CO_2 CAPTURE AS A FACTOR IN POWER STATION INVESTMENT DECISIONS

Technical Study

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CO_2 CAPTURE AS A FACTOR IN POWER STATION INVESTMENT DECISIONS

Background to the Study

There is increasing interest in capture and storage of CO_2 from fossil fuel fired power stations, to mitigate climate change. The IEA Greenhouse Gas R&D Programme (IEA GHG) has recently carried out studies to assess the performance and costs of various types of power station incorporating CO_2 capture. IEA GHG has commissioned Mott MacDonald to pull together the results from these studies on a consistent basis and review features of the technologies which may be important for plant investors. The opinions of a range of potential investors were surveyed and the results of the survey were combined with the technology evaluations using a multi-criteria analysis, to show how far each technology matches the surveyed investor preferences.

Study Basis

Technology assessment

The study focussed on the following six leading power generation ad CO_2 capture technologies:

- Natural gas-fired Combined Cycle Gas Turbine (CCGT) with post-combustion capture of CO_2 from flue gases
- Coal-fired Ultra Supercritical Pulverised Fuel (USCPF) with post-combustion capture of CO_2 from flue gases
- CCGT with pre-combustion capture of CO_2 through reformation of natural gas
- Pre-combustion capture of CO_2 on Integrated Gasification Combined Cycle (IGCC) coal plant
- Natural gas-fired CCGT with oxy-combustion
- Coal-fired USCPF with oxy-combustion

Base case USCPF and CCGT plants without capture were also assessed. Information on the technologies was drawn from recent IEA GHG studies[1]. The IGCC plant is based on a gasifier with water slurry feed and water quench of the product gas. The recent IEA GHG study showed this technology to have a lower capital cost and cost of electricity than the alternative dry-feed gasifier with a heat recovery boiler, but a lower thermal efficiency.

In most respects the technology assessments in this study were based on the set of standard assessment criteria which IEA GHG has used in all its recent studies. The main exception was the fuel price. IEA GHG's standard assessment criteria include fuel prices which were typical of prices in the early part of this decade but those prices are no longer representative of current and expected future prices. This study therefore used the average of Mott MacDonald's long-run forecast prices up to 2025, i.e. US$2.2/GJ LHV for bituminous coal and US$7.8/GJ for natural gas. Sensitivities to fuel prices were assessed to allow for the substantial uncertainties in future energy prices.

The cost estimates in IEA GHG's recent studies originated mainly in US dollars and Euros. The exchange rate between the Euro and US Dollar has varied substantially in recent years, e.g. between 0.85:1 and 1.35:1 $/€ in the last 5 years. In this study, Euro costs were converted to US Dollars using the 2005 average exchange rate of 1.23:1 $/€.

[1] IEA GHG reports PH4/19 (IGCC), PH4/33 (post-combustion capture), 2005/1 (natural gas pre-combustion capture) and 2005/9 (oxy-combustion).

IEA GHG's standard assessment criteria specify base load plant operation (85% load factor), a 10% annual discount rate and 25 year plant operating life. Sensitivities to a lower discount rate, higher capital costs and low load factor were assessed.

Survey of investors

Mott MacDonald approached 100 public and private power utilities, project developers, equipment suppliers and project lenders in 27 countries to determine their preferences with respect to thermal generation plant and what role they foresee for power generation with CO_2 capture. 34 organisations from 17 countries responded in a telephone survey. The respondents included 12 public utilities, 11 private utilities, 5 project developers, 4 project lenders and 1 equipment supplier. The telephone survey was followed up with a more detailed written questionnaire. 15 replies were received from organisations in Australia, Canada, China, Finland, Germany, Ireland, Japan, the Netherlands, New Zealand and the UK.

Results and Discussion

Costs of power generation

Base case assessments

The efficiencies and costs of power stations with and without CO_2 capture are summarised in Table 1. The costs of electricity generation include the cost of CO_2 compression to 11 MPa but exclude the costs of CO_2 transport and storage, which will depend strongly on location conditions. If CO_2 is used for enhanced oil recovery there may be a net revenue from CO_2 transport and storage, which reduce the net cost of electricity but storage without by-product production would result in a net cost. To put this in context, a cost of \$10/tonne of CO_2 stored would be equivalent to about 0.4c/kWh for the natural gas fired plants and 0.8c/kWh for the coal fired plants.

Table 1 Comparison of power stations with and without CO_2 capture

Technology	Thermal efficiency % LHV	Capital cost \$/kW	Electricity cost c/kWh	Cost of CO_2 avoided \$/t CO_2
Gas fired plants				
No capture	55.6	500	6.2	-
Post-combustion capture	47.4	870	8.0	58
Pre-combustion capture	41.5	1180	9.7	112
Oxy-combustion	44.7	1530	10.0	102
Coal fired plants				
No capture	44.0	1410	5.4	-
Post-combustion capture	34.8	1980	7.5	34
Pre-combustion capture	31.5	1820	6.9	27
Oxy-combustion	35.4	2210	7.8	36

Note: The cost of CO_2 emissions avoided for the gas fired plants is relative to the gas fired combined cycle plant without capture. The cost of CO_2 emissions avoided for the coal fired plants is relative to the pulverised coal fired plant without capture.

The costs of electricity generation are compared in figure 1. This figure also shows the perceived level of technical risk for each of the options.

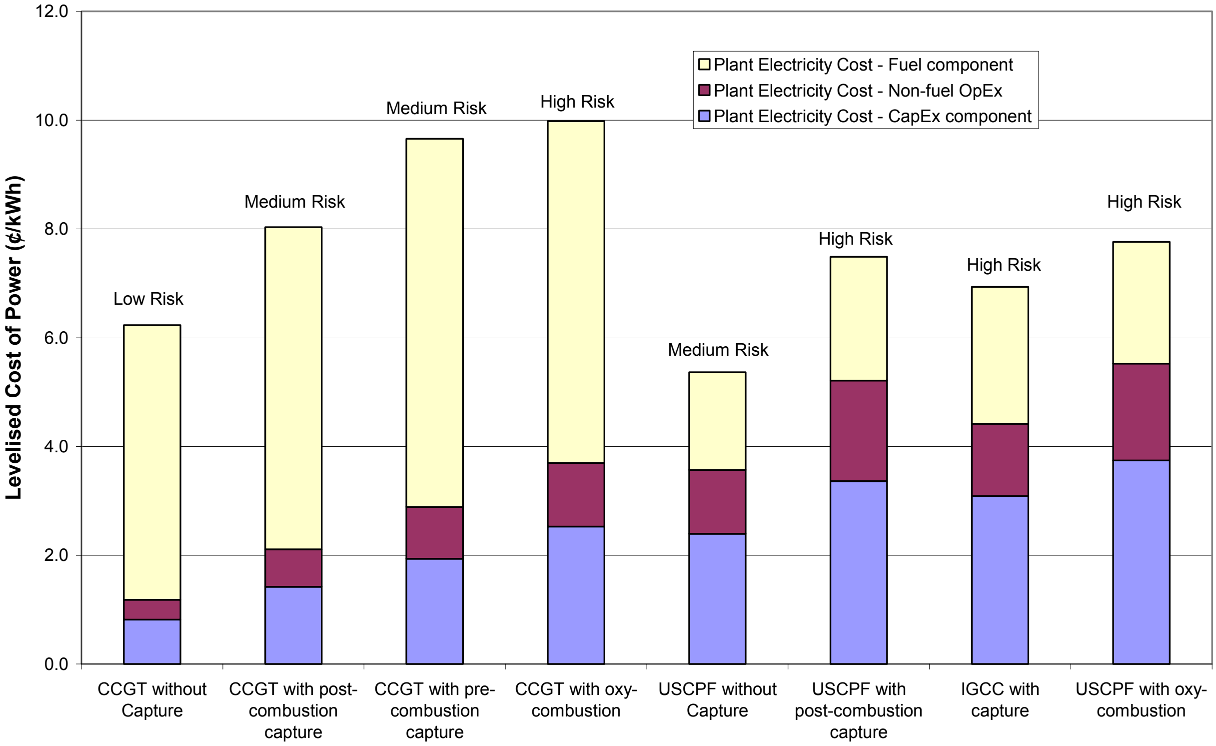

Figure 1 Base case costs of electricity generation with and without CO_2 capture

Figure 1 shows that the cost of electricity of the coal fired plant without CO_2 capture is slightly lower than the cost of the gas fired plant without capture. The costs of the coal fired plants with capture are higher than that of the gas fired plant without capture but lower than the costs of the gas fired plants with capture. A large part of the cost of gas fired power generation is the cost of fuel but in contrast the capital related costs are most significant for the coal fired plants. The lowest cost capture technology for coal fired power generation is pre-combustion capture in an IGCC and the lowest cost option for gas fired generation is post combustion capture. However, there are significant uncertainties in the cost estimates, as no large commercial power plants with CO_2 capture have yet been built and operated.

Sensitivity to discount rate and fuel price

Public energy utilities may use lower discount rates than private utilities, closer to the real yield on government-issued bonds. To illustrate the sensitivity to discount rate the costs were re-assessed using a discount rate of 5%. This reduced the cost of electricity by between 5 and 19%. The greatest reductions were for the most capital-intensive coal-fired plants, which implies that public sector utilities may be more likely to invest in coal fired plants than their private sector counterparts.

Fuel prices are different in different regions of the world and future prices are subject to considerable uncertainty. The sensitivity to fuel price was therefore assessed. Fuel accounts for a much higher proportion of the cost of generation in the gas fired plants than in the coal fired plants, as shown in Figure 1, so changes in fuel price are more significant for gas fired plants. The effects of decreasing the coal and gas prices by 50% were assessed. At these lower fuel prices, gas fired plants have the lowest costs of generation, with or without capture.

Sensitivity to load factor

In the short to medium term it is likely that power plants with CO_2 capture will operate at base load to maximise the utilisation of the capture equipment. In the longer term it is expected that the market penetration of other generation technologies with low-CO_2 emissions, based on renewable energy, will increase greatly. Some renewable energy technologies, including wind, solar and marine energy (but not biomass), have relatively high fixed costs but lower marginal operating costs. They will therefore tend to be operated whenever they are technically available and reduce the opportunities for other plants to operate at base load. Plants with CO_2 capture may then be operated at significantly lower load factors. To illustrate this scenario, costs of plants operating at a load factor of 35% were assessed and are shown in figure 2. The least cost type of plant with CO_2 capture in this scenario would be a gas fired combined cycle plant with post combustion capture. Such plants could be an attractive combination with renewable energy sources, to achieve ultra-low CO_2 emissions from an overall electricity generation system. The technical feasibility of operating capture plants with frequent load changes and start-up would need to be investigated in more detail. Costs of additional start-ups or possible benefits, e.g. from sale of hydrogen at times of low power demand have not been taken into account.

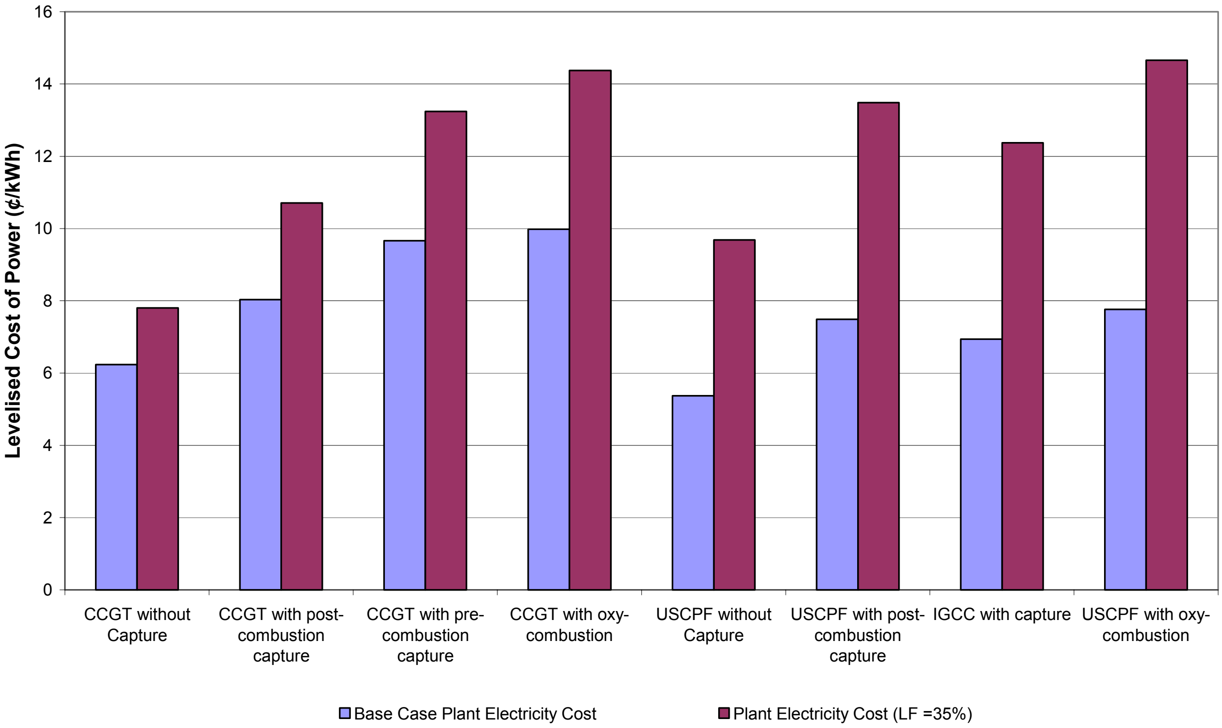

Figure 2 Sensitivity of costs to operation at 35% load factor

Survey of power plant investors

The survey sample showed a high level of interest in CO_2 capture. There is, however, a likelihood of bias in the survey sample towards those interested in CO_2 capture, and therefore motivated to participate in the survey, which limits the applicability of the above findings to global power-sector investors generally. Nearly all respondents said that abatement of greenhouse gas emissions did factor in their choice of power generation technology, typically either due to current legislation or the expectation of future legislation. Other significant reasons given for considering GHG emissions in the plant investment decisions included economic opportunity for carbon certificate trading and considerations of corporate social responsibility or image.

The most popular alternatives to CO_2 capture technologies were: exploiting remaining scope for efficiency improvements on existing plant, new build renewable energy plant and fuel switching to CO_2-neutral fuels such as biomass, although the limited biomass availability was a concern. Switching from coal or oil to natural gas and replanting with supercritical steam cycle also received significant support. The least popular measures, from the perspective of the organisations' own potential options, were reducing power output to control emissions and new build nuclear plant.

The priority that organisations give to 26 different potential criteria when making an investment decision for thermal power plant was assessed in a follow-up questionnaire. The responses to the question "How do the following key criteria play a role in your organisation's decision to invest in a particular type of plant" are summarised in table 2, where a score of 1 = always and 5 = never. Criteria which were classed as "nearly always" a priority and which received the highest average prioritisation were:

- Safety and health risks
- High financial return
- Outage requirements and expected unplanned outages
- Air quality impacts and general permitting issues

Table 2 Priority given to different investment criteria – average of questionnaire response

Investment Criteria	Average Response
Financial	
High financial return (best payback, IRR, NPV)	1.20
Low capital costs	2.07
Ability to project finance	2.73
Access to public funds	3.60
Logistics	
Build time	1.60
Modular construction	3.07
Flexibility of operation – response rates, two shifting	2.00
Outage requirements and expected unplanned outages	1.20
Availability of skilled O&M contractor	2.60
Environmental / Permitting	
General permitting issues	1.27
Land footprint	2.13
Air quality impacts	1.27
Percentage reduction in CO_2	2.07
Percentage reduction in other GHG	3.13
Water demand	1.87
By-product disposal	1.80
Traffic impacts	2.93
Public acceptability	1.40
Safety and health risks	1.07
Plant Track-record	
Proven technology	1.33
Financially strong manufacturer of technology	1.67
Technical obsolescence (anticipated future developments)	1.93
Market	
Potential for by-product sales	2.33
Availability of low cost feedstock	1.53
Diversity of fuel sourcing to mitigate security of supply concerns	2.20
Availability of skills	1.73

Assessment of technologies against the investment criteria

The capture technologies were rated against each of these investment criteria, using information from IEA GHG's technology assessment studies and ratings provided by organisations in the survey. Details are given in table 2-5 of the main report. Mott MacDonald and IEA GHG also separately rated each of the technologies against the investment criteria, to test the robustness of the results.

Multi-criteria analysis

A multi-criteria analysis was used to determine which CO_2 capture plant best matches the preferences of power sector utilities, as expressed in the survey. The investor priorities, shown in table 2, and the technology ratings were combined through a multi-criteria analysis approach. This is an economic analysis method designed to prioritise solutions from a set of options subject to a generally large number of criteria. In this study the multi-criteria analysis has been used to determine which type of CO_2 capture plant best matches the preferences of power sector investors. The technology ratings were multiplied by the criteria preferences (also termed weightings), as shown in table 2, and the square root of the multiple was taken to give a "technology preference" for each criteria. The technology preference rankings are then summed over the full set of criteria and the results adjusted back to the original 1-5 scale. No weighting was applied when summing the criteria. The results of this analysis based on the questionnaire responses are shown as the left hand series in figure 3. Technology preferences were also inferred from the responses given in the larger telephone survey. The MCA results based on these are shown as the middle series in figure 3. It can be seen that the preferences based on the written questionnaire responses and the preferences based on inferred responses from the larger number of telephone interviews are similar. MCA rankings of technologies were also similar for different types of investor: public utilities, private utilities and lenders.

Capture technology which best meets organisations' current needs

In addition to the ranking of investment criteria, the organisations were separately asked in the survey which generation technology with CO_2 capture best meets their needs. The results of this are shown as the right hand series in figure 3.

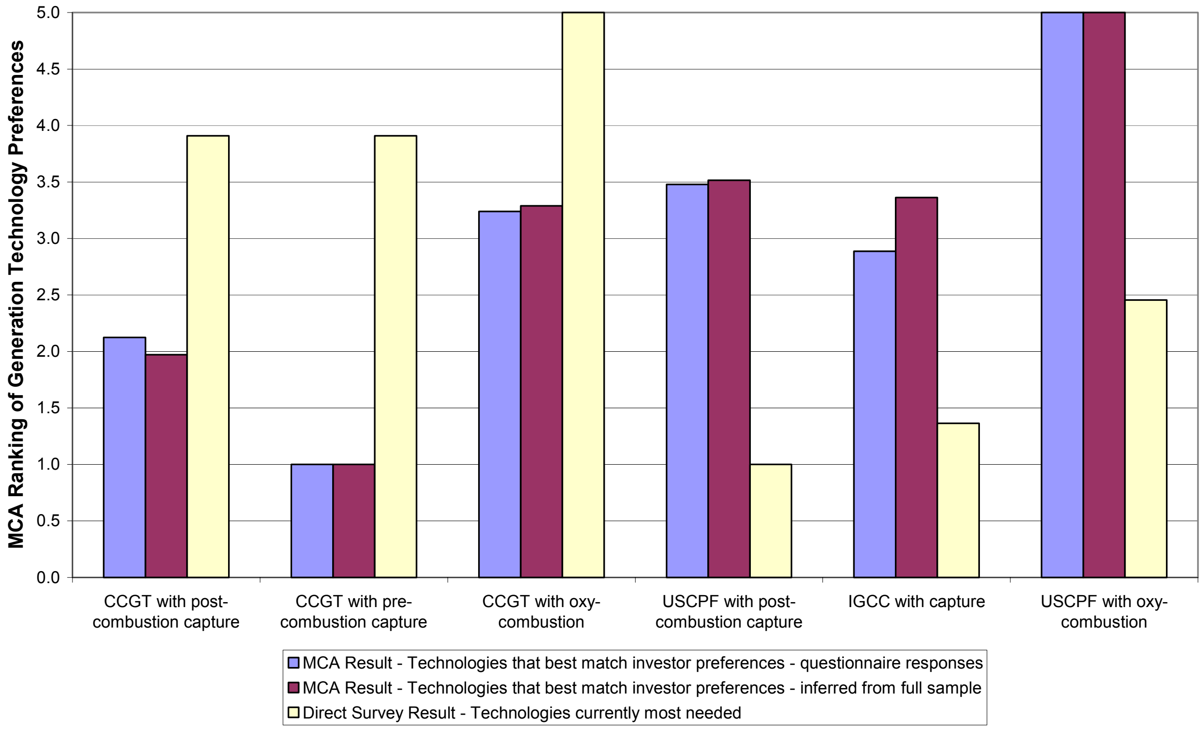

Figure 3 Multi-criteria analysis results versus current technology needs

Of the CO_2 capture plant options, the multi-criteria analysis shows that natural gas CCGT plants, particularly with pre-combustion capture, best match investors' preferences for investment in new power plants. Although gas fired plant options are ranked higher in the multi-criteria analysis results, survey respondents see CO_2 capture as more important to them for coal-fired plant than for gas-fired plants, presumably motivated by legislative drivers on CO_2 emissions that incur a greater penalty on coal-fired generation than gas-fired generation. Of the coal fired plant options, IGCC is ranked best for new plants in the multi criteria analysis but post combustion capture is seen as the most needed technology, both for new and retrofit plants. In all cases oxy-combustion options are considered the least well suited to investors' current needs or set of investment preferences but this may be due in part to the early state of development and lack of knowledge of the technology. Although caution should be used when generalising from these results, because of the small sample size, the plant rankings are robust to sensitivities on both investor preferences and plant performance.

Comments from Expert Reviewers

The draft report was sent to various experts including members of IEA GHG's Executive Committee who represent power utilities. IEA GHG is grateful to those who contributed to this review. The study was generally well received by the reviewers and the comments were mostly points of detail and clarification. The reviewers' comments were taken into account in the final version of the contractor's report.

Major Conclusions

- Coal fired power plants with CO_2 capture are predicted to have lower generation costs than gas fired plants with capture. This conclusion is based on Mott MacDonald's predicted average fuel prices over the next 20 years, which are broadly similar to current prices. However, it is recognised that there is a significant degree of uncertainty in future energy prices and the level of technology risk is considered to be higher for coal fired plants.

- Based on recent IEA GHG studies on new-build power plants, the optimum coal gasification combined cycle plant with CO_2 capture is estimated to have a lower generation cost than post combustion capture and oxy-combustion plants. None of these technologies has been fully demonstrated and the actual costs will depend on the accuracy of the cost estimates, whether the technologies perform as predicted, future technology improvements and various local factors.

- A survey of power utilities and developers worldwide showed considerable interest in CO_2 capture technologies and in many cases the companies were actively investigating the possibility of plant development.

- There is a sharp contrast evident in the survey results between the technologies that can currently best meet the different investors' broad set of investment preferences for new thermal generation plant, and those technologies that they currently see as most needed within their operations. Natural gas CCGT plant incorporating pre-combustion capture is best able to meet investors' preferences, but coal-fired plant with post-combustion capture is viewed as the "most needed" technology in the direct question responses.

Recommendations

The following additional work could complement the finding of this report:

- Further analysis of the impacts of the cost or revenue stream from CO_2 transport and storage, including particularly the role that can be played by enhanced oil recovery as an economic driver for CCS in different regions

- Further analysis of the full life-cycle emissions of greenhouse gases, including the fuel supply chain and CO_2 transport and storage.

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CO_2 Capture as a Factor in Power Station Investment Decisions

April 2006

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CO_2 Capture as a Factor in Power Station Investment Decisions

Issue and Revision Record

Rev	Date	Originator	Checker	Approver	Description
A	16/01/06	Philip Napier-Moore	Emily White	Guy Doyle	Progress Report
B	10/02/06	Philip Napier-Moore	Pete Lilley / Rob Collins	Guy Doyle	Preliminary Draft Report
C	25/02/06	Philip Napier-Moore	Pete Lilley	Guy Doyle	Draft Report
D	05/04/06	Philip Napier-Moore	Philip Napier-Moore	Guy Doyle	Draft Final Report
E	18/04/05	Philip Napier-Moore	Philip Napier-Moore	Guy Doyle	Final Report

List of Contents

Page

Summary

This report documents the attitudes of thirty-four 'investors' towards investment in power generation with CO_2 capture up to 2015, explored through a combination of interviews and questionnaires over the period November 2005 to January 2006. The scope of 'investor' organisations in the study includes power-sector utilities, developers and project lenders, operating both nationally and internationally, based across seventeen countries.

The report also summarises the performance of six leading generation technologies with CO_2 capture, based on assessments of current technology status, published by the International Energy Agency Greenhouse Gas R&D programme (IEA GHG) within the last three years. To compare the six different CO_2 capture technologies on a consistent basis, the results presented focus on new build plant and current technology, correcting for different or outdated exchange rate, fuel cost and cost structure assumptions.

This work was carried out by Mott MacDonald (MM) on behalf of IEA GHG, and is intended to provide a resource to both policymakers in IEA GHG Member Countries and to potential investors in power generation with CO_2 capture.

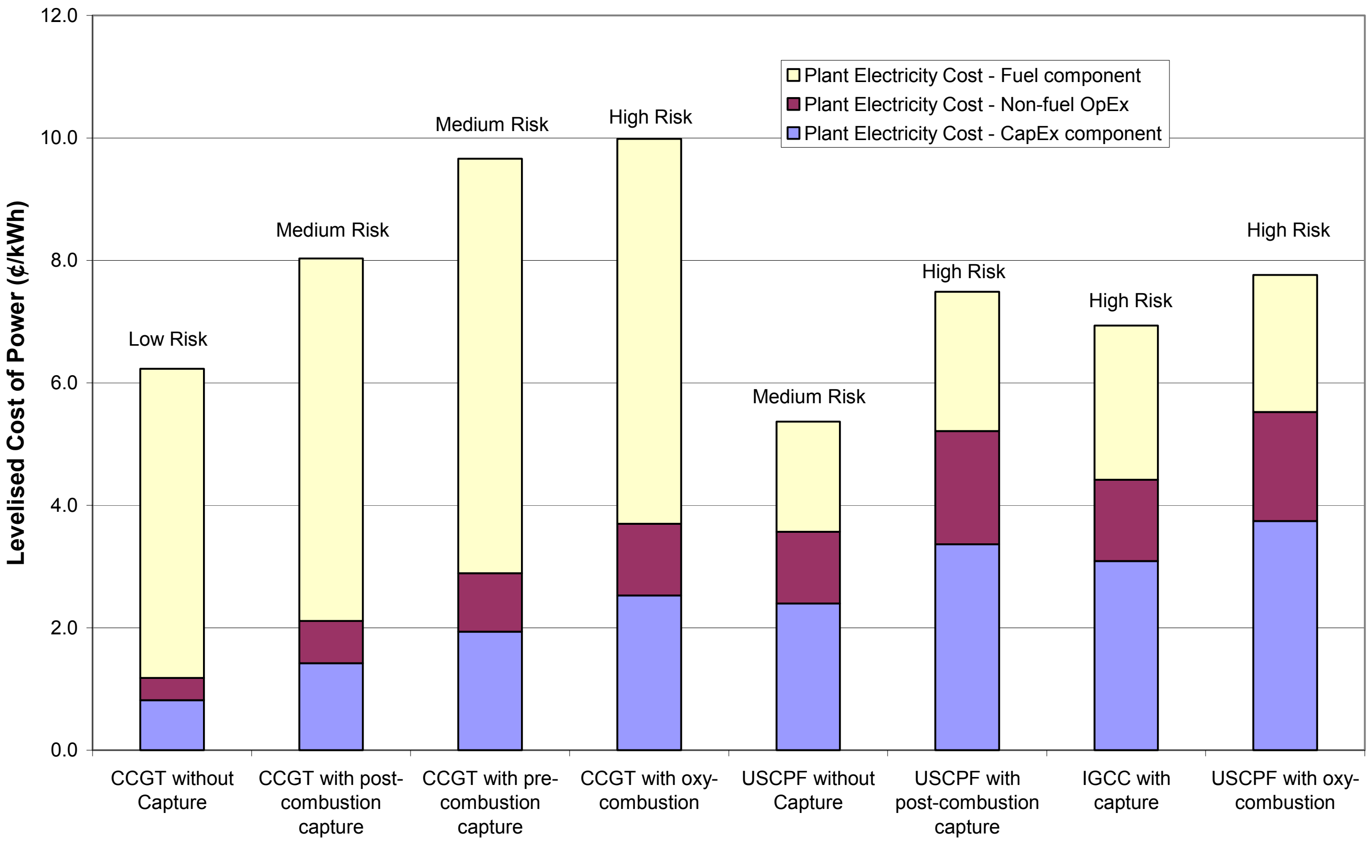
A total of 34 organisation responded to the survey, from a target list of 100 organisations. The survey sample showed a high level of interest in CO_2 capture, with five organisations currently developing generation plant with CO_2 capture. There is, however, a likelihood of bias in the survey sample towards those interested in CO_2 capture, and therefore motivated to participate in the survey. As expected, there is a wide range in respondent awareness of the technologies, with the evidence suggesting that post-combustion capture plant is most widely understood, followed by IGCC, pre-combustion capture through reformation of natural gas, and oxy-combustion least widely understood. IGCC is considered to be the most proven CO_2 capture technology in the questionnaire responses.

Comparison of the IEA GHG technology studies on a level basis under current market conditions results in upward revisions to costs from the original estimates, affecting gas-fired plant more than coal-fired plant options, due to high anticipated long-term gas-prices. Under base case conditions, coal-fired IGCC plant with CO_2 capture gives a similar levelised power cost to a gas-fired CCGT plant without capture, although this finding is sensitive to the study assumptions and whether the risks associated with IGCC incorporating CO_2 capture can be satisfactorily mitigated. Levelised cost of power for each considered plant option under base case assessment conditions is shown in the figure below.

Despite the significant attention paid by the IEA GHG studies to giving representative capital costs for CO_2 capture plant, capital costs needs to be treated with some caution due to likely instances of embedded optimism in capital cost estimates, currency exchange issues and differing degrees of conservatism in the plant designs.

The investor opinions highlighted by the survey and the technology assessment results were combined through a 'multi-criteria analysis' approach, an economic analysis method used to determine which CO_2 capture plant best matches the preferences of power-sector investors. Although based on too small a sample size to generalise widely from, the plant rankings given by the multi-criteria analysis are robust to sensitivities on both investor preferences and plant performance. Of the CO_2 capture plant options, the multi-criteria analysis shows that CCGT plant with pre-combustion capture best matches investor's preferences for thermal plant investment. The gas-fired plant options as a set are also preferred to the coal-fired plant options, for the post-combustion, pre-combustion, and oxy-combustion pairs of technologies respectively.

Although gas-fired plant options are ranked higher in the multi-criteria analysis results, survey respondents see CO_2 capture as more important to them for coal-fired plant than for gas-fired plant, presumably motivated by legislative drivers on carbon emissions that incur a greater penalty on coal-fired generation than gas-fired generation.



Glossary

ASCPF	Advanced Supercritical Pulverised Fuel
ASU	Air Separation Unit
CapEx	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	CO_2 Capture and Storage
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMAH	Control of Major Accident Hazards
EMMP	Environmental Management and Monitoring Plan
EOR	Enhanced Oil Recovery
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitation
FGD	Flue Gas Desulphurisation
GHG	Greenhouse Gas
GT	Gas Turbine
GTL	Gas to Liquid
H_2S	Hydrogen Sulphide
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
I/V	Interview
KM-CDR	Kansai-Mitsubishi - Carbon Dioxide Recovery (proprietary capture process)
LHV	Lower Heating Value
MCA	Multi Criteria Analysis
MDEA	Methyl Diethanolamine
MEA	Monoethylamine
MHI	Mitsubishi Heavy Industries
OpEx	Operating Expenditure
NO_X	Nitrogen Oxides
O&M	Operation and Maintenance
OECD	Organisation for Economic Cooperation and Development
OEM	Original Equipment Manufacturer
PF	Pulverised Fuel
SCR	Selective Catalytic Reduction (of NO_X)
SO_2	Sulphur Dioxide
SO_X	Sulphur Oxides
USCPF	Ultra-Supercritical Pulverised Fuel

1 Background to Study

This report documents the attitudes of thirty-three 'investors' towards investment in power generation with CO_2 capture up to 2015, explored through a combination of interviews and questionnaires over the period November 2005 to January 2006. The scope of 'investor' organisations in the study includes power-sector utilities, developers and project lenders, operating both nationally and internationally, based across seventeen countries.

The report also summarises the performance of six leading generation technologies with CO_2 capture, based on four assessments of current technology status, published by the International Energy Agency Greenhouse Gas R&D programme (IEA GHG) within the last three years. To compare the six different CO_2 capture technologies on a consistent basis, the results presented focus on new build plant and current technology, correcting for different or outdated exchange rate, fuel cost and cost structure assumptions.

This work was carried out by Mott MacDonald (MM) on behalf of IEA GHG, and is intended to provide a resource to both policymakers in IEA GHG Member Countries and to potential investors in power generation with CO_2 capture.

The aims of the study with respect to the policymaker audience are broader than for the investor audience, and are dealt with throughout the body of the report. These aims include:

- Provision of general feedback on the perceived technological, environmental and economic status of different power generation technologies with CO_2 capture on the global market, among the sample of investor organisations interviewed.
- Analysis of how the investment preferences expressed by the organisations interviewed fit with the main characteristics of the leading power generation technologies with CO_2 capture.
- Analysis of which aspects of the CO_2 capture, transport and storage chain are perceived by industry and investors as requiring further technological development before commercialisation is possible.
- Analyse the actual preferences of power-sector stakeholders for investment in thermal generation plant generally, and in generation technologies with CO_2 capture specifically, highlighting where these differ from the 'economically rational' position.
- Summarise and compare on a consistent basis the current economic performance of different leading power generation technologies with CO_2 capture, which have been technically analysed as part of previous IEA GHG studies.

In addition to addressing the above issues, section 4 of the report is specifically intended to provide a *guide for investors*, comparing the different leading technologies and showing which best suited the organisations interviewed.

1.1 Structure of the report

The structure of this report follows the three main components to this study, the investor survey, the technology assessment, and the combined economic analysis, as follows:

- Section 2 discusses the survey of power-sector utilities, developers and lenders, analysing the investment preferences of these different stakeholders with respect to thermal generation plant, and what role is foreseen for power generation processes with CO_2 capture over the next decade.

- Section 3 critically reviews and summarises the assessments published by IEA GHG on the performance of leading CO_2 capture technologies, to provide an analysis of the relative performance of these current technologies, namely:

    - Post-combustion capture of CO_2 from flue gases on gas plant
    - Post-combustion capture of CO_2 from flue gases on coal plant
    - Pre-combustion capture of CO_2 through reformation of natural gas
    - Pre-combustion capture of CO_2 on Integrated Gasification Combined Cycle (IGCC) coal plant
    - Oxy-combustion on gas plant
    - Oxy-combustion on coal plant

    A high level discussion of the different investment criteria seen in the investor survey is also given, focussing on the options facing investors in the above plant.

- Section 4 combines the investment criteria highlighted by the survey with technological assessment of leading CO_2 capture technologies using a 'multi-criteria analysis' (MCA) approach, to show which technologies provide the best overall match with different investor needs.

2 Investor Survey

The investor survey completed by MM required contacting 100 organisations from a ‘target list’ of major utilities, developers and power-sector project lenders based across 27 countries, operating both locally and internationally. The survey ‘target list’ agreed with IEA GHG is provided in Appendix A. The primary aim of this survey was to gather information on the investment preferences of these different stakeholders with respect to thermal generation plant, and what role is foreseen for power generation processes with CO_2 capture over the next decade.

The interview period of November 2005 to January 2006 was preceded by preparation and testing of the survey format, and of the underlying survey methodology, described in section 2.1 below.

2.1 Survey Methodology

The investor survey was structured as a 12 minute telephone interview and a follow-up questionnaire, to allow both a qualitative discussion, exploring respondent ideas and views, and an additional written and detailed numerical response from willing respondents. At each organisation surveyed, MM established contact with a ‘decision-maker’ holding partial or full responsibility for investment in new thermal generation plant, with whom to hold the interview. For the follow-up questionnaire, technical specialists were also invited to contribute.

The telephone interview used a semi-structured format to explore a wide range of preferences for investment in thermal plant, covering financial, environmental, technological, logistics and market issues. The aim of these questions was to assess the breadth of opinion across different organisation types and regions of the world, and to identify any areas where the focus of the study required adapting to fit the expressed preferences of interviewed investors.

Five MM consultants working in the energy-sector acted as interviewers for the investor survey, which aimed to adopt a consistent approach to promote comparable findings. The consultants therefore received a common briefing from internal MM specialists on interview technique, as well as on the latest CO_2 capture technologies, CO_2 transport and storage options, and the status of CO_2 Capture and Storage (CCS) in global legislation, including emissions trading legislation. A scripted interview template was followed by the five interviewers, which is included in Appendix Ca. This interview template was developed through a combination of both internal and external testing, to ensure a manageable length and appropriate focus, with an overall aim to elicit the best possible response from the organisations contacted. All interviews were carried out in English, Spanish or Greek.

In some instances, notably for organisations in Japan and China, formal written letters were sent in advance of the telephone interviews, to ensure an introduction to the appropriate level of decision-maker. Wherever possible, MM networks throughout the company’s global operations were used to make personal contact with decision-makers in the target organisations, improving the rate of response.

The follow-up questionnaire aimed both to verify the essential interview findings and to provide a further quantitative assessment of investment priorities and the relative perceived strengths of different generation technologies with CO_2 capture. The questionnaire template is included in Appendix D. The questionnaire template distributed to respondent organisations was enabled to allow fields to be completed through drop down menus to improve ease of response and required around 12 minutes to complete, the same time as the interview. As a result of the written format and greater depth of knowledge required for the follow-up questionnaire, a lower rate of response than for the interview was anticipated. The interview and questionnaire results are designed to cross-validate the findings of each other. The interview, follow-up questionnaire and target list were agreed in advance of the interview process with IEA GHG.

2.2 Geographic Scope of Interview Responses

The final sample of organisations interviewed, provided in Appendix B, covers all major geographic regions, but not all countries in the initial target list. Within Europe, interview responses were obtained for 8 of the 16 target countries, including 7 EU members and Norway. Outside of Europe, responses were obtained for 8 of the 11 target countries, comprising Australia, Canada, China, India, Japan, New Zealand, South Africa and Venezuala. Several of the organisations interviewed in the total sample of 34 are international players whose focus acts to extend the global relevance of the sample. Table 2-1 shows the numbers of interview responses achieved by country and organisation type, compared with the original organisation target list agreed with IEA GHG.

Table 2-1 Breakdown of Interview Responses versus Target List

Utilities and Developers	Number of Organisations on Target List	Number of Positive Responses comprising final Sample
- European based		
Austria	1	0
Belgium	1	0
Denmark	2	0
Finland	2	1
France	2	1
Germany	4	2
Greece	2	1
Ireland	2	2
Italy	3	0
Netherlands	5	1
Norway	3	1
Portugal	1	0
Spain	4	0
Sweden	2	0
Switzerland	2	0
UK	7	6
- Non-European based		
Australia	4	2
Canada	6	3
China	6	1

India	5	1
Japan	5	3
Korea	1	0
New Zealand	4	1
Russia	1	0
South Africa	2	1
United States	6	0
Venezuala	4	1
International Lenders		
London-based	8	4
Washington-based	2	1
Manila-based	1	0
International OEMs	2	1
Totals	*100*	*34*

The above set of completed interviews represents an overall response rate of 34%, which is typical in our experience of market survey work. A total of 15 follow-up questionnaire responses were received from 14 organisations, representing around 40% of the interview sample, again in line with our prior expectations, and in part explaining MM's rationale in proposing a verbal interview format as the primary information collection method.

2.3 Organisation Types Interviewed

As can be seen in Table 2-1 above, the sample includes developers and utilities, operating both locally and internationally. The significant differences identified between these utility-type respondents, and relevant to preferences for investment in new plant, included:

- their existing generation assets – whether hydro, coal or gas focussed
- their flexibility to invest in new plant – both in terms of scale and range of global operations
- the economic conditions faced – including fuel prices and proximity to oil fields for EOR
- the current and anticipated future legislative framework – including incentives to abate emissions, and the possibility to use nuclear generation
- whether the organisation held responsibility for security of supply

Utilities and developers comprised 82% of the total sample, which segments approximately into 18% developers and investors in Independent Power Projects (IPPs), 26% state-owned or state-controlled utilities and 38% privately-owned utilities. Lenders to power-sector projects comprised 15% of the sample and provided a more consistent set of responses than the utilities and developers, being less subject to region-specific considerations. Utilities and developers generally professed to be better informed and more active in pursuit of generation options with CO_2 capture than the lenders, which is explained by the reactive nature of project debt financing.

The one international Original Equipment Manufacturer (OEM) interviewed, Alstom, was actively pursing a range of CO_2 capture technologies for new generation plant.

There is the possibility that the sample of organisation interviewed is biased towards those interested in CO_2 capture, and therefore motivated to participate in the survey, as discussed below with reference to specific findings.

