Financial Support Mechanisms for CO_2 Capture and Storage

Final Report

December 2009

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FINAL REPORT

CO_2 Capture Project

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EXECUTIVE SUMMARY

According to the International Energy Agency, deployment of CCS could contribute nearly one-fifth of the total effort required to achieve stabilisation of atmospheric GHG concentrations and mitigate the most serious predicted impacts of global climate change. The importance of CCS as a GHG mitigation option has been acknowledged by an increasing number of policy-makers, as reflected in policy goals such as the G8 Energy Ministers' target of launching 20 full-scale CCS projects and the EU's aim of deploying 10-12 large-scale CCS demonstration plants by 2015.

Although a few large-scale CCS projects have been undertaken in Norway, Algeria, North America and elsewhere, to date CCS has only been deployed on a limited commercial basis. The major barrier to wider deployment is the investment risk that larger CCS commercial demonstration projects are likely to face. Governments in several world regions have developed, and are developing, a number of financing and incentives programs to support CCS demonstration projects. The IEA CCS Roadmap concludes that the next decade is a key period for CCS and that governments, industry and public stakeholders must act rapidly to demonstrate CCS at scale around the world in a variety of settings. The Roadmap also suggests that almost two-thirds of the capture projects required by 2020 can be deployed in industrial and upstream sectors. However, the study finds that, given the crucial role for deploying CCS in a range of industry and upstream sectors over the next decade, there is presently a lack of financing options and appropriate incentives available, and much uncertainty regarding their support levels and modalities.

This report presents an overview of existing and proposed near-term financing and incentive (F&I) support mechanisms in the EU, US and Canada to CCS projects. Based on the research undertaken, the impact upon financial viability is modelled for a range of CCS project types capturing CO_2 from industrial and upstream sources (ranging from around \$20 to \$150/tCO_2 avoided) under different potential support mechanisms.

The projects considered in this report are not undertaken by oil and gas companies as typical for-profit ventures in their core business; they are done for environmental reasons but must be commercially viable with manageable risks and reliable cost estimates for companies to be able to invest in them.

ERM has used conventional IRR analysis in this report to evaluate the financial viability of CCS projects, with transparent discount rates, weighted average cost of capital and other factors explained in this report. It is important to note, however, that project types which carry positive - even attractive - IRR figures in this analysis are typically not commercial ventures in their own right; they are environmental projects which show a given return on investment to justify them as investments when compared to commercial projects.

Existing and proposed F&I support for CCS

The study identifies a wide range of support instruments applicable to CCS, existing or proposed within the EU, US and Canada. These include both:

1. *Financing mechanisms* aimed mainly at reducing up-front investment costs (e.g. grants; early-year tax incentives; low-cost loans and loan guarantees); and
2. *Incentive mechanisms* aimed at increasing revenues and project cash flow during the operational phase of the project (e.g. carbon prices and sequestration credits/allowances).

CCS project developers and investors require certainty as well as overall adequacy of support (from ongoing incentives and/or up-front support) in order to reduce project risk. The study finds that while the range of F&I instruments potentially applicable to CCS could be adequate to incentivise a number of projects over the next decade, there remains considerable uncertainty both regarding the ongoing development of policy packages and also some of the important design issues, which could in turn significantly influence investment risk. These include for example, the timing over which EU-level funds may be disbursed to CCS projects and whether carbon price guarantees can be established to reduce revenue risk in the event of price volatility in the ETS and other emerging cap-and-trade schemes.

Support potential for CCS varies significantly across the jurisdictions

The results of modelling the impact on Project IRR for a range of possible F&I support scenarios in the EU, US and Canada shows a diverse range of possible outcomes in terms of incentivising different types of capture project.

Key findings are:

- Carbon prices are critical to incentivizing projects, particularly 'early opportunities' in the upstream sector (e.g. capture from high-CO_2 gas field and LNG plants); higher expected carbon prices within the EU Emissions Trading Scheme are seen to incentivize a wider range of low-cost projects than in the US and Canada.
- In addition to significant carbon prices some form of assurance is required over the sustainability of long-term price signals offered by the carbon markets; shorter crediting periods and/or price collapses adversely impact project viability.
- The proposed use of bonus allowance incentives under the US Waxman-Markey Bill, if extended to oil and gas projects according to the same terms as provided to coal based power projects, would likely incentivise a wider range of project types (including higher cost refinery and gas-to-liquids capture projects).
- Disbursement of EU-level funds over the project construction phase, as opposed to over longer 'performance based' time periods assists cash-flow in early years and would likely incentivize a wider range of project types.
- Because certain projects have high operating costs (due to higher energy use in capture and transport costs), ongoing incentives are critical to all but the very lowest-cost project types. In Canada there is significant up front support for several initial projects; however, ongoing support is currently insufficient to incentivize wide scale CCS deployment.

A combination of F&I instruments will be required to incentivise CCS projects

The model results show that carbon prices alone may be sufficient to incentivize only a limited number of low-cost 'early opportunity' upstream capture projects assuming guaranteed long-term prices, whereas other projects would be unlikely to be viable with carbon finance alone. The results therefore indicate the need for a range of support instruments to be used, covering up-front support as well as ongoing incentives, if projects are to be successfully incentivized across a range of capture technologies and settings. The likely combination, and detailed design and modalities, of the support options assessed in each jurisdiction is highly uncertain and subject to ongoing (domestic and international) policy developments. Such uncertainty, as well as the adequacy of potential support levels, will directly influence the extent to which project developers and investors view project risk. Strengthening policy certainty over future revenue streams and support frameworks will therefore be critical to implementing projects during the near-medium term demonstration phase ahead of wide-spread commercial deployment of CCS.

CCS projects in upstream and industrial sectors have a wide range of potential costs with opportunities at the lower end of this range having costs typically less than that for coal-fired power projects; however much of the focus of policy and financial support has focused on coal-fired power generation. The creation of enabling incentive frameworks could help drive the early commercialization of these lower cost options before the widespread deployment of CCS in the power sector.

CONTENTS

1 INTRODUCTION

This report has been prepared for Phase 3 of the CO_2 Capture Project (CCP3) by Environmental Resources Management Limited (ERM) over the period July – December 2009.

The report presents an overview of existing and proposed near-term government support mechanisms for Carbon Capture and Storage (CCS) projects and provides a quantitative assessment of the extent to which these incentives are sufficient to facilitate CCS deployment. Furthermore, it identifies specific areas for improvement of Financing and Incentives (F&I) mechanisms, and proposes additional steps that key stakeholders could proactively take to better realise commercialisation of CCS projects through the use of financial support mechanisms.

The report draws on desk-based research and interviews held with individuals from government, industry, the investment community and academia in a number of jurisdictions including Canada, US, UK and Europe. The authors gratefully acknowledge the support received from those individuals and institutions that made a valuable contribution to this report.

1.1 PROJECT BACKGROUND

The primary objective of the CO_2 Capture Project (CCP) is to develop new, breakthrough technologies to reduce the cost of CO_2 separation, capture, and geologic storage from combustion sources such as turbines, heaters and boilers. The CCP also has a parallel work stream exploring issues relating to Policies and Incentives around CCS activities. Phase 3 of the CCP is planned to be an industrial-scale demonstration of some CCP2 technologies, which would be a major step towards commercial deployment.

Although a few large-scale CO_2 capture and storage (CCS) projects (> 1MtCO_2 stored per year) have been undertaken in Norway (Sleipner), Algeria (In Salah), North America (Weyburn) and elsewhere, to date CCS is not widely deployed on a commercial basis.

The main barrier to wider deployment is the financial risk that larger CCS demonstration projects are likely to face. Estimates indicate that the cost of carbon capture in initial stages could be on the order of US$100-150/tonne of CO_2 avoided (with lower cost 'early opportunities' in certain sectors such as natural gas processing or ammonia and hydrogen production) although costs are expected to decrease in the future as result of technological improvements as experience is gained through wider deployment.

In theory, cap and trade schemes such as the European Union Emission Trading Scheme (EU ETS) could provide the financial incentives required to offset the additional costs associated with CCS. However, this depends on the medium to long-term price expectation for EU Allowances which in turn determine the value for avoiding emissions in the EU through CCS.

Based on current expectations, it appears that the EU ETS alone is not likely to be sufficient to achieve previously stated ambitions such as the G8 Energy Ministers' goal of launching 20 full-scale CCS projects or the EU's goal of deploying 10-12 large-scale CCS demonstration plants by 2015; due largely to the low projections and uncertainty in EU Allowance prices and the limited longevity of the scheme (i.e., no details regarding what happens to the EU ETS beyond 2020). For this reason, a range of additional policy mechanisms are currently being discussed or proposed to provide additional support to bridge the financial gap associated with large scale deployment of CCS in the European Union (and individual Member States), the US and Canada.

1.2 *AIMS & OBJECTIVES*

The key objectives of this study are to provide:

- An overview and understanding of existing and proposed near-term support mechanisms to CCS projects; and
- A quantitative assessment of the extent to which these mechanisms are sufficient to facilitate CCS deployment.

In order to assess the potential for support mechanisms to commercialise CCS deployment, ERM has developed a CCS cash flow model which allows for a quantitative assessment of financial performance of a range of CCS project types capturing CO_2 from industrial and upstream sources under different potential support mechanisms. As part of this study, sensitivity analysis was performed using the model in order to test a range of key variables upon project economics.

Finally, the study identifies specific areas for improvement in government F&I mechanisms, and proposes further steps that key stakeholders could proactively take to better realise commercialisation of CCS projects through the use of financial support mechanisms

The geographical scope of the study is limited to the following case study jurisdictions:

- Europe (UK and Norway)
- United States
- Canada (Alberta and Saskatchewan)

To provide a basis for understanding the economic and financial issues related to CCS, a brief overview of support mechanisms is provided in the remainder of this section.

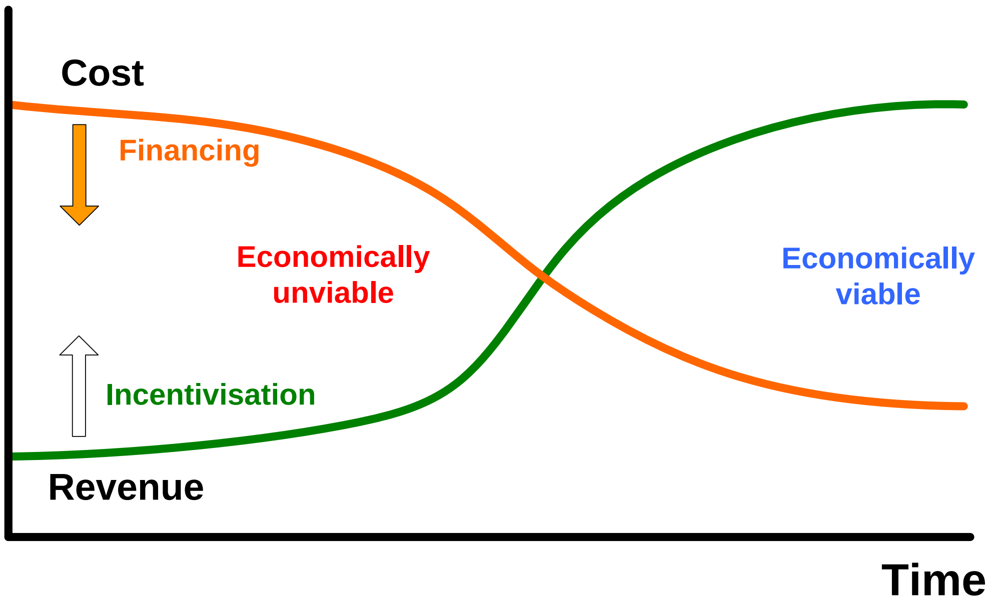
1.3 OVERVIEW OF SUPPORT MECHANISMS

In order to provide an overview of government support mechanisms, it is useful to make a differentiation between the distinct types that have been employed in the past for to support the deployment of emerging low carbon technologies. These can be broadly categorised as follows:

1. *Financing mechanisms* aimed mainly at reducing investment costs before the project is sanctioned (or during early years) and typically used to support R&D and demonstration projects; and
2. *Incentive mechanisms* aimed at increasing revenues or otherwise improve project cash flow during the operational phase of the project and are mainly relevant for commercial-scale projects or mature technologies with known costs (e.g. ethanol plants).

Figure 1.1 below outlines how these mechanisms could contribute to a project's cash flow over time.

Figure 1.1 F & I mechanisms overview



Source: ERM, 2009

Financing mechanisms are designed to provide financial support to projects in order to:

- Close the financing and risk gaps faced by early deployment of CCS projects
- Reduce investment costs before a project is sanctioned
- Promote the demonstration of CCS benefits (e.g. emission reduction potential for CCS) not included in conventional financial project appraisal; and

- Demonstrate that innovative projects and new technology can be replicated elsewhere

Incentive mechanisms aim to create or increase revenue streams of a project and provide greater certainty over the longer-term economic viability for project investors. In principle, a high value for CO_2 emission reductions should result in an effective and commercial market and in such a case government financial support would be unnecessary. However, when market mechanisms alone are not sufficient to promote emerging technologies due to low prices in the carbon market, additional government intervention may be justified. For this reason, a number of mechanisms involving fiscal incentives and market support policies can be used to ensure the commercial sustainability of a project during its operational phase.

1.4 REPORT STRUCTURE

The remainder of this report is structured as follows:

- *Section 2* explores how support mechanisms have been used in the past to support technology research, development and demonstration (RD&D) and how they can help to commercialise new low-carbon technologies.
- *Section 3* presents an overview of current or near-term proposed Finance & Incentive (F&I) options in the EU, US and Canada for CCS projects. An assessment is made of the indentified support options using a set of key criteria relevant to increasing project viability.
- *Section 4* provides a short overview of perspectives on F&I options based upon interviews with individuals from government, industry, investment and academia within the EU, US and Canada.
- *Section 5* presents a quantitative assessment of how different F&I support scenarios in each of the jurisdiction could impact the financial performance of a range of CCS project types. The analysis includes a discussion of abatement costs and assumptions, and the key sensitivities underpinning project costs and financial viability
- *Section 6* presents some high-level study conclusions.

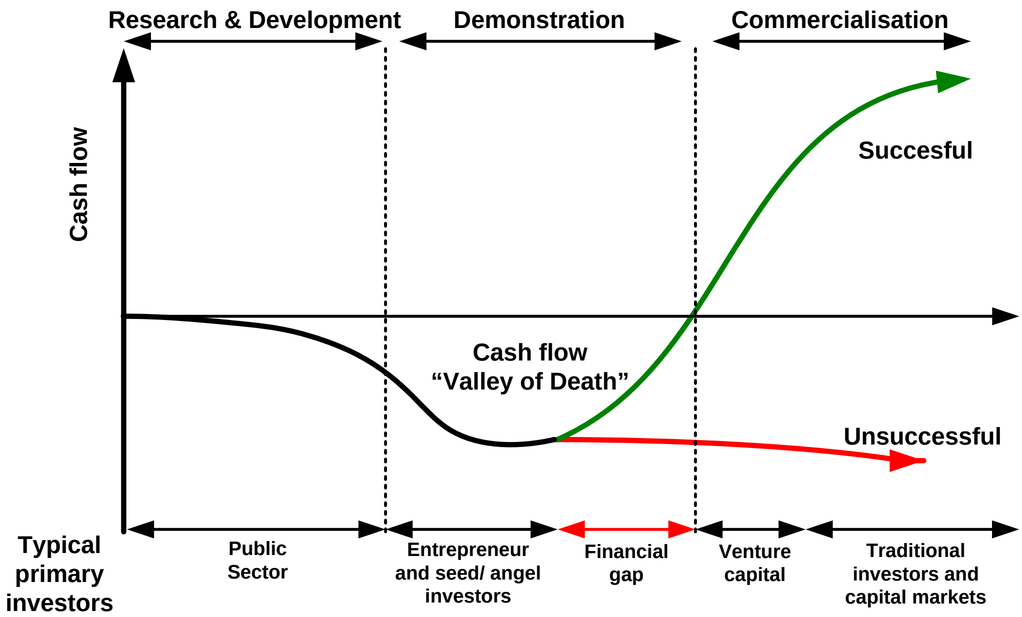
This section presents an overview of how government support mechanisms have been used in the past to support technology research, development and demonstration (RD&D) and the ways in which they can help to commercialise new low-carbon technologies.

2.1 SUPPORT MECHANISMS FOR NEW TECHNOLOGIES SUPPORTING PUBLIC GOODS

The principle constraint in advancing new technologies is the financial risk associated with the significant scale-up of investment associated with moving from Research & Development (R&D) to Demonstration phase.

As shown in *Figure 2.1*, public sector support is usually necessary to provide a portion of the financing needs during the R&D stage of developing a new technology.

Figure 2.1 The Cash Flow Valley of Death as a function of development stage with typical investors shown for the various stages



Source: Figure by ERM, based on Bridging the Valley of Death: Transitioning from Public to Private Sector Financing, National Renewable Energy Laboratory, 2003, Figure 1.

The region between where a technology moves from the R&D stage to the demonstration stage is often referred to as the cash flow *"valley of death"*. During this stage the capital requirements increase significantly, while at the same time public sector R&D financing is usually reduced.

Although some investors may be able to promote new technologies, in most cases the levels of support available are not adequate because capital requirements increase substantially during the demonstration phase, especially for capital-intensive energy sector ventures.

Usually the use of venture capital only emerges during the early commercialisation stage when financial project risks are lower and large scale markets can be more reasonably assured.

In the absence of government support, some technologies that have an end commercial market can be developed with a time delay and eventually brought to market; however this is not typically the case with technologies associated with 'public goods' - such as CCS which essentially is only undertaken for environmental reasons. This public good characteristic can make commercialisation of such technologies quite difficult and provides a rationale for government intervention (*Box 2.1*).

Box 2.1 ***Rationale for government intervention associated with public goods***

The rationale for government intervention is the potential for market failure related to technological innovation of "public goods". In the absence of government support for public good technologies such as CCS and renewables, the private benefit to investors is lower than the social benefits. Reliance on market forces alone can result in underinvestment in "public goods" from a social point of view.

Source: UK Cabinet Office, 2001

2.2 *ADDITIONAL SUPPORT IS NEEDED FOR CCS*

As fossil fuels (oil, coal and natural gas) are likely to remain the world's dominant sources of energy over the next decades, technologies that help to significantly reduce CO_2 emissions from combustion of fossil energy sources such as CCS represent important abatement options. For example, the International Energy Agency (IEA) has suggested that, to limit the global average temperature increases to less than 2 degrees Celsius at a reasonable cost, CCS will need to contribute nearly one-fifth of the necessary emissions reductions by 2050.[1]

A number of barriers associated with CCS such as significant additional investment requirements compared to standard plants, technology risk, ongoing operating costs, regulatory uncertainty and market risks need to be overcome in order for wide-scale deployment consistent with the IEA's scenario to occur.

The European Union (EU) has made important progress toward the establishment of a legal and regulatory framework governing CCS. However

[1] Energy Technology Perspectives 2008; Scenarios and Strategies to 2050, OECD/IEA, 2008.

additional work is needed to fill important gaps both in the EU as well as in other jurisdictions especially around the financing of CCS.

For example, the largest regional carbon market developed to date, the EU Emissions Trading System (ETS) has been characterised by:

1. Short term crediting periods i.e. 5 years for Phases II and 8 years for Phase III; and
2. Carbon price volatility ranging from a high of €31.58 in April 2006 to a low of €0.03 at the beginning of December 2007

Short term crediting periods provide little certainty to investors looking to develop CCS or other long term projects that have a typical investment horizon of 20 years or more. Longer crediting periods (i.e. beyond ETS Phase III) or some other supplementary form of support that provides certainty is required to provide assurance to investors looking to develop CCS.

Volatility has important implications as it can increase investment risk and increase the cost of raising capital. The uncertain regulatory market price as an incentive does not appear to be well placed to support capital intensive and long-term projects such as CCS. A 'safety mechanism' in the form of a guaranteed CO_2 floor price could provide a partial solution to this problem.

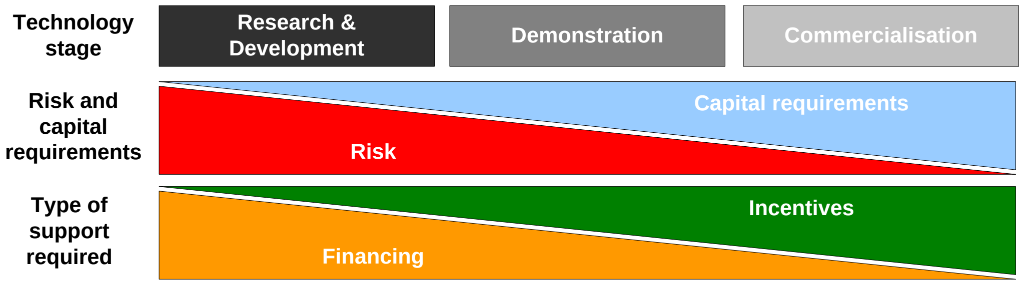
Finally, it is worth noting that CCS is different from other clean energy technologies such as renewables because it represents an extra cost that does not generate any additional revenue (except potentially when used in connection with Enhanced Oil Recovery – EOR - operations); only societal benefits (i.e. CO_2 emission reductions). For example, although a Concentrated Solar Power (CSP) or bio-fuels plant may not be economic during its demonstration stage, there is revenue to be generated from commodities such as electricity or ethanol which can reduce the overall level of risk and increase the financial viability for these projects.

2.3 *TYPES OF SUPPORT REQUIRED*

Figure 2.2 illustrates the support mechanisms required by new energy technologies at different stages of development.

During the early stage of technology development funding is typically provided in the form of direct financing (e.g. research grants, joint industry-government research initiatives etc.) to promote effective R&D. As the technology moves to the demonstration phase a mix of financing and Incentive mechanisms are required to cover the financial gap. Public financing covers the financial gap associated with the high risk transition stage from R&D to demonstration stage and incentive mechanisms and/or robust markets provide an assurance to industry during demonstration and commercialisation due to the greater certainty on the direction of policy which stimulates private sector investment.

Figure 2.2 Mechanisms required by technology stage



Source: ERM, 2009

2.3.1 *Financing*

Financing can be provided by a number of sources e.g. private, public or through joint public/private sector initiatives. A short overview of financing mechanisms that can be used for advancing new clean energy technologies is provided in *Table 2.1.*

Table 2.1 Financing Mechanisms Overview

Type	Description	Advantages	Disadvantages
Grants	Grants are made to an organisation or a project by governments towards major items of capital expenditure. Capital grants sometimes require a matching contribution from the recipient.	Grants can lower risk profile and increase financeability options, high net present value due to (usually) upfront payment.	When paid in instalments can create cash flow problems, widespread use can be inhibited in some countries especially if they are entirely composed of public funds.
Low Cost Capital/Government Loans	Low cost capital can be provided via government loan facilities to project developers.	Helps to gain access to capital at low risk rates thus reducing the debt service cost.	May not be available for financially stronger projects. Does not substantially improve viability of marginal projects.
Equity	Equity is the start up capital provided by the project developers.	Long investment cycle that does not require immediate repayments.	High risk for investors, limited funding for R&D and demonstration stage technologies. Opportunity costs usually outweigh net benefits of R&D funding.

Type	Description	Advantages	Disadvantages
Debt	Involves borrowing money from a bank with the promise to return the principal, in addition to an agreed level of interest.	Tax deductible	Require certainty on cash-flows and not usually available for high risk projects, high interest rates or new markets (CO2)
Loan guarantees	Loan guarantees have the purpose of facilitating project financing by providing risk coverage to projects. When a guarantor provides a loan guarantee to a portion (or 100% in some cases) of the loan, they undertake the obligation for the guaranteed portion to be paid to the lender if the borrower defaults.	Enable lenders to commit to longer term loans (cheaper than shorter-term), can increase access to funding sources and reduce the financing costs of the project.	Some programs may contain a significant number of requirements with the high costs and onerous application procedures. If debt support costs must be covered by project sponsor, project becomes less viable.

