Energy Technology Innovation Policy Research Group

Analysis of Financial Incentives for Early CCS Deployment

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DISCLAIMER

ENERGY TECHNOLOGY INNOVATION POLICY

The overarching objective of the Energy Technology Innovation Policy (ETIP) research group is to determine and then seek to promote adoption of effective strategies for developing and deploying cleaner and more efficient energy technologies, primarily in three of the biggest energy-consuming nations in the world: the United States, China, and India. These three countries have enormous influence on local, regional, and global environmental conditions through their energy production and consumption.

ETIP researchers seek to identify and promote strategies that these countries can pursue, separately and collaboratively, for accelerating the development and deployment of advanced energy options that can reduce conventional air pollution, minimize future greenhouse-gas emissions, reduce dependence on oil, facilitate poverty alleviation, and promote economic development. ETIP's focus on three crucial countries rather than only one not only multiplies directly our leverage on the world scale and facilitates the pursuit of cooperative efforts, but also allows for the development of new insights from comparisons and contrasts among conditions and strategies in the three cases.

ACKNOWLEDGEMENTS

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ABSTRACT

There is a growing interest in carbon capture and storage (CCS) as a technology to reduce carbon dioxide (CO_2) emissions. The substantial additional costs and complexity of CCS facilities over and above conventional use of fossil fuels mean that government subsidies are required to assist the demonstration and deployment of the technology. CCS is not unique in this respect – other forms of low carbon power generation also require policy support. However, unlike other technologies policy for CCS deployment is much less well-developed.

This paper examines the range of policy options available to assist deployment of CCS, with particular reference to its deployment in the United States. It draws on analysis of project economics and an emerging set of policy experiences with CCS internationally.

The different types of financial support already in place are reviewed. Various forms of this support are then modeled for a hypothetical coal-fired power plant with CCS to quantify their implications for project developers and governments. Different types of support are found to reduce the incremental cost of CCS in markedly different magnitudes; cost reduction estimates range from 2% up to 80%.

The goal of maximizing the discounted cash flow of the project favors policies that reduce capital or financing costs in the early years. Support during operation, which may be favored by governments to encourage output, such as the allocation of emissions allowances is also valuable to project developers provided that it is certain. However support during operation needs to be greater than support for capital cost reductions in order to offset the effects of discounting later cashflows.

No single mechanism on its own appears to be sufficient to bridge the current cost gap between CCS and conventional fossil fuel generation. In practice, a bundle of several types of support mechanisms, both at federal and state levels, are likely to be needed to meet the different barriers facing deployment and commercialization of CCS technology. Such a bundle could include carbon pricing, operating cost support through the allocation of free emissions allowances, loan guarantees, capital grants, and investment tax credits.

FORWARD

In 2009, Mohammed Al-Juaied and Adam Whitmore authored a paper on the cost of carbon capture and sequestration projects. The monograph, published by Harvard's Belfer Center for Science and International Affairs, found that the cost of early CCS plants would be significantly higher than the costs commonly quoted in the press. The authors found that a carbon tax as high as $180 per ton of CO_2 on a 2008 basis would be required for a generating plant with CCS to be competitive with a conventional facility (no CCS).

The authors argued that the costs could come down significantly over time, but only if governments could provide sufficient incentives to persuade investors to build first-of-a-kind demonstrations on a commercial scale. These early projects would lead to engineering improvements, reduced financial and regulatory risks, and thus lower costs for future facilities.

In the 2010 paper, Al-Juaied looks at the financial incentives that government could provide and analyzes how much of an impact each would have on the initial cost of a CCS project. These incentives include investment and production tax credits, loan guarantees, grants, special carbon allowances, and accelerated tax depreciation. Al-Juaied not only looks at the cost impacts, but also the political, economic, and administrative advantages and disadvantages of each.

This report is part of a series of studies on the economics and policy challenges to the dissemination of CCS technologies published by the Belfer Center's Energy Technology Innovation Policy (ETIP) Research Group.

Mohammed Al-Juaied came to the Belfer Center from Saudi Aramco where he worked on low- carbon technologies. He spent a year as a Visiting Scholar with ETIP, a year as a Mason Fellow at the Harvard Kennedy School and has now returned to Saudi Arabia. This work was supported in part by grants from BP and the Roy Family Operating Fund, but the opinions and findings in the report do not reflect those of Harvard University or its funders.

Henry Lee

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1. INTRODUCTION

Deep cuts in greenhouse gas emissions (GHGs) will be required by the middle of this century if atmospheric concentrations of greenhouse gases are to be stabilized at a level which limits the risks of dangerous climate change.[2] Several jurisdictions have now set or discussed emissions reductions goals or commitments for 2050. The principal goals are summarized in Table 1 below.

Table 1 - Emissions reductions goals for 2050

Jurisdiction and policy instrument	Emissions reduction goal or commitment for 2050[3]
G8: Declaration	Support for 50% reduction in global emissions (baseline unspecified), 80% or more relative to 1990 or more recent years for developed countries[4]
USA: Climate Security Bill (Waxman-Markey)	83% below 2005 levels
California: Executive Order S-3-05	80% from 1990 levels
EU (European Parliament): Statement	60-80% from 1990 levels (with the EU council now indicating up to 95% if deal reached on international cuts[5])
UK: Climate Change Act	Legally binding obligation of an 80% reduction from 1990 levels
Australia: Federal Government target	60% from 2000 levels

[2] The United Nations Framework Convention on Climate Change (UNFCCC), which was ratified by almost all countries, including the USA, set the objective under Article 2 of "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system". A definition of dangerous anthropogenic interference has now been accepted by governments of major economies to a rise in mean global temperatures of no greater than 2°C. The levels of greenhouse gases in the atmosphere consistent with this commitment are estimated in the IPCC Fourth Assessment Report.

[3] Goals may allow for the use of carbon offsets, which may make the targets somewhat less demanding in practice than they appear

[4] http://www.g8italia2009.it/static/G8_Allegato/G8_Declaration_08_07_09_final,0.pdf

[5] http://www.euractiv.com/pdf/DraftCouncilConclusionsOct09.pdf

Such goals are likely to require an almost complete decarbonization[6] of the power sector by 2050 at the latest.[7] Indeed, the heads of most major European utilities have committed to a carbon neutral power sector by 2050.[8] At the same time, decarbonization of other sectors such as buildings and transport, together with continued economic growth, is likely to lead to increased electricity demand, even if there are large efficiency gains.[9] This will make the challenge of decarbonizing the power sector all the greater.

Immediate progress towards decarbonizing power generation is required if 2050 emission reduction goals are to be met because of the long lifetimes of power generation equipment. AEP, America's largest coal generator, noted in testimony to Congress in 2008 that "we are still operating plants built during the Eisenhower, Kennedy and Johnson administrations and plants built today will be operating during the term of the President who sits in the Oval Office in the 2050s."[10] During the same hearings, the Natural Resources Defense Council noted that a new power plant without Carbon Capture and Storage (CCS) "carries with it a huge stream of CO_2 emissions that will likely flow for the life of the plant – 60 years or more."[11] This phenomenon is referred to as emissions lock-in.

Low carbon technologies currently account for only a minority of electricity generation. For example, in the United States in 2008, nuclear accounted for about 20% of output, hydro for 6% with little opportunity for substantial expansion, and all other renewables accounted for a further 3%.[12] Of the 3% renewable electricity, the majority was from biomass, waste, and wind. Solar

[6] That is the elimination of emissions of carbon dioxide from power generation.
[7] Examples of studies showing this include "Energy Technology Perspectives, 2008: Scenarios & Strategies to 2050," International Energy Agency, 2008; "Building a Low Carbon Economy: The UK's Contribution to Tackling Climate Change," The First Report of the Committee on Climate Change, December 2008; and "Making the Transition to a Secure and Low-Carbon Energy System: Synthesis Report," UK Energy Research Center, 2009, see: http://www.ukerc.ac.uk/MediaCentre/UKERCPressReleases/Releases2009/0904Energy2050.aspx.
[8] http://www.eurelectric.org/CEO/. The commitment to carbon neutrality appears to allow for continued emissions with the use of offsets.
[9] The studies on the UK and California cited above show this for both economies, despite their differing emissions mixes.
[10] AEP Testimony before the House Subcommittee on Energy and Air Quality July 10, 2008.
[11] NRDC Testimony before the House Subcommittee on Energy and Air Quality July 10, 2008.
[12] Energy Information Administration Net Generation by Electricity Source, Report DOE/EIA-0226, 15 October 2009. http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html. All other renewables includes generation from biomass and biogas, solar, geothermal, and wind.

PV produced less than 0.01% (see Table 2).[13] There is currently no significant amount of power generation with CCS.

Table 2 - Sources of U.S. electricity generation

Source	**% Electricity Generation**
Coal	49%
Petroleum Liquids	1%
Natural Gas	21%
Nuclear	20%
Hydro	6%
Other Renewables	3%
Biomass	*1.5%*
Waste	*0.5%*
Geothermal	*0.2%*
Solar PV	*0.01%*
Wind	*0.8%*

Low carbon

The need to reduce CO_2 emissions in the context of increasing energy demand, combined with the small contribution being currently made by renewables, imply an urgent need to increase the deployment of low carbon generating technologies. The mix of low carbon power generation technologies that will be deployed is inherently uncertain. However many studies have found that renewables (mainly wind and solar), nuclear and fossil fuels with CCS are all likely to have a role to play.[14] At the very least, each of these technologies will need to be commercialized so that the option to deploy them on a very large scale is there if other technologies cannot, for whatever reason, be deployed at the scale sufficient to meet emissions reduction goals. Demonstration of CCS in particular is required as it is also likely to be an important means of decarbonizing some industrial processes.

[13] http://www.eia.doe.gov/cneaf/alternate/page/renew_energy_consump/table3.html. Note 'waste' includes landfill gas and municipal solid waste biogenic (black liquor, and wood/woodwaste solids and liquids)
[14] See studies cited in footnote 2.

Most low carbon generation technologies currently have costs of generation well above those of conventional fossil fuel technologies. Previous work by Al-Juaied and Whitmore[15] suggested that the cost of abatement for First of a Kind[16] CCS plant is \$150/tCO_2 avoided on a 2008 basis (with a range \$120-180/tCO_2 avoided) excluding transport and storage. Costs of generation from most renewables and from nuclear power are also substantially greater than from conventional fossil fuel sources. The additional costs of low carbon generation are likely to be reduced over time as technologies develop. However a cost premium is likely to remain for most low carbon technologies, at least until 2030.