Section 4.2 provides further analysis of how the responses from different groups of respondents change their preferences for investment in thermal generation plant with CO_2 capture

Appendix B includes the full list of respondent organisations, although findings are not attributed to individual organisations, for confidentiality reasons.

2.4 Telephone Interview Responses

2.4.1 Investment in Thermal Generation Plant

The sample as a whole suggests a significant upcoming expansion in global thermal generation capacity, with 71% of respondents expecting to begin construction or invest in new plant within the next two years. A further 21% anticipated investment over a longer timeframe, of which 18% of the sample was not developing plant for at least five years due to market-specific conditions such as regulatory or demography-related demand constraints, rather than due to a lack of appetite for investment in the global market.

The main technologies that the organisations interviewed plan to develop over the next two years were the expected mix of conventional thermal technologies – combined cycle gas turbines (CCGT), pulverised fuel (PF) coal combustion, fluidised bed combustion (FBC) of coal, and supercritical PF coal plant. Four organisations were also pursuing development of integrated gasification combined cycle (IGCC) plants within two years, three of which would incorporate CO_2 capture.

The typical timeframe used for investment appraisal across the sample was 20 years. Organisations displayed different attitudes towards adjusting this period, a small number maintaining a consistent timeframe in the range 10-25 years for all power assets, and the majority adjusting the period depending primarily on plant technology, country risk and fuel supply risk. The range of investment timeframes provided by the full set of interview respondents is shown in Table 2-2 below, including non-thermal technologies for comparison purposes.

Table 2-2 Timeframes used for investment appraisal of power generation projects

Retrofit	New Build				
	Wind	*CCGT*	*Coal Plant*	*Nuclear*	*Hydro*
7-20 years	10-15 years	15-25 years	20-30 years	15-40 years	25-40 years

A small number of respondents additionally volunteered that they require project rates of return (ROR) in the range 7-10%, as an indicative value, although this would be expected to rise significantly with increasing levels of risk. A nominal post-tax project ROR of 7-10% is consistent with MM's experience of debt-financed IPPs in Western Europe. Lenders generally expressed a requirement for shorter payback periods than other stakeholders, typically using 15 years.

2.4.2 Perceived Significance of GHG emissions

Nearly all respondents stated that mitigation of greenhouse gas (GHG) emissions did factor in their choice of thermal generation technology, typically either due to current legislation or the expectation of future legislation. The strength of the response typically depended on the type of legislative regime applying in the countries where the organisation operated, a consideration discussed further in section 3.3.4(i) below. Other significant reasons given for considering GHG emissions in the plant investment decision included the economic opportunity of carbon certificate trading and considerations of corporate social responsibility or corporate image. Four organisations responded that the necessity of developing low carbon generation was a ‘core organisational belief’, irrespective of other rationale.

The most popular alternatives to CO_2 capture technologies for reducing CO_2 emissions were:

- exploiting remaining scope for efficiency improvements on existing power plant – supported by 82% of sample
- new build renewable energy plant – supported by 71% of sample
- fuel switching to CO_2-neutral fuels such as biomass – supported by 56% of sample.

In the case of fuel switching to biomass, the scope for reducing CO_2 emissions was generally seen as small, however, with 41% of the sample organisations pointing out the limited availability of biomass relative to their total electricity demand. Other measures receiving significant support from the sample were fuel switching from coal or oil to natural gas and replanting with a supercritical steam cycle. The least popular measures, from the perspective of the organisations’ own potential options, were new build nuclear plant and reducing power output to control emissions.

2.4.3 Attitudes towards generation technologies with CO_2 Capture

(i) Activity in the CO_2 Capture field

Half of the organisations interviewed had looked seriously into the potential for constructing generation plant with CO_2 capture, either completing their own feasibility studies or commissioning consultancy advice on the subject. Table 2-3 shows the level of familiarity with CO_2 capture of the different organisations interviewed, previous to participation in the current survey.

Table 2-3 Level of organisation's familiarity with CO_2 Capture technologies

Previous level of exposure	Number of Organisations
Read journal articles or familiar with terminology	11, including 3 project lenders
Attended relevant conferences or visited CO_2 capture demonstration plant	6
Conducted Feasibility Studies or commissioned consultancy advice	8
Undertaking practical R&D or currently developing generation plant with CO_2 capture	9

Of those that have seriously investigated CO_2 capture for new generation plant, five organisations (15%) are actively developing generation plant with CO_2 capture, and four organisations (12%) are carrying out technological development activity or demonstration plant testing, giving a total of 27% of the sample that appear to have taken the strategic decision to further pursue CO_2 capture technologies at the current time. The remaining eight organisations (24%) that have seriously investigated CO_2 capture appear not to be taking further action as a result of their studies. The possibility of sample bias towards those organisations interested in CO_2 capture should be considered here, so that our survey exaggerates interest of global power-sector investors in CO_2 capture technologies.

Those organisations that displayed the least interest, and had at most read journal articles on the subject of CO_2 capture, were in our view those with the lowest incentives to do so. The organisations in this category were either project lenders that had not yet seen any potentially bankable projects; hydro-power generators not closely familiar with thermal generation technologies and only considering this for back-up plant; and utilities operating in countries with lower relative incentives to limit CO_2 emissions – such as India, China and Venezuela, that are non-Annex 1 signatories to the Kyoto protocol.

A number of organisations that had seriously investigated CO_2 capture gave the opinion that retrofitting was not a viable option, and that CO_2 capture could only be economic on new build.

Although the issue of which CO_2 capture technology best meets organisations' needs is dealt with through the follow-up questionnaire (see section 2.5.3), organisations within the interview sample were also invited to comment on the relative merit of different generation technologies with CO_2 capture. The responses were conflicting but generally favoured pre-combustion, and in particular IGCC, over post-combustion capture. Oxyfiring was not perceived as a viable competitor technology at the current time. Two of the three organisations professing to have the greatest technical competence relating to capture technologies gave the proviso that they were maintaining a capability in multiple technologies, however, until a clearer winner emerged.

(ii) Views on development of Transport and Storage Infrastructure

There was a wide range of opinion on the development pathway for transport and storage infrastructure, among the organisations interviewed. Responses to the question of whether transport and storage infrastructure would be developed over the next decade yielded an even split in responses, with 12 interviewees agreeing, 12 disagreeing, and 10 undecided.

Those of the opinion that sufficient transport and storage will be in place by 2015, for any CO_2 capture plant they might wish to develop, point to the success of various demonstration projects across the world proving that the technology is ready for commercialisation, and expect that appropriate incentives will be in place to make this viable, at least for enhanced oil recovery (EOR – see section 3.2.7).

Those that responded negatively to this interview question generally expressed the view that a 15-20 year period would be required to reach commercial viability, pending the resolution of outstanding technical and legal issues with CO_2 storage. The development of transport is not generally seen as a technical barrier, with current levels of expertise in pipeline engineering expected to be sufficient.

Of the six organisations that commented on the relative merits of different storage methods, use of CO_2 for EOR or storage in depleted oil and gas reservoirs was given as the most promising option by five respondents. Two respondents also gave deep geological storage in aquifer formations as a promising option, one claiming storage in saline reservoirs is the most fully developed and therefore most viable short-term CO_2 storage method.

Public acceptance of storage as well as outstanding legal barriers, with CO_2 injection classified as 'dumping' and therefore illegal under some existing legislative frameworks, were highlighted by those giving detailed responses as the most significant points of concern facing large-scale CO_2 storage, rather than technical barriers. In particular, storage of CO_2 in the deep ocean (as a supercritical fluid in the deep-ocean water column) is seen as facing most significant public opposition.

Three of the utility/developer organisations interviewed expressed an active interest in the storage market, with one of the three professing to be a current market leader.

(iii) View on development of Carbon Market to include CO_2 Capture

Of the responses from Europe-based utilities and developers, no organisation disagreed that the EU ETS would be revised to approve captured and stored CO_2 as a reduction in reportable emissions within the next decade. From the 13 of 15 organisations in this category that offered a view, all therefore thought that Europe would offer an incentive to build generation plant with CO_2 capture before 2015, with some instead giving a timeline up to 2010. Whether the price of EUA credits would be sufficient to incentivise CO_2 capture without EOR as the primary economic driver was a subject of more uncertainty.

Looking at the global sample, 74% of organisations agreed that a commercial incentive to develop CO_2 capture and storage would be provided by the carbon market over the next decade. The global proportion of those expressing this view equates to 63% of non-Europe based utilities and developers. This stance referred either to the development of *domestic* emissions trading in Annex 1 signatories to the Kyoto protocol, or to inclusion of CO_2 capture as an approved methodology under the Kyoto offset project mechanisms, or their post-2012 equivalent.

Of the four organisation that gave a view on the Kyoto mechanisms specifically, two gave the view that CO_2 capture projects would be eligible by 2015, while two stated that longer would be required.

2.5 Follow-up questionnaire responses

Out of the 33 investor responses, MM received 15 written questionnaire replies from 14 organisations. These questionnaire responses covered 10 countries: Australia, Canada, China, Finland, Germany, Ireland, Japan, the Netherlands, New Zealand and the UK. We consider this sample a reasonable cross-section of countries, covering Kyoto Annex 1 and non-Annex 1 parties, as well as the European, Asian, North American and Australasian continents.

Each respondent provided information on the priority they give to different investment criteria for thermal generation plant, and the respondents provided a varying level of detail on their opinion of CO_2 capture technologies specifically, depending on their level of knowledge.

2.5.1 Priority given to full range of investment criteria

The priority that organisations give to different potential criteria when making an investment decision for thermal plant was assessed in the follow-up questionnaire using the question:

> "How do the following key criteria play a role in your organisation's decision to invest in a particular type of plant? *(Please choose a category – 1. always, 2. frequently, 3. some of the time, 4. rarely, or 5. never – from the drop-down menu for each of the items on the list below)*"

Table 2-4 below shows the set of investment criteria presented, the average response of the 14 organisations and the variation in their responses. Given that an entirely polarised set of responses would in this case yield a standard deviation of 4.0, and the majority of the criteria show a standard deviation of less than 1.0, these are seen as a generally consistent set, with some exceptions.

Table 2-4 Priority given to different investment criteria – average of sample response

Investment Criteria	Average Response	Standard Deviation of Responses
Financial		
High financial return (best payback, IRR, NPV)	1.20	0.41
Low capital costs	2.07	1.16
Ability to project finance	2.73	1.53
Access to public funds	3.60	0.99
Logistics		
Build time	1.60	0.83
Modular construction	3.07	0.70
Flexibility of operation – response rates, two shifting	2.00	1.00
Outage requirements and expected unplanned outages	1.20	0.41
Availability of skilled O&M contractor	2.60	1.68
Environmental / Permitting		
General permitting issues	1.27	0.80
Land footprint	2.13	1.41
Air quality impacts	1.27	0.46

Investment Criteria	Average Response	Standard Deviation of Responses
Percentage reduction in CO_2	2.07	0.96
Percentage reduction in other GHG	3.13	1.13
Water demand	1.87	1.13
By-product disposal	1.80	1.01
Traffic impacts	2.93	1.39
Public acceptability	1.40	0.63
Safety and health risks	1.07	0.26
Plant Track-record		
Proven technology	1.33	0.49
Financially strong manufacturer of technology	1.67	0.62
Technical obsolescence (anticipated future developments)	1.93	0.70
Market		
Potential for by-product sales	2.33	1.11
Availability of low cost feedstock	1.53	0.92
Diversity of fuel sourcing to mitigate security of supply concerns	2.20	0.86
Availability of skills	1.73	0.70

As expected, the key considerations in a new plant comprise the three major topics of: Safety, Finance and the Environment. The possibility of unplanned outages is seen to be a particularly important component of the risk associated with the investment. Environmental issues are viewed globally to play a significant role in the modern energy sector, especially through the regulation imposed on air quality.

The following four investment criteria can be classed as 'Nearly Always' a priority, receiving the highest average prioritisation:

- Safety and health risks
- High Financial Return
- Outage requirements and expected unplanned outages
- Air quality impacts

Those four investment criteria that are considered only 'Some of the Time', receiving the lowest average prioritisation, are shown below:

- Access to public funds
- Modular construction
- % reduction in other GHG
- Traffic impacts

It is interesting to note here that companies consider reductions of CO_2 as far more important than the reduction in other GHGs, which reflects the predominance of CO_2 as the main GHG emission in the power sector. The weight given to the importance of CO_2 does seem to show the impact that worldwide legislation is having on companies and the way they invest, particularly through the Kyoto protocol and EU ETS.

A different averaged set of investment preferences can be inferred from the full sample of 34 interview responses to question 9, asking "Apart from the economic return, what key factors does your organisation consider most seriously in deciding on plant investments?". Section 4.2 analyses these responses numerically in further detail for the multi-criteria analysis. For those 14 organisations that provided both an interview and questionnaire response, the individual questionnaire responses showed a high degree of consistency with the respective interview responses for each organisation. The full sample of interview responses allowed expression of a broader range of views on priority investment criteria than the questionnaire, however.

Individual respondents to the interview identified twelve high-priority criteria for investment that were additional or slightly different to the twenty-six criteria options presented in questionnaire, already shown in Table 2-4. These additional twelve investment criteria are shown below, with the former six taken to be new criteria not covered in the questionnaire, and the latter six interpreted as variants on existing criteria:

- Managing the risk of sufficient demand within the supply-demand balance on the power market
- Availability of capacity on the power transmission system for new plant
- Potential to 'lead by example' through development of new technologies (view from project developer)
- Experience of Project Sponsor (view from project lender)
- Contractual Risk Allocation (view from project lender)
- Political Risk – particularly nationalisation of assets or controlled input and output markets (view from project lender)
- Low Risk of Supply Interruption (interpreted as a variant on proven or reliable technology)
- Whether the technology is proven to give a good balance of availability and efficiency (interpreted as a variant on proven or reliable technology)
- Social Impact – both in terms of appropriate site selection and employment creation (interpreted as a variant on acceptability from a public perspective)
- Ability to compete on the market (interpreted as a specific variant on financial return)
- Maximising returns across a global investment portfolio (interpreted as a variant on financial return)
- 'Economic Sustainability' as distinct and additional to social and environmental sustainability (interpreted as a variant on financial return)

Because these criteria were not identified sufficiently early in the interview process to include in the questionnaires, there is no information available on their relative priority ranking by survey respondents. The first six criteria relate to the market in a specific region rather than the viability of a specific technology, however, so do not affect the relative appraisal of different plant technologies in the multi-criteria analysis. The latter six criteria in the list are used to refine the definition of existing criteria, as discussed in section 4.2.

2.5.2 Appraisal of CO_2 capture technologies – qualitative aspects

Of the 14 responses to the written-questionnaire, 13 organisations expressed an opinion on the performance of one or more generation technologies with CO_2 capture, relative to the baseline of a CCGT and PF Coal plant. Between 7 and 11 organisations responded for each CO_2 capture option presented. From the number of responses given, it appears that the sample respondents were least well informed about oxyfuel combustion and best informed about IGCC.

Using the standard deviation (σ) again as a simple indicator, the responses obtained were generally reasonably consistent, although respondents agreed significantly more on the performance of post-combustion capture and pre-combustion CO_2 removal by reformation of natural gas than on IGCC and oxyfuel combustion.

These responses show a lack of consensus on the performance of oxy-combustion, which reflects the fact that this technology is least established, and that information on cost and performance is both widely varying and not readily available. For IGCC, it appears that although information is more widely available, that views on the technology's performance are still widely varying.

Table 2-5 below shows the average set of responses ranking the performance of five CO_2 capture technologies, where a rating of '1' is best, and a rating of '5' is worst. The best and worst rankings given to the CO_2 capture technologies on each performance criterion, as expressed by the sample responses, are shaded in green (dark) and orange (light) respectively, for clarity.

Further analysis of this information is given in section 2.5.3 below.

Table 2-5 Comparison of qualitative performance of CO_2 Capture Technologies versus Conventional Thermal Plant

	Benchmark 1 – CCGT	Benchmark 2 – PF Coal	Post-combustion capture (gas)		Post-combustion capture (coal)		Oxyfuel boilers		IGCC		Pre-combustion capture of natural gas	
Number of Organisational Responses			*8*		*10*		*7*		*11*		*8*	
Environmental / Permitting			Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
General permitting issues	1	3	2.00	1.31	2.50	0.85	2.88	0.99	2.09	1.04	1.88	1.13
Public acceptability	2	3	2.38	1.69	2.50	1.27	2.63	1.41	2.09	1.14	1.88	1.13
Safety and health risks	1	1	2.38	1.51	2.30	1.34	3.00	1.51	2.36	1.29	1.88	1.13
Logistics												
Build time	1	3	3.00	0.89	2.63	0.92	3.00	1.26	3.33	1.22	3.00	0.89
Modular construction	1	4	2.67	0.52	2.75	1.04	3.50	0.84	3.00	1.32	2.83	0.41
Flexibility of operation – response rates, two shifting	1	2	2.00	1.00	2.00	0.76	2.33	0.52	2.67	0.87	2.29	0.49
Outage requirements and expected unplanned outages	1	3	2.57	0.79	3.22	0.97	3.86	1.07	3.70	1.34	2.57	0.79
Availability of O&M contractor	1	1	2.17	1.17	2.50	1.41	2.83	1.47	2.78	1.48	2.33	0.82
Plant Track-record												
Proven technology	1	1	2.63	1.30	3.10	1.29	4.33	1.32	3.00	1.00	2.63	1.41
Financially strong manufacturer of technology	1	1	2.14	1.46	2.22	1.30	2.86	1.35	2.20	1.14	2.00	1.29
Risk of technical obsolescence (low rating if risks are considered high)	2	4	2.88	1.13	3.00	1.25	2.88	1.55	2.73	1.27	2.88	1.36
Market												
Potential for by-product sales	5	4	4.00	1.00	3.22	1.48	3.71	1.38	3.00	1.73	3.29	1.60
Availability of low cost feedstock	4	3	3.75	1.28	2.60	0.84	2.29	0.76	2.40	1.17	3.25	1.16
Diversity of fuel sourcing (low rating if security of supply concerns are high)	5	4	4.00	1.41	3.00	1.12	2.71	1.11	2.80	1.23	3.63	1.30
Availability of skills	1	1	2.14	0.69	2.13	0.64	2.83	0.98	2.89	0.78	2.71	0.95
Financial												
Financiers comfort with technology	1	1	3.43	1.27	3.33	1.22	3.88	1.46	3.20	1.03	3.00	1.15
Access to public funds and subsidies	5	4	3.71	1.11	3.22	1.20	2.86	1.21	3.20	1.14	3.57	1.15

2.5.3 CO_2 Capture Technology best meeting organisations' current needs

Complementary to section 2.5.2 above, the organisations were asked which generation technologies with CO_2 capture could best fit their needs, including whether this would best be done through retrofitting/repowering or through new build. Table 2-6 below shows the number of organisations from the total questionnaire sample of 14, with the equivalent percentage in brackets, that responded in favour of each technology. Organisations were free to select multiple technologies that could to the same extent best meet their current needs. Multiple questionnaire responses from the same organisation have not been included in Table 2-6.

Table 2-6 CO_2 Capture technologies that best meet organisations' current needs

	Fuel or Specific Plant type to use with CO_2 Capture			
	Coal-fired plant	*Natural gas-fired plant*	*CCGT*	*Other fuels*
Retrofit post-combustion capture to existing power plants	7 (50%)	1 (7%)	1 (7%)	1 (7%)
Post-combustion capture for new power plants	7 (50%)	1 (7%)	2 (14%)	0
Oxyfuel conversion of boilers for existing power plants	3 (21%)	0	0	0
Oxyfuel boilers for new power plants	7 (50%)	0	0	1 (7%)
IGCC (coal) repowering of existing thermal power plants	0	NA	NA	NA
IGCC for firing of new CCGT power plants	6 (43%)	NA	NA	2 (14%)
Pre-combustion CO_2 removal by reformation of natural gas, for existing power plants	NA	1 (7%)	0	NA
Pre-combustion CO_2 removal by reformation of natural gas, for new power plants	NA	0	0	NA
Pre-combustion CO_2 removal and hydrogen purification for pipeline distribution of H_2	2 (14%)			
Pre-combustion CO_2 removal & hydrogen purification for use in advanced power generation plant (e.g. fuel cells)	1 (7%)			

Table 2-6 indicates that organisations in the sample view coal-based CO_2 capture as best fitting their needs, whether through retrofitting existing plants or through new build. This perception could be due to the higher carbon intensity of coal-based generation (producing about 50% more CO_2 emissions than gas, each using BAT plant), meaning that coal-based generators are feeling most tightly carbon constrained under current legislative mechanisms, and to the higher differential value, in terms of tradable certificates, of reducing emissions to zero. In addition, the coal generation fleet of those organisations interviewed is generally older and in poorer working condition than the equivalent CCGT plant, so that retrofitting or replacing these plants with CO_2 capture technology would fit with the capital stock replacement schedule.

Post-combustion capture is the preferred option for the majority of organisations at this point in time. While the rationale for this choice could not be investigated further within to the questionnaire format, this appears to be a conservative position, involving the least change to established generation processes, with the technology added downstream of the turbines.

Paradoxically, although Oxyfuel is deemed the worst technology across a wide range of criteria, including the criteria categories plant track record, logistics and environmental/permitting, the option to fit oxyfuel boilers in new coal plants is one of the technologies considered to best fit organisations' needs. Probable explanations for this contrast are that respondents understood the question on which technologies best fit their preferences as future-focussed, or as the technological ideal, irrespective of current costs and performance.

IGCC for new plants fits 43% of organisations' needs (47% of the sample responses, due to two responses from different sections of one organisation), potentially due to the perceived comfort of financiers with this technology and corresponding high bankability of projects relative to other CO_2 capture technologies. Perceived disadvantages of this technology are the high concern over the build time, the availability of skills and the flexibility of operation.

Pre-combustion CO_2 removal by reformation of natural gas is only seen to fit one organisation's needs, despite also being seen as being the most environmentally sound and reliable in terms of outages.

Three further organisations that did not respond to the follow-up questionnaire did provide information on the technologies they were pursuing as part of the additional technical questions in the interview. While one organisation was actively developing all CO_2 capture technologies, taking a portfolio approach towards different markets, the other two favoured pre-combustion capture technologies for new plant, including either gas- or coal-fired plant. Inclusion of these additional views produces a more even proportion of respondents currently favouring pre-combustion versus post-combustion capture technologies.

3 Technology Assessment

3.1 Approach to Technology Assessment

For each of the investment criterion outlined in section 2.5.1, MM have critically summarised the main findings of four studies on generation technologies with CO_2 capture published by IEA GHG. These studies are:

- Improvement in Power Generation with Post Combustion Capture of CO_2 (PH4/33, November 2004) – carried out by a consortium of Fluor, Mitsui-Babcock, Alstom, and Imperial College London, with contributions from Mitsubishi Heavy Industries.
- Retrofit of CO_2 capture to natural gas combined cycle power plants (2005/1, January 2005) – carried out by Jacobs Consultancy Netherlands, using various equipment supplier quotes.
- Potential for Improvement in Gasification Combined Cycle Power Generation with CO_2 capture (PH4/19, May 2003) – carried out by Foster Wheeler Energy, using various equipment supplier quotes.
- Oxy Combustion Processes for CO_2 Capture from Power Plant (2005/9, July 2005) – carried out by Mitsui-Babcock, Alstom, Air Products and Imperial College London.

Each of these studies, based on 'current' technology status within the past three years, are prepared by consortiums of equipment suppliers or using quotes from equipment suppliers that sell the relevant technology and reviewed by 'independent experts', including equipment manufacturers, academic researchers, consultants and project developers. The influence of this approach to technology assessment on the findings is discussed in section 3.2.1 below.

Section 3.2 below provides an introduction to each leading technology through a summary of the headline features and issues, compared with conventional gas and coal plant. The key results from the IEA GHG published reports are summarised and the 'lowest cost' option for each technology is highlighted, for further use in economic comparison of the different generation technologies with CO_2 capture. The 'lowest cost' option for each technology category is taken as the option giving the lowest levelised[1] cost of power at standard IEA GHG assessment conditions, but using MM projections of long-run fuel prices, as presented in subsections 3.1.1 and 3.1.2 below.

Section 3.3 discusses the performance of the leading technologies with respect to the different investment criteria identified in the market survey. The issues surrounding each investment criterion are therefore discussed, drawing from a combination of MM experience and the findings of the IEA GHG studies. For those criteria where significant investment choices exist within the context of a single generation plant technology with CO_2 capture, MM have provided a high-level assessment of the alternative options and the typical strategies adopted by investors.

This report is not intended to provide a full description of the plant designs forming the basis of the economic comparison. For a full design description including process diagrams, heat and mass balance calculations, equipment lists and detailed costing assumptions, reference should be made to the four above-listed IEA GHG studies.

[1] 'Levelised cost of power' is the power tariff that gives a zero net present value to the plant investment, so that the discounted stream of costs over the project life is exactly equal and to the discounted stream of revenues. Levelised cost of power therefore represents the long-run cost of generation, in real currency terms.

While the different IEA GHG studies have based their design performance and cost estimates on technology from specific OEMs, this typically represents ease of access to information on state of the art technology, and is not intended to endorse the selected OEMs over other equipment suppliers, or the specific technology proposed over similar variants.

3.1.1 Comparability of Results

The analysis of different generation technologies with CO_2 capture uses the standard assessment criteria applied in each of the four studies published by IEA GHG. Among the most significant IEA GHG standard assessment criteria are the following five assumptions:

- Netherlands coastal plant location – greenfield with no special civil works
- Coal grade equivalent to Australian Bituminous coal
- 85% load factor
- 10% discount rate
- 25 year operating life for all plants

The latter two economic criteria are consistent with the survey responses for gas-fired CCGT and coal-fired plant, as shown in 2.4.1. The full set of IEA GHG standard assessment criteria are given in Appendix E. Additional assumptions applied consistently throughout the IEA GHG studies, mostly derived directly from the standard assessment criteria are as follows:

- construction period of 2.5 years for CCGT plant, with capital investment phasing of 40:40:20 in years one to three respectively
- construction period of 3 years for PF plant, with capital investment phasing of 20:45:35 in years one to three respectively
- emission limits of 25 mg/Nm^3 for particulate matter (PM), 200 mg/Nm^3 for Nitrogen Oxides (NO_X), and 200 mg/Nm^3 for Sulphur Oxides (SO_X) – relevant to the plants without capture, as emissions from the plants with CO_2 capture are significantly below this
- total capital expenditure (CapEx) comprising
  - 10% contingency on installed costs
  - 7% owners costs on top of installed costs, except for oxy-combustion on coal-fired plant where a higher value of 18% is applied
- fixed operating expenditure (OpEx) comprising direct labour, administration and maintenance
  - direct labour from number of operators, with an average yearly cost of US$ 50,000
  - administration as 30% of direct labour cost
  - maintenance in range of 2-4% of installed costs per year, depending on technology
- annual insurance and local taxes of 2% installed costs, contributing to variable OpEx
- zero net revenue from sale of plant by-products (e.g. sulphur, slag, ash) and waste disposal
- compression of captured CO_2 to 110 bar, in preparation for transport
- separation of H_2S from CO_2 stream where required
- where a gas turbine (GT) is used, this is based on the GE 9FA.

MM has updated the standard fuel prices used in the IEA GHG studies, as discussed in section 3.1.2, but otherwise used the standard assessment criteria, in the general case. Those assumptions from the standard assessment criteria that are considered most significant, both in terms of likely variation in practice from the assumed levels and impact on project economics, are analysed as sensitivity cases. Section 3.1.3 describes the range of sensitivity analyses carried out, and section 3.3.1(i) discusses the results of these sensitivity cases. Further discussion of the assumptions, where required, is provided with reference to the plant option results throughout section 3.3.

Taking the above assumptions as fixed for the base case analysis, the variables considered for economic comparison of the different generation options with CO_2 capture are therefore:

- installed costs
- fuel feedrate
- net power output
- number of operators
- maintenance costs
- chemical/consumable costs

The base case values for these variables are taken from the IEA GHG studies, and focus on the costs and performance for *new-build* power plant, based on *current* technology. This information is available for each of the six generation technologies with CO_2 capture in the report, with the exception of pre-combustion capture through reformation of natural gas. Only retrofit costs are given in this instance, which have been scaled to provide a level basis for comparison, as described in section 3.2.3.

In addition to the outlined assumptions and variables, the following issues are also relevant for comparability of the different base case generation options with CO_2 capture:

- Economies and efficiencies of scale resulting from greater plant capacity. Although the standard IEA GHG investment criteria states a preference for a plant with net capacity of 500MW, the generation technologies with CO_2 capture discussed here range in net capacity from 440 to 776 MW. For those plant designs based around the standard-sized GT, the varying levels of auxiliary loads with CO_2 capture design make this variation in net output unavoidable, but nonetheless will create differences in economies of scale between the plants analysed, over this significant capacity range. The overall impact of scale economies is considered small relative to other uncertainties in the studies, however, with the more critical cost sensitivities considered in section 3.1.3 below.
- All four IEA GHG published assessments use capital costs for CO_2 capture equipment quoted directly or indirectly by the equipment suppliers, but without any commercial obligations to maintain these prices under actual project conditions. The quoted prices for all manufacturers might therefore be expected to be at the low end of the feasible range, to some extent representing a marketing effort. Without actual project costs to provide a benchmark, it would not be possible for the expert reviewers of each IEA GHG report to factually dispute the capital cost estimates, except to note that under commercial tendering conditions, a different set of incentives would act on the equipment supplier with respect to the level of their quote. The extent to which the capital cost quotes provided in each technology study are equally conservative, or otherwise, and therefore provide a consistent and comparable set of data is discussed in sections 3.2.1 through 3.2.6 below.

- The degree of integration for the CO_2 capture equipment that is assumed in the studies of new-build generation – which positively affects base case efficiency but increases the risk of outages, due to lost operating flexibility.

A broader issue relating to the final bullet point above is that comparability of designs and cost quotes from different technology studies is typically limited by the use of different design criteria, economic assumptions and pricing approaches. This lack of comparability applies equally to different studies of CO_2 capture plant and to other first-of-kind designs, whether nuclear or deep-water offshore wind, for which equipment cost and performance data is available only through non-binding quotes from equipment suppliers. A strength of the IEA GHG studies in this respect is the use of transparent standard assessment criteria, provided in Appendix E.

3.1.2 Fuel Prices

The IEA GHG studies, published over the timeframe 2003 to 2005, apply the following standard fuel prices:

- Coal price of US$ 1.5/GJ, LHV basis (equivalent to US$ 1.43/GJ HHV basis)
- Natural Gas price of US$ 3/GJ LHV basis (equivalent to US$ 2.70/GJ HHV basis)

While the use of consistent fuel costs is important for comparability of the different generation plant options, we do not consider that the above fuel price assumptions now represent a reasonable long-run base case, looking forward from 2006 over a plant life in excess of 20 years. Table 3-1 below shows MM's current forecast for delivered fuel prices up to 2026 at the assumed Netherlands coastal location of the plant, based on the following assertions:

- Long-run fuel prices will remain high relative to average historic levels due to strong demand growth and consolidation of the supply industries;

- There will, however, be a near term weakening in gas and coal prices due to easing of short term supply bottlenecks.

- Demand/supply pressure will be greatest for oil, however, gas is likely to be closely correlated to oil due to the persistence on oil indexation in utility contracts;

- Even if buyers move away from long term gas contracts, there will be strong demand for gas due to increased pressure to control CO_2 emissions and the prospect of increasing demand from GTL (gas to liquid) plant, which is likely to keep supply margins tight and prices high.

- Traded coal prices are loosely connected to crude oil prices, however, the prospect of tightening constraints on coal use should mean that coal will be sold at an increasing discount to natural gas. Long run coal supply curves are also much flatter than gas, due largely to the much larger reserve-to-production ratios.

Table 3-1 MM forecast of Long Run delivered fuel prices – Gas and Coal, Netherlands

	Coal Prices				Gas Prices			
Year	CIF Cost (US$/t)*	CIF Cost (US$/GJ net)	Transport & Handling (US$/GJ)	Delivered Price (US$/GJ)	Bunde-Oude (US$/mm BTU, gross)**	Bunde-Oude (US$/GJ, net)	Transport & Handling (US$/GJ)	Delivered Price (US$/GJ)
2005	57	2.20	0.30	2.50	6.5	6.78	0.2	7.00
2006	54	2.09	0.30	2.39	7.5	7.82	0.2	8.02
2007	50	1.93	0.30	2.23	7	7.30	0.2	7.50
2008	50	1.93	0.30	2.23	6.7	6.99	0.2	7.19
2009	50	1.93	0.30	2.23	6.5	6.78	0.2	6.98
2010	50	1.93	0.30	2.23	6.6	6.88	0.2	7.08
2011	50	1.93	0.30	2.23	6.7	6.99	0.2	7.19
2012	50	1.93	0.30	2.23	6.8	7.09	0.2	7.29
2013	50	1.93	0.30	2.23	6.9	7.20	0.2	7.40
2014	50	1.93	0.30	2.23	7	7.30	0.2	7.50
2015	50	1.93	0.30	2.23	7.1	7.41	0.2	7.61
2016	50	1.93	0.30	2.23	7.2	7.51	0.2	7.71
2017	50	1.93	0.30	2.23	7.3	7.61	0.2	7.81
2018	50	1.93	0.30	2.23	7.4	7.72	0.2	7.92
2019	50	1.93	0.30	2.23	7.5	7.82	0.2	8.02
2020	50	1.93	0.30	2.23	7.6	7.93	0.2	8.13
2021	50	1.93	0.30	2.23	7.7	8.03	0.2	8.23
2022	50	1.93	0.30	2.23	7.8	8.14	0.2	8.34
2023	50	1.93	0.30	2.23	7.9	8.24	0.2	8.44
2024	50	1.93	0.30	2.23	8	8.34	0.2	8.54
2025	50	1.93	0.30	2.23	8.1	8.45	0.2	8.65
2026	50	1.93	0.30	2.23	8.2	8.55	0.2	8.75

* Cost, Insurance and Freight (CIF) cost, based on McCloskey Marker (excludes domestic transport and handling), for bituminous coal with calorific value 25.87 GJ/t net, consistent with IEA GHG standard criteria

** Priced at the Bunde Oude natural gas hub, on the German-Dutch border, using a net to gross conversion factor of 1.1 for gas

On the basis of the above projections, MM have applied the following long-run average delivered prices, applicable to plants beginning construction in 2007 onwards:

- Coal price of US$ 2.2/GJ, LHV basis
- Natural Gas price of US$ 7.8/GJ, LHV basis

The base case analysis throughout the remainder of this report assumes the above coal and gas prices apply in real terms for the duration of each plant's 25 year operating life.

For comparison, the imported natural gas and coal prices assumed as a reference case in the IEA World Energy Outlook 2005 (OECD/IEA, 2005, p.64) can be used to calculate delivered fuel prices in the same way as in Table 3-1 above. Average delivered fuel prices between 2010 and 2030 using this data and MM's cost build-up assumptions are US$ 2.5/GJ (114% of MM forecast) for coal imports to OECD countries in general, and US$ 6.4/GJ (82% of MM forecast) for gas imports to Europe. This comparison shows that the MM gas price forecast is high relative to IEA reference assumptions, published in November 2005, although this difference can simply be said to reflect increases in crude oil prices and increased security of supply concerns for gas, leading to a risk premium on prices, since this time.

Using point-of-production natural gas and coal prices forecast by the US Department of Energy (DOE/EIA, 2006) for North America in the above analysis would instead give delivered prices of US$ 1.5/GJ for coal (68% of MM forecast for Europe) and US$ 6.4/GJ for gas (82% of MM forecast for Europe). Again using IEA (OECD/IEA, 2005) assumptions for US imported gas prices gives a delivered price of US$ 7.2/GJ (92% of MM forecast for Europe), while IEA assumptions for Japan imported gas prices give a 2% higher delivered price result than the US (94% of MM forecast for Europe). Although these fuel prices for the US and Japan are not directly comparable with the MM forecast for Europe, the contrast does help to show how the overall analysis of plant options would vary in different regions, a factor that can be addressed through the fuel price sensitivity analysis.

3.1.3 Sensitivities

The sensitivity analysis of plant economic performance aims to explore changes in the most significant assumptions of the IEA GHG studies, either where variables are subject to a high degree of uncertainty, or where a small variation in a variable can have a substantial impact on project economic performance. We note that capital and fuel costs, in particular, were the focus of expert reviewer comments for several of the previous four IEA GHG technology studies. The variables subject to sensitivity analysis are therefore the discount rate, load factor, fuel price and capital costs.

The sensitivity cases are modelled in section 3.3.1(i) as follows:

- Low Discount Rate – a decrease in the discount rate to 5% (see Figure 3-6).
- Low Fuel Price – decrease of 50% in the delivered price of both gas and coal, representing a greater absolute reduction in the price of gas (see Figure 3-3).
- High Fuel Price – increase of 50% in the delivered price of both gas and coal, representing a greater absolute increase in the price of gas.

  Both the low and high fuel price sensitivities are necessary to represent the volatility and long-run uncertainty regarding fuel prices, which are subject to substantial geopolitical influence, in addition to global variations in supply-demand balance.

- High CapEx – increase of 25% in the capital costs (Figure 3-5).

  This sensitivity represents the possibility that capital costs for any plant are underestimated in the base case. The level of the sensitivity for CapEx, at 25%, represents the significant uncertainty surrounding plant costs, discussed for each plant option in sections 3.2.1 through 3.2.6 below. This uncertainty reflects a combination of conflicting evidence on plant CapEx from different studies; currency exchange uncertainties in the original IEA GHG (2003) technology study; and the risk premium an investor could associate with unproven plant equipment. There is a linear relationship between changes to plant CapEx and the levelised cost of power, if the assumption of consistent investment phasing is maintained. Although a decrease in CapEx is considered unlikely therefore, it will simply give an opposite impact of equal magnitude on power cost.

- Low load factor – decrease in the load factor of the plant to 35% (see Figure 3-6).

  While the base case load factor of 85% defined in the IEA GHG standard assessment criteria is intended to represent base load operation for relatively unproven technologies, there is the long-term possibility that CO_2 capture plants will operate at less than base load. A load factor of 35% explores the possibility that other low-carbon generation technologies with low operating costs such as wind, and to a lesser extent nuclear, will be operated in preference to coal- and gas-fired plants with CO_2 capture. The CO_2 capture plant are therefore assumed to operate during weekday business hours, during times of high demand. This sensitivity does not take account of additional start costs or the suitability of the different plant options for rapid starts, which is discussed in section 3.3.3(iii).

- Load factor spread – modelled increase of 5% on the base case load factor for gas-fired plant (LF_G = 90%), and a decrease in the base case load factor of 5% on coal-fired plant (LF_C = 80%).

  This sensitivity case is intended to represent greater planned maintenance requirements for solid fuel handling and processing equipment, as well as greater scope for unplanned outages on the coal-fired plant with CO_2 capture, which are generally judged to be higher risk technology than the gas-fired plant options.

Results for the above sensitivity cases are shown in Table 3-7 and Table 3-8 for gas- and coal-fired plant respectively, and in the subsequent figures where noted.

Further sensitivity cases were considered in preparing this analysis, but rejected as either being too context-specific or due to a lack of consistent information across the full set of CO_2 capture technologies. These sensitivities would be of potential interest for a more in-depth technical analysis exploring alternative design configurations across all CO_2 capture plant and technical options for transport and storage:

- Addition of a range of transport and storage costs
- Consideration of revenue streams from EOR, tax credits, and sale of emissions allowances
- Attribution of a net value to the by-products of the coal-fired plant options
- Different plant configurations, including the degree of integration on the CO_2 capture equipment
- Use of larger capacity GT, such as the GE 9H, in the CCGT plant configurations.

- Delaying installation of CO_2 capture – and modelling the associated costs and benefits of retrofit at a later stage. Although the results of the four IEA GHG studies include retrofit of capture to CCGTs, this is not done across the same set of plant technologies as the new-build cases. The degree of integration and sophistication of capture technology applied, and whether this is installed up-front through construction of a 'capture-ready' plant or during retrofit, would each need to be considered to meaningfully evaluate this sensitivity. This area is too complicated to model within the scope of the current study, directly from the technical information already available, and is recommended for further analysis.

- Effect of changing ambient air and water conditions on plant operation, to represent seasonal variation and plant locations in different regions of the world.

- Effect of changing the coal specification on the coal-fired plant, to represent use of local coal and lignite, rather than export-quality bituminous coal.

The following section further discusses the different technologies to define the technical characteristics of the base case plant options, after which section 3.3.1 provides the economic comparison and sensitivity analysis.

