The Role of Fossil Fuel Carbon Abatement Technologies (CATs) in a Low Carbon Energy System - a report on analysis undertaken to advise the DTI's CAT Strategy

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Executive Summary

This report describes a study undertaken to advise the DTI in the preparation of its strategy for the development and implementation of fossil fuel carbon abatement technologies (CATs). The main results were outlined in the CAT strategy published in June 2005, but this report has been prepared to give a fuller account of the work and the results obtained. The study investigated the potential role of CATs, including the size and timing for their deployment, as the UK moves in line with the Energy White Paper (EWP) goal to progressively reduce energy related CO_2 emissions so that by 2050 these are 60% less than in 2000. The study has shown that CATs, including higher conversion efficiency processes, co-firing with carbon neutal biomass and CO_2 capture and storage (CCS) have the potential to make an appreciable contribution towards the EWP goal. For CCS, which offers the highest levels of abatement, the timing for commercial deployment in power generation lies between 2010 and 2020, with additional deployment for the production of hydrogen, to be used to substitute for petroleum in road transport, coming between 2040 and 2050. This pattern of deployment was found to be robust to a range of scenarios for economic growth, demand for energy related services, primary energy prices and social preferences. However, the level of deployment is dependent on the corresponding deployment of other abatement measures including demand side energy efficiency, renewable energy and nuclear power. Realistically CATs, and CCS in particular, should be considered as part of a portfolio of technical options for reducing CO_2 emissions. In this respect it is noteworthy that power generation from CCS technologies is complementary to renewable energy in providing a low carbon, cost effect means to back up intermittent sources.

The Energy White Paper (EWP) – *Our Energy Future – Creating a Low Carbon Economy*, addressed climate change as one of its main objectives, and set out to place the UK on a path to cut CO_2 emissions by 60% by 2050[1]. First steps for achieving this target placed the emphasis on the development and deployment of renewable technologies as well as improvements in energy efficiency. However, the EWP also recognised that fossil fuels could have a role to play in a low-carbon economy, but that they needed to significantly reduce their CO_2 emissions compared to the present. It saw this being achieved through fossil fuel based carbon abatement technologies (CATs) including CO_2 capture and storage (CCS).

Following the EWP, in September 2003, the DTI completed a review of CCS[2] which concluded that its existing Cleaner Fossil Fuels Programme

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[1] Our energy future – creating a low carbon economy, Cm 5761, (DTI/Pub URN 03/660), February 2003.

[2] Review of the feasibility of carbon dioxide capture and storage in the UK, DTI Report URN 03/1261, September 2003.

should be complemented or replaced by a broader programme aimed at the development and implementation of CATs. To assist in the development of its strategy for CATs the DTI commissioned an energy systems analysis to examine their potential role in the sort of low carbon energy system needed to deliver a 60% reduction in CO_2 emissions by 2050. Most of the study was undertaken between June and December 2004, and the results were reported in the CAT Strategy in June 2005[3]. This report presents a more detailed description of the work and the results obtained.

In scoping the CAT Strategy the DTI concluded that it should cover three generic options for reducing CO_2 emissions from fossil fuel plant, namely:

- **Higher efficiency conversion processes** – the amount of fuel consumed, and the associated emission of CO_2, is reduced when conversion processes (eg power generation, oil refining, hydrogen production) are made more efficient.
- **Fuel switching to lower carbon alternatives** – the main option to be considered was co-firing with 5-10% CO_2 neutral biomass.
- **CO_2 Capture and Storage (CCS)** – in which the carbon in fossil fuels is captured (as CO_2) and committed to long-term storage in geological formations.

All three CAT options have been investigated, but with particular attention devoted to CCS because this offers the greatest reduction in CO_2 emissions (~85%). While the first two options are applicable to both large and small-scale plant, economies of scale and infrastructure requirements dictate that CCS will only be implemented on large-scale facilities. Consequently this study focussed on the prospects for CATs deployed in power generation and the production of hydrogen as an alternative transport fuel. CCS could also be deployed with other large point sources of CO_2 such as steel and cement production, but insufficient data precluded their inclusion in the model.

A previous investigation of the technologies needed to make substantial reductions in the UK's energy related CO_2 emissions was undertaken in support of the EWP[4]. This work included a limited set of options for CO_2 capture and storage (CCS) and the results showed that these technologies could make a substantial contribution to the UK attaining a 60% reduction in CO_2 emissions by 2050. Since then a broader range of CCS options have been defined, and further studies have advanced understanding of their current and prospective cost and performance.

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[3] A strategy for developing carbon abatement technologies for fossil fuel use, DTI/Pub URN 05/844, June 2005.

[4] Options for a Low Carbon Future, DTI Economics Paper Number 4, June 2003 (DTI/Pub 6727/0.5k/06/03/NP URN03/985)

Additional data have also been derived for other CAT options. To enable comparison with the earlier work this new study was undertake with the same MARKAL systems model and supporting database, but with a revised and extended representation of CATs.

The modelling study extended to 2050 to examine options for attaining the EWP's aim of reducing CO_2 emissions by 60% by this time. Clearly there are considerable uncertainties in making such projections, such as the future pattern of UK economic development and the related demand for energy services (eg space heating, entertainment, business activity, mobility, etc), social trends and preferences and the trend in the prices of primary energy sources. Consequently, the study used a scenario-based approach to examine a range of possible futures. Three sets of scenarios were investigated:

Baseline (BL) – in which the current values of society remain unchanged and policy intervention in support of environmental objectives is pursued in a similar way to now (GDP growth 2.25% per year).

World Markets (WM) – based on individual consumerist values, a high degree of globalisation and scant regard for the global environment (GDP growth 3% per year).

Global Sustainability (GS) – based on the predominance of social and ecological values, strong collective environmental action and globalisation of governance systems (GDP growth 2.25% per year).

The main part of the investigation was undertaken by applying limits within MARKAL on the overall CO_2 emissions produced by the UK energy sector, over decade time-steps, to reach the 60% reduction target by 2050. Through this approach it was possible to observe the phased deployment of abatement technologies.

With the exception of cost effective energy efficiency improvements most technology options to reduce CO_2 emissions cost more than unabated alternatives. For example fossil fuel technologies without CCS will always be cheaper than the same technologies incorporating the additional processes for CO_2 capture, transportation and storage. Therefore many abatement technologies will not be deployed until they receive an adequate financial return for the CO_2 abatement they deliver. By applying an overall CO_2 emissions constraint to the MARKAL model it was implicitly assumed that some mechanism is put in place to reward/encourage the deployment of abatement technologies. No assumptions were necessary on what form this measure may take (eg. emissions permits, regulation, obligations, etc.). However, by applying the constraint across the complete energy system it was assumed that the measure is applied evenly across all sectors.

Overall the study has found that CATs have the potential to make an appreciable contribution to the attainment of the UK's medium and long-term aims for reducing CO_2 emissions. This contribution will come from the supply of both electricity and hydrogen, with the latter mainly used as a replacement for petroleum fuels in road transport. Thus when following a path to a 60% reduction in CO_2 emissions by 2050 the modelling results showed:

- By 2020 all existing pulverised coal plant expected to be retrofitted to meet LCPD requirements (16GW) was also retrofitted with high efficiency boilers, and later these were retrofitted with amine scrubbers to capture CO_2.
- Co-firing with energy crops was deployed up to the set maximum of 10% of total fuel input with all existing pulverised coal plant. (NB Co-firing on new fossil fuel plant was not investigated.)
- CCS was deployed for electricity and hydrogen production from both coal and natural gas fired plant starting between 2010 and 2020.

The timing and size of deployment of CCS was sensitive to scenario assumptions on the rate of improvement in energy efficiency in the economy, the rate of economic growth (and hence demand for energy services) and the deployment of alternative abatement options including energy efficiency and nuclear power. In most scenarios CCS for electricity generation was first deployed between 2010 and 2020, but for the high energy demand World Markets Scenario deployment was needed from 2010. CCS for large-scale hydrogen production was deployed from 2040 in most scenarios, again with the exception of the World Markets Scenario when this started a decade earlier. The overall level of CCS deployment increased over time from 0-25Mte CO_2 per year in 2010-20 to 50-180Mte CO_2 per year by 2040-50.

The lower levels of CCS deployment occurred with scenarios in which MARKAL was permitted to build new nuclear generation capacity. This is because MARKAL deployed new nuclear (when available) for almost all base-load generation while CCS technologies operated at load factors of 50-60%. In contrast when there was no new nuclear build fossil plant with CCS were used for base-load and medium load generation. With nuclear power CCS technologies were used to back up intermittent renewable energy generation, much of which was onshore or offshore wind, and in this sense CCS and renewable energy complement each other.

The sensitivity of CCS deployment to the availability of new nuclear capacity resulted from the way the MARKAL model functions and the range of uncertainty applying to its technology database rather than any definite cost advantage of one technology over the other. MARKAL is a cost optimisation model, and therefore without additional constraints it will differentiate strongly between technologies with very similar costs. This is the case with nuclear and CCS, because in MARKAL the costs of base-load generation from CCS technologies and nuclear power are similar, but with nuclear marginally cheaper. However, the difference is less than the uncertainty applying to the long-term cost and performance data used by MARKAL, and therefore the data do not have the precision to support differentiation between these options. Indeed it would be wrong to imply that an "either or" choice must be made between nuclear and CCS. In practice factors additional to cost will affect the choice of abatement technologies, and this could lead to a mix of options being deployed.

Notwithstanding this limitation of the modelling approach the result is useful in underlining the conclusion that CATs should be considered within a portfolio of abatement measures. While CCS in particular has the potential to make a major contribution, the exact timing and level of its deployment will depend on the deployment of other abatement options as well as on the economic conditions, fossil fuel prices and social preferences prevailing at the time. It is also significant that irrespective of the balance of technologies for electricity generation CCS was always the preferred option for the production of hydrogen for road transport.

With regard to the choice of CCS technologies, the Markal results had CCS applied to both coal and natural gas in all scenarios although the balance between these fuels varied depending on relative fuel prices. CCS on natural gas was implemented by retrofitting to GTCC plant, while with coal this involved a combination of pulverised fuel and IGCC. Most important to the present study the build rates for nuclear power and new large-scale fossil fuel power plant were limited to 1GW of capacity per year. Totally new pulverised coal plant was not constructed due to a slightly higher cost compared to IGCC. Once again, however, this cost difference was small compared with the uncertainty over long term costs, and does not support choosing winners between pulverised coal and IGCC technologies.

This analysis will be used as a starting point for consideration of the role that CATs and CCS might play, alongside other options, in the energy system to 2050 as part of the Energy Review.

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1 Introduction

The Energy White Paper (EWP) – *Our Energy Future – Creating a Low Carbon Economy*, addressed climate change as one of its main objectives, and set out to place the UK on a path to cut CO_2 emissions by 60% by 2050[5]. First steps for achieving this target placed the emphasis on the development and deployment of renewable technologies as well as improvements in energy efficiency. However, the EWP also recognised that fossil fuels could have a role to play in a low-carbon economy, but that they needed to significantly reduce their CO_2 emissions compared to the present. It saw this being achieved through fossil fuel based carbon abatement technologies (CATs) including CO_2 capture and storage (CCS).

Following the EWP, in September 2003, the DTI completed a review of CCS[6] which concluded that its existing Cleaner Fossil Fuels Programme should be complemented or replaced by a broader programme aimed at the development and implementation of CATs. To assist in the development of its strategy for CATs the DTI commissioned an energy systems analysis to examine their potential role in the sort of low carbon energy system needed to deliver a 60% reduction in CO_2 emissions by 2050. Most of the study was undertaken between June and December 2004, and the results were reported in the CAT Strategy in June 2005[7]. This report presents a more detailed description of the work and the results obtained.

In scoping the CAT Strategy the DTI concluded that it should cover three generic options for reducing CO_2 emissions from fossil fuel plant, namely:

- **Higher efficiency conversion processes** – the amount of fuel consumed, and the associated emission of CO_2, is reduced when conversion processes (eg. power generation, oil refining, hydrogen production) are made more efficient.
- **Fuel switching to lower carbon alternatives** – the main option to be considered was co-firing with 5-10% CO_2 neutral biomass.
- **CO_2 Capture and Storage (CCS)** – in which the carbon in fossil fuels is captured (as CO_2) and committed to long-term storage in geological formations.

This study examined the potential role of CATs in delivering the EWP's CO_2 goal. All three CAT options have been investigated, but with particular attention devoted to CCS because this offers the greatest reduction in CO_2 emissions (~85%). While the first two options are

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[5] Our energy future – creating a low carbon economy, Cm 5761, (DTI/Pub URN 03/660), February 2003.

[6] Review of the feasibility of carbon dioxide capture and storage in the UK, DTI Report URN 03/1261, September 2003.

[7] A strategy for developing carbon abatement technologies for fossil fuel use, DTI/Pub URN 05/844, June 2005.

applicable to both large and small-scale plant, economies of scale and infrastructure requirements dictate that CCS will only be implemented on large-scale facilities. Consequently this study has focussed on the prospects for CATs deployed in power generation and the production of hydrogen as an alternative transport fuel. CCS could also be deployed with other large point sources of CO_2 such as steel and cement production, but insufficient data precluded their inclusion in the model.

