (KOH), by electricity as shown in (2).

$$H_2O \rightarrow H_2 + \tfrac{1}{2}O_2 \qquad (2)$$

The reactions taking place at each electrode are:

$$cathode: 2H_2O + 2e^- \rightarrow H_2 + 2OH^- \quad (3)$$

$$anode: \ 2OH^- \rightarrow \tfrac{1}{2}O_2 + H_2O + 2e^- \quad (4)$$

Using clean renewable energy and this electrolysis process only hydrogen and oxygen are produced. The process is electrically very efficient, typically >85% and is able is operate successful with variable power supply, making it an ideal technique to absorb fluctuating renewable energy.

C. Methanol Production Process

The design of the methanol production process described in [4] was used as the process is technically proven and all processes readily understood.

To produce the methanol the two gases are mixed and reacted together over a catalyst of copper zinc oxide and aluminium oxide. Water is also produced as a by product.

Table 2 shows a summary of the process requirements.

TABLE 2
TYPICAL ENERGY AND CAPACITY VALUES FOR METHANOL PROCESS

Process	Energy Required (MWh)
Electrolysis (per tonne H2 produced)	45
CO2 Separation (per tonne CO2)	3.75
Methanol Synthesis (per tonne methanol)	14.2

VI. BENEFITS OF RENEWABLE ENERGY STORAGE IN METHANOL

A. Sustainable Methanol Source

Methanol is a versatile chemical feedstock used in a variety of manufacture processes such as the production of formaldehyde, for building material production and acetic acid. At present in the UK there is demand for around 850 thousand tonnes of methanol [5] and projections for demand for methanol are an increase of approximately 3% a year.

In the short term an increase in demand for methanol could arise from the higher use of MTBE (methyl tertiary butyl ether), an octane enhancer in clean burning fuels. MTBE became popular in the US in the early 1990s in response to the Clean Air Act Amendments (CAAA) and has been attributed to improved air quality in the California air basin [6]. In Europe, gasoline quality varies from country to country and does not yet have single obligatory requirements, however, moves by the European Parliament to limiting aromatics and stricter emissions controls will drastically effect the refining blending pool. Therefore it is likely that MTBE will be used to produce the necessary octane grade in the future [7].

B. Flexible Energy Storage

The fluctuating and often unpredictable nature of renewable electricity has been highlighted as one of the major constraints to integration. In modern electrolysis units power fluctuations have no significant effect to the overall electrical stability. The reduction in the efficiency due to variable power input is limited to only a few percent[8]. By using the renewable energy in an electrolysis unit to produce hydrogen the effects of the variable output can be overcome.

An additional benefit of using electrolysis to store energy is that the electrolysers are modular in design, with capacities ranging from a few kilowatts to tens of megawatts. A consequence of this is that the electrolysis unit can be placed near to the source of the renewable energy, avoiding the need for transmission line upgrades and also preventing flows of power back up the distribution network at times of low local demand and high renewable electricity generation.

C. Carbon Dioxide Abatement

The capability of this method of methanol production for CO_2 abatement comes from several features of the process. Firstly the process directly uses CO_2 captured from fossil fuel power station, a major source of such emissions. CO_2 capture and disposal in the deep ocean or depleted gas wells has been suggested for the storage of such large amounts. Issues of safety and long term security of storage are still being investigated.

Secondly, the process uses clean renewable energy and recycled CO_2 and therefore the methanol can be considered emissions free.

Finally, many of the uses of methanol as a fuel source are cleaner and more efficient than current combustion or other energy conversion techniques. For example, methanol used in a conventional internal combustion engine vehicle produces 5% lower CO_2 emissions than standard gasoline engines[9] and produces fewer particulates and nitrogen oxides.

D. Methanol as a Hydrogen Carrier

Hydrogen is frequently referred to as the fuel of the future as it can be made in a sustainable way from an abundant resource, namely water. It is the potential for methanol to be used as a hydrogen carrier for fuel cell vehicles (FCVs) which is of greater interest. Fuel cells are seen to be the power source of the future[10]. Clean, efficient and versatile, they offer the possibility of a sustainable energy supply. Fuel cells are electrochemical devices which produce a current though the combination of hydrogen and oxygen, producing only water as a by-product.

The choice of hydrogen carrier for fuel cells, particularly for mobile applications is still undecided [11,12]. Pure hydrogen is favoured by some car manufacturers as it is truly a zero emission and also more efficient as there are no conversion losses from methanol back to hydrogen. However, hydrogen has a very low energy density, about a tenth of gasoline and needs to be stored as a compressed or liquefied gas raising concerns over the safety of having H_2 tanks on board vehicles.

Methanol, in contrast, is liquid at ambient temperature and is subsequently easier to store and transport. More importantly perhaps is that is can be readily incorporated into the current vehicle refuelling infrastructure. The transition from one technology to another can be constrained by the conundrum of which comes first: the new demand or the new supply? Opposition to using methanol as the hydrogen carrier to the new fuel may be lessened as it is in a familiar, liquid medium as current vehicles.

Disadvantages of using methanol for fuel cell vehicles is that CO_2 is produced during the reforming of the methanol to H_2 and there are efficiency losses due to the extra reforming. To overcome these problems, methanol produced from renewable energy and recycled CO_2 would result in the FCV effectively beings emissions free, although CO_2 would be produced at the point of use.

The debate over the chosen hydrogen source for fuel cells is unlikely to be resolved in the near future as FCVs are still in development and have only reached the prototype stage. The impact of FCV introduction into the UK and the subsequent change in methanol demand was modelled [5] and results showed that in the UK, future demand could lead to a 20-fold increase in demand over the next few decades and a sustainable secure source of methanol will be needed.