2.3.2 *Incentives*

A short description of the incentive mechanisms that can be used for advancing clean energy technologies is provided in *Table 2.1*

Table 2.2 Incentive Mechanisms Overview

Type	Description	Advantages	Disadvantages
Cap-and trade	In a cap-and-trade scheme, covered installations are required to hold sufficient emission rights (or allowance) to cover their emissions for the scheme period. Each allowance represents a right to emit a specific quantity of a pollutant (e.g., one ton of CO_2). Allowances can be either provided for free or purchased via auction	Achieves "least cost" emission reduction (technology neutral)	Price volatility, short crediting periods/timeframe may not assist long-term projects

Type	Description	Advantages	Disadvantages
Project-based, mechanisms or credit-based systems	Project-based mechanisms, such as the Clean Development Mechanism, can generate carbon credits that are determined by reduction of greenhouse gas emissions against an agreed baseline. The baseline reflects the greenhouse gas emissions of a certain activity (e.g. the production of energy) if the project would not have taken place.	Allows for clean techniques, technologies and processes to be transferred in the developing world to deliver reductions in a cost efficient way, absent of trying to negotiate an economy or sector wide cap setting process.	Credits received ex-post (after reducing emissions), project performance risk may inhibit project financing, short crediting periods/timeframe may not assist long-term projects, project cycle and approval process is long and complex. Requires a source of credit demand.
Carbon Taxes	Carbon taxes set at the correct level can provide an incentive to reduce the cost of compliance. Projects that can reduce their emissions for less than the cost of the tax (e.g. through CCS deployment) may be commercially viable.	They give a clear predictable price signal, can integrate the CO_2 abatement costs into project's financial planning	Hard to sell politically; not technology-neutral.
Tax incentives	Tax incentives include investment tax credits, accelerated depreciation, enhanced capital allowances property tax reductions or other tax incentives. Usually tax incentives require new revenue to be foregone rather than funds from existing revenue. Some capital intensive projects pay little tax in early years. Tax incentives may include exemption from consumer taxes (e.g. Climate Change Levy in UK)	Proven to stimulate investment, they provide improved early cash flows to project.	Projects eligible for tax credits with no sufficient tax outlook must seek to partner with tax equity investors to capture this form of support.
Cost pass through arrangements	Under a cost pass through arrangement with government and regulators, CCS project developers could pass the incremental CCS costs to consumers via increased prices.	Low risk	Hard to sell politically to the public, enforceability issues in competitive markets), Not useful for CCS projects for sectors with products traded in competitive markets

Type	Description	Advantages	Disadvantages
Portfolio Standard	A portfolio standard is a mechanism of increasing the portion of energy generation from specific sources by placing an obligation on electricity suppliers or producers to source or produce a specified proportion of their electricity from eligible energy sources. Renewable portfolio standards have been widely used to promote renewable electricity generation.	Entirely market-based, stimulates competition amongst power generators.	Investors in competitive electricity markets face the risk of electricity price volatility, tends to support only those technologies which are close to market when it is introduced. Global competition in oil & gas sector will make participants in regions with standards non-competitive.
Feed-in tariffs	Projects receive a fixed amount, per unit of electricity exported, additional to the wholesale price of electricity. Project profitability depends on ability to reduce costs.	Guaranteed long-term fixed price payment is attractive to investors; has proved successful in stimulating investment in renewables in Europe.	Difficult to work in competitive market conditions. Power sector specific.
Guaranteed Carbon Price or other premium	This mechanism offers projects either a fixed price for the carbon they abate or a premium over the CO_2 market price and may be a viable alternative to feed-in tariffs in countries where a mature CO_2 market exists.	Clear signal to investors. Can boost credit standing and project revenue.	Can fail if companies make unrealistic bids against estimated future cost reductions. Asymmetry of information can lead to costly guarantees for governments.
CO_2 for Enhanced Oil Recovery (EOR)	It can provide revenue to CCS projects by O&G operators who buy the CO_2 and use it for EOR. Additional bonus payments may be available to field operators from governments provided that CO_2 is permanently stored in the geological formation.	Commercially Attractive.	Difficult to value additional benefit of EOR.

Note that once in place these policies can create a positive feedback effect: by leveraging financing and assisting in reducing investment costs before a project is sanctioned, they can reduce the need for ongoing financing mechanisms.

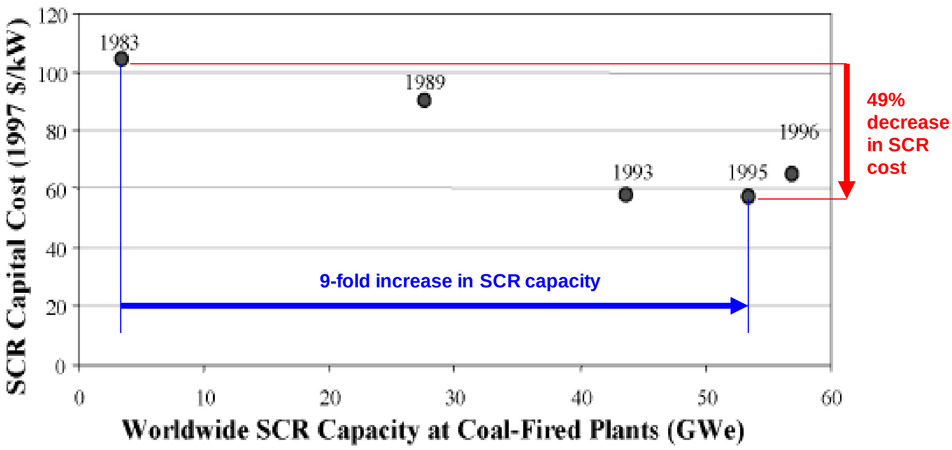
2.4 OVERVIEW OF PAST EXPERIENCE WITH CLEAN ENERGY TECHNOLOGIES AND INFRASTRUCTURE

Governments have historically encouraged and supported the development of new clean energy technologies in a range of ways. This section provides a brief overview of the types of support that have been used to date.

Environmental protection objectives have been the driving force behind government policy initiatives to make the costs of clean energy technologies competitive with conventional sources. Worldwide adoption of stricter environmental standards and targets for GHGs has been instrumental in bringing environmental benefits to the fore and helping to bridge the gap in costs to industry and investors.

Mandatory requirements have also been instrumental in disseminating clean technology: for example in the EU, the use of flue gas desulphurisation and NO_X removal technology at fossil fuel power generation plants has been introduced through direct mandates (i.e. the European Large Combustion Plant Directive). Timing considerations are also important; for example, the experience of creating strong policy frameworks for flue gas NO_X removal in a number of world regions led to a nine-fold increase in SCR (selective catalytic reduction) technology use and an almost 50% cost reduction over one decade (*Figure 2.3*). The need for strong policy incentives to achieve wide-spread global deployment of innovative technology with additional investment cost requirement is analogous with the need to demonstrate CCS over the coming decade.

Figure 2.3 Increase in Flue gas NO_X removal (Selective Catalytic Reduction) 1983-1996



Source: Rubin et al; Experience Curves for Power Plant Emission Control Technologies, 2004

Additionally, finance mechanisms have increasingly been used to drive innovation through the technological "valley of death" – in order to establish renewable technologies in the energy market of many OECD and non-OECD regions and make them accessible to those acting under compliance regimes.

Renewable energy is one example which has relied on innovation and government intervention to progress in the market place over the last few decades. With the exception of large hydropower, combustible biomass (for heat) and larger geothermal projects (>30 MW), the average costs of renewable energy are generally not competitive with wholesale electricity prices produced from fossil fuels.

Solar Photovoltaic (PV)

Significant market growth in new technologies results from a combination of policies that address specific barriers and/or complement existing policies. In the case of solar energy, Japan has followed a process designed to establish solar PV technology within its domestic energy market. Extensive investment in R&D was made to increase the competitiveness of the technology. This was followed by demonstration projects to prove viability and complemented by financial incentives to bring down the cost of purchasing PV systems. Finally, the government set a requirement for energy companies to accept excess PV power into the grid at the retail price of electricity.

The use of feed-in tariffs (FIT) has also proved effective in accelerating the installation of solar PV capacity in Germany, albeit at a high cost of generation compared to other renewable technologies. In recent years, the level of the German FIT for solar PV has been progressively reduced to incentivise a reduction in project costs and optimise the suitable application of PV systems. However, the use of FIT may also serve to incentivise sub-optimal projects (e.g. wind turbines sited in low-medium wind resource sites in Germany); this has particularly been the case in some EU Member States where FIT and other forms of guaranteed price arrangements have been designed on the basis of capacity installed rather than power generated; this can lead to inefficient resources use and fail to stimulate competition.

The US has been engaged in a programme of federal tax incentives for solar PV over the past few decades, but they have not proven sufficient to generate the expected level of increased capacity. As a result, individual states have established aggressive incentive policies for PV, including tax rebates for residential and commercial installations and quota obligation systems with specific requirements for solar energy. Net metering, favourable retail rate structures and streamlined planning rules have also enabled sizeable domestic PV markets to take off. Through these combined measures, Japan, Germany and the US were responsible for roughly 88% of the globally installed solar PV capacity at the end of 2005.

Onshore Wind

Until 2005, those countries that provided overall levels of remuneration for wind energy generation (below a certain threshold) failed to achieve significant increases in wind power generating capacity. Those countries which did succeed, such as Germany, Spain, Denmark and Portugal, mainly used FITs to encourage wind power deployment. Their success is a result of those FITs being fixed and long term in nature, thereby providing reciprocal long term investment security. The use of FITs has been typically complemented by a development model with low administrative and regulatory barriers, and relatively favourable grid access conditions. In 2005, the average remuneration levels in these countries were lower than those in countries applying quota obligation schemes such as the UK's Renewables Obligation (RO). The RO contributed to the UK having one of the highest levels of remuneration on a per unit power generation basis for wind, although wind energy deployment in the UK lagged significantly behind others where FITs were used. The same is true of other countries (e.g. Italy, Belgium) which have introduced similar trading-based quota obligation schemes. Such schemes have tended to suffer from additional non-economic barriers, uncertainty and design flaws, increasing the risk to investors. Most importantly, the failure of such schemes to provide long-term revenue certainty to project investors has proved critical to their achieving only a partial success in increasing levels of renewable generation.

National wind development in the US is supported by a mix of state and federal policies, including a 10 year production tax credit which acts like a feed-in premium, and 5 year accelerated depreciation. These, combined with state level financial incentives and quota obligation schemes, have driven national capacity. So far, one level of incentive on its own has been insufficient to encourage growth in wind power, with the market suffering peak and trough cycles due to instability in the provision of production tax credits and other financial incentives. Furthermore the US DOE under its federal loan guarantees program provides up to $30 billion in loan guarantees, for renewable energy projects.

In Spain, wind technology is supported by feed-in tariffs, low-interest loans, capital grants, and local support for manufacturing of turbines. A minimum level of remuneration, combined with favourable market conditions and the appropriate level of compliance obligations, therefore appears necessary to encourage installation of the technology.

Electricity Transmission Networks

Electricity transmission networks, especially those for wind power and other renewable, present some similarities with the development of pipeline infrastructure for CCS.

In the UK, the energy markets regulator (Office of the Gas and Electricity Markets – Ofgem) recently proposed to change the financial incentives provided applied to the transmission companies to drive increased investment in the new capacity needed to connect more remote renewable generation to the grid. Under the proposed new incentive framework, transmission companies will be able to build networks ahead of securing contractual commitments from generators to fund the grid connections. They can earn higher returns on these investments if there is sufficient demand for the capacity once it is constructed - or lower returns if the new capacity is not fully used. [1]

In the US the Federal Energy Regulatory Commission (FERC) recently approved transmission infrastructure investment rate incentives for a proposed 3,000-765 kV transmission network that could cost between $10 billion and $12 billion. The network will be designed to deliver wind-powered renewable energy from the upper Midwest to consumers in and around Chicago, Minneapolis and other demand centres. [(2)] The project developer has proposed a 'cost of service' based formula rate structure, under which the costs of the project (incl. an overall Return On Equity of 12.4%) will ultimately be recoverable through the transmission tariffs.

Furthermore, the US DOE under its federal loan guarantees program provides up to $750 million in subsidy costs, provided by the Recovery Act, to support loans for large domestic transmission infrastructure projects that use commercial technologies.

A similar arrangement for the development of CCS pipeline infrastructure networks could present significant benefits. An incentives framework would help mitigate some of the 'first mover' risks and lower the level of uncertainty concerning unrealised capacity for developers deploying backbone CO_2 pipelines with a view to accommodate future users.

Fuel Cells

The U.S. Department of Energy's Office of Fossil Energy has been partnering for almost three decades with several fuel cell developers to develop the technology for application in the stationary power generation sector. Industry participation is now extensive, with more than 40 percent of the program funded by the private sector. Over half of the states in the US have financial incentives to support fuel cells: some have exempted fuel cells from air quality permitting requirements whilst others have introduced portfolio standards or set-asides for fuel cells and net metering obliging utilities to deduct any excess power produced by fuel cells from the customer bills.[3]

In 2008, the EU established a 'Fuel cells and Hydrogen' joint technology initiative (JTI), a long-term public-private research partnership on hydrogen and fuel cells with the aim of reducing the time to market for these technologies by 2-5 years. The EU is expected to contribute some €470 million to this research programme over the next six years, with the private sector expected to contribute the same amount. Reaching the critical mass of the JTI research effort in this field is expected to give confidence to industry, public and private investors and decision-makers to join this long-term partnership.[4]

[1] Ofgem annual report 2008-2009, http://www.ofgem.gov.uk/About%20us/annlrprt/Documents1/annualreport09access.pdf

[2] http://www.ferc.gov/news/news-releases/2009/2009-2/04-13-09.asp

[3] US DOE Hydrogen Program, http://www.hydrogen.energy.gov/

[4] http://www.eu2008.si/en/News_and_Documents/Press_Releases/February/0225MVZT_COMPET.html

2.5 *KEY LESSONS LEARNED*

A review of how support mechanisms have been used in the past to support technology research, development and demonstration (RD&D) for other low-carbon, or clean energy, technologies provides some key lessons for incentivising CCS projects:

- Other technologies have been successfully supported by a range of financing mechanisms in different regions to date, covering R&D through to commercialisation stages
- The design of technology support schemes is important in order to provide the right balance of upfront finance to overcome initial high costs and longer-term sustainable revenues to provide required ongoing support
- The duration of the support provided is important to provide predictability for investors, as shown by comparing e.g. the use of feed-in-tariffs with obligation and/or market-based approaches to support renewable power generation
- The creating of an enabling incentives framework helps to mitigate some of the 'first mover' risks and lower the level of uncertainty inherent in new technology projects
- Support mechanism need to set the right price. Some examples indicate that unless the price level is right, they will not work. There is a tipping point observable here (e.g. wind has passed this point and is now becoming commercial for large-scale projects; tidal and wave, and solar PV is not yet at that stage, except in certain specific applications)

It is important to note that the price can also be influenced by what policy-makers are trying to achieve. CCS has heterogeneous costs across different sectors, and the level of support required depends on whether a broad demonstration programme is being financed or whether the focus is on trying to incentivise least cost 'early opportunities'. The development of high-cost renewable technologies shows that significant up-front support combined with predictable ongoing revenue streams, have helped to move certain technologies from the R&D stage to demonstration stages (e.g. solar PV) and towards commercialisation (e.g. onshore wind).

While financial support is important during the R&D and demonstration phase the commercial deployment of CCS, as with renewables, will be driven by more stringent and long lasting GHG targets, both at a national and regional level, backed up by the incentives (such as robust carbon prices and supplementary incentives) to make deployment viable. Without the compliance regimes that enforce such policies, support might be limited to financing mechanisms which would likely fail to provide the necessary support to commercialise the technology across a range of sectors and project types.

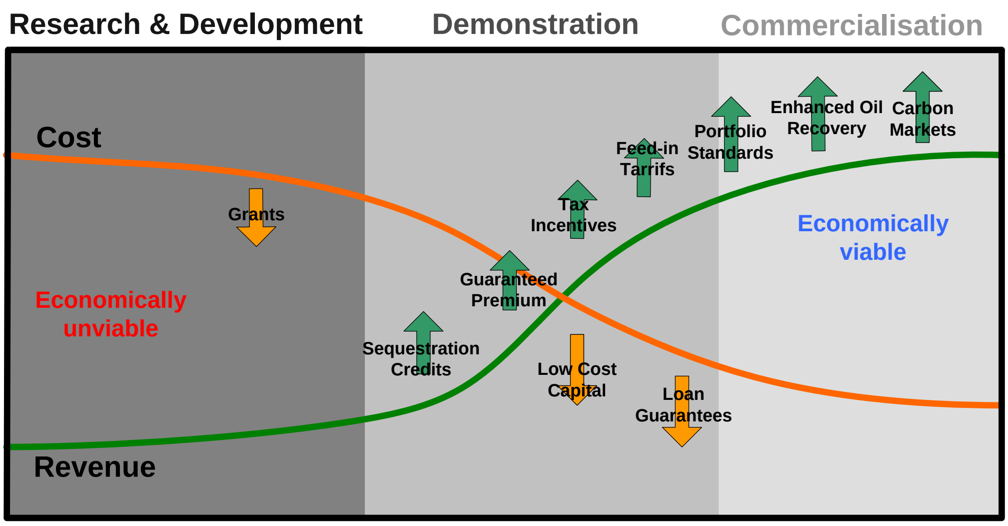
It is therefore vital that policy measures aimed at incentivising deployment are long-lasting and stable enough to provide the necessary assurances against the risk of investment. In the case of renewable energy, feed-in-tariffs have typically had an eight to twenty year time frame of guaranteed prices. Conversely, short term or 'stop and go' policy environments do not provide a sound basis to encourage private sector involvement in the development of new technologies.

3 EXISTING OR PROPOSED FINANCING & INCENTIVE OPTIONS FOR CCS

Governments in a range of world regions have developed, and are developing, a number of financing and incentives programs to support CCS demonstration projects. This section presents an overview of current or near-term proposed F&I options in the EU, US and Canada for CCS projects.

There are various financing and incentives mechanisms that governments can employ to support effective research and development, demonstration and ultimately commercialisation of CCS technology. These are summarised graphically in *Figure 3.1* below.

Figure 3.1 Financing and Incentives Options for CCS by project



Source: ERM, 2009

3.1 CRITERIA FOR ASSESSING EXISTING SUPPORT OPTIONS

The UNFCCC Bali Action Plan states that sources of financing for climate change action should have certain characteristics in order to ensure that adequate mitigation action is taken to address climate change.[1] In order to help understanding the wide variety of existing or proposed CCS support options put forward by governments, some key assessment criteria have been established, drawing on various sources of literature *(Table 3.1).*

[1] Investment and financial flows to address climate change: an update, UNFCCC, FCCC/TP/2008/7, 26 Nov 2008

Table 3.1 Criteria for Assessing CCS Support Options

Characteristic	Description	Metric
Adequate	Support options are adequate if they are sufficient to cover the relevant costs for undertaking required mitigation action.	Metrics adopted for the purposes of this study for industrial CCS projects are from IEA's CCS Roadmap and include: **Financing for Demonstration:** • EU: 5 projects capturing total of 11MtCO_2/yr by 2020 • US: 8 projects capturing total of 28MtCO_2/yr by 2020 • Canada: 4 projects capturing total of 16MtCO_2/yr by 2020 The CCS capture investment needed for the above projects is around $10bn (2010-2020) with an estimated $1bn for transport and storage. **Incentives for Commercialisation:** Adequate carbon price to support commercial CCS deployment
Predictable	Predictability of support is important for planning appropriate mitigation action, and ensuring that the financing arrangements are able to address the mitigation requirements.	The metrics adopted here are: • Support should cover at least 15 years of the project's lifetime and • Maintain performance risk at a minimum level in order to provide investment certainty to the project sponsor.
Practical	In order for a support mechanism to be practical it needs to be characterised by a low complexity of disbursement procedures and reasonable intellectual property rights allocation which can increase utilization of funds and overall mechanism effectiveness.	

Table 3.2 presents a summary of financing mechanisms and *Table 3.3* a summary of incentive mechanisms that are proposed or currently available in the EU, US and Canada. Due to the high number of existing and proposed financing and incentives mechanisms (which can be found in detail in *Annexes A*, *B* and *C*) the tables employ a simple colour coding system (where green indicate 'no issue'; orange indicates a 'minor issue'; and red a 'major issue' or gap) to identify the key issues associated for each F&I mechanism, for each jurisdiction, based on the criteria presented in *Table 3.1*.

Table 3.2 Existing or Proposed Financing Mechanisms for CCS

Support Option		European Union	US	Canada
Demonstration	Grants	Grants are available to support 6-10 CCS demonstration projects mainly in the power sector. Not adequate support for financing industrial CCS projects.	Grant programmes at Federal level such as the Clean Coal Power Initiative, the Industrial CCS and the CCS demonstration programme.	Grant programmes at Federal level such as the Clean Energy Fund and at a Provincial level (e.g. Alberta CCSF)
	Low Cost Capital	Not available	Programmes such as the Qualified Energy Conservation Bonds (QECB) and the New Clean Renewable Energy Bonds (CREBs) offer the equivalent of an interest-free loan for financing qualified energy projects for a limited term	Not available
	Loan Guarantees	Not available	There are Federal Loan Guarantees available for power and industrial CCS projects	Not available

Table 3.3 Existing or Proposed Incentive Mechanisms for CCS

Support Option		European Union	US	Canada
Demonstration	Guaranteed Premium/ Sequestration Credits	The UK provides a guaranteed premium financial mechanism to support CCS Demonstration for 2-4 projects in the power sector. No support for industrial CCS.	The proposed "American Energy & Security Act of 2009" will provide bonus sequestration allowances which could act as a significant incentive to deploy a total of 72GW of CCS power generation. Industrial sources qualify if they emit at least 50,000 tons CO2-e per year without CCS, and do not produce a liquid transportation fuel from a solid fossil-based feedstock.	The Federal Regulatory Framework for Industrial Greenhouse Gas Emissions provides $20/tCO_2$ in 2013 and thereafter escalating based on GDP growth for CCS projects (for pre-certified projects through the technology fund)
	Tax Incentives	Not available	The U.S. Treasury Department and the Internal Revenue Service provide Investment Tax Credits for power sector and industrial gasification CCS projects	An accelerated capital cost allowance is being proposed for assets used in carbon capture and storage
Commercialisation	Feed in Tariffs	Currently N/A but it could be considered as an option for some countries	Not Available and not applicable for industrial CCS	Not available and not applicable for industrial CCS

Support Option		European Union	US	Canada
	Performance or Portfolio Standards	Not available and not applicable for industrial CCS	The proposed "American Energy & Security Act of 2009" will place a performance standard for Coal-Fuelled Power Plants	Not available and not applicable for industrial CCS
	Enhanced Oil Recovery	Not available	The U.S. Treasury Department and the Internal Revenue Service provide a Carbon Sequestration Tax Credit for EOR operations provided the CO_2 is permanently stored. There are also additional tax credits at a state level (namely Texas)	Government of Alberta has the Innovative Energy Technologies Program in place that provides royalty adjustments to a number of specific pilot and demonstration EOR projects. Also there is the Saskatchewan Carbon Dioxide EOR and Storage Initiative which provides funding towards EOR investments
	Carbon Markets	The EU- Emissions Trading Scheme provides an incentive for CCS; however there are issues around: 1. Relatively short crediting periods 2. Uncertainty around price volatility. 3. Current CO2 price is not high enough to support CCS deployment on a commercial scale	The proposed "American Energy & Security Act of 2009" will impose caps to Carbon Emissions from Large Sources which will provide an incentive. Act is not finalised yet.	Under the Regulatory Framework for Industrial Greenhouse Gas Emissions CCS projects in sectors covered by the regulatory framework may be credited up to 100% of their emission targets through 2017.