3.2 Introduction to Technologies

3.2.1 Post-combustion capture on gas-fired combined cycle gas turbine plant

Post-combustion capture can be installed either on new-build or retrofitted to existing thermal power plants, including gas- and coal-fired plant. The post-combustion capture process involves scrubbing the exhaust gases after combustion with a solvent to extract the CO_2. The main features of this technology for natural gas-fired CCGTs are summarised below:

- Significant land footprint, with different estimates ranging between 9,000 and 40,000 square metres for the capture equipment – requirement for available space in retrofit of existing plant.
- CO_2 concentration in power station flue gases is typically 4% - so that large volumes of flue gases must be processed.
- Uses an organic solvent (Monoethylamine, MEA, is most usual) which captures CO_2 when in solution, using a scrubber tower in contact with the flue gases.
- Incorporates circulation of the 'rich' solution of MEA with absorbed CO_2 to a 'stripper' tower where it is reheated, leading to release of CO_2 and production of 'lean' solvent solution for return to the scrubber.
- MEA is degraded by contact with NO_2 or SO_2. These pollutants must therefore by reduced to low concentration levels (1 to 20 ppm for NO_2 and 1 to 10 ppm for SO_2) in order to result in an acceptable life for the MEA. For gas-fired plant, only NO_X levels generally require reduction.
- Continual replacement of MEA is a significant operating cost.
- As a result of the above two points, the power plant needs to be equipped with Selective Catalytic Reduction (SCR) of NO_X in the process of retrofitting for CO_2 capture, or during the design of new plants.
- Addition of capture to a CCGT plant incurs an efficiency penalty of around 6.0-8.2 percentage points, LHV (IEA GHG, 2004).

IEA GHG (2004) models the costs of a CCGT based on the GE 9FA gas turbine, with a net power output of 776 MW without capture, at US$ 499/kW. The same basic plant with post-combustion capture has a reduced net power output of 662-692 MW and a specific capital cost of US$ 869-887, implying a capture penalty of US$ 370-388/kW. A similar analysis for the full range of CO_2 capture technologies on gas plant is shown in Table 3-4 below.

The range of results for new build post-combustion capture on gas plant reflects the performance of two different proprietary CO_2 capture processes, those of Fluor and Mitsubishi Heavy Industries (MHI). There is a trade-off presented here between capital investment and thermal efficiency of the capture process, with MHI offering the more capital intensive and efficient process. The MHI process is the lowest cost option using the assumptions of the IEA GHG report – a conclusion that is reinforced when long-run gas prices of US$ 7.8/GJ LHV are considered, rather than a gas price of US$ 3/GJ LHV as used in the original report. However, the full set of performance data for the MHI option is not publicly available, so that the Fluor process has been used for this analysis.

The 'least cost' Fluor process, based on 2004 technology, has been taken to be the base-case CCGT with post-combustion capture ('Case 2'). Although the assessment indicates that a GE 9H gas turbine would provide a more economic result, the technical profile for this GT combined with CO_2 capture is given under the proviso of high uncertainty, and would not allow a consistent comparison with the other generation technologies with CO_2 capture, so has not been included in this analysis.

(i) Capital Cost Uncertainty

As noted in section 3.1.1 above, all four IEA GHG published assessments use capital costs for CO_2 capture equipment directly or indirectly provided by the equipment suppliers, but without any commercial obligations to maintain these prices under actual project conditions. In the case of IEA GHG (2004), CO_2 capture equipment prices are directly quoted by Fluor or MHI. Costs for other plant equipment, particularly for power generation, are well known and limited scope exists for these to be quoted low. In each of the IEA GHG studies there is potentially greater scope for low price quotes on the un-proven capture-specific equipment, for which a market track-record does not yet exist. At the time of writing this report, MM experience with post-combustion CO_2 capture projects currently under development, for confidential clients, are that specific capital costs for the post-combustion capture plant are estimated around 50% higher on a new-build generation plant than the estimates given by Fluor or MHI, even for a design based on the GE 9H gas turbine. This difference occurs despite the fact that Fluor has used "estimates for real projects which have been built from lump sum bids" (IEA GHG, 2004, p.82) as the basis for their assessment.

A further comparison of the *new-build* capital costs provided in IEA GHG (2004), led by Fluor, is the study on *retrofit* capital costs in IEA GHG (2005) coordinated by independent consultants, Jacobs Netherland. Whereas MM would expect total capital costs for the generation plant with CO_2 capture to be up to 30% higher in the retrofit case, the Jacobs study gives 50% higher total capital costs (equivalent to 90% higher capital costs for the capture-specific equipment), as shown in Table 3-2 below. On first inspection this comparison suggests that either the 2004 study CapEx for new-build post-combustion capture is around 20% too low, or the 2005 retrofit CapEx estimate around 20% too high.

A potential response to this concern, in IEA GHG (2005, p.vii/viii) is that the Fluor and MHI results are based on high-quality, proprietary scrubbing processes, with economies of scale on CO_2 absorbers and lower steam requirements for solvent regeneration. By contrast, the Jacobs design based on equipment quotes from UOP (a subsidiary of Honeywell) is a conservative design, based on eight trains, with associated high auxiliary energy demand, rather than the two trains used by each of Fluor and MHI. The extent to which the different capital cost results reflect different scrubbing process and the extent to which they embody different approaches to price quotation is not entirely clear. Although this concern was a minor issue to the original IEA GHG studies, which aimed only to compare the merits of the technologies within each study, this point is important to this report's comparison of CO_2 capture technologies across the four studies. The uncertainty deriving from equipment price quotes justifies the 25% CapEx increase that is applied as a sensitivity case, as per section 3.1.3 above.

3.2.2 Post-combustion capture on coal plant

The post-combustion capture process for coal plant involves similar equipment and processes to post-combustion capture for gas turbine plant, except that the CO_2 concentration in the plant flue gases is typically 13-14%, so that lower volumes of flue gases must be processed to capture an equivalent mass of CO_2. There is also a requirement for 'super-desulphurisation' equipment, in addition to the SCR used on a gas-fired plant, since MEA degradation through contact with SO_2 is a significant additional issue for coal-fired plant.

Based on IEA GHG (2004), the cost of avoided CO_2 emissions is therefore 70-80% the equivalent level for a CCGT with post-combustion capture. By the same token, however, the greater carbon content of coal compared with gas results in a 45-75% greater penalty on the levelised cost of power for capture of the CO_2 on a coal plant than on a gas plant. The lowest cost cases for each technology are compared in more detail in section 3.3.1.

As in the case of post-combustion capture on gas plant, the 'least cost' Fluor process, based on 2004 technology, has been taken to be the base-case post-combustion capture on coal plant ('Case 4'). This case assumes an ultra-supercritical pulverised fuel (USCPF) plant with steam conditions of 29MPa, 600OC and a reheat temperature of 620OC. The efficiency penalty for additional of CO2 capture is 9.2 percentage points (LHV), bringing overall efficiency for the plant with CO2 capture to 34.8%.

IEA GHG (2004) models the costs of the USCPF plant, with a net power output of 758 MW without capture, at US$ 1171-1222/kW net. The same basic plant with post-combustion capture has a reduced net power output of 666-676 MW and a specific capital cost of US$ 1755-1858, implying a capture penalty of US$ 533-687/kW. A similar analysis for the full range of CO2 capture technologies on coal plant is shown in Table 3-5 below, with capital costs adjusted upwards to reflect current costs after exchange rate changes.

The Fluor study for IEA GHG (2004) applied a parity exchange rate from Euros to US Dollars (1 US$/€) on a proportion of the equipment used in the coal-fired plant designs, which the contractor considered to be representative of exchange rates in recent years. Taking annual average exchange rates over the twelve months up to 31 January 2006 gives an exchange rate[2] of 1.23 US$/€, so that the cost of equipment originally quoted in Euros would be underestimated by up to 23% when converted to current US Dollars. Few commentators expect the Dollar to strengthen against the Euro in the medium-term, with general expectations of any move being a weakening (Consensus Forecasts, 2006). The parity exchange rate used in the Fluor study for IEA GHG does not, therefore, accurately reflect current prices or probable future prices for hypothetical plant construction in the period 2007 to 2010. A neutral position would instead be to assume the current rate, for which MM has taken the annual average to smooth the noise present in the daily spot rate. For illustration of recent currency variation, the interbank spot rate[2] varied between 1.17 US$/€ and 1.35 US$/€ around the mean level of 1.23 US$/€ over the twelve months prior to 31 January 2006.

To reduce the uncertainty of the capital cost estimates, MM has therefore recalculated capital costs for the coal-fired plant options in IEA GHG (2004), applying an exchange rate of 1.23 US$/€ to the boiler island, power island, de-NO_X and desulphurisation equipment, which we understand were originally quoted in Euros by Alstom and Mitsui Babcock. Although this amendment more accurately reflects the original price quote, it does not take into account shifts in the market position of US- and EU-based suppliers, which are likely to modify their prices to ensure continued competitiveness in spite of shifting exchange rates. Real price changes for power generation equipment have generally been minor since 2004, when the study was completed, however.

An important point with respect to post-combustion capture on coal-fired plant is the finding of the Fluor study for IEA GHG (2004, p.15) that trace impurities in the flue gas mean the current USCPF technology with CO_2 capture "requires demonstration before a very large capture plant could be designed with an acceptable technical and commercial risk level". Fluor's report presents two designs – a 2004 and a 2020 design. Fluor's conclusion based on current level of technology demonstration is that only the latter of their two plant designs is viable, and this would require government-led sponsorship of a demonstration plant at an appropriate scale. In practice, it could be expected that a full commercial scale coal-fired plant with post-combustion capture would come on-line between 2010 and 2015.

To compare each technology on a level footing it is necessary to use the 'current' technologies for all cases, rather than creating additional uncertainty in the results by projecting the improvement of each technology into the future. Instead of using a projected future design for USCPF with post combustion capture, therefore, this report applies a 'high' technical risk level to the 2004 design (see section 3.3.2(ii) below) and suggests that the 'High CapEx' sensitivity be used to represent a risk premium on plant construction and operation as required. The coal-fired plant has the same potential for low CapEx as the gas-fired plant with post-combustion capture in the 2004 study, due to low supplier quotes, as discussed in section 3.2.1(i) above. The 'High CapEx' sensitivity therefore represents both technology risk and installed cost uncertainty.

[2] Based on FXHistory data, www.oanda.com

3.2.3 Pre-combustion CO_2 removal by reformation of natural gas

For pre-combustion CO_2 removal from natural gas, the equivalent of the 'gasification' route discussed for coal in section 3.2.4 below, is steam 'reformation'. The basic steam reformation reaction between natural gas and steam produces a mixture of hydrogen and carbon monoxide (CO). Further steam addition, with a 'shift' reaction, converts the CO to hydrogen and CO_2. The more efficient auto-thermal reformation reaction first oxidises the hydrocarbons, requiring addition of air or oxygen to the process prior to steam. Looking at either reformation process, the natural gas is changed to hydrogen and CO_2 while retaining the majority of its calorific value on combustion.

Reformers and shift reactions are currently used in the petrochemical industry, but still require demonstration at larger capacities to be proven suitable for commercial-scale CCGT.

As with post-combustion capture, CO_2 can be captured, though in this case from the fuel gas by using solvent-based scrubbing after cooling. The requirements for fuel gas cleaning are not as severe as from coal systems, due to clean feed, and there is no need for an ASU in this stage of the process.

The gas turbines of the CCGT will need to operate on hydrogen fuel, probably with some dilutant. The Jacobs report for IEA GHG (2005) selected water vapour as the preferred dilutant, since the alternative of using nitrogen would need a dedicated ASU, greatly increasing costs and reducing efficiency.

The GT used in the IEA GHG scenarios is the GE Frame 9FA. This GT has not yet run on reformer fuel hydrogen, but the supplier states that the required modifications are minor. H-class GTs have operated from 2002 on natural gas, but suppliers will not give performance data on hydrogen until many more operating hours have been accumulated on natural gas.

The IEA GHG study (2005) on *retrofit options* estimates that a CCGT with pre-combustion capture of CO_2 has a capital cost of US$ 1420/kW at a net output of 690 MW, compared to a plant without capture with specific capital costs of US$ 530/kW, at a net output of 785 MW. None of the four IEA GHG reports gives results specific to new-build pre-combustion capture for gas plant. The capital and operating costs for retrofitting pre-combustion CO_2 capture onto a CCGT that is not 'capture ready' would be expected to be significantly higher than for a new-build pre-combustion CO_2 capture plant, however, due to foregone opportunities for:

- system integration to reduce parasitic loads
- design GT to take into account different properties of working fluid – hydrogen gas mixture
- design HRSG and steam turbine to make efficient use of different properties of GT exhaust gases

Each of the above new-build design improvements would increase plant net efficiency, leading to reduced specific fuel costs for a given plant net capacity, or equivalently to increased net capacity and reduced specific CapEx at a given fuel feedrate. Similar arguments can also be made for post-combustion capture and IGCC retrofits to existing CCGTs versus new-build plants. The four IEA GHG reports give results for both new-build and retrofits for post-combustion capture and IGCC. Although the particular opportunities and gains from new-build will vary by CO_2 capture technology, the difference in capital and operating costs for these other technologies is indicative of the gains that could be expected from new-build pre-combustion capture plant versus retrofit in the different capture technologies. Table 3-2 below makes this comparison, and proposes scaling factors, representing the increase in costs between retrofit and new-build, for pre-combustion capture. Based on the design considerations highlighted above, MM has assumed that the new-build CCGT with pre-combustion capture requires 20% lower CapEx than the retrofit design case in IEA GHG (2005), to compare each CO_2 capture technology on a level basis as new build plant. Fuel and Non-fuel operating costs are conservatively assumed to remain equal in the new-build and retrofit cases. Improved plant efficiency is represented through the higher net output at a constant fuel consmuption, and hence reduced specific CapEx, rather than reduced fuel and consumables consumption, while other OpEx components would not necessarily vary if the plant processes the same amount of fuel.

Table 3-2 Comparison of new-build and retrofit of CO_2 capture on CCGTs

	CCGT with post-combustion capture			IGCC with capture			CCGT with pre-combustion capture	
	New Build	Retrofit	*Scaling factor*	New Build*	Retrofit	*Scaling factor*	Retrofit	*Scaling factor***
Capital Cost (US$ million)	570	810	-	1090	1380	-	820	-
Net Power Output (MWe)	662	626	-	730	751	-	694	-
Specific Capital Cost (US$/kW net)	869	1294	*49%*	1495	1837	*23%*	1419	*20%*
Thermal efficiency, LHV – proxy for fuel costs (%)	47.4	44.6	*6%*	31.5	35.4	*-11%**	41.5	*0%*
Non-fuel Operating Costs (US$ million/year)	32.9	51.4	*56%*	66.6	84	*26%*	42.5	*0%*

* As discussed in section 3.2.4 below, this new-build Texaco IGCC plant represents the 'low capex, low efficiency' option given in IEA GHG (2003).

** While the scaling factors for IGCC and post-capture are based on IEA GHG study data, for pre-capture this scaling factor is proposed based on MM experience.

The retrofit analysis in IEA GHG (2005) also uses different assumptions on the structure of operating costs than the other new-build cost analyses – for consistency these have been revised in our analysis to be consistent with the IEA GHG standard assessment criteria outlined in section 3.1.1. The results of our analysis consistently comparing the full range of CO_2 capture technologies on gas plant are shown in Table 3-4 below.

The IEA GHG (2005) study applies an exchange rate of 1.23 US$/€, which is consistent with the annual average exchange rate over the past year, to 31 January 2006, and does not therefore need adjustment to reflect 'current' prices. Although the study was prepared by an independent consultant, Jacobs, and is generally conservative on plant design, the scope for low equipment cost estimates is explored through the 'High CapEx' sesnitivity, as for the other plant options. The 25% CapEx increase in this sensitivity would in this case bring capital costs for *new-build* plant to 5% above the *retrofit* cost estimate originally given in the Jacobs study for IEA GHG (2005).

3.2.4 IGCC with CO_2 capture

Integrated Gasification Combined Cycle (IGCC) involves gasifying coal by heating it in a restricted oxidant supply and steam to produce a gas stream comprised mainly of CH_4 and CO. Nitrogen is also a major part of the fuel gas if air is used for oxidation, but most gasifiers use pure oxygen, removing the nitrogen in an ASU prior to the gasifier. The initial fuel gas is reacted with further steam ('shift reaction') to produce hydrogen and CO_2. The CO_2 is then removed using a solvent scrubbing process and the hydrogen used as the fuel for combustion. In the IEA GHG study (2003) a Selexol solvent is used for scrubbing and the hydrogen combusted in a combined cycle arrangement with one ST and two GTs, based on the GE Frame 9FA. Although this GT does not yet have a track-record running on hydrogen fuel, as noted in 3.2.3 above, the supplier maintains that modifications to adapt the design to the new working fluid are minor.

The IEA GHG study looked at two gasifiers - both of the oxygen-blown, entrained flow type. The OEMs for these gasifiers were Texaco (now GE) and Shell. Both gasifiers require the product gas to be cooled prior to cleaning, as no high temperature clean-up is yet feasible. The Shell gasifier cools the fuel gas in a heat recovery boiler, whereas the Texaco gasifier uses a water-quench, so does not recover the heat into the power cycle. The main IGCC options examined are therefore based on the following two gasifiers:

1. Texaco: 'low' capital cost, 'low' efficiency – slurry feed, quench cooling of product gas, 4 x 33% gasifiers

2. Shell: 'high' capital cost, 'high' efficiency – dry feed, heat recovery cooling of product gas, 2 x 50% gasifiers

The information on performance and cost of these options is based on 'current commercial offerings' during 2002, at the time the study work was carried out, and is therefore likely to be conservative for new-build in 2006, due to intervening improvements in this technology. For both gasifier types, the IGCC design assumes that the ASU is partially integrated – with 50% of the compressed air requirement extracted from the gas turbine at full load operation.

Of these two supplier options, the IGCC using the Texaco gasifier gives the lower levelised cost of power for any coal price below US$ 9.5/GJ – so that the Texaco option is 'lowest cost' under any foreseen coal market conditions. For the Texaco plant, the expert review section of the IEA GHG study (2003) additionally identified a change to the process that further reduces the levelised cost of power. This change entails reducing the number of gasifiers from four to three, although each still with greater capacity for redundancy, and adding a radiant fuel gas cooler with fully integrated energy recovery to the base case study design, before water quench. In this case, investment costs are estimated by Texaco, on the basis of existing plant without CO_2 capture, to remain at the same level but thermal efficiency of the IGCC plant to increase by 2.0 percentage points.

Evidence from other studies, summarised in a paper given by the US-based Electric Power Research Institute (EPRI) at the 'Gasification Technologies Conference', suggest the CapEx would be higher for radiant cooling, however. EPRI (2003) gives data for four IGCC plants designs without CO_2 capture incorporating a Texaco gasifier. In the EPRI paper, the specific CapEx estimates for two plant designs using radiant cooling are between 12% and 15% higher than for two plant designs with quench cooling. Based on the EPRI study, a significant CapEx increase can reasonably be expected for IGCC plant design with CO_2 capture, adding radiant cooling in place of quench cooling, although no estimate of these costs is available.

Table 3-3 summarises the results of the IEA GHG study (2003), comparing the above IGCC designs with and without capture.

Table 3-3 Comparison of IGCC Plants designed using Texaco and Shell gasifiers

	Texaco IGCC			Shell IGCC	
	Without Capture	Capture Base Case	Updated Capture Design*	Without Capture	Capture Base Case
Capital Cost (US$ million)	980	1090	-	1060	1260
Specific Capital Cost (US$/kW net)	1187	1495	-	1371	1860
Net Power Output (MWe)	826	730	777.8	776	676
Thermal efficiency, LHV	38.0%	31.5%	33.5%	43.1%	34.5%

* Radiant fuel gas cooler to replace quench-cooling, 3 x 50% gasifiers to replace 4 x 33% gasifiers, assuming capital costs remain constant

The *base case* Texaco IGCC design is taken as the least cost IGCC plant, for which we also have a full design and cost estimate, as shown in further analysis of the full range of CO_2 capture technologies on coal plant in Table 3-5 below, with capital costs adjusted upwards to reflect current costs after exchange rate changes.

Other sensitivities addressed in the IEA GHG study are different gasifier operating pressures and the possibility of using a 'clean' rather than 'sour' shift reaction – removing the H_2S before reacting the fuel gas with steam. Each of these sensitivities increased overall project costs, so are not incorporated in the least cost IGCC design.

A further sensitivity conducted on the Shell and Texaco plants explores capture of CO_2 and H_2S together, using MDEA as the solvent. Combined capture of CO_2 and H_2S is an option for all gasifier types, which improves efficiency and reduces capital costs. Assessed per tonne of CO_2 captured, combined capture reduces capture costs by 20%. For some Enhanced Oil Recovery (EOR) applications, the H_2S content can be useful (oil miscibility) although problems also include additional permitting; materials; and souring of gas from oil fields, which might outweigh the cost benefits of reduced capture costs. For comparability with the 'clean' CO_2 stream achieved with the other capture processes, the analysis in this report uses the base case Texaco IGCC plant, which separates H_2S and CO_2 in the captured gas stream.

For the IGCC with CO_2 capture, the Foster Wheeler study for IEA GHG (2003) uses lower contingency costs than the 10% of installed costs given in the standard assessment criteria, instead using 6.4% for the Texaco base-case design. This has been altered for the purposes of this analysis, which instead uses a 10% contingency on all plant designs.

As for IEA GHG (2004), the study of IGCC with capture in IEA GHG (2003) uses a parity Dollar-Euro exchange rate. The CapEx estimates have therefore been brought in line with current market conditions by applying an exchange rate of 1.23 US$/€ to the majority of the plant equipment, which was originally quoted in Euros. The gasification section is understood to have been originally quoted in Dollars, and the cost for this equipment is not therefore adjusted. As discussed in section 3.2.2, this indexation does not take into account changes to the real level of supplier prices, which can be altered to ensure continued competitiveness in spite of shifting exchange rates. Real price changes for power generation equipment have generally been minor since 2003, when the study was completed, however.

Although IEA GHG (2003) presents the same potential issue of low supplier price quotes discussed in section 3.2.1(i) above, the study has the benefit of completion by a semi-independent contractor, Foster-Wheeler, with experience of actual IGCC projects in Italy. In comparison with a range of other studies of IGCC plant based on the Texaco gasifier (EPRI, 2003) the Foster-Wheeler specific CapEx estimates in IEA GHG (2003) are midrange, after adjusting for different gas turbine sizes. The *new-build* cost estimates given by Foster-Wheeler are also compared with the cost estimates for *retrofitting* a gasifier to a CCGT plant, prepared by Jacobs, as in Table 3-2 above. The difference in CapEx for these two plant options is within the expected range of up to 30%, whereas specific fuel costs are actually 11% higher in the new-build case, when comparing with the 'low efficiency, low CapEx' Texaco gasifier option. Foster-Wheeler gives an accuracy of plus or minus 25% to their CapEx estimates, the higher end of which is represented in this report through the 'High CapEx' sensitivity.

3.2.5 Oxy-combustion for CCGT

Oxy-fuel combustion is a relatively immature CO_2 capture technology. The oxy-fuel procedure uses pure oxygen, diluted in CO_2, instead of air for the intake to the combustion process. The exhaust gases from the gas turbine are therefore mainly and water vapour, and the CO_2 can be captured directly, after drying. The main additional equipment required for oxy-fuel combustion is an air separation plant (ASU), therefore. The air separation plant capacity required for utility-scale power generation is significantly greater than that demonstrated by existing single train units. The main features of this technology are summarised below:

- Optimum oxygen purity is around 95%, so less costly than the 99% plus required in current chemical process applications of ASUs
- Minor flue gas emissions in normal operation. The only significant plant emissions to atmosphere are clean nitrogen from the ASU. There is also a CO_2 bleed stream of around 3% the emissions of a CCGT without capture, in the order of 0.01 tCO_2 per megawatt-hour of power generated.
- If SO_2 and NO_X are not subsequently separated from the CO_2 as industrial feedstocks, in a 'simple' cryogenic process as part of the removal of incondensibles, then the transport and storage of the CO_2 has the potential for corrosion from these acid gases. Acid gases can change the pipeline and storage design requirements, although H_2S in particular can be beneficial applied to EOR.

- Oxyfuel combustion with gas requires the development of a new GT, due to the different working fluid of combustion products plus CO_2 dilutant, rather than air. The need for a new GT creates uncertainty on the schedule and costs of developing this technology to market.

The recent IEA GHG study (2005a), assumes the use of two gas turbines and one steam turbine in combined cycle configuration for the oxy-combustion design. Although the different working fluid of the oxy-combustion process was acknowledged to require the development of a new gas turbine, the technology-status of GE 9FA was used as the basis for design of the new turbine. A single basic design for CO_2 capture with oxy-combustion for gas plant ('Case 4') is given in the IEA GHG report, which is therefore taken here as the 'least cost' option.

The IEA GHG study estimates specific capital costs for this design at US$ 1495/kWe, for a net output of 440 MWe and efficiency of 44.7% on LHV basis. This is compared to a conventional CCGT with a capital cost of US$ 559/kWe, an output of 388 MWe, and 56% efficiency. A similar analysis for the full range of CO_2 capture technologies on gas plant is shown in Table 3-4 below.

IEA GHG (2005a) uses an exchange rate of 1.2 US$/€, as opposed to the annual average exchange rate over the past year of 1.23 US$/€. Although this would only lead to an underestimate of plant CapEx by 2.5%, comfortably within the 25% sensitivity applied, for consistency CapEx has been adjusted using a 1.23 US$/€ on all plant equipment, which we understand was originally quoted in Euros.

The 'High CapEx' sensitivity is relevant to the oxy-combustion plant designs particularly in that these constitute the least proven of the options analysed in this report.

For the CCGT with oxy-combustion, the IEA GHG study (2005a) uses owner's costs of 5.0%, rather than the 7% of installed costs given in the standard assessment criteria. This has been altered for the purposes of this analysis, which instead uses owner's costs of 7% installed costs on all plant designs.

3.2.6 Oxy-combustion for Coal-fired plant

IEA GHG (2005a) proposes an advanced supercritical pulverised fuel (ASCPF) plant firing bituminous coal, and a CO_2 recycle that feeds 30% oxygen in CO_2 to the boiler, allowing use of current, proven boiler technology. ASCPF is interpreted here as substantially similar to USCPF. Other differences for coal-fired compared with gas-fired oxy-combustion are:

- No Flue Gas Desulphurisation (FGD) or Selective Catalytic Reduction (SCR) of NO_X required – implying a major cost saving
- Electrostatic Precipitation (ESP) is still required:
  (a) for start-up;
  (b) to protect compressors etc downstream from fine particulates
- ESP temperature limits lead to a compromise in the thermodynamic cycle
- Primary flue gas recycling requires drying (and therefore cooling) and then reheating, in order to preheat and dry the coal in the mills.

A single design for CO_2 capture with oxy-combustion for coal plant ('Case 2') is given in IEA GHG (2005a), which is therefore taken here as the 'least cost' option. The IEA GHG study estimates that addition of CO_2 capture to the USCPF without capture increases specific capital costs from US$ 1513/kW to US$ 2342/kW. The net efficiency (LHV) of the oxy-fuel combustion option would be 35.4%, compared to 44.2% in the conventional plant. A similar analysis for the full range of CO_2 capture technologies on coal plant is shown in Table 3-5 below.

Owner's costs for the oxy-fired PF capture plant are given in the report (2005a) as substantially higher than standard IEA GHG assessment criteria, averaging at 18%, taking general costs of 7% and costs of 20% on the PF capture plant. This has been altered for the purposes of this analysis, which instead assumes owner's costs of 7% installed costs on all plant designs.

As discussed in the above sections, IEA GHG (2005a) uses an exchange rate of 1.2 US$/€, which could lead to an underestimate of plant CapEx by 2.5%, which is comfortably within the 25% uncertainty range on CapEx applied in the study. The 'High CapEx' sensitivity is, however, still relevant to the relatively unproven oxy-combustion plant designs.

3.2.7 Transport and Storage of CO_2

Although not within the central scope of this report, transport and storage of CO_2 is discussed briefly below, to highlight the leading options. These options generally imply a net cost additional to the capture and compression of CO_2 during the power generation process. IEA GHG (2004) gives the illustration that a transport and storage cost of US$ 10/tCO_2 would increase the cost of coal- and gas-fired electricity generation by US¢ 0.8/kWh and US¢ 0.4/kWh respectively. Use of CO_2 for enhanced oil recovery is also discussed below, which under favourable circumstances can generate a net revenue from the transport and storage component of a CO_2 capture, transport and storage chain.

It is generally expected that captured CO_2 - compressed as a super-critical fluid - will be stored in the long term by injection into suitable deep geological formations such as aquifers, or oil and gas wells.

These formations will usually prove to be remote from the sites of power station facilities, so the captured CO_2 will first require to be transported to the storage location. An extensive infrastructure of pipelines would be necessary, in most cases, connecting the power plants to the injection point(s). Alternative unit transport methods (primarily ships for onshore or offshore injection points) would also be considered, and would perhaps be favourable in particular circumstances.

Clearly, the infrastructure for transport of CO_2 does not yet exist. For the purposes of our investigation of capture technology preferences it should be assumed by the power plant operators that some third party will develop the necessary infrastructure on a timescale comparable to that for implementation of CO_2 capture. The transport developer will then be available to power station operators to provide a service of CO_2 removal from the site in return for a known commodity charge, likely to relate to the carbon market allowance/credit price per tonne of CO_2.

Geological storage of CO_2 has been demonstrated at pilot scale in several locations, notably in the North Sea (Norway). Remote sensing of the presence of CO_2 at depth is being developed, along with containment and verification procedures, preparatory to including CO_2 storage in due course as an acceptable mitigation procedure under emissions trading mechanisms. Again, the timescales for such acceptance should be assumed to be consistent with the progress of CO_2 capture.

It is also possible to use CO_2 for Enhanced Oil Recovery (EOR), to extend the lifetime of existing oil wells by recovering reserves that would otherwise be inaccessible to normal oil extraction methods. CO_2-EOR would form a further stage following and in association with the better known steam-injection EOR which is used already. For CO_2-EOR, supercritical CO_2 is injected into peripheral wells and is used to dissolve the oil at depth and drive it towards the main recovery well(s). In the process, some CO_2 is left stored in the porosity of the oil-bearing rocks, while a larger proportion returns to the surface with the oil, where it can be separated and re-injected. CO_2-EOR has been used at the Weyburn oil field in Canada, using gasification and CO_2 seperation, and extensively in the USA, using CO_2 from natural sources.

CO_2-EOR provides a system where the CO_2 has a positive value, due to the extra oil which can be extracted and sold as a result of its use. A disadvantage over other geological storage methods is the limited life of the depleting well and hence the possible need to deliver the CO_2 for injection to a succession of fields over the life of any power project. There is also the fundamental point that production of extra oil can be seen to *add* to the global emissions of CO_2, over and above those that would occur in a business as usual scenario, unless all users of the oil are themselves subject to CO_2 capture. The logistics of trading emission permits based on this use of CO_2-EOR have therefore been questioned. This point rests heavily on the assumed base case – which could range from exploitation of oil sands and other emissions-intensive hydrocarbons, to a 100% renewable scenario, such as the 2020 policy goal recently announced by the government of Sweden.

Alternative methods of CO_2 disposal / storage have been suggested, though the scientific consensus at present is strongly in favour of the geological storage. Particularly, Japan has suggested storage of super-critical CO_2 at the base of the water column in deep oceans. Documented concerns with this storage approach are the damage to deep ocean fauna at the storage location, as well as future disruption of the storage site through water movement or seismic activity, spreading the CO_2 into the wider marine environment. A potentially major effect of the build-up of CO_2 *in the atmosphere* is already the major effects on ocean chemistry. The perceived consensus is that further work is required to assess risks to the marine environment from deep-water storage.

Of long term interest, potentially, is the use of mineralisation for capture and storage of CO_2, discussed for example in 'Greenhouse Gas Control Technology' conference papers (2002) and IEA GHG (2005b). Rather than capturing and storing CO_2 as a fluid, this method would produce a stable solid waste for disposal. Mineralisation is at laboratory scale only at present. With the best available feedstocks, and associated chemicals, pressures and temperatures; observed residence times for reaction down to 1 hour (for 80% conversion) have been demonstrated. The required feedstock is almost invariably Magnesium Silicate. There is debate over the most appropriate forms of Magnesium Silicate for mineralization, as well as the availability and locations of associated reserves for each of these forms.

The specific process conditions (as well as the costs of the feedstock and its disposal) mean that any advantages of 'mineralisation' over other CO_2 capture methods would be limited, as it would also incur significant capital costs and auxiliary power requirements. Indeed it might be a secondary method which is used on the power plant site to process CO_2 captured by one of the other technologies. By this means, the process conditions could be optimised. The savings would be from the reduced transport and storage costs and the guaranteed permanence of storage. Disposal of the resulting magnesium silicon carbonate would be by placement in deep mines and quarries from which the feedstock had been removed. Possible issues are the contaminants that the material will also have accumulated in the capture process.

3.3 Plant performance relative to Investment Criteria

This section discusses in turn each of the criterion, identified by the respondents to the interview and follow-up questionnaire, used to make an investment decision for thermal generation plant. Each of the criterion is discussed to highlight the role this can play in selecting a generation technology, and the relative performance of the CO_2 capture plant options is discussed, where differences exist.

Where significant investment choices exist within the context of a single generation plant technology with CO_2 capture, this section aims to provide a high-level assessment of the alternative options faced and the typical strategies adopted by investors.

The layout of this section of the report is given below, for ease of reference.

3.3.1 Plant Economic Performance

A standard cashflow spreadsheet model provided by IEA GHG was used to calculate the economic performance of the different generation plant options with CO_2 capture, compared with gas- and coal-fired plant without CO_2 capture. This cashflow spreadsheet used the standard IEA GHG assessment criteria discussed in section 3.1.1, together with the plant cost and performance data for the 'least-cost' option in each of the six leading CO_2 capture technology categories. The spreadsheet has been set up to assume new-build plant, beginning construction in 2007 with cashflows discounted back to this time.

Table 3-4 and Table 3-5 below summarise the main economic performance results and basic plant performance data for gas-fired and coal-fired plant options respectively. The results presented comprise the 'base case' findings for each least-cost plant option, since the standard base case assumptions are applied in the cashflow spreadsheet model. The 'capture penalty' represents the cost difference between the capture options and the plant without capture, separately for each of gas-fired and coal-fired plant. In addition to the quantitative results given in the tables, a qualitative assessment of technical risk is provided to cover the relative likelihood of delays and unplanned outages, as discussed in section 3.3.2(ii) below. Screenshots of the cashflow spreadsheet for each plant option are included in Appendix F.

The CCGT and USCPF plants without capture presented in Table 3-4 and Table 3-5 below are based on the results of Fluor's analysis, in IEA GHG (2004). These plant options allow comparison of the CO_2 capture plant options with state of the art new-build plant without capture. Figure 3-1 compares these capture and non-capture plant by levelised cost of power over the assumed 25 year plant lifetime. The USCPF plant capital costs have been adjusted in the same way as for the coal-fired post-combustion capture plant, discussed in section 3.2.2 above, to take account of a current Dollar-Euro exchange rate.

Although each IEA GHG study gives a different non-capture plant for comparison purposes, the performance of these different non-capture plants is similar among the four IEA GHG studies, with thermal efficiency of the gas and coal plant within 1% accuracy. Specific capital costs for non-capture plant do vary more significantly, however, with 12% higher costs seen on the CCGT and 9% higher costs seen on the USCPF, in the oxy-combustion study (2005a). Using these higher capital costs would reduce the penalty seen for addition of CO_2 capture, so that use of the Fluor non-capture plant designs represents a conservative comparative analysis. Specific capital costs for an IGCC without capture are comparable to the USCPF without capture, with the Shell non-capture IGCC design varying only 3% from the USCPF non-capture base case shown in Table 3-5.

Table 3-4 Comparison of Gas Plant with CO_2 capture – Base Case

	CCGT Without Capture	**CCGT with post-combustion capture**		**CCGT with pre-combustion capture***		**CCGT with oxy-combustion**	
	Plant Data	Plant Data	Capture Penalty	Plant Data	Capture Penalty	Plant Data	Capture Penalty
Electricity Cost (US¢/kWh)	6.2	8.0	1.8	9.7	3.4	10.0	3.8
Cost of CO_2 avoidance (US$/t$CO_2$)	-	57.6	-	111.7	-	102.2	-
Capital Cost (US$ million)	390	570	180	820	430	670	280
Net Power Output (MWe)	776	662	114	694	82	440	336
Specific Capital Cost (US$/kW net)	499	869	370	1182	683	1532	1033
Thermal efficiency, LHV	55.6%	47.4%	8.2%	41.5%	14.1%	44.7%	10.9%
Technical Risk factor:	Low	Medium		Medium		High	

*CapEx scaled from retrofit results to take into account improved integration in new-build – see section 3.2.3

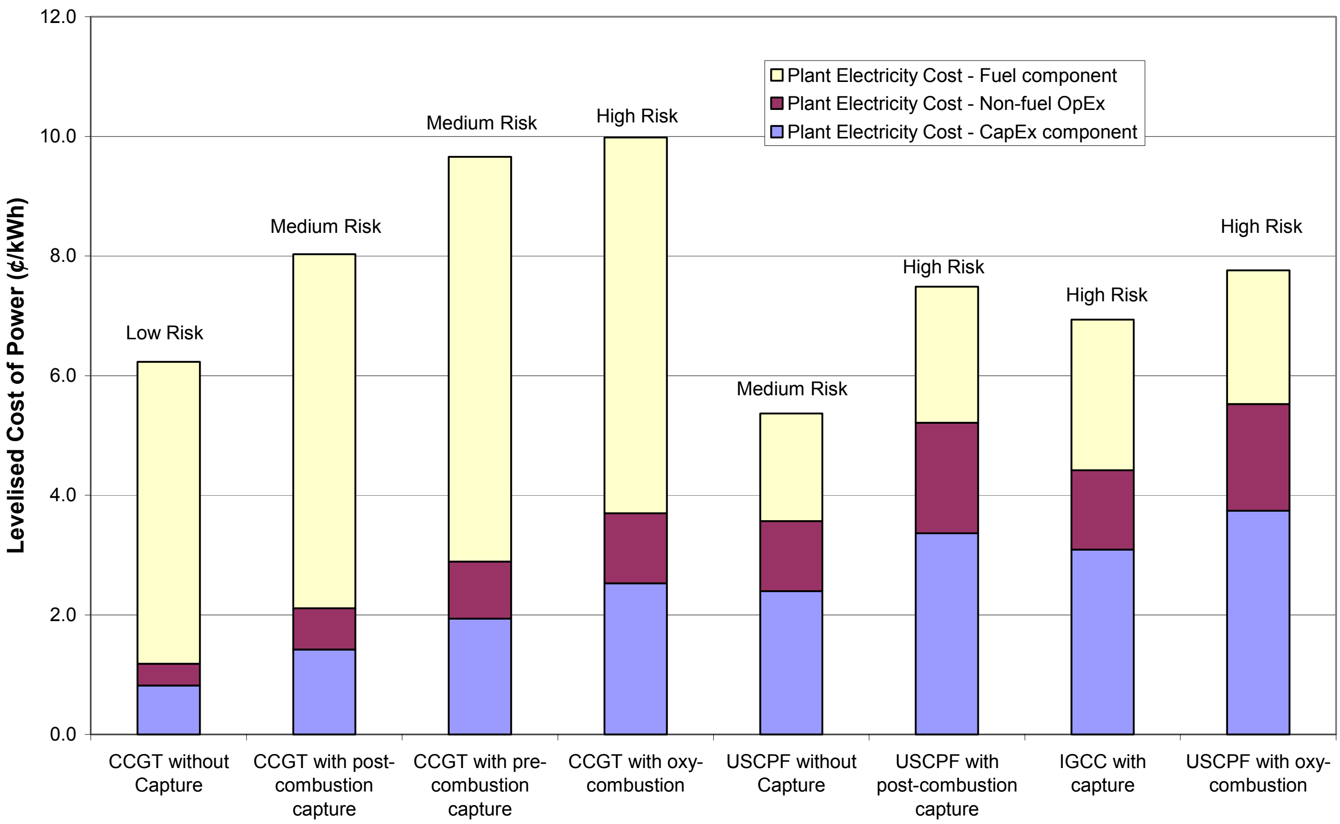
Table 3-5 Comparison of Coal Plant with CO_2 capture – Base Case

	USCPF Without Capture	**USCPF with post-combustion capture**		**IGCC with CO_2 capture**		**USCPF with oxy-combustion**	
	Plant Data	Plant Data	Capture Penalty	Plant Data	Capture Penalty	Plant Data	Capture Penalty
Electricity Cost (US¢/kWh)	5.4	7.5	2.1	6.9	1.6	7.8	2.4
Cost of CO_2 avoidance (US$/t$CO_2$)	-	33.9	-	26.6	-	36.3	-
Capital Cost (US$ million)	1070	1320	250	1330	260	1170	100
Net Power Output (MWe)	758	666	92	730	28	532	226
Specific Capital Cost (US$/kW net)	1408	1979	571	1815	407	2205	796
Thermal efficiency, LHV	44.0%	34.8%	9.2%	31.5%	12.5%	35.4%	8.6%
Technical Risk factor:	Medium	High		High		High	

Figure 3-1 below can be used to show the merit order of the different generation technologies considered in this report, using levelised cost of power under the standard IEA GHG assessment criteria. The four gas-fired plant are shown on the left and the four coal-fired plant on the right of the figure.