This paper assesses the cost-effectiveness of the range of financial incentives available to stimulate the initial deployment and subsequent commercialization of CCS[17], by comparing a base case to scenarios that adopt specific incentives. Since the early CCS plants will be very expensive and will not be competitive with conventional power facilities unless there is a very high price on carbon, government incentives will be needed, if these plants are to be deployed in the 2012-2025 time frames. In the earlier study by Al-Juaied and Whitmore, a model is produced, which derived a price as high as \$180 per tonne of CO_2. This study looks at how much this figure could be reduced through the use of various government subsidies.

The paper is structured as follows:

Section 2 outlines the core financial incentives selected to be investigated.

Section 3 describes the financial model that was developed and used in this work.

Section 4 describes in-depth the effects and costs of a range of incentives on the economics of early IGCC plants with CCS.

Section 5 concludes by reviewing how, in light of current practice and the analysis reported here, policy might be developed to secure more effective deployment of CCS.

Appendices A, B & C provide further details on a number of issues raised in the report:

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[15] Al-Juaied, Mohammed and Adam Whitmore. "Realistic Costs of Carbon Capture." Discussion Paper 2009-08, Energy Technology Innovation Policy Research Group, Belfer Center for Science and International Affairs, Harvard Kennedy School, July 2009.
[16] First of a kind means a first plant to be built using a particular technology.
[17] It does not consider policy for stimulating research and development in any detail as the most important challenge is achieving substantial deployment. However the importance of further research and development and the need to fund this adequately is fully acknowledged.

1. The limitations of this piece of work.
2. Inputs into the economic model.
3. Inputs into the EOR Case of the economic model.

Appendix D provides additional information on other policy mechanisms. This includes consideration of how financial support might be allocated, for example, qualification by means of defined criteria, reverse auctions, and competitions.

2. FINANCIAL INCENTIVES

Federal and state governments have frequently used direct and indirect incentives to mobilize private sector investment in projects and to advance policy objectives in numerous sectors of the economy. Types of direct incentives have included tax-based incentives, loan guarantees, and other forms of direct government participation such as grants. Indirect incentives can also be valuable tools for mobilizing private sector investment, such as permitting acceleration, and other indirect forms of risk sharing.

This paper selects a core set of CCS federal support mechanisms and analyzes each for their potential effectiveness. These include:

1. Investment tax credits;
2. Accelerated depreciation;
3. Production tax credits;
4. Tax credits for storage or CO_2 EOR;

Tax incentives

5. Loan guarantees;
6. Capital grants (Federal cost sharing);
7. Allocation of multiple emissions allowances;
8. Contracts for difference on the carbon price.

The United States has already taken actions on several fronts in the form of legislation and regulations that strengthen financial incentives to encourage deployment of early commercial IGCC/CCS projects. These are discussed here:

Investment tax credits

The 2005 Energy Policy Act authorized $1.65 billion in investment tax credits for CCS and gasification; $800 million for IGCC electricity (up to 20 percent tax credit), $500 million for other types of coal power plants with CCS (up to 15 percent tax credit), and $350 million for non-power related gasification projects. The Department of Energy (DOE) has already made a number of awards under this tax credit scheme in two separate rounds, in 2006 and 2007-2008.[18] $392 million from this initial $1.65 billion was awarded in a third round in 2008-2009.

Additional investment tax credit funding was authorized in the HR 1424 Emergency Economic Stabilization Bill 2008. A further $1.5 billion was made available to power sector and industrial gasification capture projects with certain qualification criteria.[19] Credits were also made available for CO_2 storage on a per-tonne stored basis (limited to 75 million tonnes), either in a secure geological formation ($20/tonne), or for use in qualified EOR or natural gas recovery projects ($10/tonne). The total extra value of these investment tax credits added in 2008 equates to $2.5 billion.[20]

Stimulus and state level funding

The American Recovery and Reinvestment Act 2009 (ARRA) provided $3.4 billion of stimulus funding for CCS, which the Department of Energy is distributing[21] (this includes yet more investment tax credit). ARRA money was also provided for the Futuregen plant, a public-private partnership.[22]

In addition to this direct funding being made available, some states indirectly fund CCS by allowing certain specific projects to recover extra costs through the rate base (states that have allowed this include California, Colorado, Texas, Indiana, and Illinois).

[18] http://www.energy.gov/media/CleanCoalTaxCreditFactSheet.pdf
[19] http://www.nma.org/ccs/031309_credit.pdf
[20] http://www.pa-erg.com/pdfs/aer_100408.pdf
[21] http://fossil.energy.gov/recovery/index.html A recent example of this funding being used in practice is the awarding of $308 million to the Hydrogen Energy California project.
[22] http://www.futuregenalliance.org/faqs.stm

Proposed future funding under climate change legislation

There have been numerous attempts to formulate a winning climate bill in the U.S. Congress over the past several years. Most recently, in June 2009, the House of Representatives passed a climate bill known as Waxman-Markey. A similar bill was introduced, by Senators Boxer and Kerry, into the Senate in September 2009, but the measure did not gain sufficient traction to bring it to a vote.[23]

Regardless of the fate of the U.S. government's response, an audit of the recent proposed climate legislations affecting CCS will allow some conclusions to be reached about the likelihood of early CCS to be deployed.

The Waxman-Markey bill (HR 2454, American Clean Energy and Security Act 2009 - ACES) contains provisions for CCS plants that cover at least 200MW of capacity, have capture rates greater than 50%, and use at least 50% coal and/or petcoke mixes:[24]

- Payments in the form of bonus allowances[25] established for the first 6GW at $50/t for 50% capture rising to $90/t for 85% capture. Amounts are inflation indexed and for the first 10 years of operation.
- Additional $10/t for projects which begin capturing at least 50% before 1st January 2017 and an unspecified reduction for projects receiving EOR revenue.
- Provision for $1 billion annually of funding for ten years based on a charge for fossil generation, for a total of $10 billion.

After January 1, 2017 there would be reverse auctions for government support of CCS, broken down into different categories. These auctions could support up to an additional 66GW of CCS. The support would be made up of bonus allowances allocated in tranches of 6GW, each tranche getting less government support than the previous one.

[23] http://www.bbc.co.uk/news/science-environment-10739800
[24] http://energycommerce.house.gov/Press_111/20090701/hr2454_house.pdf
[25] Bonus allowance is a term referenced in the Waxman Markey Bill as part of the formula to decide the quantity of allowances to be freely allocated. It is a measure of what strength of support is provided.

The U.S. Environmental Protection Agency projections for cap-and-trade allowance prices estimate that funding for coal with CCS in Waxman-Markey would be at the level of $100 billion to 2030 and $240 billion to 2050.[26]

The Kerry-Boxer Bill (S1733) is even more generous to CCS, and allocates a certain proportion ($5.5 billion allowances) of the revenues from the sale of allowances in a cap-and-trade scheme to CCS. It does, however, aim to put a ceiling on allowance prices of $28/tonne, a ceiling that would escalate in real terms each year by 5% to 2017 and 7% thereafter.

Loan guarantees

The DOE loan guarantee program provides $8 billion for advanced clean coal technologies, authorized from the 2005 Energy Policy Act. Six billion dollars of this total is for coal based power generation and industrial gasification that incorporates CCS or other beneficial uses of carbon, and $2 billion is for advanced coal gasification.[27] In 2010, DOE has made conditional commitments to issue loan guarantees for 13 clean energy projects.[28] No DOE loan guarantees, however, have yet been authorized for CCS.

Current legislated funding in the United States stands at $7.6 billion of investment tax credits and other funding with $8 billion plus in additional loan guarantees. Table 3 is a summary of U.S. funding. (Some additional non cash support to CCS, such as accelerated depreciation, is not included in this total.)

[26] http://www.pewclimate.org/federal/what-waxman-markey-does-for-coal
[27] http://www.energy.gov/media/Loan_Guarantee_Fact_Sheet.pdf
[28] http://www.lgprogram.energy.gov/press/070310.pdf

Table 3 – Summary of U.S. funding

Source		**Value $ billion**
Investment Tax Credits	Energy Policy Act 2005	1.65
Investment Tax Credits	HR 1424	2.5
Grants	ARRA	3.4
DOE Loan Guarantee	Energy Policy Act 2005	8
Total ($ billions)		**$7.6 + $8 in loan guarantees**

3. MODELING THE IMPACT OF CCS INCENTIVES

This section provides a description of the model used to evaluate the cost effectiveness of eight incentives that could improve the financial prospects of first-of-kind CCS projects. I use the costs of a generic IGCC with CCS in the United States as the base case for my calculations. It is worth noting that CCS has a range of plausible costs, so this section should be taken as being indicative of how certain measures can reduce the cost gap, between CCS and conventional fossil fuel generation relative to other options, rather than giving definitive cost reduction potentials for incentive mechanisms.

IGCCs with CCS are characterized by a capital intensive construction and commissioning phase lasting about five years, followed by an operation period of 20 years or more. Revenue comes from the sale of electricity, and CO_2 sales if Enhanced Oil Recovery (EOR) opportunities are available.

Key risks to commercial success include the inability to secure a sufficient power price to cover costs, tough permitting requirements or unanticipated increases in the costs of the capital equipment needed to complete the plant and bring it online. Each of these factors adds to the cost of early plants. Such risks need to be mitigated for a project to succeed. My analysis shows that a sustained policy commitment is needed to address the financial risks associated with projects of this size, cost, and complexity.

3.1 Financial Model Description

The financial model developed in this work is a discounted cash flow, used to evaluate the impact of various incentives on the economics of an early CCS plant. An IGCC plant is assumed for the purposes of illustration, but the general conclusions would also apply to a power plant with post combustion capture technologies.

The model incorporates financing, including interest during construction, depreciation, debt payments, senior and subordinated debt, alongside assumptions on escalation of feedstock prices, operations and maintenance (O&M) costs, and electricity prices.

The Levelized Cost of Electricity (LCOE) which gives a zero NPV for a set return is calculated by the model. The project's cash flow is determined by accounting for all costs, financial obligations (including servicing debt[29]) and revenues for the CCS project. Positive cash flows are available for return to equity investors. Thus, in this work, the IRR corresponds to the project's return on equity.

A Debt Service Coverage Ratio (DSCR) constraint, which measures the ratio of pre-tax earnings before interest to the debt principal and interest payments, has been included in order to ensure that the modeled project can sustain its debt payments over time. The minimum DSCR required to satisfy this cash flow constraint in the base case is 1.5[30] (in year 2) growing to over 2 in the later years. Early CCS facilities are risky, so banks are likely to require higher as opposed to lower DSCRs. The requirement is relaxed in the first year of operation, after construction, since the plant is in the startup phase (operating at 45% capacity), and does not have enough cash to cover its debt service (interest + principal).

Working capital is included in the model and is calculated in each year as current assets minus current liabilities. Current assets include accounts receivable and operating cash to cover operating and fuel expenses. Current liabilities include a working capital loan which is used to

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[29] Cash required over a given period for the repayment of interest and principal on a debt.