VII. Costs of Renewable Energy Storage in Methanol

The economic and energy efficiency costs of storing renewable energy and reducing CO_2 emissions in methanol were investigated to establish whether the process would be worthwhile. It is folly to think just because a process or technique is environmentally sound or infinitely sustainable, that the costs will be covered irrespective of the burden.

A. Energy Efficiency of the Methanol Production

An advantage of using electrolysis as an energy conversion technique is that high efficiencies can be achieved. Table 3 shows the conversion efficiencies of methanol and hydrogen production and use. The conversion into methanol from hydrogen does result in some energy loss although the extra cost in terms of energy efficiency could be considered to be negated by the advantages of ease of storage and transportation.

Process	Hydrogen	Methanol
Production Efficiency	>85%	60%
Compression	62%	n/a
Storage	95%	>99%
Fuel Cell Use Efficiency	50%	35%
Total	~25%	~21%

TABLE 3 COMPARISON OF ENERGY CONVERSION EFFICIENCIES OF METHANOL AND HYDROGEN BASED UPON WATER ELECTROLYSIS

B. Economics of Methanol Production from Renewable Electricity

For any capital investment project to be successful it must be shown that there will be a return on the investment. That is the outlay of resources in one period will be rewarded with a return on the resources at some stage in the future. Projects which have a long life span cannot readily be assessed unless the time value of money or discounting is taken into account, where the discount rate takes into account factors such as inflation, risk and the need for a return on an investment.

The Net Present Value (NPV) method of investment appraisal compares the present value of future cash flows of an investment opportunity with the cash outlay needed to finance the opportunity. If the NPV is positive, the investment generates a surplus and the investment will increase the wealth of the investors. If the NPV is negative, the project will generate a deficit and therefore will not be profitable.

It was assumed that the electrolyser had an average capacity factor of 60%. This figure was chosen as a compromise between requiring a high availability of electricity to offset the high capital cost of electrolysis units[1] and to simulate that the process is designed to accept fluctuating and variable levels of power. The discount rate used to convey the level of risk associated with the investment proposal was set to 10. The NPV of the production process was calculated for a range of plant sizes and the results are shown in Fig. 3.

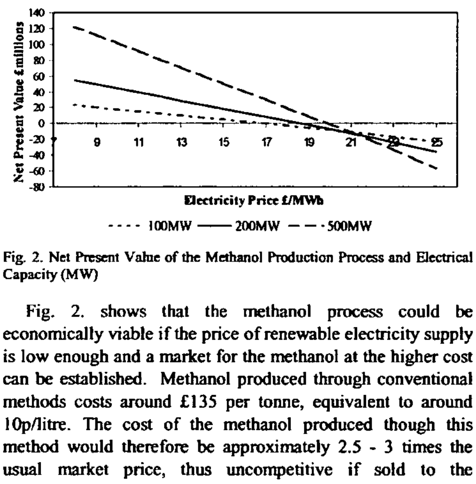

Fig. 2. Net Present Value of the Methanol Production Process and Electrical Capacity (MW)

Fig. 2. shows that the methanol process could be economically viable if the price of renewable electricity supply is low enough and a market for the methanol at the higher cost can be established. Methanol produced through conventional methods costs around £135 per tonne, equivalent to around 10p/litre. The cost of the methanol produced though this method would therefore be approximately 2.5 - 3 times the usual market price, thus uncompetitive if sold to the conventional chemical industries.

This higher cost may not be prohibitive to the economic viability of the project if favourable fiscal measures were put in place that would take into account the environmentally beneficial aspects of the process. The methanol process incorporates CO_2 abatement which could be rewarded through CO_2 taxation and it also produces a renewable, carbon-free source of methanol that could be used in a thermal plant and considered as renewable generation.

[1] The electrolysis unit makes up approximately 80% of the capital costs of the production process.

Alternatively, methanol could be marketed as a renewable vehicle fuel, where favourable taxation could overcome the higher price.

VIII. Conclusions

The developed world is facing the challenge of securing reliable and sustainable energy supplies for the future. Renewable energy is a currently underutilised source that will be able to fill the gap left by fossil fuels. There are a number of technical problems associated with large scale renewable electricity which need to be overcome before this can become practical.

Storing renewable energy using electrolysis to produce hydrogen provides an efficient and effective means of integrating greater levels. Producing methanol to overcome storage and transportation problems of pure hydrogen, a technically and economically viable method of securing a wide range future energy supplies needs can be met.

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X. Biographies

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Methanol synthesis from flue-gas CO_2 and renewable electricity: a feasibility study

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Abstract

The twin requirements of reducing CO_2 emission levels and increasing the level of penetration of renewable energy will involve innovative technical and operational solutions. This paper describes a novel but proven process ($CO_2 + 3\ H_2 \rightarrow CH_3OH + H_2O$) which could be adapted to use, as input reagents, CO_2 emitted from fossil-fuelled power stations and hydrogen from electrolysis of water by a zero-emissions electricity source, e.g. renewable and/or nuclear energy. This approach, in addition to addressing the above two issues, would produce methanol for which there is a ready and expanding market.

A preliminary analysis is presented of the process economics and operational regimes necessary in the UK Electrical Supply Industry to accommodate the methanol plant. Four different designs are assessed, all based on a supply of renewable energy limited to 16 h/day when demand is off-peak. Option 'A' relies on a variable 100–500 MW supply, whereas Option 'B' makes use of a steady 100 MW during the availability period. Option 'C' is identical to 'B', except for the use of pressurised electrolysers at 30 bar instead of conventional ones. Option 'D' departs from 'B' with the use of hydrogen-powered fuel cells for power generation during the period of no availability. In the absence of a market for the electrolytic oxygen, Option 'B' is found to be the most economical, and it should be profitable if a favourable taxation regime applies on zero-emission automotive fuels. However, if the oxygen can be sold to a local industry via pipeline, Option 'C' could be potentially viable, even in the absence of tax breaks.