Fuel price can be seen to be a highly significant driver of costs of the gas-fired plants. For the CCGT without capture, fuel costs comprise 81% of the levelised cost of power. If gas prices were forecast at their level two years ago, say at the IEA GHG standard assessment criteria of US$ 3/GJ for a Netherlands coastal plant location, then the total levelised cost of power for a CCGT without capture would be US¢ 3.13/kWh. The rise in long-term gas price forecast has therefore increased the levelised cost of power for a CCGT without capture by 100%, to the US¢ 6.23/kWh shown in Figure 3-1 below.

Figure 3-1 Cost Comparison of Generation Plant with CO_2 capture – Base Case



The above power cost estimates include only capture and compression of CO_2 to 110 bar, but do not allow for any costs (or revenues) from transport and storage. As referred to in section 3.2.7, an illustrative transport and storage cost of US$ 10/tCO_2 would increase the cost of coal- and gas-fired electricity generation by US¢ 0.8/kWh and US¢ 0.4/kWh respectively. Figure 3-7 below shows the impact of transport costs on the financial return of each plant option.

Previous expert reviewers of the IEA GHG studies have suggested that the standard assessment criteria lead to an overestimate of annual non-fuel OpEx relative to total plant CapEx. Table 3-6 shows this OpEx to CapEx ratio for all eight plant options included in this study, together with the MM benchmark for conventional CCGT and PF Coal Plant of 500 MW capacity, for comparison purposes.

The IEA GHG (2004) non-capture plant results give an OpEx to CapEx ratio that is 10-20% greater than the MM benchmark, and is therefore considered an overestimate. For the capture plant options the OpEx to CapEx ratio is 12-36% higher than the benchmark, although this is considered reasonable given that chemical costs can be up to 3 times greater for fuel- or flue-gas scrubbing than for non-capture plant.

Table 3-6 Plant non-fuel OpEx relative to CapEx

	CCGT without capture		CCGT with post-combustion capture	CCGT with pre-combustion capture	CCGT with oxy-combustion
	MM benchmark	IEA GHG (2004)			
Ratio of annual non-fuel OpEx to total plant CapEx	4.7	5.2	5.8	5.8	5.7
	PF Plant - MM benchmark	**USPCF - IEA GHG (2004)**	**USCPF with post-combustion capture**	**IGCC with capture**	**USCPF with oxy-combustion**
Ratio of annual non-fuel OpEx to total plant CapEx	5.0	6.0	6.8	5.3	5.8

On balance, the IEA GHG standard assessment criteria are considered reasonable for comparative analysis of CO_2 capture plant options, although less so for cost comparison of these capture options with non-capture generation plant. Using the MM benchmark operating costs would reduce the levelised cost of power for the non-capture options by up to 2.2%, an uncertainty that is small in comparison with the broader sensitivities considered by this study.

It is interesting to note in Figure 3-1 that while USCPF is lower cost than a CCGT without CO_2 capture, as would be expected at current European fuel prices, IGCC with CO_2 capture also gives a levelised cost of power only 11% higher than that of CCGT without capture, under the standard assessment criteria. This finding should be qualified by the following considerations:

- The fact that IEA GHG standard assessment criteria apply a common load factor and percentage contingency cost to all plant, whereas the IGCC could reasonably be assumed to perform less well on these criteria than the CCGT, as a base case assumption.
- A substantially higher risk associated with IGCC than a gas-fired CCGT – requiring greater error margins on capital costs and availability, applied to the different base case assumption above. This uncertainty could also be represented within the absolute cost levels through addition of a risk premium, appropriate to the degree of risk aversion displayed by a particular investor.
- The relative lack of competition in the equipment supply market for gasifiers relative to CCGTs (see section 3.3.2(iii) below) leading to greater supply cost and reliability risk.
- The significant dependence of relative power cost on the assumptions made on fuel cost, as also shown by Figure 3-3 below.

- Transport and storage costs for CO_2 are higher per unit of energy generated for coal-fired plant, due to the higher volumes of CO_2 produced. This higher marginal cost is likely to be a particular constraint if transport and storage implies a net liability, which is the general case where the CO_2 stream is not employed for EOR. An indication of the effect of transport costs on plant financial performance is shown in Figure 3-7 below.

Another finding apparent from Figure 3-1 is that oxy-combustion is the least competitive capture approach on both cost and risk at the current time, for either coal- or gas-fired plant options respectively. A decrease of 50% in either of fuel cost or CapEx would still not bring these plants into competition with the USCPF and CCGT options respectively. On the basis of these results, pre- and post-combustion capture technologies can be expected to dominate the emerging CO_2 capture market in the short-term.

(i) Economic Sensitivity Results

The impacts on levelised cost of power for the different sensitivity cases, discussed in section 3.1.3, are shown in Table 3-7 and Table 3-8, for gas- and coal-fired plant options respectively. All power costs are given in units of US¢/kWh.

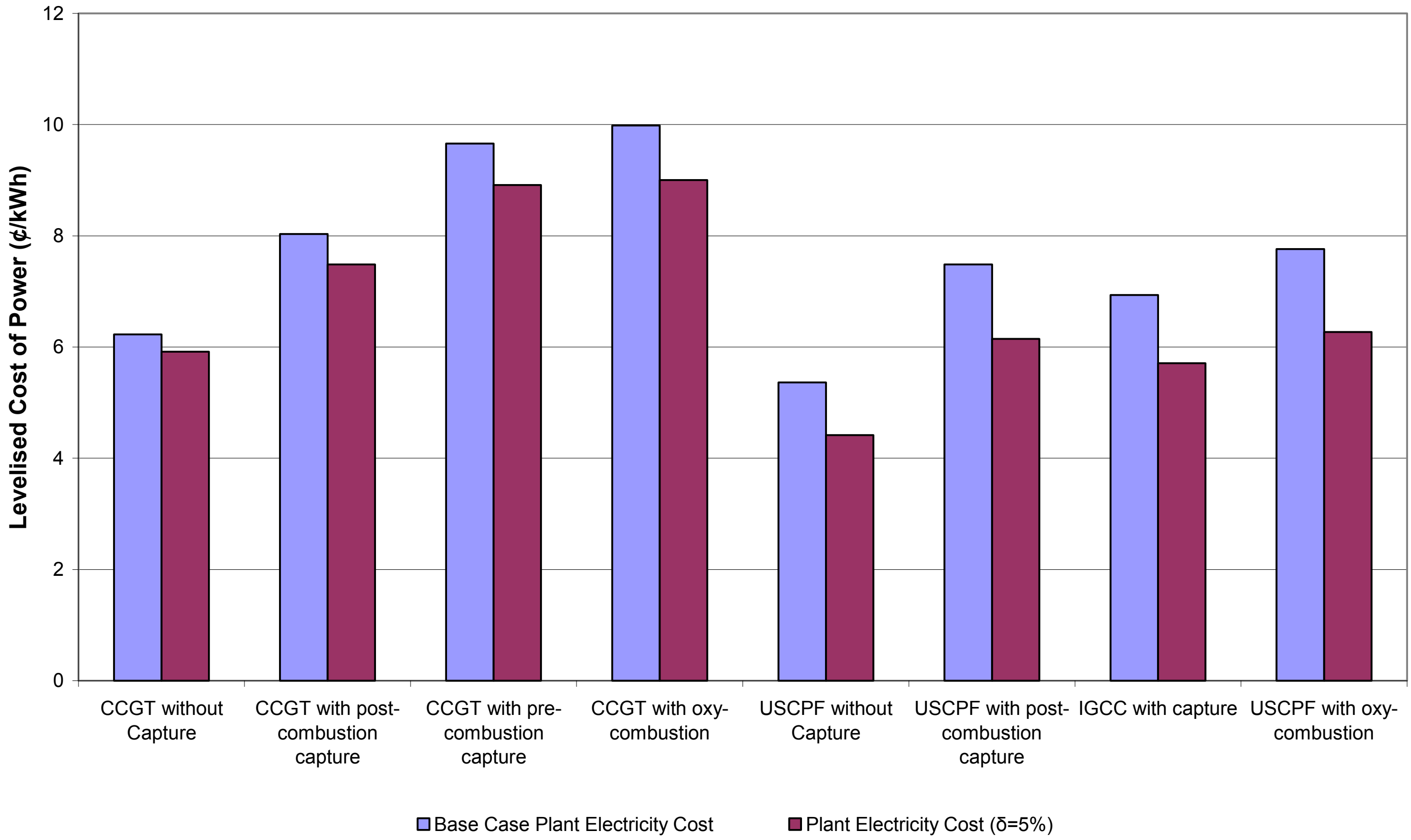
Table 3-7 Comparison of Gas Plant with CO_2 capture – Sensitivity Cases

Sensitivity Cases	CCGT Without Capture		CCGT with post-combustion capture		CCGT with pre-combustion capture*		CCGT with oxy-combustion	
	Cost of Power	Change vs. Base Case	Cost of Power	Change vs. Base Case	Cost of Power	Change vs. Base Case	Cost of Power	Change vs. Base Case
Low Discount Rate (δ=5%)	5.9	-5%	7.5	-7%	8.9	-8%	9.0	-10%
Low Fuel Price (fuel -50%)	3.7	-41%	5.1	-37%	6.3	-35%	6.8	-31%
High Fuel Price (fuel + 50%)	8.8	41%	11.0	37%	13.0	35%	13.1	31%
High Capital Cost (CapEx + 25%)	6.5	4%	8.4	5%	10.2	6%	11.2	12%
35% Load Factor	7.8	25%	10.7	33%	13.2	37%	14.4	44%
90% Load Factor on CCGT cases	6.2	-1%	7.9	-1%	9.5	-1%	9.8	-2%

Table 3-8 Comparison of Coal Plant with CO_2 capture – Sensitivity Cases

Sensitivity Cases	USCPF Without Capture		USCPF with post-combustion capture		IGCC		USCPF with oxy-combustion	
	Cost of Power	Change vs. Base Case	Cost of Power	Change vs. Base Case	Cost of Power	Change vs. Base Case	Cost of Power	Change vs. Base Case
Low Discount Rate (δ=5%)	4.4	-18%	6.1	-18%	5.7	-18%	6.3	-19%
Low Fuel Cost (fuel -50%)	4.5	-17%	6.3	-15%	5.7	-18%	6.6	-15%
High Fuel Cost (fuel + 50%)	6.3	17%	8.6	15%	8.2	18%	8.9	15%
High Capital Cost (CapEx + 25%)	6.0	13%	8.4	13%	7.2	3%	10.1	30%
35% Load Factor	9.7	80%	13.5	80%	12.4	78%	14.7	89%
80% Load Factor on USCPF and IGCC	5.6	4%	7.8	4%	7.2	4%	8.1	4%

Figure 3-2 Cost Comparison of Base Case Plant with Sensitivity – discount rate of 5%



The discount rate (δ) applied to cost and revenue cashflows in the economic analysis of the different options has a significant affect on plant economic performance. A reduction of 5 percentage points in the base case discount rate, reduces levelised cost of power by between 5% and 19%, as in Figure 3-2 above. A greater reduction in power cost is seen for the more capital intensive plant (where up-front costs are higher), so that using a 5% discount rate improves the performance of the high-CapEx coal-fired plant relative to the gas-fired plant. Public energy utilities, with discount rates close to the real yield on government-issued bonds, would therefore be relatively more likely to invest in coal-fired plant with CO_2 capture than their private sector counterparts, in particular project lenders, which attribute a higher time value to money.

Figure 3-3 Cost Comparison of Base Case Plant with Sensitivity – 50% lower fuel cost

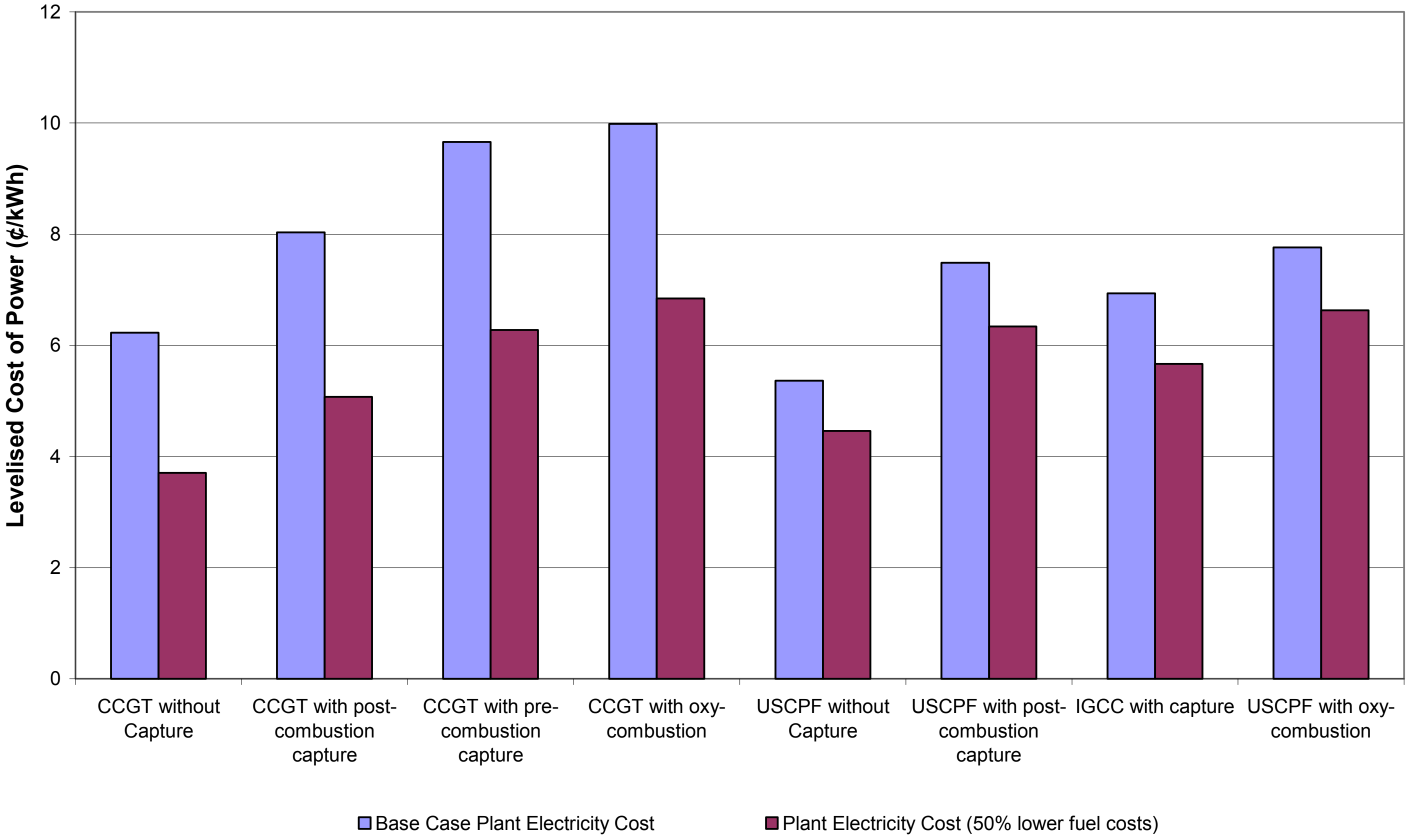


Figure 3-3 above shows the impact on the economic performance of each plant option from a 50% reduction in both coal and gas prices. This sensitivity case equates to a greater absolute reduction in the cost of gas, to US$ 3.9/GJ, than on coal, for which the delivered price reduces to US$ 1.1/GJ. This sensitivity is similar to a return to the fuel prices used in the IEA GHG studies, and as expected substantially improves the relative performance of gas-fired plant to coal-fired plant. Under this sensitivity a CCGT without capture is the lowest cost generation option, at 82% the cost of USCPF without capture. The CCGT with post-combustion capture also becomes the lowest cost plant option with CO_2 capture, at 10% lower than the IGCC, as opposed to 16% higher in the base case. Taking into account the relatively lower risk factors ascribed to gas-fired plant options, investors would have further reason to choose the CCGT with post-combustion capture as the most favourable overall new-build capture option at these fuel price levels.

Figure 3-4 Cost Comparison of Generation Options with changing fuel prices

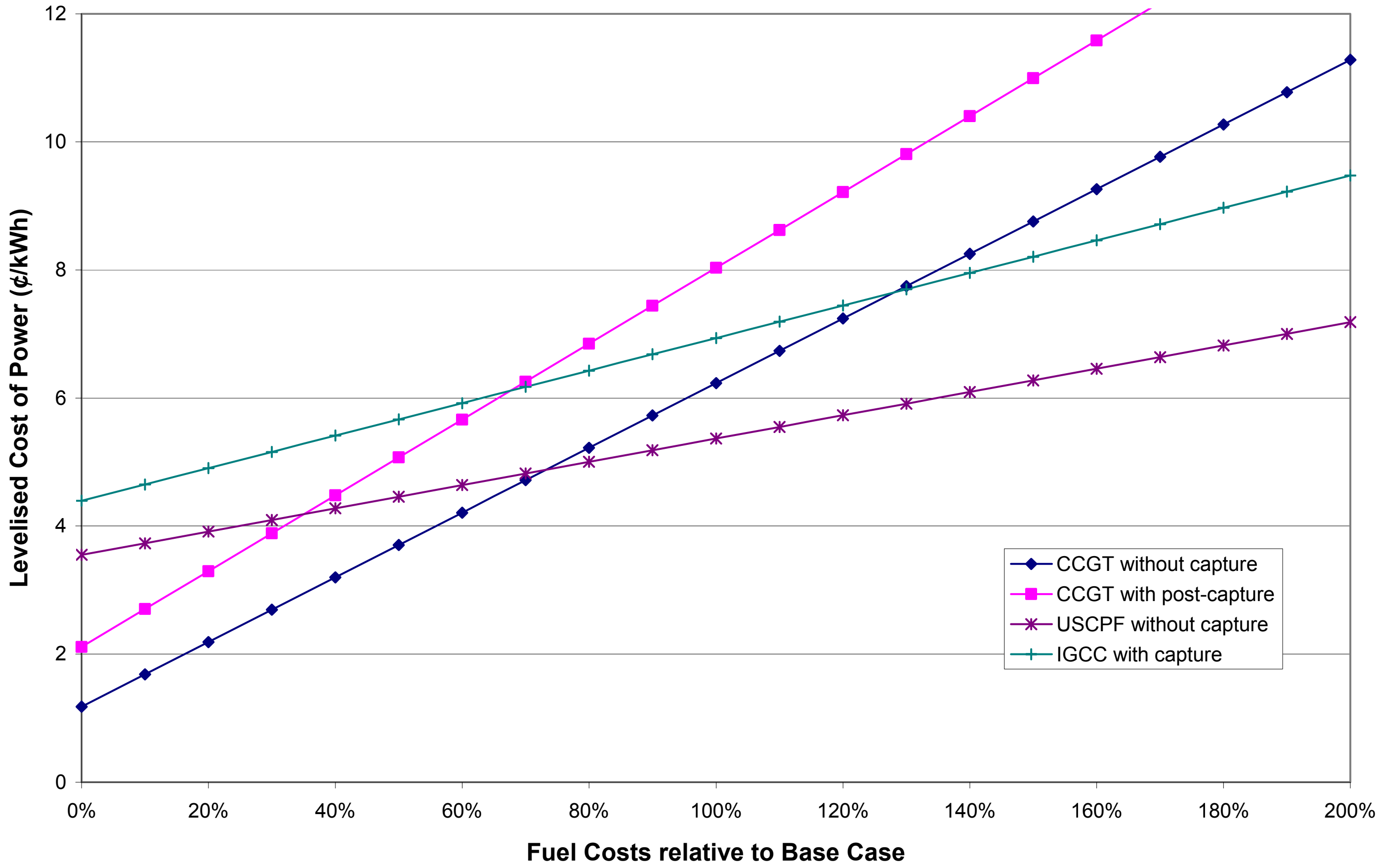


Figure 3-4 above is intended to highlight the continuous linear change in relative costs of generation using the two lowest-cost plant options from each of the gas- and coal-fired plant options, as fuel prices move away from the levels assumed in the base case. Delivered Gas and Coal prices are assumed to change in the same proportions.

In reality coal prices are not likely to be as volatile as gas prices, so that the coal plants are likely to have flatter profiles than shown above. For a given change in gas prices, Figure 3-4 nonetheless provides an indication of the anticipated changes in relative economic performance of CCGT and the leading coal plants. Comparing the relative favourability of investing in an IGCC with capture and a CCGT with post-combustion capture, on cost grounds alone, fuel costs would have to reduce to 68% of their forecast level for the CCGT with post-combustion capture to become more economic.

If coal prices are instead assumed to stay constant at the base case level of US$ 2.2/GJ, then the cost of gas would instead have to fall 18.5% from the base case level to US$ 6.35/GJ, for CCGT with post-combustion capture to become the more favourable option on cost grounds.

Figure 3-5 Cost Comparison of Base Case Plant with Sensitivity – 25% higher CapEx

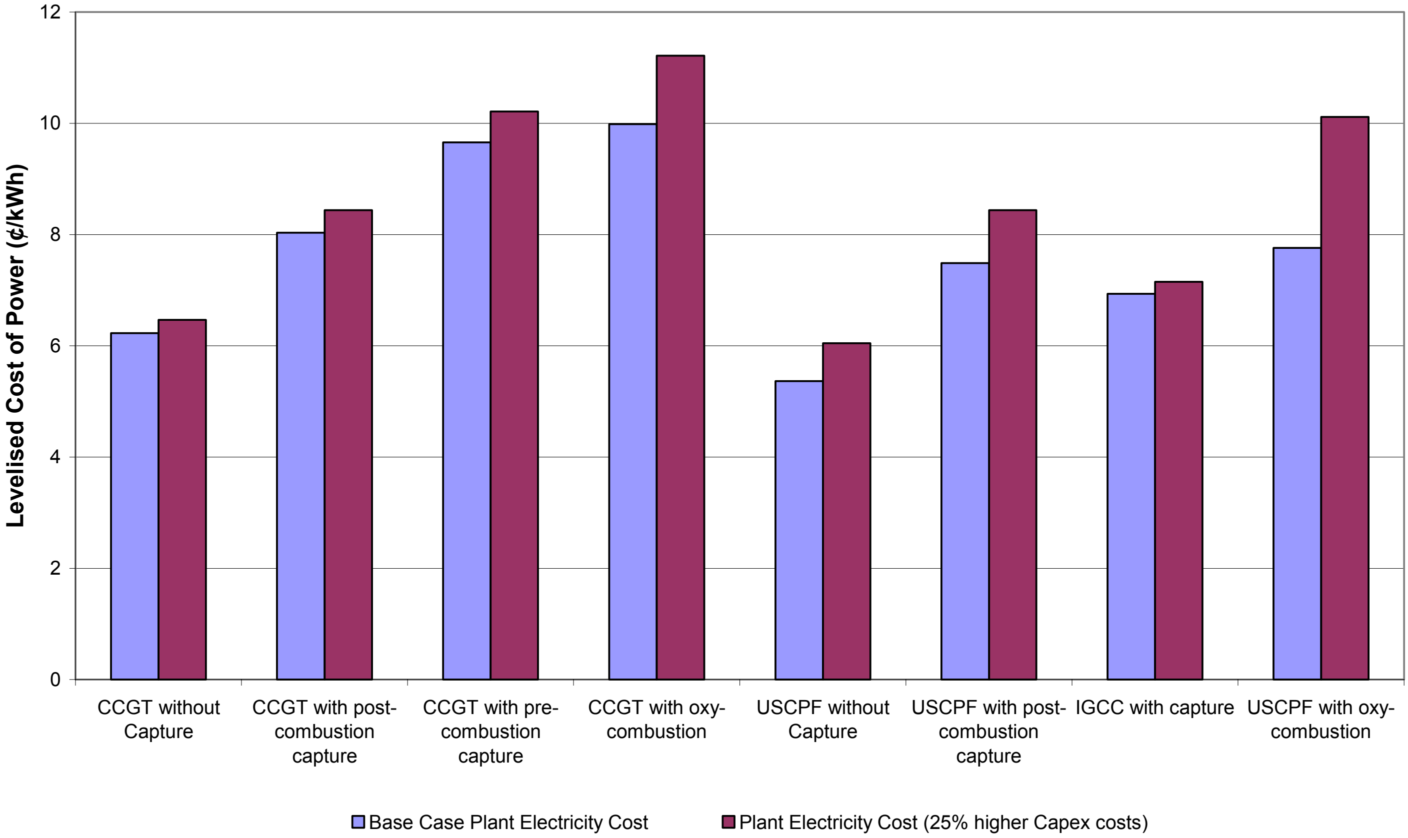


Figure 3-5 can be used to compare a 25% increase in the capital cost of any plant option with other base case results, for instance to compare a higher cost USCPF with post-combustion capture against a base case CCGT with post-combustion capture, to represent the higher risk-premium on the former option. Those annual operating costs that are stated in the standard assessment criteria to change as a multiple of CapEx, namely insurance and local taxes, also vary with this sensitivity.

A sensitivity to increase the capital cost of one or more plant can be used to represent any of the following issues raised in section 3.2 above, that imply an underestimation of plant CapEx:

- embedded optimism in supplier CapEx estimates for new-build capture plant
- likelihood of underestimation introduced by currency exchange issues, converting equipment quoted in Euros to US dollars without accounting for shifts in market prices with exchange rates
- increasing the cost of high-capacity plant to allow comparison with low-capacity plant on a level playing field, compensating for the greater economies of scale on the high-capacity option
- need for a risk premium to account for unproven technology, requiring further demonstration plant testing before commercial development

An intermediate CapEx sensitivity can readily be modelled using the base case and above sensitivity, as the relationship between CapEx and levelised cost of power is effectively linear.

Figure 3-6 Cost Comparison of Base Case Plant with Sensitivity – Load Factor of 35%

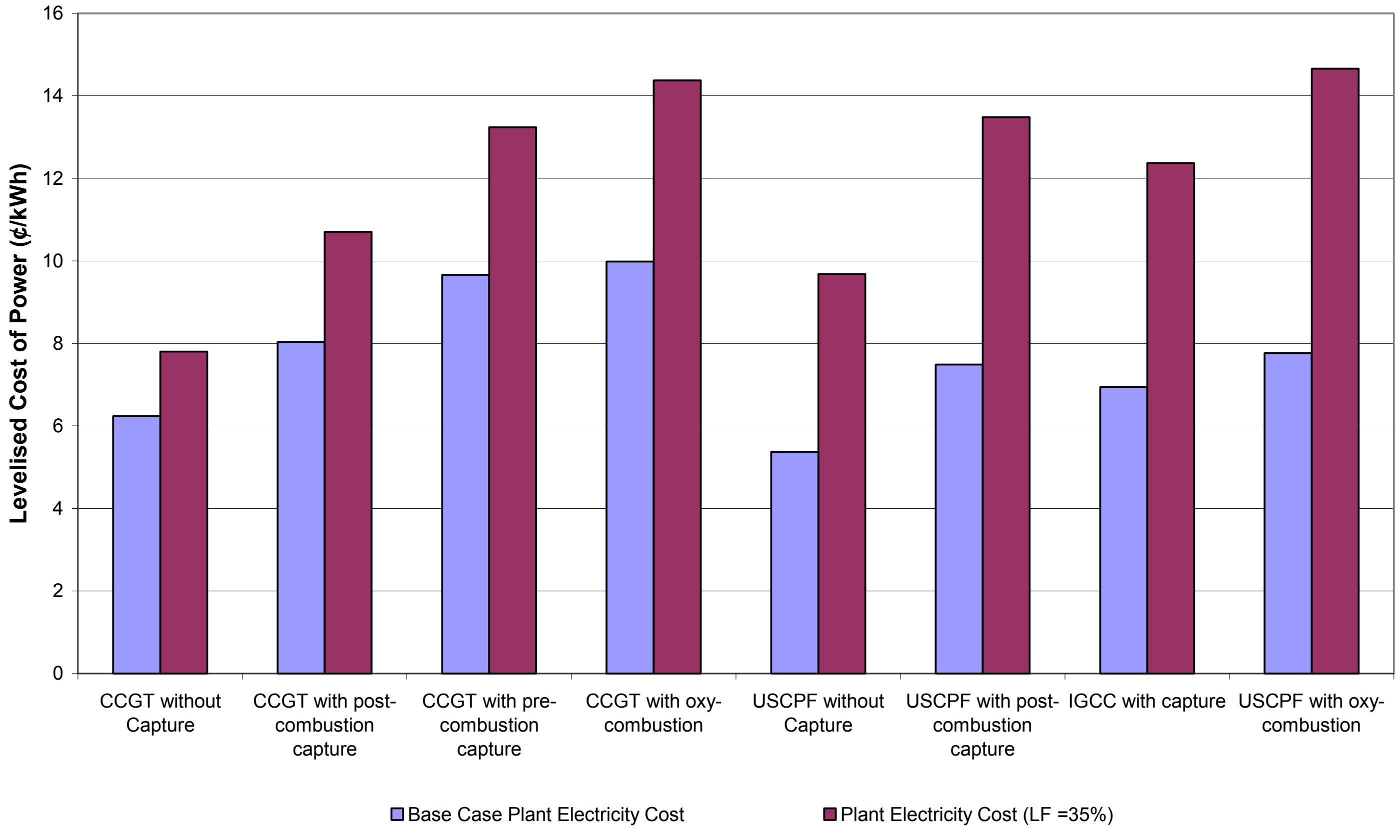


Figure 3-6 above shows the "Low Load Factor" sensitivity, equivalent to operation of CO_2 capture plant options only during weekday business hours at peak demand. This sensitivity explores the long-term possibility that other low-carbon generation technologies with low operating costs such as wind, and to a lesser extent nuclear, will be operated in preference to coal- and gas-fired plants with CO_2 capture. This sensitivity does not take account additional start costs or the suitability of the different capture plant options for rapid starts, which is discussed in section 3.3.3(iii). The pre-combustion capture options, notably IGCC, are likely to face particular constraints in flexible operation due to low response rates, although these plants could also operate only in hydrogen-production mode when not generating power. Generating hydrogen at partial load mitigates start-up costs to some extent, while if export opportunities exist for hydrogen as an energy source for heat, power or transport, the hydrogen production equipment can be operated at higher load factors than the power generation equipment.

The low load factor scenario increases average generation costs by 35% for the gas-fired plant options and by an average of 82% for the coal-fired plant options. The economic performance of gas-fired plant improves substantially relative to coal-fired plant, therefore. For the non-capture plant, the CCGT moves position in the merit order to become 24% more economic than the USCPF plant. For the capture plant, the CCGT with post-combustion capture becomes the most economic option, over IGCC with capture.

The second load factor sensitivity shown in Table 3-7 and Table 3-8 reduces the load factor on the coal-fired options by 10 percentage points relative to the gas-fired options, to represent anticipated differences in both planned and unplanned outages:

- greater planned maintenance requirements for solid fuel handling and processing equipment, even on proven coal-fired plant
- greater scope for unplanned outages on the coal-fired plant with CO_2 capture, which is generally judged to be higher risk technology than the gas-fired plant options.

The percentage changes implied by the above sensitivity case are small, and does not change the merit order on the plants analysed, but could be considered to provide a more realistic analysis of the relative economic performance of the plant options.

(ii) Financial Return

If the long run wholesale electricity price is assumed to equal the long run levelised cost of electricity for a CCGT without capture, plant options can be compared on financing criteria such as net present value (NPV) and internal rate of return (IRR). Financial performance of the plant options on this basis correlates strongly with their respective levelised costs of power. All those plant with levelised costs exceeding the non-capture CCGT option give a negative NPV if no provision for an additional commercial driver to reduce CO_2 emissions is included. This result would be on the basis that abated CO_2 emissions have zero value, which is unrealistic for contexts where generation plant with CO_2 capture are likely to receive serious commercial interest, such as Europe or Canada.

The analysis of financial return below therefore assumes that traded emissions credits have a positive value. For illustration, we assume a US\$ 37/tCO_2 (€ 30/tCO_2) credit value is assigned to abated emissions, consistent with widespread projections of long-run EUA prices during phases two and three of the EU ETS. It is also assumed for simplicity that the generator must pay the full value for their emissions allowances through an annual auctioning process. This is considered a more reasonable assumption than giving ongoing free allowance allocations to plants based on BAT (Best Available Technology) emissions, which would give a perverse incentive to build high-emissions plants and then generate revenue by capturing the emissions, a mechanism that is unlikely to receive EU approval.

The long run levelised cost of electricity for a CCGT without capture therefore changes for the purpose of this analysis to US¢ 7.63/kWh, which includes purchase of all necessary emissions allowances. Again taking this cost of generation with CCGT as the long run wholesale electricity price, Figure 3-7 below shows the NPV of the different plant options after purchase of credits/allowances for all emissions at US\$ 37/tCO_2.

Figure 3-7 also shows the impact of a US\$ 10/tCO_2 cost for transport and storage of CO_2 after capture, assuming that transport and storage is a net liability, on the financial return of the capture plant options.

Figure 3-8 provides an illustration of the impact of the carbon credit price, without consideration of transport and storage costs. The three series compare NPV at a zero credit price, a US\$ 37/tCO_2 (€ 30/tCO_2) credit price and a US\$ 74/tCO_2 (€ 60/tCO_2) credit price. For each series shown in Figure 3-8, the wholesale electricity price is assumed to equal the levelised cost of generation on CCGT plant, including the CO_2 liability, so that financial return is essentially relative to a CCGT without capture.

Figure 3-7 NPV of Capture Plant Investment Options, after purchase of CO_2 credits at \$37/t

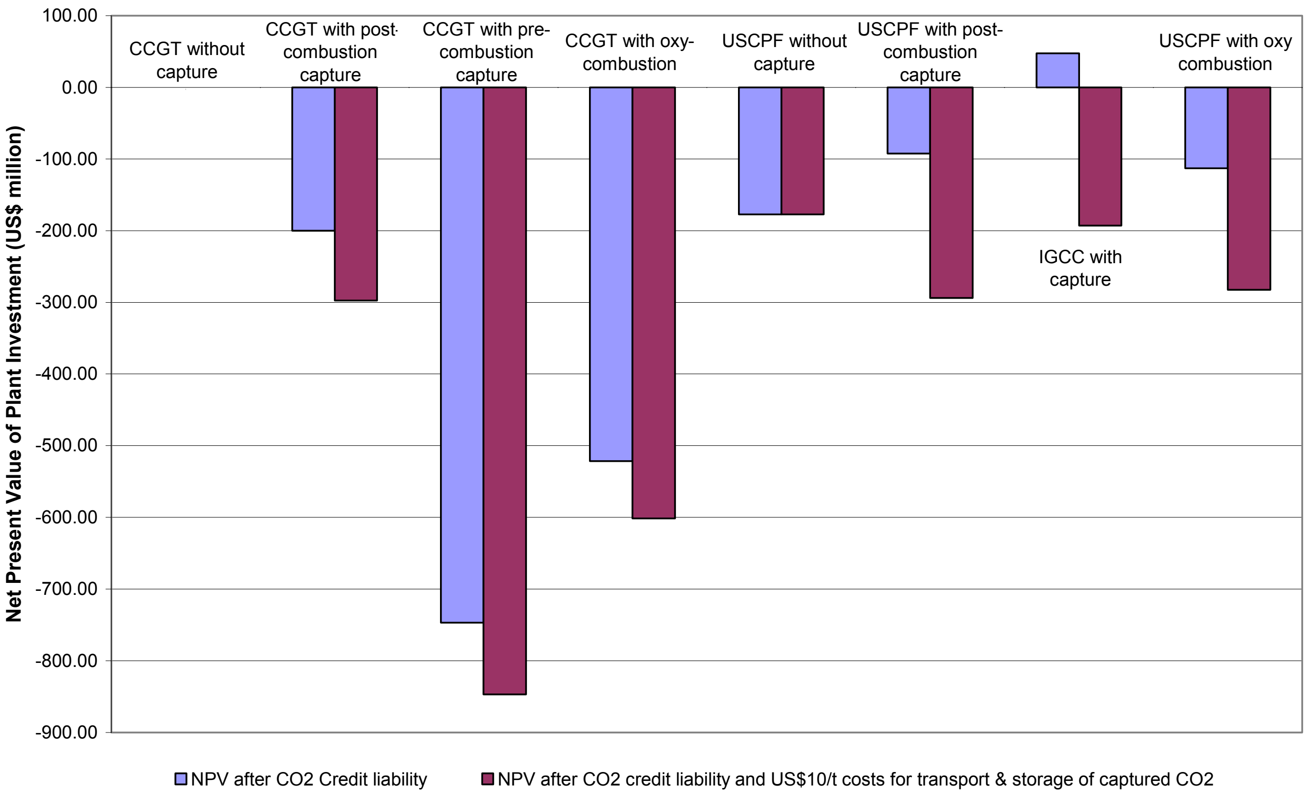


Figure 3-8 NPV of Capture Plant after purchase of CO_2 credits – impact of credit price

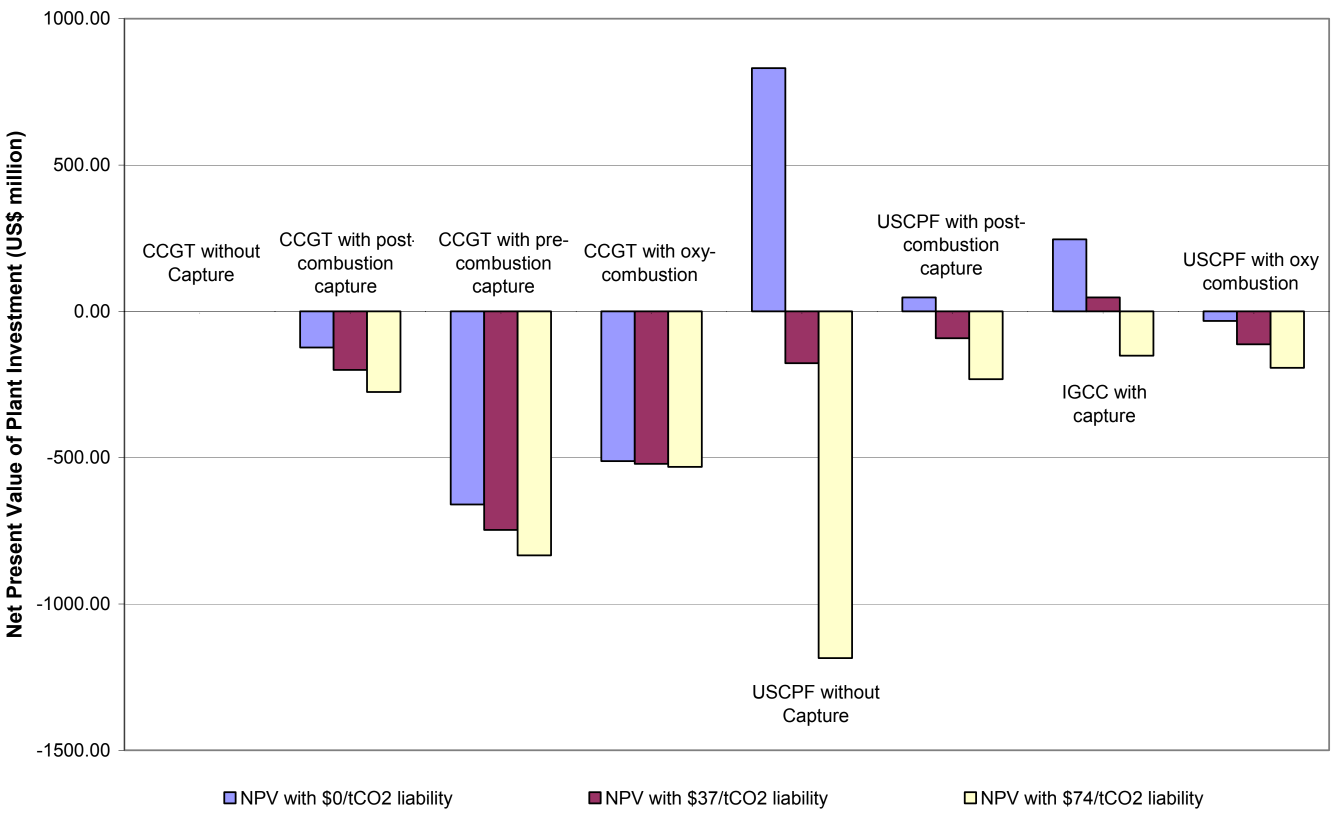


Figure 3-7 shows that the cost of transporting and storing CO_2 impacts around twice as much on the financial return of a coal-fired plant options with CO_2 capture plant than for the gas-fired capture plant options. Even with transport and storage costs, however, this analysis clearly identifies IGCC as the capture plant investment yielding the best financial return, although this conclusion is subject to the discussion given following Figure 3-1 above.