[30] Finnerty, John D., Project Financing: Asset-Based Financial Engineering, 2nd edition, John Wiley & Sons, Inc, pp. 138-139

finance the everyday operations of the project. At the end of the project life, the working capital is returned to equity holders as a positive cash flow.

3.2 The Choice of an Appropriate Rate of Return

A survey by the DOE's National Energy Technology Laboratory (NETL) suggested that the industry standard equity rate of return for power project investors was in the high teens to the low/mid 20s.[31]

The cost of debt is less than the cost of equity because debt is senior to equity (paid first). This holds even in countries where the interest tax shield is not present. Leverage therefore, increases the net present value of a project. For high-risk capital intensive projects like CCS, debt financing will be more difficult to obtain, so project developers will likely need more equity.

The NETL survey suggests debt will likely be more expensive than the industry standard with a 5% premium above LIBOR (or the London Interbank Offered Rate) to account for the technology uncertainty. Table 4 shows an estimate by NETL for the Weighted Average Cost of Capital of an IGCC with CCS. The 60% debt share seems to be a likely maximum, with a range of 50-60%.

Table 4 – Estimate of cost of capital

Type of security	% of Total	Current (Nominal) Dollar cost	Weighted current cost of capital
Debt	60	8.5% (LIBOR Plus 5%)	5.1
Equity	40	20%	8
Average			13.1%

In reality, the cost of capital allowed by state utility regulators is much lower than 13%. For example, California views a return of about 8.5% as appropriate for a standard Combined Cycle Gas Turbine (CCGT), with a 0.5%-1% premium[32] for low carbon power such as renewables and

[31] http://www.netl.doe.gov/energy-analyses/pubs/Project%20Finance%20Parameters%20-%20Final%20Report%20-%20Sept%202008_1.pdf

[32] http://www.energy.ca.gov/emission_standards/documents/sb_1368_bill_20060929_chaptered.pdf Sect. 8341 b, 6.

CCS. Indiana and Virginia also suggest a 1-1.5%[33] premium on the weighted cost of capital for CCS compared with a standard return available to a CCGT. This would suggest a more plausible weighted average cost of capital of 9-10% in most regulated markets in the United States.

This is backed up by comparison with the published costs of capital for certain large utilities, chemical companies, and industrial gas companies, which mostly fall in the 8%-11% range.

The cost of capital used in this economic model is 10.5% in post-tax, nominal terms. This was chosen to be consistent with the previous work by Al-Juaied and Whitmore, in which the assumed interest rate was 10% pre-tax in real terms (12% pre-tax in nominal terms or 10.5% post-tax nominal).

3.3 Base Case

The base case is a greenfield IGCC that uses bituminous coal and captures 90% of its CO_2 emissions, compressing and transporting them for geologic storage in a depleted oil field. The cost of CO_2 transport is included in the base case analyses. Instead of choosing whether CO_2 storage would be a cost or a source of revenue (if the CO_2 were to be used for EOR), the base case excludes any net cost or revenue from CO_2 storage. All other assumptions for the base case are provided in Appendix B.

The base case analysis indicates that the cost of abatement needs to be $160 per tonne of CO_2 for a plant to achieve its cost of capital of 10.5%. If a transport and storage cost of $10 per tonne of CO_2 is included in every year's calculation (indexed to inflation), then the cost of abatement will be $182 per tonne of CO_2. This is to say, inflation reduces the present value of the cash inflows from the project. This in turn increases the price of CO_2 needed to bring the negative NPV back to zero.

There is a wide range of plausible assumptions for key aspects of plant operation and costs, such as availability, cost of debt, and cost of electricity. Therefore any detailed discussion of sensitivities in this paper is somewhat arbitrary. Consequently this paper makes all its

[33] http://209.85.229.132/search?q=cache:gjEojtS7nMcJ:www.dom.com/dominion-virginia-power/electricity-reregulation-in-virginia.jsp+Senate+Bill+1416+and+House+Bill+3068+2%25+return+renewable&cd=2&hl=en&ct=clnk&gl=uk Virginia allows a 2% premium on equity (equates to 1% assuming 50% equity). http://www.in.gov/legislative/ic/code/title8/ar1/ch8.8.pdf. Indiana allows a 3% premium on equity for clean coal (equates to 1.5% with 50% equity).

calculations using the base case economic assumptions. Its core aim is to demonstrate the relative effectiveness (rather than the absolute value) of different types of CCS incentives in closing the CCS cost gap.

4. ANALYSIS OF FINANCIAL INCENTIVES

In this section, I examine how the application of incentives discussed in section 2 would improve the financial feasibility of the economics of an IGCC with CCS. The cost of abatement (at zero NPV) is found for each incentive and the associated reduction on the base case cost is noted.

4.1 Tax Incentives

Tax incentives improve project economics by decreasing the tax liability generated by a project, which improves the cash flow to equity investors. This subsection considers the effects of four types of tax incentive: (1) investment tax credits, (2) accelerated depreciation, (3) production tax credits, and (4) tax credits for CO_2 storage and CO_2 EOR.

4.1.1 INVESTMENT TAX CREDITS

Overview

Investment Tax Credits (ITC) decrease the effective cost of the plant by offsetting taxes on corporate profits each year against ITC until the total agreed ITC value is credited. Therefore, they effectively reduce the capital cost of a project. The 2005 Energy Policy Act and subsequent top-up funding in later acts provide more than $4 billion in ITC support in the United States, as described in section 2.

Assumptions

- ITC of 30% is applied to the eligible portion of total plant costs. This eligible portion includes the gasification unit and certain other associated units, which make up 20% of the total costs.[34] The project total cost is $3.45 billion, so the credit generated is $207 million (i.e. 30% of 20%, or 6% of the total cost).

[34] http://www.climatevision.gov/pdfs/Co-Production_Report.pdf

- To avoid double counting the tax credit, the depreciable tax basis of the capital costs is reduced by an amount equal to the value of the ITC.
- The tax credit is generated in year 2, which is the first full year of operation. Any excess of credit over the amount of tax liability due for that year is rolled forward and taken as a credit against the tax liability due for the following year until the credit is fully consumed.

Results

With the above assumptions, the new cost of abatement is \$174/tCO_2, a reduction of 5% from the base case (\$182/tCO_2). The \$207 million tax credit is absorbed by the tax liability in years two to six. In year one the amount of tax is zero, since the income is negative and therefore losses are carried forward and set off against the profits of the second year. The benefit of the ITC is offset slightly by increased tax liability from reduced depreciation in the year the credit is generated and in future years. If this reduction in depreciation is not considered, then the decrease in the cost of abatement is slightly higher at 6%. This reduction is commensurate with the 6% reduction in the capital cost combined with the effects of cash flow discounting.

The ARRA legislation now allows companies with no "tax appetite" to collect cash grants in lieu of ITC. A company may have no "tax appetite" when, for example, their tax burden is sufficiently reduced by another incentive so meaning that an additional tax credit cannot be fully realized so a cash option is preferred. Under I.R.S. Section 48, the cash grant allowable for both businesses and individuals takes the form of a one time upfront tax credit equal to 30% of their investment in renewable energy projects, such as solar and wind.

If this 30% upfront cash grant in lieu of the tax credit is extended to CCS projects and so received in the first year of operation, then the benefit is even larger due to the time preference of cash through discounting. The reduction in the cost of abatement would then be 7%. If the tax base is not adjusted for depreciation by the amount of the credit (as described above to prevent double counting), then the reduction in cost of abatement is 8%.

The cost to the government is estimated as the present value of the revenue forgone from taxes to the U.S. Treasury Department over the life of the project. The discount rate is included in this calculation and for a 20 year project is 4%[35] as of March 10, 2010. The budgetary effect is estimated to amount to almost $176 million.

Advantages of mechanisms

- The ITC reduces the high upfront capital costs of an IGCC. When all else is equal, reducing project costs early in the plant's life-cycle will reduce the cost of abatement more than incentives that apply later, owing to the effect of discounting.
- ITCs are particularly useful to regulated utilities and profitable Independent Power Producers (IPPs) because they effectively reduce upfront capital cost.

Disadvantages of mechanisms

- They are expensive to the government, costing $176 million in tax credits in this case. Since it is a tax credit, it reduces taxes on a dollar-for-dollar basis, meaning that a tax credit of $1,000 would reduce the amount of taxes owed by the same $1,000.
- They enhance the creditworthiness of a project only to the extent they increase cash flows; and hence they are limited on their impact on the cash flows because of the small amount of the credit in years where it is offsetting the tax liability.
- ITCs can be restrictive; in this case the ITCs only apply to innovative portion – the gasification subsystem and exclude other aspects of the plant. If ITCs were allowed to apply to the total cost of an IGCC, then the reduction in the cost of abatement would be much higher.
- ITCs can be time restricted; in this case the program may be valid within a particular period of time. Longer term ITCs availability could lead to greater market certainty about ongoing support with reducing capital costs, potentially stimulating more investment in CCS projects as risk is reduced.
- Only commercial projects and profitable organizations can take advantage of this incentive. Municipal utilities and state power agencies cannot take advantage of ITCs

[35] http://www.ustreas.gov/offices/domestic-finance/debt-management/interest-rate/yield.shtml

since they are tax exempt. Most cooperative utilities are also tax exempt and therefore would not be able to use such credits.[36]

4.1.2 ACCELERATED DEPRECIATION

Overview

This incentive recognizes larger amounts of depreciation in earlier years compared to later years of a fixed assets life. It reduces the project owner's taxes in the early years of the project, offset by an increased tax liability after the asset is fully depreciated. (Tax levels rise after deductions for depreciation are exhausted or completed, whether the depreciation is accelerated or normal.)

Assumptions

- As with the ITC, it is assumed that only the gasification portion of the plant is eligible for accelerated depreciation, which represents 20% of the total capital costs.
- Under current tax laws, the gasification portion of the IGCC plant will be depreciated for tax purposes over a 10-year period.[37] It is assumed under accelerated depreciation that 50% of the gasification capital cost (50% of the 20% capex) is expensed in the first year, with the remaining 50% being depreciated over the next 10 years. The rest of capex (80%) is depreciated as in the base case using the 20-year MACRS method.
- It is assumed that any tax loss generated in any year will be usefully used within the year by the project owner to offset tax liabilities.