A previous investigation of the technologies needed to make substantial reductions in the UK's energy related CO_2 emissions was undertaken in support of the EWP[8]. This work included a limited set of options for CO_2 capture and storage (CCS) and the results showed that these technologies could make a substantial contribution to the UK attaining a 60% reduction in CO_2 emissions by 2050. Since then a broader range of CCS options have been defined, and further studies have advanced understanding of their current and prospective cost and performance. Additional data have also been derived for other CAT options. To enable comparison with the earlier work this new study was undertake with the same Markal model and supporting database, but with a revised and extended representation of CATs.

The report describes and discusses the size and timing for the deployment of CATs, as the UK follows a path to reducing its CO_2 emissions by 60% by 2050, against different scenarios for future economic growth, demand for energy related services, primary energy prices, social preferences and the deployment of other low carbon technology options. For completeness it starts by setting out the analytical modelling approach and the methods adopted for establishing and reviewing the supporting database on CAT options.

This analysis will be used as a starting point for consideration of the role that CATs and CCS might play, alongside other options, in the energy system to 2050 as part of the Energy Review.

2 Approach to systems modelling

There are various methods for modelling energy supply and demand systems and the choice is normally determined by such factors as the questions needing to be answered and the quality of the supporting data available. In this particular study the key issues were the choice and timing for the deployment of individual energy supply and demand side technologies (eg. CATs) over timescales of up to 50 years. Such studies are best addressed by systems models that contain a detailed engineering representation of the network of extraction, conversion, transmission, distribution and end-use technologies that deliver energy

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[8] Options for a Low Carbon Future, DTI Economics Paper Number 4, June 2003 (DTI/Pub 6727/0.5k/06/03/NP URN03/985)

services (eg. light, heat, motive power, etc.) to the consumer. The particular model used in this study was MARKAL, which was also used for the previous EWP studies. MARKAL yields the cost optimal mix of energy technologies needed to deliver an exogenously defined set of demands for energy services. For example it considers the relative cost effectiveness of investment in additional supply capacity versus energy saving measures. Similarly, when examining CO_2 abatement, it considers the cost effectiveness of actions in different sectors such as electricity generation, households, industry, transport, etc.

Some of the advantages to be derived from using such a systems model are that it:

- Enables coverage of a wide range of technologies in the energy system and allows feedback between the energy supply and demand sides;
- Provides a framework to evaluate technologies on the basis of cost assumptions, check the consistency of results and explore sensitivities to key data and assumptions;
- Looks across a timeframe (in this case to 2050), thus providing information on the phasing of technology deployment;
- Enables emissions constraints to be applied, with the energy system adjusting to meet these at least cost.

However, like all models, Markal also has limitations that need to be taken into account when assessing its results:

- By cost optimising it effectively represents a perfect energy market, and neglects barriers and other non-economic criteria that affect decisions. One consequence of this is that, without additional constraints, it tends to over-estimate the deployment of nominally cost effective energy efficiency technologies.
- Because the demand for energy services is set as an exogenous scenario assumption (see below) the model does not have complete feedback between delivered energy prices and demand. Thus the model may respond to increasing energy prices by investing in more energy efficiency, but it cannot simply reduce the demand for energy services.
- Because the model cost optimises it may differentiate between technologies with very similar costs whereas in practice other, none cost, considerations may lead to a more balanced mix of technologies. This is a particular issue with base load electricity (see later).
- Being deterministic the model cannot directly assess data uncertainties, which have to be investigated through separate sensitivity analyses.

The data needing to be input to MARKAL consists of both *scenario* and *technology* information (Figure 1). The scenario information consists of primary energy prices, demands for energy services (useful energy demands) and any emissions constraints; the technology information concerns data on the costs (capital and operating) and performance (efficiencies, availability etc) for the menu of technologies included in the model.

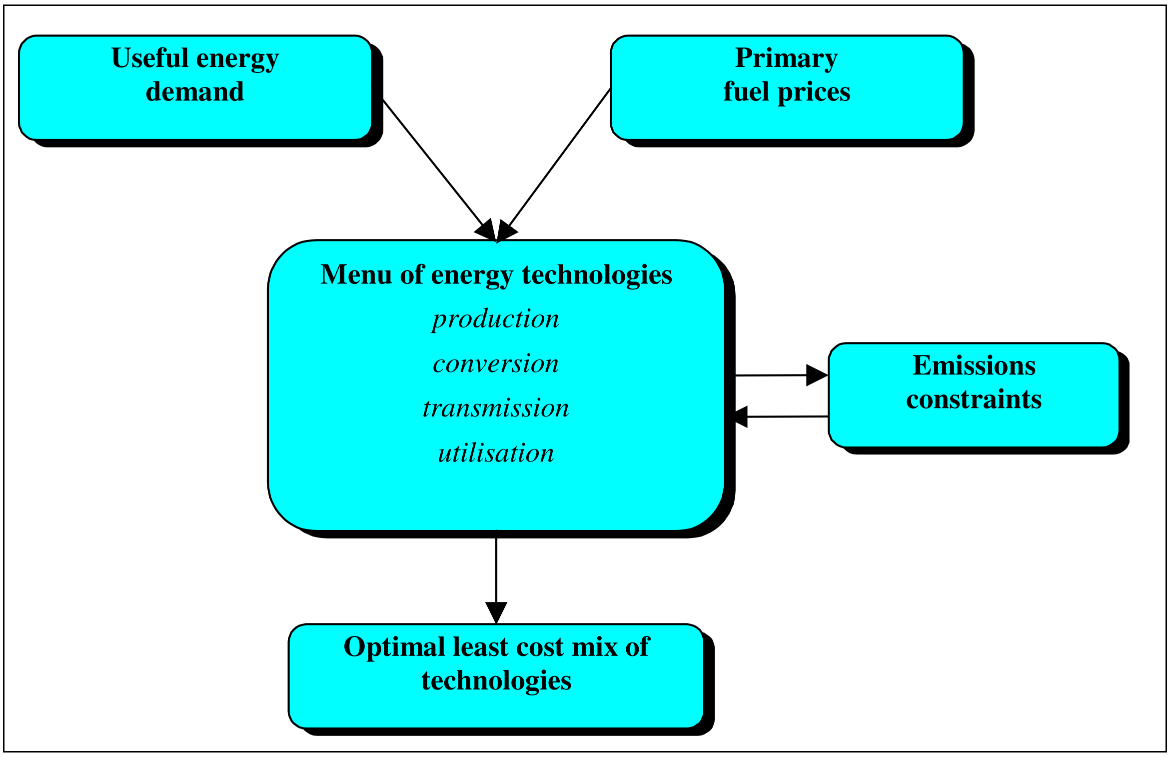

Figure 1 Schematic representation of the key features of the MARKAL Model

2.1 Scenario development

The future demand for energy services and the costs of primary energy supplies are uncertain, particularly over the long time frame to 2050 covered by this study. Consequently it is normal in energy modelling to explore a range of possible futures through scenarios that conceptualise alternative development paths. This supports debate on future options as well as assessing how robust the deployment of individual technologies is to price and market uncertainties.

In the previous Markal EWP work three scenarios were developed, namely Baseline, World Markets and Global Sustainability and these were retained for the present study. The scenarios were designed to explore how the path to a 60% reduction in CO_2 emissions by 2050 was affected by different rates of economic growth, primary energy prices, life styles and attitudes towards the environment and climate change. The scenarios can be briefly characterised as follows.

- **Baseline** – in which the current values of society remain unchanged and policy intervention in support of environmental objectives is pursued in a similar way to now (GDP growth 2.25 % per year).
- **World Markets** – based on individual consumerist values, a high degree of globalisation and scant regard for the global environment (GDP growth 3 % per year).
- **Global Sustainability** – based on the predominance of social and ecological values, strong collective environmental action and globalisation of governance systems (GDP growth 2.25 % per year).

None of the scenarios envisaged major changes to the main trends apparent in developed economies such as the growing demand for personal and commercial transport, the move to more and smaller households, increased demand for entertainment and leisure, growth in the services business, etc. However, what the scenarios did do was to examine alternative choices for satisfying these trends, for example private or public transport, comfort levels in households, choice of household appliances, building standards, etc. The scenarios did not considered security of supply as an issue for the choice of fuels or technologies.

Demand for energy services

The demand for energy services, or useful energy demand, is a measure of the utilisation of a service for which energy is consumed. Useful energy demands can be met by a variety of competing fuels, burned in different devices with different efficiency. For example the useful energy demand for space heating reflects the desired level of comfort (thermostat setting) and the room space to be heated. This demand could be met by electric heating, gas or oil boilers, or alternatively it could be ameliorated by insulation measures designed to reduce the heat supply required.

The method adopted to estimate useful energy demands over the period to 2050 was as follows.

1. Estimate the level of useful energy demand for the relevant end use in 2000, U_{2000}
2. Select a proxy measure (P) for growth of useful energy demand.
3. Calculate for the proxy measures an escalation factor E_n, for each year in the future $E_n=P_n/P_{2000}$
4. Derive useful energy in the year n, $U_{n} = E_n \times U_{2000}$

The escalation factors E_n for each sector under the three scenarios are shown below. A more detailed account of the development of these, with greater disaggregation of the demands is given in documents supporting DTI Economics Paper No.4 – Options for a low carbon future[9].

Table 1 Index of Useful Energy Demands for Each Scenario

Baseline Scenario

	Domestic	Industry	Service	Transport
2000	100	100	100	100
2010	118	103	116	118
2020	133	107	127	135
2030	145	110	135	148
2040	151	114	142	158
2050	154	117	149	165

World Markets Scenario

	Domestic	Industry	Service	Transport
2000	100	100	100	100
2010	128	104	119	122
2020	150	108	132	145
2030	168	111	142	165
2040	180	115	154	183
2050	184	119	166	198

Global Sustainability Scenario

	Domestic	Industry	Service	Transport
2000	100	100	100	100
2010	117	104	114	112
2020	131	108	120	122
2030	140	112	127	127
2040	145	116	133	130
2050	145	120	138	129

Energy prices

The energy prices required for the model were the primary prices for oil, natural gas and coal. These were originally developed in 2002, in consultation with DTI and DEFRA, for the EWP study and were retained for this project. These estimates took account of the long run supply position and demand variations between scenarios, and assumed that the world would be following the same scenario development pathway as the UK. Consistent with this, the demand for oil, and hence price, was assumed to be strongest in the World Markets Scenario and weakest in the Global Sustainability Scenario, with the Baseline Scenario lying roughly midway between these. Demand for gas was also expected to be strongest in the World Markets Scenario, but in this case demand in the Global Sustainability Scenario was expected to be stronger than in the

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[9] http://www.dti.gov.uk/energy/environment/eerp/reports/ClimateChange_AnnexA.pdf

Baseline Scenario. This is because natural gas was expected to command a premium price, as a relatively "clean" fuel in an environmentally driven future. Demand for internationally traded coal was expected to be relatively weak in all scenarios because of the environmental and technical advantages of other fuels. With this view, and taking account of the high level of global coal reserves, the coal price was set at a constant value, which was close to year 2000 prices. The primary energy prices agreed through this approach are listed in Table 2.

Table 2 Primary Energy Prices used in the Study ($ 2000)

Baseline Scenario

	Oil ($ per barrel)	Gas ($/toe)	Coal ($/tonne)
2000	28	120	36
2010	20	120	36
2020	20	135	36
2030	25	160	36
2040	25	180	36
2050	25	180	36

World Markets Scenario

	Oil ($ per barrel)	Gas ($/toe)	Coal ($/tonne)
2000	28	120	36
2010	24	145	36
2020	28	170	36
2030	35	210	36
2040	35	210	36
2050	35	210	36

Global Sustainability Scenario

	Oil ($ per barrel)	Gas ($/toe)	Coal ($/tonne)
2000	28	120	36
2010	15	130	36
2020	15	150	36
2030	15	180	36
2040	15	190	36
2050	15	200	36

Because the scope of the modelling study did not include oil refining, or the transmission and distribution costs of refined liquid fuels and natural gas, these prices were estimated off-model. These estimates were based on the assumption that the present absolute price differential between primary and delivered energy prices would be maintained throughout the modelling period. A complete listing of the end-user energy prices used in the model is presented in Annex A.

Energy crops were offered for both co-firing and utilisation in dedicated power generation and gasification plant. The prices assumed for this fuel were not assumed to be scenario dependent, and are listed in Annex B

Another factor affecting delivered energy prices is taxation and duty. Here it was assumed that the current rates would apply throughout the modelling period. One important exception was alternative road transport fuels, where it was assumed that they would be duty free (as at present) until they exceeded 3% of the market. Further production above the 3% level attracted the same duties as gasoline and diesel (ie. on a unit of energy basis) on the assumption that tax revenues would need to be broadly maintained.

Since the above assumptions were developed in 2002 there have been significant changes in the price of some fossil fuels, particularly oil. The DTI is considering revised fossil fuel price assumptions for its own modelling work. The following were issued for consultation in August 2005:

	2010	**2020**
Crude Oil	\$20-40/barrel	\$25-45/barrel
Natural Gas	\$110-186/toe	\$127-2007/toe
Coal	\$34-44/tonne	\$26-44/tonne

In comparison to Table 2 the most important differences are in the assumptions on oil prices, and the price differential between natural gas and coal. The implications of the differences for the results of the present study are discussed in Section 7.4.