It is claimed that significant benefits might accrue from successful development of a methanol process and that it may ease the absorption of increasing levels of embedded generation into the electricity supply network.

Keywords: Methanol; Electrolysis; Renewable energy; Power plants; Flue gas; CO_2 abatement

1. Background

The summit meeting at Kyoto saw the UK agree to cut emissions of so-called "greenhouse gases" by 12.5% (based on 1990 values) by 2010. A significant proportion of this reduction is targeted to come from the UK Electricity Supply Industry (ESI), and the industry will have to address this requirement. The reductions achieved to the present are largely as a result of fuel switching to gas-fired power stations, but this cannot be expected to continue at the rate it did during the 1990s.

There have also been significant developments in the ESI: it is now facing challenges which will affect how the network is operated, which energy sources are used and how the economics of bulk electricity supply will evolve. The new trading arrangements (NETA) which have recently emerged have a significant effect on how electricity is bought and sold. This change in trading rules comes at a time when the industry is being asked to play its part in the reduction of

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[1] Bert Whittington was Professor of Electrical Power Engineering at the University of Edinburgh, until his tragic death in a car accident in March 2002. He will be surely missed by family, friends and collegues alike.

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those gaseous emissions, such as CO_2, which are thought to cause climate change. The recently announced renewable energy obligations follow on from a series of five funding tranches in England and Wales and three in Scotland. To complicate matters further, the nuclear contracts in Scotland will run out soon, posing the question of how nuclear power will fit into the new structure for the ESI.

The civil nuclear industry has made significant advances in terms of reducing costs but the ESI appears reluctant to invest in new plants. Government intervention is unlikely and the future position of nuclear power in the new trading arrangements is not completely clear. The future market for nuclear energy is not totally assured. When present contracts finish, it is not guaranteed that the new contracts will be "must take". The identification of an assured market for nuclear energy in CO_2 abatement will assure the economic future for nuclear for some years to come, so we suggest that one option for part of the nuclear generation would be in powering the electrolysis plant for hydrogen production. This, in turn, would feed the methanol process.

The level of penetration of renewable energy into the ESI has been encouraged by the various statutory obligations but UK as a whole is still well short of the EC fifth Framework target of 10% of electricity from renewable sources by the end of this decade. The new arrangements for green (renewable) energy announced in February 2000 should make the development of renewable energy sources more attractive financially. However, there remain problems associated with the embedded nature of both renewable energy and of combined heat and power plant which need to be addressed before the required levels of such embedded generation can be achieved. The use of modern electrolysers capable of operating with a highly intermittent power supply could help absorbing disruptive surges from these generators. Finally, plants generating renewable power would increase their profits if their off-peak output was used for the methanol process, instead of being dumped.

2. Introduction

A catalytic process for the conversion of CO_2 and H_2 into methanol [1,2] is being investigated as a way to use CO_2 as a hydrogen carrier. The hydrogen must be produced from a renewable source of energy, for instance by electrolysis of water using hydroelectric power or wind power. Pilot stage studies of similar projects have already been carried out in Japan [3] and in Germany [4]. Eliasson [5] also suggested using the reaction in a load-levelling scheme for an integrated gasification combined cycle (IGCC) power plant. This paper details the production process and its economics within the context of a market for methanol car fuel.

A 1000 MW coal-fired station supplies diluted CO_2 in its flue gases. The station is assumed to comprise four pressurised fluidised bed (PFB) combuster units. PFB technology seems largely to prevail for newly built power stations:

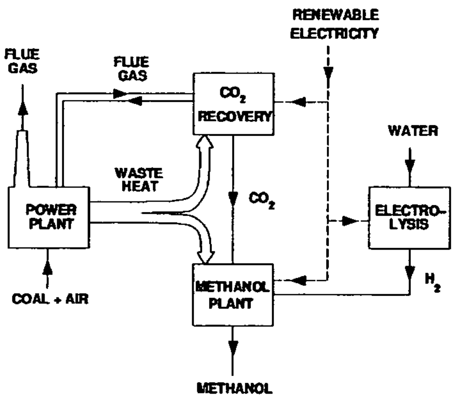

Fig. 1. Use of waste heat and renewable electricity to produce methanol from flue gas CO_2.

Table 1
Availability of renewable electricity: simplified schedule over 24 h

Period	Excess supply (MW)	Duration (h)	Price (£/kWh)
1	500	4	0.015
2	100	12	0.01
3	0	8	—

Although IGCC is a commercially viable and existing option (e.g. the Polk's Power Station has been operational since 1996—Teco Energy, Inc. [6]), its adoption has been very slow. The technology currently presents high capital costs, which results in a specific cost for the electricity about 45% higher than with PFB [7]. Therefore, PFB was retained as the basis for this study. The renewable electricity for electrolysis is assumed to be available only during the 'off-peak' period of low demand. Electricity from fossil fuel may only be used during peak demand, for running the process, which operates in continuous mode and relies on stored hydrogen during the peak period. Waste heat may also be available, in the case of an older power station with low efficiency. Fig. 1 summarises this approach.

Two assumptions were made on the availability of renewable electricity: there were considered to be three periods during a 24 h/day, and a low price was negotiated with the suppliers. Duration and prices for the periods are reported in Table 1.

Four options were investigated:

- Option A, use of conventional electrolysis, with variable amounts of electricity available during off-peak time (base case);
- Option B, as in A, but with a constant supply of electricity during off-peak period;

- Option C, as in B, with the use of pressurised electrolysis to save energy;
- Option D, as in B, but with the use of a fuel cell plant to save on electricity of fossil origin.