Results

The resultant cost of abatement is \$179/tCO_2, equating to roughly a 2% reduction in the cost of abatement from the base case. This is a smaller reduction than that experience with the ITC because whilst the majority of the eligible capex (20% of the total) is the same as that eligible for the ITC, the depreciation benefit comes in the form of a tax reduction of 35% of the eligible

[36] http://www.epatechforum.org/documents/2006-2007/2006-11-09/2006-11-09-IGCC%20POLICY%20&%20FINANCING%20--%20FINAL%20DRAFT%20PAPER%20-%20REVISED%2011-17-06.pdf

[37] MACRS is the current method of accelerated asset depreciation required by the United States income tax code. http://en.wikipedia.org/wiki/MACRS

capital (in the early years which benefits through discounting) rather than what is effectively a grant equal to the eligible capital. Therefore the reduction is less than the ITC by an amount of the order of the tax rate (35%). To be clear, whilst the tax bill is less in the early years, the total nominal tax is made up by larger payments later on, but this has less of an effect to the project due to discounting.

Advantages

- Accelerated methods often better match the benefit received with the revenue earned.
- Accelerated methods reduce cash outflow for tax purposes during the first half of the asset life, improving cash flow during times when the effect of discounting makes it more helpful for the project's economics.

Disadvantages

- The total nominal tax over the project life remains constant through different depreciation mechanisms as already stated. There is, however, a timing issue so the difference between the present value[38] of the tax to the government in the base case against the accelerated depreciation case is not equal to zero, hence it is a cost to the government. Discounted tax revenues in the base case are $1,507 million and in this case it is $1,471 million, leaving a net cost to the government of $36 million.
- It has a limited value in terms of decreasing the cost of abatement (2% reduction in this modeled case).

4.1.3 PRODUCTION TAX CREDITS

Overview

Production tax credits provide a plant operator with a direct payment to offset against corporate tax based on the amount of electricity generated from the electric utility, up to a specified production limit. Under the 2005 Energy Policy Act, production tax subsidies were

[38] The Treasury discount rate of 4% for the government has been used. http://www.ustreas.gov/offices/domestic-finance/debt-management/interest-rate/yield.shtml

made available for qualifying advanced power system technology facilities in order to increase power generation through enhanced operational, economic, and environmental performance.

A production tax credit incentivizes plant operation as it is only paid when the plant generates electricity. Therefore the government avoids project technology risk when it deploys this incentive.[39]

Assumptions

- Worth 1.8 cents per kWh (nominal) up to an annual limit of $125 million.
- The facility owner could begin receiving the credits in 2014 for 8 years.
- The credit is applied to offset the tax liability in the year it is generated and any excess credit is carried forward for the following year until the credit is fully consumed.

Results

The cost of abatement becomes $163/t$CO_2$, a reduction of 11% from the base case. This is a higher reduction than the ITC because it is a more generous subsidy that equates to a total nominal value of approximately $500 million. This is over double the $207 million available through the ITC, hence this incentive appears to be just over twice as effective at reducing the cost of abatement than with the ITC.

Advantages

- The cost of producing low-carbon electricity is lowered through the tax savings from the tax credits.
- The ongoing generation of low carbon power is incentivized by linking the incentive to production.

[39] http://www.epatechforum.org/documents/2006-2007/2006-11-09/2006-11-09-IGCC%20POLICY%20&%20FINANCING%20--%20FINAL%20DRAFT%20PAPER%20-%20REVISED%2011-17-06.pdf

Disadvantages

- Like other tax instruments, production tax credits are expensive for the government. They count on a dollar-for-dollar basis. The total estimated cost to government in this case is $370 million. This is the present value of the tax savings from eight years of credits.
- The benefit is limited to eight years and is capped on a yearly basis (although this seems to be less of an issue with this 460 MW modeled plant not reaching this limit).
- The credits are not received until the project is generating electricity, reducing their value via discounting. This reduces the helpfulness of this mechanism in the start up phase of the plant when production is being ramped up to steady state.

4.1.4 TAX CREDITS FOR CO_2 STORAGE WITHOUT AND WITH EOR

Overview

This subsection analyzes the effect of a tax credit for CO_2 storage or CO_2 EOR. The 2009 ARRA, mentioned in section 2, provides a new tax credit for storage of CO_2, including for EOR projects. Like the production tax credit, this incentive differs from the investment tax credit in that it is only received when the plant is operating and storing CO_2.

Assumptions

ARRA rules have been used as the basis for modeling the impact of storage tax credits.

- These apply to facilities capturing more than 500,000 tonnes of CO_2 per year.
- A $20 per tonne tax credit is applied to the first 75 million tonnes of CO_2 stored if EOR is not being employed and $10 per tonne if EOR is being employed. These incentives are assumed to be in 2009 dollars and are indexed to inflation.
- It is assumed that until the 75 million tonne CO_2 limit is reached, the incentive is applicable to all stored CO_2 production from the plant, and that the plant continues to store CO_2 after the tax credit expires.
- The tax credit is equal to the amount of tax in the year it is generated. If it exceeds tax liability, it may be carried forward as an offset to tax liability for future years until it is consumed.

In order to analyze the benefit of the storage credit including EOR, it is necessary to make some further assumptions about how the project is operated. For this work it is assumed that the owner of the power plant with carbon capture will also own the carbon storage and EOR operation, therefore receiving all of the profit from a CO_2-EOR operation (in other words, a vertically integrated project is assumed).

All other assumptions used for this analysis are provided in Appendix C.

Results

For storage without EOR: Based on the above assumptions, the cost of abatement is \$141/tCO_2, a 22% decrease from the base case results. The total cost to the government is \$1,227 million. In this case, the tax credits offset the entire tax liability for the project including year 20 at which point some excess credits still remain.

Wind and solar currently receive support through tax credits, and in the past, this has helped encourage investment. Some wind and solar companies have not been able to use the tax credits directly themselves, but instead have partnered with banks, which use the credits instead. In this model, I assume the credits are sold to banks at the end of their life, which assumes a bank with the appetite to purchase these tax credits can be found.

For storage with EOR: The base case cost of abatement using CCS with EOR (\$73/tCO_2) is much lower than the cost without EOR (\$182/t CO_2). When the \$10/t EOR tax credit is applied to the first 75 million tonnes of CO_2 stored, the cost of abatement falls to \$51/tCO_2 which is a 29% decrease on the base case. The cost to the government is \$510 million. In the EOR case, there are no excess credits at the end of the 20 year project life as all credits have been consumed.

In absolute terms, the EOR incentive of \$10/t reduces the cost of abatement by \$22/t and without EOR the \$20/t incentive reduces the cost of abatement by \$41/t. This difference of a factor of two in the absolute cost of abatement reductions is indicative of the larger incentive being approximately twice the size of the EOR incentive.

Advantages

- Both incentives produce a significant reduction of the cost of abatement, and encourage higher levels of CO_2 capture and storage.

- Larger scale CCS is encouraged by signaling a minimum threshold capture requirement (500,000 tonnes CO_2 annually in this particular incentive).

Disadvantages

- A CO_2 related payment may discourage the use of the best possible fuel in favor of a more carbon-intensive alternative. For example, a CCS project that would run best on natural gas may switch to less efficient coal (including from lower grades of coal) in order to generate more CO_2 per kWh of power generated, creating more storage credits.
- The credits only begin applying when the plant is already operating so the effects of discounting again reduce the incentive's relative effect.
- This incentive, as with other tax incentives, is only useful provided that project developers are paying sufficient tax to make full use of it.

4.2 Loan Guarantees

Overview

The Loan Guarantee Program was introduced by Congress in 2005, as described in section 2, and is administrated by the DOE to fund investments in certain energy projects including industrial gasification projects that incorporate CCS. The DOE has been implementing the program and assessing applicants since then. By the early summer of 2010, the DOE had issued conditional commitments for loan guarantees to support 13 clean energy projects.[40]

Under the loan guarantee program, guarantees may be provided for up to 100% of a loan although there is a preference for loans which shall not exceed 80% of the total project cost. Project developers are required to make a significant equity contribution to the project to minimize the risks and costs of the loan guarantee to the government.

A credit subsidy premium must also be paid by the borrower (in this case borrower is the project developer). The credit subsidy premium is the net present value of the estimated long-

[40] http://www.lgprogram.energy.gov/press/070310.pdf

term cost to the U.S. government of the loan guaranteed.[41] The government calculates the credit subsidy premium based on an in-depth credit review of the project.

Assumptions

- The debt level was increased from the base case value of 60% to 80% of project cost and three separate cases were analyzed:[42]
    - Case 1: 100% Debt guarantee;
    - Case 2: 100% Debt guarantee with a credit subsidy premium payable (the current DOE requirement);
    - Case 3: 80% Debt guarantee with a credit subsidy premium payable (the DOE's preferred structure).
- In Case 1, the project developers do not have to pay the credit subsidy premium, as these funds are assumed to be appropriated so are not causing a long term cost to the U.S. government by being used. Case 2 and 3 assumes that project developers fund the credit subsidy premium payment through equity or subordinate debt. The credit subsidy is assumed to be 7.5 % of the guaranteed loan.
- The analysis incorporates a final maturity assumption of 20 years after debt issuance (Case 1 and 2). The 20% of the debt that is not guaranteed in Case 3 would not benefit from the loan guarantee but would have an amortization period of 20 years as in Case 1 and 2.
- The analysis assumes an interest rate of 6% for cost of debt that is guaranteed for Case 1 and 2. The remaining 20% of unguaranteed debt in Case 3 is assumed to cost 13.5%. The un-guaranteed debt is effectively subordinate to the guaranteed debt, resulting in a quasi-equity risk profile for which lenders will demand a higher interest rate (This structure is different from typical project financing and may be less attractive for lenders that would otherwise be interested in financing projects side-by-side with DOE). In this work, for

[41] As determined under the applicable provisions of the Federal Credit Reform Act of 1990, as amended ("FCRA").
[42] http://www.climatevision.gov/pdfs/Co-Production_Report.pdf

Case 3, the cost of capital for the guaranteed portion is assumed to be higher at 6.75%. The resulting cost of capital for the debt portion in Case 3 is then calculated to be 8.1%.

Results

- In Case 1, the abatement cost is \$111/tCO_2, a reduction of 39% from the base case. The cost to the government is the subsidy cost which is \$197 million. The borrower would benefit not only from decreased interest rates, but also from an increased debt amortization period (20 years versus 10 years for the base case) and from the increased debt portion of 80% in the project's financing, which reduces the weighted average cost of capital. This demonstrates the benefits of a loan guarantee in the form of lower interest costs, a longer amortization period, and increased leverage providing economic benefits to the project sponsors.
- In Case 2, the resultant abatement cost is \$128/tCO_2, a reduction of 30% from the base case. The borrower benefits from a decreased interest rate, a decreased weighted average cost of capital, increased leverage, and an increased debt amortization period of 20 years. To offset the expected cost to the government, the applicant would have to pay a credit subsidy premium of approximately \$197 million for the loan guarantee. This changes the effective debt/equity ratio from 80:20 in Case 1 to 74:26 in Case 2 as equity is spent in funding the credit subsidy. Case 2 has a zero net cost to the government because the project developer (rather than the government) pays the credit subsidy cost.
- In Case 3, the cost of abatement is \$147/tCO_2, a reduction of 19% from the base case results. Unlike the other cases, the project sponsor would not benefit from a reduced interest rate on the project's debt as the unguaranteed 20% debt carries a high 13.5% interest rate. However, the project still benefits relative to the base case from increased leverage and a longer debt amortization period. The project developers pay a credit subsidy premium for the loan guarantee of approximately \$158 million. The credit subsidy cost is lower in Case 3 than in Case 2 because of the smaller amount of guaranteed debt. Case 3 also has a zero net cost to the government.
- The equity share in Case 3 is bigger than in Case 1 by 3%, but less than the 4% that Case 2 is over Case 1. This is because the credit subsidy premium in Case 3 (\$158 million) is

smaller than Case 2 ($197 million), so Case 3 has a lower contribution from equity holders.