2.2 Emission Constraints

A key aim of this study was to investigate how the mix of supply and demand side technologies used in the UK's energy system might change when following a path to a 60% reduction in CO_2 emissions by 2050. In particular the study was aimed at investigating the size and timing for the deployment of CATs, and how this might vary across a range of scenarios for future UK energy demand and prices. To do this a phased set of constraints on CO_2 emissions was imposed on the model as follows:

2010	10%
2020	20%
2030	35%
2040	45%
2050	60%

These same constraints were set for all three of the above scenarios.

Note that no assumption was made about the policy instrument that would be used to deliver these emission reductions, which could be some form of emissions charge or regulation. However, by applying the same constraint across the full energy system it was implicitly assumed that the measure would be evenly applied and not targeted on particular sectors.

MARKAL responds to such a constraint by changing the portfolio of demand and supply side technologies it deploys in order to meet the constraint while continuing to minimise the overall systems cost. For example a typical response would be to deploy additional energy efficiency technologies while fuel switching out of high emission fossil fuel plant to renewables, CATs or nuclear.

2.3 Technology Characterisation

Original database

The choice of technologies to be included in a systems analysis study is crucial because this effectively sets limits on the range of options available. The original EWP study aimed to cover a broad range of current and prospective technologies relevant up to 2050 and this menu was retained in the present study. Technologies were specified for the following areas:

- Electricity generation (centralised and decentralised)
- Production of alternative fuels for transport
- Hydrogen production and distribution
- Passenger car transport
- Freight transport (road and rail)
- Public transport (road, rail and air)
- Domestic sector
- Commercial and Services Sector
- Industry sector

Individual technologies are represented in the MARKAL model through a data set covering capital and operating costs, efficiency, availability and operating lifetime. Clearly these parameters will change with time through economies of production, innovation, learning by doing, etc., and the database was designed to consider this evolution. A broad range of data sources was used to establish a reference database on all the technologies. These data were assessed and adjusted to produce an internally consistent database by comparison of both the individual performance parameters and their overall production/end-use costs. Gaps in data time series were filled by interpolation and extrapolation. The underlying principles guiding this process were:

- The costs and performance data were set to be representative of commercially deployed technologies enjoying the benefits of volume production (ie. not first of a kind costs).
- Technologies with low deployment prospects in the UK were still assumed to gain the benefits of volume of production if they had significant global potential (eg. PV).

This reference database, common to all three scenarios, which was subject to review by DTI, DEFRA and the PIU team, and subject to further checking through preliminary runs of the model. Additionally the assumptions affecting two key technology areas, namely electricity supply and hydrogen production and distribution, were further examined by two peer review workshops. The finalised database is listed in Annex D to DTI Economics Paper No.4 [10].

Additional data on CATs

In setting a strategy for the development of CATs it was concluded that three generic groups of technologies should be considered, namely:

- **Higher efficiency conversion processes** – the amount of fuel consumed, and the associated emission of CO_2, is reduced when conversion processes (eg. power generation, oil refining, hydrogen production) are made more efficient. This can contribute emissions reductions of 10-30% depending on the performance of the old and replacement plant. For example, increasing the efficiency of coal-fired power generation plant from 36% to 45% reduces emissions by 20%.
- **Fuel switching to lower carbon alternatives** – the main option considered was co-firing with 5-10% CO_2 neutral biomass, which can deliver emissions reductions of 5-10%.
- **CO_2 Capture and Storage (CCS)** – in which the carbon in fossil fuels is captured (as CO_2) either pre-combustion or post-combustion and committed to long-term storage in geological formations. This approach can reduce emissions by up to 85% depending on the type of non-capture plant displaced[11].

This study aimed to examine all of these options, but with particular attention devoted to CCS because this offers the greatest reduction in CO_2 emissions (~85%). While the first two options are applicable to both large and small-scale plant, economies of scale and infrastructure requirements dictate that CCS will only be implemented on large-scale facilities. Consequently this study focussed on the prospects for CATs deployed in power generation and the centralised production of hydrogen as an alternative transport fuel.

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[10] http://www.dti.gov.uk/energy/environment/eerp/reports/ClimateChange_AnnexD.pdf

[11] *Review of the feasibility of carbon dioxide capture and storage in the UK*, DTI, September 2003 (DTI/Pub URN 03/1261).

Each of these technology groups were included in the previous MARKAL studies but a more detailed set of options were developed for the present work. For example, higher efficiency processes for electricity generation were explicitly included in the previous work because the technology database included evolutionary advances in new plant efficiencies. This has been extend in the current work to include retrofit options for existing coal plant with advanced, high efficiency boilers, and the construction of coal gasification technology to feed synthesis gas into existing gas turbine combined cycle plant (GTCC). Likewise the previous work only included new build options for CCS based on electricity generation with GTCC and integrated coal gasification combined cycle (IGCC) technology and hydrogen production from natural gas. In this study a broader range of options for CCS has been introduced to cover both new build and retrofit.

The full listing of the CAT options included in the model is given in Table 3 below.

Table 3 CATs included in the MARKAL Model

Efficiency Improvement
Evolutionary improvements in the generation efficiency of new build gas and coal fired power plant
Coal gasifier to feed synthesis gas into an existing GTCC
Retrofitting advanced boiler technology to existing coal fired generation plant.
Co-firing
Up to 10% blending of energy crops with coal to feed into existing pulverised fuel generation plant
CO_2 Capture
Retrofit CO_2 capture to existing coal fired generation plant
Retrofit CO_2 capture to existing gas fired generation plant
Retrofit advanced boilers and CO_2 capture to existing coal fired generation plant
New pulverised coal plant with CO_2 capture
New pulverised coal plant with oxy-firing and CO_2 capture
New IGCC plant with CO_2 capture
New GTCC plant with CO_2 capture
Coal gasifier with CO_2 capture feeding H2 into existing GTCC
Coal gasifier with CO_2 capture producing H2 for existing GTCC and direct use
New IGCC for joint production of electricity and hydrogen with CO_2 capture

Coal gasification to produce hydrogen for transport with CO_2 capture
Gas reforming to produce hydrogen for transport with CO_2 capture
CO_2 Transport
Pipeline transport to offshore storage facilities
CO_2 Storage
CO_2 used for enhanced oil recovery
Storage in depleted gas fields or saline aquifers

Cost and performance data for these technology options was first assembled from a wide range of data sources. This was subject to review at a workshop involving specialists drawn from industry and academia and a final database assembled. This is presented in Annex C while delegates to the review workshop are listed in Annex D.

These data aim to take into account improvements in performance and reductions in capital costs stemming from technical advances and learning by doing. Clearly the data is increasingly uncertain the longer the extrapolation and an uncertainty of at least +/-30% should be applied. Also because of this uncertainty, cost and performance data were fixed beyond 2030 for pulverised coal technology and from 2040 for IGCC and GTCC technology.

The data for the CCS options involve reductions in capture costs relative to 2010 technology of roughly 15% in 2020 and 30% in 2030 for pulverised fuel technology. The corresponding trends for IGCC were 20% in 2020 and 40% in 2030, and for GTCC 20% in 2020 and 45% in 2030, reflecting the expected greater potential for technical development with these technologies. These trends are in line with estimates of the potential for reductions in capture costs for these technologies[12]. These reductions in capital cost came from a combination of increased overall plant efficiency and a reduction in capital/construction costs.

CO_2 Transport and Storage

It was assume in the study that CCS would only be implemented for quantities exceeding 1Mt/yr and therefore that transport would be undertaken through dedicated pipelines. The storage options considered were utilisation of the CO_2 for enhanced oil recovery (EOR) and storage pure and simple in either a depleted natural gas field or deep saline aquifer. Only offshore storage was considered.

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[12] Carbon dioxide capture for storage in deep geological aquifers - results from the CO_2 capture project: Capture and separation of carbon dioxide from combustion sources, Volume 1, Edited by David C Thomas, published by Elsevier, 2005

Clearly transport costs will vary to some extent depending upon the location of the source of CO_2 in relation to the storage site(s) or sink. Moreover, a detailed estimation of these costs would need to take account of the volume of CO_2 to be handled, since at higher volumes economies of scale will arise from networking and sharing of the pipeline system. Storage costs, particularly for EOR, will also be sensitive to oil and possibly natural gas prices.

A detailed analysis of these variables was beyond the scope of the study, therefore transport and storage costs were represented by a simple cost supply curve consisting of three tranches, as follows:

Tranche 1	available from 2000 up to 20 Mt CO_2	£4/t
Tranche 2	available from 2010 up to 80 Mt CO_2	£5.5/t
Tranche 3	available from 2020 up to 80 Mt CO_2	£5.5/t

The three tranches were additive and therefore the total transport capacity available to the model was 100Mt in 2010 rising to 180Mt in 2020.

These values were based on previous work that examined a limited set of source-sink combinations and estimated transport costs in the northern North Sea of £8-10/tCO_2, while similar estimates for storage in the southern North Sea were £5.5-7.5/tCO_2. On the basis of these estimates Tranche 1 was set to represent EOR, assuming that a modest return from the additional oil produced would partially offset transport costs. Tranche 2 was based on storage in depleted gas reservoirs and aquifers, and assumed the most favourably located sources and sinks would be used first. Tranche 3 was also based on storage in depleted gas reservoirs and aquifers but with greater transport distances between sources and sinks. Tranche 3 was available later, and could only be deployed by the model after Tranches 1 and 2, and therefore would benefit from the infra-structure established for these earlier tranches. For this reason the cost of Tranche 3 was set to be the same as for Tranche 2.

At present there is some uncertainty over whether CO_2 storage pure and simple is permitted under the London and OSPAR treaties governing disposal in and under the sea, but it is generally acknowledged that CO2 use for EOR is permitted. By only allowing the model to deploy storage pure and simple after 2010, it was implicitly assumed that any necessary treaty amendments will be made by this time.

Other technical constraints

In addition to the above constraints on the availability of CO_2 storage capacity some other constraints were applied to the model to impose realistic limits on the rate of deployment of certain technologies. Most important to the present study the build rate for nuclear power and new large-scale fossil fuel power plant was limited to 1GW of capacity per year.

Also it was assumed that a maximum of 16GW of existing coal fired capacity would invest in the equipment needed to meet the requirements of the Large Combustion Plant Directive (LCPD). This is roughly half the existing stock of coal fired capacity. It was assumed that the existing coal-fired capacity not investing to meet LCPD requirements would cease production between 2010-2020. Only the capacity meeting LCPD requirements was assumed to be available for retrofitting with advanced boiler technology and/or amine scrubbing for CO_2 capture.

3 Deployment of CATs without Carbon Dioxide Constraints

An initial set of MARKAL modelling assessments was made without explicit constraints on CO_2 emissions. These explored all three scenarios and included existing policy measures, but did not anticipate additional measures to drive the UK towards a 60% reduction in CO_2 emissions by 2050. With regard to power generation key assumptions were:

- 16 GW of existing coal fired generation capacity would invest in equipment to meet the requirements of the Large Combustion Plant Directive (LCPD).
- Existing coal-fired capacity not investing to meet LCPD requirements would cease production between 2010-2020[13].
- The UK would achieve its targets to generate 10% and 15% of electricity from renewable energy sources by 2010 and 2015 respectively, and its aspirational target to generate 20% from renewables by 2020.

Most of this study was undertaken between June and December 2004, before the European Union's Emission Trading Scheme (EU-ETS) had started, and it was not clear how the price of CO_2 emission permits was likely to develop. Hence this initial work did not include the affect of permit prices on the generation costs of alternative supply options.

Figure 1 shows MARKAL's projections for the fuel mix and technologies to be used for electricity generation under the Baseline Scenario up to 2050. This differs from the previous MARKAL study for the EWP in showing coal retaining an appreciable share of power generation beyond 2020. This is due to two important changes in the new CAT database compared to the original menu of power generation technologies in MARKAL:

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[13] Under the LCPD such plant must cease production by 2016. Because Markal works on 10 year time steps the plant was retired by 2020 in the model.

a) The introduction of the option to retrofit existing coal plant with advanced high efficiency boilers. By utilising existing facilities and structures (eg. fuel handling, water supply, cooling towers, flue gas clean-up) this is a lower cost option for replacing aging coal generation capacity.
b) The capital cost of new build coal plant was reduced compared to the previous MARKAL data on the basis of more recent design and costing studies.