The possibility of selling the oxygen by-product from the electrolysis plant was also considered.

3. Method

A preliminary design study was made by a team of chemical engineering students at Edinburgh University, UK. These processes were then adapted in an attempt to improve the economics and the use of energy of the process. A 'base case' flowsheet and its description is provided in the section below. Details of the options departing from the base case are then given, followed by a general discussion on the technical and financial choices made for the process.

3.1. Flowsheet

The simplified flowsheet for the base case ('Option A') is presented in Fig. 2 and detailed here. Coal is burned in air in a pressurised fluidised bed combuster (PFB) in order to generate pressure and steam for power generation. The pressurised flue gases from the combustion are passed through a gas turbine, and the steam is used through a steam turbine, producing a total power output of 1000 MW_{el} for distribution. The flue gas stream (1) is cooled, and dehumidified. The gases then enter the N_2 separation stage. Here, the flue gas is contacted with monoethanolamine (MEA) in an absorption column [T201], and the CO_2 is absorbed by the MEA, forming an intermediate compound. The N_2 is not absorbed and is vented out (2). The MEA intermediate (3) is fed to a stripping column [T202], where the CO_2 is liberated by heating. The bottom product (4) is MEA and is recycled back to T201, while tops contain CO_2 along with some MEA. This stream is cooled and passed to a stripper reflux drum. The feed CO_2 stream (5) is taken from there and pressurised, before being fed to the reactor [R301].

In the electrolysis section, the electrolyser plant splits water (6) into H_2 and O_2. The temperature is maintained at 80°C, by using cooling water and recirculating the electrolyte in each of the 54 modules. For clarity, cooling circuits were not represented from Fig. 2. O_2 is either vented away or processed further and sold via pipeline, while H_2 is compressed, cooled and transferred to holding tanks [D101] and [D102]. From the tank, H_2 (7) is again compressed and cooled, and fed to the reactor [R301].

The gases are mixed (8) and reacted together over a catalyst of $Cu/ZnO/Al_2O_3$ oxide, to produce methanol and water. An adiabatic mode of operation was retained, with inlet temperature of 230°C and inlet pressure of 50 bar, and a recycle ratio of 7.9. The design currently assumes that no by-products are formed. The product stream (9) contains methanol, water, and any unreacted CO_2 and H_2.

The product stream is cooled near to dew point, while re-heating the reactor recycle stream that is left after condensing out methanol and water. It then reaches a condenser, before being fed to a liquid–vapour separator [D301] where most of the unreacted gas is separated (10). As mentioned before, the gas is re-heated by using the hot product stream, and it is then mixed with (8) from D303 and recycled to the reactor. The liquid product (11) is passed to a let-down drum [D302] to reduce the pressure before final purification.

The product separation involves an absorption column and a distillation column ([T301] and [T302], respectively).

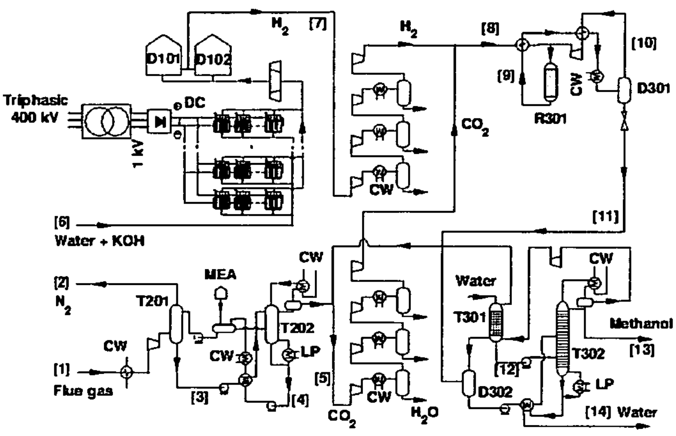

Fig. 2. Process flowsheet.

In [T301], all substances more volatile than methanol are removed from the condensate and recycled back to the reactor, while water and methanol are removed as bottoms (12) and are fed to [T302]. [T302] produces methanol as distillate (13), and water as bottoms. The bottoms are used to preheat the feed to [T401]. Some of this water is recycled to [T301] to increase methanol recovery, while some is purged (14).

3.2. Options for design and power management

The base case (Option A) presented in the above paragraphs, assumed electrolysis at 1.5 bar, full use of the 500 MW available in period 1, and the use of fossil electricity to power the process during period 3. Three further options were considered:

- *Option B.* only 100 MW were used during period 1. This option was considered because the electrolyser in Option A had to be vastly oversized. A very substantial decrease of capital costs of the order of 70–80% was expected, while methanol production was only halved.
- *Option C.* as in Option B, but this time pressure electrolysis allowed the production of hydrogen at 30 bar; this was expected to allow saving on compression costs, decreased use of fossil fuel electricity in period 3, and more electricity available for electrolysis.
- *Option D.* conventional electrolysis as in B, but with the use of hydrogen powered-fuel cells to run the process in period 3. The hydrogen consumed was generated from electrolysis during periods 1 and 2 and stored. Power from fossil sources was avoided. This option achieved the lowest CO_2 emission.

3.3. Heat management

Low-pressure steam would supply the heat necessary to desorb the carbon dioxide from the MEA solvent, and for the distillation of the methanol product. Alternatively, there might be enough waste heat from the power plant for the process. However, this approach really makes use of pre-existing, very sub-optimal capacity, which may as well be retrofitted for better efficiency. In any case, use of LP steam could be related to CO_2 emissions, which would appear in a final mass balance. These may then be counted in or discarded in a final appraisal, depending on the power plant design.