3.2 SUMMARY CONCLUSIONS

Deployment of CCS could contribute up to 19% of the total effort required to achieve the stabilisation targets of limiting global warming to around 2 degrees Celsius (2^{O}C).[1] CCS projects deployed in industrial and upstream sectors are expected to account for a large share of the effort.

However, there is presently a lack of financing options and appropriate incentives applicable to CCS at industrial and upstream installations (and uncertainty regarding their support levels and modalities), taking into account the key role CCS will need to play in reducing emissions from activities such as refining, gas production, cement making and iron & steel production in order to reach a required 450ppm stabilisation level as suggested by the IEA.

Governments will therefore need to broaden the current dialogue on CCS financing from just the power sector to other large emitting industrial activities.

3.2.1 *Support for Capture*

The assessment of support mechanisms applicable to capture from industry and upstream sectors suggests a gap - both in terms of overall support, and the certainty likely required by investors – between what is currently existing or proposed and what will be required in the near-to-medium term.

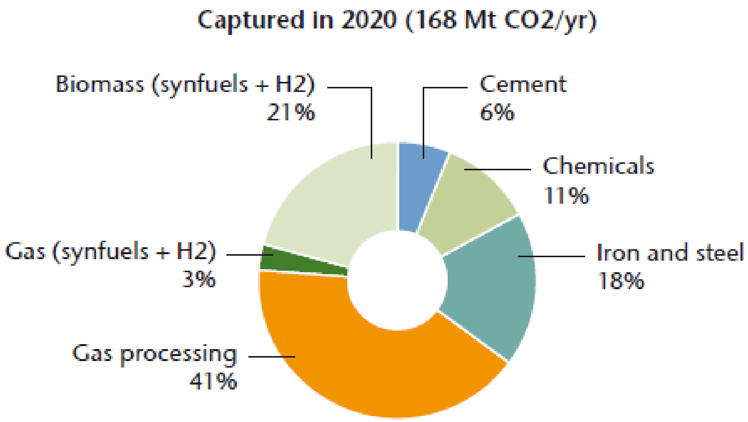
The recently published IEA CCS Roadmap[2] suggests that in order for CCS to contribute to the range of mitigation options needed to achieve atmospheric stabilisation of CO_2 levels, some 100 projects will need to be deployed worldwide by 2020, capturing some 300 $MtCO_2$/year across a range of sectors and world regions. These targets are estimates to require a cumulative total plant investment of around $150 billion, $42 billion of which is additional capture-related investment).

Although the focus of government F&I support is currently demonstration of CCS from power generation, the IEA estimate that capture from industry and upstream sources will account for 62 of the 100 projects required by 2020 (see *Figure 3.2*), with 17 of these to be deployed in Europe and North America. It can be seen that upstream projects are expected to account for around two thirds of this total, with 'early opportunities' in the gas processing sector representing the largest share (41% of the total capture volume in 2020). The Roadmap estimates that within these sectors around $1.25 billion will be required per project, capturing on average of 2.7 $MtCO_2$/year, therefore representing a total investment requirement of around $20 billion in these regions over the next decade.

[1] Energy Technology Perspectives 2008, OECD/IEA, 2008

[2] Technology Roadmap – Carbon Capture and Storage, IEA, 2008

Figure 3.2 Global Deployment of CCS in Industry and Upstream 2020



	Number of projects in 2020	Captured 2020 ($MtCO_2$/ year)	Global deployment share 2020
OECD NA	12	44	26%
OECD Europe	5	11	7%
OECD Pacific	5	17	10%
China & India	15	29	17%
Other Non-OECD	25	68	40%
World	**62**	**168**	**100%**

Source: IEA, 2009

Given the current levels of support envisaged in the near term for industrial and upstream capture projects (and importantly, the uncertainty concerning their ongoing policy developments), there appears to be a significant financing gap between what is proposed and what is required for CCS to play a significant role over the next decade. For example, in the EU, although European-level funding is available to support 6-10 CCS demonstration projects, most of all of these are currently expected to be in the power sector; the final provision of grants, and other potential support schemes, to industry and upstream projects, within the US remains dependent upon ongoing policy developments.

Given that the IEA forecast the need to deploy several thousand CCs projects globally by 2050, the need to incentivise and demonstrate capture ahead of wide-spread deployment is critical; the IEA Roadmap concludes that the next decade is a key "make or break" period for CCS and that governments, industry and public stakeholders must act rapidly to demonstrate CCS at scale around the world in a variety of settings.

The timescale of moving from R&D through to demonstration and commercialisation is important, as shown by the dissemination and cost reduction for FGD and NO_X removal technology worldwide on the basis of strong policy support to promote environmental protection.

The IEA Roadmap suggests that it will be necessary to provide policy frameworks worldwide that combine near term technology financing with carbon constraints and/or CCS technology mandates. The role of demonstration in non-OECD regions is also highlighted, suggesting that the approval of a CCS project methodology under the Clean Development Mechanism (CDM) will be an important first step to help developing countries to begin mitigating their fossil plant emissions in the near- to medium-term.

Overall there is a need to:

- Mobilise substantial financial resources to further enhance the full, effective and sustained implementation of the IEA CCS roadmap and the fulfilment of G8 commitments;
- Provide scaled-up, new, additional, predictable, and sustainable financial resources and incentives; and
- Employ various incentives and financial mechanisms in order to promote access funding for a variety of project types

Some high-level region-specific conclusions regarding existing and proposed F&I instrument can be made with respect to the assessment criteria (*Table 3.4*).

Table 3.4 Summary of CCS Support Options across regions

Region	Adequacy	Predictability	Practicality
EU	- EU-level funds may be adequate to support at least 5 CCS projects (with aim to support 6-10); although focus is mainly on power generation - Size of the NER300 will crucially depend on how, and when, the value of the allowances is raised - Lack of detailed proposals regarding public finance sources and/or loan guarantees and tax incentives suggests project developers will incur significant project risk	- Price volatility during Phase III of the ETS creates significant project finance risk - Unknown future of the EU ETS post-Phase III and possible future carbons price is also problematic - Carbon price guarantees and the use of feed-in tariffs would significantly reduce risk	- The optimal project finance strategy for project developers may be unclear given current policy uncertainty. - The approach to, and timing of, disbursement of funds remains a considerable issue of concern (also affecting *predictability*)

US	- A large number of federal and state-level F&I incentives exist or are proposed, which if implemented could be adequate to incentivise 8 CCS demonstration projects - Federal funds, loan guarantees and sequestration tax credits could incentivise low-cost projects outside of the power sector - The development of a cap-and-trade scheme and the use of bonus allowances could provide significant incentives to project developers for a range of project types	- Fund are provided during construction phase, assisting project finance predictability and risk levels - Ongoing policy developments regarding the proposed American Energy & Security Act presents significant uncertainty; the final package of eligible support options and their details are unknown.	Unknown
Canada	- A range of funds at federal and provincial level may be adequate to incentivise 4 CCS 'early opportunity' projects - However, low up-front funds (20%) and performance-based disbursement places high risk on project developers - Absence of loan guarantees and low-cost financing options, increasing project finance requirements - Support levels envisaged under the RFIGHG are comparatively low in terms of ongoing project support	- The use of enhanced capital cost allowances, which could provide additional up-front support to project cash-flow is not finalised at present - The support provided under the RFIGHG runs only to 2017	Unknown

3.2.2 *Support for Transport and Storage*

Most of the incentives examined in the study are found to focus on promoting capture only. Integrated demonstration projects across all parts of the CCS chain (i.e. capture, transport and storage) are therefore likely to be dependent upon the capture operator dispersing these funds down the CO_2 value chain. Whilst this may be feasible for vertically integrated projects, this may not occur under currently envisaged policy frameworks to a sufficient degree for full scale infrastructure development at the level envisioned under the IEA Roadmap beyond 2020 (where there is likely to be increasingly less vertical integration of CCS projects).

Moreover, the expertise to develop the pipeline/storage concept is likely to lie in sectors other than power generation which is the focus of near-term financial support (i.e. the O&G sector). However, as shown in the previous section, the current incentives for the O&G sector to undertake capture projects are not as clearly developed as for other sectors. Therefore, new business models with enabling policy support mechanisms need to be sought between the different actors working across the CCS chain. Moreover, clear guarantees are needed to provide adequate finance for all actors in non-vertically integrated projects concepts and network developments in the future.

Analysis and modelling undertaken by ERM[1], suggests that there is an opportunity for governments to provide the support that is needed in the first few years of operation to help first movers to build pipelines with excess capacity for new entrants and realise economies of scale. Favourable financing options could enable the financial viability of a pipeline network and take up some of the risks associated with excess capacity. Although support as part of the overall demonstration project funding is available in the jurisdictions assessed, the research indicates that there is a wide gap around financing CO_2 transport infrastructure which would be essential for successful CCS deployment. Incentives are needed to promote large scale infrastructure and help mitigate some of the first mover risks, as experience has shown with the incentives framework for electricity transmission networks in the UK [2] and the US. For CCS deployment, governments will need to lower the level of uncertainty around unrealised capacity for developers deploying backbone pipelines with a view to accommodate future users.

Financing support could be provided in the form of capital grants, recycling of auction revenues (i.e. from CO_2 allowances) and/or low cost government financing sources such as guaranteed bonds, etc. Project revenue guarantees or cost-of-service subsidies for an operator which allows for the building of a pipeline with excess capacity in order to accommodate future users could represent another type of support. Direct government involvement, in terms of ownership, could be another support option where the government would assume the project risk entirely. Any fiscal incentives adopted would need to be sufficiently long term, as investors will be reluctant to participate in the development of CO_2 infrastructure if there is uncertainty that these can be changed during the project lifetime. In principle, once the price of carbon is stable and high enough to cover the aforementioned risks, these incentives would no longer be needed.

There is therefore a considerable gap in the need to incentivise the development of pipeline networks and what is currently proposed within the EU, US and Canada; The IEA Roadmap estimates that approximately $15-20 billion per year in additional investment will be required to finance transport infrastructure and storage sites through 2020. Taking operating costs into

[1] Assessment of the range of potential funds and funding mechanisms for CO_2 transportation networks, ERM, May 2008

[2] In order to connect more remote renewable generation UK OFGEM has proposed that transmission companies be able to build networks ahead of securing contractual commitments from generators to fund the links

account, this translates into an additional per project cost of almost $45 million/year for the industry and upstream sectors through 2020.

4 PERSPECTIVES ON FINANCING AND INCENTIVE OPTIONS

From June to October of 2009, ERM conducted semi-structured interviews with individuals from government, industry, investors and academia. Information received was used to develop the survey of F&I options as well as informing the development of the modelling approach and support scenarios chosen for each jurisdiction. This section summarises the experts' views and opinions and draws some summary conclusions regarding the existing and proposed support options that can influence CO_2 capture and storage (CCS) deployment.

4.1 INTERVIEWS

ERM used its existing range of contacts in government, the financial sector and other relevant organisations in order to gain relevant contacts and then undertook interviews with individuals identified in appropriate organizations. ERM approached individuals from the following organisations and/or institutions in order to take part in the interview process:

- Directorate General for Research (Energy), European Commission
- DG Environment, European Commission
- UK Department of Energy & Climate Change
- U.S. Department of Energy (DOE)
- Carbonet
- TranAlta
- US Internal Revenue Service (IRS)
- Shell
- Infrastructure Canada
- Saskatchewan Ministry of Energy & Resources
- Environment Canada

4.2 KEY MESSAGES

The interviews were conducted around four main topics:

- Description and applicability of funds
- Understanding the prerequisites to financial viability
- Practical details of F & I Mechanisms
- Identifying risk and uncertainty issues

An overview of the findings and perspectives arising from these interviews are presented below for each separate jurisdiction.

4.2.1 European Union

Provisions of EU-level funds for CCS projects

EU and UK officials were asked to provide their perspectives on the adequacy and design details of the funding for CCS projects from the 300 million allowances in the New Entrants Reserve (NER300) and the European Energy Programme for Recovery. The following views were made:

- The levels of funds and other mechanisms (including the ETS) are adequate to sufficiently demonstrate a number of CCS projects in Europe by 2015
- The availability of financing itself is predictable for capture project investors; however the disbursement of NER300 funds may be linked to performance i.e. actual tCO_2 abated, providing inherent uncertainty.
- The payment mechanism has not yet been confirmed although at present two options are being considered: 1) Project milestones to be established for first ten years of operation and disbursement of funds made conditional on meeting performance targets or 2) funds to be provided in step with construction of project made conditional upon the possibility of fund claw-back in event of project failure.
- The European Investment Bank is likely to play an important role in the disbursement of EU-level funding (details not known at present).
- The European Commission has considered the development of incentives for longer term application of CCS such as CO_2 price guarantees and other mechanisms; the use of public-private partnerships are also considered as a potential option which might also include longer term R&D activities. Some interviewees viewed the use of feed-in-tariffs as potentially favourable as an additional incentive for CCS in the power sector due to their providing a level of security to investors
- No additional support schemes were envisaged specifically in relation to industry and upstream sector projects.

UK financing mechanisms for CCS demonstration

In relation to the current UK CCS project bidding process (UK demonstration competition), UK officials expressed the view that significant performance risk is likely to be assumed by the developers of projects whom will be required to make upfront investments whilst government payments will be linked to performance i.e. actual tCO_2 abated.

The risk of developers presenting unrealistic bids was highlighted as a concern which could de-rail the support process. It was noted in this context that the UK government has dealt with this issue in the past by requiring projects awarded funding to commence construction based on a series of clearly defined milestones. The view was expressed that the UK government funded FEED study (for the UK demonstration competition) will serve to alleviate this issue for the project developer of the first project undertaken.

4.2.2 *United States*

In relation to the CCS support options made available in the US, Department of Energy (DOE) interviews suggest that:

- The US DOE puts in place co-operative agreements with the project developers which lay out specific requirements and goals that the project must meet.
- The award methodology uses a gated system for making payments for different budget periods but that the majority of funds are given during pre-construction and construction phase.
- As such, there is little performance risk for project developers, which is therefore likely to enhance the utilisation of funds.

It was noted in this context that similar incentives to those currently employed for CCS have been used successfully for the US federal Clean Coal Technology Program (CCT). The CCT, which begun in 1986, was the most ambitious government-industry initiative ever undertaken to develop environmental solutions for using national coal resources. The federal government's funding share totalled $1.6 billion. The private sector, on the other hand, exceeded official expectations, contributing $3.2 billion – equal to nearly two-thirds of total project costs. The program had required only 50% non-federal financing.

4.2.3 *Canada*

One official expressed the view that sizeable investment will be necessary to promote significant demonstration of CCS – equal to approximately CN$600 to CN$800 million per project. Overall the Canadian CCS funding was considered to be adequate, especially Alberta's government-level funding which has great potential to support CCS in terms of the total amount of funds available (C$2 billion).

However it was suggested that there is likely to be considerable performance risk assumed by industry in the use of these funds. It was noted that performance risk arises most noticeably via the structure of the funding, in which projects would need to be financed almost entirely (with government providing a maximum of 20% capture cost funding paid on commencement of operations) by the project developer, who would subsequently recoup costs based on project performance (financing is to be linked to t/CO_2 sequestered) over a maximum period of 10 years.

The view was expressed that whilst levels of funding are important, the suitable selection of demonstration projects is also important; governments should evaluate projects for both the associated learning effects and the likelihood of long-term success and benefits, including the long-term development and dissemination of capture technology.

In relation to incentives previously applied to other O&G sector policy areas, it was noted that one of the most successful incentives introduced in Canada has been the tax incentive provided for oil sands as a royalty reduction (from 20%-40% to 1%) until project costs are recovered by the operator. However, it was conceded that recovery of oil sands create a revenue stream from a market commodity whereas CCS does not.

5 *ECONOMIC MODELLING*

5.1 *RATIONALE*

The purpose of the economic modelling exercise is to assess whether, and to what extent, different government F&I instruments can effectively incentivise CCS projects in the industry and upstream sectors.

Principally, the key question faced by a developer is whether the combinations of support mechanisms currently or potentially available in each of the studies jurisdictions may be sufficient to provide suitable financial returns for certain project investments. More specific criteria were outlined and discussed in *Section 3*.

In order to quantify the impact of various F&I instruments on CCS project economics , a simple methodology was developed using a discount cash flow (DCF) model to assess project cash-flow for a range of project 'types' according to defined F&I scenarios for each jurisdiction.

The model aimed to quantify the potential impact on project economics within each jurisdiction, based on an assessment of (a) CCS project technical and cost assumptions; and (b) potential F&I instruments applicable within each jurisdiction. The resulting analysis aims to provide a basis for understanding (a) which types of projects may or may not be incentivised via potential F&I instruments; (b) which types of F&I instruments may be more suitable to different project types; and (c) which are the key factors/policy design choices with a major impact on project viability.

This section presents:

- Modelling methodology and assumptions (*Section 5.2*)
- Key model dynamics (*Section 5.3*)
- Scenario results (*Section 5.4*)
- Conclusions (*Section 5.5*)

5.2 *MODELLING METHODOLOGY AND ASSUMPTIONS*

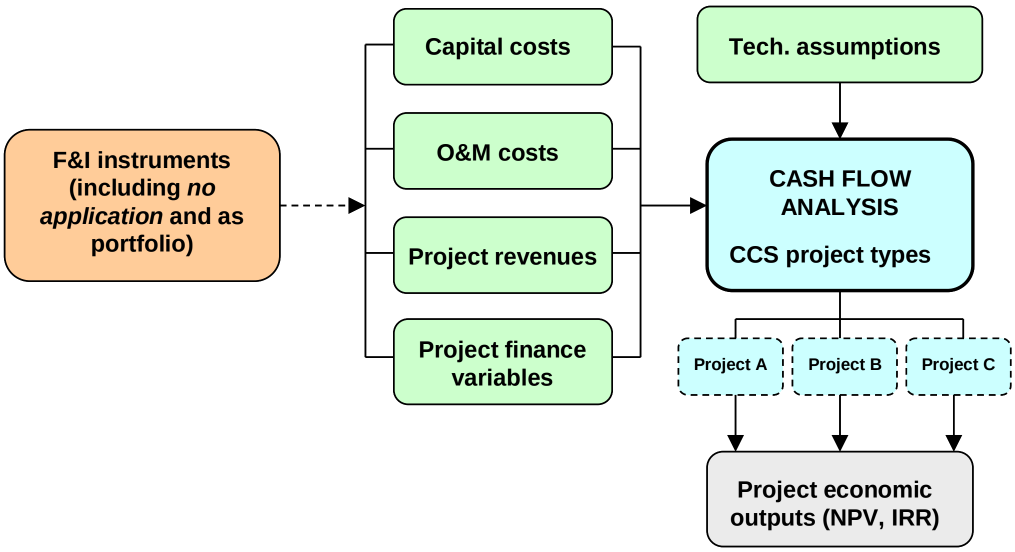
5.2.1 *Overview of modelling approach*

Figure 5.1 shows a simple schematic of the model methodology. The cash-flow analysis was performed for six different capture project types within the industry and upstream sectors (Projects A-F), each of which was characterise by a different set of technical and cost assumptions (factors such as fuel price and financial assumptions were common for all projects). The underlying key data inputs to the analysis were therefore the economic and technical assumptions for each project type, resulting in a different cost of abatement ($/t$CO_2$ avoided) for each of the six project types.

On the basis of the research undertaken for each jurisdiction (EU, US and Canada) the F&I instruments were then applied in various combinations to each of the project types. The key output chosen to assess financial performance comparatively across all six projects was project 'internal return on investment' (IRR). IRR measures the financial return for a project based on a series of cash flows (costs and revenues) over a defined time period. Unlike net present value (NPV) is can be used as a comparative indicator of economic viability across a range of capture project sizes. The introduction of F&I instruments decreases project costs and/or creates revenues which positively change the cash-flow of each project, thereby changing the project IRR calculated.

Using project IRR outputs, the financial performance of CCS projects could therefore be assessed (across the range of project types and the three jurisdictions), on the basis of different potential F&I assumptions, including levels of different kinds support (e.g. carbon prices, tax credits, grants) and various combinations thereof.

Figure 5.1 Cash-flow modelling overview



The 'project' for which each cash-flow analysis was undertaken was take to be the CCS component only i.e. an analysis of the *additional* costs and *additional* revenues arising from CCS being undertaken at the facility/plant compared to an equivalent reference (non-CCS) facility/plant. Therefore, project costs included:

- Capital costs associated with capture equipment
- Increased operating costs (O&M, insurance etc)

- Increased fuel costs (associated with additional fuel and/or power consumption to meet capture energy requirements)
- Cost of transport and storage (T&S)

For the purpose of simplicity it was assumed that for those projects where CO_2 was not injected in-situ, then transport and storage (T&S) of the CO_2 captured from each project was undertaken by a third party (e.g. pipeline operator) to which the CCS project develop pays a gate fee per tonne of CO_2 captured. Therefore, T&S was treated as a simple cost in the cash-flow analysis as opposed to a series of investment and cost flows in which the developer also finances pipeline infrastructure etc.

Due to the boundary chosen for the cash-flow analysis, no revenues were therefore available to any of the projects in the absence of F&I incentives (apart from CO_2 sold for enhanced oil recovery – EOR - purposes, which was modelled as a sensitivity). Where F&I incentives resulting in annual revenues were applied, these were assumed to accrue in full (i.e. their full face cash value) to the project cash-flow. For example, where applied tax relief incentives were assumed to retain their full theoretical value and treated as a cash revenue to the project, regardless of their actual use and/or the company's tax accounting procedures. Similarly, transactions costs and value discounting associated with potential sales of carbon credits were not considered; simple carbon prices in each project year were assumed (as a net value to the project cash-flow, regardless of whether credits were sold or the purchase of credits avoided).

5.2.2 *Choice of project types and costs of abatement*

Choice of project types

The purpose of the study was to assess the potential impact of F&I instruments upon CCS projects undertaken outside of the power sector, specifically at facilities/plants typically operated by industrial and O&G companies. Six model project 'types' were therefore chosen; three capture projects within the industry sector and three capture projects within the O&G upstream sector. These are described briefly in *Table 5.1*. More detailed project assumptions and data reference sources are provided in *Annex E* to this report.

The choice of projects was made on the basis of balancing several aims:

- Assessing capture projects for which there is available (technical and cost) data described in studies/academic papers in the public domain
- Assessing a broad range of project types (costs, fuel penalty, technologies, applications etc)
- Assessing capture sources for which the O&G sector has significant operations/ownership

Figure 5.2 Project assumptions summary

	Project A	Project B	Project C	Project D	Project E	Project F
	Refinery complex	GTL plant	Hydrogen plant	High CO_2 gas field (offshore)	High CO_2 gas field (onshore)	LNG plant
Captured ($MtCO_2$/yr)	2.00	2.03	0.68	2.00	2.00	2.00
Capture rate (%)	90%	90%	91%	98%	98%	98%
Avoided ($MtCO_2$/yr)	1.40	1.82	0.63	1.87	1.87	1.87
Add. capex ($M)	701	858	57	496	204	204
O&M ($/$tCO_2$ captured)	14.02	16.93	6.23	9.91	4.07	4.07
Fuel (GJ/tCO_2 captured)	6.20	2.13	1.45	1.15	1.15	1.15
Fuel cost ($/GJ)	6.00	1.00	6.00	1.00	1.00	1.00
T&S cost ($/$tCO_2$ captured)	15	15	15	in-situ (<$2)	in-situ (<$2)	15

Project details and assumptions were taken from existing literature as far as possible. However, few comparative studies of CCS costs across range of projects exist (at least outside of the power sector) with sufficient detail to allow for robust economic modelling. Detailed studies in the public domain were chosen where available to allow for a breakdown of data whereby certain cost factors could then be modelled equivalently. Therefore, as far as possible (and where relevant), common data assumptions were made in the modelling across all six projects to allow for fair comparison of results.