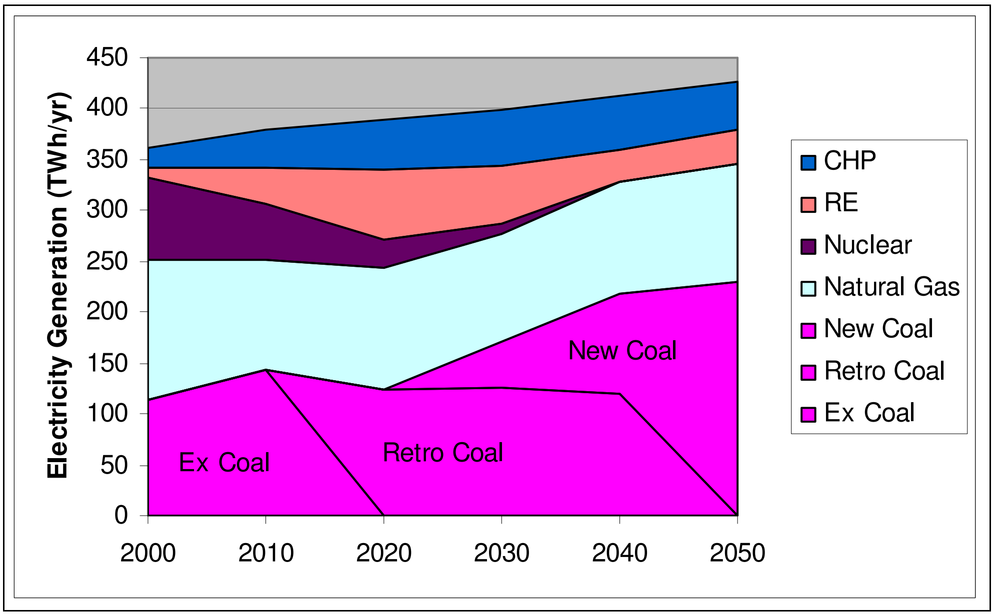

Figure 1 Electricity generation by fuel type under the Baseline Scenario

Between 2010 and 2020 advanced high efficiency boilers were retrofitted to all the existing coal generation capacity that is expected to fit equipment to meet LCPD emissions requirements (16GW). This capacity operates for its specified technical life of 30 years retiring between 2040-2050. Additional totally new coal fired generation capacity is built from 2020.

With regard to other CAT options co-firing with energy crops was deployed on existing coal plant but only up to about 5% of the total fuel burn compared to the technical limit of 10% set in the model. Not surprisingly CCS was not deployed when there was no constraint on CO_2 emissions.

Figure 2 shows the same results for the World Markets (WM) Scenario. Compared to Baseline World Markets envisaged higher economic growth and consequently faster growth in demand for electricity, and also a higher price for natural gas. This combination of factors accelerated the deployment of both retrofit and new coal fired capacity with a corresponding reduction in the share of generation produced from natural gas. In this scenario natural gas is not used for power generation by 2040, but reappears in the generation mix in the last decade of the modelling period. This is because new GTCC plant is expected to achieve conversion efficiencies of about 70% by this time, making it the lowest cost power source at low and medium load factors, even at the relatively high prices assumed for natural gas by this time.

With regard to co-firing with biomass, the trend was similar to the Baseline Scenario with this carbon neutral fuel only substituting for 2-3% of the coal burned in existing plant.

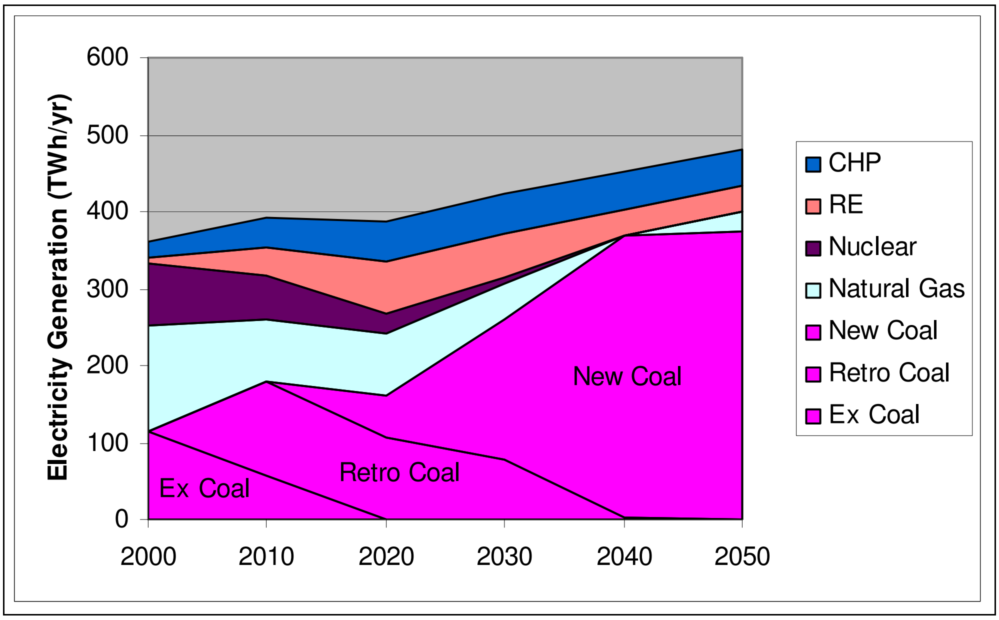

Figure 2 Electricity generation by fuel type under the World Markets Scenario

It was noted in Section 2.1 that more recent views on future prices for coal and natural gas envisage a greater price differential in favour of coal. Such circumstances are most in line with the World Markets Scenario, and clearly favour coal fired generation over gas.

4 Influence of the EU-ETS on the deployment of CATs

A separate set of model runs was undertaken at the end of the study to investigate the impact of the EU-ETS on the deployment of CATs. This focussed on power generation and examined two EU-ETS permit prices of Euro 10 and 20 per tonne of CO_2 emitted. These prices were assumed to be constant over the modelling period.

At present CCS is not included in the EU-ETS because the necessary monitoring and verification procedures have not been established. However, for the purpose of this model investigation it was assumed CCS could be included from 2010.

Table 4 gives the results for the Baseline Scenario and Table 5 results for the World Markets Scenario.

Table 4 Electricity Generation from fossil fuel technologies at various EU-ETS permit prices with the Baseline Scenario (TWh)

Technology	2000	2010	2020	2030
EU-ETS Price	**Zero**			
Existing Coal	114	144	-	-
Retrofit Coal		-	124	125
New Coal		-	-	46
Existing Gas	136	33	-	-
New Gas		75	119	105
Nuclear	80	56	28	9
Other	30	73	118	113
Total	**362**	**380**	**389**	**399**
EU-ETS Price	**Euro 10/tCO$_2$**			
Existing Coal	114	114	-	-
Retrofit Coal		-	124	125
New Coal		-	-	-
Existing Gas	136	29	-	-
New Gas		105	101	115
Nuclear	80	56	28	9
Other	30	75	113	146
Total	**362**	**380**	**366**	**395**
EU-ETS Price	**Euro 20/tCO$_2$**			
Existing Coal	114	72	-	-
Retrofit Coal		-	124	122
New Coal		--	-	-
Existing Gas	136	70	0	0
New Gas		105	96	109
Nuclear	80	56	28	9
Other	30	77	112	155
Total	**362**	**380**	**359**	**396**

The main impact of the EU-ETS in the Baseline Scenario is to reduce generation from existing coal fired plant in 2010, but retro-fitting with advanced boilers goes ahead between 2010 and 2020, and the deployment of this plant is unchanged. However, there is no build of totally new coal plant. Gas fired generation is increased in 2010 to make up for lower coal fired generation, but thereafter it is largely unaffected by the EU-ETS. After 2010 the reduction in generation from coal plant is mainly accommodated by reduced demand (mainly in 2020) and an increase in supply from renewable energy sources (mainly offshore wind).

Compared to Baseline the World Markets Scenario (Table 5) envisages a future with higher electricity demand and higher prices for natural gas. Under these conditions the impact of the EU-ETS was to delay retrofitting coal generation with advanced boilers from 2010 to 2020, but thereafter the technology was fully utilised. Construction of totally new coal plant was delayed beyond 2030 with the exception of 1 GW built in 2030 at the lower EU-ETS permit price of Euro10/tCO_2.

The reduction in coal fired generation was made up by a combination of increased production from gas fired and renewable energy plant (mainly in 2030), and a small reduction in demand (mainly in 2020).

CCS technologies were not deployed in any of the scenarios at either of the EU-ETS permit prices assumed. This shows that higher permit prices will be needed to support the deployment of CCS.

Table 5 Electricity Generation from fossil fuel technologies at various EU-ETS permit prices with the World Markets Scenario (TWh)

Technology	2000	2010	2020	2030
EU-ETS Price	**Zero**			
Existing Coal	114	58	-	-
Retrofit Coal		120	105	77
New Coal		-	55	182
Existing Gas	136	-	-	-
New Gas		82	81	47
Nuclear	80	56	28	9
Other	30	75	117	110
Total	**362**	**392**	**386**	**424**
EU-ETS Price	**Euro 10/tCO_2**			
Existing Coal	114	107	-	-
Retrofit Coal		-	125	125
New Coal		-	-	5
Existing Gas	136	26	-	-
New Gas		127	116	134
Nuclear	80	56	28	9
Other	30	75	117	149
Total	**362**	**392**	**385**	**423**
EU-ETS Price	**Euro 20/tCO_2**			
Existing Coal	114	67	-	-
Retrofit Coal		-	124	125
New Coal		-	-	-
Existing Gas	136	63	0	0
New Gas		127	111	132
Nuclear	80	56	28	9
Other	30	77	116	158
Total	**362**	**391**	**379**	**424**

5 Deployment of CATs with CO_2 constraints

This aspect of the work was aimed at investigating the deployment of technologies along a pathway to the EWP's goal of reducing energy related CO_2 emissions by 60% by 2050. It involved an additional set of MARKAL runs in which CO_2 emissions were constrained so that an overall reduction of 60%, compared to the 2000 level, was reached by 2050. Emission reductions for intermediate years were:

2010	10%[14]
2020	20%
2030	35%
2040	45%

Note that no assumption was made about the policy instrument that would be used to deliver these emission reductions, which could be some form of emissions charge or regulation. However, by applying the same constraint across the full energy system it was implicitly assumed that the measure would be evenly applied and not targeted on particular sectors.

EU-ETS permit prices were not included in these runs because the aim was to limit CO_2 emissions through a direct constraint on the model rather than through a price signal.

5.1 General results

The fuel mix used for electricity generation under the above conditions for the Baseline and World Markets Scenarios is shown in Figures 3 and 4 respectively. With the Baseline Scenario all three types of CAT were deployed:

- Conversion efficiency improvement through the retrofitting of advanced boilers to existing coal fired plant from 2010.
- Co-firing with up to the maximum of 10% energy crops in existing coal plant from 2010 until these were retired in 2040.
- Retrofitting of CCS to coal fired plant from 2020 and gas fired plant from 2030.

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[14] Note the UK's target to reduce CO2 emissions by 20% by 2010 is set against a 1990 baseline and approximates to a 10% reduction relative to 2000.

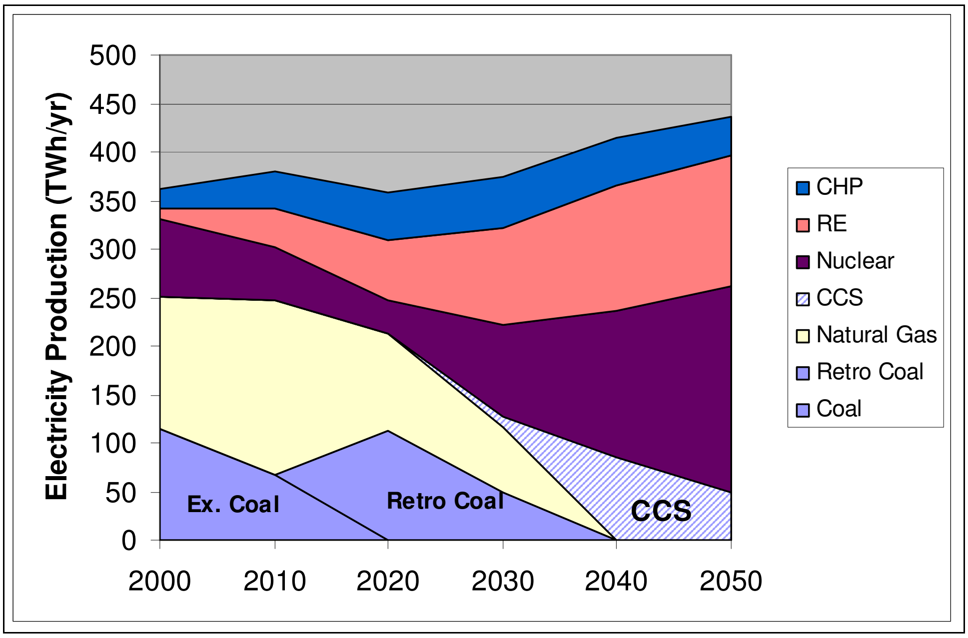

Figure 3 Electricity generation by fuel type under the Baseline Scenario with CO_2 emissions constraints.