For a given flow rate of steam, the amount of shaft work delivered from a steam turbine will be a lower value than the heat available. Bolland and Hundrum [8] quoted the ratio of "incremental power reduction to incremental heat output" for the particular case of low-pressure steam around 120°C, and taking into account a pressure drop through a reboiler: this ratio equals 0.25.

3.4. Electrolysis plant

Low-pressure (ca.1 bar) alkaline electrolysis was adopted. The electrolyte used was a 25–40% KOH solution. Nickel wire mesh coated with Raney nickel would be used for the cathode, while the anode can be coated with a Raney nickel–cobalt spinel (or perovskite) composite. Diaphragms are also available to replace pure asbestos (e.g., Zirfon), with improved conductivity and lower thickness (fraction of a mm). The 'zero-gap' approach consists in combining together in one single element (a 'cell') the anode and cathode with the diaphragm sandwiched in between. With these improvements, current densities $> 9\ kA/m^2$ may be used [9], while maintaining a workable voltage between electrodes (1.75 V).

Tentatively, the layout suggested for the 500 MW electrolysis plant would consist of the following:

- Three transformers in parallel would bring down the triphasic power supply from 40,000 to 1000 V; 54 silicon controlled rectifier units would deliver DC current at a voltage of 1000 V;
- Cells would be assembled in series within a module; their surface area (one side) was $2.5\ m^2$;
- Cell voltage of 1.68–1.76 V, and optimum current density of $7.5\ kA/m^2$;
- Two modules in series comprising 284 cells each would constitute a branch, and there should then be 27 branches in parallel, each comprising two electrolysis modules in series, and each taking a current of 18.5 kA. A 100 MW plant would require only five branches.
- Efficiency at full load (500 MW in Option A, period 1, and 100 MW in Options B and D) would be 72%; at 20% load (Option A, period 2) it would be 81%.

High-pressure alkaline electrolysers are on the market for green energy applications and 'peak shaving', with cell stacks of up to 200 kW (MTU, Germany). These are able to cope with highly intermittent and variable power supply. They also show higher efficiency (80% at full load, and 87% at 20% load). Details on technology and performances can be found in the literature [10] and on the MTU brochures.

The capital cost of an electrolysis plant per kW_e of electricity used decrease in a non-linear fashion with capacity in kW_e. Scaling-up of the electrolysis cells and certain electric components such as rectifiers and bus bars should be expected to be somewhat linear, and the specific price of these components should vary little with numbers required. On the other hand, water purification, electrolyte preparation, cooling, pumping, electronics, and transformation of the power supply, all of these items follow a power law with capacity. The following correlation was obtained from fitting data from Dutton et al. [11] and Wendt and Imarisio [12]:

$$C_{el} = 200P + 16,000P^{0.60625} \quad (1)$$

in which C_{el} is the total investment cost (£), and P is the electrolyser capacity (kW_e). This correlation was extrapolated for capacities up to 500 MW for this study. Zittel and Wurster [13] gave some indication on capital costs for advanced high-pressure electrolysers, from which it was inferred the following formula:

$$C_{el} = 800P + 16{,}000P^{0.60625} \qquad (2)$$

3.5. Processing and uses for the oxygen by-product

Finding uses or customers for the oxygen produced by the electrolysis plant, alongside hydrogen, may require careful planning or the right environment for the plant. The grade of oxygen (99.9% after drying) and the absence of impurities such as CO may make the product suitable for medical applications or the manufacture of semiconductor components. However, transporting oxygen over more than 200 km is usually not economical [14]. Besides, liquefaction proves very expensive [15], and compression to 250 bar and delivery to customers via tanker trucks would require almost a hundred trips per day (from Bain [13], initial case study with capacity comparable to Option A). Moreover, the output of the plant seems too high for local hospitals too. The most practical option would be to secure a contract with a local chemical plant using oxygen as feedstock (e.g. ethylene oxide, metallurgy, semiconductors), and supply the gas to the plant via pipeline at 30–35 bar [14]. This last option was retained for this study. It should be noted here that our evaluation did not take into account specific requirements, such as allowable amounts of water vapour or hydrogen. If necessary, additional drying or a catalytic oxidation reactor should be used.

In the absence of a local market for the oxygen, the gas could be used for improving the efficiency of the combustion. However, the relatively small amount of oxygen generated by electrolysis would mean these gains are modest. Assuming that the warming-up of inert nitrogen from ambient temperature to flue gas temperature uses 6% of the coal Lower Heating Value, and that the electrolytic oxygen can barely contribute 2.7% of the combustion (Option A), the added oxygen would raise the thermal efficiency by $2.7 \times 6/94 = 0.14\%$. The final efficiency would increase by the same relative amount, which means that the 1000 MW_{el} power plant would be able to produce an extra $0.0014 \times 1000 = 1.4$ MW_{el}. This is within the context of a daily average of 133 MW_{el}, made available at a 'cheap' rate for the process. Similar limitations due to the scarce current availability of renewable electricity would be present with a O_2/CO_2 recycle scheme, or an O_2 blown—IGCC plant. These options were not considered any further here. However, they would be relevant in a different context, e.g. with a 100 MW power plant, or a very developed level of renewable generation that could spare 1000 MW daily. Substantial energy savings would arise there from simplified CO_2 recovery or CO_2 enriched-flue gas [7].