Table 5 – Loan Guarantee Analysis

Type of loan guarantee	Credit Subsidy Premium?	D/E	WACC	Cost of CO_2 avoided	% change from Base Case
100% Debt Guarantee	No	80/20	7.0%	111	39%
100% Debt Guarantee	Yes	76/24	7.7%	128	30%
80% Debt Guarantee	Yes	77/23	8.6%	147	19%

Advantages

Loan guarantees have a very favorable impact on the weighted average cost of capital, especially if the debt is non-recourse to the project owner because:

- they reduce interest rates;
- they increase the debt amortization period;
- they increase leverage in the project's capital structure; and therefore
- they reduce the weighted average cost of capital.

In addition, they increase the probability that the project owners will secure a loan because of the government guarantee to the lenders that they will be repaid. From the government's perspective, they permit a given amount of support to spread over more projects as probability suggests not all projects will default. This compares favorably with incentives like tax credits which apply on a dollar per dollar basis in the government budget.

Disadvantages

- Arranging the guarantees is complex. Only recently DOE has offered loan guarantees for clean energy projects under the 2005 loan guarantee program but on a conditional basis.
- The DOE requires assets pledged as collateral to include non-project related assets to ensure repayment. For some projects this removes the non-recourse benefit of project financing and may create uncertainty for the sponsors as to how many of their assets they will need to put at risk in order to obtain a loan guarantee.
- The applicant must submit a significant amount of information in order to apply for a loan guarantee, which costs project developers time and money. Furthermore some application fees may not be reimbursed, even if the project does not succeed in obtaining a guarantee.
- The true subsidy cost is unknown, but is still significant. The Office of Management and Budget (OMB) calculates the credit subsidy cost using a proprietary financial model. Neither the OMB nor DOE has made its model public.[43]

4.3 Federal Cost-Sharing Grants

Overview

Much of the U.S. support for CCS described in section 2 is administered through a federal grants program by the DOE (the Clean Coal Power Initiative, or CCPI). It is intended to promote early CCS plants through the provision of direct funding, thus reducing the projects' capital costs. In some cases grants carry provisions for repayment, but the repayment terms may have significant flexibility.

CCPI will provide $200 million every year from 2006 to 2014. The program is being implemented via successive solicitations (rounds). The maximum private sector cost-share in CCPI is 50%. There have been 12 projects to date in two rounds; of which about half are complete or still active, and half of which have not successfully proceeded.[44] In the most recent round (CCPI-3), DOE is providing up to $1 billion in funding to Hydrogen Energy California

[43] http://www.lw.com/upload/pubContent/_pdf/pub2558_1.pdf
[44] http://www.netl.doe.gov/technologies/coalpower/cctc/ccpi/index.html

and Summit Energy to construct new pre-combustion CCS power plants in California and Texas, and to Basin Electric Power Cooperative, AEP, and NRG Energy for retrofit of power plants with post-combustion CCS technology in North Dakota, West Virginia, and Texas.[45]

Assumptions

- For this work, the analysis considered two sizes of grant:
    - a large cost-sharing grant of $1.5 billion (representing 50% of the facility's construction costs), and
    - a smaller $250 million grant, which is a similar size to those grants actually made so far.
    - Both were modeled with and without a repayment requirement to DOE.
- The depreciable capital base for the plant is reduced by the amount of the grant to avoid double counting (for the scenarios where the grant is not repayable);
- The cost share is provided in proportion with the project's capital cost profile during construction.
- The scenarios with repayment assume that the grant will be repaid over 20 years in equal installments, starting in the first year of plant operation.
- Grants where repayment is required effectively function like a soft loan at a very low interest rate:
    - they may be treated as loans for tax purposes, expanding the depreciable amount compared to a grant without repayment;
    - they hold the same position as subordinate debt on the project's balance sheet; and
    - repayments are generally made after other investors have recouped their investments.

[45] http://www.netl.doe.gov/publications/press/2009/09043-DOE_Announces_CCPI_Projects.html

Results

In the large grant scenario, the cost of abatement where no repayment is required is $95/t$CO_2$. If repayment is required, the cost of abatement is $124/t$CO_2$. This equates to a reduction in the cost of abatement of 48% without repayment and 32% with repayment. The cost to the government is equal to $520 million if repayment is required (which is equal to the total grant value minus the present value of the repayments) and the grant amount ($1.5 billion) if repayment is not required.

It should be noted, however, that a $1.5 billion grant is nearly twice the size of the largest grant being talked about globally ($800 million for the Quest project in Canada, based at Shell's Scotford upgrader) and U.S. grants appear to be leveling out around $300-400 million. Therefore, whilst this level of grant is technically feasible, it is unlikely to be a much used mechanism. A smaller grant of the order of $250 million is more likely.

In the smaller grant scenario, the cost of abatement where no repayment is required is $168/t$CO_2$. If repayment is required, the cost of abatement is $173/t$CO_2$. This equates to a reduction in the cost of abatement of 8% without repayment and 5% with repayment. The cost to the government is equal to $87 million if repayment is required and the grant amount ($250 million) if repayment is not required.

Advantages

- Cost-sharing grants without repayment have the advantage of simply reducing the cost of the project to the developers.
- Even grants which require repayment are beneficial as they are equivalent to soft loans.

Disadvantages

Grants are expensive to the government – a direct observable subsidy to CCS project owners which, if repaid, will be on soft terms. The experience of the history of DOE grant giving also highlights practical complexities:

- In some cases, grants require the grantee to secure additional funding to be eligible.
- The applications, agreements, record-keeping, and reporting requirements required may be both more difficult than and inconsistent with standard business practices.

- The relationship between federal entities and private enterprise are complicated and restricted which in some cases could potentially result in interference with projects.

4.4 Allocation of Multiple Emissions Allowances

Overview

The Waxman-Markey bill provides incentives for early deployment of CCS in the form of bonus allowances from the emissions allowances under a cap and trade program, as described in section 2. To be eligible to receive emission allowances, the owner of a project must implement CCS at an electric generating unit that meets certain standards relating to capacity, fuel source, total CO_2 stored and permitting.

Assumptions

Specific assumptions in the analysis of this incentive are designed to match the plan envisaged in the Waxman-Markey bill:

- Any requirements for receiving emissions allowances, such as plant size and carbon capture totals, are assumed to be met by the plant.
- It assumes CO_2 allowances are allocated to the project for free. These were calculated based on section 782(a)(f) of H.R.2454, where allowances are granted according to the total tonnes of CO_2 stored[46] per year by a project. The number of freely allocated allowances equals the ratio of bonus allowance value to the market value of CO_2 multiplied by the amount of CO_2 stored. This formula provides certainty to utilities and investors in terms of the value of the incentive and is sufficient to almost cover the incremental cost of deploying CCS.
- The bonus allowance value is assumed to be \$90/tCO_2 stored as proposed in the bill, with some adjustments to account for changes in the market carbon price and inflation (assuming 90% capture rate).

[46] The definition appears subtly differently in H.R. 2454, where it implies "tonnes avoided" rather than "tonnes stored." It is the author's understanding that the intention of the wording of "tonnes avoided" used in the bill actually refers to "tonnes captured."

- The market value of each CO_2 allowance is assumed to be approximately \$40/tCO_2 in 2014 (in real terms), increasing to approximately \$80/tCO_2 in 2030.[47] This is derived from MIT analysis based on a policy scenario whereby all nations apply the same price on carbon emissions and this price rises at a constant real rate of 4% per year.
- These allowances are assumed to be given for the first 10 years of CCS operation.

Results

These assumptions result in a cost of abatement of \$41/tCO_2, a 77% decrease from the base case results. The cost to government is \$3,761 million. I assume that the government owns these allowances, if they are not allocated to CCS projects. However, they might be given to other parties, affected by the cap and trade program, in order to minimize their costs.

Advantages

- Emissions allocation schemes such as those envisaged in Waxman-Markey have the advantage of sending a signal about support of CCS, and may incentivize U.S. firms to invest in CCS and hence generate a significant amount of funding in total.

Disadvantages

- Free allocation of large volumes of credits will reduce the funds raised by the emissions trading scheme, which could potentially be spent on other forms of CO_2 abatement.
- Additionally, certain features of the scheme (such as the way rebates are provided to consumers and the method of calculation of allocations) are designed in ways that may interfere with the incentives of firms and consumers.[48]

4.5 Contracts for Difference on the Carbon Price

Overview

A state or federal government could agree with CCS project developers on a contract for difference (CfD) against the carbon price. The CfD could specify a threshold price (strike price) for carbon (for example \$50/tCO_2) with payments to or from the CCS project if the carbon price

[47] *Assessment of U.S. Cap-and-Trade Proposals*, MIT, 2007
[48] http://climateprogress.org/2009/05/28/robert-stavins-waxman-markey-allocation/

differed from this level. This is a mechanism that the UK government has stated is their preferred choice currently for disbursing funds to CCS projects.

A one-way CfD would provide additional revenue to the CCS project if the carbon price were below the strike price. A two-way CfD would require payments to the funding entity from the project owners if the carbon price were above the strike price. Other more complex variants could be used, for example the use of two separate strike prices over time.

The objective of such a mechanism would be to guarantee a certain level of reward to a project independent of the carbon price. The implicit assumption is that the project will benefit from any rise in the carbon price through higher market prices for electricity or other products that the project produces. For example, in a competitive electricity market an increase in the carbon price would increase market prices by more than the costs to generators with CCS, because the emissions of other plants will at the margin be greater than the plant with CCS.

Under such an arrangement the price adjustment under the CfD will seek to offset the changes in revenue to the project due to changes in the carbon price. In its simplest form the CfD for a power project will have the structure shown in Equation 1.