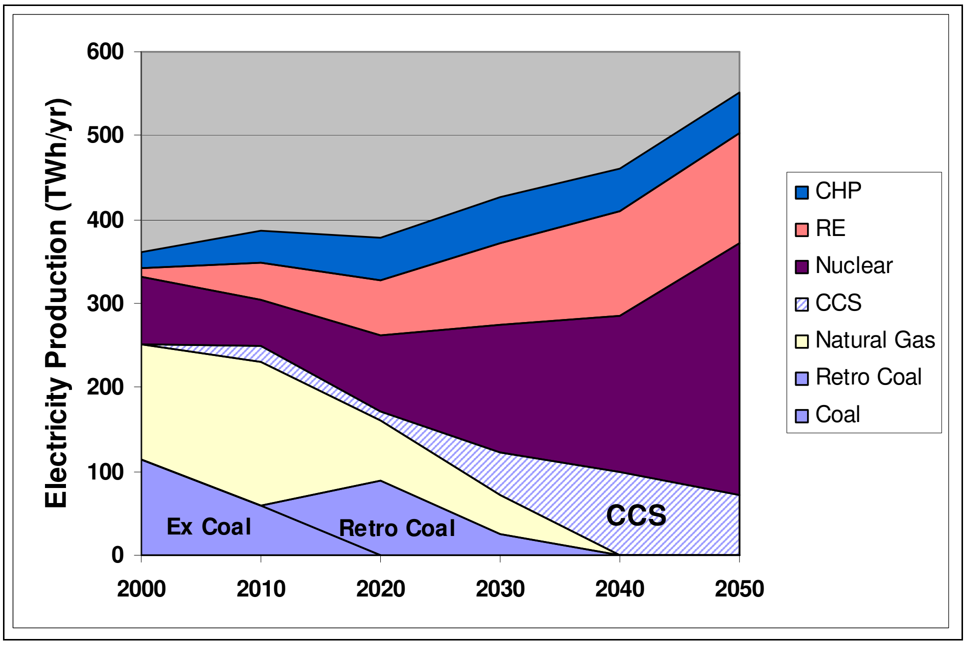

Figure 4 Electricity generation by fuel type under the World Markets Scenario with CO_2 emissions constraints.

Other notable trends are the construction of new nuclear capacity from 2020, which grew to account for 40% of total generation by 2050. There was also a substantial increase in power generation from renewable energy sources, particularly onshore and offshore wind, together with dedicated biomass plant. However, unlike the results without CO_2 constraints no totally new coal fired capacity was built.

Similar trends were apparent in the other scenarios as shown for the World Markets Scenario in Figure 4. Here again there was a substantial increase in generation from nuclear and renewable energy, particularly after 2020.

With regard to CATs the retrofitting of advanced boilers to existing coal plant was started earlier than for the Baseline Scenario, in this case from 2010. Also co-firing with energy crops was deployed to the maximum 10% from 2010. CCS was deployed from 2010, when capture equipment was retrofitted along with advanced boilers to some existing coal capacity. However, CCS was limited to about $4MtCO_2$/yr until 2020 when capture technology was fitted to more of the existing coal capacity and also to some gas generation plant. CCS then increased to $25MtCO_2$/yr by 2040.

A notable feature of the results with all three scenarios is that the load factor of CCS plant ranged between 25-55%, while all nuclear plant operated at a base load. This is because the generation cost of CCS plant is less sensitive to load factor than nuclear, and is used as a cost effective back-up to the renewable energy capacity, much of which was intermittent on and off shore wind.

5.2 Deployment of CCS with no new nuclear capacity

As a cost optimisation model MARKAL chooses the lowest cost technologies to meet scenario demands for energy services, while accommodating any additional constraints (eg. limits on CO_2 emissions). Consequently it may strongly differentiate between technologies with very similar costs. One example of this is the costs of base load power generation from nuclear and CCS technologies, where the difference lies within the uncertainty range for the construction and operating costs of the technologies in 2020 and beyond (Section6). Because the database has slightly lower costs for nuclear compared to CCS MARKAL deploys mainly nuclear for base load while deploying CCS capacity at medium load (Section 5.1).

To further investigate CCS deployment prospects a second series of MARKAL runs was undertaken in which the model was constrained to prevent the deployment of new nuclear capacity. Results for the Baseline and World Markets Scenarios are illustrated in Figures 5 and 6.

Once again with the Baseline Scenario all types of CATs were deployed along the path to a 60% reduction in CO_2.

- Conversion efficiency improvement through the retrofitting of advanced boilers to existing coal fired plant from 2010.
- Co-firing with up to the maximum of 10% energy crops in existing coal plant from 2010 until these were retired in 2040.

- Retrofitting of CCS to coal fired plant from 2020 and gas fired plant from 2030.
- Building of totally new coal fired plant with CCS from 2030 (12GW by 2040).

However, in the absence of nuclear the scale of CCS deployment was much greater reaching 50% of total electricity generation by 2040, with CCS providing both base load and back-up to intermittent renewable energy sources.

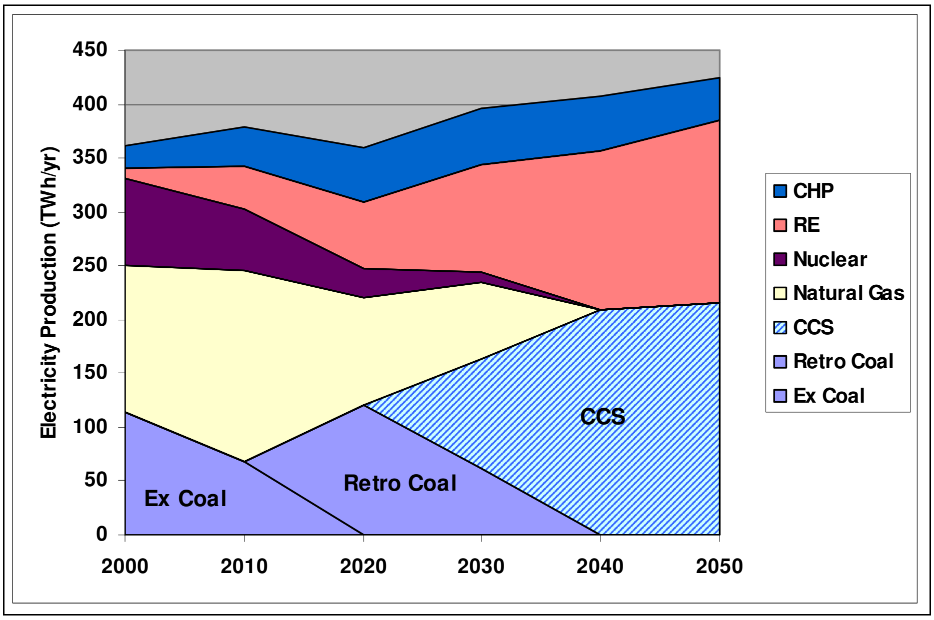

Figure 5 Electricity generation by fuel type under the Baseline Scenario with CO_2 emissions constraints and no new nuclear build.

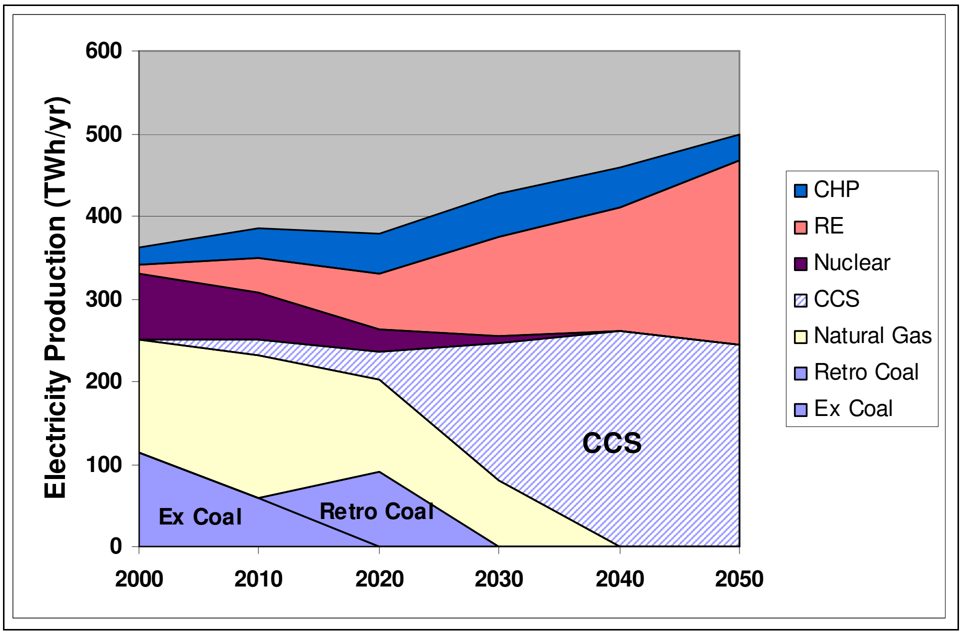

Figure 6 Electricity generation by fuel type under the World Markets Scenario with CO_2 emissions constraints and no new nuclear build.

Once again similar trends were apparent in the other scenarios although the size and timing of the deployment of CATs varied depending on the scenario assumptions for fuel prices and energy demand. With the World Markets Scenario the deployment of CCS was advanced to 2010 with the retrofitting of capture plant, together with advanced boilers, to existing coal generation plant. CCS capacity was increased further with the fitting of capture plant to gas fired capacity and the construction of completely new coal plant with CO_2 capture between 2020 and 2030. By 2030 CCS accounts for 39% of power generation, increasing to over 50% by 2040.

5.3 Deployment of CCS with other scenario variations

Because MARKAL is a cost optimisation model it deploys all cost effective energy efficiency measures. As a consequence the energy efficiency of the economy (expressed as the ratio of final energy demand to GDP[15]) increases appreciably up to 2050 at an average rate of 2.7% per year. Historically it has proved difficult to achieve this level of improvement in energy efficiency, for example over the last 30 years the UK's energy intensity has only improved (fallen) by 2.1% per year. One effect of a higher rate of deployment of energy efficiency is to reduce the rate of growth in demand for electricity, which in turn could reduce the need for CCS. To investigate the significance of this factor another set of MARKAL model runs was undertaken in which the rate of reduction in energy intensity was limited to the historically achieved level of 2.1% per year.

Results for the Baseline Scenario are shown in Figure 7. Compared to the same result without any limitation on energy efficiency (Figure 3) the demand for electricity is about 30% higher by 2050. Also the deployment of CCS is about double (eg. 107TWh compared to 49TWh in 2050), but the start of deployment was unaffected (ie. after 2020).

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[15] This ratio is commonly referred to as the Energy Intensity.

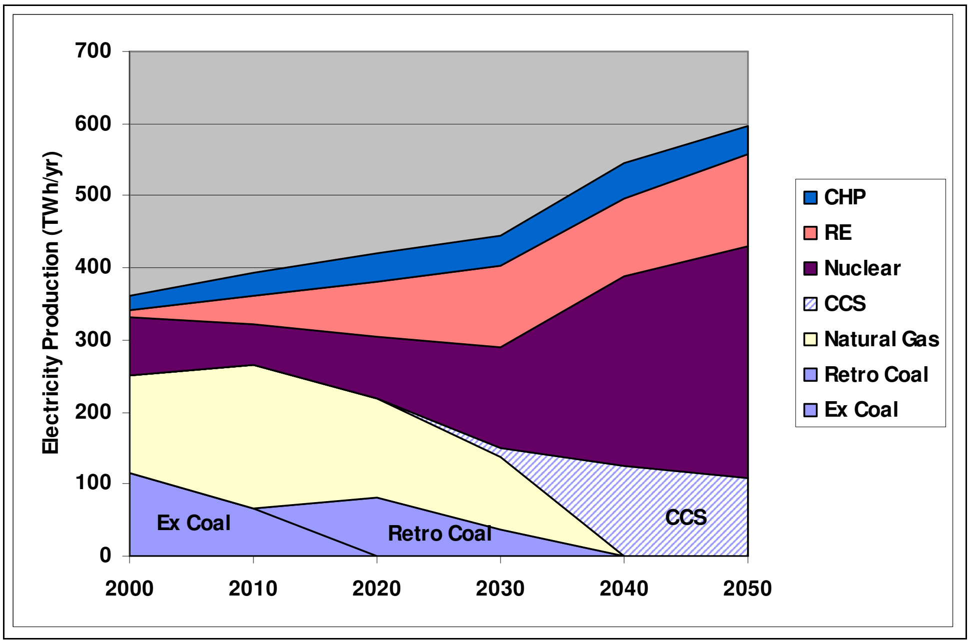

Figure 7 Electricity generation by fuel type under the Baseline Scenario with CO_2 emissions constraints and the rate of improvement in energy efficiency limited to the UK's historic rate

When the limitation on energy efficiency was combined with no new nuclear build the deployment of CCS was much increased with the technology replacing nuclear in the provision of base load generation. Also under these conditions the deployment of CCS was advanced to come in after 2010 compared to after 2020 without the limitation on energy efficiency (compare Figures 5 and 8).