Similarly, to avoid significant cost 'scale effects' a balance was sought between achieving similar capture project sizes (in terms of annual volumes of CO_2 captured) and realistic - or broadly representative – descriptions of facility/plant types and production outputs. To this end, all projects apart from Project C (hydrogen plant) were modelled according to a capture rate of $2MtCO_2$/year. Project C was modelled according to a capture rate of around 683,000 tCO_2/year, on the basis of emissions produced by a typical medium- to large-sized hydrogen production facility. The six chosen capture project types were therefore considered to be reasonably typical optimal 'candidate' capture projects representing an illustrative range of capture sources, sectors and costs.

It should be noted that whilst Project B (GTL) has been included for the purpose of comparison (and because it likely represents the most promising synthetic fuel production process for capture), it is understood that there are currently no plans to build GTL plants in the regions included in this study; for example, existing GTL plants are located in regions with stranded gas such as Qatar, Nigeria, South Africa and Malaysia and most current plans for major new-build GTL facilities are located in the Middle East , Australia and South America.

Table 5.1 CCS project descriptions

Project ID	Project type	Basic project description
Project A	Refinery complex	Retrofit of large scale PC amine capture technology capturing 2MtCO_2 per year from a refinery and petrochemical complex from refinery-fired heaters (fuel oil and gas-fired), power plant boilers (fuel-oil fired) and chemical plant reaction furnaces (gas-fired). Total required additional energy consumption of 396 MW, fired by natural gas in a CHP plant to produce steam and power.
Project B	Gas-to-Liquids (GTL) plant	Post-combustion capture of 2.03MtCO_2 per year from a new-build 44,000 bbl/day gas-to-liquids plant producing diesel and naphtha from natural gas feedstock. Additional capture energy requirements met by on-site gas-fired power generation.
Project C	Hydrogen plant	Post-combustion capture of 683,000tCO_2 per year from a new-build 270mmscfd hydrogen production plant using modern steam methane reforming (SMR) technology. Additional capture energy requirements met by on-site gas-fired power generation.
Project D	High CO_2 gas field (offshore)	Installation of retrofit compression plant to an existing offshore (shallow water) natural gas processing facility. 2MtCO_2 per year captured from high CO_2 natural gas. Additional capture energy requirements met by on-site gas-fired power generation. Compressed CO_2 injected in-situ into depleted gas field.
Project E	High CO_2 gas field (onshore)	Installation of retrofit compression plant to an existing onshore natural gas processing facility. 2MtCO_2 per year captured from high CO_2 natural gas. Additional capture energy requirements met by on-site gas-fired power generation. Compressed CO_2 injected in-situ into depleted gas field.
Project F	LNG plant	Installation of retrofit compression plant to an existing onshore LNG facility. Additional capture energy requirements met by on-site gas-fired power generation. 2MtCO_2 per year captured, transported and stored.

Abatement costs

From the technical and economic data used in the cash-flow analysis, the cost of abatement (i.e. \$/tCO_2 avoided) could be calculated as an intermediate output for each of the six project types chosen. As described earlier, technical and cost data were derived from a range of available studies. All cost data used were then adjusted to current (2009) US dollars using the most recent Marshall and Swift CECPI price indices[1].

In addition to the capital and operating costs determined by existing studies (see *Annex E*), the following project assumptions were made:

- Fuel (gas) price
  - \$6/GJ industrial gas tariff (Projects A and C)
  - \$1/GJ upstream/feedstock gas value (Projects B, D ,E and F)
- Transport and storage (T&S) cost[2]
  - \$15/tCO_2 stored (Projects A,B,C and F)
  - In-situ onshore injection at \$0.64/tCO_2 (Project E)
  - In-situ offshore injection at \$1.26/tCO_2 (Project D)
- Project lead-time
  - 3 years; investment spread 30%:30%:40% (Projects A, B and C)
  - 2 years; investment spread 50%:50% (Projects D, E and F)

Abatement costs were calculated assuming the following 'baseline' financial assumptions common to all projects:

- Financial lifetime: 20 years;
- Commercial financial structure: 70% debt (at 9.57%[3]); 30% equity (at 15%)
- Inflation rate: 2.5%
- Resulting Weighted Average Cost of Capital (WACC): 8.7%.

The WACC represents the cost of capital or real discount rate[4], by which the incremental capital cost of each project was levelised over the financial lifetime. The 'baseline' value chosen was assumed to represent a typical large-scale commercial rate used by the O&G sector in OECD countries (the resulting IRR value calculated for each project indicates the required return for which the NPV of the project is 0 (zero) at this discount rate).

Tonnes of CO_2 avoided were calculated from the available technical data according to the formula:

$$Avoided\ CO_2 = captured\ CO_2\ x\ CE / [eff_{new} / eff_{old} - 1 + CE]$$

[1] See http://docs.google.com/gview?a=v&q=cache:MGNaDNE2B-AJ:www.lib.purdue.edu/chem/inst/che497b/chem_eng.pdf+marshall+and+swift+equipment+cost+index+2008&hl=en&gl=uk

[2] For Projects A, B, C and F, it was assumed that a third party transports and stores the CO_2 captured from the facility/plant gate. This was undertaken at a baseline cost of \$15/tCO_2 captured, reflecting the default assumption currently used by the US EPA on the basis of source-sink studies (Dooley et al, 20008) undertaken in North America (in which around 80% of identified source-sink pairings were attributed a cost of \$12-15/tCO_2). For Projects D and E in-situ injection was assumed with a detailed calculation of associated T&S costs based on e.g. flow rate compression and storage site requirements.

[3] US LIBOR + 4%

[4] Where real discount rate = nominal discount rate – inflation rate.

where CE = fraction captured; eff_{old} = energy efficiency of plant without capture (%); eff_{new} = energy efficiency of plant with capture(%)[1]

The resulting abatement costs for each of the six capture project types are shown in *Figure 5.3* and *Table 5.2*, which also indicate the contribution of each cost component to the total.

Figure 5.3 Baseline abatement costs for modelled CCS projects

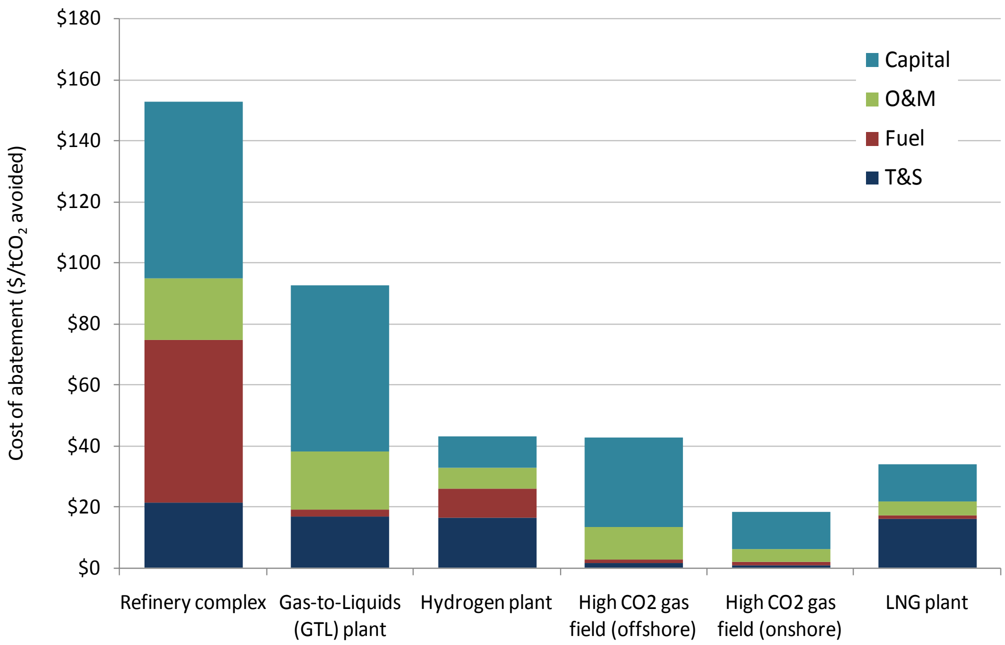


Table 5.2 Baseline abatement costs for modelled CCS projects (US$/t$CO_2$ avoided)

Cost component	**Project A**	**Project B**	**Project C**	**Project D**	**Project E**	**Project F**
	Refinery complex	Gas-to-Liquids plant	Hydrogen plant	High CO_2 gas field (offshore)	High CO_2 gas field (onshore)	LNG plant
Capital	$58.00	$54.54	$10.47	$29.64	$12.18	$12.18
O&M	$20.03	$18.83	$6.78	$10.60	$4.36	$4.36
Fuel	$53.14	$2.37	$9.49	$1.23	$1.23	$1.23
T&S	$21.43	$16.69	$16.33	$1.34	$0.68	$16.04
Total	**$152.60**	**$92.43**	**$43.07**	**$42.81**	**$18.45**	**$33.80**

It can be seen that there is a considerable range in the baseline costs of abatement calculated for the six projects. The relatively low costs of projects in

[1] see p.64 'CCS – A key carbon abatement option' (IEA, 2008).

the upstream sector (Projects D, E, and F) can be contrasted with the higher costs within industry, in particular for capture undertaken at a refinery complex or GTL plant.

The breakdown of cost components indicates that there are several factors underpinning the differences seen.

Significant factors include the considerable difference in capital cost between projects types - with Projects A and B having particularly high capital costs. In addition, fuel costs vary across projects, driven by a combination of (a) fuel price paid by each project; and (b) capture energy penalty; for example, it can be seen that whereas the large energy requirements and industrial gas tariff paid result in a high fuel cost for Project A, a lower fuel price and energy penalty for Projects D, E and F results in a relatively small fuel cost component. Similarly, the in-situ gas-field injection (Projects D and E) result in much lower T&S costs compared to Projects A,B,C and F (Project A has the highest T&S cost per tCO_2 avoided due to its proportionately large energy penalty, associated with on-site compression and blowing and having multiple capture sources).

The abatement cost data therefore illustrate that, in addition to there being a wide range in abatement costs for CCS projects within the industry and upstream sectors, projects can be very different in terms of their cost components (e.g. relative share of capital costs vs. annual costs). This is an important consideration in view of different types of F&I support required to meet additional costs for different project types. For example, some CCS projects may face significant up-front investment costs but relatively minor ongoing annual costs from increased energy requirements, thereby benefiting to a greater extent from investment support.

Sensitivity analysis of key cost factors

Due to the lack of existing project experience, the costs – and performance - of CCS undertaken for the project types chosen are highly uncertain. Numerous unknown factors may significantly increase the costs of CCS compared to the 'baseline' costs presented. The rate of future technology cost reductions are unknown, as are movements in energy markets and regional prices; T&S costs are highly specific to project location, terrain, and storage site as well as the rate and optimisation of pipeline infrastructure development over the near to medium term. In addition, CCS costs will be highly case-specific according to a range of regional and local technical and cost factors. In common with most engineering operations, scale effects may also be considerable for CCS project economics, giving rise to significant cost reductions for large capture projects and escalated costs for smaller demonstration projects.

In view of the uncertainty, a series of sensitivities were undertaken to assess abatement costs against some key project cost parameters. These were performed by varying the following factors:

- Fuel price (+/- 50% of baseline prices)
- T&S cost ($5-$25/tCO_2 stored range)
- Additional capture investment cost (+/- 50% of baseline costs)
- WACC (2%-15%, representing potential rates ranging from low interest governmental loan to high equity/high risk lending)

The resulting sensitivity outputs are shown in *Figure 5.4*, *Figure 5.5*, *Figure 5.6* and *Figure 5.7*.

Figure 5.4 Cost of abatement – fuel price sensitivity

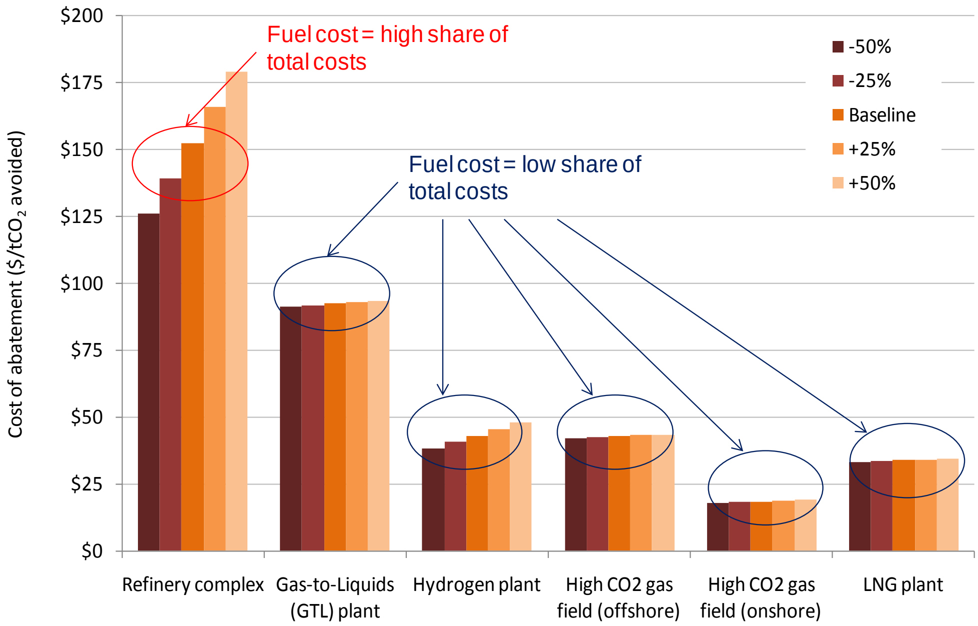


Figure 5.5 Cost of abatement – T&S cost sensitivity

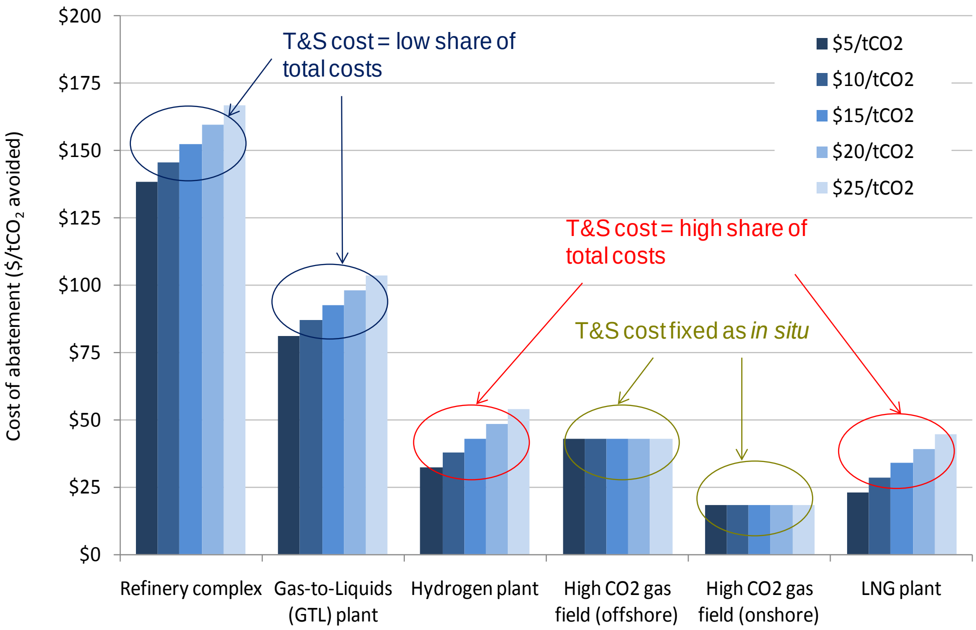


Figure 5.6 Cost of abatement – Additional capture investment cost sensitivity

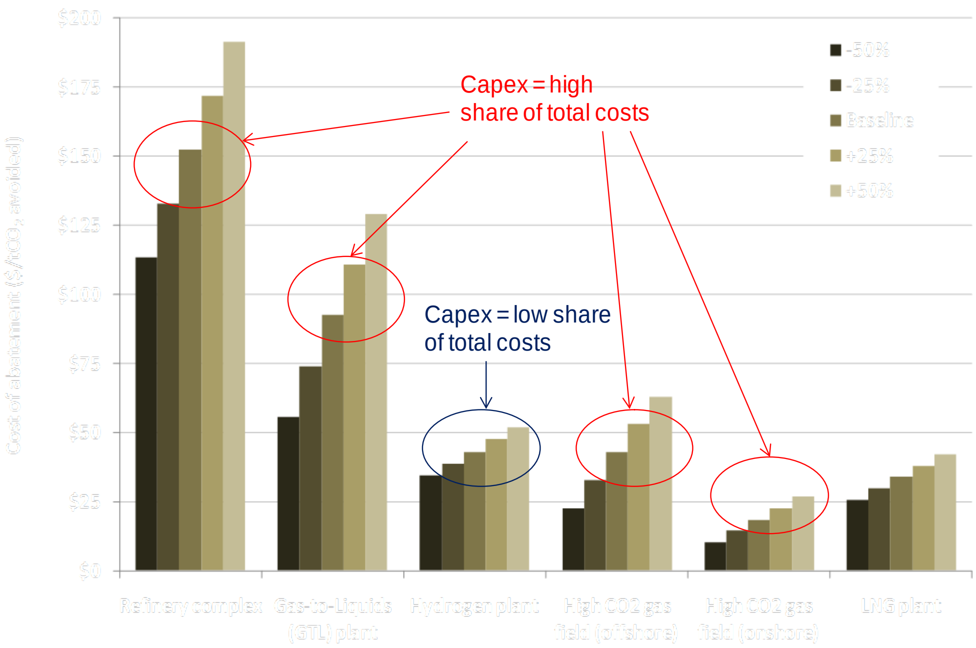
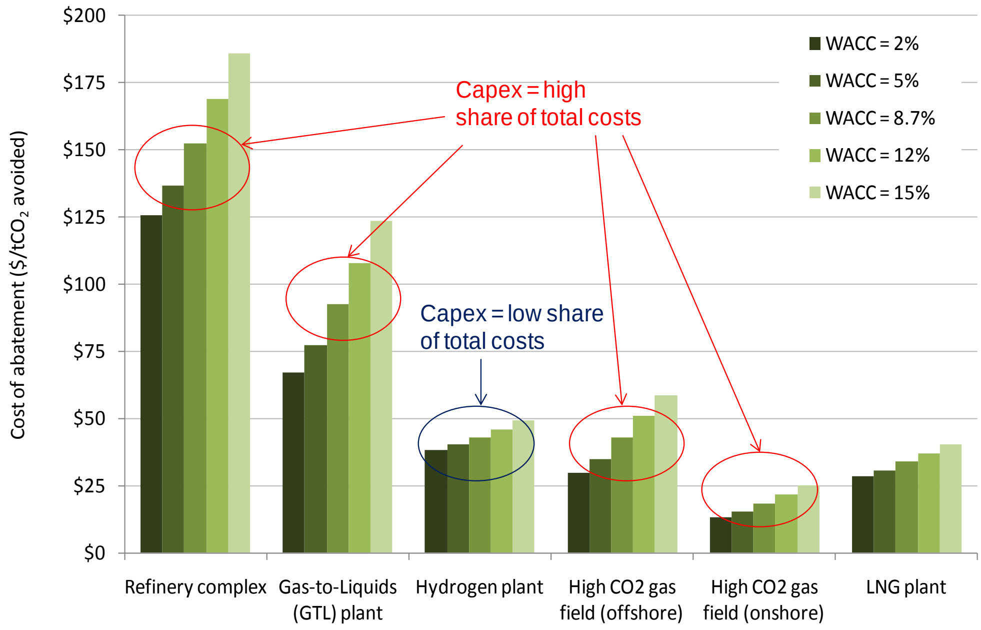


Figure 5.7 *Cost of abatement – Cost of capital (WACC) sensitivity*



The sensitivity results illustrate some key differences between the economics of project types, and further, how CCS abatement costs are highly sensitive to a range of uncertain and/or variable data assumptions.

As shown in *Figure 5.4*, the cost of Project A (and to a lesser degree Project C) is highly sensitive to fuel (gas) prices. This is because, as shown in *Figure 5.3*, fuel costs represent a large share of the overall capture costs from a refinery complex; these costs are seen to be less significant for upstream projects where the net energy efficiency of capture is higher and a typically lower price of gas is assumed.

Figure 5.5 shows that T&S costs can also be a significant factor in determining the overall cost of abatement. They represent a large share of the total cost of Projects C and F (because the cost if capture is relatively low).

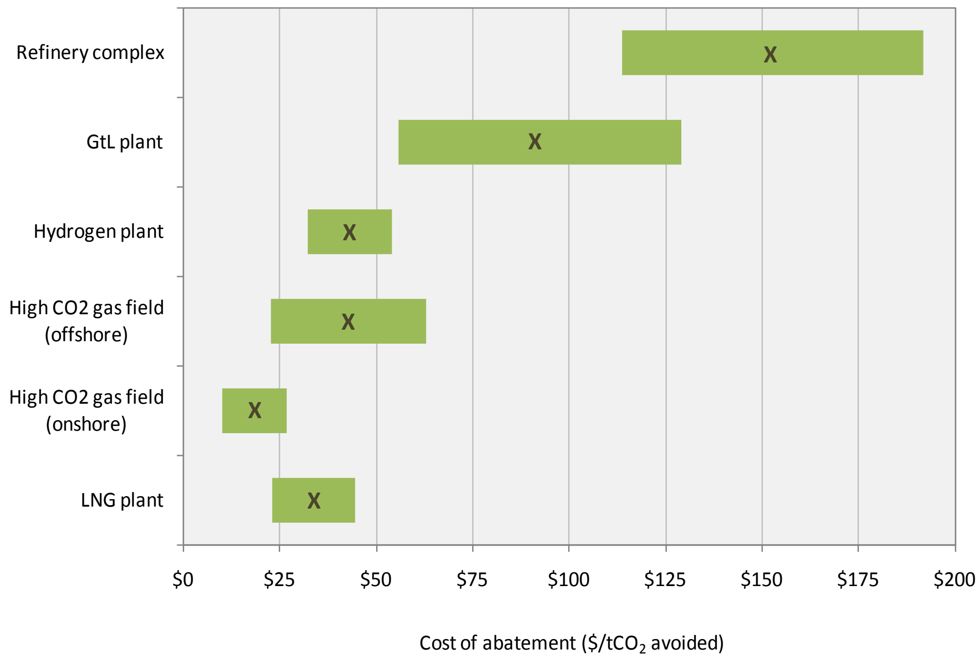
Figure 5.6 illustrates the relative sensitivity of project cost to the investment cost of capture plant. The wide range of values chosen (e.g. +/- 50% the baseline cost estimates) may serve to reflect both significantly reduced costs (e.g. due to falling technology costs; economies of scale from deployment of very large capture projects) and significantly increased costs (e.g. project and/or engineering design complexity; increased costs due to smaller project size). It can be seen that where capital costs represent a large share of overall cost (Projects A,B, C and D), the sensitivity to changes in capital cost are high; for example; the cost of Project B ranges between around $55/t$CO_2$ and $130/t$CO_2$. The sensitivity is less pronounced in Projects C and F in which investment costs represent a relatively smaller share of overall project cost.

Varying the weighted average cost of capital (WACC) produces a similar set of results (see *Figure 5.7*): those projects that are most capital intensive are most cost sensitive to increased financing rates (e.g. the project's discount factor). The results here indicate that the financing structure of a large-scale CCS project is key to its overall cost; for example the cost of Project B at a WACC of 2% (i.e. project finance from a low interest government loan) is around half as much as it would be for a WACC of 15% (i.e. a high equity and/or high risk rate).

As discussed earlier, the cost of undertaking CCS across the range of chosen project types is dependent upon a wide range of underlying factors, some of which are highly project/location specific in practise; the cost components within the overall abatement cost are therefore uncertain. However, the sensitivity analyses undertaken indicate that whilst the magnitude of costs is uncertain, the relative ranking of costs across the six projects does not change e.g. under a wide range of key cost sensitivities, capture from industrial sources such as refineries and gas-to-liquids plants would be undertaken at much higher cost than for 'early opportunity' low-cost projects such as high-CO_2 gas field projects.

The range of abatement costs provided under the sensitivity analysis is summarised in *Figure 5.8* (the 'baseline' abatement cost for peach project used in the model analysis are indicated by a cross).