Equation 1 - Typical CfD Formula

$$\boxed{\text{Payment per MWh} = (EM - EC) \,.\, (Ps - C)}$$

Where:

EM is the emissions of CO_2 per MWh from marginal plant on the system

EC is the emissions of CO_2 per MWh from the CCS plant

Ps is the contract strike price, a defined carbon price in $/t$CO_2$

C is the carbon price prevailing in the market into which the electricity is sold.

There is no adjustment for other influences on revenue, such as fluctuations in market power prices due to changes in fuel prices.

Assumptions

- Carbon prices (C) are modeled using MIT assumptions as used previously in this paper.

- Coal plants are assumed to be at the margin. EM is assumed to be 0.836 tonne/MWh, and EC is assumed to be 0.160 tonne/MWh.
- Strike price (Ps) is assumed to be \$60/tCO_2 (in 2014) indexed to inflation and also increasing at real rate of 4% per year as in the MIT analysis.

Results

These assumptions result in a cost of abatement of \$169/tCO_2, a 7% decrease from the base case results. For \$90/t strike price the cost of abatement is \$128/tCO_2, a decrease of 30% from base case results. The net cost to the government is assumed to be zero for this incentive with the government raising rather than appropriating funds, but it may be costly in practice.

Advantages

A CfD mechanism could have benefits for both investors and the funding agency:

- Investors could be protected against the risk of low carbon prices;
- The risk of windfall profits in the event of high carbon prices could be reduced by a two-way CfD, potentially making the project more politically acceptable;
- The contract could be presented as a risk management instrument rather than a subsidy, potentially making it more acceptable to legislators.

If such CfDs were tradable they may also be bought by other parties and used as financial instruments in ways which are intrinsically difficult to predict. It may be desirable to restrict tradability in order to safeguard the objective of support specific projects.

Disadvantages

- The emissions of the marginal plant on the system are likely to be difficult to predict because there will be plants with different efficiencies and in many cases different fuels setting the price over the year. The weighting of these in any average will be intrinsically uncertain. The assumed parameter for emissions from the marginal plant is thus unlikely to match exactly the actual effect of the carbon price on the electricity price even in a competitive power market such as Texas.

- In many markets CCS plants are likely to be remunerated by Power Purchase Agreements (PPAs) which may not include terms that vary the power price with the carbon price (other than potentially to allow pass through of additional generation costs). This could lead to the position where support from a CfD mechanism drops with increasing carbon prices, but power price support through the PPA stays constant which causes increased risk to the project. This risk could, however, be mitigated through ensuring the PPA contract when combined with a CfD is agreeable to the project developer, although the practicalities of achieving this in practice may be uncertain.

4.6 Combination of Incentives

This subsection presents the impact on the base case of a combination of several incentives that are authorized or being considered in the United States today. Two combination cases are considered.

4.6.1 COMBINATION CASE 1

This case combines the following financial incentives:

1. Loan Guarantee type 2 (see subsection 4.2): This loan guarantee covers 100% of the project debt and the project sponsor pays the credit subsidy premium using equity or subordinate debt.
2. A $250 million federal grant without a re-payment requirement.
3. A tax credit for storage.

In this case, the cost of abatement declines to $90/t which is a 51% reduction on the base case. The base case debt-to-equity ratio assumption is 60:40. The loan guarantee incentive permits greater leverage, so this analysis assumes an 80:20 debt-to-equity ratio, which decreases to 76:24 because of the requirement to fund the credit subsidy premium with equity. In this combination case, excess storage credits are sold to banks in year 20.

4.6.2 COMBINATION CASE 2

This case combines the following financial incentives:

1. A $250 million federal grant without a re-payment requirement.
2. A carbon trading scheme that includes a bonus allowances of \$90/tCO_2 as explained in the allowance allocation subsection.
3. Accelerated depreciation
4. Tax credit for storage

This case results in a cost of abatement of \$0/tCO_2, resulting in the full costs of CCS being covered. The large value of the bonus allowances through Waxman-Markey as previously shown in subsection 4.4 results in an 80% drop in the cost of abatement by itself. This case is designed to demonstrate that it is not a stretch to bridge the remaining cost of CCS, but the price to government may be steep.

As with any modeling exercise, the results here rely on the assumptions built into the model and thus should be interpreted as an indication of the direction and magnitude of potential impacts of these incentives combined rather than an exact prediction. Even this case may not cover all the incremental costs of other CCS projects.

4.7 Economic Summary

Table 6 below presents the economics associated with each of the incentive mechanisms as modeled. The magnitude of the savings under each of the mechanisms is a typical value and levels of support under each mechanism can vary greatly. The numbers should thus be taken as indicative of the general scale of contribution only.

Table 6 – Summary of incentives analyzed (460MW net IGCC with 90% CCS)[49]

	Incentive Type	Comments	Cost of CO_2 Avoided ($/tonne)	% change from Base Case[50]	Cost to Government (US$m)[51]
1	Investment Tax Credit	-	174	5%	176
2	Accelerated Depreciation	-	179	2%	36
3	Production Tax Credit	-	163	11%	370
4	Tax Credit for CO_2 storage	-	141	22%	1,227
	Tax Credit for CO_2 EOR	-	51	29%	510
5	100% Loan Guarantee	Government pays credit subsidy	111	39%	197
	100% Loan Guarantee	Self-pay credit subsidy	128	30%	0
	80% Loan Guarantee	Self-pay credit subsidy	147	19%	0
6	50% Cost-Sharing Grants	Without repayment	95	48%	1,495
	50% Cost-Sharing Grants	With repayment	124	32%	520
	$250 million grant	Without repayment	168	8%	250
	$250 million grant	With repayment	173	5%	87
7	Allocation of multiple emissions allowances	-	41	77%	3,761
8	Contract for difference on the carbon price	strike price=$60/t$CO_2$	169	7%	0
		strike price=$90/t$CO_2$	128	30%	0
9	Combination Case 1	Loan guarantee, $250m grant, CO_2 storage credit	90	51%	1,088
10	Combination Case 2	Allocation of allowances, $250m grant, accelerated depreciation, CO_2 storage credit	0	100%	4,707

[49] The model input data is summarized in Appendices B and C
[50] Base case costs are consistently $182/t except the EOR base case which is $73/t.
[51] The net present value cost to the federal government is in 2009 dollars.

Investment tax credits (ITCs) decrease the effective cost of the plant by offsetting against corporate profit taxes each year until the total agreed ITC value is credited. The benefit of ITCs depends on:

- the percentage of the plant to which the incentive applies;
- the level of the ITC; and
- the ability of a project sponsor to utilize the tax benefit in the year it is generated.

Current tax codes confine ITCs to the most 'innovative' portion of the plant — the gasification subsystem, for example, and not the turbines or coal handling systems. As a result, the impact of current ITCs on the cost of abatement is small (only 5%). The larger the percentage of the plant that an ITC can be applied against and the higher the level of the ITC, the lower the effective cost of the capital equipment and the larger the reduction in the cost of abatement.

Benefits of tax incentives depend on the tax loss absorption capacity of project sponsors and the timing of benefits. Tax incentives can create a one-time tax benefit or a continued stream of tax credits or tax losses. A project sponsor can only realize the benefits associated with a tax incentive if it has sufficient tax liability to absorb the tax credit or tax loss.

The cash flow of a project will depend on the timing of these benefits. Tax incentives (such as investment tax credits and accelerated depreciation) decrease the cost of investing in capital equipment by providing early cash flow when the project starts operating. The early cash flow to equity helps improve equity returns more than tax incentives that spread the benefit over time.

Production-based tax credits provide cash based on the level of the tax credit and the quantity of electricity produced. However, the cost to the government is high. To the extent the law permits, the government could tailor the level of a tax credit depending on the support a plant would need given the prevailing price of electricity.

Storage tax credits based on the amount of CO_2 stored is an effective incentive for encouraging sequestration. It is unique in that it directly incentivizes storage; a plant owner will earn no tax credit unless CO_2 is actually stored. (By comparison, ITCs create an incentive to construct facilities that have the capacity to store CO_2, but since these tax credits are granted once such a facility has been constructed, they do not create an ongoing incentive to operate the storing facilities.)

EOR presents an additional opportunity to stimulate early commercial projects as shown in the previous work by the author. The use of carbon credits in EOR projects is still uncertain. Although in the absence of credits, the value of the CO_2 in EOR goes some way to bridging the CCS cost gap.

Loan Guarantees: A new CCS facility is a high risk facility, since there is little experience from which to value the risks. Further, it is a stretch in the current credit environment to secure a loan without any collateral. Therefore the ability to finance a project through non-recourse borrowing backed by a federal loan guarantee is a powerful inducement for project developers and equity providers to develop and invest in CCS projects.

Loan guarantees help to decrease the overall project risk that equity and debt investors face and help partially to offset technology, construction, and market risks associated with a project. A loan guarantee can therefore increase the prospects of obtaining financing, increase leverage, and reduce the interest rate paid.

The analysis shows that loan guarantees can provide significant improvements in the cost of abatement to projects that utilize project finance structuring. Loan guarantees decrease the cost of abatement more effectively, and at a lower cost to government, than tax incentives.

The effectiveness of a loan guarantee depends on its structure. Several factors play a role: whether the guarantee covers the entirety or a portion of the debt, what risks the loan guarantee addresses, whether the guaranteed portion of the debt is amortized at the same rate as the un-guaranteed portion, and whether the applicant or the government funds the credit subsidy premium for the loan guarantee.

Cost sharing and grants: A 50% cost-share grant improves the economics of early CCS plant significantly, enabling early commercial projects by lowering capital costs paid by the sponsor, although such a grant is expensive to government. By enabling construction of the first few plants utilizing CCS, cost-share agreements of this magnitude would help mitigate technology and integration risks in subsequent plants, which otherwise might not be built. This high level of capital grant is unlikely to be widely used, however, with most U.S. grants appearing to level out between $300 and $400 million.

Relatively small cost-share grants do not help the financial prospects of early IGCC with CCS plants as significantly as a 50% cost share, and interest-free payback of such grants does not materially impact the economics of the incentive. However, small grants early in the development of a project, when risk is greatest, may increase the chance of project completion and are much more likely to be secured than a 50% cost share.

Allocation of free emissions allowances: Emissions allowances in an emissions trading scheme under which the IGCC with CCS plant may operate can be allocated freely by the government or ruling body. This mechanism leads to a substantial cost reduction depending on the existence and magnitude of the bonus allowance value. This option, envisaged Waxman-Markey, has the advantage of signaling strong support of CCS, and may generate a significant amount of funding in total. Free allocation of large volumes of credits will, however, reduce the funds available for other uses, which could potentially include other forms of CO_2 abatement. Additionally, certain features of the scheme (such as the way rebates are provided to consumers the method of calculation of allocations) are designed in ways that may interfere with the incentives of firms and consumers.

