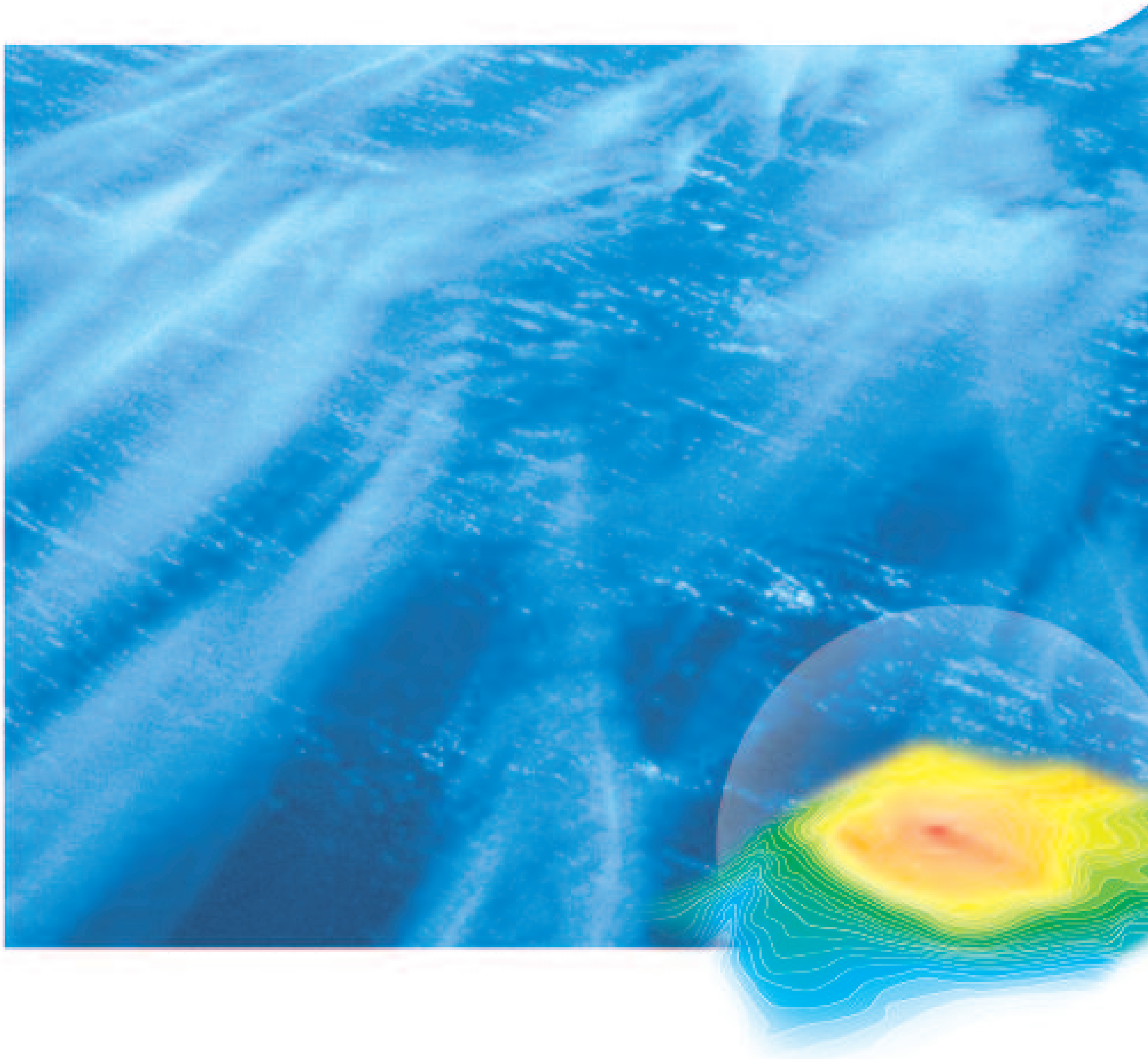

Carbon Dioxide Capture and Storage in Ireland

Costs, Benefits and Future Potential

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Executive Summary

Research into emerging technologies, improvements in energy efficiency, and relevant policies are recognised as methods of reducing carbon dioxide emissions. Carbon dioxide capture and storage (CCS or 'Clean Coal'[1]) is receiving worldwide attention for its emissions reduction potential. The purpose of this study is to build on the previous SEI report on emerging technologies, which dealt with CCS and hydrogen, and provide more accurate economic figures and scenarios of future deployment. In the previous study, integrated gasification combined cycle (IGCC) plants with CCS were identified as potential medium term emissions reducing solutions. These are thus the focus of this study.