Figure 5.8 Range of CCS abatement costs under sensitivity analysis



Note: Cost ranges represent the lowest and highest values calculated for each project across all sensitivity analyses undertaken; crosses indicate 'baseline' abatement costs within each cost range used in the cash-flow analysis.

Note that the abatement costs presented above, including the ranges shown, should be viewed as indicative of likely 'optimal' or 'early opportunity' project opportunities within each sector; for smaller-scale demonstration projects costs could be significantly higher than the upper ranges presented.

Existing publicly available estimates of CCS abatement costs vary considerably according a wide range of different assumptions made (scope of emissions captured; technology deployed; fuel type and costs; economic and financial assumptions etc). Studies of capture costs for projects in the sectors chosen are less extensive than for power generation sector sources. However, available estimates suggest a reasonable alignment with the values shown in *Figure 5.8*.

Existing studies of CCS costs from refinery sources vary significantly. For example, Simmonds et al (2003) suggest a figure of around \$50-60/tCO_2 captured whereas a recent study by StatoilHydro[1] (StatoilHydro, 2008) estimates the cost of post-combustion capture from the Mongstad oil refinery near Bergen in Norway would lie in the range of \$185-255/tCO_2. The IPCC Special Report on Carbon Dioxide Capture and Storage (IPCC, 2005) suggests a cost range *excluding transport and storage* of \$2-56/tCO_2 avoided (and a 'representative value' of \$15/tCO_2) for capture from a new hydrogen plant. A detailed study of abatement costs in the gas processing sector (high CO_2 gas field and LNG) undertaken by the IEA GHG R&D Programme[2] (IEA GHG R&D, 2008) estimate costs in 2012 lying in the range of around \$10 - \$31 per tCO_2 abated depending on a range of project sizes and locations. Other studies concur than such projects represent low-cost project opportunities; for example WWF have cited a figure of 200 MtCO_2 being available for abatement in gas processing activities worldwide for less than \$20 per tCO_2 abated.[3]

The following broad conclusions can be made regarding the costs of the project types used as the basis for the model analysis:

- Abatement costs vary dramatically across project types
- Project cost components can vary significantly; in particular, certain projects may be highly capital-intensive whereas others may face higher annual operating costs (e.g. fuel costs, T&S costs)
- A wide range of unknowns will impact costs (differently across project types) and influence project economics

[1] StatoilHydro (2008). "Mongstad master plan", as discussed in Al-Juaied, M and Whitmore, A 'Realistic costs of Carbon Capture', Harvard, 2009.
[2] 'Carbon Dioxide Capture and Storage in the Clean Development Mechanism: Assessing market effects of inclusion' (IEA GHG R&D, 2008)
[3] See: IEEP (2007) CO_2 Capture and Storage in Developing Countries and the role of the Clean Development Mechanisms: A paper for the World Wildlife Fund (WWF) European Policy Office; submitted to the UNFCCC in 2007 by the WWF.

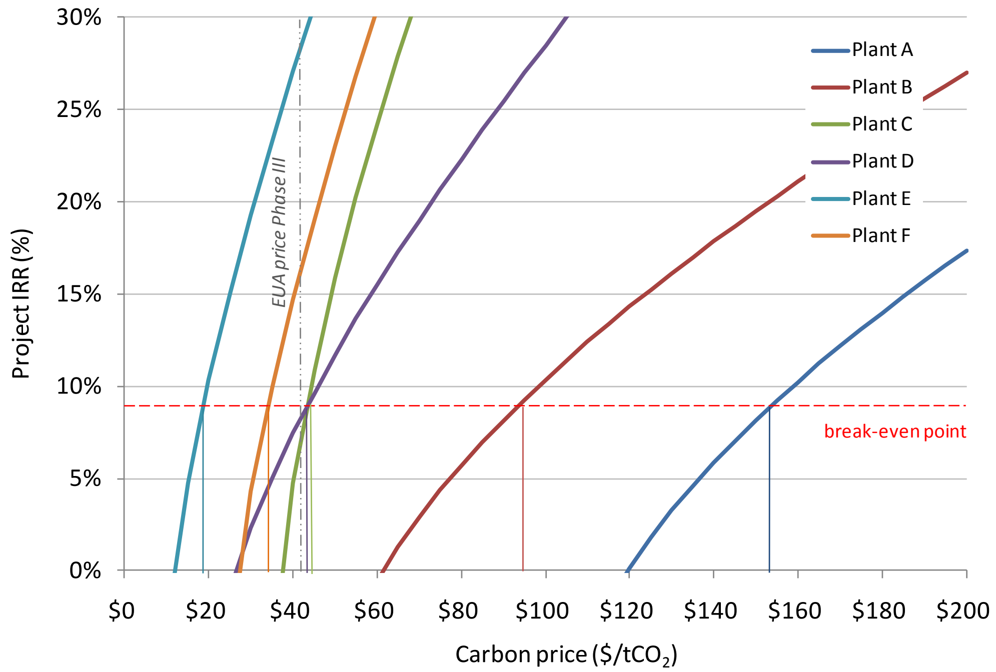
- The relative cost ranking of the six project types chosen remains constant as key cost factors are varied (i.e. under each sensitivity analysis)

5.3 *KEY MODEL DYNAMICS*

This section presents an overview of the key model dynamics determining project IRR across the six chosen projects. Some simple high-level conclusions are made regarding the implications for support mechanisms before developing scenarios of potential F&I packages for each jurisdiction in the next section (*Section 5.4*).

Figure 5.9 shows a plot of project IRR over a 20 year period calculated for each of the six CCS project types against carbon price (which remain constant over the full 20-year period). The graph is therefore an illustration of the carbon price(s) required - in the absence of any other financial support for CCS - to achieve an IRR equal or greater than the WACC (i.e. the chosen baseline value of 8.7%, shown as a red horizontal line on the plot). The calculations assume that every tCO_2 avoided by undertaking CCS is realised as a carbon value to the project developer, (i.e. transactional and other costs are not modelled). Because the NPV of each project is always positive where the project IRR is greater than the WACC, any IRR value shown above the WACC therefore represents an economically viable project. Each curve therefore intersects the WACC (shown as a red dashed line) at the carbon price corresponding to its baseline abatement cost. These points are shown by the coloured vertical lines; for example Project A would require a carbon price of at least \$153/tCO_2 to meet the WACC, whereas Project E would require only \$18/tCO_2.

Figure 5.9 ***Project IRR as a function of carbon price (over 20 years)***

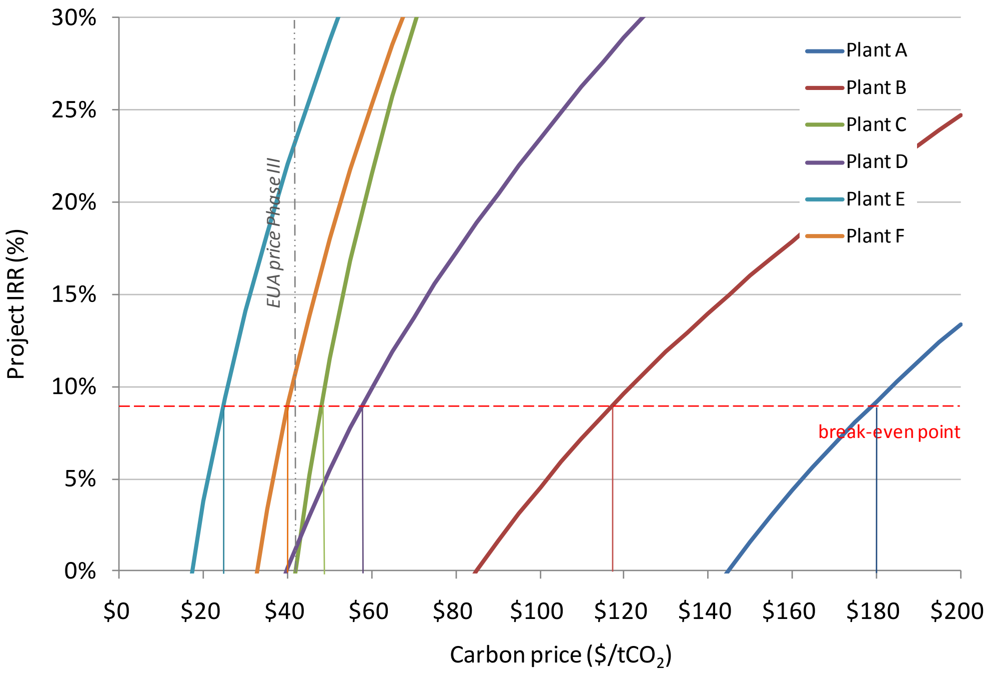


The curves clearly show that progressively higher carbon prices would be required to achieve project returns higher than the WACC (e.g. higher rates required by high-equity finance or higher risk values) – and conversely that lower carbon prices could support projects with lower required returns (e.g. lower rates required by government and low-interest debt finance). It can also be seen that each curve has a different shaped curve – with a rough grouping of Projects E, F and C (with steep curves) and Projects D, B and A (with shallower curves). The difference in the curves is due to the higher capital costs of the latter grouping.

The European Commission's forecast of average EUA prices under Phase III of the EU Emissions Trading Scheme (ETS) is shown for reference on the graph (as a grey dashed line). It can clearly be seen that only two of the low-cost CCS project types – Projects E and F - would be economically viable (for a WACC of 8.7%) if supported by a market carbon price at this level alone.

Figure 5.10 shows the same set of model results but calculated over a 10 year period only. The results are therefore indicative of a financial analysis based on a smaller period of known carbon credit revenues streams (or avoided carbon costs), reflecting e.g. political uncertainty around future commitments and/or prices. The results clearly show that, when based on only 10 years of revenues, significantly higher carbon prices would be required to achieve the required project IRR values. This increase is most marked in those projects with high capital costs (e.g. Projects A and B); Projects E, F and C require only a marginally higher carbon price to achieve a given project IRR.

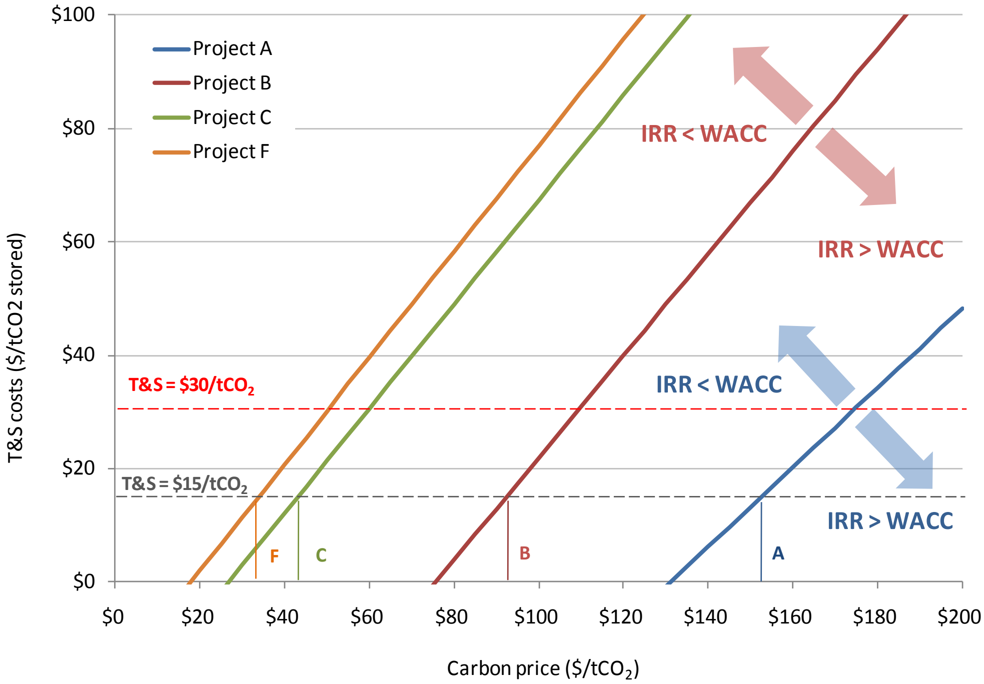
Figure 5.10 Project IRR as a function of carbon price (over 10 years)



As discussed earlier, the costs of transport and storage (T&S) are highly project and location-specific, depending upon e.g. proximity to a suitable storage site, the future evolution and optimisation of pipeline infrastructure and the geological characteristics of the storage media. These costs have been assumed to represent an average of \$15/tCO_2 stored within the baseline assumptions, although they are highly uncertain and variable. *Figure 5.11* illustrates the impact of this potential cost variation by showing the 'break-even' plots – whereby the Project IRR is equal to the WACC, thus 'breaking even' at a NPV of 0 – for different T&S cost levels and carbon prices (note that the *in-situ* injection projects D and E are not shown). The required carbon prices are shown where each project line intersects the baseline T&S cost assumption of \$15/tCO_2 (shown by the grey dashed line); these are equal to the carbon prices shown in *Figure 5.9* - and are the same as the baseline abatement costs.

It can be seen that were T&S costs to be twice as high as the baseline assumption (increased to \$30/tCO_2, shown by the red dashed line), then higher carbon prices would be required to support the projects shown – the increase being equal to the additional \$15/tCO_2 *stored* converted to a cost per tCO_2 *avoided* for each project. The shallower gradient seen for Project A reflects the relatively larger difference between captured/stored CO_2 and avoided CO_2 for this project, owing to its comparatively high energy penalty.

Figure 5.11 ***Project break-even points as a function of carbon price and T&S cost***



The breakdown of abatement cost components for each project (see *Section 5.2.2*) showed how some projects have higher capital costs than others. This factor has an important bearing on the degree of overall support (in terms of achieving financial viability) which different *types* of F&I instruments can provide to different CCS projects, as shown in *Figure 5.12*.

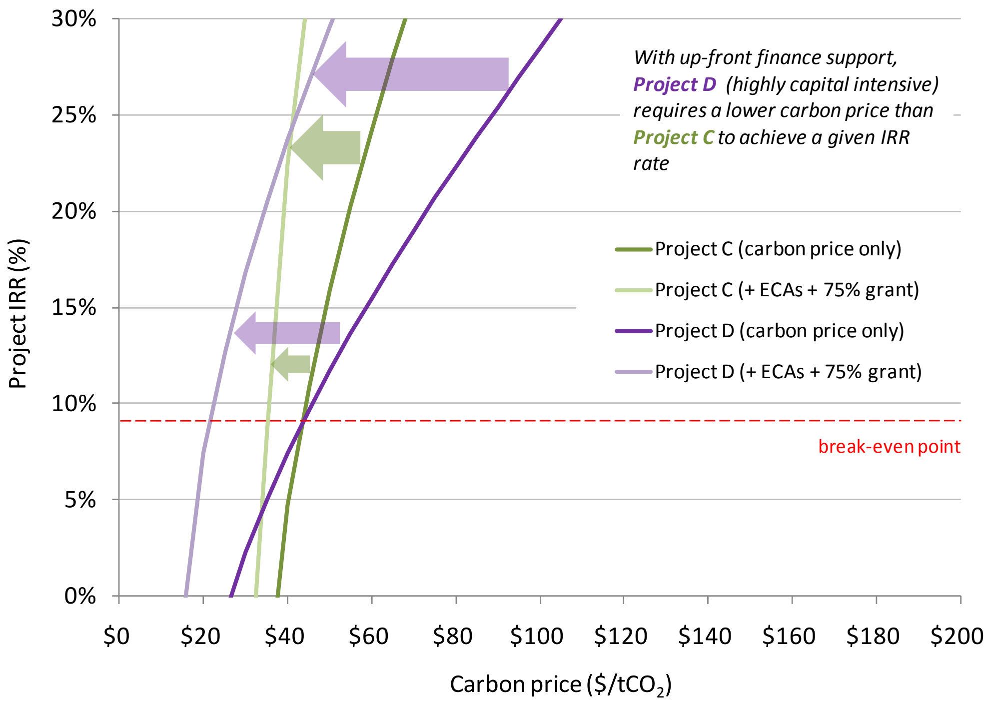
The graph shows the Project IRR corresponding with increasing carbon prices for two projects: Project C (capture from a hydrogen plant) and Project D (capture from a high-CO_2 offshore gas field). Although both projects have the same overall cost of abatement ($43/t$CO_2$) they have very different cost structures: capital costs comprise only 25% of the total cost for Project C whereas they represent almost 70% of Project D's costs (i.e. Project D is much more *capital intensive* than Project C). Two hypothetical F&I scenarios are modelled:

1. Projects supported by the market carbon price alone (i.e. an annual project benefit); and
2. Projects supported by carbon price + a government grant covering 75% of the additional capital cost of capture + enhanced capital allowances (spread over the first 5 years to improve up-front cash-flow)[1]

The impact upon Project IRR arising from the introduction of up-front support provided by the grant and ECAs is shown by the coloured arrows in the graph. It can clearly be seen that, with the additional up-front support package, then to meet the WACC (shown by the red dashed line) Project D would require a carbon price of only $20/t$CO_2$ whereas Project C would require a much higher carbon price of around $35/t$CO_2$. Essentially, although both projects have the same cost of abatement, Project D benefits more from the provision of up-front financial support due to its higher capital costs (in this case, due to *inter alia* retrofit and offshore location cost factors).

[1] ECAs are assumed to represent the tax relief value of that share of the additional capital cost not covered by grants, spread equally over the first 5 years (including construction years), assuming a corporate tax rate of 30%.

Figure 5.12 Project IRR for Projects C and D with and without investment support



From the above analysis, the following broad conclusions can be made:

- Fairly modest carbon prices (e.g. €30 – or US$42/$tCO_2$) may be sufficient to incentivise a limited number of low-cost 'early opportunity' upstream capture projects assuming guaranteed long-term prices; other projects unlikely to be viable with carbon finance alone (according to near-medium term price forecasts)
- Smaller crediting horizons (e.g. 7-10 years) would adversely impact project IRR (and may increase required project returns from investors)
- T&S costs are highly uncertain and project/location-specific; increased costs would require higher carbon prices to incentivise projects
- The capital costs of CCS projects can vary widely; more capital intensive projects benefit more from the introduction of up-front F&I support packages

5.4 SCENARIO RESULTS

5.4.1 *Defining the scenarios*

This section presents the results of modelling the economic impacts of potential packages of F&I instruments applied across the range of CCS project types and jurisdictions chosen (EU, US and Canada).

The survey of existing or proposed F&I options for CCS presented in *Annexes A-C* (and assessed in *Section 3*) describes a wide range of possible support mechanisms which could be made applicable to capture projects from industrial and upstream sectors. At the time of writing, the likely implementation of many of these instruments is uncertain, as are their design details, modalities, applicability criteria, timing and overall level of financial provision (e.g. cash value of funds/grants).

There is therefore considerable uncertainty for investors and CCS project developers regarding the most likely combination of F&I support which may be available for CCS in the medium-long term as well as the short-term. Given the uncertainty, a range of scenarios has been developed to quantify the potential impacts of various support packages upon project IRR. The cash-flow modelling then aims to assess which types of projects may be incentivised (under the baseline cost and finance assumptions) under different scenarios. Given the high degree of uncertainty regarding potential support levels and also the possible levels of support provided to capture projects in the power sector, the modelling does not attempt to quantify *how many projects* (or what volume of tCO_2 captured/stored) might be incentivised under different scenarios.

The scenarios chosen do not attempt to describe most likely or 'baseline' policy developments but rather a feasible range of support packages, based on the potentially applicable options identified by the research and consultation exercise. Although the details of specific options vary by jurisdiction (see *Annexes A-C*), in each case, the F&I instruments have been combined in such a way as to describe progressively 'supportive' CCS scenarios available to all six project types as follows:

- Scenario 1: carbon price only
- Scenario 2: carbon price + low grant (25%)
- Scenario 3: carbon price + medium grant (50%)
- Scenario 4: carbon price + high grant (75%)
- Scenario 5: carbon price + high grant (75%) + tax incentives

The presence of a carbon price is common to each scenario and, within each jurisdiction, is not increased (i.e. the same price forecast is used in each scenario). Where grants are applied, these apply only to the investment costs of capture plant (i.e. additional plant capital costs); additional fiscal incentives such as tax relief assumes a corporate tax rate of 30% in all jurisdictions and applies only to that share of investment made *net* of any grants. The value of grants and fiscal measures are disbursed over different time periods, according to the jurisdiction, as described in *Annex D*.

In addition to these baseline scenarios, alternative sensitivities have been developed for the EU and the US.

In the case of the EU, a major uncertainty relates to, *inter alia*, how EU-level funds (i.e. from the 300 million allowances in the ETS New Entrant Reserve) may be disbursed over the timing of an awarded project; the uncertainty is compounded further by the question of how funds would be created (e.g. by auctioning of allowances, and the optimal timing thereof) and whether they might be transferred to Member States to disburse to eligible national projects. Various approaches have been proposed, ranging from up-front provision of funds to a longer-term disbursal based on 'performance milestones' with the possibility of some claw-back in the event of project failure. To reflect this key uncertainty, the baseline scenario assumes a 10-year disbursal of funds over the project lifetime and the alternative case assumes up-front disbursal over the project construction phase (i.e. 2 or 3 years, depending upon the CCS project type).

In the US, a wide range of F&I options are proposed for potential CCS support, with much uncertainty regarding which options may be passed into law and their potential design, eligibility and overall funding details. In order to manage the possible combinations of options, an alternative set of scenarios has been developed around the application of proposed 'bonus allowances' for sequestration; the value of such allowances is highly uncertain and would likely vary according to successive tranches of projects. This is reflected in the values chosen.

A full description of the scenarios is provided in *Annex D*.

5.4.2 *Model results*

The modelled impacts upon project IRR are shown below for each jurisdiction, showing the results for each project type and F&I support scenario. In each case, the 'baseline' technical, cost and financial assumptions as described in *Section 5.2* are used. A simple 5-colour 'traffic light' format has been used to summarise the results in terms of progressively large Project IRR categories (*Figure 5.13*). Those projects which achieve an IRR equal or greater to the baseline WACC (8.7%) are shown in pale and dark green; dark green indicates where they achieve an IRR greater than 15% (illustrative of a high equity finance structure and/or a higher investor risk evaluation). Projects which have no IRR (i.e. less than zero) are shown in red. Projects which have a positive IRR but which do not meet the baseline WACC are shown in orange and yellow: yellow indicates a project which achieves a return of 4% (illustrative of a low-interest government loan) and orange indicates a positive project IRR below this value.

Figure 5.13 Key to project IRR results under F&I support scenarios

Project IRR (%)	***Description***
< 0	Project IRR is less than zero (0%)
0 - 4	Project IRR is between zero (0%) and 4%
4 - 8.7	Project IRR is between 4% (e.g. low interest debt) and baseline WACC (8.7%)
8.7 - 15	Project IRR exceeds WACC (8.7%) and is less than 15%
> 15	Project IRR exceeds 15% (e.g. required return for high equity/high risk project)

European Union

Figure 5.14 shows the scenario results for the six project types deployed in the EU, based on two alternative cases relating to the timing of grant disbursement.

In both cases it can be seen that the project IRR for four of the six projects (Project C, D, E and F) meet the baseline WACC of 8.7% when supported by the carbon price under the EU ETS alone. These 'early opportunity' projects – representing the three upstream gas projects and capture from a hydrogen plant – would likely require additional support where underlying cost assumptions may be underestimated (e.g. for smaller demonstration projects and/or where T&S costs are higher than those assumed in the baseline assumptions). Similarly, the results assume carbon prices over the entire project based on a forecast Phase III EUA price of €30/tCO_2, increasing by 50% thereafter; a collapse in prices resulting from oversupply of allowances, reduced demand and/or uncertainty regarding the future of the ETS itself would reduce the IRR values.

In both cases, Project A (refinery complex) does not achieve a positive IRR; the additional up-front support from a high grant and tax relief is not sufficient to meet the high annual cost of implementing CCS at this facility type. However, it can seen that for Project B (GTL plant), the use of grants to offset the high investment costs allow the project to achieve a positive IRR; under Case A with a 75% grant, a return greater than 4% is achieved and under Case B a return of greater than the WACC (8.7%) is achieved. This illustrates that for some medium-high cost CCS projects, the timing of fund disbursement is likely to be critical to project viability.