3.6. CO_2 extraction

Amine absorption is the dominant technology for carbon dioxide extraction from flue gases. It is available on the market [16,17], and previous studies have shown it to be the most economical option if the flue gas is emitted by a conventional pulverised fuel power station e.g. [18]. In particular, Göttlicher and Pruschek [19] reviewed more than 300 papers and 60 plant variants: They noted that chemical absorption with amines was the cheapest in terms of cost per ton of CO_2, but only when applied to retrofit cases. The other economical option was extraction with a physical solvent such as Selexol®, and it was found to be slightly cheaper provided that the power plant was a newly built IGCC unit integrated with the CO_2 plant. However, the present study made use of just a fraction (1–3%) of the emitted CO_2, and hence the combined costs from integrating a new IGCC power plant and the Selexol®-based extraction plant would not be seen. Within this context, the solvent retained in this study was a 20% monoethanolamine (MEA) aqueous solution. This strength is comparable to the one used in the Kerr-McGee/ABB Lummus MEA process (15–20%).

Other processes make use of higher MEA concentrations, e.g. Fluor Daniel's Econamine FG process. In fact, the Kerr-McGee/ABB Lummus process has been criticised for its larger capital cost and its higher power and steam requirements, much of this due to its low MEA concentration [20]. However, improved processes such as Econamine FG seem to require SO_2 and NO_x concentrations in the flue gas that are very low, below 10 ppmv. Finding a commercial process that is capable of achieving these low values seems problematic and expensive, although it can be done [21]. In the present study, we opted for retaining a dilute MEA solution (20%) similar to that of the Kerr-McGee/ABB Lummus process, on the basis that it could cope with SO_2 and NO_x concentrations of 100 ppmv. Indeed, at least three commercial plants that are based on this technology are reported to extract CO_2 from coal-fired power stations [22]. An example of these is the Applied Energy System (AES) Plant in Poteau, Oklahoma: It produces 200 t/day of food-grade CO_2 from the flue gas of a coal-fired cogeneration plant.

3.7. Additional NO_x and SO_2 removal prior to CO_2 extraction

In the light of the previous section, SO_2 and NO_x concentrations of 100 ppmv had to be achieved in the flue gas. Assuming that conventional flue-gas desulphurisation (FGD) had already been applied as standard treatment to the flue gas in a coal fired power station, typical concentrations before additional treatment were taken as 200–400 ppmv for SO_2, and 100–400 ppmv for NO_x. After cooling of the flue gas to 25°C, a simple water wash was adopted to remove more than 75% NO_x and some of the SO_2. This step was simulated with the Aspen® software. For desulphurisation, however, the traditional lime or limestone wet scrubbing processes found in European power plants may still leave 137 ppmv SO_2, and could not be applied to this problem [21]. On the other hand, the Wellman–Lord process, in which the sodium sulphite absorbent is mostly regenerated, has been reported to attain levels down to 67 ppmv [16]. Since this process is also widely known and applied (at least in the US), it was retained for this study. Crude estimates for chemical inputs and outputs, and power and steam requirements, were taken from [11,23], while the capital cost was evaluated using a formula given by Cofala and Syri [24].

3.8. Storage and compression before reactor feed

Hydrogen production is intermittent and not happening during period 3, and some storage is necessary during period 1 (Option A), or period 1 and 2 (Option B–D). Floating head tanks were selected as the cheapest option in terms of net present value, except for option C (pressurised tank). Both the hydrogen and the carbon dioxide feeds are compressed in four stages (with intercooling). With reactor inlet temperatures at 230–280°C, some preheating of the feed is required, and this could be achieved by using the hot product outlet from the reactor.

3.9. Reactor

A C-programme was written to simulate methanol synthesis in the reactor. The catalyst considered was a commercial $Cu/ZnO/Al_2O_3$ (ICI 51-2). It is widely used for methanol production from synthesis gas, and has been extensively studied for methanol synthesis from CO_2 feed. The kinetic model we used was taken from Vanden Bussche and Froment [25]. Options and parameters were optimised so as to minimise power consumption, while operating at the lowest recycle ratio that would give a yield of 99% with respect to methanol (after condensation). This approach was based on the premise that purging hydrogen was wasting the electricity. The optimal design and operational parameters were found to be the following: Adiabatic operation, one single-injection point at the top, 14000 kg of catalyst, inlet temperature at 230°C, pressure 50 bar, and recycle ratio equal to 7.9.

3.10. Product recovery and methanol purification

The Aspen® simulation programme was used for LVE estimates and design of the cooler and the condenser in the recycle stream of the reactor. It was also used for the design, sizing and costing of the absorption packed tower and the distillation column in the methanol purification plant.

3.11. Fuel cell plant

At the time of writing, fuel cell plants for stationary applications were available on the market from manufacturers such as Ballard and International Fuel Cell (IFC), with modules of capacity 200–250 kW. To the authors' best knowledge, such fuel cells using hydrogen only have not been commercialised yet. However, these have been developed by IFC ([26], report written prior to 1998), and they were shown to be more efficient (44% efficiency) and of simpler design than the conventional stacks—which require a converter to produce the hydrogen that the fuel cells can then utilise. We assumed that the price of a 200 kW hydrogen fuelled unit would be the same as for a natural gas one, i.e. $990,000.

4. Results and discussion

4.1. Mass and energy balances

4.1.1. CO_2 abatement

The process is limited by the availability of renewable electricity: At present levels of supply in the UK, only about 3% of the CO_2 emissions from power plants could be recycled this way. Table 2 shows that some CO_2 is generated indirectly, due to the use of electricity for compressors, pumps, control equipment, etc. The chemicals involved in the removal of NO_x and SO_2, were omitted from this table. However, CO_2 emissions from their synthesis and their degradation were taken into account (50% aqueous NaOH

Table 2
Mass balances (including CO_2 emissions from energy demands of the process)

Compound	In (t/day)				Out (t/day)			
	Option				Option			
	A	B	C	D	A	B	C	D
MEA	0.98	0.47	0.53	0.47	0.98	0.47	0.53	0.47
Water	633	304	345	301	211	101	114	99.3
CO_2	517	246	281	243	95.3	45.8	33.0	0
					(+377)[a]	(+179)[a]	(+209)[a]	(+188)[a]
					(− 167)[b]	(− 79)[b]	(− 102)[b]	(− 98)[b]
O_2					555	267	302	264
Methanol					372	178	201	175

[a]Denotes additional CO_2 emissions due to steam consumption ('process steam' scenario).
[b]Denotes additional credit on CO_2 emissions if the oxygen is compressed and sold.