Similar to the analysis in Figure 3-8, the credit value necessary to bring the project NPV to zero for each plant option is shown in Table 3-9 below.

Table 3-9 Abatement Cost of CO_2 emissions relative to Plant without Capture

Cost relative to CCGT (US$/t$CO_2$)			Cost relative to USCPF (US$/t$CO_2$)		
CCGT with post-combustion capture	CCGT with pre-combustion capture	CCGT with oxy-combustion	USCPF with post-combustion capture	IGCC with capture	USCPF with oxy-combustion
57.6	111.7	102.2	33.9	26.6	36.3

The ability to Project Finance will be lender-driven combination of financial return, as outlined above, context-specific commercial risk, and technical risk, which is discussed in section 3.3.2(ii) below.

(iii) Access to Public Funds

As CO_2 capture technology is relatively new to the energy industry, there is very little specific legislation to subsidise CO_2 capture projects or provide other fiscal incentives to invest in this developing technology. There are however clear precedents for supporting low-carbon generation already in place, with the majority of Annex 1 parties to the Kyoto protocol (capped countries) supporting renewable technologies through subsidies and tax incentives to renewable energy projects. Direct fiscal support for renewables is complemented in several European countries (for example Germany) through guaranteed feed-in tariffs for the electricity produced by renewable energy and priority access to the grid, both measures that act to mitigate project development risk. There are a number of reasons to expect that CO_2 capture technologies will receive similar support from Annex 1 national governments within the next five years:

- Submissions in 2006 to include CCS as an approved methodology for CO_2 abatement under the Clean Development Mechanism

- Talks in May 2006 at an EU level on inclusion of CCS for CO_2 abatement in future phases of the EU Emissions Trading Scheme (ETS).

- International partnerships to promote cooperation on developing 'clean coal' technologies generally and CO_2 capture technologies specifically – such as the UK-Norway and UK-China commitments.

- Diversity of supply considerations, heightened by perceived insecurity of gas supplies from Russia, together with international and domestic commitments on CO_2 emissions attracting policy support for a range of 'clean coal' technologies, including IGCC with CO_2 capture.

- Ongoing controversy over the extent to which new-build nuclear power should play a role in the electricity generation mix of Annex 1 countries.

In addition, a number of countries currently offer grants on a project by project basis in the challenge to improve energy efficiency and reduce CO_2 emissions. In these instances, the government typically sets up a committee/program that is allotted a fund to spend on projects it deems offer a benefit to the energy challenge, ranging from research and development to raising public awareness. Examples of such programmes are the Community Energy Program in the UK (£50million over 5 years), the Market Incentive Program for Renewable Energy Sources in Canada, and the Climate Challenge Program in USA. These programs and similar examples elsewhere have the capability to provide funds to aid in the development of CO_2 capture projects, where costs at present are too high to make the project feasible on its own. Already in Norway in 2001, a grant was provided to an international CO_2 sequestration project. These *ad hoc* support measures do not provide a reliable level of support to specific technologies, however, and so cannot be relied on by companies when making investment decisions. Non-annex 1 countries, although offering nominal political support to projects have limited (if any) funds available to finance CO_2 capture projects, so that public funding rarely influences investment decisions in these countries.

In general, a project's access to public funding, where it exists in the regions surveyed, does not vary with the different CO_2 capture technology, as all technologies offer comparable reductions in CO_2 emissions. Although generation technologies with CO_2 capture have marginally greater potential to access funds than CCGT or coal plants, support is not on the same level as for renewables. The common consensus from the follow-up questionnaires and the interview responses was that access to public funds is one of the criteria considered least often when deciding on thermal plant investments. MM consider this response reflects the current lack of significant public funding available to CO_2 capture plant, and lack of clarity on the funding opportunities that do exist.

3.3.2 Plant Track-record

(i) Technological Obsolescence

Post-combustion capture technologies inevitably reduce the efficiency of the power plant, whether coal-fired or gas-fired. If, in addition, the capture system is a retrofit then there is a real risk that the remaining effective life of the plant will be too low to justify the costs involved, or even too low to 'survive' in operation until CO_2 infrastructure becomes available. CO_2 capture equipment installed in that case would prove to be technically obsolescent.

Such plants, with their reduced efficiency, are expected to be overtaken by newer, more efficient, and improved ways to generate power and to capture CO_2. Among the plant types to be considered should be ultra-supercritical (USC) coal combustion and coal gasification. Improved methods of CO_2 absorption, replacing either MEA (post-combustion) or Selexol, could also render obsolescent plants fitted with capture systems in the early phase of CCS development.

Specifically, the IEA GHG studies have identified a trend of developments relevant to post-combustion capture. These trends include potential reductions in capital cost, operating costs and parasitic loads for the capture process using amines (MEA or Selexol); and increases in overall plant efficiencies due to the adoption of higher operating temperatures (USC pf coal combustion; and supercritical steam cycles in CCGTs). These trends would make early-phase post-combustion plants unable to compete due to their inferior efficiencies, although there might be possibilities to retrofit improved solvents later in the plant life, depending on the relative scrubbing equipment properties designed for old and new solvents.

For natural gas fired plant, pre-combustion separation combined with development of new high efficiency gas turbine plants optimised for the hydrogen-rich fuel gas should be expected once the market for such turbines becomes clear. This will again leave early installations at a disadvantage.

Future shortages / price increases of natural gas might result in gas taking a rather smaller share of the power station fuel market than at present. If so, an option that is already being considered is the use of front-end gas producer units which convert coal to a gas suitable for the existing gas turbines.

Oxyfuel systems have been put forward as a retrofit option for existing plants, on a par with post-combustion capture. In the case of coal-firing, this might be possible – though the investment in process changes and in air separation would be substantial and unlikely to be justifiable for a plant of limited lifetime and already inferior efficiency. For CCGTs, it seems clear that oxyfuel retrofits are even less of an option since the gas turbine also would need to be replaced so as to be compatible with the CO_2-rich working fluid.

New plant builds incorporating oxyfuel should be expected to use state-of-the-art burners and mills developed specifically for the purpose. As 'new' designs, they might be superseded fairly rapidly by minor design improvements though this should not be a fundamental reason for obsolescence. Rather, the trends to higher overall plant efficiencies already mentioned for post-combustion capture would be the main risk.

For both coal-based pre-combustion capture (which uses oxygen-blown coal gasification) and oxyfuel systems for gas or coal, the air separation unit (ASU) is fundamental to the plant costs and performance. Differing levels of integration of the ASU within the overall power plant cycle are possible, with increasing efficiency though increased inflexibility/risk. IEA GHG have assumed minimum integration, in general, but this would probably be overtaken by more efficient designs once confidence had been gained from the initial plants, leaving the initial plants at a disadvantage. It is also already apparent that the ASU based on cryogenic separation processes may be replaced by membrane-based separators of lower cost and higher efficiency. Efforts should be made to bring the membrane designs to a state where they could be used in a practical large ASU.

Alternative forms of gasifier might be developed having advantages, especially of reduced capital cost, over existing designs. Fluidised bed systems, in particular, are mentioned in the IEA GHG studies (2003, p.686; 2006) and these may become available from a variety of suppliers, though "none are yet truly commercial". An interesting feature of most fluidised bed gasifiers is that they might be air-blown. This would clearly need a radical redesign of the pre-combustion capture system as a whole since the ASU would no longer be required; actual capture of CO_2 from the product gas fuel would have to allow for a substantial nitrogen dilution; and the gas turbine combustors would have to be designed for much lower heating value fuel. Technology development for the current pre-combustion capture components would then become obsolete, with important implications for investment decisions to be taken in the near future. However, it is not expected that significant improvements of efficiency or operating costs would result from fluidised bed-based systems - even though the reduction in first-costs would drive their introduction. Early phase CO_2 capture systems would therefore not be disadvantaged as far as day-to-day operation is concerned.

(ii) Proven Technology – Risk Level

For each technology, MM has qualitatively assessed the technology-based risk associated with developing a full-scale plant, based on the extent of new development required. This judgement of risk is intended to include the following uncertainties:

- Construction cost and time over-runs due to unanticipated technology problems
- Higher probability of unplanned outages due to unanticipated technology problems
- Delays in permitting and planning due to health and safety concerns

The risk factors assigned are shown in Table 3-4 and Table 3-5, as well is in Figure 3-1, replicated in the summary pages of this report. No low-risk coal-fired plant is shown – the established technology that would qualify for a low risk rating would be traditional PF coal, but this is not included in the generation technologies considered by this study. Supercritical PF plant, operating around 230 bar, would lie between the low risk conventional PF and the medium risk advanced or ultra supercritical plant options without CO_2 capture.

(iii) Manufacturers of Technology

CO_2 capture through solvent systems; oxyfuel-compatible boiler plant; and coal gasification are specialist fields, which do not yet show sufficient diversity of suppliers to promote effective market competition.

Provided that appropriate commercial drivers for CO_2 capture emerge, then competition can be expected to develop in the following markets:

- CO_2 absorption methods, which may well come to include a wider range of processes than the MEA and Selexol solvents, each of which is of very limited supply availability
- gasifier system suppliers, where some limited diversity of supplier and process already exists
- oxyfuel boiler supply, beyond the laboratory and pilot scale equipment tested so far

On the amine absorption processes, we note that Flour (IEA GHG, 2004) commented that "whilst in theory there are any number of chemical engineering companies" that could supply these systems, "in practice very few would be prepared or able to offer technology which has been adapted and proven for use in oxygen-containing flue gases".

We would conclude that the scope for equipment supply diversity exists but has not yet developed. Only by strong promotion and political drive for CCS will the necessary market drivers become sufficient to encourage multiple suppliers to enter the market. In this case, each of the capture technologies do also provide significant scope for technology transfer, through licensing of equipment to local manufacturers in different countries worldwide. Those plant options requiring GT units would typically be expected to have these manufactured by international companies, although with China and India continuing to have licensees manufacturing locally. For the capture-specific equipment on any plant option, however, only a limited number of specialist equipment items are expected to require manufacture internationally, in the same way as only high-pressure components in USCPF plant are typically sourced internationally, with all other components manufactured locally. Any such technology transfer would require a critical mass of demand for the technology, in turn stimulated by appropriate legislation to favour low-emission generation plant.

The subsections below provide further detail on the manufacturers currently active in each CO_2 capture technology, and the prospects for medium-term emergence of a competitive equipment supply market.

Post-combustion capture of CO_2 on natural gas and coal plant

The following equipment manufacturers are currently active in post-combustion CO_2 capture technology:

- Mitsubishi Heavy Industries (MHI)
- Fluor
- ABB
- AK Kvaerner

Each of the four equipment manufacturers are vertically integrated international companies, and the former three are major global players in the chemical or energy sectors. These companies have the capacity to act as both suppliers and operation and maintenance (O&M) contractors. The size and strong financial base of the companies involved helps to ensure the performance of the technology meets guarantees provided for construction and operation.

Our view is that sufficient diversity exists in the post-combustion CO_2 capture technology supply industry with these four players to ensure the competitiveness of the market, assuming no consolidation takes place.

At least three of the above companies have proven high efficiency solvent scrubbing processes. Mitsubishi has developed the KM-CDR Process (Kansai-Mitsubishi proprietary Carbon Dioxide Recovery Process) in conjunction with Kansai Electric Power Company. KM-CDR has six years operating experience for a plant in Malaysia, capturing CO_2 for fertiliser production. Fluor has long-term commercial operating expertise, with 20 years experience capturing CO_2 from high oxygen flue gas via their patented process. AK Kvaerner is currently developing a CO_2 capture plant in Norway. Although ABB have a long track-record with CO_2 capture from flue gases (see IES GHG, 2004, p.42), they have been less active in recent years and are not known to have operational experience with high-efficiency scrubbing processes.

Pre-combustion capture of CO_2 through reformation of natural gas

Each of the major oil companies (BP, Shell etc) is already experienced in reformation technologies, generating both hydrogen and CO_2 – with half of the world's industrial hydrogen demand currently produced via the reformation of natural gas. The great majority of world hydrogen supply is produced at oil refineries for use in refining and for the petrochemical manufacturing industry. No major development of the underlying steam reformation and auto-thermal reformation technologies is required to adapt these for use in pre-combustion reformation on power generation plant, capturing CO_2 ready for transport and storage, except for an increase in scale.

Other established manufacturers, in addition to the oil companies, include Linde, BOC, and KBR, a division of the Haliburton group. BOC have been operating in Europe for over a decade. KBR's autothermal reformer has been proven in commercial operation starting in 1994.

Competing reputable companies with international exposure and fiscal stability have already gained experience in the major aspects of the design, operation and maintenance of this technology, so that medium-term prospects of a competitive industry are promising.

Pre-combustion capture of CO_2 on IGCC plant

GE, Shell and the Dow Chemical Company (formerly Destec Energy) have the greatest recent experience in development of gasifiers for existing IGCC technology. Several other companies have also installed gasification plant, sometimes for IGCC on a regional level, and numerous research institutions are collaborating with the manufacturers to develop IGCC technology with CO_2 capture. IGCC technology itself is fairly established, with two decades of operating experience, at least one decade of which has been on a commercial basis.

Shell are the technology provider in the development of a 275 MWe IGCC plant with CO_2 capture in Queensland, Australia, together with Stanwell Corporation. The project plans to include sequestration of the captured CO_2 and, if successful, would be the first operational plant of its kind globally. The Great Plains Synfuels Plant, uses Sasol Lurgi coal gasification technology coal and transports CO_2 to the Weyburn oil field in Canada for EOR.

There are a number of internationally established companies with proven credibility involved in this technology, along with the extensive research at governmental and university level, which suggest that a competitive supplier market for gasifier plant is likely to emerge if the appropriate commercial drivers are present.

Oxy-Combustion

Oxy-combustion is the least mature of the leading CO_2 capture technologies for generation plant considered in the IEA GHG studies. As such, there is emerging interest from potential plant developers such as Air Products, Praxair, Vattenfall and Foster-Wheeler, but experience with the technology is currently only at a research level.

The currently weak economic case for oxy-combustion, discussed in section 3.3.1, has also been highlighted by ACCAT (Advisory Committee for Carbon Abatement Technology) which suggested that further investigation be suspended, due to prohibitively high costs for the ASU capacity required for oxy-combustion on utility scale generation plant.

There is therefore more limited competition in this field due to the unproven and potentially uneconomic technology. Should further development of this technology bring costs to a similar level to the other capture options, then the well-established consortium members are positioned to offer services within the European, North American and Asia Pacific regions.

3.3.3 Plant Logistics

(i) Build time

We note that the construction period for new power plants with CO_2 capture in previous IEA GHG studies has been standardised (so as to assist in comparisons) as 2.5 years for ‘500 MW’ gas-fired plants and 3 years for ‘500 MW’ coal-based plants.

While agreeing with this general distinction, specific plant options and combinations might be expected to differ depending on equipment design and supply availability. Conventional coal-fired plant require longer build times on average than 3 years, typically in the range 3-4 years. Trends to in-factory modular construction of equipment could reduce this uncertainty by minimising on-site erection times. This in turn will be another potential geographical factor, along with that of fuel supply and CO_2 disposal, in ensuring that delivery routes for major equipment are compatible with the large modules. For the present, we would expect that coal-based systems, with CO_2 removal, might exceed the 3-year timescale for construction.

The whole project cycle from concept, design, permitting (e.g. local acceptance), financial closure (allowing for technology risk), procurement, site assembly and plant testing will also be influenced by other factors which will make CO_2-capture plants have a significantly longer lead time than conventional power stations.

(ii) Modular Construction

A different concept of 'modular construction' is the production of standard size power station outputs (for example, IEA GHG's nominally '500 MW units) which can be pre-designed, fully-integrated (if required) and delivered wherever required. This method of power station procurement has worked well for CCGTs, because they are based on factory-assembled gas turbines of known capacities, albeit these capacities changed (increased) as newer technology was introduced successively. For coal-fired power stations the situation was becoming similar when (in the UK) coal stations were discontinued in the late 1980s. In this case, though, the standard unit was based on the steam turbine and specifically the technological limits on size of the last row turbine blades. The rest of the station, particularly the boiler and fuel handling, was not able to be standardised. These aspects vary significantly with coal specification, which argues against modular units. This continues to apply with the addition of CO_2 capture, by whatever method.

(iii) Flexibility of Operation

Investigation carried out by MM appears to show that the issue of operational flexibility, though acknowledged, is not thought to be of high importance to the feasibility of CO_2 capture at power plants. Indeed it is often stated that the chosen designs must ensure that plant operability and flexibility are not impaired. There are, however, certainly factors that need to be considered in retrofit or new-build CO_2 capture systems. These factors include:

<u>Pre-combustion capture and oxy-combustion using CCGTs</u>

- CO_2 capture can affect the ability and efficiency of operation at part-load, which therefore affects flexibility.
- Pre-combustion capture and oxyfuel systems both add a large amount of process equipment, which is certain to increase start-up times unless gas fuel storage is included.

- The gasification process for IGCC plant increases start-up times particularly severely, compared with a gas-fired CCGT, a factor which limits the flexibility of power plant operation. The possibility of low load factor modes (of 50% or less) implies daily start-up and shutdown, which might be incompatible with the thermal cycling limits of the gasifier unit. Options to either maintain the process temperatures at minimal load (with associated losses), or run at a constant load and utilise hydrogen gas storage, would need to be investigated for part-load operation scenarios.

- The air separation unit, used for the production of oxygen in both IGCC and Oxy-combustion systems, should be more amenable to cycling than the gasifier or reformer units used for the pre-combustion options, but could also be buffered by oxygen gas storage if necessary. Pressurised gas storage of hydrogen and oxygen will be capital intensive and would add safety concerns (siting restrictions); but would ensure that the fuel and oxidant supply processes do not affect the power plant flexibility. Pressurised gas storage facilities could be used to enable gas export, so that the gasifier, reformer or ASU could be operated at higher load factors than the power generation plant equipment, reducing the need for flexible operation of these former units.

- Oxyfuel firing of CCGT requires complex control systems since the composition of the gas turbine working fluid, though dominantly CO_2, varies during plant operation. There is also a large amount of stored energy in the gas recycle loop which would affect the responsiveness of the gas turbine, and require special vent design to avoid turbine overspeed events.

- Oxyfuel-fired CCGTs would ideally have the ability for hot restarts following a trip so as to minimise downtime. This would, however, pose problems due to relative thermal expansion of components.

- Additional equipment will lead to more planned and forced downtime.

<u>Oxy-combustion for gas- and coal-fired plants</u>

- For Advanced Supercritical Cycles using Oxyfuel, the degree of integration with the air separation plant will largely determine the effects on flexibility. The IEA GHG studies assume <u>no</u> integration, even though this leads to lower efficiency

- A basic premise for the IEA GHG study was that the design must have minimal impact on operability and flexibility, so ensuring that their chosen combination of equipment achieves this aim. Other valid process diagrams would have the disadvantage that flexibility might be compromised.

- Additional equipment will lead to more planned and forced downtime, though it is noted that the availability of the Air Separation Unit is quoted at 98-99%, so individually this item would have little influence on the total.

<u>Post-combustion capture for gas- and coal-fired plants</u>

Whereas for pre-combustion and oxy-combustion capture technologies there is scope to vary the degree of integration, such as through heat-exchange and gas recycle systems, this does not apply to post-combustion capture. Post-combustion capture does still affect flexibility of operation relative to a plant without capture, however:

- Post-combustion capture may itself affect flexibility due to limits on rates of change in temperature, as well as the initial warm up period until the process is operating at design efficiency.

- For systems using solvent, particularly post-combustion capture, there is a need for a reliable steam supply for regeneration. During start-up and shutdown, and also during disturbances during load changes, this would restrict operations. This problem could be avoided by including standby boiler plant kept in readiness at all times.

- The constraint on operational flexibility introduced by the steam and auxiliary power demand of the post-combustion capture equipment, including super-FGD, could be mitigated simply by by-passing the capture unit during times of peak power price. A partial measure that could also allow continued operation of the capture unit would be storage of CO_2-rich solvent during times of peak demand, lowering steam demand, and regenerating stored solvent in periods of low demand.

Generally, for all technologies, it also should be noted that plant optimised for operation without CO_2 capture would be of lower efficiency when capture is included. To a lesser extent this would still apply to purpose-designed capture-ready plants operated without capture pending CO_2 disposal infrastructure. This loss of efficiency would tend to reduce load factors (due to pricing merit order) so leading to more frequent load changes, making worse the effects of any flexibility restrictions.

One factor that could actually improve flexibility of operation is the use of once-through boilers and HRSGs, which are necessary for any super-critical or ultra super-critical designs. These types of boiler have a much faster response time than traditional drum boilers with water/steam natural or forced circulation as the thick-walled drum itself imposes limits on the rates of temperature change that can be allowed. This improved response from the boiler should, to some extent, mitigate the reduced responsiveness from other system components. It would apply to all the CO_2 capture options except for post-combustion or oxyfuel retrofits to existing sub-critical plants.

The start-up time of gasification systems is expected to be longer than that for conventional pf coal-fired systems. As mentioned above, this might restrict IGCCs with or without pre-combustion capture from the sort of daily cycling that has to be carried out by coal-fired plants currently. However, intermediate storage of hydrogen gas would largely decouple the fuel supply from the power plant operation and allow full flexibility.

(iv) Outage Requirements

As already mentioned above, all the technologies involve the addition of process equipment compared to plants without CO_2 capture:

Post-combustion capture

- extra flue gas clean-up of SO_2 and NOx
- solvent contact with the flue gases
- solvent regeneration
- CO_2 treatment/compression, and on-site storage if necessary

Oxyfuel

- air separation unit
- flue gas recycle system
- exhaust system for cooling, drying, and compression of gas
- separation of SO_2 and NOx from gas if necessary
- on-site storage if necessary

Pre-combustion capture

- coal gasification plant or natural gas reforming process
- shift reaction process
- air separation unit
- solvent contact with fuel gas
- solvent regeneration
- CO_2 treatment/compression, and on-site storage if necessary

Of these, post-combustion capture has the least impact on equipment inventory, followed by pre-combustion capture from natural gas; oxyfuel coal or gas turbine systems; and pre-combustion capture from coal. A qualitative indication of the probable effects (with rough suggestions for quantitative analysis) are included below:

It would be expected that forced outages of the additional equipment would be significant in the overall reliability of the power station. Coal gasification systems, in particular, have been found to be sensitive to coal properties and have had poor - but improving - reliability. A reliability penalty of, perhaps, 10% (i.e. extra 880 hours per year) might be expected compared to conventional coal combustion power plants without capture.

Gasifier components which are subject to improvement efforts to make them more reliable include:

- feed injectors, which currently have a life of 1 to 6 months, whereas a 12 month life is being sought
- high temperature thermocouples for temperature measurement which fail very frequently, giving a choice of either outages to replace or operation ‘blind’ with reduced process control / efficiency
- refractory linings of the gasifier which currently require replacement, during an extended outage, every 1 to 2 years. A 3-year life is being sought.

Mitigation of gasifier unreliability and outages can be achieved by using multiple small capacity trains, including standby units, though this would defeat one of the main methods of capital cost reduction through increased unit capacities.

Other than coal gasification (in the pre-combustion capture from coal) the other equipment should ideally be of lesser effect on reliability. However, in many cases it will involve significant scale-up from current experience, so the early examples would also incur forced outage penalties. At this stage, we would recommend that the same additional forced outages be assumed.

Planned outages for conventional power plants are timed to achieve essential periodic maintenance on turbines, furnaces and boilers; and would typically be of 2-4 weeks per year duration. Periodic maintenance of other equipment is carried out at the same time, but doesn't usually determine the outage duration.

For the additional equipment, this pattern should continue in general. The exception might be for the coal pre-combustion technology which could require a more extended annual outage and/or more than one planned outage per year. These planned outages would be in addition to potential for flow blockages from dust, which are included under forced outages. Suggested planned outages of two weeks extra duration should be included.

It is noted that all the IEA GHG comparisons use 'standard' load factors of 85%, including the effects of forced and planned outages. Experience on the current power plants is that solid-fuel firing is always associated with extra outages (for fuel handling and processing) compared to gas-fired plants such as CCGTs. There is as yet no clear reason to see this differential being removed in new coal- and gas-fired plants, with or without CO_2 capture. Therefore, we have suggested a sensitivity under which all coal-based options have a load factor of 80% and gas-based options achieve 90%, as better representing reasonable expectations. These fundamental differences apply to the base-plants without capture, and so are subject to adjustment in practise as discussed above for specific capture options.

(v) Availability of skilled O&M contractor

In the fledgling market for CO_2 capture technologies, it is expected that the equipment supplier will fulfil the role of O&M contractor, so that the relevant availability and competition issues are addressed through section 3.3.2(iii) above. As the market develops, local as well as international companies would be expected to enter the operation and maintenance contractor market.

3.3.4 Environmental Impacts and Permitting

(i) General Permitting Issues

Permitting for power plants with CO_2 capture technology will generally require consideration of location, noise, emissions and visual impact, among other potential impacts, addressed through the Environmental Impact Assessment (EIA), in the same way as for thermal plant without CO_2 capture. CO_2 capture plant would have to fulfil greater health and safety requirements due to handling of pressurised O_2, H_2 and CO_2 gases in the different plant options. Emissions and health & safety are specifically discussed in subsections (iii), (iv) and (x) below. Visual impact and noise are highly specific to the location and national legislation in force, and are not further considered in this report.

The main practical difference associated with CO_2 capture plant will be the requirement to verify the volume of CO_2 that has been captured in countries where CO_2 emissions are controlled, rather than simply monitoring the CO_2 emissions implied by the fuel consumed. An independent verifier/accredited body would be expected to assess the volume of CO_2 generated and captured to evaluate the level relative to mass limits permitted, for example under the EU ETS extending the current monitoring and verification of 'installations' to include the CO_2 capture plant equipment. The costs for such monitoring and verification would be expected to be small, both in comparison with capture costs and with potential revenue from sale of emissions allowances in CO_2 trading systems.

Additional, potentially more significant, permitting issues relate to the transport and storage of CO_2. A well documented concern is over the leakage of CO_2, particularly during transport. Although CO_2 is not flammable or particularly toxic, large scale releases can be a hazard because the dense gas tends to remain at ground level, which can cause suffocation. As a result of this health hazard the location of the pipeline network is an important consideration in the permitting process because it is undesirable to locate the network near a residential community. For transport, the risks associated with leakage (and pressure regulation) are considered minor, however, as pipeline technology has been well proven through use for transporting hydrocarbons. Although public opinion will play a role (see subsection (ix) below), on technological grounds the transport of CO_2 is not seen as a significant barrier to CCS permitting.

Storage of CO_2 is not within the scope of this report, but should nonetheless be mentioned with respect to permitting arrangements due to the attention this subject received from survey respondents. The different storage options have been discussed in section 3.2.7, which highlights that certain options require further demonstration before they are likely to be considered proven safe, while others such as EOR are already in use, and would not require proving from a technological perspective. Few countries have specifically developed legal or regulatory frameworks for long-term CO_2 storage, however it is understood that the environmental risks associated with storage would be comparable to the risks of current activities such as natural gas storage, EOR and deep underground disposal of acid gas. Whether permitting arrangements in different countries would reflect this relative lack of new risks is far from certain, however.

General permitting issues play a highly significant role in all surveyed organisations' decision making processes, across all regions. Almost 50% of companies interviewed volunteered that they considered it a key factor and the majority questionnaire response was that permitting is 'nearly always' considered when deciding on investments. This view on permitting applies to all thermal generation plant, including CO_2 capture projects, although not obviously to CO_2 capture projects in particular, as it is generally believed that the same essential issues need to be addressed.

Each of the CO_2 capture technologies were rated by survey respondents as being 'better' than coal for the permitting process but 'worse' than CCGT power plants. Our view based on the interview responses is that respondents assign this difference in technology rating due to a belief in the 'proven technology' status of CCGTs, which are seen as easier to permit due to widespread understanding of the technology and lower CO_2 emissions than coal-fired plant. Although PF coal is also a well proven technology, respondents believe that issues of air quality and CO_2 emissions increase permitting obstacles for conventional coal-fired plant relative to CO_2 capture technologies.

Among the CO_2 capture technologies, oxy-combustion was considered the most difficult to permit and pre-combustion CO_2 removal by reformation of natural gas the easiest. Since oxy-combustion produces no flue gas emissions in normal operation, our view is the poor rating of this technology with respect to permitting stems more from the lack of knowledge surrounding this technology from the sample as a whole. The fact that the technology is the least proven of those discussed in this report, as discussed in section 2.5.2, would therefore mean that it attracts a risk premium in the rankings, due to concern with unknown risks.

(ii) Land Footprint

IEA GHG (2005) provides an approximate site layout and land footprint for a CCGT without capture, and for the capture-specific additions to IGCC, pre-combustion reformation and post-combustion plant. Table 3-10 below combines the IEA GHG report findings with MM experience to estimate the minimum footprint of each CO_2 capture plant, assuming net plant capacities of around 500 MW. The relative areas of plants with and without CO_2 capture do not take into account the fact that the net power output is reduced when capture is added.

Table 3-10 Approximate Minimum Land Footprint of CO_2 Capture Plant

<table>
<tr><th></th><th>CCGT with post-combustion capture</th><th>CCGT with pre-combustion capture</th><th>CCGT with oxy-combustion</th><th>USCPF with post-combustion capture</th><th>IGCC with capture</th><th>USCPF with oxy-combustion</th></tr>
<tr><td>Site dimensions – generation equipment (m)</td><td>170 x 140</td><td>170 x 140</td><td>170 x 140</td><td>400 x 400</td><td rowspan="2">475 x 375</td><td>400 x 400</td></tr>
<tr><td>Site dimensions – CO2 capture equipment (m)</td><td>250 x 150</td><td>175 x 150</td><td>80 x 120</td><td>125 x 75</td><td>80 x 120</td></tr>
<tr><td>Capture Plant Site footprint (metres square)</td><td>62,000</td><td>50,000</td><td>34,000</td><td>170,000</td><td>180,000</td><td>170,000</td></tr>
</table>

By comparison, a CCGT without capture would be expected to have a minimum footprint of around 24,000 square metres (170m x 140m) and a USCPF without capture of around 160,000 (400m x 400m). The site space quoted for the coal-fired plant includes fuel storage and handling, but not ash lagoons.

Clearly the importance of land footprint is more critical for retrofit of capture to an existing plant, which may have constraints on available space, than to new-build capture plant.

(iii) Carbon Footprint

Each of the plant options with CO_2 capture presented in this report clearly acts to reduce the CO_2 emissions to atmosphere from combustion of gas and coal in power generation. Table 3-11 shows the absolute level of emissions during normal operation for each plant option, and compares these emissions for the plant options with CO_2 capture to the CCGT and USCPF plant without capture.

Table 3-11 Plant CO_2 emissions relative to power generation without Capture

	CCGT without capture	CCGT with post-combustion capture	CCGT with pre-combustion capture	CCGT with oxy-combustion
CO_2 emissions (g/kWh)	379	66	72	12
CO_2 Emissions relative to CCGT	-	17.4%	19.0%	3.2%
	USCPF without capture	**USCPF with post-combustion capture**	**IGCC with capture**	**USCPF with oxy-combustion**
CO_2 emissions (g/kWh)	743	117	152	84
CO_2 Emissions relative to USCPF	-	15.7%	20.5%	11.3%
CO_2 Emissions relative to equivalent gas-fired plant technology above	1.96	1.77	2.11	7.0

It can be seen from Table 3-11 that CO_2 emissions are approximately double for coal-fired plant compared with gas-fired plant, for each pair of plant using pre-combustion capture, post-combustion capture and without capture. This ratio of CO_2 emissions for each technology reflects two factors:

- the chemical composition of coal and gas, with gas containing approximately 70% the mass of carbon per unit of net calorific value
- the higher thermal efficiency of gas-fired than coal-fired plant, with the coal-fired plant options giving an average thermal efficiency of 76% the equivalent gas-fired options (see Table 3-4 and Table 3-5 above).

For coal-fired oxy-combustion CO_2 emissions are instead around seven times the level of gas-fired oxy-combustion, due to specific nature of the capture technology. Given the relatively low level of absolute CO_2 emissions, the relative emissions of coal-fired and gas-fired plant are also likely to be within the margin of error on plant design. The CO_2 emissions remaining from the pre- and post-combustion capture plants reflect the recovery rate of the solvent scrubbing processes used to separate CO_2 from the fuel and flue gas streams, respectively. None of the plant options would result in significant emissions of other greenhouse gases during normal operation.

In addition to the CO_2 emissions during plant operation, the construction phase will imply potentially significant GHG emissions, due to construction traffic and construction site operations. No information on the relative merits of construction impact of the different plant options is available, although the coal-fired plant generally uses more bulky equipment, requiring more extensive site operations during construction, and hence would generate a larger carbon footprint during this stage.

(iv) Air Quality Impacts

In addition to CO_2 emissions, the combustion of both natural gas and coal give rise to emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_X), and carbon monoxide (CO). SO_2 emissions depend on the sulphur content of the fuel, and are generally a significant issue only for coal. The specification for the Australian bituminous coal grade assumed by this study gives a sulphur content of 1.1% (IEA GHG, 2004, p.33). Combustion of coal also gives rise to particulate matter (PM).

The plant options with and without CO_2 capture have been designed assuming legislation to limit emissions to 25 mg/Nm^3 for PM, 200 mg/Nm^3 for NO_X and 200 mg/Nm^3 for SO_X. A comparison of the emissions to atmosphere from each of the plant options is given in Table 3-12 below, summarised from the information available in the IEA GHG studies.

Table 3-12 Air Quality Impacts of CO_2 Capture Plant

	CCGT without capture	CCGT with post-combustion capture	CCGT with pre-combustion capture	USCPF without capture	USCPF with post-combustion capture	IGCC with capture
Oxygen Content of dry gas at measurement		15%			6%	10%
NO_2 (mg/Nm^3)	< 20	< 20	-		< 20	-
NO_X (mg/Nm^3)	-	-	-	200	-	50
SO_2 (mg/Nm^3)	0.5	0	-	200	10[1]	0.7
CO (mg/Nm^3)	-	-	-	-	-	31
PM (mg/Nm^3)	0	0	-	0[2]	0	4.3

1. This result is given in IEA GHG (2004, p. 79). In practice SO_2 emissions for post-combustion capture are expected to be <1 mg/Nm^3, since remaining SO_2 after desulphurisation would react with the MEA during CO_2 scrubbing.

2. This result is also given in IEA GHG (2004, p. 79). For USPCF without capture, at least 10 mg/Nm^3 of particulate emissions would normally be expected after electrostatic precipitation (ESP).

The oxy-combustion plant options are not included in Table 3-12, since there are no significant emissions to atmosphere during normal operation, except nitrogen from the ASU. Where a cell in the above table is left blank, this implies that no information was presented in the IEA GHG studies.

The USPCF plant without capture in Table 3-12 is taken from IEA GHG (2004) and is assumed to meet legislative emissions limits. By contrast the USCPF plant designs presented in IEA GHG (2003) instead give NO_X emissions of 5-10 mg/Nm^3 and SO_X emissions of 50-80 mg/Nm^3, however. Emissions of NO_X and SO_X are significantly below the assumed legislative limits for all other plants.

Transport emissions during operation are generally small compared with products from the fuel combustion process, as discussed in subsection (viii) below. In addition to emissions during plant operation, the design and construction phases will imply a potentially significant impact on local air quality, due to construction traffic and construction site operations. No information on the relative merits of construction impact of the different plant options is available, and would in any case be highly site specific, depending on the proximity of sensitive receptors.

A power plant development would generally manage their emissions to atmosphere through an Environmental Management and Monitoring Plan (EMMP). The EMMP aims to ensure integration and implementation of all environmental management commitments, conditions and statutory requirements that the development must observe. The EMMP relates to each of the design, construction and operational phases of the development.

(v) Raw Material Demand

Raw material and feedstock demand for the plant options, in addition to fuel, include water (see (vi) below), water additives, flue gas scrubbing material and catalysts. The information on consumption of the main chemicals and consumables that is given in the IEA GHG studies for the plant with CO_2 capture is summarised in Table 3-13, with a blank cell indicating no available information.

Table 3-13 Chemicals and Consumables – Comparison of CO_2 Capture Plant

	CCGT with post-combustion capture	CCGT with pre-combustion reformation	CCGT with oxy-combustion	USCPF with post-combustion capture	IGCC with CO_2 Capture	USCPF with oxy-combustion
Net Power Output (MWe)	662	694	440	666	730	532
Make-up Water (t/h)	135	-	-	238	315	-
Limestone (t/h)	0	0	0	7.73	0	0
Ammonia (t/h)	0	0	0	0.465	0	0
MEA Solvent (t/h)*	0.33	-	0	0.67	0	0
Selexol Solvent (kg/h)	0	-	0	0	16.8	0
Miscellaneous Consumables noted in study	Activated carbon, soda ash, amine inhibitors	$DeNO_X$ catalyst	-	$DeNO_X$ catalyst, activated carbon, soda ash, amine inhibitors	Claus catalyst, hydrogenation catalyst, sour shift catalyst, sodium hydroxide, and hydrogen chloride	-

* Using MEA consumption of 1.6kg/tCO_2 (IEA GHG, 2004), emissions in Table 3-11 and given plant capacities

The IEA GHG studies note different plant configurations and degree of capture integration that can affect the resource consumption levels noted above. A specific discussion of these measures has not been included in this study, as this did not appear a priority in the responses to the investor survey.

(vi) Water Demand

For each of the plant options, the IEA GHG studies assume a coastal location in the Netherlands, so that each plant would be expected to use seawater for cooling purposes, in an open cooling system. In addition, the plant would be expected to draw fresh water from the urban water network, for make-up of the sealed cooling system. Other minor water demands would include wash down water for the plant and potable water for use by on-site personnel. Where make-up water demand is given in the plant studies, this is shown in Table 3-13.

Discharge of used water would either be back to the sea or to the local foul sewer system, for disposal of domestic waste water.

The nature of water demand and requirement for on-site treatment will vary significantly with plant location, including ambient temperature for the cooling circuit, and proximity to the residential freshwater and wastewater networks.

(vii) By-product Disposal

The different plant options produce varied amounts of waste and by-products, with all plants producing at least wastewater and hazardous reagents requiring controlled disposal. The coal-fired plant options additionally produce significant quantities of solid residue, typically around 10% of the original bituminous coal mass. This solid waste requires either disposal or use, generally implying either storage on (or near) site in ash lagoons, or sale to the construction and building materials industries for use as aggregate.

If the coal plant includes FGD, the resulting gypsum is another significant solid by-product, which can also be sold for use in construction materials, such as plasterboard.

A chloride purge is required for all coal-fired plant options, and needs to be disposed of with appropriate care following local environmental guidelines and regulation.

For the gas- and coal-fired plant using post-combustion CO_2 capture, chemical waste from the amine unit is a further significant waste steam.

Table 3-14 below summarises the main by-products and waste resulting from each CO_2 capture option, using the information available in the IEA GHG studies, with a blank cell indicating no available information.

Table 3-14 By-product Disposal – Comparison of CO_2 Capture Plant

	CCGT with post-combustion capture	CCGT with pre-combustion reformation	CCGT with oxy-combustion	USCPF with post-combustion capture	IGCC with CO_2 Capture*	USCPF with oxy-combustion
Net Power Output (MWe)	662	694	440	666	730	532
Bottom Ash / Course Slag (t/h)	0	0	0	8.1	76.3	6.4
Filter Cake / Fine Slag (t/h)	0	0	0	0	31.8	0
Fly Ash (t/h)	0	0	0	24	0	19.1
Sulphur (t/h)	0	0	0	0	2.15	-
Mill rejects (t/h)	0	0	0	0.5	-	-
Gypsum (t/h)	0	0	0	14.1	0	0
Chloride** (t/h)	0	0	0	0.61	-	-
Amine unit waste (t/h)	0.79	-	0	1.75	-	0
Wastewater (t/h)	135	-	-	238	131	-

* The mass flowrate for IGCC slag includes 50-70% water content, as quoted in IEA GHG (2003)

** Although data is not available, the IGCC and USCPF with oxy-combustion would produce chloride wastes

The potential for revenue from sale of those by-products where an active market exists, such as slag, ash and sulphur, is discussed in section 3.3.5(iii) below. The high slag output of the IGCC primarily reflects both the high water content of the slag (50-70%) included in the mass flowrate data in IEA GHG (2003) as well as a 10-30% higher capacity plant design than the other coal-fired capture plant options.

(viii) Traffic impacts

Traffic impacts of power generation plant include delivery of construction materials and plant equipment during the construction phase, and during operation the movement of station staff and delivery or removal of solid fuel, chemicals and waste by truck or rail.