Figure 5.14 F&I support scenarios for industry + upstream capture projects in the EU

Case A: Grants disbursed over 10 yrs "milestone-based"

Project IRR (%)	**Carbon price only**	**Carbon price + 25% grant**	**Carbon price + 50% grant**	**Carbon price + 75% grant**	**Carbon price + 75% grant + ECAs**
Project A	< 0	< 0	< 0	< 0	< 0
Project B	< 0	0 - 4	0 - 4	4 - 8.7	4 - 8.7
Project C	> 15	> 15	> 15	> 15	> 15
Project D	8.7 - 15	8.7 - 15	> 15	> 15	> 15
Project E	> 15	> 15	> 15	> 15	> 15
Project F	> 15	> 15	> 15	> 15	> 15

Case B: Grants disbursed over construction phase

Project IRR (%)	**Carbon price only**	**Carbon price + 25% grant**	**Carbon price + 50% grant**	**Carbon price + 75% grant**	**Carbon price + 75% grant + ECAs**
Project A	< 0	< 0	< 0	< 0	< 0
Project B	< 0	0 - 4	0 - 4	8.7 - 15	8.7 - 15
Project C	> 15	> 15	> 15	> 15	> 15
Project D	8.7 - 15	> 15	> 15	> 15	> 15
Project E	> 15	> 15	> 15	> 15	> 15
Project F	> 15	> 15	> 15	> 15	> 15

Note: All Project IRR values calculated over 20 years. Carbon prices under the EU ETS; EU-level grants covering up to 50% of additional capture investment costs possible from 300 million EUA within the ETS New Entrant Reserve and/or European Economic Recovery Package; additional grants from Member State support; ECAs = enhanced capital allowances (assuming 50% tax relief on additional capture investment costs spread over first 5 years, where corporation tax = 30%).

United States

Figure 5.15 shows the scenario results for the six project types deployed in the US, based on different possible combinations of F&I options (with and without use of bonus sequestration allowances).

Because of the lower forecast for allowance values in the proposed US cap-and-trade scheme compared to the EU ETS, the results indicate that only one of the 'early opportunity' upstream sector projects (Project E; capture and in-situ injection from an onshore high CO_2 gas field) achieves a project IRR greater than the baseline WACC when supported by carbon prices alone. As with the EU scenarios, the results assume guaranteed carbon prices over the project financial lifetime and no price collapse. In Case A, the addition of grants and tax credits are seen to incentivise four of the six project types, whilst Projects A and B do not achieve the WACC. The support provided by guaranteed revenue stream from the tax credits is seen to be particularly instrumental in incentivising Project C (hydrogen plant), where the annual operating costs represent a high share of overall CCS cost.

The results under Case B clearly show that the introduction of the proposed bonus sequestration allowances has a positive impact upon financial viability across all project types (when combined with carbon prices and tax credits). When applied at the maximum proposed rate of $90/tCO_2$ stored, they serve to achieve positive IRR values for all six project types. However, due to high investment costs, the highest cost project (Project A; refinery complex) requires additional grant funding to achieve the WACC of 8.7%.

Figure 5.15 *F&I support scenarios for industry + upstream capture projects in the US*

Case A: Without use of bonus sequestration allowances

Project IRR (%)	***Carbon price only***	***Carbon price + 25% grant***	***Carbon price + 50% grant***	***Carbon price + 75% grant***	***Carbon price + 75% grant + STCs***
Project A	< 0	< 0	< 0	< 0	< 0
Project B	< 0	< 0	< 0	< 0	4 - 8.7
Project C	< 0	< 0	< 0	< 0	> 15
Project D	0 - 4	0 - 4	4 - 8.7	8.7 - 15	> 15
Project E	8.7 - 15	> 15	> 15	> 15	> 15
Project F	< 0	0 - 4	4 - 8.7	8.7 - 15	> 15

Case B: With use of bonus sequestration allowances

Project IRR (%)	***Carbon price only***	***Carbon price + STCs***	***+ bonus allowances ($50/tCO2)***	***+ bonus allowances ($90/tCO2)***	***+ 25% grant***
Project A	< 0	< 0	< 0	0 - 4	8.7 - 15
Project B	< 0	< 0	4 - 8.7	> 15	> 15
Project C	< 0	8.7 - 15	> 15	> 15	> 15
Project D	0 - 4	8.7 - 15	> 15	> 15	> 15
Project E	8.7 - 15	> 15	> 15	> 15	> 15
Project F	< 0	> 15	> 15	> 15	> 15

Note: All Project IRR values calculated over 20 years. Carbon prices under US cap-and-trade; Grants covering up to 75% of additional capture investment costs from US DOE Industrial Carbon Capture and Storage programme (spread over construction phase); STCs = permanent sequestration tax credits (equal to $20/tCO_2$ sequestered over full 20 years of project capture with no EOR). Case B bonus allowances and 25% grant are additional to carbon price + STCs.

Canada

Figure 5.16 shows the scenario results for the six project types deployed in Canada.

The lower carbon price forecast for Canada (i.e. the value of avoiding payment into the CCS Fund) is sufficient to incentivise Project E only. The additional up-front support provided by grants and tax relief does not allow other project types to meet the WACC level of 8.7%; only in the case of the other upstream projects (Projects D and F) is a positive financial return seen – which in the case of low-interest debt finance - may be sufficient to achieve economic viability. When compared with the equivalent scenarios for the EU and US, the results show the importance of carbon prices to low-medium cost CCS projects i.e. although up-front support may be decisive in incentivising such project types, differences in the guaranteed value of revenues (or avoided costs) associated with regional carbon markets are key to ongoing project cash flow.

Figure 5.16 ***F&I support scenarios for industry + upstream capture projects in Canada***

Project IRR (%)	***Carbon price only***	***Carbon price + 25% grant***	***Carbon price + 50% grant***	***Carbon price + 75% grant***	***Carbon price + 75% grant + CCAs***
Project A	< 0	< 0	< 0	< 0	< 0
Project B	< 0	< 0	< 0	< 0	< 0
Project C	< 0	< 0	< 0	< 0	< 0
Project D	< 0	0 - 4	4 - 8.7	4 - 8.7	4 - 8.7
Project E	8.7 - 15	> 15	> 15	> 15	> 15
Project F	< 0	< 0	0 - 4	0 - 4	4 - 8.7

Note: All Project IRR values calculated over 20 years. Carbon prices under Regulatory Framework for Industrial Greenhouse Gas Emissions; Grants covering up to 75% of additional capture investment costs from CCS Fund (spread over initial 7 years); CCAs = accelerated capital cost allowances (assuming 50% tax relief on additional capture investment costs spread over first 5 years, where corporation tax = 30%).

Comparison of results

Comparing results across the three jurisdictions indicates that carbon prices are critical to incentivising projects, particularly 'early opportunities', needed to demonstrate CCS outside of the power sector in the near-medium term; higher carbon prices within the ETS can be seen to incentivise a wider range of low-cost projects (where these may exist) than in the US and Canada. However, the results also indicate that significant up-front funds must be made available in the near-medium term to deploy a wider range of project types. This is illustrated in *Table 5.3* below which indicate the grant levels (i.e.

the share of capture investment costs) required for each project type to achieve the baseline WACC (8.7%) within each of the jurisdictions. The figures show that whilst some projects cannot be incentivised by the forecast carbon prices and grants alone, the use of significant grants to help offset up-front costs will be needed to demonstrate a large range of project types across the three jurisdictions. Only in the US, with the additional use of favourable bonus allowances and sequestration credits does the use of grants allow for the highest cost project type to become viable (Project A; capture from refinery complex).

Table 5.3 Grant levels required to achieve WACC of 8.7% in different jurisdictions

Grant level (% of investment costs)	**EU**		**US**		**Canada**
	Case A	*Case B*	*Case A*	*Case B*	-
Project A	-	-	-	*17%*	-
Project B	*94%*	*72%*	-	*0%*	-
Project C	*0%*	*0%*	-	*0%*	-
Project D	*0%*	*0%*	*61%*	*0%*	*80%*
Project E	*0%*	*0%*	*0%*	*0%*	*0%*
Project F	*0%*	*0%*	*75%*	*0%*	-

Note: All results assume (region-specific) carbon prices; EU Cases A and B assume different timing of grant disbursement; US Case B assumes use of sequestration taxes of \$20/tCO_2 and bonus allowances of \$90/tCO_2 throughout. Dashes = 100% grant insufficient to meet WACC.

5.5 CONCLUSIONS

The simple project cash-flow analysis presented in this section demonstrates that possible combinations of existing and proposed government F&I instruments could potentially incentivise a range of CCS project types in the industry and upstream sectors across the three jurisdictions of the EU, US and Canada. The results of the scenarios provide a basis for understanding the potential *level* and *type* of support packages that may be needed to deploy typical capture project types in these sectors within each region, and therefore also the *financing gap* between what exists or is being proposed and what is required to demonstrate a range of project types.

Clearly, the largest area of uncertainty influencing future deployment of CCS projects concerns the development of enabling policy frameworks in each jurisdiction, including the establishment and successful growth of regional carbon markets and near-term supplementary finance support mechanisms required to demonstrate large-scale CCS.

An assessment of financing needs for CCS in the O&G sector begins with a robust understanding of project costs. There is limited project experience within the sector as a whole, and existing cost estimates in the public domain are few (compared to studies of capture from power generation sources) and usually highly case-specific. A wide range of factors influence costs across all parts of the CCS chain and will be highly dependent upon region- and project-specific circumstances, which in turn may vary in the future and across the lifetime of a CCS project. Despite the large uncertainty in developing illustrative costs, existing data and sensitivity analyses suggest that the cost of abatement from CCS varies dramatically across project types, ranging from comparatively low-cost 'early opportunities' in e.g. gas processing and hydrogen production to higher cost projects in refining and fuel transformation.

Section 5.2 indicated that across the six chosen project types, abatement costs may vary from around \$18-153/tCO_2 under baseline assumptions; the sensitivity analysis showed that whilst these estimates could vary considerably, the relative cost ranking of the six chosen project types remained constant as key cost factors were changed. As well as overall abatement cost levels, *Section 5.2* showed that project cost components can vary significantly between project types; in particular, certain projects may be highly capital-intensive whereas others may face higher annual operating costs (e.g. fuel costs, T&S costs).

Section 5.3 demonstrated that fairly modest carbon prices (e.g. €30/tCO_2) may be sufficient to incentivise a limited number of low-cost 'early opportunity' upstream capture projects assuming guaranteed long-term prices whereas other projects would be unlikely to be viable with carbon finance alone (according to near-medium term price forecasts). Cash-flow analysis results showed that smaller crediting horizons (e.g. 7-10 years) would adversely impact project IRR and that more capital intensive projects benefit more from the introduction of up-front F&I support (e.g. grants and tax relief in early years).

Section 5.4 presented a range of possible CCS support scenarios in terms of their impacts upon project viability. The likely combination, and detailed design and modalities, of the F&I options assessed in each jurisdiction is highly uncertain and subject to ongoing (domestic and international) policy developments. The scenarios chosen do not attempt to predict ongoing or future market and policy developments but rather describe a broad set of possible F&I support frameworks within each region on the basis of existing information. The model results are therefore illustrative only - and are determined by the assumptions chosen (e.g. abatement costs, financial parameters, carbon prices.

However, some useful conclusions can be drawn:

Support potential for CCS varies significantly across the jurisdictions

In the **EU**, the inclusion of CCS in the ETS may be sufficient to incentivise certain low-cost project types with abatement costs less than around \$50/tCO_2 (e.g. capture from gas fields, LNG and hydrogen plants); however, this is based on the need for EUA prices to achieve the forecast level of €30/tCO_2 in Phase III (2013-2020) and to rise thereafter with increased strengthening of caps. For higher cost projects such as capture from GTL plants, additional up-front grant support will be required. An important consideration in this context is the likely timing of fund disbursement; for example where funds are disbursed over the construction phase of the GTL project, the project is seen to meet the WACC (i.e. is financially viable) whereas it does not in the case of funds being disbursed over a longer time period, reflecting a 'milestone' or 'performance-based' approach to payments. Although not modelled here, the latter approach would also likely increase the risk of such a project and require a higher rate of return from commercial lenders. High-cost industrial capture projects (e.g. capture from refineries) facing large operating costs may not be viable even with large grant funding; additional measures not yet proposed and/or higher carbon prices would likely be required. As noted earlier however, these results are illustrative only; for example, there are no know GTL project plans within the EU.

In the **US**, the uncertainty regarding the potential package of F&I instrument applied to CCS is greater. Forecast carbon prices under a federal cap-and-trade scheme are lower than for the EU ETS Phase III and would likely incentivise only very low-cost project types such as capture from some on-shore gas fields; the provision of grants and sequestration tax credits could incentivise a wider range of projects including capture from other upstream sources and early opportunities in the industrial sector such as hydrogen plants. However, the potential use of bonus allowances at the high end of the values proposed (e.g. \$90/tCO_2 stored) in addition to carbon prices and tax credits could potentially incentivise high cost projects including capture from GTL plants and refinery complexes, by creating a large and guaranteed annual revenue stream during the project lifetime.

In **Canada**, the range of F&I options currently proposed appears likely to incentivise only the very lowest cost 'early opportunities' (e.g. from high-CO_2 gas fields). The provision of grants from the CCS Fund may incentivise other early opportunities in the upstream sector were low-interest public lending to be made available, while the use of tax relief appears to have only a marginal impact upon project economics. Under the modelled scenarios, none of the industrial capture projects (Project A, B and C) achieve a positive project IRR.

A combination of F&I instruments is required to incentivise CCS projects

As illustrated in *Section 5.3* and *Section 5.4*, the wide range of cost structures faced by different CCS project types suggests a need for different types of F&I instruments. In particular, those projects with proportionately higher capital costs benefit to a greater extent from up-front support packages than do those with higher operating costs. This finding can be seen most clearly when comparing Projects C and D under the US (Case A) support scenarios in *Figure 5.15*. Both projects have the same abatement cost of $43/tCO_2$; however whereas Project D (offshore gas field) is incentivised by an up-front grant, Project C (hydrogen plant) requires additional support from sequestration tax credits to offset the higher annual operating costs. The same finding can be seen to a lesser degree in the Canadian CCS support scenarios and points towards a need for policy-makers to understand the different F&I support needs faced by differing project types (in terms of both *overall funding* levels and *up-front versus ongoing support* requirements).

The scenario results indicate that carbon prices, whose future levels will be driven by a number of uncertain factors, are critical to incentivising projects. The results also indicate that in common with capture from the power sector and other sources, significant up-front funds must be made available ahead of support from future (higher) carbon prices and/or other policy instruments such as mandatory CCS requirements. The required levels of up-front grant support vary significantly by project type and also jurisdiction, depending upon the degree of support provided by differences in regional carbon prices.

As discussed earlier, the results provided are highly dependent upon the many modelling and baseline data assumptions made. An important final consideration is the degree to which investors view project risk; where large-scale capture projects are to be financed from sources other than public funds, required project returns may be considerably higher than the baseline WACC level chosen, reflecting a range of technology, policy and overall project economic risk factors. The need for up-front guaranteed support and strengthening policy certainty over future revenue streams and support frameworks will therefore be critical to implementing projects ahead of wide-spread commercial deployment of CCS.

6 STUDY CONCLUSIONS

The study finds that a number of barriers associated with CCS projects such as additional investment requirements compared to standard plants, technology risk, ongoing operating costs and regulatory uncertainty need to be overcome in order to move from the demonstration phase to wide-scale deployment. Public sector support will be necessary to demonstrate CCS.

The study finds that up-front as well as ongoing support may be needed to reduce project investment risk; for example the development of high-cost renewable technologies shows that significant up-front support combined with predictable ongoing revenue streams, have helped to move certain technologies from the R&D stage to demonstration stages (e.g. solar PV) and towards commercialisation (e.g. onshore wind). It is also important that CCS policy measures are long-lasting and stable to provide the necessary assurances against the risk of investment, as shown in the case of feed-in-tariffs used to support new power generation technologies in the EU and elsewhere.

Governments in a range of world regions have developed, and are developing, a number of financing and incentives programs to support CCS demonstration projects. However, the study finds that, given the crucial role for deploying CCS in a range of industry and upstream sectors over the next decade, there is presently a lack of financing options and appropriate incentives available, and much uncertainty regarding their support levels and modalities.

The projects considered in this report are not undertaken by oil and gas companies as typical for-profit ventures in their core business; they are done for environmental reasons but must be commercially viable with manageable risks and reliable cost estimates for companies to be able to invest in them.

ERM has used conventional IRR analysis in this report to evaluate the financial viability of CCS projects, with transparent discount rates, weighted average cost of capital and other factors explained in this report. It is important to note, however, that project types which carry positive - even attractive - IRR figures in this analysis are typically not commercial ventures in their own right; they are environmental projects which show a given return on investment to justify them as investments when compared to commercial projects.

The results of modelling the impact on Project IRR for a range of possible F&I support scenarios in the EU, US and Canada shows a diverse range of possible outcomes in terms of incentivising different types of capture project.

Key findings are:

- Carbon prices are critical to incentivising projects, particularly 'early opportunities' in the upstream sector (e.g. capture from high-CO_2 gas field and LNG plants); higher expected carbon prices within the ETS are seen to incentivise a wider range of low-cost projects than in the US and Canada;
- The need for significant carbon prices is critical, as well as some form of assurance over the sustainability of long-term price signals offered by the carbon markets; shorter crediting periods and/or price collapses adversely impact project viability;
- The use of the proposed bonus allowances in the US, combined with other F&I options currently envisaged, would likely incentivise the wider range of project types (including higher cost refinery and GTL capture projects) compared to those F&I options currently proposed in the EU and Canada
- Disbursement of EU-level funds over the project construction phase, as opposed to over longer 'performance based' time periods assists cash-flow in early years and would likely incentivise a wider range of project types.
- Because certain projects have high operating costs (due to higher energy use in capture and T&S costs), ongoing incentives are critical to all but the very lowest-cost project types; even with generous up-front investment support, incentives in Canada appear insufficient to incentivise a wide range of project types outside of the power sector.

The model results show that carbon prices alone may be sufficient to incentivise a limited number of low-cost 'early opportunity' upstream capture projects assuming guaranteed long-term prices, whereas other projects would be unlikely to be viable with carbon finance alone (according to near-medium term price forecasts). In common with capture from the power sector and other sources, significant up-front support funds must therefore be made available to demonstrate a wider range of project types.

The required level of up-front grant support varies significantly by project type and jurisdiction, depending upon the degree of support provided by differences in regional carbon prices (which are assumed to range between around $18 in Canada to $42 in the EU in the period 2012-2020).

- In the **EU**, higher cost capture from a project with costs similar to a GTL plant might require grant funding of between 72% and 94% of additional cost, depending upon the timing of EU-level grant payments
- In the **US**, a grant level of around 17% may incentivise high-cost projects such as refinery captures, when combined with other support policies such as bonus allowances
- In **Canada**, grant levels of up to 80% may be required to incentivise a range of low cost 'early opportunities', although a wider range of project types are unlikely to incentivised.

The most 'optimistic' scenarios of possible F&I mechanisms therefore show that, with the right package of support, capture from a wide range of sources could be possible.

The study finds that the likely combination, and detailed design and modalities, of the government Financing &Incentive options assessed in each jurisdiction is highly uncertain and subject to ongoing (domestic and international) policy developments. Such uncertainty, as well as the adequacy of potential support levels, will directly influence the extent to which project developers and investors view project risk. Strengthening policy certainty over future revenue streams and support frameworks will therefore be critical to implementing projects during the near-medium term demonstration phase ahead of wide-spread commercial deployment of CCS.

Annex A

Financing and Incentives for CCS projects in the European Union, UK and Norway

Table A.1 Overview of Financing for CCS projects in the European Union, UK and Norway

Name	Type	Origination	Amount	Financing Conditions	Timing	Description and Eligibility
NER300 (Free Allowances under article 10a (8) of the revised EU ETS Directive)	Grant	EU-ETS, New Entrants Reserve	300 million allowances or €6 billion (assuming an allowance price of €20/tCO_2)	No more than 15% of allowances for any individual project and, in principle, no more than 50% of incremental costs of CCS to be financed per project. Commission decision on the modalities for the disbursement of this funding by end of 2009; currently two options on the table: 1) Project milestones to be established for first ten years of operation and disbursement conditional on meeting performance targets 2) Funds to be provided in step with construction of project but option only possible if claw-back can be ensured.	The allowances will be awarded through two calls for proposals: 240 million allowances by 31 December 2011, and the 60 million allowances by 31 December 2014. The first set of projects should be operational by the end of 2015 and the second by end 2017.	300 allowances are set aside from the new entrants reserve to provide a guaranteed reward for the first such CCS projects in the Union for tonnes. This financing applies to projects of sufficient scale, which are innovative in nature and which are significantly co-financed by the operator covering, in principle, more than half of the relevant investment cost, and taking into account the viability of the project. For CCS it is expected that a minimum of 8 projects will be financed, two each from pre-combustion (250MW), post-combustion (250MW), oxy-fuel (250MW) • Refineries: 500kt/y avoided CO_2 at 85% capture • Cement: application to cement kiln, 500kt/y avoided CO2 at 85% capture • Iron and Steel and Aluminium production: application to integrated mill, 500kt/y avoided CO2, in principle at 85% capture • Lower capture rates may be acceptable if justified in detail.

Name	Type	Origination	Amount	Financing Conditions	Timing	Description and Eligibility
Financing infrastructure projects as part of the EERP European economic recovery plan (EERP)	Grant	European economic recovery plan (EERP)	€1.05 billion	Up to 80% of additional costs		€1.05 billion are to be distributed as follows: • €180 (each) to Germany, Netherlands, Spain, Poland and UK for power generation projects; • €100 to Italy for a power generation project • €50 million to France for an industrial project (Steel plant) **Eligibility:** Capture of at least 85% of CO_2 in industrial installations that will have at least 300 MW electrical output or equivalent. The recovery plan shortlists 13 CCS projects in the above seven Member States including 7 post combustion capture, 2 oxycombustion, 3 Integrated Gasification Combined Cycle with capture, and one steel plant.

Table A.2 Overview of Incentives for CCS projects in the European Union, UK and Norway

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
EU- Emissions Trading Scheme (EU-ETS)	Incentive	EU-ETS	Can vary depending on emissions, carbon price and auctioning modalities	Applies to capture production of hydrogen (H_2) and synthesis gas by reforming or partial oxidation with a production capacity exceeding 25 tonnes per day	Between 2008 and 2012, CCS can be included by "opt-in." Between 2013 and 2020, CO2 captured and stored will be considered as "not emitted" under the ETS.	Emissions captured and stored are recognised as not emitted under the EU-ETS. The main long-term incentive for CCS is that allowances will not need to be surrendered for CO2 emissions which are permanently stored or avoided. According to the revised Directive on the EU ETS full auctioning should be the rule from 2013 onwards for the power sector, taking into account its ability to pass on the increased cost of CO_2.

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
UK Financial Mechanism to support CCS Demonstration	Grant	Funds to be raised by levy from electricity suppliers who are likely to pass the cost to consumers	£8.7 – £10.3 billion for up to 4 CCS demonstration projects		The levy could be collected from 2011 and is estimated to end in 2032. The first power plant is expected in 2014 (UK Demonstration Competition) with the rest of the projects around 2015-2016	Two mechanisms are currently proposed to fund up to 4 CCS demonstration plants. The mechanism which appears to be preferred by the UK government the Contract for difference (CfD) mechanism offers CCS demonstration projects a fixed/strike price for the carbon they abate minus the EU ETS carbon price. CCS projects would be invited to bid on the basis of the fixed/strike price for carbon that they would require (in £/t CO_2) to provide a specified amount of CCS generation.
FEED Study Support	Grant	UK Budget 2009	£90 million from Government to fund detailed design and development work (FEED studies)			Allocated for the first UK Demonstration project
Norway Carbon Tax	Carbon tax		The tax level is currently NOK 230 (\$4O/tCO_2)	Facilities that burn oil, diesel and gas mainly for power production and flaring on the installations		Norway introduced a CO_2 emission tax for petroleum-related activities on the continental shelf in 1991. The carbon tax was the main driver for oil and gas companies to engage in CCS.