Table 3
Energy balance for the process

Utility	In				Out (MWh/day)[a]			
	Option				Option			
	A	B	C	D	A	B	C	D
Cooling water 'In' (t/h)	3425	1750	1888	1738	85.8	41.3	46.8	40.8
Heat ($\geqslant 120°C$) (MW)	80.8	38.5	43.6	38.0				
Fossil fuel electricity (MW)	15.7×8 h	7.49×8 h	5.67×8 h	0				
Renewable electricity (MW)	500×4 h 100×12 h	100×16 h	100×16 h	100×16 h				

[a]Energy out based on methanol production (with a lower heating value of 19.93 MJ/kg).

Table 4
Energy efficiency of the process

Option	A	B	C	D
Fossil fuel electricity used, (kWh/kmol methanol)	10.8	10.8	7.2	0
Specific electricity use from renewable source, (kWh/kmol methanol)	274.5	288.7	255.2	292.8
Conversion efficiency to chemical energy (%) (waste heat scenario) (kW_{th}/kW_{el})	61.9	59.1	67.5	58.4
Conversion efficiency to chemical energy (%) (process steam scenario) (kW_{th}/kW_{el})	54.1	52.0	58.3	51.4

for absorbent make-up; lime and limestone for HCl control; natural gas for reduction of SO_2 to S), and they were found to be barely significant (0.8 t/day for Option A). It is important to note that, if no waste heat (i.e. no low-pressure steam from the power plant) was available for other energy demands of the process, then there would be no net CO_2 abatement. The amount of power required would result in CO_2 emissions about equal to the CO_2 being recycled by the process. These figures are improved if use can be made of the oxygen product: Since the oxygen is not generated by conventional air distillation, CO_2 emissions are avoided that would correspond to 0.42 kWh/kg O_2 (35 bar) [27]. Table 2 shows that this credit was not enough to compensate for the losses due to the use of LP steam. Table 3 shows the requirements of the process in terms of cooling water, renewable power, fossil-fuel power and heat (LP steam or waste heat at a similar temperature). Some of these figures were used to generate Table 4, which is discussed hereafter. The CO_2 stripping unit required 71% of the steam, the rest being used by the distillation column for the methanol product.

4.1.2. Conversion of electricity to methanol

According to Table 3, the overall efficiency of conversion (kW_{th}/kW_{el}) is between 58% and 68% if waste heat is available. This ratio drops to 51–58% if process steam must be used. The ratio of electricity use from the fossil fuel source to that from renewable origin was 3.6% (Option A) or less. The overall efficiency was slightly decreased if oxygen was compressed to 35 bar and distributed via pipeline, e.g. for Option 'A' with no waste heat it changed from 54.1% to 53.1% (other results were not reported here).

4.2. Process economics

4.2.1. Without a market for the oxygen

The effect of the selling price of methanol on the net present value (NPV) was investigated, first in the absence of a market for the oxygen. The value retained for the minimum accepted rate of return on the initial investment (MARR) was 10%. Taxes were taken at 35% of taxable positive profits on the same year, and a yearly depreciation allowance for tax taken as 15% of initial capital expenditure minus the amount already discounted in previous years. The lifetime of the plant was 15 years, and no scrap value was considered. Fixed operating costs were assumed at 5% of the capital expenditure. Table 5 breaks down the capital costs for each option, while Table 6 summarises the variable operating costs. The price of LP steam was included in Table 6, as a 'worst-case scenario' when no waste heat was available. Table 7 shows for each design option the selling price of methanol which nullify the NPV. It can be seen that Option B was by far the most advantageous, since it allows a price significantly lower than the other options. Option C was least favourable due to the high cost of pressurised electrolysers.

If the methanol produced is to be sold as a fuel for vehicles, the case could be made that a favourable taxation regime applies. Comparison with gasoline must account

Table 5
Capital expenditure in million £s

£10^6	Option A	Option B	Option C	Option D
Electrolysis	141	34.7	90.9	34.4
Extra de-NO_x capacity	0.107	0.054	0.0607	0.05356
Extra FGD (Wellman–Lord)	2.871	1.368	1.548	1.350
CO_2 recovery	9.36	4.46	5.05	4.40
H_2 compression/storage	17.6	8.40	9.51	8.28
CO_2 compression	4.46	2.13	2.40	2.09
Reactor	2.46	1.17	1.33	1.16
Separation	1.01	0.48	0.54	0.47
Water purification	0.660	0.315	0.356	0.310
Fuel cell plant	0	0	0	54.5
Total	179.6	53.1	111.6	107

Table 6
Variable operating costs (including steam) in million £s per year (assumption of 8000 working hours per year; unit costs—steam £0.59/te, cooling water £0.05/te, fossil power £0.038/kWh)

(£10^6/year)	Option A	Option B	Option C	Option D
Renewable power	14.0	6.00	6.00	6.00
Fossil fuel power	1.10	0.527	0.407	0
Cooling Water	1.37	0.701	0.752	0.694
LP steam	3.53	1.68	1.90	1.65
Feed and Chemicals	0.470	0.224	0.254	0.221
Total	20.5	9.13	9.31	8.57

Table 7
Minimum selling price for methanol, if NPV nil after 15 years of operation and MARR = 10%

	Option A	Option B	Option C	Option D
Price (£/l)	0.3720	0.2720	0.3886	0.4224

for the energy content of a litre of gasoline being twice that of a litre of pure methanol: the data should refer to litre-equivalent (l_{eq}) of gasoline (equivalent to 2.0 l of pure methanol). Following the approach of Specht et al. [4], the respective costs of gasoline and M85 (85% vol. methanol + 15% gasoline) at the pump are presented in Table 8.