Generation plant with CO_2 capture requires the installation of additional equipment compared to the plant options without capture. Traffic impacts of installing CO_2 capture are therefore likely to be greater during construction, particularly for the more capital intensive coal-fired plant options.

In terms of traffic impacts during construction, fuel delivery is the major factor and this impact is therefore most relevant to the coal-fired plant options. Comparing the USCPF plant without capture to each of the coal-fired plant with CO_2 capture, the increase in auxiliary loads required by the capture equipment decreases the net efficiency of the plant. For a capture plant of equivalent net capacity to a non-capture coal-fired plant, therefore, a greater mass of fuel would be delivered, increasing total traffic flows.

The impacts of increased traffic flows could include degradation of local air quality, road congestion, increased noise and vibration. The significance of these impacts will be highly site-specific, depending on the local road and road-bridge network, residential density and proximity of other sensitive receptors. These site-specific impacts, as well as CO_2 emissions from increased traffic flows, are generally not significant during plant operation, but can constitute a permitting barrier during plant construction.

(ix) Public Acceptability

The survey responses suggest that public acceptability plays a key role in most organisations' decision making process, to maintain good public relations with respect to environmental and safety practice.

A common view expressed by respondents is that regulations are written by politicians, who are answerable to the general public, so that maintaining adequate public and media relations is centrally important to a company's continuing operations. As part of this perceived need, one company interviewed held a "customer energy forum" to discuss issues in the energy sector and how their customers would like to see their problems mitigated.

On the whole, there is very little public awareness of CO_2 capture (Interview responses; IPCC et al, 2005; IEA GHG, 2004) and so the technologies' status in public opinion is difficult to judge. Where opinions do exist, the critical issues that concern the public in terms of CO_2 capture fall into two main categories: health & safety, and the environment. As stated in section (i) on general permitting, the risks associated with CO_2 leakage must be mitigated in order to satisfy the public that there is no health risk posed to humans or wildlife. This perceived risk can be satisfactorily mitigated using the same technology already in operation for the transport and storage of hydrocarbons, however.

The environmental acceptability of CO_2 capture is a more complex public perception issue. In developed countries where climate change is widely viewed as a 'civilisational challenge', we can generally assume that limiting CO_2 emissions is viewed as an important objective. As CO_2 capture does not limit the emissions produced by thermal power plants, however; but lowers the efficiency of the plant and releases more CO_2 per unit of energy generated, public support can currently be mixed. As a result, the public generally prefer to see energy conservation and renewable energy generation employed to reduce CO_2 emissions instead of CO_2 capture (IPPC et al, 2005, p.36). However, where climate change and the full range of energy-sector mitigation options are well established in the public consciousness, CO_2 capture can be seen as a useful component in a strategy to reduce global warming while meeting national energy demand.

Other environmental concerns with CO_2 capture surround the implications of storage in or beneath the ocean, and the potential effects this will have on marine life, as discussed in section 3.2.7. This issue requires further research both to supplement the currently limited knowledge, and to improve the public credibility of CO_2 storage out to sea.

In conclusion, public acceptability is a key issue surrounding CCS as a whole, although at present there is too little awareness to compare technologies, except that the technology that results in the least CO_2 being produced is likely to be the most favoured. On a global perspective, developed countries are seen to view climate change as a more significant issue, so that public acceptance for CO_2 emissions mitigation measures is readily forthcoming. In order to extend public awareness of CO_2 capture technologies in countries such as China and India, climate change must first be established in the public consciousness as a serious threat requiring a concerted response.

(x) Safety and Health Risks

Where survey respondents responded that health and safety issues were important to their decision to invest in thermal generation plant, this is understood to relate primarily to major hazards, rather than to occupational procedures for minimising health and safety risks. Some examples of such occupational procedures are mandatory use of personal protective equipment, training and inductions for site staff and visitors, restricted access to hazardous areas and alarm systems to give early warning of threats to human health. While occupational health and safety is an important consideration in power plant design, therefore, MM do not consider that this generally constitutes a barrier to investment, but rather one of several central issues that a specific plant design must take into account. The following discussion therefore focuses on hazards of CO_2 capture plant as a criterion affecting investment.

<u>Hazards Associated with CO_2 Capture</u>

A brief assessment of the new hazards associated with CO_2 capture, in comparison with a conventional power station, is shown in Table 3-15.

Table 3-15 Hazards of CO_2 Capture Plant

CO_2 Capture Plant Technology	Identified hazards relative to conventional thermal generation
Post-combustion capture of CO_2 from flue gases on gas-fired CCGT plant	Storage & transport of CO_2 away from plant at 110bara
Post-combustion capture of CO_2 from flue gases on coal-fired USCPF plant	Storage & transport of CO_2 away from plant at 110bara
Pre-combustion capture of CO_2 on Integrated Gasification Combined Cycle (IGCC) coal-fired plant	Storage & transport of CO_2 away from plant at 110bara; on-site storage and use of H_2 gas at 65bar and N_2 gas at 26barg
Pre-combustion capture of CO_2 through reformation of natural gas	Storage & transport of CO_2 away from plant at 110bara
Oxy-combustion on coal-fired USCPF plant	Storage & transport of CO_2 away from plant at 110bara; on-site storage and use of O_2 and CO_2 gas mix (30:70) at 30bar for boiler inlet
Oxy-combustion on gas-fired CCGT plant	Storage & transport of CO_2 away from plant at 110bara; on-site storage and use of O_2 and CO_2 gas mix (30:70) at 30bar for CCGT inlet

These hazards all relate to the high pressure systems introduced to transport the captured CO_2, or other gases introduced to the process. Taking the UK as an example, the Pressure Systems Safety Regulations, 2000, apply to systems containing gases at pressures greater than 0.5bara and already apply to conventional power stations.

Major Accident Hazards

The Control of Major Accident Hazards (COMAH) Regulations 1999 and the COMAH Amendment Regulations 2005 are the UK response to the EU Seveso II Directive (Council Directive 96/82/EC), and again provide example of the mitigation measures that would be applied to CO_2 capture plant. The regulations list dangerous substances (in schedule 1) and threshold quantities of these materials for both storage and process use, above which power plant 'establishments' are required to take specific actions to control the risk.

At the lower threshold, the operator should prepare and implement a major accident prevention policy and should notify the Competent Authority about the establishment and the dangerous substance. The Competent Authority varies dependent upon the location of the establishment within the UK, but is defined in COMAH. At the higher threshold, the operator is also required to prepare and revise a Safety Report; prepare, review and implement on-site and off-site Emergency Plans; and provide information to the public.

A review of the substances described in Section 3.3.4(v) has indicated that some of these might be covered by the COMAH regulations, dependent upon the quantities stored or used. The threshold quantities beyond which actions would be required, in the COMAH Amendment Regulations 2005, are shown in Table 3-16.

Table 3-16 Dangerous Substances to which the COMAH Regulations Apply

Substance	Hazard from Material Safety Data Sheet	Appropriate part of Schedule 1	Lower Threshold (Tonnes)	Higher Threshold (Tonnes)
Carbon Dioxide	Asphyxiant	-		
Carbon Monoxide	Toxic, Highly Flammable	Part 3	50	200
Hydrocarbons (non-specific)	(typically flammable)	Part 3	5000	50000
Hydrogen	Highly Flammable	Part 2	5	50
Monoethylamine (MEA)	Highly flammable	Part 3	50	200
Methyldiethanolamine (MDEA)	Combustible	-		
Nitrogen	Asphyxiant	-		
Oxygen	Oxidising	Part 2	200	2000
Poly(ethylene glycol) dimethyl ether (Selexol)	None recorded for poly (ethylene glycol) methyl ether	-		

Any establishment storing or using quantities of dangerous materials greater than the higher threshold will be required to develop a Safety Report. This report will include a Quantified Risk Assessment, considering the safety risk to people both on-site and off-site and will be required to demonstrate that the risks gave been reduced to as low as is reasonably practicable (ALARP). This requirement to control the safety risk to neighbours might influence the choice of site for a COMAH establishment.

As already discussed in subsection (ix) above, there are not considered to be any fundamentally different safety or health risks associated with generation plant incorporating CO_2 capture, that are not already established for thermal generation plant or the petrochemicals industry.

The point highlighted by the example of the UK COMAH legislation, however, is that CO_2 capture plant would have to fulfil greater health and safety requirements than conventional thermal generating plant, due to handling of pressurised gases and solvents in the different plant options.

3.3.5 Market Issues

(i) Fuel Security Issues

There are two main categories of risks considered when assessing the significance of diversity of fuel supply for a new power plant investment – commercial and political risk.

Commercial risk is concerned with ensuring the greatest profitability when producing energy, through avoidance of high fuel prices. This risk is mitigated by individual companies exploiting the possibility of multiple, diverse fuel suppliers, so that fluctuations in the price of a particular fuel do not impinge on the company's competitiveness in the market. If a company has the option of switching fuels when one fuel price increases, the company can mitigate the cost increase so as to remain as competitive as possible. This competitiveness is critical in open markets. For example, while Hong Kong and Canada utility organisations have the guarantee that their electricity will be bought through obligation agreements with their government, in the UK where there is the opportunity of open market trading, controlling commercial risk is essential to be able to sell into the market. The interview responses reinforced this viewpoint, with companies in Ireland, UK, Japan and Greece stating that fuel supply diversity was a key consideration in the investment process, whereas this investment criterion was not mentioned by respondents from elsewhere, where electricity markets are less open.

Political risk relates to the long-term issues of global shortages, climate change and political instability in fuel supplying countries. Governments are responsible for mitigating geo-political risk exposure sufficiently to ensure that the relevant country has sufficient security of its energy supply.

Table 3-17 below shows key global energy users and their reliance on other countries for fuel supplies. For those countries that can rely on domestic fuel production, using a long-term fuel resource within their borders (e.g. China and United States, Russia, Australia, etc), it is less imperative to diversify fuel sources. However, where countries rely on imported energy (e.g. most of Europe and Japan) having a diversified fuel portfolio is important in order to mitigate the risk of supply disruption and price hikes.

The level of diversity will depend on the perceived supply risks versus the commercial and environmental benefits of a particular fuel. For instance, gas is seen by many as a risky fuel, due to the concentration of export capacity in sensitive countries (Middle East, Russia, Nigeria, etc, see Table 3-17), inflexibility of transport networks and difficulty of storing gas in large volumes. Coal by contrast comes from more reliable countries, has more flexible transport arrangements and can be easily stored.

Table 3-17 Fuel Supply Dependency by Country

	Long supply of coal within country	Long supply of gas within country	Short in fuels within country - poor grid interconnections	Short in fuels within country - good grid interconnections	Major Exporter of Coal (2004)	Major Exporter of Gas (2004)
China	X				X	
USA	X				X	
Russia	X	X			X	X
South Africa	X				X	
Australia	X	X			X	X
Canada	X	X			X	X
Japan			X			
Taiwan			X			
South Korea			X			
Germany			x			
UK		x	X			
France			X			
Italy			X			
Spain			X			
Poland	X				X	
Netherlands		X	x			X
Belgium			X			
Denmark				X		
Finland			x			
Greece			X			
Turkey			X			
Ireland			X			
Sweden			x			
Norway		X				X
Brazil			X			
Mexico		X				X
Indonesia	X	X			X	X
Venezuela	X	X			X	
Middle East		X				X

In order to achieve security of energy supply, governments in the dependent countries shown in Table 3-17 have sought diversity of fuel supply sources for generation or alternatively have developed indigenous primary electricity generation, whether nuclear, hydropower or other renewables.

Mitigation options for short term supply risks are also required to ensure smooth day-to-day operation of the electrical supply, so interruptions in fuel supply can be met in a stable manner. The different operational characteristics of generation plant further requires diversified fuel sources to respond to supply shocks, as coal-fired steam turbine plants can require more than twelve hours to spin up to full load whereas hydropower is near instantaneous, and a simple cycle gas turbine could be up and running within two minutes.

Limiting the reliance on one fuel supply, particularly imports from unreliable countries, results in most countries assessing their fuel supply and investing in power plants that broaden their fuel range, and therefore although not a major consideration, companies frequently factor this into their decision making process, especially in competitive markets.

We would not necessarily expect that concerns over security of fuel supply would vary by CO_2 capture technology, beyond the distinction of coal- and gas-fired plant options. Nonetheless, concerns over the availability and diversity of fuel supply were more prominent for the oxyfuel and IGCC plant options, and least prominent for post-combustion capture. This is perhaps due to the ability to use either gas- or coal-fired plant with flue gas scrubbing, and rely on established fuel supply routes, whichever fuel is selected.

For IGGC there is the added possibility of using the fuel Orimulsion, a patented heavy crude-water mix emulsion from Venezuela's Orinoco basin, which provides a good case study in fuel security concerns. Orimulsion is a relatively inexpensive fuel, marketed as "liquid coal", which provides a suitable feedstock for IGCC however it is only produced in Venezuela so buyers would be forced to rely on this country with the only substitute being a highly expensive heavy fuel oil.

(ii) Availability of Low Cost Feedstock

According to the interview responses only Australia, New Zealand and Greece were specifically concerned about the availability of low cost feedstock (other than fuel). However, although the organisations that provided a questionnaire response did not specify feedstock availability as a priority during the telephone discussion, this was 'nearly always' considered making a plant investment decision.

Table 3-13 above shows the major feedstocks and volumes (where this information was provided in the IEA GHG studies) required for the leading CO_2 capture technologies, at the base case load factor of 85%. As seen in Table 3-13, oxy-combustion does not require feedstocks other than fuel, and so is the preferred technology from the perspective of low-cost feedstocks.

When analysing the other main CO_2 capture technologies it is critical to ensure adequate water is available. This is a particular challenge in dry areas (such as in the Middle East) where there is water shortage, so this can add significant costs and/or limit the plant availability. In general, siting the plant close to the feed-water source is crucial to minimise water transport and infrastructure costs.

The other main feedstock is the FGD re-agent limestone, which is needed for the post-combustion capture of CO_2 from flue gases on coal plant, due to the need for super-FGD plant. If considering this option for investment a local supply source for the limestone is crucial, otherwise transport costs can again be a handicap. Limestone resources are typically scattered worldwide. It is worth noting that using the CO_2 capture increases the limestone needed for the overall coal plant by less than 20% and so does not constitute a significantly greater issue than for a coal plant without capture.

The other chemicals employed in the processes are in smaller volumes and are typically costs are negligible in comparison to other feedstocks.

The availability of low cost feedstocks would be considered in the overall economic analysis of a power plant design, but is not generally a major driver of project economics in the way that fuel clearly is. There is no information available to MM at present to suggest there will be a shortage in any of the feedstocks required. Looking at the CO_2 capture options, oxy-combustion is the best performing process due to the lack of need for other feedstocks, while the post combustion process is most affected by the availability of feedstocks. Site location is the greatest determinant of feedstock availability.

(iii) Potential for By-product Sales

In addition to generating electricity, a number of the generation plant options with CO_2 capture produce by-products with established market value. The quantity and quality of each of these by-products is determined by how the station is operated. Table 3-14 above provides indicative quantities for each capture plant on the basis of a common 85% load factor.

In particular, the coal-fired plant options will produce for following saleable by-products:

- Sulphur, and/or sulphuric acid – used principally in fertiliser industry
- fly ash, furnace bottom ash (coarse slag) and filter cake (fine slag) – used as aggregate in the construction and road building industries
- gypsum, used in construction materials such as plasterboard

All generating plant will produce:

- high pressure or low pressure steam – potentially used for export to industrial facilities if more profitable than use within power generation plant
- CO_2 – used for EOR, and at high purity as a refrigerant in the transportation and storage of frozen foods, and for the carbonation of soft drinks

Existing examples of coal IGCC projects which are operating on a commercial basis, selling the by-products, include the 253 MW Nuon Power Buggenum in the Netherlands (coal) and the 300 MW Elcogas Power Station in Puertollano, Spain (50/50 mix of coal and petroleum coke). Nuon Power reports that slag and fly ash from the Buggenum Power Plant is sold as building materials and 99% of the sulphur content of the coal is removed and sold to the chemical industry while Elcogas has also been marketing by-products of the gasification process (sulphur, fly ash and part of the slag) since the beginning of the plant's operation.

There is however a risk that by-product markets, particularly for sulphur and gypsum, become saturated. For the purposes of this study, the revenue from by-products is assumed to be zero, in line with the IEA GHG studies. No specific sensitivity case has been applied to by-product sales, as the level of revenue available depends heavily both on local markets and on fuel composition.

(iv) Availability of skills

This investment criterion relates to the compatibility of the thermal generation technology options with utility operating experience, and includes the possibilities of an investor organisation sourcing technically skilled staff, either internally or externally, to operate a plant with CO_2 capture.

The availability of skills is not viewed by organisations interviewed as a critical issue when considering which type of thermal generation plant to invest in – with no interview respondent mentioning the issue. However, from the written questionnaire responses, it is clear that companies do factor it into making their decisions frequently, if only as a side issue. As CO_2 capture technologies are a relatively new subset of the energy industry and the number of demonstration and operational plants employing these technologies is limited, the confidence in the operators' skill level throughout the world is lower than conventional thermal plants, as illustrated in the written questionnaire responses. However, companies do not appear to view this as a limiting issue, presumably seeing the skills gap as surmountable by building on existing experience.

Post combustion capture technologies are the most compatible with existing thermal generation plants as they leave the combustion (generation) process unchanged and only involve adding components for scrubbing the flue gases at the end of the process. As a result, post combustion was rated as offering the least concern to companies, with the other CO_2 capture technologies all faring worse.

Although IGCC, reformation of natural gas and oxy-combustion offer more complexity, through changes to the basic plant processes, MM believes that the confidence levels for available operator experience are approximately the same as for post-combustion technology, through sourcing of expertise in reformers, gasifiers, shift reactors and air separation units from the petrochemical industry. The practical development of gasifiers for utility-scale IGCC plant is also further advanced than oxy-fuel and gas reformation, indicating a greater pool of available skills globally.

4 Matching Investor Preferences to Capture Technologies

The Multi-Criteria Analysis (MCA) is an economic analysis method designed to prioritise solutions from a set of options subject to a, generally large, number of criteria. For the purposes of this study, the MCA approach has been used to determine which CO_2 capture plant best matches the preferences of power-sector investors, as expressed in the survey sample response.

For each of the investment criteria in the initial survey, extended as necessary during the course of interviews, MM has therefore established an average set of preferences from the survey respondents. Investor preferences have been expressed numerically on a scale of 1 to 5, where '1' represents a criterion being of highest priority and '5' a criterion irrelevant to the utility in question. These preferences are cross-validated results in the analysis to compare the results from the small questionnaire sample with the broader interview sample.

The range of CO_2 capture technology options considered are also 'scored' on their ability to meet each criterion, either using quantitative data on the technology's performance (see section 3.3) or the opinions of questionnaire respondents (see section 2.5.2). The rankings or scores given to a technology's performance with respect to any given criterion are also expressed on a scale of 1 to 5, where '1' represents the best technology assessed and '5' the worst.

The criteria, the criteria preferences (also termed 'weightings') and the ranking (or scoring) on the technology options constitute the inputs to the multi-criteria analysis model, programmed to process numerical factors or numerical proxies on qualitative factors. Sensitivity studies using different technology rankings or investor preferences are conducted, to explore the reliability and robustness of the MCA results.

In the simple case, results can be generated by multiplying rankings and preferences for each criterion and taking the square root for the multiple, giving a 'technology preference' ranking for each criterion. 'Technology preference' rankings are then summed over the full set of criteria and the results adjusted back to the original 1-5 scale. Table 4-1 below shows a simplified example of the MCA approach, using three criteria (shown in the top row) and two technology options. Hypothetical preferences and rankings are used to compare the two technology options, giving the example result in this case that IGCC is preferable to Oxy-combustion.

Table 4-1: Example Multi-Criteria Analysis Results – using hypothetical rankings

	Diversity of Fuel Suppliers	Health and Safety Risks	Capital Costs	
Average Preference:	2	3	4	
Plant Option Rankings				Multi-Criteria Result
IGCC with capture	4	3	2	1
USPCF with oxy-combustion	2	3	4	5

The MCA result rankings again use a 1 to 5 scale, where '1' represents the best technology assessed and '5' the worst. Since only two plant options are included in the example, these appear at opposite ends of the scale, although generally intermediate rankings would also result.

In the full analysis, ranked 'technology preference' results for each criterion are first averaged within the category of criteria they belong to before summing and rescaling. This additional step reduces the 'noise' that would otherwise be seen in the results from the relatively small sample of investors surveyed, with undue emphasis attached to specific criterion rather than the groups or similar themes of criteria. The categories of criteria are the same as those applied in both the interview and questionnaire stages of the survey, namely:

- Economic & Financial
- Plant Track-record
- Logistics
- Environmental / Permitting
- Market

The analysis is limited by a small sample size, which in turn relates to the small total number of organisations globally that might reasonably be expected to invest in CO_2 capture technologies, as well as the limited resources available to the study. The MCA approach is largely indicative, however, and does not rely as heavily on a large sample as would a statistical analysis of survey results based around a defined sample distribution (e.g. normal distribution). Cross-validation of interview and questionnaire responses also acts to mitigate the limiting affects of the small sample sizes.

Sections 4.1 to 4.3 below endeavour to present the full set of MCA preferences, rankings and results in a transparent tabular form, so that these can readily be reinterpreted by different investors as required.

4.1 Technology Assessment based on Survey and Study Findings

The relative performance of the different power generation plants with CO_2 capture is ranked in Table 4-2 below, where '1' represents the best assessed technology and '5' the worst. The quantitative or qualitative information provided by the four IEA GHG technology studies, and assessed in section 3.3, is used to rank the plant technology options on selected economic and environmental criteria (these numerical results shown in italics in Table 4-2). The majority of results are taken directly from the opinions of investors responding to the questionnaire, shown in Table 2-5, and are therefore intended to reflect average industry opinion on the performance of different plant options relative to each investment criteria. The original rankings provided by investors responding to the questionnaire used rankings for non-capture CCGT and USCPF agreed between MM and IEA GHG for reference, and open to modification by respondents. These reference rankings are also shown in Table 4-2.

Where the plants' performance has been assessed quantitatively in section 3.3, the ranking given reflects a linear scaling of these quantitative results to lie within the interval 1-5, and may be expressed to two decimal places. Where the plants performance has been assessed qualitatively in our discussion, leading to an indicative ranked order among the assessed plants, an integer ranking of their relative performance has been applied. Where no clear comparison of the technologies can be made on the basis of the information presented, no ranking has been assigned to the plants.

Italicised criteria headings reflect amendments to the scope of the criteria as a result of the interview findings, discussed below in section 4.2. Specific to the technology rankings under the 'Market' category of criteria, a clearer distinction has been made between security of supply concerns for fuel and non-fuel feedstock, and the rankings applied to the non-capture CCGT and USPCF plant updated from the original questionnaire to reflect this.

Table 4-2 Ranked Assessment of Technology Options with respect to Investment Criteria – Survey and Study Results

	CCGT Without Capture	CCGT with post-combustion capture	CCGT with pre-combustion capture	CCGT with oxy-combustion	USCPF Without Capture	USCPF with post-combustion capture	IGCC with CO_2 capture	USCPF with oxy-combustion
Economic & Financial								
Levelised Cost of Power – Financial Return	*1.75*	*3.31*	*4.72*	*5.00*	*1.00*	*2.84*	*2.36*	*3.07*
Capital Costs	*1.00*	*1.77*	*2.83*	*2.19*	*3.89*	*4.96*	*5.00*	*4.32*
Ability to Project Finance	1	3.43	3.00	3.88	1	3.33	3.20	3.88
Access to public funds	5	3.71	3.57	2.86	4	3.22	3.20	2.86
Plant Track-record								
Proven technology – *low risk of supply interruption*	1	2.63	2.63	4.33	1	3.10	1.29	4.33
Manufacturers of technology – *financially strong & diverse*	1	2.14	2.00	2.86	1	2.22	2.20	2.86
Low risk of technological obsolescence	2	2.88	2.88	2.88	4	3.00	2.73	2.88
Logistics								
Build time	1	3.00	3.00	3.00	3	2.63	3.33	3.00
Modular construction	1	2.67	2.83	3.50	4	2.75	3.00	3.50
Flexibility of operation	1	2.00	2.29	2.33	2	2.00	2.67	2.33
Outage requirements and expected unplanned outages	1	2.57	2.57	3.86	3	3.22	3.70	3.86
Availability of O&M contractor	1	2.17	2.33	2.83	1	2.50	2.78	2.83
Environmental / Permitting								
General permitting issues – licensing risk	1	2.00	1.88	2.88	3	2.50	2.09	2.88
Land footprint	*1.00*	*1.97*	*1.67*	*1.26*	*4.49*	*4.74*	*5.00*	*4.74*
Carbon footprint in operation	*3.01*	*1.30*	*1.33*	*1.00*	*5.00*	*1.57*	*1.77*	*1.39*
Air quality impacts	*1*	*1*	*1*	*1*	*5*	*1*	*2*	*1*
Raw Material *& Water demand*	*1*	*3*	*1*	*1*	*3*	*4*	*5*	*2*
By-product disposal	*1*	*5*	*2*	*4*	*4*	*5*	*3*	*4*
Traffic impacts	-	-	-	-	-	-	-	-
Public acceptability *& Social Impact*	2	2.38	1.88	2.63	3	2.50	2.09	2.63
Safety and health risks	1	2.38	1.88	3.00	1	2.30	2.36	3.00
Market								
Potential for by-product sales	5	4.00	3.29	3.71	4	3.22	3.00	3.71
Availability of non-fuel feedstock	2	3.75	3.14	2.29	4	2.60	2.40	2.29
High fuel security	4	4.00	3.14	2.71	2	3.00	2.80	2.71
Availability of skills	1	2.14	3.14	2.83	1	2.13	2.89	2.83

Table 4-3 Ranked Assessment of Technology Options with respect to Investment Criteria – MM / IEA GHG control

	CCGT Without Capture	CCGT with post-combustion capture	CCGT with pre-combustion capture	CCGT with oxy-combustion	USCPF Without Capture	USCPF with post-combustion capture	IGCC with CO_2 capture	USCPF with oxy-combustion
Economic & Financial								
Levelised Cost of Power – Financial Return	*1.75*	*3.31*	*4.72*	*5.00*	*1.00*	*2.84*	*2.36*	*3.07*
Capital Costs	*1.00*	*1.77*	*2.83*	*2.19*	*3.89*	*4.96*	*5.00*	*4.32*
Ability to Project Finance	1	3	3	5	1	3	3	5
Access to public funds	5	2	1	4	4	1	1	3
Plant Track-record								
Proven technology – *low risk of supply interruption*	1	3	2	5	1	4	4	5
Manufacturers of technology – *financially strong & diverse*	1	2	2	3	1	2	2	3
Low risk of technological obsolescence	2	3	3	5	4	3	3	5
Logistics								
Build time	1	2	2	2	3	4	4	4
Modular construction	1	1	1	1	4	4	4	4
Flexibility of operation	1	2	3	3	2	3	4	4
Outage requirements and expected unplanned outages	1	2	2	2	3	4	4	4
Availability of O&M contractor	1	2	2	2	1	2	2	2
Environmental / Permitting								
General permitting issues – licensing risk	1	2	2	2	3	2	2	2
Land footprint	*1.00*	*1.97*	*1.67*	*1.26*	*4.49*	*4.74*	*5.00*	*4.74*
Carbon footprint in operation	*3.01*	*1.30*	*1.33*	*1.00*	*5.00*	*1.57*	*1.77*	*1.39*
Air quality impacts	*1*	*1*	*1*	*1*	*5*	*1*	*2*	*1*
Raw Material *& Water demand*	*1*	*3*	*1*	*1*	*3*	*4*	*5*	*2*
By-product disposal	*1*	*5*	*2*	*4*	*4*	*5*	*3*	*4*
Traffic impacts	-	-	-	-	-	-	-	-
Public acceptability *& Social Impact*	2	1	1	1	3	1	1	1
Safety and health risks	1	3	3	3	1	3	3	3
Market								
Potential for by-product sales	5	5	3	5	4	4	2	3
Availability of non-fuel feedstock	2	4	3	1	4	5	4	1
High fuel security	4	5	5	5	2	3	4	3
Availability of skills	1	2	2	2	1	2	2	2

To provide a control case for comparative purposes, MM and IEA GHG also agreed a set of qualitative technology rankings to substitute for the questionnaire results. The combined set of these expected technology rankings with those resulting directly from the technology assessment findings are shown in Table 4-3 above. This alternative set of technology rankings is potentially useful for the following two reasons:

- To test whether the survey rankings provide reasonable results – since the averaged ranking results from the questionnaire are not always consistent e.g. For the 'fuel security' criterion results in Table 4-2, a CCGT with oxy-combustion is rated as having significantly higher fuel security than a CCGT without capture, although both are fired on natural gas, have the same capacity for fuel storage, and the oxy-combustion option would have a higher specific fuel consumption, which would be expected to result in a worse rating.

- To show where the average sample response varies from the response anticipated by IEA GHG. Since IEA GHG aims to disseminate results and data from evaluation studies that are targeted at practical technologies to reduce greenhouse gas emissions, a variation between industry and IEA GHG perceptions of the technologies would provide useful feedback.

The two sets of rankings given in Table 4-2 and Table 4-3 do in fact result in a similar capture plant ranking order from the multi-criteria analysis, as shown in Figure 4-3 below. This offers assurance of the robustness of the MCA results, and suggests that IEA GHG has a similar outlook on the technologies to the investors within the survey sample

4.2 Prioritised Investor Preferences

For the base case, the investor preferences used in the multi-criteria analysis are based on the set of rankings given by respondents to the follow-up questionnaire, shown in Table 2-4 above. There are several changes made to the set of investment criteria for the purposes of the MCA, however. These changes include removal of two marginally significant criteria, reducing the total number of investment criteria to twenty-four, and changes to the remaining criteria definitions as given below to reflect additional input from the interviews, also introduced in section 2.5.1.

- The "GHG emissions" criterion is removed, as GHG emissions other than CO_2 are assumed to be zero from all plant options. This criterion also received a low ranking in the questionnaire and was not given as a priority criterion in any interview response, so is considered to be of marginal significance.

- The "traffic impacts" criterion is removed, on the basis that the impact of additional traffic is a site specific consideration that cannot be compared across technology options. This criterion also received a low ranking in the questionnaire and was not given as a priority criterion in any interview response, so is considered to be of marginal significance.

- The "Financial Return" criterion is represented in the MCA by levelised cost of power, which is used throughout this report and gives an equivalent plant ranking result to NPV. Although IRR might generally be used as the basis for comparing the financial return of different projects, this is not a real number for most capture plant options under the assumptions of this analysis, unless further assumptions are made about support mechanisms to give further revenue than that available from the assumed wholesale electricity price. To maintain a broadly applicable analysis, the 'lowest cost' plant in levelised terms is therefore taken here as the one with the greatest potential financial return.

- The scope of "Levelised Cost of Power – Financial Return" (Economic & Financial) is broadened based on the interview responses to include 'ability to compete on the market'; 'maximising returns across a global investment portfolio'; and 'economic sustainability' as distinct and additional to social and environmental sustainability. While there are aspects to these additional interview responses that are not captured by levelised cost of power alone, these are not necessarily technology-specific so would not affect the MCA ranking results.

- The scope of "Proven technology – low risk of supply interruption" (Plant Track-record) is broadened from only proven technology based on the interview responses to include 'low risk of supply interruption' and whether the 'technology is proven to give a good balance of availability and efficiency'.

- The scope of "Raw Material & Water demand" (Environmental/Permitting) is broadened from only water demand based on the interview responses to reflect potential environmental/permitting as well as market aspects to plant raw material demand.

- The scope of "Public acceptability & Social Impact" (Environmental/Permitting) is broadened from only public acceptability based on the interview responses to include social impact, both in terms of appropriate site selection and employment creation.

- The scope of "Availability of non-fuel feedstock" (Market) is clarified based on interview responses to include only non-fuel feedstock. Some questionnaire respondents may have interpreted this criterion as referring to fuel, giving this criterion a higher ranking than intended. This does not affect the multi-criteria analysis significantly due to aggregation of all 'market' criteria, of which fuel security and cost issues is also one. Changes in the prioritisation in this and the fuel security criterion of up to 50% were tested as a sensitivity case, and resulted in variations to technology specific rankings of up to 5%, a substantially lower change than required to affect the ranked order of the MCA results.

- The scope of "High fuel security" (Market) is clarified based on interview responses to include 'availability of fuel'; 'diversity of fuel supply'; and 'ability to mitigate supply interruptions', such as through strategic reserves of stockpiled coal.

In addition to the investor priorities given in the questionnaire response, a set of investment priorities can be inferred from the investor responses to question 9 of the interview – "Apart from the economic return, what key factors does your organisation consider most seriously in deciding on plant investments?".

The number of instances where a criterion was volunteered in response to this question can be used to rank the priority of the criterion by taking the inverse and adjusting the full range of results to the 1 to 5 scale. Criterion given as a priority, but of secondary importance, were assigned a 50% weighting. Although crude, this approach is valuable to cross-validate the interview and questionnaire results. The limitations to this approach of using rankings inferred from the interview responses include:

- Gives emphasis to vocal respondents, who identify multiple priority criteria.

- Takes into account only those criteria receiving primary or secondary priority from respondents, so that no information is available on the relative importance of low priority criteria – giving a polarised set of preferences, clustered at the ends of the scale.

- Potentially more biased towards a focus on public relations than the questionnaire responses – with investors emphasising public acceptability over proven technology of fuel security issues, for example, that may reflect the public nature of the survey results more than actual investment preferences.

- Under-emphasis of economic criteria due to focus of question.

The above-listed disadvantages relative to the questionnaire rankings are substantially mitigated by the larger sample size of 34 investors, compared with the questionnaire sample size of 15, however. A further benefit of the interview responses is that the greater number allows more meaningful disaggregation to give preference sets for different groups of investor.

The major identifiable groups of stakeholders and investors giving different responses in the interview (I/V) and questionnaire were the public utilities (12 I/V responses), private utilities (12 I/V responses) and project lenders (5 I/V responses). The total number of questionnaire responses was too low to meaningfully disaggregate into groups of responses, even for the largely illustrative MCA analysis. Another distinctive grouping of respondents was between those subject to a carbon regulatory regime and those without national-level regulatory incentives to reduce CO_2 emissions. However, since only one investor in the interview sample volunteered carbon emissions as a priority criterion for investment decisions, distinct from general permitting and regulatory issues, this contrast between investor groups is not visible in the MCA results.

Table 4-4 below shows the investor preferences for the 24 criteria used in the MCA, derived from both the questionnaire and interview results.

Table 4-4 Ranked Investor Preferences for Thermal Plant

	Direct Results – Based on full questionnaire response (sample of 15)	Inferred Results – Based on full interview response (sample of 34)
Economic & Financial		
Levelised Cost of Power – Financial Return	1.20	2.93
Capital Costs	2.07	5.00
Ability to Project Finance	2.73	4.70
Access to public funds	3.60	5.00
Plant Track-record		
Proven technology – *low risk of supply interruption*	1.33	1.89
Manufacturers of technology – *financially strong & diverse*	1.67	5.00
Low risk of technological obsolescence	1.93	5.00
Logistics		
Build time	1.60	4.56
Modular construction	3.07	5.00
Flexibility of operation	2.00	4.70
Outage requirements and expected unplanned outages	1.20	5.00
Availability of O&M contractor	2.60	5.00
Environmental / Permitting		
General permitting issues – licensing risk	1.27	1.55
Land footprint	2.13	5.00
Carbon footprint in operation	2.07	4.21
Air quality impacts	1.27	4.21
Raw Material *& Water demand*	1.87	5.00
By-product disposal	1.80	5.00
Public acceptability *& Social Impact*	1.40	1.16
Safety and health risks	1.07	3.65
Market		
Potential for by-product sales	2.33	5.00
Availability of non-fuel feedstock	1.53	4.26
High fuel security	2.20	2.78
Availability of skills	1.73	5.00

4.3 Multi-Criteria Analysis Results

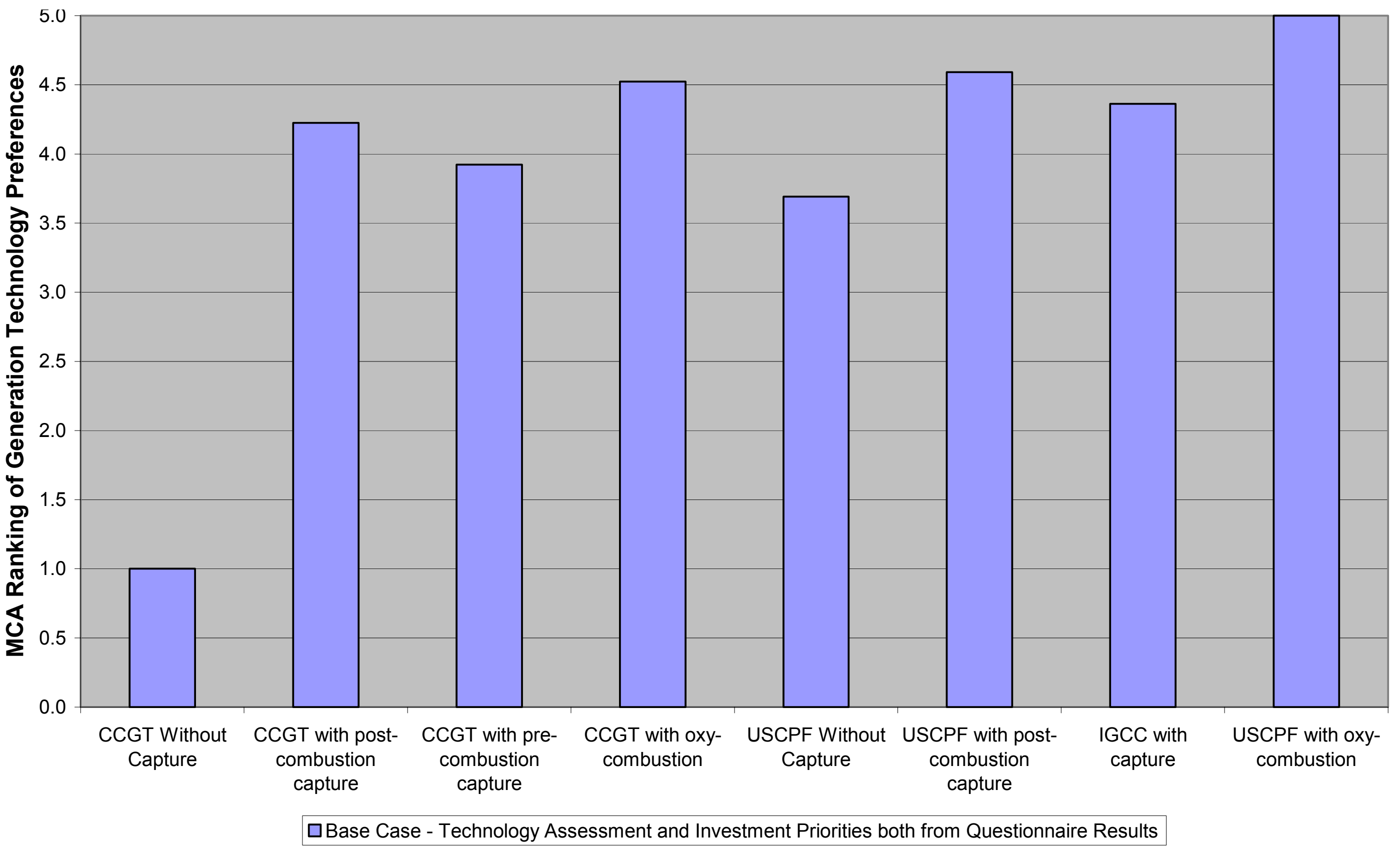
The multi-criteria analysis results combine the assessment of different technologies with the sample investment preferences to infer the aggregated *technology preferences* of the investors in the survey sample. Table 4-5 and Figure 4-1 show the results of the MCA for the full set of plant options included within this report, including both gas-fired CCGT and USCPF without capture, in addition to the six capture plant options. This analysis of investor technology preferences uses the questionnaire sample results both for the technology assessment and for the investment preference rankings.

Table 4-5 Technology Preference Results – Full Set of Plant Options

CCGT without capture	CCGT with post-combustion capture	CCGT with pre-combustion capture	CCGT with oxy-combustion	USPCF without capture	USCPF with post-combustion capture	IGCC with capture	USCPF with oxy-combustion
1.0	4.2	3.9	4.5	3.7	4.6	4.4	5.0

Figure 4-1 shows that the CCGT without capture is the clear favourite for current new-build plant investment, based on the match between questionnaire sample preferences and views on the technologies, as might be expected given the proven nature of the technology and the general current lack of fiscal incentives to develop capture plant. The USCPF without capture is the second ranked technology, although significantly behind the CCGT. This result mainly reflects a high degree of investor comfort with the performance of established technologies across a broad range of criteria.