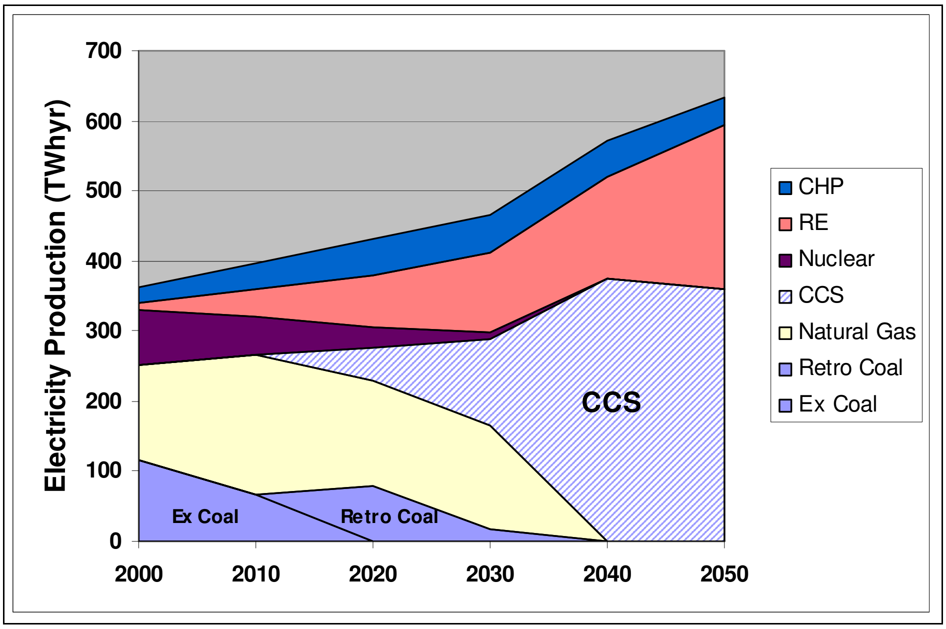

Figure 8 Electricity generation by fuel type under the Baseline Scenario with CO_2 emissions constraints, a limited rate of improvement in energy efficiency and no new nuclear build

6 Hydrogen Production

As well as electricity generation the other area where CCS technologies were included in the MARKAL model was for hydrogen production (Table 3). This hydrogen was made available for use in a range of road transport vehicles, micro-generation fuel cells and hydrogen powered aircraft. In practice MARKAL only used hydrogen for road transport as shown in Figures 9 and 10.

The results show conventional gasoline, diesel and kerosene (for air transport) dominating the early decades of the modelling period. One exception is the small fractions of hydrogen, CNG and Methanol used for road transport. This occurs because the model was set up to explore the deployment of alternative transport fuels by permitting up to 3% of such fuels to be deployed before incurring excise duty (Section 2.1). This resulted in the model using these fuels in adapted conventional vehicles up to the 3% level.

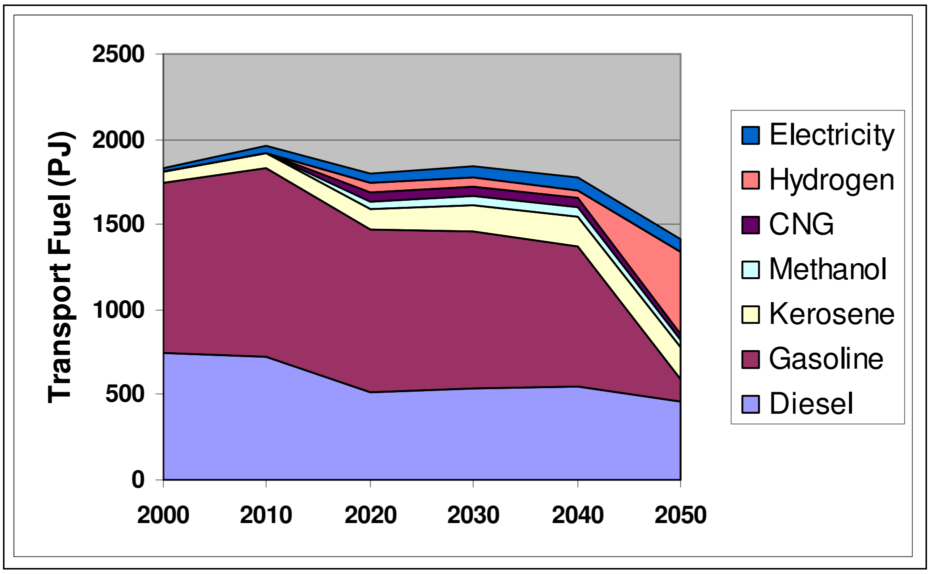

Figure 9 Fuel mix used in transport in the Baseline Scenario with CO_2 emissions constraints

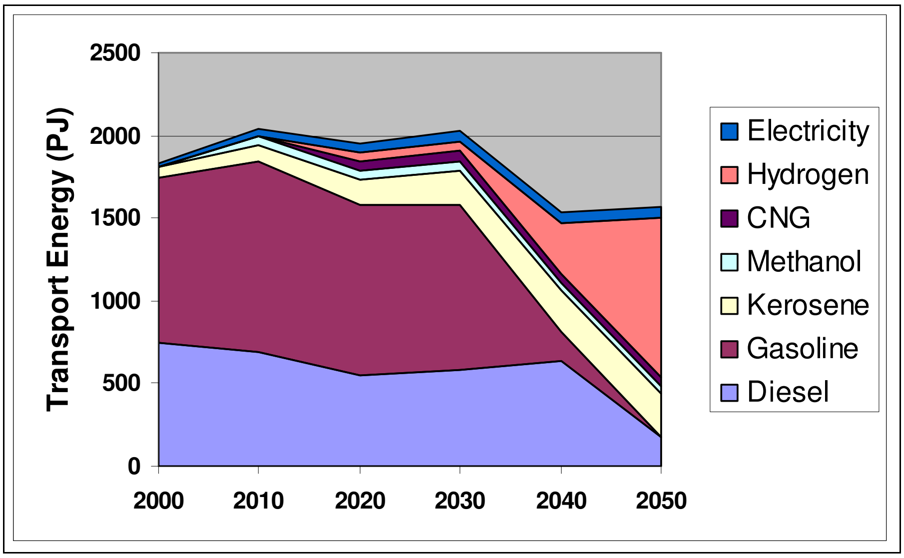

Figure 10 Fuel mix used in transport in the World Markets Scenario with CO_2 emissions constraints

Major changes in the fuel mix for transport only occurred in the later decades of the modelling period, after lower cost CO_2 abatement measures had been deployed in other sectors, but when additional measures were needed to move to a 60% reduction of CO_2 by 2050. With the Baseline Scenario (Figure 9) a substantial part of gasoline fuel consumption was replaced with hydrogen from 2040. This hydrogen was used in highly fuel efficient fuel cell cars, which accounts for the overall reduction in fuel demand. With the World Markets Scenario this transition started earlier (Figure 10), after 2030, reflecting the higher demand for energy services in this scenario, and consequently the requirement for an earlier change to low carbon fuels to achieve the 60% reduction in CO_2 by 2050.

In all of the scenarios the demand for hydrogen was supplied from fossil fuels using one or more of three technologies, all fitted with CCS:

- Coal gasification
- Co-production of hydrogen and electricity from coal
- Natural gas reforming.

The lower volumes of hydrogen required up to 2030 in World Markets and 2040 in Baseline were supplied using coal gasification, and in those scenarios with no new nuclear deployment, from plant co-producing hydrogen and electricity. However, when demand increased substantially, from 2030 or 2040 depending on the scenario, most of this was met from gas reforming plant. This switch was driven by two factors:

- Although hydrogen production from coal was cheaper, the cost difference was significantly reduced when CO_2 transport and storage was included because coal gasification produces about twice as much CO_2 as natural gas reforming per unit of hydrogen.
- In the scenarios with no new nuclear build the deployment of CCS was very high and all the pipeline capacity for CO_2 transport was filled (ie. 180Mt). Recognising this the model acted to maximising the abatement achievable with this limited capacity for CCS by deploying gas rather than coal plant.

It is noteworthy that hydrogen was produced exclusively from fossil fuels in all of the scenarios investigated. Although several technical options were included for production using electrolysis with renewable or nuclear electricity these were never deployed because the model treated carbon free electricity as a premium fuel and always used it directly (e.g. for lighting, motive power, etc.) rather than applying it to another energy conversion process.

7 Overview and Discussion

The overall purpose of this study was to advise the development of DTI's CAT strategy by investigating the potential role of CATs in delivering a low carbon energy system. Specifically the focus was on investigating the level and timing of the deployment of CATs as CO_2 emissions were reduced along a pathway to the EWP goal of a 60% reduction in CO2 by 2050. The study extended to ten scenarios (Table 6), covering variations in economic growth rate, social choices, primary energy prices and the impact of other low carbon energy options, to assess their effect on the deployment of CATs, and the main findings for each of the CAT options are discussed below.

7.1 Increased generation efficiency

Increasing the generation efficiency of existing coal fired power plant by retrofitting advanced boilers was consistently adopted as a short to medium term (2010-2020) option for reducing emissions. All 16GW of the existing coal capacity that were assumed to make modifications to meet LCPD requirements were retrofitted with advanced boilers across all the ten scenarios. This occurred for two reasons. Firstly the model saw this technology as an economic option for replacing existing plant while also delivering reductions in emissions of 10-20% in the medium term to 2020. Secondly the model saw that this could be followed by retrofitting capture technology, which again was cheaper than building completely new coal fired plant with capture.

The assessments of EU-ETS permit prices of Euro 10 and 20/tCO_2 (Section 4) showed that retrofitting advanced boilers still went ahead under this measure, whereas the construction of new coal fired plant was delayed or reduced. Once again this reflects the economic advantage of retrofitting over new build.

It should be noted however, that recent discussions with industry representatives have indicated that the MARKAL data for this option may be over optimistic since it neglects the revenue lost while the plant is off line being retrofitted.

Table 6 Scenarios investigated in the MARKAL study

Scenario Description	Identifier
Baseline – 60% CO_2 reduction by 2050	BL-60
Baseline – 60% CO_2 reduction by 2050, no new nuclear	BL-60NN
Baseline – 60% CO_2 reduction by 2050, limited improvement in energy efficiency	BL-60EE
Baseline – 60% CO_2 reduction by 2050, no new nuclear, limited energy efficiency	BL-60EN
Global Sustainability - 60% CO_2 reduction by 2050	GS-60
Global Sustainability - 60% CO_2 reduction by 2050, no new nuclear	GS-60NN
Global Sustainability - 60% CO_2 reduction by 2050, no new nuclear, limited improvement in energy efficiency	GS-60EN
World Markets - 60% CO_2 reduction by 2050	WM-60
World Markets - 60% CO_2 reduction by 2050, no new nuclear	WM-60NN
World Markets - 60% CO_2 reduction by 2050, no new nuclear, limited improvement in energy efficiency	WM-60EN

7.2 Biomass co-firing

Co-firing with carbon neutral biomass was consistently deployed to the maximum 10% of total fuel input on existing coal fired plant across all ten of the CO_2 constraint scenarios (Table 6). The model did not include the option for co-firing on new coal plant, therefore this practice ceased after 2040 when all existing plant retrofitted with advanced boilers was retired. Co-firing continued to be used when amine capture plant was retrofitted to the coal plant, effectively increasing the level of CO_2 abatement.

7.3 Carbon dioxide capture and storage (CCS)

The deployment of CCS for all the abatement scenarios is summarised in Figure 11. CCS was deployed in all of the scenarios, but the timing and volume of CCS deployment depended on the rate of growth in demand for energy services, fossil fuel prices and the effectiveness of other abatement measures/technologies. Deployment began earliest, around 2010, in the World Markets Scenario that involved the highest rate of economic growth and was about a decade later in the lower growth rate Baseline and Global Sustainability Scenarios.

The timing of CCS deployment was less sensitive to the rate of improvement in energy efficiency across the economy. However, limiting the rate of improvement to the average of the last 30 years did increase the volume of CCS deployed.

The position of CCS in relation to nuclear power is particularly uncertain and difficult to assess. Based on the MARKAL database base load nuclear generation costs about 3p/kWh. In comparison base load generation costs for fossil technologies fitted with CCS are about 3.2p/kWh for retrofitting to existing coal fired capacity, and 3.6p/kWh for new gas fired plant and 3.8p/kWh for new coal fired plant[16]. Consequently, because MARKAL is a cost optimisation model it adopts nuclear almost exclusively for base load, while building a smaller capacity of CCS to provide back-up to intermittent renewable energy generation (mainly on and off-shore wind), because the generation costs of CCS plant are less sensitive than nuclear to load factor. (NB There are also technical advantages for using fossil fuel plant as back-up capacity but these were not represented in the model.)

However, there is uncertainty over the long term costs and performance of both new nuclear and CCS technologies. The 2002 Energy Review[17] considered future nuclear costs and estimated the central inter-quartile range of costs to be 3-4p/kWh with both lower and higher outcomes possible. Clearly at the upper end of the Energy Review range CCS would be cost competitive with nuclear for base load generation, and would be deployed for base load supply by MARKAL without an explicit constraint on new nuclear build. However, the costs of CCS are also uncertain with a margin of +/- 30% generally applied to capital cost estimates. Also there is uncertainty over future fossil fuel prices that will affect the competitiveness of CCS in relation to non-fossil abatement options.