A model was built to simulate the techno-economic performance of the capture, transport and storage of CO_2 from an IGCC plant built on the current site of Moneypoint power plant. A range of data was taken from the available literature and the cost of electricity (COE) generated by such a plant was calculated and compared to that of a pulverised coal combustion (PCC) plant. Scenarios were analysed for the present day, 2020 and 2050. CO_2 storage was considered in an aquifer beneath Moneypoint, the Kinsale and Corrib gas fields, and EOR in the as yet undeveloped Spanish Point oil field.

The following cost components were identified and quantified: plant capital, plant O&M, fuel, emissions, transport capital, transport O&M, storage capital, and storage O&M. Variable input parameters were examined and the overall sensitivity of the COE to each parameter was determined. The important parameters were found to be fuel cost, carbon cost, rate of IGCC technological learning, and in the case of CO_2 enhanced oil recovery (EOR), the cost/benefit of EOR.

The results of the analysis indicate that CCS deployment now, with a carbon tax[2] in place would result in a COE approximately 30% higher than that for conventional coal-fired generation. By 2020, IGCC with CCS may be competitive with PCC. Projections to 2050 indicate that with a reasonable rate of technology learning, CCS could be more cost effective than conventional coal. Emissions from IGCC plants with CCS are on average 88% lower than PCC plants. This means than if Moneypoint were to be replaced with one, Irish national emissions would be reduced by 5.3 $MtCO_2$ or 7.7%. This would go some way to addressing Ireland's Kyoto commitment.

Ireland's CO_2 storage capacity needs to be assessed in detail as a matter of urgency. Resource studies similar to those carried out in Australia and Canada would be of particular benefit. In addition to this, legal, safety and public perception concerns must be addressed before real progress can be made in the area. Furthermore, it is recommended that Ireland join one or more of the many international collaborations working in the technology and application of CCS.

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[1] 'Clean Coal' in this case refers to the capture and storage of CO_2 from coal-fired plants, not to efforts to make conventional coal-fired generation cleaner.

[2] This analysis assumed that the environmental cost of CO_2 emissions are internalised by the use of a carbon tax.

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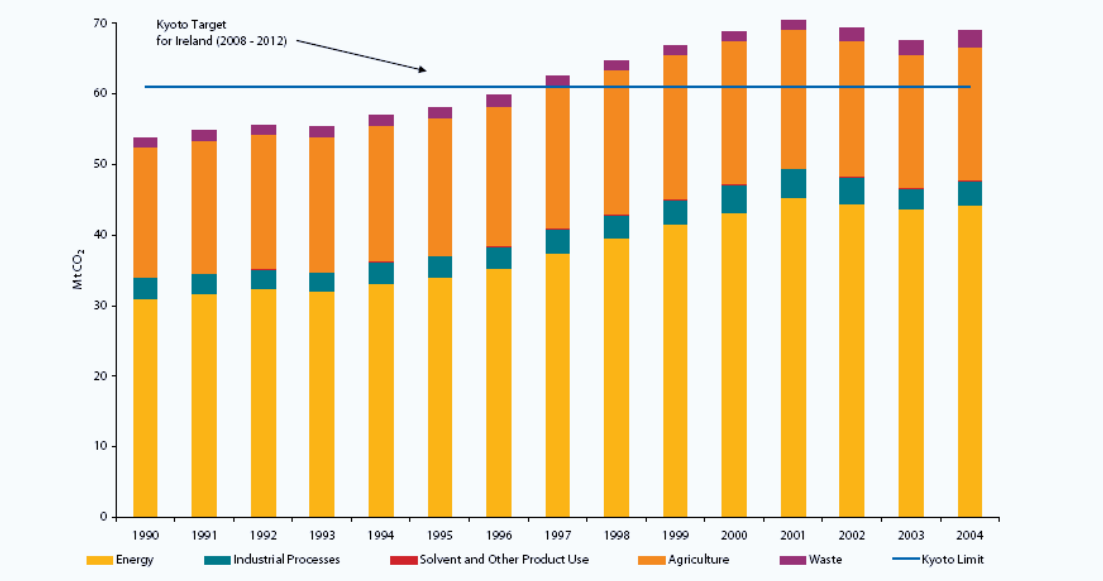
Introduction