Annex B

Financing and Incentives for CCS projects in the United States

Table B.1 Overview of Financing for CCS projects in the US at a Federal Level

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
U.S DOE, *Clean Coal Power Initiative, Round 3*	Grant	American Recovery and Reinvestment Act of 2009 (ARRA) and US DOE	$1.4 billion (approx. $800 million from ARRA)	Financing up to 50% of project costs	24 Aug 09	Clean Coal Power Initiative, provides government co-financing for new coal technologies. CCPI Round 3 Announcement is seeking advanced coal-based projects that have progressed beyond the research and development stage to a point of readiness for operation at a scale that, once demonstrated, can be readily replicated and deployed into commercial practice within the electric power industry. **Eligibility:** Minimum capture 300,000 tons per year of with 50% CO2 capture efficiency and a capture efficiency of 90% in a gas stream containing at least 10% CO2 by volume. The project should result in less than 10% increase in the cost of electricity (COE) for gasification systems and less than 35% for combustion and oxycombustion systems all as compared to current (2008) practice. (1)
U.S DOE *Industrial Carbon Capture and Storage*	Grant	American Recovery and Reinvestment Act of 2009 (ARRA)	$1.5 billion	Financing up to 80% for Phase I (preliminary design and permitting) and for Phase II (Design, Construction and Operation) target is 50% (up to 80%) of project costs.	07 Aug 09	**Eligibility:** Includes, but not limited to, cement plants, chemical plants, refineries, steel and aluminium plants, manufacturing facilities, and petroleum coke-fired and other power plants.
U.S DOE *Carbon Capture and Storage*	Grant	American Recovery and Reinvestment Act of 2009 (ARRA),	$1 billion		(FutureGen)	Funding to develop a fully integrated advanced coal gasification based power plant with utility-scale CCS technology. **Eligibility:** IGCC based power plant

(1) US DOE, Amendment 005** to the Final FOA (DE-PS26- 08NT43181), http://www.fossil.energy.gov/programs/sequestration/publications/arra/DE-FOA-0000042.pdf

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
US DOE, *Federal Loan Guarantees for coal-based power generation and industrial or advanced gasification facilities that incorporate CCS*	Loan Guarantee	Title XVII of the Energy Policy Act of 2005, FY 10 Federal Budget, American Recovery and Reinvestment Act of 2009 (ARRA)	Total of $6 billion for coal-based power generation and $2 billion industrial or advanced gasification facilities. (2)	Total guarantee cannot exceed 80% of total project cost	22 Dec 08 for Part I, 23 Mar 09 for Part II	Title XVII of the Energy Policy Act of 2005 (EPAct 2005) authorizes the U.S. Department of Energy (DOE) to issue loan guarantees to eligible projects. The FY 2010 Budget will support a wide-range of eligible projects including CCS. **Eligibility:** Eligible projects are those that "avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases" and "employ new or significantly improved technologies as compared to technologies in service in the United States at the time the guarantee is issued"
U.S. Treasury Department/IRS, New Clean Renewable Energy Bonds (CREBs)	Tax Credit Bond	American Recovery and Reinvestment Act of 2009 (ARRA)	$800 million expanded to an additional $1.6 billion by ARRA	100% to be used within a three-year period from date of issuance of New CREBs.	Available until exhausted	A CREB is a special type of bond, known as a "tax credit bond," that offers the equivalent of an interest-free loan for financing qualified energy projects for a limited term. Unlike normal bonds that pay interest, tax credit bonds pay the bondholders by providing a credit against their federal income tax. **Eligibility:** The project must generate electricity which must be from a "clean process" including clean coal. (3)
Qualified Energy Conservation Bonds (QECB)	Tax Credit Bond	American Recovery and Reinvestment Act of 2009 (ARRA)	$800 million expanded to an additional $2.4 billion by ARRA	100% to be used within a three-year period from date of issuance for capital expenditures.	Available until exhausted	**Eligibility:** Demonstration projects that are designed to, amongst others, promote the commercialization of CCS in power generation

(2) http://www.lgprogram.energy.gov/FE_Sol9_22_08.pdf
(3) http://www.crebs.org/

Table B.2 Overview of Incentives for CCS projects in the US at a Federal Level

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
Cap to Carbon Emissions from Large Sources	Emissions Trading System	H.R. 2454, the "American Energy & Security Act of 2009"	\$11 to \$15 in 2012, \$13 to \$17 in 2015, \$17 to \$22 in 2020, and \$22 to \$28 in 2025 (EPA estimates in 2005 dollars)	Emissions must be reduced by 17% below 2005 levels by 2020 and 83% below 2005 levels by 2050.	Bill to be approved by senate	Starting in 2012, the act establishes annual tonnage limits on emissions of carbon and other global warming pollutants from large U.S. sources like electric utilities and oil refiners.
Bonus Sequestration Allowances	Bonus Allowances	H.R. 2454, the "American Energy & Security Act of 2009"	For phase I (first 6 GW) projects with sequestration of >85% will receive a bonus allowance of \$90t/CO_2 and for 50%-85% sequestration \$50-\$90. For Phase II (remaining 66GW) there will be a competitive bid on the sequestration incentive required by the project.	Projects may only receive allowances for the first 10 years of operation.	Bill to be approved by senate	**Eligibility:** Electric generating unit (EGU) must have a minimum capacity of 200 MW and derive at least 50% of fuel input from coal or petroleum coke or a combination thereof. Industrial sources qualify if they emit at least 50,000 tons CO_2-e per year without CCS, and do not produce a liquid transportation fuel from a solid fossil-based feedstock. Qualifying sources (for both EGUs and industrial) must capture and permanently sequester at least 50% of the CO_2 measured on an annual basis that would have otherwise been emitted but for the CCS. Bonus allowances for EOR projects will be reduced to reflect the lower net cost of the project relative to sequestration into geologic formations

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
Performance Standards for Coal-Fuelled Power Plants	Performance Standard	H.R. 2454, the "American Energy & Security Act of 2009"		Applicable for units permitted after January 1, 2009.	Bill to be approved by senate	Establishes performance standards that are applied to certain electric generating units (EGU) that derive at least 30% of annual heat input from coal, petroleum coke, or a combination of the two. EGU permitted before January 1, 2020 shall achieve an emission reduction of 50% and after January 1, 2020 a 65% reduction in emissions of the CO_2 produced by the unit, measured on an annual basis.
§48A – Power Sector Tax Credits	Investment Tax Credit	U.S. Treasury Department/IRS & American Recovery and Reinvestment Act of 2009 (ARRA)	30% Investment Tax Credit up to $1.25 billion in credits total	Must be taken in the year the facility is placed in service		**Eligibility:** Must include equipment to capture 65% of a project's CO2 emissions
§48B – Industrial Gasification Tax Credit	Investment Tax Credit	U.S. Treasury Department/IRS & American Recovery and Reinvestment Act of 2009 (ARRA)	30% Investment Tax Credit up to $350 million in credits total	Credit can only be given to a maximum of $650 million for qualifying gasification equipment		Industrial Gasification projects related to: Chemicals, Fertilizers, Glass, Steel, Petroleum residues, Forest products, Agriculture, including feedlots and dairy operations, Transportation grade liquid fuels, as well as any project that that converts a solid or liquid product from coal, petroleum residue, biomass, or other materials recovered for their energy/ feedstock value into a synthesis gas composed primarily of carbon monoxide and hydrogen. **Eligibility:** Must include equipment to capture 75% of a project's CO2 emissions

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
§48C Advanced Energy Investment Tax Credit	Investment Tax Credit	U.S. Treasury Department/IRS & American Recovery and Reinvestment Act of 2009 (ARRA)	30% ITC Investment Tax Credit up to $2.3 billion in credits total			Tax credit for facilities that manufacture advanced energy projects. Awarded through competitive bidding program. **Eligible** projects include: • CCS • Renewable energy • Energy storage • Energy conservation • Efficient transmission and distribution of electricity
§48Q Permanent sequestration requirement for carbon dioxide (CO2) capture tax credit	Carbon Sequestration Tax Credit	U.S. Treasury Department/IRS & American Recovery and Reinvestment Act of 2009 (ARRA)	$10/tCO_2$ for EOR/CCS and $20/tCO_2$ for Non EOR/CCS for up to $75MtCO_2$. Both credit amounts to be adjusted for inflation after 2009			The $10 credit per ton for CO_2 sequestered in enhanced oil recovery (EOR), enacted in 2008, has been modified so that anyone claiming the credit for CO_2 used in EOR must also ensure that such CO_2 is permanently stored in a geologic formation. **Eligibility:** Capture at least 500,000 metric tons of carbon dioxide per year to qualify
EOR Tax Incentive	Tax Credit	Section 43(c) (2) (A) of the Internal Revenue Code of 1986	15% tax credit			Applies to all costs associated with installing the CO_2-flood, CO_2 purchase cost, and CO_2 operating costs for injection. When the credit is taken, the remaining 85% of the qualifying costs are expensed (or depreciated) normally

Table B.3 Overview of Financing for CCS projects in the US at a State Level

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
Advanced and Renewable Energy Fund	Grant	Indiana SB 224, HB 1117, Government fund from State of Indiana (IURC)	Provides for the timely recovery of costs associated with the project, including capital, operating, maintenance, depreciation, tax, research and development, and financing	For project that were not in general commercial use at time of enactment of the federal Clean Air Act Amendments of 1990	electricity supplier that seeks to receive one or more financial incentives must submit an application to the commission	Requires an electricity supplier that fails to supply electricity from advanced or renewable energy resources (2% by December 31, 2011; 4% by December 31, 2011; and 6% of the electricity supplier's Indiana retail sales by December 31, 2020) or pay a penalty in the advanced and renewable energy resources fund. The fund will be used to finance renewables and CCS. For CCS it includes capture technologies including pre-combustion treatment of coal that are used in a new or existing energy production or generating. Projects that have been selected for funding by US DOE funding or loan guarantees under an Innovative Clean Coal Technology or loan guarantee program under the Energy Policy Act of 2005 or any successor program are, by definition, considered eligible.

Table B.4 Overview of Incentivisation Options for CCS projects in the US at a State Level

Name	Type	Origination	Amount	Conditions and Eligibility	Timing	Description and Eligibility
Clean Coal Portfolio Standard		Illinois Clean Energy Bill SB1987	Contractual price be determined using a cost of service methodology	Other grants received by the project from the State of IL or US government to credited against the revenue requirement		Requires utilities to buy up to 5% of their electricity from a coal plant with CCS. **Eligibility:** Initial clean coal facility to have a a nameplate capacity of at least 500 MW using coal mined in Illinois. Facility to capture 50% of its carbon emissions. Capture level increases to 70% for facilities entering operation between 2015 and 2017, and 90% for facilities starting after 2017
					Commenced construction of a coal gasification facility by July 1, 2010	Authorises any gas utility to enter into a contract for up to 20 years of supply with any company for the purchase of substitute natural gas (SNG) produced from coal through the gasification process. **Eligibility** SNG facilities sequester 90% of their carbon emissions. The price these facilities can charge consumers is capped. The first coal-to-gas facility likely to be constructed under this provision is expected to be in Jefferson County

Name	Type	Origination	Amount	Conditions and Eligibility	Timing	Description and Eligibility
Franchise tax credit	Tax Incentive	Texas House Bill 469	Incentives in the form of tax credits for the first three coal-fired power plants equal to 10 percent of the capital cost of the project, excluding financing costs, or $100 million, whichever was less	On verification that a project met the requirements, a franchise tax credit would be issued.	The bill will take effect 1 Sep 2009. Franchise tax credits may not be issued before 1 Sep 2013	**Eligibility:** Have a capacity of at least 200 megawatts; use integrated gasification combined cycle or other pre-combustion technology; capture at least 70 percent of the carbon dioxide (CO2) resulting from the generation of electricity by the facility; be capable of permanently sequestering CO2 in a geologic formation; and be capable of supplying the capture CO2 for an enhanced oil recovery (EOR) project.
Severance tax reduction for EOR	Tax Incentive	Texas House Bill 469	Extended severance tax rate reduction for 30 years.			CSHB 469 would amend Tax Code, sec. 202.0545 by providing that a producer of oil recovered by an enhanced oil recovery (EOR) project that used CO2 generated by a clean energy project would be entitled to an extended severance tax rate reduction for 30 years.
CO_2 reduction credit	Business Tax Incentive	Michigan S.B. 1166	Maximum $20 million per facility. Total amount of all credits is $250 million for each calendar year. 10% Of the total amount to be approved for CCS infrastructure, including pipelines		N/A	Credit against the Michigan Business Tax equal to one or both of the following multiplied by the per ton market price for commodity carbon dioxide: • The number of tons of eligible reductions in emissions of carbon dioxide. • The annual capacity in tons of critical carbon dioxide sequestration infrastructure, including carbon dioxide pipelines and other related equipment. "Per ton market price for commodity carbon dioxide" is defined as one allowance in the European Union Emissions Trading System (EU ETS) on December 31 of each calendar year or $50 per metric ton of carbon dioxide, whichever is greater. The amount. Also for motor vehicle and parts manufacturing (NAICS 3361 & 3363) market price would be twice the closing price for one allowance in the EU ETS on December 31 or $100 per metric ton. **Eligibility:** Emit at least 10,000 metric tons of carbon dioxide annually

Name	Type	Origination	Amount	Conditions and Eligibility	Timing	Description and Eligibility
General property tax	Property Tax Incentive	Michigan S.B. 708	Property tax exemptions for carbon dioxide carbon equipment			
CO_2 pipeline rights of way	Rights of way for CO_2 pipelines	State of Minnesota, Global warming Preparedness Act, S.B. 1586 and H.B. 2307	Provides for free CO_2 pipeline rights of way		N/A	For CO_2 pipelines wishing to use existing rights of way the legislation requires from electric and gas utilities to make all of their rights of way available with compensation solely to cover actual “out of pocket” costs incurred.
Income tax reductions and property tax exemptions	Tax Incentive	Kansas HB 2419	Allows property tax exemption and a tax deduction from Kansas adjusted gross income for CCS		Effective	The legislation provides incentives for carbon capture and sequestration by allowing any carbon dioxide capture, sequestration and utilization property and any electric generation unit which captures and sequesters all carbon dioxide and other emissions, to be exempt from all property taxes for a period of five taxable years following completion of construction or installation of the property. Additionally, it provides for a 55 percent amortization tax deduction on state income tax for 10 years.

Annex C

Financing and Incentives for CCS projects in Canada

Table C.1 Overview of Financing for CCS projects in Canada

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
CCS Fund (CCSF), Government of Alberta	Grant	Government of Alberta	C$2 billion	Projects must be located in Alberta. Program supports max 75% of total incremental CCS costs. Max of 20% paid on commencement of operations; remaining funding dispersed over max of 10 years.	Submission of full project proposals: by 31 Mar 09	The Alberta Government would consider providing a portion of the eligible costs (incremental cost to capture, transport and store CO_2) for three to five large-scale commercial CCS projects that will capture and permanently store up to five million tonnes of carbon dioxide per year by 2015, for a period of at least 10 years. As of December 2009, three winning project proponents have signed Letters Of Intent (LOIs) with the Government of Alberta and will each receive a portion of $2 billion. These include the Quest Project, a joint venture by Shell Canada Energy/Chevron Canada Ltd./Marathon Oil Sands L.P. (CCS at the Scotford oil sands upgrader); and the TransAlta coal-fired CCS project located near Edmonton.
Crown Investments Corporation	Grant	Crown Investments Corporation	Up to US$225 million (awarded to Saskatchewan-Montana CCS Demonstration Project)	The Government of Saskatchewan will provide up to C$50 million through CIC and has requested funding of C$100 million from the federal government through its Clean Energy Fund. The State of Montana has requested US$100 million from the DOE.	Development phase 31 Aug 09, construction after Sep 09 and operational earliest summer 2011	**Eligibility:** Will construct a technology-neutral CO_2 capture plant (reference plant) in Saskatchewan, a CO_2 storage facility in the Montana, pipeline infrastructure for the transportation of the CO_2, and a North American training facility to meet the growing needs of CCS industry and regulators.

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
EcoTrust for Clean Air and Climate Change (EcoTrust)	Grant	Canadian federal government	C$1.5 billion			Announced in February, 2007 it is a fund that is to co-fund major projects with the provinces to promote clean energy, and to combat climate change, air pollution and greenhouse gases. The Government of Alberta has received C$155.9 million (U.S. $122 million) from the Canadian federal government's EcoTrust for Clean Air and Climate Change (EcoTrust) initiative. That money is to be used to help fund projects that meet EcoTrust's objectives. Those projects include CCS projects.
Green Infrastructure Fund	Grant	Government of Canada, Infrastructure Canada, Economic Action Plan	C$1 billion over five years	Allocation based on merit to support green infrastructure projects on a cost-shared basis. The fund will focus on a few, large scale, strategic infrastructure projects. The merit of the projects will be based on assessment criteria such as eligibility, leveraging financial investments and project benefits.		Fund focuses on green priorities such as green energy generation and transmission infrastructure. **Eligibility** Any of the following categories: wastewater infrastructure; green energy generation infrastructure; green energy transmission infrastructure and solid waste infrastructure, and carbon transmission and storage infrastructure.
ecoENERGY Technology Initiative	Grant	Government of Canada, Natural Resources Canada	C$230 million		Closed - No further calls for proposals under the ecoENERGY Technology Initiative are anticipated	ecoETI funds research, development and demonstration to support the development of the next-generation clean-energy technologies. Examples are technologies for clean-coal, carbon sequestration, and for reducing oil sands' environmental impact, and new end-use technologies such as hydrogen and fuel cells, and energy efficient buildings and industry. 8 projects have been selected for funding. Projects are expected to commence by late summer 2009, following completion and signing of contribution agreements with the successful proponents.

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
Clean Energy Fund	Grant	Government of Canada, Natural Resources Canada, Economic Action Plan	C$1 billion over 5 years, C$650 million for large-scale carbon capture and storage (CCS) demonstration projects, C$200 million for smaller-scale demonstration projects and C$150 for research	A minimum total demonstration project cost of C$100 million, it is expected [1] that for CCS projects maximum funding per project will not exceed 50% of costs and total Canadian government assistance [2] will not exceed 75% of costs.	Full Project Proposals by 14 Sep 09	This fund will support research and demonstration projects focused on clean energy technologies, including carbon capture and storage. Natural Resources Canada has launched the first Request for Proposals under the program, with up to $191 million for technology Demonstrations and will also solicit proposals for up to $650 million for large-scale carbon capture and storage projects in the summer of 2009

Table C.2 Overview of Incentives for CCS projects in Canada

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
Accelerated capital cost allowance	Tax Incentive	Government of Canada	Proposed	Class 43.1 and Class 43.2 provide acceleration of the capital cost allowance rate of 30% and 50 % respectively for certain energy systems	Interested parties have been invited to make written submissions by 30 June 09	The CCA is a non-refundable tax deduction that reduces taxes owed by permitting the cost of business-related assets to be deducted from income over a prescribed number of years. Consultations on the extension of accelerated capital cost allowance (CCA) to assets used in carbon capture and storage were launched on April 17, 2009. Interested parties have been invited to make written submissions by June 30.

(1) Based on the recent RfP for renewable Energy and Clean Energy Systems Demonstration projects

(2) from federal, provincial/territorial and municipal governments, not including investment or funding from Crown or municipally-owned utilities

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
Regulatory Framework for Industrial Greenhouse Gas Emissions	Incentive	Government of Canada	C$15/$tCO_2$ in 2010 – 2012, $20/$tCO_2$ in 2013 and thereafter escalating based on GDP growth	Obligation of sectors covered can be met by: 1) Paying in a Technology Fund (C$15/$tCO_2$ in 2010 – 2012, $20/$tCO_2$ in 2013, and thereafter escalating based on GDP growth) 2) Contributing the same amount in pre-certified investments (i.e. CCS projects) 3) Offsets (domestic or CDM)	Regulations planned to come into force on Jan 1 2010.	The regulations state that a specific incentive for CCS will be in place by 2018. CCS projects in sectors covered by the regulatory framework may be credited up to 100% of their emission targets through 2017. Targets are intensity based (linked to production) with 2006 as baseline year as follows: 18% by 2010, 2% thereafter. Sectors related to CCS include amongst others power generation and oil & gas (oil sands, upstream O&G, natural gas pipelines and refining). Co-generation is also covered by the same targets with a baseline as if electricity and heat were produced separately
Alberta Climate Change and Emissions Management Amendment Act	Incentive	Government of Alberta	Ceiling on the price of carbon at C$15/$tCO_2$. Amount can be paid into a technology fund. To date, the fund currently holds C$122.4 million.		Will begin to accept applications for funding later in fiscal 2009-10.	Coverage: Facilities that emit more than 100,000 tonnes of greenhouse gases a year will be required to reduce their emissions intensity by 12% compared to 2003-2005 baseline.

Name	Type	Origination	Amount	Conditions	Timing	Description and Eligibility
Innovative Energy Technologies Program	EOR Incentive	Government of Alberta	$200 million over five years	Successful applicants in the program will be provided royalty adjustments up to a maximum of 30% of approved project costs. Industry must provide the remaining 70% or more of total project costs. Total government funding (i.e. from other government programs) should not exceed 50% of total project costs.	Program began in 2005 and will run over 5 years.	The program provides royalty adjustments to a number of specific pilot and demonstration projects that use innovative technologies such as EOR to increase recoveries from existing reserves and encourage responsible development of oil, natural gas, and in-situ oil sands reserves.
Saskatchewan Carbon Dioxide Enhanced Oil Recovery (EOR) and Storage Initiative	EOR Incentive					The Saskatchewan Carbon Dioxide EOR and Storage Initiative will provide funding towards EOR investments. This initiative will also assist SaskPower's proposed clean coal electric generating plant and TransCanada Energy's proposed polygeneration project by establishing a new market for carbon dioxide that would be captured from these proposed facilities and other potential sources of carbon dioxide.