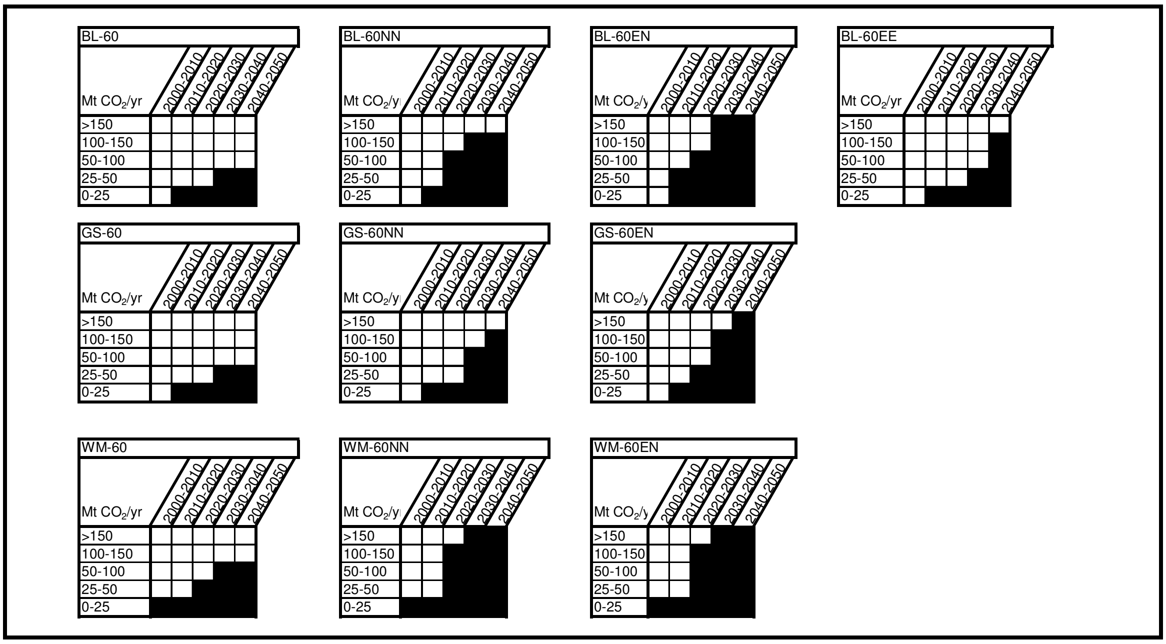

Figure 11 Summary of MARKAL model results for the deployment of CCS technologies ($MtCO_2$/yr)

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[16] This comparison is based on a 15% discount rate.

[17] The Energy Review, a performance and Innovation Unit Report, Cabinet Office, February 2002.

In addition to electricity generation fossil fuel technologies with CCS were used in all scenarios to produce hydrogen, which was used as a substitute for petroleum products in order to reduce CO_2 emissions from road transport. This route to hydrogen was favoured over electrolytic production from either nuclear or renewable electricity with the model regarding low to zero carbon electricity as a premium fuel to be used directly rather than to be put through another transformation process.

7.4 Implications of fossil fuel price assumptions

The long term prices of fossil fuels are central to the assessment of CATs since they affect their production costs, and hence their competitiveness relative to other low carbon options. However, projections of fossil fuel prices are subject to considerable uncertainty. The scenarios used in this study were designed to investigate a broad range of fossil fuel prices, and the results have shown that the deployment of CATs is robust to these price variations (Figure 11). However, the fossil fuel price assumptions used in this study were developed in 2002, and since then there have been significant changes in the near term prices of fossil fuels, particularly oil and natural gas. This section considers the potential impact of even wider price variations on three aspects of CCS deployment:

- Relative costs of CCS applied to natural gas and coal plant
- Cost competitiveness of CCS relative to other near zero emissions electricity options
- Cost competitiveness of hydrogen produced from fossil fuels

Relative cost of CCS with natural gas and coal

Table 7 lists snapshot generation costs for a range of CCS generation technologies in 2020 using Baseline Scenario fuel prices, and fuel prices set +/-30% from the Baseline values.

Table 7 Generation costs for CCS technologies in 2020 (p/kWh)[18]

Technology	Generation Costs (p/kWh)		
	Low	Central	High
Existing coal plus capture	3.0	3.4	3.8
Existing coal plus retrofit boiler plus capture	2.7	3.0	3.3
New pulverised coal with capture	3.5	3.8	4.1
New oxy-firing	3.8	4.1	4.4
New IGCC with capture	3.3	3.6	3.9
New IGCC with H2 production and CCS*	3.1	3.4	3.7
Existing GTCC with capture	2.7	3.3	3.8
New GTCC with capture	2.8	3.3	3.7

*Assumes hydrogen price of £5/GJ

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[18] Central values were £30.5/tonne for coal and 25.5p/therm for gas. Calculations used a 15% discount rate.

The central values in the table show that for new build gas fired plant is less expensive than new coal plant. However, if the cost of gas increases by 30% relative to coal this price advantage is eliminated. Therefore, not surprisingly the long term price of coal in relation to natural gas will be important in determining the relative cost competitiveness of CCS technologies.

Cost competitiveness of CCS relative to other near zero emissions electricity options

The cost of CCS applied to both natural gas and coal power generation increases with fuel prices. Therefore high fossil fuel prices could make CCS uncompetitive relative to other options for producing electricity with low to zero CO_2 emissions (eg. additional renewable energy, new nuclear). However, CCS technologies are only going to be commercially deployed as part of a strategy to deliver CO_2 abatement, for example following a path similar to the UK goal, set in the EWP, to reduce emissions by 60% by 2050. In such circumstances fossil fuel demand would be expected to come under pressure causing fossil fuel prices to stabilise or even fall.

The above is a global view. CCS is more vulnerable to high fossil fuel prices during early deployment when a limited number of projects may be undertaken by countries aiming to give a lead on CO_2 abatement. In these circumstances the drive to reduce CO_2 emissions may not be strong enough to impact on global fossil fuel prices, making early CCS projects less economically attractive.

Cost competitiveness of hydrogen produced from fossil fuels

The study has shown that in moving to a low carbon energy system hydrogen is mainly used to replace petroleum products in road transport. Higher oil prices feed through to higher prices for refined fuels such as petrol and diesel. Consequently, if the cost of hydrogen was unchanged, this would make fuel switching to hydrogen for road transport more cost effective, which would cause this to happen sooner than in the present investigation (Section 6). However, natural gas prices tend to be linked to oil, and in any case are expected to increase in the future. Such a trend would mean that hydrogen produced from natural gas would also be more expensive. Since the large volume of hydrogen required by the model to reduce transport emissions after 2030-2040 is produced from natural gas, this would tend to offset the increased competitiveness for hydrogen derived from higher oil prices. Alternatively the higher gas prices would also favour increased hydrogen production from coal with CCS, since coal is generally expected to be competitively priced compared to gas.

7.5 Choice of CCS technology

The CCS technologies deployed across the scenarios were as follows:

- Retrofitting advanced boilers and amine scrubbing to existing coal generation capacity.
- Hydrogen production from coal gasification.
- Hydrogen production from natural gas reforming
- Co-production of electricity and hydrogen with IGCC technology
- GTCC plant

However, as shown in Table 7 the costs of the CCS technologies are quite closely grouped. For example the cost of power generation from new coal and natural gas plant range from 3.3 to 3.8p/kWh[19] in 2020, which lies well within the range of uncertainty over future plant costs and performance levels. Therefore it is stressed that the main conclusion to be drawn from this study is that CCS has the potential to make a major contribution to UK abatement targets. The current database does no provide a firm basis for choosing between technologies.

8 Conclusion

This study has investigated the potential role of CATs in delivering the EWP's goal of putting the UK on a path to a 60% reduction in CO_2 emissions by 2050. It has done this by using an energy systems model, MARKAL, to explore a range of scenarios for future economic growth, demand for energy related services, primary energy prices, social preferences and the availability of other low carbon technologies. Limits on the overall CO_2 emissions from the UK energy sector were imposed on the model, over decade time-steps, to reach the 60% reduction target by 2050. Through this approach it was possible to observe the phased deployment of abatement technologies.

With the exception of cost effective energy efficiency improvements most technology options to reduce CO_2 emissions cost more than unabated alternatives. For example fossil fuel technologies without CCS will always be cheaper than the same technologies incorporating the additional processes for CO_2 capture, transportation and storage. Therefore many abatement technologies will not be deployed until they receive an adequate financial return for the CO_2 abatement they deliver. By applying an overall CO_2 emissions constraint to the MARKAL model it is implicitly assumed that some mechanism is put in place to reward/encourage the deployment of abatement technologies. No assumptions are necessary on what form this measure may take (eg. emissions permits, regulation, obligations, etc.). However, by applying the constraint across the complete energy system it is being assumed that the measure is applied evenly across all sectors.

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[19] This omits oxy-firing which is a less advanced technology with more uncertain cost and performance data.

Overall the study has found that CATs have the potential to make an appreciable contribution to the attainment of the UK's medium and long-term aims for reducing CO_2 emissions. This contribution will come from the supply of electricity and hydrogen, with the latter mainly used as a replacement for petroleum fuels in road transport. Thus when following a path to a 60% reduction in CO_2 emissions by 2050 the modelling results showed:

- By 2020 all existing pulverised coal plant expected to be retrofitted to meet LCPD requirements (16GW) was also retrofitted with high efficiency boilers, and later these were retrofitted with amine scrubbers to capture CO_2.
- Co-firing with energy crops was deployed up to the set maximum of 10% of total fuel input with all existing pulverised coal plant. (NB Co-firing on new fossil fuel plant was not investigated.)
- CCS was deployed for electricity and hydrogen production from both coal and natural gas fired plant.

The timing and size of deployment of CCS was sensitive to scenario assumptions on the rate of improvement in energy efficiency in the economy, the rate of economic growth (and hence demand for energy services) and the deployment of alternative abatement options including energy efficiency and nuclear power. In most scenarios CCS for electricity generation was first deployed between 2010 and 2020, but for the high energy demand World Markets Scenario deployment was needed from 2010. CCS for large-scale hydrogen production was deployed from 2040 in most scenarios, again with the exception of the World Markets Scenario when this started a decade earlier. The overall level of CCS deployment increased over time from 0-25Mte CO_2 per year in 2010-2020 to 50-180Mte CO_2 per year by 2040-2050.

The lowest levels of CCS deployment occurred with scenarios in which MARKAL was permitted to build new nuclear generation capacity. This is because MARKAL deployed new nuclear (when available) for almost all base-load generation while CCS technologies operated at load factors of 50-60%. In contrast, when there was no new nuclear build, fossil plants with CCS were used for base-load and medium load generation. With nuclear power CCS technologies were used to back up intermittent renewable energy generation, much of which was onshore or offshore wind, and in this sense CCS and renewable energy complement each other.

The sensitivity of CCS deployment to the availability of new nuclear capacity resulted from the way the MARKAL model functions and the range of uncertainty applying to its technology database rather than any definite cost advantage of one technology over the other. MARKAL is a cost optimisation model, and therefore without additional constraints it will differentiate strongly between technologies with very similar costs. This is the case with nuclear and CCS, because in MARKAL the costs of base-load generation from CCS technologies and nuclear power are similar, but with nuclear marginally cheaper. However, the difference is less than the uncertainty applying to the long-term cost and performance data used by MARKAL, and therefore the data do not have the precision to support differentiation between these options. Indeed it would be wrong to imply that an "either or" choice must be made between nuclear and CCS. In practice factors additional to cost will affect the choice of abatement technologies, and this could lead to a mix of options being deployed.

Notwithstanding this limitation of the modelling approach the result is useful in underlining the conclusion that CATs should be considered within a portfolio of abatement measures. While CCS in particular has the potential to make a major contribution, the exact timing and level of its deployment will depend on the deployment of other abatement options as well as on the economic conditions, fossil fuel prices and social preferences prevailing at the time. It is also significant that irrespective of the balance of technologies for electricity generation CCS was always the preferred option for the production of hydrogen for road transport.

With regard to the choice of CCS technologies, the Markal results had CCS applied to both coal and natural gas in all scenarios although the balance between these fuels varied depending on relative fuel prices. CCS on natural gas was implemented by retrofitting to GTCC plant, while with coal this involved a combination of pulverised fuel and IGCC. The pulverised fuel plant were existing facilities that were also refurbished with advanced boilers and steam turbines, while the IGCC was always deployed in cogeneration mode to produce both electricity and hydrogen. Totally new pulverised coal plant was not constructed due to a slightly higher cost compared to IGCC. Once again, however, this cost difference was small compared with the uncertainty over long term costs, and does not support choosing winners between pulverised coal and IGCC technologies.

This analysis will be used as a starting point for consideration of the role that CATs and CCS might play, alongside other options, in the energy system to 2050 as part of the Energy Review.