Carbon dioxide capture and storage (CCS or 'Clean Coal'[3]) is thought by many to be an important part of any strategy to combat global climate change [1]-[3] & [26][4]. Atmospheric CO_2 is responsible for 62% of the increase in the earth's global radiative forcing [4]. The concentration of carbon dioxide in the atmosphere has risen by 30% since the dawn of the industrial era [5]. This increase is widely believed to be responsible for a 0.6 °C rise in global mean temperature over the twentieth century, and is mostly due to anthropogenic activities. Fossil-fuel-burning power plants account for about one third of total global CO_2 emissions, which were 23.5 $GtCO_2$/yr in 2000 [6] & [7]. The world CO_2 storage potential has been estimated at 1,678 to 11,100 $GtCO_2$, or about 70 to 470 years worth of emissions at 2000 levels [7].

In response to rising greenhouse gas (GHG) emissions and possible subsequent climate change, many countries have signed the Kyoto Protocol, a legally binding document, which aims to reduce emissions. The European Union has agreed to reduce annual GHG emissions to 8% below 1990 levels by 2008-2012. Ireland has committed to limit its annual emissions to 13% above 1990 levels. Figure 1 shows Irish GHG emissions by source from 1990 to 2004 [8]. From the figure it can be seen that in 2004, Irish emissions were 28% above 1990 levels. Energy-related sources, in the power generation, transport, industrial, residential and agricultural sectors, are by far the largest emitters. Power generation, transport and heating each account for roughly one third of total energy-related emissions.

Figure 1 Irish GHG emissions by source from 1990 to 2004[5]



Source: Based on EPA data.

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[3] 'Clean Coal' in this case refers to the capture and storage of CO_2 from coal-fired plants, not to efforts to make conventional coal-fired generation cleaner.

[4] The IEA *Energy Technology Perspectives 2006* was drafted in support of the G8 Plan of Action at the Gleneagles Summit in July 2005.

[5] Graph reproduced from reference [8] from original EPA data.

Individual transport and heating-related emission sources are small and/or mobile in nature. In contrast, power plants are large point emitters. For example, the coal-burning power plant at Moneypoint, Co. Clare emits about 5.9 $MtCO_2$ per annum.[6] This source alone accounts for 8.6% of Ireland's total CO_2 emissions, and it is the largest single emitter. If Moneypoint were to be replaced with a cleaner source of electricity, or modified to reduce emissions, it would be of enormous benefit to Irish climate change mitigation efforts.

However, the reason Moneypoint is so polluting is also the reason it is essential to Ireland. Coal, while being a dirty fuel compared to oil and gas,[7] is mined in many stable democracies throughout the world, and so offers security of supply as a transition fuel to a sustainable energy future. Ireland relies on natural gas for two thirds of its electricity supply [9]. Almost all of this gas is imported from the United Kingdom. In the future, the country, and Europe as a whole, may be even more heavily dependent on imported gas. In addition to the supply security issue, coal reserves are much larger than other fossil fuels, implying stable supply further into the future. Currently, renewables cannot be considered to replace Moneypoint as a supplier of baseline electricity due to intermittency issues.

Coal-fired CCS in Ireland was considered in SEI's report on emerging energy technologies in Ireland [9]. The results of the analysis contained in that report indicated potential for Clean Coal technologies in Ireland. The object of this work is to build on the previous work and provide more concise information on the options for constructing a coal-fired IGCC power plant with CCS in Ireland. This work will provide estimates of the costs of a CCS project from an Irish perspective, and give prospects for the future. The following sections will detail the options available in tackling GHG emissions, the nature of CCS, previous work in the field, and the application of these technologies to Ireland.