Contract for difference (CfD): This is a mechanism in which a guaranteed emissions price is set by the provision of funding to make up the difference between prevailing carbon price levels and an agreed price sufficient to support CCS. The implicit assumption is that the project will benefit from any rise in the carbon price through higher market prices for electricity or other products that the project produces. This mechanism could potentially provide the opportunity for the government and tax payers to claw-back funds in the event of higher than expected carbon prices.

Overview of individual mechanisms: Tables 7 and 8 below present an overview of the chosen incentives from the perspective of a project developer and government by considering certain key drivers. The preference of either the project developer or government is indicated by a range of ticks, dashes and crosses which correspond to a range of good to bad preferences respectively. These preferences are drawn from the analysis made here of the different financial incentives.

Table 7 – Overview of mechanisms from the project developer perspective

	Level of Cost Reduction	Timing of benefit	Likely to be awarded	Helps finance-ability of project	Overall
Investment Tax Credit	~	✓	✓	~	✓
Accelerated Depreciation	×	✓	✓	~	~
Production Tax Credit	~	~	✓	~	~
Tax Credit for CO_2 sequestration	✓	~	~	~	~
Tax Credit for CO_2 EOR	✓	~	~	~	~
Loan Guarantee	✓	~	~	✓	✓
50% Cost-Sharing Grants	✓✓	✓	×	~	✓
$250 million grant	~	✓	✓	~	✓
Allocation of multiple emissions allowances	✓✓	~	✓	~	✓
Contract for difference on the carbon price	~	~	~	~	~

Table 8 - Overview of mechanisms from the Government perspective

	Cost to Govt.	Encourage Operation	Overall
Investment Tax Credit	~	×	~
Accelerated Depreciation	✓	×	~
Production Tax Credit	~	✓	✓
Tax Credit for CO_2 sequestration	×	✓	~
Tax Credit for CO_2 EOR	×	✓	~
Debt Guarantee	✓	×	~
50% Cost-Sharing Grants	×	×	×
$250 million grant	✓	×	~
Allocation of multiple emissions allowances	××	×	×
Contract for difference on the carbon price	✓	×	~

Combinations of incentives: These cases utilize three or four incentives together to reduce cost of CO_2 avoided to the point that the costs reach the plausible long-range costs of CCS plants. If these incentive combinations were matched with a high, stable carbon price ($35-$70/t CO_2), or a premium power price authorized by a Public Utilities Commission (PUC), then financing and development of first-of-a-kind CCS plants would likely become possible. However, the probability of such a scenario is low, given the present political and fiscal climate.

4.8 Conclusions Summary

The incentives analyzed provide a broad range of options that policymakers can utilize to improve the prospects for early commercial IGCC/CCS plants. Project developers may prefer incentives that improve the discounted cash flow of the project and reduce risk as much as possible, such as generous allocation of emissions allowances during operation, or smaller incentives that reduce capital costs or financing costs early in the project. Governments would tend to favor incentives that encourage operation at lowest cost to government, such as tax credits for EOR.

In general, incentives that decrease the capital and financing cost of the plant seem to provide the best balance between providing incentives to CCS investors, while keeping the costs to the government low. However operating subsidies can also be valuable and are attractive from a public policy point of view as they provide incentives for operation and therefore emissions abatement.

State-level incentives can also help promote investment by improving the business climate and speeding development of a project. State incentives can be targeted to provide benefits in numerous ways. For example, development grants assist in developing the project and provide funding assistance before the project reaches financial close. Employment-related tax incentives decrease the cost of employing state residents. In the long-term, states can assist early CCS projects by funding research to develop technology by making necessary infrastructure available, and by facilitating or accelerating permits for a project. While not discussed in this paper, the importance of these incentives should be analyzed in future work.

Different combinations of government incentives can reduce the costs of capital investment substantially. The ideal mix of the incentives will vary depending on project-specific factors, and whether the project is a first-of-a-kind or a later early commercial plant.

5. CONCLUSIONS

No single mechanism is likely to be sufficient to finance CCS through its deployment and commercialization, nor is it appropriate that any should do so given the range of market failures to be addressed and the different characteristics of the differing stages of CCS deployment. Instead an appropriate policy package will comprise a mix of mechanisms.

Public Utilities Commissions (or PUCs) will play a major role in most states in assessing whether a CCS project will be in the interests of rate payers. In making the comparison between CCS projects and conventional generation, PUCs should take into account the effect of a carbon price on the costs of generation from different sources. However it appears a carbon price is likely to be too low in the absence of further support to make CCS economic when compared with conventional generation.

The national benefits of early CCS projects imply the need for national support. The proposed payment of \$90/tCO_2 available to high capture rate CCS projects, as proposed in the Waxman-Markey bill, would be automatically granted for early projects. This would encourage their early development and greatly reduce the burden on local ratepayers. Mechanisms such as the current sequestration tax credit may have similar advantages.

CCS projects are capital intensive so loan guarantees have the potential to lower costs effectively. They may form a useful part of a wider policy package, provided that their implementation is kept simple so as not to place an undue burden on project developers.

Capital grants and investment tax credits can also reduce the burdens on ratepayers as they provide a known upfront payment which will be valuable to investors.

As the industry begins to mature beyond the first few GW of projects, the level of support can be adjusted to reflect the cost information from early projects and likely cost reductions from scale and learning. Support is likely to take the form of premium prices authorized by the PUC taking into account any prevailing carbon prices, perhaps with production tax credits continuing to be available. Investment tax credits and capital grants for technology development seem less likely to play a major role in large scale commercial roll-out due to difficulties of securing such large funding to be dispersed in such a short space of time.

Throughout the process of assembling a package of support PUCs will maintain downward pressure on costs to minimize the burden on ratepayers. This may in some cases lead to formal tendering to select from competing projects. In competitive power markets, notably Electric Reliability Council of Texas, there will be direct competitive pressures.

A suitably complementary range of federal and state mechanisms such as that outlined here, combined with the active support of PUCs is likely to be effective in stimulating the urgently needed deployment of CCS.

APPENDIX A: LIMITATIONS OF THIS WORK

This paper is subject to a number of limitations, including the following.

Exclusion of developments after January 2010. This paper draws on experience to date of policy for CCS and other low-carbon technologies in North America, Europe, and Australia. The situation is rapidly changing in many jurisdictions and the reader should note that there may have been changes from the time some of the work underlying this paper was carried out (late 2009) and the present. References to the Waxman-Markey bill are to the version that was passed by the U.S. House of Representatives, except where noted otherwise.

Limited consideration of value chain structure. The effect of different forms of incentive may depend on where in the value chain they are applied. This is considered only briefly in the current work. Examination of how the CCS value chain might be structured commercially, and of how rewards may be distributed along the chain, are large topics in its own right and might have further implications on the effects of incentive mechanisms.

Assumptions on costs. Analysis of the financial effects of policy draws on cost data presented in previous work by Al-Juaied and Whitmore and may not reflect changes since then. That work suggested costs for CCS on a 2008 basis in the range \$120-180/tCO_2 for early plant, falling to \$30-50/tCO_2 for Nth of a kind plant, excluding costs of transport and storage. The cost per MWh of low-carbon generation with CCS was found to be similar to that of other low-carbon technologies, except for onshore wind at a good site which was cheaper and solar PV which was more expensive. Similar cost estimates are adopted for the analysis in the current work. However most of the conclusions in this paper are not dependent on the precise magnitude of the costs assumed.

APPENDIX B: FINANCIAL BASE-CASE ASSUMPTIONS

MEANS OF FINANCE	Assumption	Comments
Term Loan	60%	Early CCS is risky and therefore D/E is limited to 60%.
Equity Share Capital	40%	D/E ratio of 60/40 could also meet equity investors' rate of return targets at minimum level.

Inflation	2%	Inflation rate will remain constant over the life of the project. In this work the evaluation is made in current dollars using the nominal (inflated) rate of return.
Tax Rate (TR)	35%	US Corporate tax rate.
Cost of Debt (CD)	7%	CD in this work is assumed to be 7%.
Cost of Equity (CE)	19.5%	Projects with added risk elements and newer, less proven technologies such as IGCC with CCS might run up into the mid teens and even as high as 18-20%. In this work cost of equity is assumed to be 19.5%.[52]
Estimated WACC (nominal)	10.5%	WACC = % Equity x CE + %Debt x CD x (1-TR)
Debt Amortization Period (years)	10	The debt is repaid in equal principal installment payments over 10 years.

Heat Rate (Btu/kWh)	12,000	The heat content of bituminous coal ranges from 10,500 to 14,000 BTU/lb. This value is on an HHV basis.
Fuel Cost ($/MMBtu)	1.8	These fuel prices are on an HHV basis.
Annual Escalation	2%	These inputs for fuel are in nominal terms.
Capital Cost ($/kW)	6,500	The capital cost includes the cost of capture and compression.
Fixed O&M ($/kW-yr)	90	Fixed costs include labor and other costs that are independent of the plant output

[52] http://www.netl.doe.gov/energy-analyses/pubs/Project%20Finance%20Parameters%20-%20Final%20Report%20-%20Sept%202008_1.pdf.

		level.
Variable O&M ($/MWh)	2	Variable O&M costs include all consumable items, spare parts, and labor that fluctuate with the actual plant output.
Annual Escalation	2%	These inputs for fixed and variable operating expenses are in nominal terms
Interest on WC Loan	13.5%	A working capital (WC) loan is not used to buy long term assets or investments. Instead it's used to clear up accounts payable. In this analysis is set at 75% of total current assets.
Interest on Construction Loan	7%[53]	Construction loan is 50% of the hard cost. Hard cost is the actual costs such as equipment and engineering expenses. Soft cost is the interest incurred during construction.
Construction period	5 years	The construction period is used to calculate the interest expenses incurred during the construction period. The expenditure profile is assumed as follows: 5% (year1), 30% (year2), 35% (year3), 20% (year4) and 10% (year5). Equity investment is made as construction proceeds and represents the percentage of the total project cost that the investors agreed to fund.
Plant life	20 years	Plant life is assumed to be 20 yrs for early CCS. Plant may last longer.
Depreciation	20-year MARCS	The 20 year Modified Accelerated Cost Recovery System (MACRS) method is assumed in the base case.

Capacity of the Plant (MWe)	460	Net power output.
Plant Load Factor	85%	A capacity factor of 85% is used as the basis for the base case. However with CCS such first of kind plants may not be dispatched to such a high capacity factor.
Start up time (year 1)	3 months	To account for the plant start-up period. Load factor for the remainder of year 1 is

[53] Cost of debt and the cost of the construction loan are assumed to be the same although it would seem to be that the latter should be higher given the higher risk borne by lenders during the construction stage in project finance, however, this would not make any changes to the conclusions.