Annex A

End User Energy Prices used in Scenarios

Baseline Scenario

		2000	2010	2020	2030	2040	2050
Jet Kerosene	(p/litre)	16.49	12.57	12.57	15.31	15.31	15.31
DERV	(p/litre)	80.80	75.78	75.78	78.72	78.72	78.72
Unleaded petrol	(p/litre)	80.09	74.95	74.95	77.96	77.96	77.96
Fuel Oil (industrial)	(p/litre)	12.38	10.22	10.22	11.81	11.81	11.81
Fuel oil (ESI)	(p/therm)	34.7	28.3	28.3	32.3	32.3	32.3
Petroleum (services)	(p/litre)	15.5	13.1	13.1	15.2	15.2	15.2
Petroleum (domestic)	(p/litre)	16.3	13.8	13.8	16.0	16.0	16.0
Gas oil (ESI)	(p/therm)	46.1	39.7	39.7	43.7	43.7	43.7
Gas (industrial)	(p/therm)	21.5	21.5	24.0	28.2	31.5	31.5
Gas (domestic)	(p/therm)	50.0	50.0	52.5	56.7	60.0	60.0
Gas (services)	(p/therm)	27.5	27.5	30.0	34.2	37.5	37.5
Gas (ESI)	(p/therm)	23.0	23.0	25.5	29.7	33.0	33.0
Coal (Industrial)	(p/therm)	14.4	14.4	14.4	14.4	14.4	14.4
Coal (domestic)	(p/therm)	57.2	57.2	57.2	57.2	57.2	57.2
Coal (services)	(p/therm)	19.5	19.5	19.5	19.5	19.5	19.5
Coal (ESI)	£/tonne	30.5	30.5	30.5	30.5	30.5	30.5

World Markets Scenario

		2000	2010	2020	2030	2040	2050
Jet Kerosene	(p/litre)	16.49	14.75	16.14	20.74	20.74	20.74
DERV	(p/litre)	80.80	78.11	80.45	84.53	84.53	84.53
Unleaded petrol	(p/litre)	80.09	77.35	79.75	83.93	83.93	83.93
Fuel Oil (industrial)	(p/litre)	12.38	11.49	12.76	14.96	14.96	14.96
Fuel Oil (ESI)	(p/therm)	34.7	31.5	34.7	40.3	40.3	40.3
Petroleum (services)	(p/litre)	15.5	14.7	16.4	19.3	19.3	19.3
Petroleum (domestic)	(p/litre)	16.3	15.5	17.4	20.4	20.4	20.4
Gas oil (ESI)	(p/therm)	46.1	42.9	46.1	51.7	51.7	51.7
Gas (industrial)	(p/therm)	21.5	25.7	29.8	36.5	36.5	36.5
Gas (domestic)	(p/therm)	50.0	54.2	58.3	65.0	65.0	65.0
Gas (services)	(p/therm)	27.5	31.7	35.8	42.5	42.5	42.5
Gas (ESI)	(p/therm)	23.0	27.2	31.3	38.0	38.0	38.0
Coal (Industrial)	(p/therm)	14.4	14.4	14.4	14.4	14.4	14.4
Coal (domestic)	(p/therm)	57.2	57.2	57.2	57.2	57.2	57.2
Coal (services)	(p/therm)	19.5	19.5	19.5	19.5	19.5	19.5
Coal (ESI)	£/tonne	30.5	30.5	30.5	30.5	30.5	30.5

Global Sustainability Scenario

		2000	2010	2020	2030	2040	2050
Jet Kerosene	(p/litre)	16.49	9.83	9.83	9.83	9.83	9.83
DERV	(p/litre)	80.80	72.84	72.84	72.84	72.84	72.84
Unleaded petrol	(p/litre)	80.09	71.93	71.93	71.93	71.93	71.93
Fuel Oil (industrial)	(p/litre)	12.38	8.85	8.85	8.85	8.85	8.85
Fuel Oil (ESI)	(p/therm)	34.7	24.3	24.3	24.3	24.3	24.3
Petroleum (services)	(p/litre)	15.5	11.0	11.0	11.0	11.0	11.0
Petroleum (domestic)	(p/litre)	16.3	11.5	11.5	11.5	11.5	11.5
Gas oil (ESI)	(p/therm)	46.1	35.7	35.7	35.7	35.7	35.7
Gas (industrial)	(p/therm)	21.5	23.2	26.5	31.5	33.2	34.8
Gas (domestic)	(p/therm)	50.0	51.7	55.0	60.0	61.7	63.3
Gas (services)	(p/therm)	27.5	29.2	32.5	37.5	39.2	40.8
Gas (ESI)	(p/therm)	23.0	24.7	28.0	33.0	34.7	36.3
Coal (Industrial)	(p/therm)	14.4	14.4	14.4	14.4	14.4	14.4
Coal (domestic)	(p/therm)	57.2	57.2	57.2	57.2	57.2	57.2
Coal (services)	(p/therm)	19.5	19.5	19.5	19.5	19.5	19.5
Coal (ESI)	£/tonne	30.5	30.5	30.5	30.5	30.5	30.5

Annex B

Assumed Prices and Availability of Energy Crops

	2010	2020	2030	2040	2050
Tranche 1					
Price (£/GJ)	1.3	1.1	1.0	1.0	1.0
Availability (PJ/yr)	14	23	32	41	41
Tranche 2					
Price (£/GJ)	1.6	1.4	1.2	1.2	1.2
Availability (PJ/yr)	3	50	72	72	72
Tranche 3					
Price (£/GJ)	2.0	1.8	1.5	1.5	1.5
Availability (PJ/yr)	99	163	226	226	226

Annex C

Assumed Cost and Performance Data for the Carbon Abatement Technologies included in MARKAL

Data for Pulverised Coal Plant

Technology	Start Year	Cap Cost (£/kW)	Ops Fix £/kW	Ops Var p/kWh	Efficiency %	Availability %	CO_2 Sep. %	Plant Life yrs
Existing Coal Plant								
Existing Coal (no FGD)	N/A		14.0	0.07	38.0%	80%	N/A	15
			14.0	0.07	37.0%	60%	N/A	15
			12.0	0.07	35.5%	40%	N/A	15
			12.0	0.07	34.0%	20%	N/A	15
Existing Coal (with FGD)	N/A		21.0	0.10	37.0%	90%	N/A	30
			21.0	0.10	36.0%	60%	N/A	30
			19.0	0.10	34.5%	40%	N/A	30
			19.0	0.10	33.0%	20%	N/A	30
Existing Coal (with FGD) Retrofit Options								
Amine Scrubbing	2010	407	27.5	0.25	28.0%	90%	85%	20
Amine Scrubbing	2020	407	27.5	0.25	30.0%	90%	90%	10
SC Boilers	2010	263	16.7	0.10	42.5%	90%	N/A	30
SC Boilers	2020	289	14.5	0.10	50.0%	90%	N/A	30
Amine Scrubbing to SC Boilers fitted in 2010	2020	337	8.2	0.15	33.5%	90%	90%	20
Amine Scrubbing to SC Boilers fitted in 2020	2030	289	4.9	0.15	43.0%	90%	90%	20
SC Boilers and amine scrubbing	2010	601	24.9	0.25	33.5%	90%	90%	30
SC Boilers and amine scrubbing	2020	578	19.4	0.25	43.0%	90%	90%	30
SC Boilers, and oxy-firing	2010	647	57.9	0.00	34.4%	90%	90%	30
SC Boilers, and oxy-firing	2020	523	46.3	0.00	43.0%	90%	90%	30

Data for Pulverised Coal Plant (cont.)

Technology	Start Year	Cap Cost (£/kW)	Ops Fix £/kW	Ops Var p/kWh	Efficiency %	Availability %	CO_2 Sep. %	Plant Life yrs
New Coal Plant								
New PF Plant	2010	694	27.5	N/A	45.6%	90%	N/A	50
New PF Plant	2020	633	27.5	N/A	50.0%	90%	N/A	50
New PF Plant	2030	575	27.5	N/A	55.0%	90%	N/A	50
New PF Plant	2040	575	27.5	N/A	55.0%	90%	N/A	50
New PF Plant - retrofit options								
Amine scrubbing to 2010 new PF	2020	323	51.2	N/A	38.6%	90%	90%	40
Amine scrubbing to 2010 new PF	2030	323	51.2	N/A	38.6%	90%	90%	30
Amine scrubbing to 2020 new PF	2030	295	46.0	N/A	43.0%	90%	90%	40
Amine scrubbing to 2020 new PF	2040	295	46.0	N/A	43.0%	90%	90%	30
Amine scrubbing to 2030 new PF	2040	268	41.2	N/A	48.0%	90%	90%	40
Amine scrubbing to 2030 new PF	2050	268	41.2	N/A	48.0%	90%	90%	30
Adapt for oxy-firing to 2010 new PF	2020	293	53.1	N/A	38.6%	90%	90%	40
Adapt for oxy-firing to 2020 new PF	2030	263	47.6	N/A	43.0%	90%	90%	40
Adapt for oxy-firing to 2030 new PF	2040	235	42.7	N/A	48.0%	90%	90%	40
New PF Plant (with capture)								
Amine Scrubbing	2010	1017	51.2	N/A	36.6%	90%	90%	50
Amine Scrubbing	2020	928	46.0	N/A	43.0%	90%	90%	50
Amine Scrubbing	2030	843	41.2	N/A	48.0%	90%	90%	50
Amine Scrubbing	2040	843	41.2	N/A	48.0%	90%	90%	50
Oxy-firing	2010	1233	57.9	N/A	35.4%	90%	90%	50
Oxy-firing	2020	1115	47.6	N/A	43.0%	90%	90%	50
Oxy-firing	2030	998	42.7	N/A	48.0%	90%	90%	50
Oxy-firing	2040	998	42.7	N/A	48.0%	90%	90%	50

Data for Coal IGCC plant

Technology	Start Year	Cap Cost £/kW	Ops Fix £/kW	Ops Var p/kWh	Efficiency %	Availability %	CO2 Sep. %	Plant Life yrs
New IGCC (capture ready)								
	2010	750	20	N/A	44.5%	90%	N/A	35
	2020	726	20	N/A	46.0%	90%	N/A	35
	2030	703	20	N/A	47.5%	90%	N/A	35
	2040	703	20	N/A	47.5%	90%	N/A	35
	2050	703	20	N/A	47.5%	90%	N/A	35
New IGCC (capture ready) capture retrofit options								
	2020	203	5	N/A	39.0%	90%	90%	25
	2030	135	5	N/A	41.0%	90%	90%	25
	2040	135	5	N/A	42.5%	90%	90%	25
	2050	135	5	N/A	42.5%	90%	90%	25
New IGCC (capture ready) retrofit with capture and 10% hydrogen options								
	2020	203	5	N/A	39%	90%	90%	25
	2030	135	5	N/A	41%	90%	90%	25
	2040	135	5	N/A	43%	90%	90%	25
	2050	135	5	N/A	43%	90%	90%	25

Data for Coal IGCC plant (cont.)

Technology	Start Year	Cap Cost £/kW	Ops Fix £/kW	Ops Var p/kWh	Efficiency %	Availability %	CO2 Sep. %	Plant Life yrs
New IGCC with capture								
	2010	1020	25	N/A	39.0%	90%	90%	35
	2020	928	25	N/A	41.0%	90%	90%	35
	2030	838	25	N/A	42.5%	90%	90%	35
	2040	838	25	N/A	42.5%	90%	90%	35
	2050	838	25	N/A	42.5%	90%	90%	35
New IGCC with capture and 10% hydrogen								
	2010	1020	25	N/A	39.0%	90%	85%	35
	2020	928	25	N/A	41.0%	90%	90%	35
	2030	838	25	N/A	42.5%	90%	90%	35
	2040	838	25	N/A	42.5%	90%	90%	35
	2050	838	25	N/A	42.5%	90%	90%	35

Data for GTCC plant

Technology	Start Year	Cap Cost £/kW	Ops Fix £/kW	Ops Var p/kWh	Efficiency %	Availability %	CO2 Sep. %	Plant Life yrs
Existing GTCC		0	N/A	0.20	52.0%	90%	N/A	25
New GTCC								
	2010	400	N/A	0.20	58.0%	90%	N/A	35
	2020	380	N/A	0.20	61.0%	90%	N/A	35
	2030	357	N/A	0.20	65.0%	90%	N/A	35
	2040	331	N/A	0.20	70.0%	90%	N/A	35
	2050	331	N/A	0.20	70.0%	90%	N/A	35
GTCC Retrofit Capture Options								
	2010	290	N/A	0.14	44.0%	90%	85%	15
	2020	218	N/A	0.14	51.0%	90%	90%	25
	2030	145	N/A	0.14	55.0%	90%	90%	25
	2040	116	N/A	0.14	59.0%	90%	90%	25
	2050	116	N/A	0.14	59.0%	90%	90%	25
New GTCC with capture								
	2010	690	N/A	0.34	51.0%	90%	90%	35
	2020	598	N/A	0.34	55.0%	90%	90%	35
	2030	502	N/A	0.34	58.0%	90%	90%	35
	2040	448	N/A	0.34	65.0%	90%	90%	35
	2050	448	N/A	0.34	65.0%	90%	90%	35

Annex D

Participants in CAT Data Review Workshop, 21st July 2004

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Rodney Allam	Air Products
Mike Evans	RWE
Paul Freund	IEA Greenhouse Gas R&D Programme
John Gibbins	Imperial College
Carol Greaves	Synnogy
Stephen Green	DTI
John Griffiths	Jacobs Consulting
George Marsh	FES
Chris McGlen	UK Coal
John McMullen	University of Ulster
Brian Morris	DTI
Nick Otter	Alstom Power
Steve Pye	FES
Andy Read	EON UK
Douglas Spalding	Mitsui Babcock