This report is structured in the following way: options for reducing greenhouse gas emissions are discussed, with particular attention paid to international strategies and CCS, overviews of the analysis and scenarios used in this study are given, sensitivity analysis on the identified variable parameters is performed, the results of the analysis in terms of cost of electricity and emissions are discussed, and conclusions and recommendations are made.

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[6] Emissions (Mt/yr) = Coal CO_2 (g/kWh_f) x Output (MW_e) x Operating hours / Plant efficiency / 10^9
For Moneypoint, Coal CO_2 = 340.6 g/kWh_f, Output = 855 MW_e, Operating hours = 7,600, Plant efficiency = 37.5%.

[7] Emissions factors for fossil fuels are: 197.8 gCO_2/kWh_f for gas, 263.9 gCO_2/kWh_f for oil, 340.6 gCO_2/kWh_f for coal, and 414.0 gCO_2/kWh_f for peat.

Options for Reducing GHG Emissions

International Perspectives

Any strategy aimed at reducing GHG emissions is inextricably linked to efforts in other major energy challenges, namely security of supply, competitiveness, and reliability and efficiency. A review of national energy policies was carried out with the view of assessing countries' pathways for addressing climate change. Table 1 shows a summary of international pathways to climate change mitigation. The use of emissions-reducing technology, alongside energy efficiency and policy mechanisms, features on every country's agenda and most countries also recognise the importance of R,D&D for emerging energy technologies. SEI's report on emerging energy technologies in Ireland [9] reviews the current state of renewable energy, nuclear energy, CCS and hydrogen, and their applicability to Ireland. Of the technologies not currently applied in Ireland, CCS appears to have the best chance of successful deployment, due to the public perception issues and infrastructural investment needed for nuclear energy and hydrogen, respectively.

Table 1 International pathways to climate change mitigation[8, 9]

Country	Reference	Pathways							
		Kyoto	**Emissions trading**	**RE**[10]	**CHP/ DG**[11]	**Nuclear**	**Efficiency**	**Transport**	**R,D&D**
Australia	[1]	No, but will meet targets	No	Solar and remote RE			Monitor & manage	Efficiency & biofuels	Solar, CCS
Denmark	[10]	Yes	Trial period	Wind, solar geothermal, biomass	Funding scheme		Domestic uses		H_2, wind, biomass, solar
Germany	[11]	Yes		All RE		Phase out	-40% by 2050	Biodiesel	H_2[12]
Japan	[12],[13]	Yes	Yes	All RE (inc. hydro)	Waste heat	Expand	1% use growth limit	All alternatives	Access for innovators
New Zealand	[14]	Yes	Yes	RE program			National program	Efficiency	
United Kingdom	[2]	Yes	Yes	On- & off-shore wind		Pending review[13]	Domestic uses	Efficiency & alternatives	RE, CCS, H_2, fusion
United States	[3]	No, action linked to world action	Yes	Grid integration		Expand	Domestic & buildings	Diesel & hybrids	Private sector, CCS, RE, H_2, nuclear

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[8] Table adapted from data in reference [9].

[9] Note that at time of writing, Ireland does not have a stated energy policy, although an Energy Green Paper is expected in the Summer/Autumn of 2006.

[10] RE: Renewable energy.

[11] CHP/DG: Combined heat and power/Distributed generation.

[12] H_2: Hydrogen.

[13] Since the original literature review, the British government has announced a major expansion plan for nuclear energy in the UK.

Carbon Dioxide Capture and Storage

In brief, CCS involves three steps: capture, transport and storage. Capture involves the separation of CO_2 either from a synthesis gas prior to combustion (pre-combustion), or from flue gas downstream of a combustor/boiler (post-combustion). CO_2 capture or "stripping" is employed widely in the oil and gas industry. Current methods include physical separation for CO_2 concentrations over 10% and chemical separation for lower concentrations. Membranes and molecular sieves are under examination for mechanical separation of carbon dioxide or hydrogen from synthesis or flue gases.