		60%.
A/C Receivable Cycle (Days)	45	To calculate accounts receivable as [revenue x # days receivable]/365.
A/C Payable Cycle fuel (Days)	60	To calculate operating cash to cover fuel costs as [cost of fuel x # days payable]/365.
A/C Payable Cycle O&M (Days)	30	To calculate operating cash to cover O&M costs as [O&M costs x # days payable]/365.
Number of Operating Days	365	The number of days in a year.
Initial Working Capital Requirement	5%	Initial Working capital, at 5% of the total project cost, is the fund that is set up in the year prior to operations to initially fund the Working Capital account.
Insurance and property taxes	2%	2% of installed costs per year and included as an operating cost.

Capture Rate	90%	Full capture (defined as 90% of the total). CO_2 emissions before capture is 160 g/kWh.
Transport and Storage, $/tonne	10	The costs of storage and transportation are set to 10 $/tonne. Other several types of costs such as transport of coal, liability and regulatory issues for CCS are ignored.

APPENDIX C: FINANCIAL CO_2-EOR CASE ASSUMPTIONS

Capital Costs ($ Million)	
Pipeline	80
CO_2 Recycle Plant	90
Injection Pump	15
Construction	100
O&M ($/BBl)	
Pipeline Operation	0.28
Other Costs	5
Oil Price ($/Bbl)	40
CO_2 Injected/Day	206 MMscf
Over Project Life	1,500,150 MMscf
CO_2 Injected/Bbl	0.529 tonnes/Bbl
Total Oil Production (Million Barrels)	150
Total CO_2 Demanded (Million Tonnes)	79.4
Produced Oil/tonne CO_2	1.89 Bbl/tonnes

APPENDIX D: MECHANISMS FOR AWARDING FUNDING

This appendix considers how support for CCS might be implemented, in particular how funds might be allocated between projects to assist them move through the critical stages of project development to operation.

Funding should be allocated towards those projects that promise the greatest opportunities to accelerate the construction and operation of CCS projects. Engagement should be with those projects in the early stage of development, which face real obstacles to their success, and towards which can have an immediate impact.

There are four broad types of mechanism for allocating funding to projects:

- Automatic qualification according to preset criteria;
- Administrative decision;
- Competition between projects for award of funding; and
- Reverse auctions, which differ from competitions mainly in their use of price as the main selection criterion

Each of these is now reviewed for their ability to efficiently allocate funding to CCS projects.

Automatic Qualification According to Set Criteria

All projects meeting set criteria may qualify for a specified level of support, perhaps up to some capacity limit. Examples of this type of mechanism include support for the first 6GW of CCS capacity proposed under the Waxman-Markey bill, and feed-in-tariffs, which are used to support renewables in many European countries.

Such support mechanisms have a number of advantages for project developers:

- It is known from an early stage whether a project will qualify and the benefits can thus be factored in to estimates of a project's Net Present Value from an early stage in its development, encouraging developers to progress the project through to later stages.
- The certainty of the level and duration of project cashflows may allow for reduced rates of return, so lowering project costs. It has been estimated that the required rates of return for wind energy projects are typically 1-2% lower under a feed-in-tariff system, than for a green certificate scheme where revenues are less certain.[54]
- If the level of support for new projects reduces over time it may encourage early stage investments in CCS projects, thus fostering the development of the technology.

The greatest difficulty in setting support of this type is the unknown cost of technologies such as CCS that are in the very early stages of deployment. This difficulty will be exacerbated by the variability of costs between projects. Furthermore, there is likely to be strong political resistance to any payment which results in excessive returns. These difficulties are likely to lead to subsidy thresholds being set at a level which may reward most, but not all, of the additional costs of early CCS projects. The remaining subsidy is paid by local electricity ratepayers, or perhaps through other support mechanisms such as capital grants or investment tax credits. This retains most of the advantages of an automatic mechanism while maintaining appropriate downward pressure on the costs and returns of early projects.

[54] Implementation of EU 2020 renewable Target in the UK Electricity Sector, Redpoint, Trilemma UK, University of Cambridge Technical Services, Table 8.

Administrative Decision

It is possible to allocate support without any competition or tender process. For example, in the EU, €1billion was awarded under an economic stimulus package (the European Energy Programme for Recovery - EEPR) to CCS projects selected from a shortlist. Both the shortlisting and the subsequent project selection have been by administrative decision alone.

Such a mechanism can result in prompt allocation of some funding. However it lacks transparency, acceptability to the range of stakeholders and any process for ensuring value for money. Its use in the EU appears to reflect the particular circumstances of the stimulus funding and is not intended to form the basis of a wider model.

An apparently more successful example, reflecting different circumstances for CCS in a different political culture, is the Iwaki CCS project in Japan.[55] The shortage of practical sinks in Japan allows for only one full-scale project at present. A single project (converting an existing IGCC to become a pre-combustion CCS plant) with the participation of a wide range of companies, including all the Japanese utilities and oil refiners, appears to have represented a mechanism for getting the greatest benefit for Japanese industry out of this single opportunity. However this clearly does not apply to the situation in the United States where there are many available sinks.

Advantages of co-operation similar to those in the Japanese example may be obtained in the United States from Futuregen, a CCS project in which a number of companies are participating. However, Futuregen has undergone both open review and a competitive process on site selection, and is only one of many proposed CCS projects in the United States. Allocation of central funding by administrative decision alone, without any open review or competitive process, does not offer a useful model for future funding arrangements in the United States.

[55] The Iwaki is an IGCC project in Japan that is already operating. The project will add carbon capture equipment and inject the CO_2 captured offshore in a depleted gas field. It is receiving support from the government for construction but the exact details of support are unclear.

Competitions

Open competitions have already proved an effective means of disbursing funds rapidly to CCS projects:

- In Alberta, Canada, four projects have been selected following a competitive process lasting approximately one year.
- In the US, the most recent round of cost-sharing grants from the DOE (the CCPI-3 program) was awarded to two projects within six months of the original application.
- Competitive processes are being introduced in Australia, again over the timescale of approximately one year, and a similar process is likely for some European projects.

In all cases there has been a well defined tender process allowing a range of interested parties to bid for support according to how well their projects meet policy objectives.

However the experience of the UK government's competition for a CCS demonstration project offers an example of how such competitions can prove protracted, at least at first. The UK government first prescribed its options, and thus the scope for competition, by restricting eligibility to the demonstration of post-combustion CCS technology. The schedule has subsequently proved protracted with the competition, first announced in 2007, likely to produce a result in either 2010 or 2011. The reasons for this are unclear, but appear to include lack of consistent political impetus, uncertainties about the availability of funding, the time taken to develop detailed engineering studies for a large scale project, and the slow development of a regulatory regime governing potential sinks. As these issues have been resolved the competition appears to be progressing more successfully, but the experience seems to suggest that overly prescribing options in a competition is potentially not conducive to quick decision making.

Competitive processes may become cumbersome if employed for very large numbers of CCS plants during widespread deployment, rather than the relatively few plants that form part of an initial demonstration. Correspondingly they may have a greater role to play in early deployment than in subsequent large scale roll-out.

Reverse Auctions

Reverse auctions have received considerable attention recently as a possible means of allocating support to CCS, and are proposed under the Waxman-Markey bill as a dispersal mechanism once the first 6 GW has been built. In broad terms, proposals envisage CCS projects bidding in a price required to implement the project. The price could be specified as either per MWh or per tonne of CO_2. The lowest price offers would be selected. It is intended to result in the lowest cost projects that meet the objective being chosen and thus the greatest amount of CCS deployment for limited funds. This model draws on extensive experience of procurement practice where reverse auctions are used to secure best value for money from suppliers.

Reverse auctions work best in mature markets for well defined commodity purchases where the supply curve is continuous and well defined, that is:

- with a homogenous product,
- with numerous sellers, and
- where costs are well known by sellers.

There are certain issues that could potentially be relevant in applying reverse auctions to the benefit of CCS projects. These are detailed here:

A non-homogenous product. In the early stages of CCS development the policy goal will likely comprise various dimensions, including the demonstration of different technologies, fuels, sink types, locations and scales. There will not be a single homogenous product such as a tonne of emissions avoided to be bought. In these circumstances, where support will be buying technology development as well as emissions abatement, choosing projects with the lowest price per tonne CO_2 or per MWh will not always be optimal. In contrast a competition allows a range of objectives to be weighed against each other.

It may be possible to address this problem by creating a number of separate auctions for different categories of project, as proposed under Waxman-Markey, which envisages up to five separate auctions for different types of project. However, this will risk reducing the number of projects competing with each other within a given auction category, limiting the degree of price competition.

Limited numbers of projects. The small number of credible projects in early stages of CCS development may lead to reverse auctions not being competitive enough to secure good value for money (which would be exacerbated if the reverse auction were subdivided into several separate auctions for different technologies or fuels).

Costs are not well known even to project developers. Auctions are likely to experience a high failure rate as projects that under-estimate costs, and so bid a low price, get chosen. Developers may underestimate costs either inadvertently, because they have carried out inadequately detailed studies, or deliberately, because they have adopted a strategy of bidding aggressively.

The potential problems associated with reverse auctions are exacerbated by the difficulties of coordinating state and federal level funding. Most projects will need approval from their state's PUC to proceed. Prevailing power prices will differ between states; and the willingness of PUCs to pay a premium above prices will also differ.

This may lead to a situation in which projects with similar costs bid quite different amounts into an auction because of different amounts of state level funding. Consequently projects which are lower cost overall may not be selected.

A more serious difficulty is created when the level of funding available at the state level for a particular project is unknown. A project may be bidding in to a federal auction without knowing how much funding it needs to be able to achieve PUC approval. This is likely to further reduce the ability of the auction to reveal costs and increase the likelihood of non-delivery as some projects that bid aggressively in the auction fail to win sufficient federal funding to secure PUC approval.

Examples of reverse auctions in practice

Evidence of reverse auctions potentially not resulting in the desired outcome for early phases of technology development come from experience in the UK and Ireland where they were employed for renewables. In the UK only 25% of selected schemes were eventually built, in Ireland only 38% were built. Both schemes have now been replaced with quantity obligations using tradable green certificates.

There almost no other examples of the use of reverse auctions for procuring low carbon power of which the author is aware. There is use of a similar process for procurement of some offshore wind power in Denmark, but this takes into account non-price factors and so more closely resembles a tender or competition than a reverse auction.

Conclusion on reverse auctions

Governments may see a perceived advantage to reverse auctions under certain circumstances when they are combined with a bid quality threshold through the offer of low-cost funding. Reverse auctions may not, however, be entirely effective for the demonstration phase of CCS when there are a low number of projects with uncertain costs. Some of the features of reverse auctions may become less problematic as costs become better known and the number of projects increases. Consequently there do not appear to be compelling advantages to reverse auctions in practice at the current stage of CCS development.

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