Figure 4-1 MCA Ranking of Technology Preferences – Full Set of Plant Options



Of the CO_2 capture plant options, pre-combustion capture on CCGT best matches investor's preferences for thermal plant investment. The gas-fired plant options as a set are also preferred to the coal-fired plant options, for the post-combustion, pre-combustion, and oxy-combustion pairs respectively.

The MCA results for the CO_2 capture plant options alone are shown in Table 4-6. As in Table 4-5, the *base case* ranking of investor technology preferences uses the questionnaire results both for the technology assessment and for the investment preferences, and is shown in the first result row of Table 4-6.

The remaining rows show alternative MCA results based on different sets of investor preferences or technology rankings. While the large number of equally significant variables makes it difficult to extract meaning from sensitivity analyses based on specific criterion, the comparison of alternative sets of inputs from different sources helps to show whether the MCA result are robust.

Table 4-6 Technology Preference Results – Capture Plant Options

Investor Preference Rankings	Technology Assessment Rankings	CCGT with post-combustion capture	CCGT with pre-combustion capture	CCGT with oxy-combustion	USCPF with post-combustion capture	IGCC with capture	USCPF with oxy-combustion
Questionnaire Results	Questionnaire Results	2.1	1.0	3.2	3.5	2.9	5.0
Full I/V Results	Questionnaire Results	2.0	1.0	3.3	3.5	3.4	5.0
I/V Results – Public Utilities	Questionnaire Results	1.9	1.0	3.3	3.5	3.3	5.0
I/V Results – Private Utilities	Questionnaire Results	2.0	1.0	3.3	3.5	3.3	5.0
I/V Results – Lenders	Questionnaire Results	2.0	1.0	3.4	3.5	3.5	5.0
Questionnaire Results	MM & IEA GHG Assessment	2.4	1.0	3.7	4.4	4.1	5.0
Rankings using 'direct' technology preferences, rather than 'indirect' MCA results		3.9	3.9	5.0	1.0	1.4	2.5

Result rows two through five show the MCA results when the investor preference set is inferred from the interview results, as described in section 4.2. This MCA sensitivity result is also shown compared with the base case in Figure 4-2. Result row six shows the MCA results when the MM and IEA GHG technology assessment rankings are used, as described in section 4.1. The MCA results using this control set of technology rankings is also compared with the base case in Figure 4-3.

The final row of Table 4-6 shows a set of technology preference results entirely separate to the MCA analysis. Rather than the 'indirect' results of the MCA that combine separate preferences and rankings, these results take the 'direct' responses to question 5 of the questionnaire – "Which of the following generation technologies with carbon capture could best fit your organisation's needs?". The full response to this question in the questionnaire is shown in Table 2-6. For the purposes of comparison with the MCA ranking, only those responses relevant to the leading capture technologies (whether new-build or retrofit) included in this study are taken, however. Additionally, answers from those four organisations that instead volunteered responses to this point in the 'technical question' section of the interview are included. This set of 'direct' rankings therefore uses a total sample of 19 – from 15 questionnaire responses, across 14 organisations, and from another 4 interviewees.

The total number of positive responses for a technology are inverted and scaled to give the rankings shown in Table 4-6. The results of this direct set of rankings are shown in Figure 4-4, compared with the base case MCA results.

Figure 4-2 MCA Ranking of Capture Plant Technology Preferences – using Questionnaire and Interview Investment Preference Results

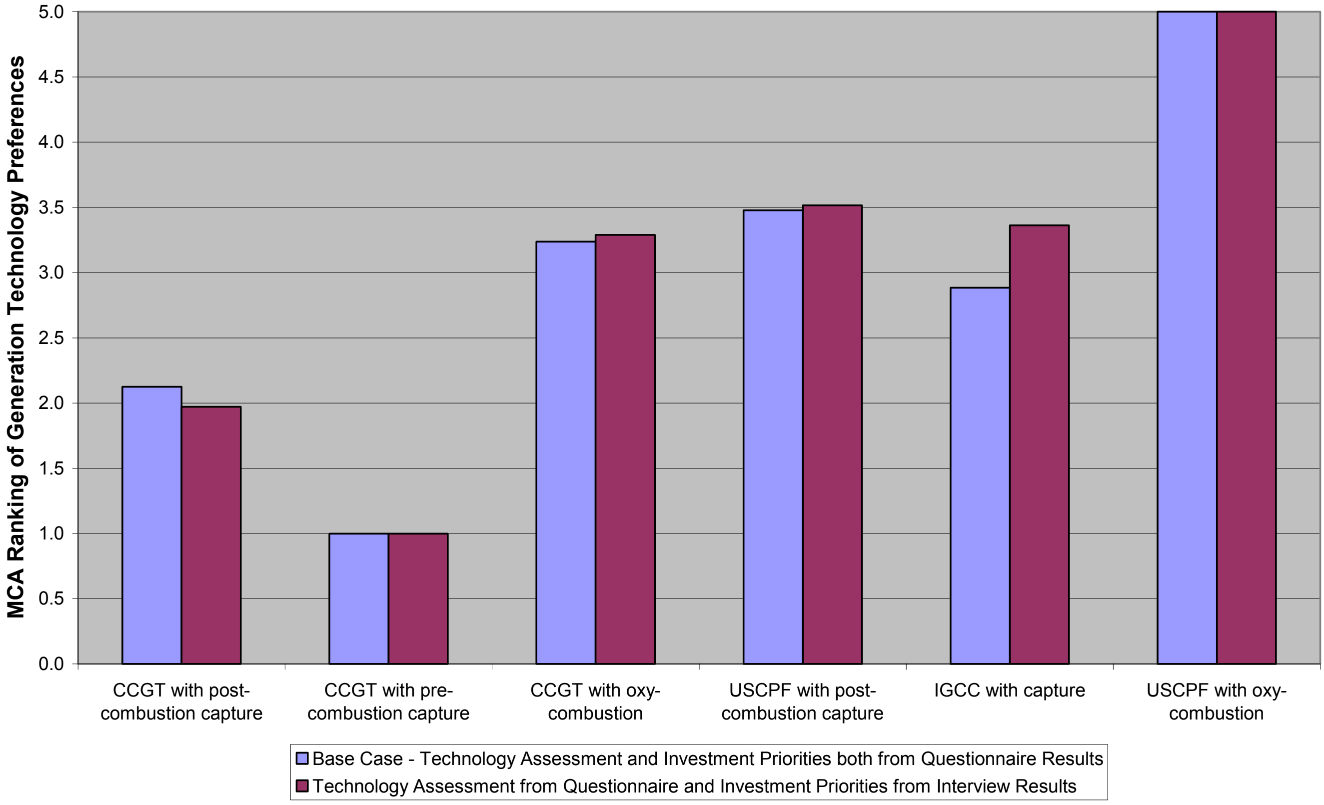


Figure 4-2 shows that the MCA results do not significantly change, whether investor preferences are taken from the questionnaire or inferred from the interview results for the full survey sample. There is one change to the merit order of the plants as a result of using the interview preference set, with IGCC dropping from third to fourth place. Within the gas- and coal- fired plant categories, no change in merit order occurs.

There is also no significant difference between results from different investor groups within the interview responses – the public utilities, private utilities and lenders, with the ranking of any technology varied by up to 5%, and no change in the merit order. Although these different stakeholder groups focussed on different specific investment criteria, the average results for each category of investment criteria (e.g. Economic, Logistic, Environment etc) were very similar, giving practically identical aggregated results.

Figure 4-3 MCA Ranking of Capture Plant Technology Preferences – using Questionnaire and MM / IEA GHG Technology Assessment Results

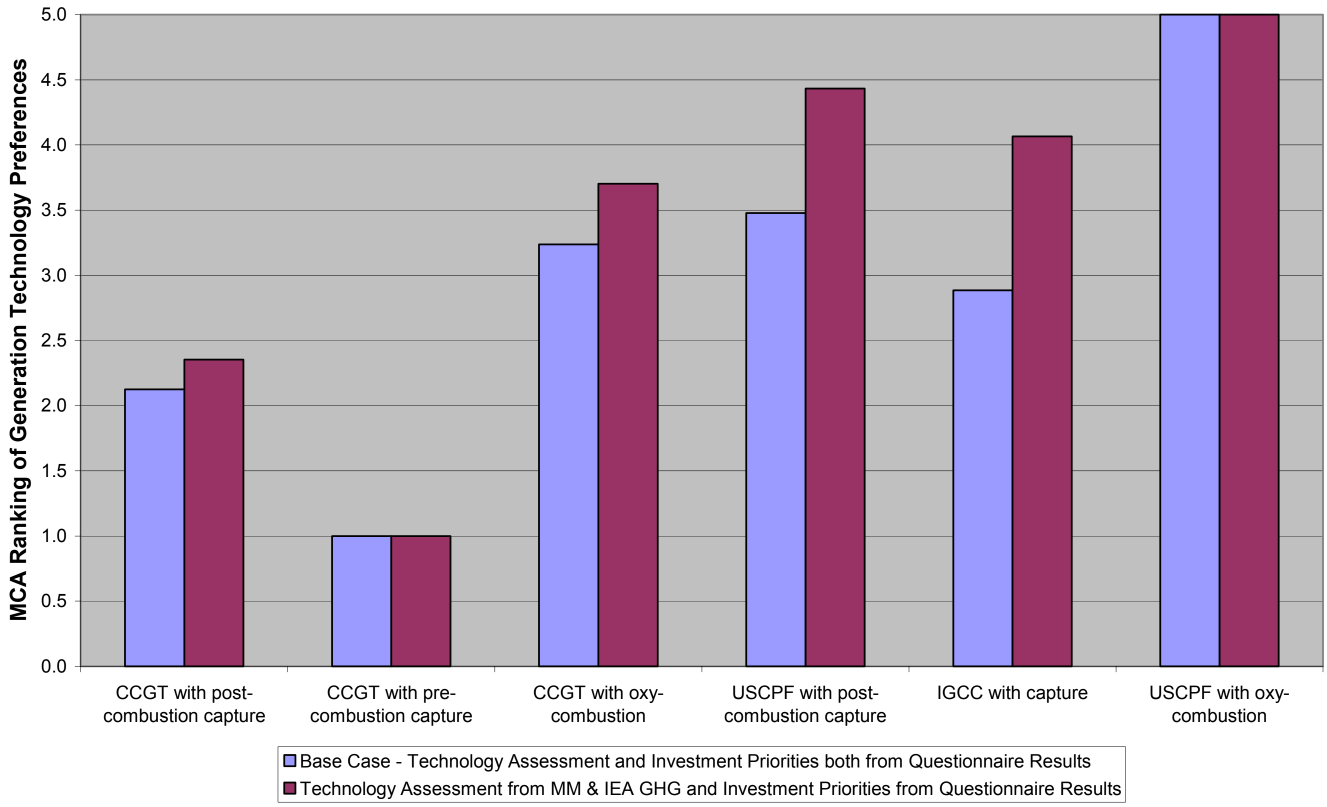
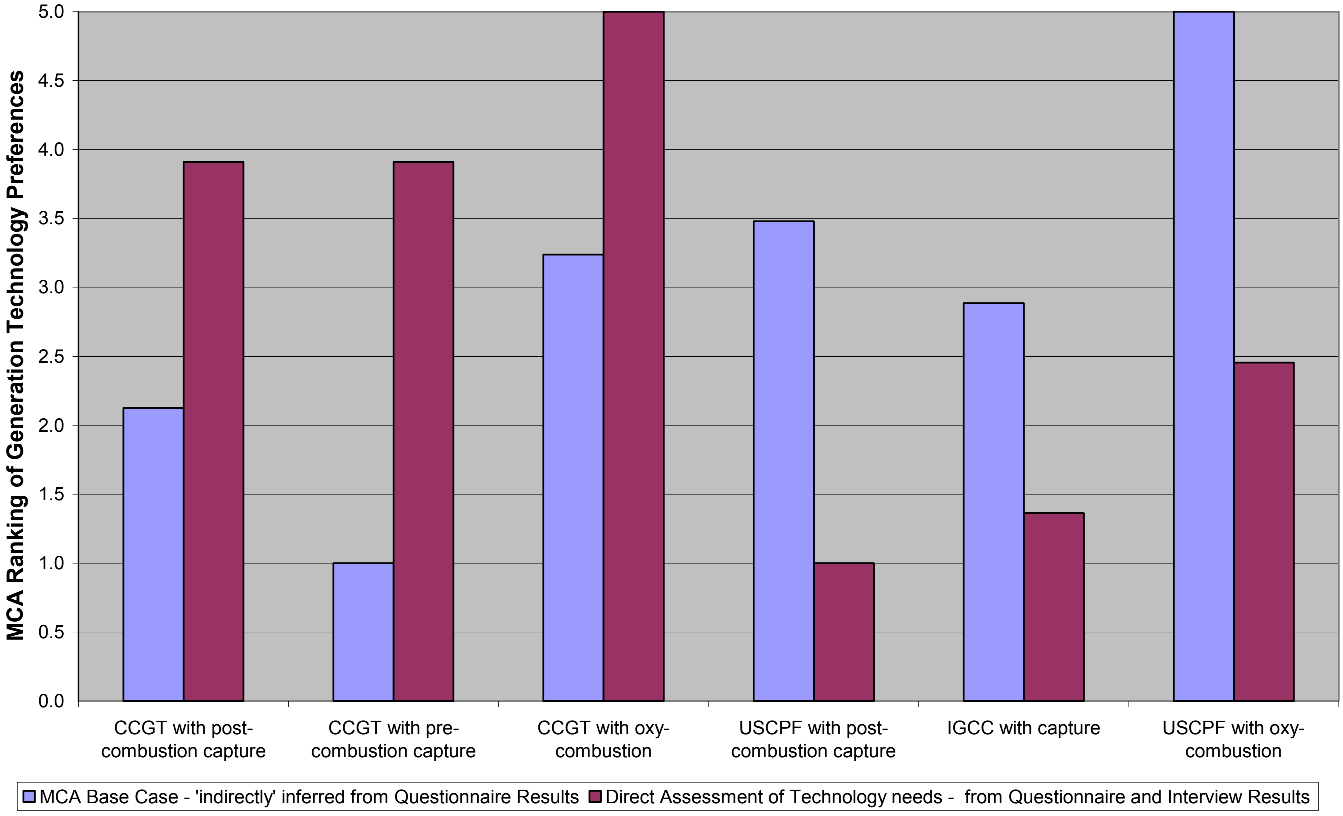


Figure 4-3 shows further demonstrates the robustness of the MCA results, with the MM and IEA GHG technology rankings used as a control. Although the ranked results are similar, in this case there is again one change to the merit order relative to the base case MCA results, with the control technology rankings placing IGCC behind CCGT with oxy-combustion in the merit order.

Although the MCA sensitivities carried out above show that the ‘indirect’ ranking of technologies through the MCA gives a fairly consistent and robust set of results, Figure 4-4 below shows that a that the MCA results contrast substantially with the technology needs directly expressed by investors in a combination of the interview and questionnaire results. MM consider that the large difference between the MCA results and the direct question results from the same survey reflects different interpretations to the questions and, therefore, different meanings to the results. Whereas the MCA shows which plant options best match an investor’s broad set of preferences for investment in thermal generation plant, the direct response to ‘which technology best fits your needs?’ gives the technology that would *ideally* fit the needs of an organisations current operations.

Figure 4-4 Ranking of Capture Plant Technology Preferences – Base Case MCA and Direct Questionnaire Response



The main feature of the results shown in Figure 4-4 is that questionnaire respondents see CO_2 capture as more important to them for coal-fired plant than for gas-fired plant, although the gas-fired plant technologies might be better developed and better fit their broader set of investment preferences. Our view is that this response to the direct question reflects the legislative drivers on carbon emissions in countries where legislation exists, which incur a greater penalty on coal-fired generation than gas-fired generation. The direct question responses would in this case essentially represent a more limited set of investment criteria – such as a combination of reduced CO_2 emissions and familiarity with the technology.

Looking at the coal-fired plant options specifically, post-combustion capture is viewed in direct responses as the best available technology, despite the fact that this technology has not been fully demonstrated. Both IGCC with capture and USPCF with post-combustion capture are viewed as the most ‘needed’ technologies in the direct question responses.

For the gas-fired plant specifically, pre-combustion and post-combustion capture are also approximately equally ranked as best able to meet investor’s needs.

In all cases, the oxy-combustion options, for gas- and coal-fired plant respectively, are considered the least well suited to investors needs based on current technology.

5 Conclusions

The major conclusions noted in the different sections to this study are summarised below.

Investor Survey

- The survey sample showed a high level of interest in CO_2 capture, with 50% of respondents having seriously investigated CO_2 capture (attended conferences or received consultancy advice) and 25% pursuing capture technology through involvement in demonstration plants or R&D.

- Five organisations (15% of the survey sample) interviewed are currently additionally developing generation plant with CO_2 capture.

- There is a likelihood of bias in the survey sample towards those interested in CO_2 capture, and therefore motivated to participate in the survey, which limits the applicability of the above findings to leading global power-sector investors generally.

- There is an even split in opinion in the survey sample on whether transport and storage infrastructure will be developed over the next decade, based on disagreement on how close CO_2 storage is to commercial viability.

- Depleted oil and gas reservoirs, together with Enhanaced Oil Recovery is considered the most promising CO_2 storage option, followed by deep geological storage in aquifer formations.

- As expected, there is a wide range in respondent awareness of the technologies, with the evidence suggesting that post-combustion capture plant is most widely understood, followed by IGCC, pre-combustion capture through reformation of natural gas, and oxy-combustion least widely understood.

- IGCC is considered to be the most proven CO_2 capture technology in the questionnaire responses, while CCGT with pre-combustion capture is seen to present the lowest environmental concerns. These two pre-combustion options are also considered the capture plant options that could most readily receive project financing.

- Post-combustion capture on coal-fired plant and IGCC with capture are the technologies viewed by organisations as best able to fit their current needs.

- 71% of survey respondents expected to invest in new thermal generation plant within the next two years. Investment periods used for appraisal of natural gas-fired CCGT and Coal-fired Plant with in the range 15-25 years and 20-30 years respectively, consistent with IEA GHG standard assessment criteria

- Groups of respondents with the most distinct responses were public utilities, private utilities and project lenders (together comprising 85% of the sample). Major differences in the attitude towards CO_2 emissions were visible between those countries subject to national emissions legislation and those only facing abatement incentives as non-capped Kyoto signatories, as would be expected given the differing associated incentive levels.

Technology Assessment

- Comparison of the IEA GHG technology studies on a level basis under current market conditions results in upward revisions to costs from the original estimates, affecting gas-fired plant more than coal-fired plant options, due to high anticipated long-term gas-prices.

- Under base case conditions, coal-fired IGCC plant with CO_2 capture gives an 8% higher levelised power cost than gas-fired CCGT plant without capture. This finding is particularly sensitive to the forecast of long-run fuel costs, plant load factor and whether the risks associated with IGCC incorporating CO_2 capture can be satisfactorily mitigated. The cost comparison is also for capture only; i.e. before transport and storage costs, which would be around twice as high per tonne of CO_2 stored for coal-fired generation.

- Post-combustion capture on either gas- or coal-fired plant is the next most favourable capture plant technology after IGCC with capture, assessed on a levelised cost of power basis.

- CCGT with pre-combustion capture and oxy-combustion on either gas- or coal-fired plant are high-cost options in the short run, at least 48% more expensive than a CCGT without capture. Oxy-combustion performance is expected from the survey results to improve significantly relative to other options over the next decade, however.

- Despite the significant attention paid by the IEA GHG studies to giving representative capital costs for CO_2 capture plant, capital costs needs to be treated with some caution due primarily to:

  - potential for embedded optimism in CapEx projections, particularly for post-combustion capture

  - changes in market conditions that would affect the accuracy of dollar-adjusted equipment supply costs

  - different degrees of risk associated with each technology, which adds a risk premium to the investment that is not currently represented.

- Risks are assessed for each plant technology, with most capture plant technologies being classed as ‘high risk’ to represent the likelihood of construction delays, permitting delays and high unplanned outages.

- If CO_2 capture plant is considered to operate at low load factors, for example to meet twelve-hour business day demand, the economic performance of the gas-fired options improves substantially relative to the coal-fired options.

Multi-Criteria Analysis

Although based on too small a sample size to generalise widely from, the plant rankings given by the multi-criteria analysis are robust to sensitivities on both investor preferences and plant performance, giving the following findings:

- CCGT and USCPF plant without capture currently better match investor’s preferences for thermal generation plant than the capture plant options based on current technology performance, reflecting the proven nature of the technologies and the general current lack of fiscal incentives to develop capture plant.

- Of the CO_2 capture plant options, the multi-criteria analysis shows that CCGT plant with pre-combustion capture best matches investor's preferences for thermal plant investment. The gas-fired plant options as a set are also preferred to the coal-fired plant options, for the post-combustion, pre-combustion, and oxy-combustion pairs of technologies respectively.

- Although gas-fired plant options are ranked higher in the multi-criteria analysis results, questionnaire respondents see CO_2 capture as more important to them for coal-fired plant than for gas-fired plant, presumably motivated by legislative drivers on carbon emissions that incur a greater penalty on coal-fired generation than gas-fired generation.

- Looking at the coal-fired plant options specifically, post-combustion capture is viewed in direct responses as the best available technology, despite the fact that this technology has not been fully demonstrated. Both IGCC with capture and USPCF with post-combustion capture are viewed as the most 'needed' technologies in the direct question responses.

Recommendations

MM make the following recommendations for further work to complement the findings of this report:

- An in-depth study of the relationship between costs on new-build and retrofit capture plant – including the extent to which a retrofit on capture-ready plant is economic. This study would be particularly useful to further understand the differences in cost for post-combustion capture, for which the IEA GHG 2004 and 2005 reports give significantly different results. We understand IEA GHG has commissioned a study on capture-ready plants that would provide an opportunity to explore this issue.

- Further analysis on the marginal cost or revenue stream from CO_2 transport and storage, including particularly the role that can be played by enhanced oil recovery as an economic driver for CCS in different regions.

- Further analysis of the lifetime GHG emissions of different generation plant options with CO_2 capture, including carbon payback, broadening the analysis from simply combustion-related emissions during operation. This analysis would be expected to include primarily the impact of site operations and equipment delivery during construction and delivery of fuel and feedstocks during operation. Such an analysis would aid in understanding the full life-cycle emissions intensity of each generation process, relevant in economic terms for upstream and downstream industries that are or might in the future also be subject to GHG emissions limits and associated liabilities.

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Appendix A Survey Target List

The target list of utilities was developed in response to the terms of reference for the study, focussing on those countries that are members of the IEA GHG, and on countries of particular interest to IEA GHG, including China and India.

The target list is not therefore intended to represent an unbiased sampling method, but instead reflects a combination of the priorities of the study and the availability of personal contacts at the organisations, to facilitate the survey process making efficient use of available resources. The potentially skewed nature of the sample is therefore considered to be offset by likelihood of an improved response rate, which can be very low for this type of market survey exercise.

Table A–1 and Table A–2 show the target list, which comprises 100 organisations – 51 from within Europe and 49 from outside of Europe, and separated this way for convenience.

Table A-1 European Organisation Target List

Belgium	Electrabel (Suez)	Utility
Denmark	Elsam	Utility
Denmark	E2	Utility
Finland	Fortum	Utility
Finland	Pohjolan Voima	Utility
France	EdF	Utility
France	GdF	Utility
Germany	RWE	Utility
Germany	Eon	Utility
Germany	VEAG	Utility
Germany	EnBW	Utility
Greece	Public Power Company (PPC)	Utility
Ireland	ESB	Utility
Ireland	ESBI	Developer
Italy	Enipower	Utility
Italy	Enel	Utility
Italy	Edison	Utility
Netherlands	Nuon	Utility
Netherlands	Essent	Utility
Netherlands	Electrebel Netherlands	Utility
Netherlands	E.on	Utility
Netherlands	Shell	Developer
Norway	Statkraft	Utility
Norway	Norsk Hydro	Utility
Norway	Skarcagrat	Developer
Portugal	EdP	Utility
Spain	Endesa	Utility
Spain	GasNatural	Utility
Spain	Iberdrola	Utility
Spain	Union Fenosa	Utility
Sweden	Sydkraft	Utility
Sweden	Vattanfall	Utility
Switzerland	EGL	Utility
Switzerland	Atel	Utility
UK	Scottish Power	Utility
UK	SSE	Utility
UK	Centrica	Utility
UK	EdF	Utility
UK	RWE	Utility
UK	Eon	Utility
UK	Progressive Energy	Developer
UK	BG Group	Developer
UK	BP	Developer
UK (London)	Calyon	Lender
UK (London)	Bank of Ireland	Lender
UK (London)	CSFB	Lender
UK (London)	Socgen	Lender
UK (London)	Rothschild Bank	Lender
UK (London)	Citigroup	Lender
UK (London)	RBS	Lender
UK (London)	EBRD	Lender

Table A-2 Non-European Organisation Target List

Australia	Macquarie	Lender
Australia	CS Energy	Utility
Australia	Tarong	Utility
Australia	Stanwell	Utility
Canada	Ontario Hydro	Utility
Canada	Nova Scotia Power	Utility
Canada	TransAlta	Utility
Canada	Saskpower	Utility
Canada	Hydro - Quebec	Utility
Canada	Manitoba Hydro International	Utility
China	Huang Neng Power	Utility
China	Datang Power	Utility
China	Guodian Power	Utility
China	Huadian	Utility
China	China Power Investment Corp.	Utility
China	China Light and Power	Utility
China	Hong Kong Electric (HEC)	Utility
India	National Thermal Power Corporation	Utility
India	Reliance Energy	Utility
India	Tata	Utility
India	ESSAR	Utility
India	LANCO and Nav Bharat	Developer
Japan	Tokyo Electric Power Company	Utility
Japan	Chubu Electric Power Company	Utility
Japan	Kansai Electric Power Company	Utility
Japan	Tohoku Electric Power Company	Utility
Japan	Sumitomo Corporation	Developer
Korea	Korea Electric Power Company (KEPCO)	Utility
Mexico	Cemex	Developer
New Zealand	Contact Energy	Utility
New Zealand	Meridian Energy	Utility
New Zealand	Genesis Power	Utility
New Zealand	Mighty River Power	Utility
Phillippines	Asian Development Bank (ADB)	Lender
Russia	RAO UES	Utility
South Africa	Eskom	Utility
USA	Constellation Power	Utility
USA	Duke	Utility
USA	Tennessee Valley Authority	Utility
USA	Florida Light & Power	Utility
USA	El Paso Energy International	Utility
USA (Washington)	IADB	Lender
USA (Washington)	IFC	Lender
Venezuala	EDELCA	Utility
Venezuala	CADAFE	Utility
Venezuala	ELECAR	Utility
Venezuala	Enelven	Utility
International	Alstom	Equipment Manufacturer
International	Globeleq	Developer

Appendix B Sample of Organisations Interviewed

Of the organisations on the target list, in Appendix A above, the sample of organisations from which a response was received are shown in Table B–1 below. In columns two to five, a cross is given against those organisations that responded. Detailed technical responses were provided both during the telephone interview, in some cases, as well as through the follow-up questionnaire. In the case of Nova Scotia Power, Canada, responses from two different departments were received to both the telephone interview and follow-up questionnaire.

Table B-1 Sample Responses to Interview and follow-up questionnaire

National Base	Organisation	Main Interview Completed	Technical Interview Questions Completed	Follow-up Questionnaire Received
Australia	CS Energy	x		x
Australia	Stanwell	x		
Canada	Manitoba Hydro International	x		
Canada	Nova Scotia Power, both investment and technical managers	x 2	x	x 2
Canada	Saskpower	x		x
China	Hong Kong Electric (HEC), Finance Department	x		x
Finland	Fortum, Generation Division	x		x
France	Electrcité de France (EdF), Renewable Energy Division	x		
Germany	RWE	x	x	x
Germany	Eon Energy, New Technologies	x		
Greece	Public Power Corporation (PPC), Production	x		
India	LANCO and Nav Bharat	x		
Ireland	Electrcity Supply Board (ESB)	x		
Ireland	ESB International (ESBI)	x		x
Japan	Sumitomo Corporation, Power & Water, Investment Department	x		x
Japan	Tohoku Electric	x		
Japan	Tokyo Electric Power Company (TEPCO)	x		x
Netherlands	E.on Benelux	x		x
New Zealand	Genesis Power	x		x
Norway	Statkraft	x		
South Africa	Eskom	x	x	
UK	BP, Hydrogen Power Division	x	x	
UK	EdF Energy	x		
UK	Eon	x		x
UK	Progressive Energy	x	x	x
UK	Scottish and Southern Energy (SSE)	x		x
UK (London)	Bank of Ireland	x		
UK (London)	BG Group	x		
UK (London)	Calyon, Energy Division	x	x	
UK (London)	Citigroup	x		
UK (London)	Socgen, Energy Project Finance, Corporate Investment Banking	x		
USA (Washington)	Inter American Development Bank (IADB)	x		
Venezuala	EDELCA, Strategic Planning	x		
International	Alstom, Carbon Capture and Storage (CCS) Development	x	x	
Total number of Organisations (Responses)		*34 (35)*	*7*	*14 (15)*

Appendix C Telephone Interview Template

The following telephone interview template was developed through both internal and external testing, and was adapted as necessary to each organisation contacted.

Introduction

Mott MacDonald is interviewing decision-makers at leading power-sector players on behalf of the International Energy Agency Greenhouse Gas Research & Development programme (IEA GHG) for a study of carbon capture technologies.

The study aims to survey attitudes on investment in new generation capacity over the next decade, particularly in plants with CO_2 capture.

[Organisation name] has been selected by Mott MacDonald together with the IEA GHG as a leading player in the power sector, likely to be involved in the future development of new generation plant. The survey is composed of two sections, the first part is a phone interview to explore qualitatively your attitudes, and the second part is a written questionnaire to assess quantitatively the importance you attach to different investment criteria. Your answers to our questions will be treated as confidential. The interview questions are included in order for you to prepare in advance of the call that should last approximately 12 minutes.

As a participant *[organisation name]* will receive a complementary copy of the IEA GHG report on the current performance of the range of CO_2 capture technologies and how these complement different utility investment preferences. For this survey, carbon-capture technologies refers to post-combustion capture, pre-combustion capture (IGCC, CO_2 removal by reformation of natural gas) and oxyfiring. It does not include low carbon options such as biomass co-firing and supercritical coal plant.

Organisational Investment Preferences and Views on CO_2 Capture Technologies

1a) Are you planning to expand thermal generating capacity within the next two, five or ten years?

- Yes, two years
- Yes, five years
- Yes, a decade
- No, no additions planned
- No, preference for nuclear
- No, preference for hydro and other renewables

1b) *If no additions planned* – Are you planning to retrofit existing thermal generating capacity over the same timeframe?

- Yes, two years
- Yes, five years
- Yes, decade
- No, no additions planned
- No, preference for nuclear
- No, preference for hydro and other renewables

1c) *If still no additions planned* – How would you describe your organisation's long term investment horizons (10 years plus)?

2) What are the types of thermal generating plant you are considering over this timeframe?

- Combined Cycle Gas Turbine
- Open cycle gas turbine
- Pulverised coal steam turbine
- Oil/gas fired steam turbine
- Integrated Gasification Combined Cycle
- Fluidised bed combustion

3a) Does mitigation of CO_2 and other greenhouse gas emissions factor in your choice of thermal technology?

- Yes, strongly
- Yes, moderately
- no

3b) *If yes* – What is *[organisation name]*'s interest in mitigation of greenhouse gas emissions primarily motivated by?

- Current legislation
- Expected future legislation
- Carbon credit or renewable certificate market opportunities
- Other factors *(specify)*

The following few questions focus on carbon capture specifically

4) What is your previous level of exposure to CO_2 capture technologies?

- Heard of CO_2 capture
- Read articles
- Attended conferences / meetings
- Visited demonstration plants
- Received consultancy advice
- Practical experience at laboratory scale
- Practical experience at full scale

5) Do you believe that suitable CO_2 transport and storage infrastructure will be developed in time for you to consider CO_2 capture at *[organisation name]*'s power plants within the next decade? (if they have a view on this)

- Strongly agree
- Agree
- Disagree
- Strongly disagree
- No view

We are making the assumption that the storage infrastructure will be in place for the purposes of answering remaining questions and for the questionnaire

6) Do you believe that *[the relevant carbon market mechanisms: EU ETS, CDM, JI]* will approve emissions credits for CO_2 capture and storage (CCS) to offer a commercial incentive for these technologies within the next decade?

- Strongly agree
- Agree
- Disagree
- Strongly disagree
- No view

7a) Have you or your colleagues considered CO_2 capture (or separation) and storage options for new plant?

- Yes, actively exploring
- Yes, but awaiting greater confidence in technology, regulatory approval for CO_2 storage
- Yes, planning to make plant capture ready
- Yes, but awaiting financial incentives
- No, don't believe it will ever be viable/ allowed
- No, not an issue for us

7b) *If no* – Have you or your colleagues considered CO_2 capture (or separation) and storage options for retrofitting?

- Yes, actively exploring
- Yes, but awaiting greater confidence in technology, regulatory approval for CO_2 storage
- Yes, but awaiting financial incentives
- No, don't believe it will ever be viable/ allowed
- No, not an issue for us

7c) *If yes to any of above subsections* – Would *[organisation name]* be interested in further studies or information on CO_2 capture technologies produced by the IEA (e.g. comparison of economics based on demonstration plants), if this were available?

- Yes (*record information type if specified*)
- No – not needed
- No – not an issue

The remaining few questions are investment focussed.

8a) What timeframe would *[organisation name]* use for investment appraisal (assessing viability of projects)?

- < 10 years
- 10 years
- 15 years
- 20 years
- 25 years
- > 25 years

8b) Does this investment timeframe vary by plant type (e.g. coal versus gas)? *If so, describe how.*

9) Apart from the economic return, what key factors does *[organisation name]* consider most seriously in deciding on plant investments?

Market	*Logistics*
• *Potential for by-product sales*	• *Build time*
• *Availability of skills*	• *Modular construction*
• *Diversity of fuel sourcing (relates to security of supply concerns)*	• *Flexibility of operation – response rates, two shifting*
• *Availability of low cost feedstock*	• *Outage requirements and expected unplanned outages*
	• *Availability of O&M contractor*
Plant Track-record	
• *Proven technology*	*Environmental / Permitting*
• *Financially strong backer of technology*	• *General permitting issues*
• *Technical obsolescence (through anticipated future developments)*	• *Land footprint*
	• *Air quality impacts*
	• *Water demand*
Financial	• *By-product disposal*
• *Ability to project finance*	• *Public acceptability*
• *Access to public funds*	• *Safety and health risks*

10) Please answer 'yes' or 'no' to whether *[organisation name]* would consider each the following options to reduce CO_2 emissions?

a) fuel switching from coal or oil to natural gas
b) fuel switching to CO_2-neutral fuels such as biomass
c) efficiency improvements *(if still feasible on existing plant?)*
d) replanting with supercritical steam cycle
e) reduced annual power output
f) renewables
g) nuclear

Thank-you for your answers so far – if you have specialist technical knowledge on carbon capture we'd be grateful if you could answer the next section as well. Finally, we're going to follow up this conversation with a brief written questionnaire, building on your answers to provide an analysis of how the different carbon capture technologies fit with *[organisation name]*'s investment preferences.

Follow Up Questions for Technical Specialists

1) What are your organisation's opinions on the relative merits of the different generation technologies with CO_2 capture?

2) What are your views on the relative merits of the various CO2 storage methods?

- deep geological storage in aquifer formations etc.
- use for enhanced oil recovery, leading to storage in depleted oil reservoirs
- storage in depleted gas/oil reservoirs
- onshore versus offshore injection points
- storage of supercritical CO_2 at bottom of deep ocean water column (so not contained).
- developing other means of storing CO_2 in the long term [e.g. 'mineralisation' - turning it into rock]

3) Does your organisation have interest in the potential CO_2 storage market?

4) How would the respondent describe the organisation's in-house technical expertise with respect to power generation technologies with CO_2 capture?

Appendix D Follow-up Questionnaire Template

As with the interview template, the follow-up questionnaire was developed through both internal and external testing, and was tailored to the organisation in question to be sent out following each completed telephone interview. In the original questionnaire document version, the form fields were set to allow selection of the options presented from a drop-down menu. A set of appendices explaining the acronyms and generation technologies with CO_2 capture was also included with the questionnaire, as now included in the main body of this report.

Follow-up Questionnaire
- Views on investment in power generation and CO_2 capture

Thank you for your assistance so far. Our intention is that this follow-up questionnaire will build on the responses of the telephone interview, and should take about 10 minutes of your time to complete.

You can easily complete the questionnaire in Word using the grey-shaded form fields, or if you prefer you can print the respond to the questions by hand.

When completed please return by email to philip.napier-moore@mottmac.com, emily.white@mottmac.com, or rob.collins@mottmac.com, or fax to +44(0)1273 365362, marked for the attention of the 'IEA Carbon Capture study team'.

Please call +44(0)1273 365000 and ask for one of the above team-members if you have any questions.

1) What best describes *[organisation name]*? (*Please check boxes if correct, or amend as necessary)*

General

- Private Project Development Company ☐
- Municipal Government ☐
- State-owned Agency – Generation ☐
- State-owned Agency – Vertically Integrated ☐
- Private Utility Company – Generation ☐
- Private Utility Company – Vertically Integrated ☐
- Other (e.g. in process of unbundling – *please specify*)

- Operating in single country ☐
- Operating in multiple countries *(please specify)*

- Responsible for security of electricity supply ☐

Organisational Characteristics – Investment

- Possessing strong appetite for capital investment ☐
- Investing according to standard industry criteria ☐
- Investing only in 'high performance' projects ☐
- Not currently investing in new plant ☐
- Other *(please specify)*

Organisational Characteristics – Carbon/Environment

- Facing strong pressure to deliver CO_2 reductions ☐
- Facing internal corporate pressures to ensure investments mitigate detrimental environmental impacts ☐
- Facing in-country legislative framework for CO_2 capture and/or CO_2 credits ☐
- Geographically located close to possible CO_2 sinks ☐
- Familiar with CO_2 capture technology ☐
- Do not consider carbon emissions a relevant factor in plant investment decisions ☐

Organisational Characteristics – Technology Preferences

- Positively motivated to invest in carbon capture capable technology due to current economic conditions (e.g. low spark spread compared with clean dark spread) ☐
- Positively motivated to demonstrate low-carbon generation technologies through investment in plant ☐
- Positively motivated to invest in carbon capture generation technologies due to perceived benefits possible from certificate trading ☐
- Concerned about the risks of low load factor after capture technology fitted ☐
- Concerned about the risk of technical obsolescence arising from policy changes or technological changes ☐
- Not concerned about carbon issues ☐

2) We understand that *[organisation name]*: (*Please check boxes if correct, or amend as necessary)*

- Is interested in investing in new thermal generation plant within the next two years ☐
- Is interested in investing in new thermal generation plant within the next five years ☐
- Is interested in investing in new thermal generation plant within the next ten years ☐
- Is interested in investing in new thermal generation plant within the foreseeable future ☐
- Is not interested in investing in new thermal generation plant within the foreseeable future ☐

- Is currently mainly generating using coal plant ☐
- Is currently mainly generating using gas plant ☐
- Is currently generating using an even mix of coal and gas plant ☐
- Generates using other plant technology *(please specify)*

3a) How do the following key criteria play a role in *[organisation name]*'s decision to invest in a particular type of plant?

(*Please choose a category – 1. always, 2. frequently, 3. some of the time, 4. rarely, or 5. never – from the drop-down menu for each of the items on the list below)*

<u>Financial</u>

- High financial return (best payback, IRR, NPV) -
- Low capital costs -
- Ability to project finance -
- Access to public funds -

<u>Logistics</u>

- Build time -
- Modular construction -
- Flexibility of operation – response rates, two shifting -
- Outage requirements and expected unplanned outages -
- Availability of skilled O&M contractor -

<u>Environmental / Permitting</u>

- General permitting issues -
- Land footprint -
- Air quality impacts -
- % reduction in CO_2 -
- % reduction in other GHG -
- Water demand -
- By-product disposal -
- Traffic impacts -
- Public acceptability -
- Safety and health risks -

<u>Plant Track-record</u>

- Proven technology -
- Financially strong manufacturer of technology -
- Technical obsolescence (anticipated future developments) -

<u>Market</u>

- Potential for by-product sales -
- Availability of low cost feedstock -
- Diversity of fuel sourcing to mitigate security of supply concerns -
- Availability of skills -

3b) What key differences would there be in your responses in question 3a above, when considering different countries/regions for new thermal investment?

4) Using current standard technologies, either a CCGT or PF Coal Plant, as a benchmark, please rate the following carbon capture technologies according to your view on the listed criteria. Please answer generally for *[organisation name]*'s operations.