The results shown in Table 4 assumed the same level of taxes applied to gasoline and M85 from fossil fuel, although M85 is not yet, to the authors' knowledge, used in the UK. The pump price per litre-equivalent of these two fuels is then the same. However, M85 with methanol from renewable energy would be competitive only if taxation allows it, i.e. a tax of no more than 0.20 £/l_{eq} should apply, i.e. 0.094 £/l. This value would really be a practical maximum, since with a MARR at 10% the NPV after 15 years would only be £17m (compared with an initial investment of £52m). The NPV, however, would be £31m if waste heat were available instead of process steam (Fig. 3).

4.2.2. If selling the oxygen

Only Options B and C were compared, since Option B was by far the most economical in the previous section, and Option C alone offered substantial savings for oxygen compression and delivery. Capital costs and operating costs for the oxygen processing plant are shown in Table 9. Capital costs included only the compressors, coolers, storage tanks, and the construction of a 20 km pipeline. More compressors were required for Option B, whereas pressurised storage was required for Option C. This resulted in almost identical capital costs. However, the operating costs for Option B were almost twice as high as for Option C. With a selling price of £10 per 100 N m^3 and conditions identical to those listed in the previous section, the oxygen plant gave an NPV of £55m for Option B, and a much higher figure of £200m for Option C. When combined with the results from the previous section (process steam scenario), Fig. 4 shows that the figures were substantially improved for both projects. Option B broke even at a selling price that was 40% lower than when the oxygen was not sold; Option C was better than option B (plus oxygen sales), since it still managed

Table 8
Comparison of price for untaxed methanol product (assumed to be 0.32£/l) with taxed price for gasoline and methanol (data for gasoline refer to Higher Octane Unleaded sold in the UK, Nov. 2000)

Fuel	Before distribution and taxes (£/l_{eq})	Distribution (£/l_{eq})	After taxes at the pump (£/l_{eq})
Gasoline	0.160 (=0.160£/l)	0.060	0.844 (£/l)
M85, fossil fuel	0.163 (=0.092£/l)	0.106	0.269 + tax(£/l_{eq})
M85, renewable	0.539 (=0.305£/l)	0.106	0.645 + tax(£/l_{eq})

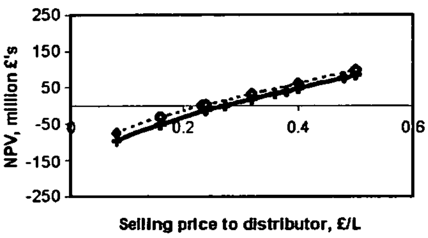

Fig. 3. NPV for methanol plant after 15 years of operation as a function of sales prices for Option B, with *no processing* and *no sale* of oxygen (MARR 10%, taxation 35%, 15% tax allowance for depreciation): (----) *waste heat*; (—) *LP steam*.

Table 9
Capital cost, operating cost and Net Present Value for oxygen processing plant in Options B and C with process steam scenario. Oxygen was distributed via 20 km pipeline (35 bar) and sold at £10/100 Nm^3. Conditions as in Table 6

O_2 plant in option	B	C
Capital costs (£10^6)	5.0	5.1
Operating costs (£10^6/year)	0.48	0.26
NPV (15 years, 10% MARR) £10^6	55.7	202

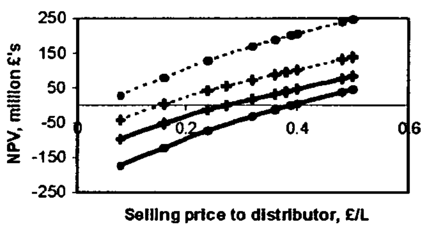

Fig. 4. NPV for methanol plant with LP process steam scenario, after 15 years of operation (MARR 10%, taxation 35%, 15% tax allowance for depreciation; oxygen sold at £10/100 N m^3). (—) *No sale of* O_2; (----) *Sale of* O_2; (+) Option B; (●) Option C.

an NPV of about £28m when methanol was sold at market price for bulk (£0.08/l).

These promising figures should be considered with caution, since a local industrial customer for the oxygen must be available. In the case of Option C, there was also uncertainty on the capital cost of pressurised electrolysers.

4.3. Future work

These would include: use of a better catalyst with a higher conversion rate; stripping of CO_2 either with a solvent requiring less heat, or under a vacuum; discontinuous operation, in order to avoid using power during peak-time; closed cycle using CO_2/O_2 mixture instead of air in power plant, or IGCC power generation; shipping the extracted CO_2 to areas where renewable energy is plenty.

5. Conclusions

CO_2 abatement is currently limited by the availability of renewable power. The process in its current form must also make use of vast quantities of 'waste heat', in the absence of which its value for CO_2 abatement is almost nil.

Conversion of renewable electricity to renewable fuel was achievable with an efficiency of 59%. A small amount of fossil-fuel electricity was also required (3.6% of total power). When the waste fossil-fuel heat used in the process was taken into account, overall efficiency was 52%.

Option B for the process design was the only one profitable if a local customer was not available for the oxygen by-product. However, taxation for fuels derived from renewable sources should be no more than 0.20£/l. Option B was much more profitable if the oxygen was sold to a local industrial client, but option C was then much better and even became viable in the absence of tax breaks.

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