Annex D

Financing and Incentives Support Scenarios

Table D..1 Financing and Incentives Scenarios

Jurisdiction	Emissions trading systems only	ETS + Low Grant (25%)	ETS + Medium Grant (50%)	ETS + High Grant (75%)	ETS + High Grant + Tax Incentives	Sensitivity Parameters
Europe	1. EU- Emissions Trading Scheme (EU-ETS) with a carbon price of €30/tCO_2 2012-2020 and assumed to rise to €45/tCO_2 thereafter	2. EU- Emissions Trading Scheme (EU-ETS) 1. Grant from NER300 Free Allowances + EEPR	3. EU- Emissions Trading Scheme (EU-ETS) 1. Grant from NER300 Free Allowances + EEPR	4. EU- Emissions Trading Scheme (EU-ETS) 1. Grant from NER300 Free Allowances + EEPR + Member State funds	5. EU- Emissions Trading Scheme (EU-ETS) 1. Grant from NER300 Free Allowances + EEPR + Member State funds 2. Enhanced Capital Allowances (modelled as option)	• Disbursement of grants according to (a) 10-year performance-based approach; and (b) construction phase
United States of America	1. Cap to Carbon Emissions from Large Sources ($20/$tCO_2$ in 2015-2020, and assumed to rise to $30/$tCO_2$ thereafter)	1. Cap to Carbon Emissions from Large Sources 2. Grant from U.S DOE Industrial Carbon Capture and Storage programme	1. Cap to Carbon Emissions from Large Sources 2. Grant from U.S DOE Industrial Carbon Capture and Storage programme	1. Cap to Carbon Emissions from Large Sources 2. Grant from U.S DOE Industrial Carbon Capture and Storage programme	1. Cap to Carbon Emissions from Large Sources 2. Grant from U.S DOE Industrial Carbon Capture and Storage programme 3. §48Q Permanent sequestration credit	• Bonus Sequestration Allowances (proposed) assumed in alternative case

Jurisdiction	Emissions trading systems only	ETS + Low Grant (25%)	ETS + Medium Grant (50%)	ETS + High Grant (75%)	ETS + High Grant + Tax Incentives	Sensitivity Parameters
Canada	1. Regulatory Framework for Industrial Greenhouse Gas Emissions (C\$20/tCO_2 in 2012-2020, and C\$30/tCO_2 afterwards)	1. Regulatory Framework for Industrial Greenhouse Gas Emissions 2. Grant from CCS Fund (CCSF)	1. Regulatory Framework for Industrial Greenhouse Gas Emissions 2. Grant from CCS Fund (CCSF)	1. Regulatory Framework for Industrial Greenhouse Gas Emissions 2. Grant from CCS Fund (CCSF)	1. Regulatory Framework for Industrial Greenhouse Gas Emissions 2. Grant from CCS Fund (CCSF) 3. Accelerated capital cost allowance (proposed)	

Colour Legend = Existing financing or incentive, Proposed or assumed financing or incentive

Table D.2 Details of F&I instruments

<table>
<tr><th>Support Option</th><th>Instrument details</th></tr>
<tr><td>EU- Emissions Trading Scheme (EU-ETS)</td><td>Table 15: Example of impact on GHG reductions of limited access to JI/CDM type of mechanisms for the independent GHG reduction commitment
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<tr><th></th><th>Cost efficient case within the EU (no JI/CDM)</th><th colspan="2">Cost efficient case with different levels of JI/CDM</th><th>Targets Non ETS modulated with access to JI/CDM</th></tr>
<tr><td>Carbon value in all sectors (€/ton CO2-eq.)</td><td>39</td><td>35</td><td>30</td><td>30</td></tr>
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<tr><td>Free Allowances (under article 10a (8) of the revised EU ETS Directive)</td><td>Applicable for refineries: 500kt/y avoided CO_2 at 85% capture. No more than 15% of allowances for any individual project and, in principle, no more than 50% of incremental costs of CCS to be financed per project.</td></tr>
<tr><td>Norway Carbon Tax</td><td>Applicable only for petroleum-related activities. The tax is currently NOK 230 (\$40/tCO_2)</td></tr>
</table>

Support Option	Instrument details
Cap to Carbon Emissions from Large Sources	\$11 to \$15 in 2012, \$13 to \$17 in 2015, \$17 to \$22 in 2020, and \$22 to \$28 in 2025 (EPA estimates in 2005 dollars)
Grant from U.S DOE Industrial Carbon Capture and Storage programme	Financing up to 80% for Phase I (preliminary design and permitting) and for Phase II (Design, Construction and Operation) target is 50% (up to 80%) of project costs.
US DOE, Federal Loan Guarantees	Total guarantee cannot exceed 80% of total project cost. We would need to lower the WACC basically for this one.
Bonus Sequestration Allowances	For phase I (first 6 GW) projects with sequestration of >85% will receive a bonus allowance of \$90t/CO2 and for 50%-85% sequestration \$50-\$90. For Phase II (remaining 66GW) there will be a competitive bid on the sequestration incentive required by the project. Projects may only receive allowances for the first 10 years of operation. **Industrial sources** qualify if they emit at least 50,000 tons CO2-e per year without CCS, and do not produce a liquid transportation fuel from a solid fossil-based feedstock.
§48B – Industrial Gasification Tax Credit	30% Investment Tax Credit. Industrial Gasification projects related to: Chemicals, Fertilizers, Glass, Steel, Petroleum residues, Forest products, Agriculture, including feedlots and dairy operations, transportation grade liquid fuels, as well as any project that that converts a solid or liquid product from coal, petroleum residue, biomass, or other materials recovered for their energy/ feedstock value into a synthesis gas composed primarily of carbon monoxide and hydrogen.
§48Q Permanent sequestration requirement for carbon dioxide (CO2) capture tax credit	\$10/tCO_2 for EOR/CCS and \$20/tCO_2 for non EOR/CCS. Both credit amounts to be adjusted for inflation after 2009
Regulatory Framework for Industrial Greenhouse Gas Emissions	CN\$15/tCO_2 in 2010 – 2012, CN\$20/tCO_2 in 2013 and thereafter escalating based on GDP growth. Sectors related to CCS include amongst others power generation and oil & gas (oil sands, upstream O&G, natural gas pipelines and refining).
CCS Fund (CCSF)	Program supports max 75% of total incremental CCS capture costs. Max of 20% paid on commencement of operations; remaining funding dispersed over maximum period of 10 years
Accelerated capital cost allowance	Proposed - Class 43.1 and Class 43.2 provide acceleration of the capital cost allowance rate of 30% and 50 % respectively for certain energy systems

Annex E

CCS project model assumptions and data sources

Project ID	Project A	
Project type	**Refinery complex**	
Parameter	**Value chosen**	**Source/notes**
Project time		
Project lead time (years)	3	Project team assumption
Project life (years)	20	Project team assumption
Costs		
Total additional capex ($m)	**476**	*Simonds et al (2003)* study of retrofit of large scale PC amine capture technology (costs based on Fluor Econamine FG design) at large UK refinery. Capture from refinery-fired heaters (fuel oil and gas-fired) , power plant boilers (fuel-oil fired) and chemical plant reaction furnaces (gas-fired). Collection system requires 15 MW for blowers to push the flue gas through the network and 10 MW for the pressure drop imposed by the packed column absorbers.
Gas gathering systems	*39*	
NOx and SOx removal	*74*	
Amine plant	*166*	
CO_2 drying and compression	*48*	
Utility and offsite systems	*149*	
Total additional capex ($m) 2009 adjusted	**701**	Calculated using CEPCI price indices
Capex paid over construction phase	*Year 1: 30%*	Project team assumption
	Year 2: 30%	Project team assumption
	Year 3: 40%	Project team assumption
O&M (% of capex/yr)	4%	Project team assumption *Dolf Gielen, IEA (2003)*
T&S cost ($/t$CO_2$ stored)	15.00	Project team assumption, based on *Dooley et al (2008)*
Additional fuel gas requirement (GJ)	12,400,000	*Simmonds et al (2003)* estimate total required energy consumption for PC capture process at 396 MW, fired by natural gas in a CHP plant to produce steam and power; equivalent to 6.2 GJ/tCO_2 captured *(IEA, 2008).*
Base gas price ($/GJ)	6.00	*IEA (2008)* OECD region industrial gas tariff
CO_2 emissions		
Additional CO2 emissions (CO2/yr)	600,000	*Simmonds et al (2003)*
Reference plant (tCO_2/yr)	1,622,222	Calculated
Plant with capture (tCO_2/yr)	2,222,222	Calculated
Capture rate	90%	Project team assumption
CO_2 captured (tCO_2/yr)	2,000,000	*Simmonds et al (2003)*
CO_2 avoided (tCO_2/yr)	1,400,000	Calculated

References:

1. Simmonds et al (2003). Simmonds, M., P. Hurst, M.B. Wilkinson, C. Watt and C.A. Roberts "A Study of very large Scale Post Combustion CO_2 Capture at a Refi nery and Petrochemical Complex",
2. Dolf Gielen, IEA (2003). The Future Role of CO_2 Capture and Storage: Results of the IEA-ETP Model, IEA/EET Working Paper, 2003.
3. Dooley et al (2008). J.J. Dooley, R.T. Dahowski, C.L. Davidson, S. Bachu, N. Gupta, and J. Gale. A CO_2 storage supply curve for North America and its implications for the deployment of Carbon Dioxide Capture and Storage Systems, Batelle/Pacific Northwest National Laboratory, 2008.
4. IEA (2008). Carbon Capture and Storage – A Key Abatement Option, IEA, 2008.

Project ID	Project B	
Project type	**Gas-to-liquids (GtL) plant**	
Parameter	**Value chosen**	**Source/notes**
Project time		
Project lead time (years)	3	Project team assumption
Project life (years)	20	Project team assumption
Production		
Plant capacity (bbl/day)	44,000	Project team assumption based on medium-size new GtL plant
Utilisation factor	85%	*Jaramillio et al (2008)*
Plant production (tonnes/yr)	1,862,347	Assumes 1 tonne product = 7.33 barrel
Plant production (GJ/yr)	81,943,247	Assumes 44 GJ/tonne for syndiesel
Costs		
Capex - Reference plant ($/bbl/day)	69, 231	Based on Shell Pearl project data in public domain; (260,000 bbl/day at total estimated total capex of $18bn) See http://www.upstreamonline.com/live/article150373.ece
Capex - Plant with capture ($/bbl/day)	86,539	Based on multiplier of 1.25 (Project team assumption)
Total additional capex ($m)	**762**	Calculated
Total additional capex ($m) 2009 adjusted	**858**	Calculated using CEPCI price indices
Capex paid over construction phase	*Year 1: 30%*	Project team assumption
	Year 2: 30%	Project team assumption
	Year 3: 40%	Project team assumption
O&M (% of capex/yr)	4%	Project team assumption
T&S cost ($/t$CO_2$ stored)	15.00	Project team assumption, based on *Dooley et al (2008)*
Additional energy requirement from capture (GJ/GJ product)	0.01	*Dolf Gielen, IEA (2003)*
Gas-fired power plant GT effic (%)	38%	Project team assumption
Additional fuel gas requirement (GJ)	4,312,802	Assumes all fuel requirements met from gas
Base gas price ($/GJ)	1.00	Assumes low cost feedstock nat. gas (project team assumption)
CO_2 emissions		
Reference plant (tCO_2/yr)	2,047,650	Based upon 0.15tCO_2/bbl *(IEA, 2008)*
Plant with capture (tCO_2/yr)	2,252,415	Assumes 10% additional energy requirement
Capture rate	90%	Project team assumption
CO_2 captured (tCO_2/yr)	2,027,174	Calculated
CO_2 avoided (tCO_2/yr)	1,822,409	Calculated

References:

1. Jaramillo et al (2008). Paulina Jaramillo, W. Michael Griffin, and H. Scott Matthews. Comparative Analysis of the Production Costs and Life-Cycle GHG Emissions of FT Liquid Fuels from Coal and Natural Gas. ASAP Environ. Sci. Technol.
2. 'Pearl GTL set for big payback' Upstream Online article 11 March 2008; See http://www.upstreamonline.com/live/article150373.ece
3. Dooley et al (2008). J.J. Dooley, R.T. Dahowski, C.L. Davidson, S. Bachu, N. Gupta, and J. Gale. A CO_2 storage supply curve for North America and its implications for the deployment of Carbon Dioxide Capture and Storage Systems, Batelle/Pacific Northwest National Laboratory, 2008.
4. Dolf Gielen, IEA (2003). The Future Role of CO_2 Capture and Storage: Results of the IEA-ETP Model, IEA/EET Working Paper, 2003.
5. IEA (2008). Carbon Capture and Storage – A Key Abatement Option, IEA, 2008.

Project ID	Project C	
Project type	**Hydrogen plant**	
Parameter	**Value chosen**	**Source/notes**
Project time		
Project lead time (years)	3	Project team assumption
Project life (years)	20	Project team assumption
Production		
Plant capacity (mmscf/day)	90	Based on data from *Hydrocarbon Engineering, February 2004*; assumes typical modern SMR plant.
Utilisation factor	95%	Project team assumption
Hydrogen production (GJ/day)	32,580	Assuming 1mmscf hydrogen contains 362 GJ (HHV). (*Joan Ogden, Princeton University, 1997)*
Hydrogen production (GJ/yr)	11,403,000	Assuming 1mmscf hydrogen contains 362 GJ (HHV). *(Joan Ogden, Princeton University, 1997)*
Costs		
Book price capital cost SMR plant ($m)	96.2	$55m (for 90 mmscfd plant) from *Hydrocarbon Engineering, February 2004*; based on modern SMR plant. Figure excludes treatment plant, civil works etc. Therefore increased by 75% for more realistic capex estimate. Note, for a 90 mmscfd plant, *US National Research Council* study ("The Hydrogen Economy") suggests compariative capex of $89m
% increase in capital cost for capture plant	18%	Incremental capex of 18% suggested by IPCC SRCC considered very low. Increased capex arising from MEA scrubber; CO2 compressors; increased general facilities, engineering and miscallenous costs estimated at 37.7% based on large SMR plant with ($624m capex) and without CCS ($453m capex) See "The Hydrogen Economy" (*US NRC*)
Total additional capex ($m)	**38.5**	Calculated
Total additional capex ($m) 2009 adjusted	**56.7**	Calculated using CEPCI price indices
Capex paid over construction phase	*Year 1: 30%*	Project team assumption
	Year 2: 30%	Project team assumption
	Year 3: 40%	Project team assumption
O&M - ref plant (% of capex/yr)	6%	"The Hydrogen Economy" (*US NRC*) assumes total fixed O&M = 5% of
O&M - CCS plant (% of capex/yr)	7.5%	Additional 1.5% variable costs estimated for elec. requirements
T&S cost ($/t$CO_2$ stored)	15.00	Project team assumption, based on *Dooley et al (2008)*
Additional fuel gas requirement (%)	8%	*US NRC* and *IPCC SRCCS (2005)* agree at 8%
Additional fuel gas requirement (GJ)	991,919	Assumes all fuel requirements met from gas
Base gas price ($/GJ)	6.00	*IEA (2008)* OECD region industrial gas tariff
CO_2 emissions		
Emission rate without capture (kgCO_2/GJ)	61	"The Hydrogen Economy" *(US NRC)*
Emission rate with capture (kgCO_2/GJ)	6	"The Hydrogen Economy" *(US NRC)*
Capture plant efficiency (%)	60%	*IPCC SRCCS (2005)*
Emissions factor gas (tCO_2/GJ)	0.056	*IPCC default EF*
Reference plant (tCO_2/yr)	695,583	Based upon 0.15tCO_2/bbl (IEA, 2008)
Plant with capture (tCO_2/yr)	751,230	Assumes 10% additional energy requirement
Capture rate	91%	Calculated
CO_2 captured (tCO_2/yr)	682,812	Calculated
CO_2 avoided (tCO_2/yr)	627,165	Calculated

References:

1. Hydrogen Engineering (2004). Clay A. Boyce, M. Andrew Crews, and Robin Ritter. Assessment of hydrogen plant technology options, Hydrocarbon Engineering February, 2004.
2. US NRC (2004), The Hydrogen Economy – Opportunities, Costs, Barriers and R&D needs, Unites Stated National Research Council and National Academy of Engineering, 2004.
3. J. Ogden (1997), Prospects for Building a Hydrogen Energy Infrastructure, chapter in Annual Review of Energy and the Environment, Vol. 24, pp. 227-279
4. IPCC SRCCS (2005) IPCC Special Report on Carbon dioxide Capture and Storage (Chapter 8), 2005.

Project ID	Project D	
Project type	High CO_2 gas field (offshore)	
Parameter	**Value chosen**	**Source/notes**
Project time		
Project lead time (years)	2	Project team assumption
Project life (years)	20	Project team assumption
Costs		
Additional capex - capture ($m)	**433.4**	Breakdown of capex data based upon ERM analysis for IEA GHG R&D study of CDM CCS early opportunities *(IEA GHG R&D, 2008)* ; most capex estimates are based on UCD engineering study of equip. requirements for different CO_2 gas flow rates *(McCollum and Ogden, 2006)*
CO_2 compressors	*38.4*	
Pumps	*1.9*	
Interstage coolers	*5.4*	
Interstage separators	*1.0*	
Dryers	*32.3*	
Gas-fired power plant OCGT	*20.0*	Assumes elec. provided by on-site OCGT at $750 per kW installed (Project team assumption)
Construction and engineering	*24.8*	Assumes 25% of plant capex *(IEA GHG R&D, 2008)*
Retrofit cost multiplier (xfactor)	*1.5*	*(IEA GHG R&D, 2008)*
Retrofit cost	*61.9*	
Offshore cost multiplier (xfactor)	*3*	*(IEA GHG R&D, 2008)*
Offshore cost adjustment	*371.5*	
Additional capex - capture ($m) 2009	**495.7**	Calculated using CEPCI price indices
Capex paid over construction phase	*Year 1: 50%*	Project team assumption
	Year 2: 50%	Project team assumption
O&M (% of capex/yr)	4%	*(IEA GHG R&D, 2008)*
T&S cost ($/t$CO_2$ stored)	1.26	Based on well capex and opex cost estimates and monitoring costs for in-situ (shallow water) offshore injection of 2MtCO_2/yr *(IEA GHG R&D, 2008)*
CO_2 mass flow rate (tCO_2/day)	6,027	Assumes 10% over-capacity requirement *(IEA GHG R&D, 2008)*
Compressor power (kW)	25,205	Based on 5-stage compression and pump power requirements *(McCollum and Odgen, 2006)*
Compressor elec. energy (GJ/yr)	761,590	
Pump power (kW)	1,458	Based on pump power vs. CO_2 mass flow rate algorithm *(McCollum and Odgen, 2006)*
Pump elec. energy (GJ/yr)	44,055	
Total power (MW)	26.7	
Total elec. requirement (GJ/yr)	805,645	
Additional fuel gas requirement (GJ/yr)	2,301,842	Based on on-site OCGT with 35% efficiency
Base gas price ($/GJ)	1.00	Assumes low cost condensate/gas (project team assumption)
CO_2 emissions		
Capture rate	98%	*(IEA GHG R&D, 2008)*
CO_2 captured (tCO_2/yr)	2,000,000	*(IEA GHG R&D, 2008)*
CO_2 avoided (tCO_2/yr)	1,870,867	Calculated

References:

1. IEA GHG R&D (2008). Carbon Dioxide Capture and Storage in the Clean Development Mechanism – Assessing market effects of inclusion, IEA GHG R&D Programme, 2008.
2. McCollum and Ogden (2006). McCollum, D. L., Ogden, J, M. (2006) Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity. Institute of Transportation Studies, University of California-Davis.

Project ID	Project E	
Project type	**High CO_2 gas field (onshore)**	
Parameter	**Value chosen**	**Source/notes**
Project time		
Project lead time (years)	2	Project team assumption
Project life (years)	20	Project team assumption
Costs		
Additional capex - capture ($m)	**185.8**	Breakdown of capex data based upon ERM analysis for IEA GHG R&D study of CDM CCS early opportunities *(IEA GHG R&D, 2008)* ; most capex estimates are based on UCD engineering study of equip. requirements for different CO_2 gas flow rates *(McCollum and Ogden, 2006)*
CO_2 compressors	*38.4*	
Pumps	*1.9*	
Interstage coolers	*5.4*	
Interstage separators	*1.0*	
Dryers	*32.3*	
Gas-fired power plant OCGT	*20.0*	Assumes elec. provided by on-site OCGT at $750 per kW installed (Project team assumption)
Construction and engineering	*24.8*	Assumes 25% of plant capex *(IEA GHG R&D, 2008)*
Retrofit cost multiplier (xfactor)	*1.5*	*(IEA GHG R&D, 2008)*
Retrofit cost	*61.9*	
Additional capex - capture ($m) 2009	**203.7**	Calculated using CEPCI price indices
Capex paid over construction phase	*Year 1: 50%*	Project team assumption
	Year 2: 50%	Project team assumption
O&M (% of capex/yr)	4%	*Base on well capex and opex cost estimates and monitoring costs for*
T&S cost ($/t$CO_2$ stored)	0.64	Based on well capex and opex cost estimates and monitoring costs for in-situ onshore injection of 2MtCO_2/yr *(IEA GHG R&D, 2008)*
CO_2 mass flow rate (tCO_2/day)	6,027	Assumes 10% over-capacity requirement
Compressor power (kW)	25,205	Based on 5-stage compression and pump power requirements
Compressor elec. energy (GJ/yr)	761,590	
Pump power (kW)	1,458	Based on pump power vs. CO_2 mass flow rate algorithm *(McCollum and Odgen, 2006)*
Pump elec. energy (GJ/yr)	44,055	
Total power (MW)	26.7	
Total elec. requirement (GJ/yr)	805,645	
Additional fuel gas requirement (GJ/yr)	2,301,842	Based on on-site OCGT with 35% efficiency
Base gas price ($/GJ)	1.00	Assumes low cost condensate/gas (project team assumption)
CO_2 emissions		
Capture rate	98%	*(IEA GHG R&D, 2008)*
CO_2 captured (tCO_2/yr)	2,000,000	*(IEA GHG R&D, 2008)*
CO_2 avoided (tCO_2/yr)	1,870,867	Calculated

References:

1. IEA GHG R&D (2008). Carbon Dioxide Capture and Storage in the Clean Development Mechanism – Assessing market effects of inclusion, IEA GHG R&D Programme, 2008.
2. McCollum and Ogden (2006). McCollum, D. L., Ogden, J, M. (2006) Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity. Institute of Transportation Studies, University of California-Davis.

Project ID	Project F	
Project type	LNG plant	
Parameter	**Value chosen**	**Source/notes**
Project time		
Project lead time (years)	2	Project team assumption
Project life (years)	20	Project team assumption
Costs		
Additional capex - capture ($m)	**185.8**	Breakdown of capex data based upon ERM analysis for IEA GHG R&D study of CDM CCS early opportunities *(IEA GHG R&D, 2008)* ; most capex estimates are based on UCD engineering study of equip. requirements for different CO_2 gas flow rates *(McCollum and Ogden, 2006)*
CO_2 compressors	*38.4*	
Pumps	*1.9*	
Interstage coolers	*5.4*	
Interstage separators	*1.0*	
Dryers	*32.3*	
Gas-fired power plant OCGT	*20.0*	Assumes elec. provided by on-site OCGT at $750 per kW installed (Project team assumption)
Construction and engineering	*24.8*	Assumes 25% of plant capex *(IEA GHG R&D, 2008)*
Retrofit cost multiplier (xfactor)	*1.5*	*(IEA GHG R&D, 2008)*
Retrofit cost	*61.9*	
Additional capex - capture ($m) 2009	**203.7**	Calculated using CEPCI price indices
Capex paid over construction phase	*Year 1: 50%*	Project team assumption
	Year 2: 50%	Project team assumption
O&M (% of capex/yr)	4%	*(IEA GHG R&D, 2008)*
T&S cost ($/t$CO_2$ stored)	15.00	Project team assumption, based on *Dooley et al (2008)*
CO_2 mass flow rate (tCO_2/day)	6,027	Assumes 10% over-capacity requirement
Compressor power (kW)	25,205	Based on 5-stage compression and pump power requirements
Compressor elec. energy (GJ/yr)	761,590	
Pump power (kW)	1,458	Based on pump power vs. CO_2 mass flow rate algorithm *(McCollum and Odgen, 2006)*
Pump elec. energy (GJ/yr)	44,055	
Total power (MW)	26.7	
Total elec. requirement (GJ/yr)	805,645	
Additional fuel gas requirement (GJ/yr)	2,301,842	Based on on-site OCGT with 35% efficiency
Base gas price ($/GJ)	1.00	Assumes low cost condensate/gas (project team assumption)
CO_2 emissions		
Capture rate	98%	*(IEA GHG R&D, 2008)*
CO_2 captured (tCO_2/yr)	2,000,000	*(IEA GHG R&D, 2008)*
CO_2 avoided (tCO_2/yr)	1,870,867	Calculated

References:

1. IEA GHG R&D (2008). Carbon Dioxide Capture and Storage in the Clean Development Mechanism – Assessing market effects of inclusion, IEA GHG R&D Programme, 2008.
2. McCollum and Ogden (2006). McCollum, D. L., Ogden, J, M. (2006) Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity. Institute of Transportation Studies, University of California-Davis.
3. Dooley et al (2008). J.J. Dooley, R.T. Dahowski, C.L. Davidson, S. Bachu, N. Gupta, and J. Gale. A CO_2 storage supply curve for North America and its implications for the deployment of Carbon Dioxide Capture and Storage Systems, Batelle/Pacific Northwest National Laboratory, 2008.