(*Please rate the technologies – from 1{best} to 5 {worst} – using the drop-down menu for each of the items on the list below. Although we have provided provisional responses for the Benchmark technologies, please feel free to amend these. Please leave blank if you have no view on a particular technology.)*

	Benchmark 1 – CCGT	**Benchmark 2 – PF Coal**	**Post-combustion capture (gas)**	**Post-combustion capture (coal)**	**Oxyfuel boilers**	**IGCC**	**Pre-combustion CO_2 removal by reformation of natural gas**
Environmental / Permitting							
General permitting issues	1	3	-	-	-	-	-
Public acceptability	2	3	-	-	-	-	-
Safety and health risks	1	1	-	-	-	-	-
Logistics							
Build time	1	3	-	-	-	-	-
Modular construction	1	4	-	-	-	-	-
Flexibility of operation – response rates, two shifting	1	2	-	-	-	-	-
Outage requirements and expected unplanned outages	1	3	-	-	-	-	-
Availability of O&M contractor	1	1	-	-	-	-	-
Plant Track-record							
Proven technology	1	1	-	-	-	-	-
Financially strong manufacturer of technology	1	1	-	-	-	-	-
Risk of technical obsolescence (low rating if risks are considered high)	2	4	-	-	-	-	-
Market							
Potential for by-product sales	5	4	-	-	-	-	-
Availability of low cost feedstock	4	3	-	-	-	-	-
Diversity of fuel sourcing (low rating if security of supply concerns are high)	5	4	-	-	-	-	-
Availability of skills	1	1	-	-	-	-	-
Financial							
Financiers comfort with technology	1	1	-	-	-	-	-
Access to public funds and subsidies	5	4	-	-	-	-	-

If there are any further qualitative criteria you wish to add, please do so in question 6 below.

5) Technology selection – Which of the following generation technologies with carbon capture could best fit *[organisation name]*'s needs?

(*Please check any boxes that apply – see Annexes below for summary descriptions of each technology)*

- Retrofit post-combustion capture to existing coal-fired power plants ☐
- Retrofit post-combustion capture to existing natural gas-fired thermal power plants ☐
- Retrofit post-combustion capture to existing CCGT power plants ☐
- Retrofit post-combustion capture to existing power plants - other fuels *(specify)* ☐

- Post-combustion capture for new coal-fired power plants ☐
- Post-combustion capture for new natural gas-fired thermal power plants ☐
- Post-combustion capture for new CCGT power plants ☐
- Post-combustion capture for new power plants - other fuels *(specify)* ☐

- Oxyfuel conversion of boilers for existing coal-fired power plants ☐
- Oxyfuel conversion of boilers for existing natural gas-fired thermal power plants ☐
- Oxyfuel conversion of boilers for existing power plants - other fuels *(specify)* ☐

- Oxyfuel boilers for new coal-fired power plants ☐
- Oxyfuel boilers for new natural gas-fired thermal power plants ☐
- Oxyfuel boilers for new power plants - other fuels (specify) ☐
- Oxyfuel firing of new CCGT power plants [long-term option only - technology not ready] ☐

- IGCC (coal) repowering of existing thermal power plants ☐
- IGCC (coal) for coal-firing of new CCGT power plants ☐
- IGCC (other fuels - specify) for firing of new CCGT power plants ☐

- Pre-combustion CO_2 removal by reformation of natural gas, for existing thermal power plants ☐
- Pre-combustion CO_2 removal by reformation of natural gas, for new thermal power plants ☐
- Pre-combustion CO_2 removal by reformation of natural gas, for existing CCGT ☐
- Pre-combustion CO_2 removal by reformation of natural gas, for new CCGT ☐
- Pre-combustion CO_2 removal and hydrogen purification for pipeline distribution of hydrogen, possibly including advanced distributed generation ☐
- Pre-combustion CO_2 removal and hydrogen purification for use in advanced power generation plant (e.g. fuel cells) ☐

Please add any comments to explain your choice in the additional space provided on page 6 below.

6) Please add any further comments that you have in the space below.

Appendix E IEA GHG Standard Assessment Criteria

This Appendix contains a general list of technical and financial assumptions used in the four IEA GHG appraisal studies. The assumptions used to assess the different generation technologies in this study are in the general case these standard assessment criteria. The exception to this statement is for item 17, where MM have updated the standard fuel prices, as discussed in section 3.1.2 above. MM have instead applied the following long-run average delivered prices, applicable to plants beginning construction in 2007 onwards:

- Coal price of US$ 2.2/GJ, LHV basis
- Natural Gas price of US$ 7.8/GJ, LHV basis

Technical/Financial Factor (notes)	Assessment Convention
1. <u>Development Status</u> *(It is well documented that the cost of technology decreases and its performance improves as experience is gained.)*	*For commercially available technology current 'state-of-the-art' cost and performance figures will be assumed.* *Where technology has only reached the demonstration stage or earlier stages of development, 1st (commercial) generation costs and performance will be assumed and compared with 'state-of-the-art' current figures. The cost vs. installed capacity relationship assumed should be presented in the results.*
2. <u>Plant Size</u> *(Significant economics of scale can apply up to the size at which increases can only be obtained by using plant modules and/or the cost of working capital due to extended construction periods outweighs benefits of scale.)*	*The net power output after deducting ancillary power requirements will be 750 MW. There will be cases (e.g. gas turbines which have fixed sizes) where it is not possible or advisable to match the required net power output. In such cases the power output will be agreed with IEA GHG.*
3. <u>Location</u> *(The standard site for IEAGHG studies is on the NE coast of The Netherlands; this appears to give costs which are in the middle of the range for OECD member countries.)*	*A green field site with no special civil works implications will be assumed. Unless otherwise specified, the plant will be assumed to be on the NE coast of The Netherlands. Adequate plant and facilities to make the plant self sufficient in site services will be included in the investment costs.* *Alternative and/or multiple sites will be specified for some studies.*

<table>
<tr><th>Technical/Financial Factor (notes)</th><th>Assessment Convention</th></tr>
<tr><td>4. Currency
(Converting US$ costs to a local currency equivalent involves more than using the current exchange rate; members of the IEA GHG programme will need to take their own views on appropriate rates.)</td><td>The results of the studies will be expressed in US $ applicable to a specific year. Data obtained in other currencies will be converted at rates to be agreed.</td></tr>
<tr><td>5. Design and Construction Period
(Project finances can be sensitive to the time required to erect the plant.)</td><td>Coal fired power generation plant: 3 years.
Natural gas fired combined cycle plant: 2 years.
CO_2 capture plant and ‘chemical plants’ in general: 2 years.
Underground CO_2 storage: 2 years
Ocean storage: 4 years (assuming a long pipeline to the disposal point)
Modular renewable technologies such as wind turbines: 1 year

Typical `S' curves of expenditure during construction will be used, viz:
<table>
<tr><th>Year</th><th>Coal-fired Power Plant %</th><th>Natural gas fired Power Plant %</th><th>`Chemical' Plant %</th></tr>
<tr><td>1</td><td>20</td><td>40</td><td>40</td></tr>
<tr><td>2</td><td>45</td><td>60</td><td>60</td></tr>
<tr><td>3</td><td>35</td><td></td><td></td></tr>
</table></td></tr>
<tr><td>6. Plant Life
(Design life to be used as a basis for economic appraisal. A financial assessment convention; actual life is frequently extended.)</td><td>Twenty-five years. Where for technical reasons this is regarded as excessive, provision will be made for the cost of any major maintenance/refurbishment or a shorter life will be assumed.</td></tr>
<tr><td>7. Load Factor
(Achieved output as a percentage of rated/nameplate capacity. Appropriate to the ranking of technical options; in practice, because of system limitations, many power plants achieve considerably less output.)</td><td>For coal, other solids, and liquid processing plants; 1st. year: 60% of rated capacity; subsequent years: 85% of rated capacity. For natural gas fuelled plants (and other plants solely processing gases) 90% of rated capacity for all operating years. Renewable technologies on a case-by-case basis.

Allowance should be made for sufficient installed duplicate/spare capacity to meet required load factor taking into account maintenance requirements and reliability. No allowance for decline as plant ages.</td></tr>
</table>

Technical/Financial Factor (notes)	Assessment Convention
8. <u>*Cost of Debt*</u> *(Note that money is required during design, construction and commissioning i.e. before any returns on sales are achieved.)*	*For simplicity, all capital requirements will be treated as debt at the same discount rate used to derive capital charges. No allowance for grants, cheap loans etc. (More complex financial modelling might be considered for certain studies.)* *Specific capital cost figures should be presented without including an allowance for funds used during construction (i.e. independent of discount rate).*
9. <u>*Capital charges; inflation*</u> *(In the event of the reduction in carbon emissions being achieved at a significantly later date than the expenditure, the investment costs should be projected forwards.)*	*Discounted cash flow calculations will be expressed at a discount rate of 10% and, to illustrate sensitivity, at 5%; the resulting capital charge rate will be quoted. All annual expenditures will be assumed to be incurred at the end of the year.* *Inflation assumptions will not be made. No allowance will be made for escalation of fuel, labour, or other costs relative to each other.*
10. <u>*Contingencies*</u> *(A contingency is added to the capital cost to allow for unforeseen set-backs, cost under-estimates, programme overruns etc.)*	*A contingency will be added to the capital cost to give a 50% probability of a cost over-run or under-run. In the absence of a more detailed assessment, the default value for the contingency should be 10% of the installed plant cost (overnight construction).* *All plant should be assumed to be built on a turnkey basis, ie; the cost of risk should be built into the contractor's fees.*
11. <u>*Fees and other owners costs*</u> *(The contractor's fees for design and build will form part of the basic plant cost estimate; additional fees and costs covered here include:- process/patent fees, fees for agents or consultants, legal and planning costs, land purchase, surveys and general site preparation etc. Start-up costs are not included here as they are calculated separately)*	*A total of 7% of the installed plant cost (overnight construction, excluding contingency) will be included to cover these owners costs.* *A separate statement of the cost should be made where any proprietary technology or other technology license fee exceeds 2% of the plant cost.*

Technical/Financial Factor (notes)	Assessment Convention
12. <u>Commissioning and Working Capital</u> *(Commissioning is defined as the period between the construction period [item 3] and the start of the 1st year of operation [item 4]. Working capital includes raw materials in store, catalysts, chemicals etc.)*	*A 3 month commissioning period will be allowed for all plant. Sufficient storage for 30 days operation at rated capacity will be allowed for raw materials, products, and consumables (except for natural gas and other gaseous fuels in which case provision should be made for an alternative supply of fuel). No allowance will be made for receipts from sales in this period.*
13. <u>Decommissioning</u> *(Costs associated with final shut down of the plant, long term provisions and 'making good' the Site).*	*This will be included to facilitate comparison with technologies where decommissioning can be a significant proportion of project cost.*
14. <u>Taxation and Insurance</u> *(The treatment of these items will differ markedly from country to country. Therefore, a simple treatment is used which can be readily adapted to suit the circumstances of individual members.)*	*Allow 1% per year of the installed plant cost (overnight construction, excluding contingency and fees) to cover specific services e.g. local rates. Taxation on profits will not be included in the assessments.* *Allow 1% per year of the installed plant cost (overnight construction excluding contingency and fees) to cover insurance.*
15. <u>Maintenance</u> *(To include labour, materials and contract maintenance costs)*	*Routine and breakdown maintenance will be allowed for at: 4% per year of installed plant cost (overnight construction excluding contingency and fees) for solids handling plant and at 2% per year for plants handling gases and liquids and services plant.*
16. <u>Labour</u> *(Agreed conventions are required for the treatment of operating, supervising, maintenance and other labour elements; including administrative, other general overheads and items such as social security payments.)*	*The cost of maintenance labour is assumed to be covered by item 15.* *Operating labour only will be identified and assumed to work in a 5 shift pattern. If not estimated in detail, an allowance of 20% of the operating labour direct costs will be included to cover supervision. A further 30% of direct labour costs will be included to cover administration and general overheads. (ie; total cost = (direct operating labour cost x 1.2) x 1.3)*

Technical/Financial Factor (notes)	Assessment Convention
17. Fuels and Raw Materials *(Where a range of fossil fuels could be used, coal and natural gas will normally be specified as they span the range of H:C ratios for fossil fuels.)*	*'Typical' bituminous coal and natural gas are used as a standards. Their specifications are given on the last page of this document.* *Where appropriate the analysis of alternative fossil fuels fuel will be supplied.* *The cost of coal delivered to site is to be assumed to be US$1.5/GJ (LHV basis).* *The cost of natural gas delivered by pipeline to site is to be assumed to be US$3/GJ (LHV basis).* *The studies will show the cost of power generated for a range of fuel prices (0-3 US $/GJ for coal and 0-6 US $/GJ for gas).*
18. Water.	*The use of sea water cooling will be assumed for the site in the Netherlands and other coastal sites. Direct cooling will be used for the steam turbine condenser and large compressor intercoolers and an indirect cooling system will be used for other process coolers. Unless otherwise stated, any inland sites will be assumed to use closed circuit cooling water systems.* *Sea-water cooling conditions are: Average inlet temperature 12C; maximum temperature rise 7C; salinity 22grams/litre.*

Technical/Financial Factor (notes)	Assessment Convention
19. <u>Effluent/Emissions and Solids Disposal</u> *(a) Sulphur, ash, oils and tars, NO_x, SO_x etc (other than CO_2)*	*The plant will be assumed to have effluent abatement and treatment facilities sufficient to meet achievable reductions, eg* *Particulate matter < 25 mg/Nm^3* *NO_x < 200 mg/Nm^3* *SO_2 < 200 mg/Nm^3* *Where disposal of waste is required the cost of appropriate plant and methods will be included in the assessments. The cost of ash disposal, value of by-products e.g. sulphur, etc., will be treated on a case-by-case basis.*
(b) CO_2 processing.	*Unless otherwise specified, minimum CO_2 capture level is to be 80%; and the preferred level 85%.* *Unless otherwise specified, CO_2 is to be compressed to 110 bar before injection into the transfer pipeline.* *Note will be taken of possible emissions arising from CO_2 processing, eg, amine scrubbing.*
20. <u>Site Conditions</u>	*Ambient air temperature: 9C* *Ambient air relative humidity: 60%* *Ambient air pressure: 1.013 bar*
21. <u>Heat Content</u>	*Lower Heating Value will be used in all efficiency calculations*

FUEL SPECIFICATIONS

1. Natural gas specification

Component	volume %
Methane	83.9
Ethane	9.2
Propane	3.3
Butane +	1.4
CO_2	1.8
Nitrogen	0.4
Sulphur (as H_2S)	4 mg/Nm^3
Gross CV	53.76 MJ/kg
Net CV	48.51 MJ/kg

The gas specification is based on a pipeline quality gas from the southern part of the Norwegian off-shore reserves.

2. Coal specification

Proximate analysis:	weight %
coal (dry, ash-free)	78.3
ash	12.2
moisture	9.5
Ultimate analysis:	
Carbon	82.5
Hydrogen	5.6
Oxygen	9.0
Nitrogen	1.8
Sulphur	1.1
Chlorine	0.03
Ash analysis:	
SiO_2	50.0
Al_2O_3	30.0
TiO_2	2.0
Fe_2O_3	9.7
CaO	3.9
MgO	0.4
Na_2O	0.1
K_2O	0.1
P_2O_5	1.7
SO_3	1.7
Gross CV	27.06 MJ/kg
Net CV	25.87 MJ/kg
Hardgrove Index	45
Ash fusion point (reducing atmosphere)	1350 C

The coal specification is based on an open-cut coal from Eastern Australia.

Appendix F Economic Assessment of Plant Options – Results

Version 1
Date : February 2003

IEA GREENHOUSE GAS R&D PROGRAMME

Cost Evaluation - Fluor CCGT without Capture (IEA GHG, 2004, Case 1)

Production		
Fuel feedrate	1396.0	MW
Net power output	776.0	MW
By-product output	0.00	t/h
Solid waste output	0.00	t/h
CO_2 emissions	379	g/kWh
Thermal efficiency	55.6%	
Reference plant data		
For calculation of cost of emission avoidance		
CO_2 emissions	379	g/kWh
Electricity cost	6.230346	c/kWh

Capital Cost		**Million $**
Installed costs		331.0
Average contingencies	10.0%	33.1
Owners costs	7.0%	23.2
Total capital cost		387.3
Working Capital		
Chemicals storage		0.0
Fuel storage		0.0
Total working capital		0.0
Decommissioning cost		0
Specific Capex		499 US$/kW net

Operating Costs at 85% load factor	**Million $/year**
Fuel	291.9
Maintenance	9.1
Chemicals + consumables	0.4
Insurance and local taxes	6.6
Waste disposal	0.0
Operating labour	4.0
Power Sale Tariff	**c/kWh**
Wholesale Power tariff	6.2303

Economic parameters		
Discount rate	10.0	%
Load factor (years 2-25)	85.0	%
Fuel price	7.80	$/GJ
By-product price	0.0	$/t
Waste disposal cost	0.0	$/t
Insurance and local taxes	2.0%	of installed cost/y
Number of operators	62	
Cost per operator	50.0	$k/y
Administration	30%	of operators cost
Fuel storage	0	days
Chemicals storage	30	days
Start up time	9	months
Load factor, remainder year 1	85	%

Results summary		
Electricity production cost	6.230	c/kWh
NPV	0.00	M$
IRR	10.00%	
Emission avoidance cost	#DIV/0!	$/t CO_2
Breakdown of c/kWh cost		
Fuel	81.08%	
Capital	13.09%	
Other costs	5.83%	

CASH FLOW ANALYSIS

Million $	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Year	**000**	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				21%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				1862	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	0%	40%	40%	20%																									
Revenues																													
Electricity	0.0	0.0	0.0	90.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	360.0	
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs																													
Fuel	0.0	0.0	0.0	-73.0	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	
Maintenance	0.0	0.0	0.0	-2.3	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	-9.1	
Labour	0.0	0.0	0.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	
Chemicals & consumables	0.0	0.0	0.0	-0.1	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes	0.0	0.0	0.0	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	
Fixed Capital Expenditures	0.0	-154.9	-154.9	-77.5																									
Working Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning Cost																													0.0
Total Cash Flow (yearly)	0.0	-154.9	-154.9	-73.5	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	0.0
Total Cash Flow (cumulated)	0.0	-154.9	-309.8	-383.3	-335.3	-287.3	-239.3	-191.3	-143.3	-95.3	-47.3	0.7	48.8	96.8	144.8	192.8	240.8	288.8	336.8	384.8	432.8	480.8	528.8	576.8	624.8	672.8	720.8	768.8	768.9

Version 1

Date : February 2003

IEA GREENHOUSE GAS R&D PROGRAMME

Cost Evaluation - Fluor Gas Post-combustion Capture (IEA GHG, 2004, Case 2)

Production		
Fuel feedrate	1396.0	MW
Net power output	662.0	MW
By-product output	0.00	t/h
Solid waste output	0.00	t/h
CO_2 emissions	66	g/kWh
Thermal efficiency	47.4%	
Reference plant data		
For calculation of cost of emission avoidance		
CO_2 emissions	379	g/kWh
Electricity cost	6.230346	c/kWh
	0.2818	

Capital Cost		**Million $**
Installed costs		491.5
Average contingencies	10.0%	49.1
Owners costs	7.0%	34.4
Total capital cost		575.0
Working Capital		
Chemicals storage		0.5
Fuel storage		0.0
Total working capital		0.5
Decommissioning cost		0
Specific Capex		869 US$/kW net

Operating Costs at 85% load factor	**Million $/year**
Fuel	291.9
Maintenance	13.5
Chemicals + consumables	5.5
Insurance and local taxes	9.8
Waste disposal	0.0
Operating labour	4.0
Power Sale Tariff	**c/kWh**
Wholesale Power tariff	6.2303

Economic parameters		
Discount rate	10.0	%
Load factor (years 2-25)	85.0	%
Fuel price	7.80	$/GJ
By-product price	0.0	$/t
Waste disposal cost	0.0	$/t
Insurance and local taxes	2.0%	of installed cost/y
Number of operators	62	
Cost per operator	50.0	$k/y
Administration	30%	of operators cost
Fuel storage	0	days
Chemicals storage	30	days
Start up time	9	months
Load factor, remainder year 1	85	%

Results summary		
Electricity production cost	8.032	c/kWh
NPV	-560.12	M$
IRR	#DIV/0!	
Emission avoidance cost	57.6	$/t CO_2
Breakdown of c/kWh cost		
Fuel	73.72%	
Capital	17.69%	
Other costs	8.59%	

CASH FLOW ANALYSIS

Million $	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Year	**000**	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Load Factor				21%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				1862	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	0%	40%	40%	20%										
Revenues														
Electricity	0.0	0.0	0.0	76.8	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Costs														
Fuel	0.0	0.0	0.0	-73.0	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9
Maintenance	0.0	0.0	0.0	-3.4	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5
Labour	0.0	0.0	0.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0
Chemicals & consumables	0.0	0.0	0.0	-1.4	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance and local taxes	0.0	0.0	0.0	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8
Fixed Capital Expenditures	0.0	-230.0	-230.0	-115.0										
Working Capital	0.0	0.0	0.0	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning Cost														
Total Cash Flow (yearly)	0.0	-230.0	-230.0	-130.3	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6
Total Cash Flow (cumulated)	0.0	-230.0	-460.0	-590.3	-608.0	-625.6	-643.3	-660.9	-678.5	-696.2	-713.8	-731.5	-749.1	-766.7

Million $	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Year	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor															
Revenues															
Electricity	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1	307.1	
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs															
Fuel	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	-291.9	
Maintenance	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	-13.5	
Labour	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	
Chemicals & consumables	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	-5.5	
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	-9.8	
Fixed Capital Expenditures															
Working Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Decommissioning Cost															0.0
Total Cash Flow (yearly)	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	-17.6	0.5
Total Cash Flow (cumulated)	-784.4	-802.0	-819.7	-837.3	-854.9	-872.6	-890.2	-907.9	-925.5	-943.1	-960.8	-978.4	-996.1	-1013.7	-1013.2

Mott MacDonald

IEA GREENHOUSE GAS R&D PROGRAMME

Cost Evaluation - Pre-combustion Capture (IEA GHG, 2005, Case 2.1)

Production		
Fuel feedrate	1672.4	MW
Net power output	693.7	MW
By-product output	0.00	t/h
Solid waste output	0.00	t/h
CO_2 emissions	72	g/kWh
Thermal efficiency	41.5%	
Reference plant data		
For calculation of cost of emission avoidance		
CO_2 emissions	379	g/kWh
Electricity cost	6.230346	c/kWh

Capital Cost		**Million $**
Installed costs		700.9
Average contingencies	10.0%	70.1
Owners costs	7.0%	49.1
Total capital cost		820.1
Working Capital		
Chemicals storage		1.1
Fuel storage		0.0
Total working capital		1.1
Decommissioning cost		0
Specific Capex		1182 US$/kW net

Operating Costs at 85% load factor	**Million $/year**
Fuel	349.7
Maintenance	18.7
Chemicals + consumables	11.1
Insurance and local taxes	14.0
Waste disposal	0.0
Operating labour	4.0
Power Sale Tariff	**c/kWh**
Wholesale Power tariff	6.2303

Economic parameters		
Discount rate	10.0	%
Load factor (years 2-25)	85.0	%
Fuel price	7.80	$/GJ
By-product price	0.0	$/t
Waste disposal cost	0.0	$/t
Insurance and local taxes	2.0%	of installed cost/y
Number of operators	62	
Cost per operator	50.0	$k/y
Administration	30%	of operators cost
Fuel storage	0	days
Chemicals storage	30	days
Start up time	9	months
Load factor, remainder year 1	85	%

Results summary		
Electricity production cost	9.659	c/kWh
NPV	-1,117	M$
IRR	#DIV/0!	
Emission avoidance cost	111.7	$/t CO_2
Breakdown of c/kWh cost		
Fuel	70.09%	
Capital	20.03%	
Other costs	9.88%	

CASH FLOW ANALYSIS

Million $	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Year	**000**	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				21%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				1862	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	0%	40%	40%	20%																									
Revenues																													
Electricity	0.0	0.0	0.0	80.5	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	321.8	
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs																													
Fuel	0.0	0.0	0.0	-87.4	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	-349.7	
Maintenance	0.0	0.0	0.0	-4.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	-18.7	
Labour	0.0	0.0	0.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	-4.0	
Chemicals & consumables	0.0	0.0	0.0	-2.8	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	-11.1	
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes	0.0	0.0	0.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	
Fixed Capital Expenditures	0.0	-328.0	-328.0	-164.0																									
Working Capital	0.0	0.0	0.0	-1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1
Decommissioning Cost																													0.0
Total Cash Flow (yearly)	0.0	-328.0	-328.0	-197.6	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	-75.7	1.1
Total Cash Flow (cumulated)	0.0	-328.0	-656.1	-853.6	-929.3	-1005.0	-1080.7	-1156.4	-1232.1	-1307.8	-1383.5	-1459.2	-1534.9	-1610.7	-1686.4	-1762.1	-1837.8	-1913.5	-1989.2	-2064.9	-2140.6	-2216.3	-2292.0	-2367.7	-2443.4	-2519.1	-2594.8	-2670.5	-2669.4

Mott MacDonald

	Version 1
IEA GREENHOUSE GAS R&D PROGRAMME	Date : February 2003

Cost Evaluation - MBEL Oxyfuel Gas with Capture (IEA GHG, 2005a, Case 4)

Production		
Fuel feedrate	984.5	MW
Net power output	440.0	MW
By-product output	0.00	t/h
Solid waste output	0.00	t/h
CO_2 emissions	12	g/kWh
Thermal efficiency	44.7%	

Reference plant data		
For calculation of cost of emission avoidance		
CO_2 emissions	379	g/kWh
Electricity cost	6.230346	c/kWh

Capital Cost		**Million $**
Installed costs		576.1
Average contingencies	10.0%	57.6
Owners costs	7.0%	40.3
Total capital cost		674.0
Working Capital		
Chemicals storage		0.0
Fuel storage		0.0
Total working capital		0.0
Decommissioning cost		0
Specific Capex		1532 US$/kW net

Operating Costs at 85% load factor	**Million $/year**
Fuel	205.8
Maintenance	22.5
Chemicals + consumables	0.1
Insurance and local taxes	11.5
Waste disposal	0.0
Operating labour	3.9
Power Sale Tariff	**c/kWh**
Wholesale Power tariff	6.2303

Economic parameters		
Discount rate	10.0	%
Load factor (years 2-25)	85.0	%
Fuel price	7.80	$/GJ
By-product price	0.0	$/t
Waste disposal cost	0.0	$/t
Insurance and local taxes	2.0%	of installed cost/y
Number of operators	60	
Cost per operator	50.0	$k/y
Administration	30%	of operators cost
Fuel storage	0	days
Chemicals storage	30	days
Start up time	3	months
Load factor, remainder year 1	85	%

Results summary		
Electricity production cost	9.983	c/kWh
NPV	-817.37	M$
IRR	#DIV/0!	
Emission avoidance cost	102.2	$/t CO_2
Breakdown of c/kWh cost		
Fuel	62.94%	
Capital	25.31%	
Other costs	11.75%	

CASH FLOW ANALYSIS

Million $

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Year	000	00	0	1	2	3	4	5	6	7	8	9	10	11
Load Factor				64%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				5585	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%											
Revenues														
Electricity	0.0	0.0	0.0	153.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Costs														
Fuel	0.0	0.0	0.0	-154.4	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8
Maintenance	0.0	0.0	0.0	-16.9	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5
Labour	0.0	0.0	0.0	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9
Chemicals & consumables	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance and local taxes	0.0	0.0	0.0	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5
Fixed Capital Expenditures	-134.8	-303.3	-235.9											
Working Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning Cost														
Total Cash Flow (yearly)	-134.8	-303.3	-235.9	-33.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7
Total Cash Flow (cumulated)	-134.8	-438.1	-674.0	-707.7	-747.5	-787.2	-826.9	-866.7	-906.4	-946.2	-985.9	-1025.7	-1065.4	-1105.1

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Year	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor															
Revenues															
Electricity	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	204.1	
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs															
Fuel	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	-205.8	
Maintenance	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	
Labour	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	
Chemicals & consumables	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	
Fixed Capital Expenditures															
Working Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Decommissioning Cost															0.0
Total Cash Flow (yearly)	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	-39.7	0.0
Total Cash Flow (cumulated)	-1144.9	-1184.6	-1224.4	-1264.1	-1303.9	-1343.6	-1383.4	-1423.1	-1462.8	-1502.6	-1542.3	-1582.1	-1621.8	-1661.6	-1661.6

IEA GREENHOUSE GAS R&D PROGRAMME

Cost Evaluation - Fluor USCPF without Capture (IEA GHG, 2004, Case 3)

Version 1
Date : February 2003

Production		
Fuel feedrate	1723.0	MW
Net power output	758.0	MW
By-product output	0.00	t/h
Solid waste output	0.00	t/h
CO_2 emissions	743	g/kWh
Thermal efficiency	44.0%	
Reference plant data		
For calculation of cost of emission avoidance		
CO_2 emissions	743	g/kWh
Electricity cost	5.366492	c/kWh

Capital Cost		**Million $**
Installed costs		912.4
Average contingencies	10.0%	91.2
Owners costs	7.0%	63.9
Total capital cost		1067.6
Working Capital		
Chemicals storage		0.6
Fuel storage		9.8
Total working capital		10.4
Decommissioning cost		0
Specific Capex		1408 US$/kW net

Operating Costs at 85% load factor	**Million $/year**
Fuel	101.6
Maintenance	31.3
Chemicals + consumables	6.5
Insurance and local taxes	18.2
Waste disposal	0.0
Operating labour	8.1
Power Sale Tariff	**c/kWh**
Wholesale Power tariff	6.2303

Economic parameters		
Discount rate	10.0	%
Load factor (years 2-25)	85.0	%
Fuel price	2.20	$/GJ
By-product price	0.0	$/t
Waste disposal cost	0.0	$/t
Insurance and local taxes	2.0%	of installed cost/y
Number of operators	124	
Cost per operator	50.0	$k/y
Administration	30%	of operators cost
Fuel storage	30	days
Chemicals storage	30	days
Start up time	3	months
Load factor, remainder year 1	60	%

Results summary		
Electricity production cost	5.366	c/kWh
NPV	316.83	M$
IRR	13.74%	
Emission avoidance cost	#DIV/0!	$/t CO_2
Breakdown of c/kWh cost		
Fuel	33.55%	
Capital	44.62%	
Other costs	21.83%	

CASH FLOW ANALYSIS

Million $	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Year	**000**	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electricity	0.0	0.0	0.0	186.2	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	351.6	
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs																													
Fuel	0.0	0.0	0.0	-53.8	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	-101.6	
Maintenance	0.0	0.0	0.0	-23.5	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	-31.3	
Labour	0.0	0.0	0.0	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	-8.1	
Chemicals & consumables	0.0	0.0	0.0	-3.4	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	-6.5	
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes	0.0	0.0	0.0	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	-18.2	
Fixed Capital Expenditures	-213.5	-480.4	-373.6																										
Working Capital	0.0	0.0	0.0	-10.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.4
Decommissioning Cost																													0.0
Total Cash Flow (yearly)	-213.5	-480.4	-373.6	68.7	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	185.9	10.4
Total Cash Flow (cumulated)	-213.5	-693.9	-1067.6	-998.9	-812.9	-627.0	-441.0	-255.1	-69.1	116.8	302.8	488.7	674.7	860.6	1046.6	1232.5	1418.5	1604.4	1790.4	1976.3	2162.2	2348.2	2534.1	2720.1	2906.0	3092.0	3277.9	3463.9	3474.3

Mott MacDonald

IEA GREENHOUSE GAS R&D PROGRAMME

Cost Evaluation - Fluor Coal Post-combustion Capture (IEA GHG, 2004, Case 4)

Production		
Fuel feedrate	1913.0	MW
Net power output	666.0	MW
By-product output	14.08	t/h
Solid waste output	34.20	t/h
CO_2 emissions	117	g/kWh
Thermal efficiency	34.8%	
Reference plant data		
For calculation of cost of emission avoidance		
CO_2 emissions	743	g/kWh
Electricity cost	5.366492	c/kWh
	0.567006	

Capital Cost		**Million $**
Installed costs		1126.6
Average contingencies	10.0%	112.7
Owners costs	7.0%	78.9
Total capital cost		1318.1
Working Capital		
Chemicals storage		2.0
Fuel storage		10.9
Total working capital		12.9
Decommissioning cost		0
Specific Capex		1979 US$/kW net

Operating Costs at 85% load factor	**Million $/year**
Fuel	112.8
Maintenance	37.7
Chemicals + consumables	20.5
Insurance and local taxes	22.5
Waste disposal	0.0
Operating labour	8.5
Power Sale Tariff	**c/kWh**
Wholesale Power tariff	6.2303

Economic parameters		
Discount rate	10.0	%
Load factor (years 2-25)	85.0	%
Fuel price	2.20	$/GJ
By-product price	0.0	$/t
Waste disposal cost	0.0	$/t
Insurance and local taxes	2.0%	of installed cost/y
Number of operators	130	
Cost per operator	50.0	$k/y
Administration	30%	of operators cost
Fuel storage	30	days
Chemicals storage	30	days
Start up time	3	months
Load factor, remainder year 1	60	%

Results summary		
Electricity production cost	7.486	c/kWh
NPV	-404.63	M$
IRR	5.35%	
Emission avoidance cost	33.9	$/t CO_2
Breakdown of c/kWh cost		
Fuel	30.39%	
Capital	44.95%	
Other costs	24.66%	

CASH FLOW ANALYSIS

Million $	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Year	**000**	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electricity	0.0	0.0	0.0	163.6	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	309.0	
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs																													
Fuel	0.0	0.0	0.0	-59.7	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	-112.8	
Maintenance	0.0	0.0	0.0	-28.2	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	-37.7	
Labour	0.0	0.0	0.0	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	-8.5	
Chemicals & consumables	0.0	0.0	0.0	-10.8	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	-20.5	
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes	0.0	0.0	0.0	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	-22.5	
Fixed Capital Expenditures	-263.6	-593.1	-461.3																										
Working Capital	0.0	0.0	0.0	-12.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.9
Decommissioning Cost																													0.0
Total Cash Flow (yearly)	-263.6	-593.1	-461.3	20.9	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	12.9
Total Cash Flow (cumulated)	-263.6	-856.8	-1318.1	-1297.2	-1190.2	-1083.2	-976.1	-869.1	-762.1	-655.1	-548.1	-441.0	-334.0	-227.0	-120.0	-13.0	94.0	201.1	308.1	415.1	522.1	629.1	736.2	843.2	950.2	1057.2	1164.2	1271.3	1284.2

Version 1

IEA GREENHOUSE GAS R&D PROGRAMME

Cost Evaluation - F-W Texaco IGCC with Capture (IEA GHG, 2003, Case D1)

Date : February 2003

Production		
Fuel feedrate	2321.8	MW
Net power output	730.3	MW
By-product output	2.78	t/h
Solid waste output	108.10	t/h
CO_2 emissions	152	g/kWh
Thermal efficiency	31.5%	

Reference plant data		
For calculation of cost of emission avoidance		
CO_2 emissions	743	g/kWh
Electricity cost	5.366492	c/kWh

Capital Cost		**Million $**
Installed costs		1133.1
Average contingencies	10.0%	113.3
Owners costs	7.0%	79.3
Total capital cost		1325.7
Working Capital		
Chemicals storage		0.4
Fuel storage		13.2
Total working capital		13.6
Decommissioning cost		0
Specific Capex		1815 US$/kW net

Operating Costs at 85% load factor	**Million $/year**
Fuel	136.9
Maintenance	35.1
Chemicals + consumables	3.9
Insurance and local taxes	22.7
Waste disposal	0.0
Operating labour	8.3
Power Sale Tariff	**c/kWh**
Wholesale Power tariff	6.2303

Economic parameters		
Discount rate	10.0	%
Load factor (years 2-25)	85.0	%
Fuel price	2.20	$/GJ
By-product price	0.0	$/t
Waste disposal cost	0.0	$/t
Insurance and local taxes	2.0%	of installed cost/y
Number of operators	128	
Cost per operator	50.0	$k/y
Administration	30%	of operators cost
Fuel storage	30	days
Chemicals storage	30	days
Start up time	3	months
Load factor, remainder year 1	60	%

Results summary		
Electricity production cost	6.936	c/kWh
NPV	-249.29	M$
IRR	7.28%	
Emission avoidance cost	26.6	$/t CO_2
Breakdown of c/kWh cost		
Fuel	36.30%	
Capital	44.52%	
Other costs	19.18%	

CASH FLOW ANALYSIS

Million $	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Year	**000**	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electricity	0.0	0.0	0.0	179.4	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	338.8	
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs																													
Fuel	0.0	0.0	0.0	-72.5	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	-136.9	
Maintenance	0.0	0.0	0.0	-26.3	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	-35.1	
Labour	0.0	0.0	0.0	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	
Chemicals & consumables	0.0	0.0	0.0	-2.1	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	-3.9	
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes	0.0	0.0	0.0	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	-22.7	
Fixed Capital Expenditures	-265.1	-596.6	-464.0																										
Working Capital	0.0	0.0	0.0	-13.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.6
Decommissioning Cost																													0.0
Total Cash Flow (yearly)	-265.1	-596.6	-464.0	33.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	131.9	13.6
Total Cash Flow (cumulated)	-265.1	-861.7	-1325.7	-1291.8	-1159.9	-1028.0	-896.1	-764.2	-632.4	-500.5	-368.6	-236.7	-104.8	27.1	159.0	290.9	422.8	554.7	686.6	818.4	950.3	1082.2	1214.1	1346.0	1477.9	1609.8	1741.7	1873.6	1887.2

Mott MacDonald

Version 1

IEA GREENHOUSE GAS R&D PROGRAMME

Cost Evaluation - MBEL Oxyfuel Coal (IEA GHG, 2005a, Case 2)

Date : February 2003

Production		
Fuel feedrate	1502.2	MW
Net power output	532.0	MW
By-product output	0.00	t/h
Solid waste output	26.00	t/h
CO_2 emissions	84	g/kWh
Thermal efficiency	35.4%	
Reference plant data		
For calculation of cost of emission avoidance		
CO_2 emissions	743	g/kWh
Electricity cost	5.366492	c/kWh

Capital Cost		**Million $**
Installed costs		1002.5
Average contingencies	10.0%	100.3
Owners costs	7.0%	70.2
Total capital cost		1172.9
Working Capital		
Chemicals storage		0.0
Fuel storage		8.6
Total working capital		8.6
Decommissioning cost		0
Specific Capex		2205 US$/kW net

Operating Costs	**Million $/year**
at 85% load factor	
Fuel	88.6
Maintenance	39.1
Chemicals + consumables	0.3
Insurance and local taxes	20.1
Waste disposal	0.0
Operating labour	8.8
Power Sale Tariff	**c/kWh**
Wholesale Power tariff	6.2303

Economic parameters		
Discount rate	10.0	%
Load factor (years 2-25)	85.0	%
Fuel price	2.20	$/GJ
By-product price	0.0	$/t
Waste disposal cost	0.0	$/t
Insurance and local taxes	2.0%	of installed cost/y
Number of operators	136	
Cost per operator	50.0	$k/y
Administration	30%	of operators cost
Fuel storage	30	days
Chemicals storage	30	days
Start up time	3	months
Load factor, remainder year 1	60	%

Results summary		
Electricity production cost	7.761	c/kWh
NPV	-393.93	M$
IRR	4.83%	
Emission avoidance cost	36.3	$/t CO_2
Breakdown of c/kWh cost		
Fuel	28.82%	
Capital	48.22%	
Other costs	22.97%	

CASH FLOW ANALYSIS

Million $	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Year	**000**	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electricity	0.0	0.0	0.0	130.7	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	246.8	
By-product	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs																													
Fuel	0.0	0.0	0.0	-46.9	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	-88.6	
Maintenance	0.0	0.0	0.0	-29.3	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	-39.1	
Labour	0.0	0.0	0.0	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	-8.8	
Chemicals & consumables	0.0	0.0	0.0	-0.1	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	
Waste disposal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance and local taxes	0.0	0.0	0.0	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	-20.1	
Fixed Capital Expenditures	-234.6	-527.8	-410.5																										
Working Capital	0.0	0.0	0.0	-8.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.6
Decommissioning Cost																													0.0
Total Cash Flow (yearly)	-234.6	-527.8	-410.5	16.8	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	89.9	8.6
Total Cash Flow (cumulated)	-234.6	-762.4	-1172.9	-1156.1	-1066.2	-976.2	-886.3	-796.4	-706.4	-616.5	-526.5	-436.6	-346.6	-256.7	-166.8	-76.8	13.1	103.1	193.0	283.0	372.9	462.8	552.8	642.7	732.7	822.6	912.6	1002.5	1011.1

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