Transportation of CO_2 may be by pipeline or tanker ship. CO_2 pipelines are widespread, again for use in the oil and gas industry, and also for beverage carbonation. Piped carbon dioxide is kept in the supercritical state, at over 73 atmospheres and 31.1 °C, in order to maintain high density and therefore high mass flow rates. Transportation by tanker ship is not yet carried out on any scale, although cryogenic CO_2 is transported by road and rail. Typically pipelines are considered for use for distances up to approximately 500 km, for longer distances tanker ships are favoured.

The storage of carbon dioxide is the greatest unknown quantity in the process. CCS typically assumes geological storage of CO_2 in deep aquifers or depleted oil or gas fields. Additionally, CO_2 may be used in enhanced oil recovery (EOR). This is a mature technology, but current commercial projects do not involve long term CO_2 storage. Enhanced gas recovery (EGR) and enhanced coalbed methane recovery (ECBM) using CO_2 are less developed options, but could hold promise in the future. Non-geological options include storage in the deep ocean, dissolved limestone, dissolved minerals and synthetic hydrocarbon fuels.

Capture and long term storage of carbon dioxide is currently being employed in only three projects worldwide: Sleipner in Norway, In Salah in Algeria, and Weyburn in Canada. Sleipner and In Salah strip CO_2 from natural gas and store it in deep aquifers at depths of 800 m and 1,850 m respectively, while Weyburn uses CO_2 for EOR with permanent storage. These projects are discussed in some detail in reference [9]. They are all heavily funded in order to study the operational aspects of CCS, and geological storage in particular.

Barriers need to be overcome with respect to legal, safety and public perception concerns about CCS. International treaties, such as London and OSPAR, prohibit dumping at sea, which possibly affects offshore storage. The risk of gradual or sudden CO_2 leakage from storage must be addressed. Perhaps most importantly, the public must be made aware of CCS and its potential benefits as an alternative to other technologies, such as increased conventional fossil fuel generation and nuclear energy [31].

Previous Work in Ireland

SEI undertook an initial study of CCS for Ireland in 2005 [9]. Using world-averaged figures for the costs of CCS from the IEA's report *Prospects for CO_2 Capture and Storage* [15], five case studies were analysed with various capture, transport and storage techniques employed. Descriptions and results are displayed in Table 2. A range of CO_2 emissions prices from €10/tCO_2 to €60/tCO_2 were included in the study. It is clear from the data presented that only the first and last case studies are viable at realistic carbon dioxide prices.[14] It should also be noted that given the age of the Moneypoint plant, it may not be worth retrofitting it with CCS when that technology that may take over 20 years to mature. This leaves the option of building a new CCS-enabled power plant as the most viable.

Only an IGCC plant was considered for new build analysis. This is because pre-combustion carbon dioxide separation in an IGCC can be performed easier and with less energy penalty than post-combustion flue gas clean-up in a pulverised coal combustion (PCC) plant. Despite the fact that IGCCs are currently more expensive than similarly sized PCCs, technology learning will likely reduce their costs significantly. Currently only a handful of IGCC plants are in operation in the world: Buggenum in the Netherlands, Puertollano in Spain, and Polk and Wabash River in the United States. None of these plants capture or store their CO_2 emissions, but were space available onsite, it would be relatively straightforward to install physical scrubbers for CO_2 removal. The plant efficiency would decrease due to the energy requirement of the scrubbers, and compressors for CO_2 transport.

Table 2 Results of CCS case studies from previous SEI work[15]

Case study	**Cost of electricity**		**Crossover carbon price**	**Emissions**		**Irish CO_2 emissions reduction**
	With CCS €c/kWh	**Without CCS €c/kWh**	**€/tCO_2**	**With CCS gCO_2/kWh$_e$**	**Without CCS gCO_2/kWh$_e$**	**%**
Retrofitted Moneypoint – Tanker – EOR off Scotland	**6-7**	**5-10**	**20-30**	**197**	**946**	**7.0%**
Retrofitted Moneypoint – Tanker – Utsira Aquifer	10-11	5-10	>60	197	946	7.0%
Retrofitted peat plants – Pipeline – EGR in Corrib field	9-10	5-11	50-60	227	1,090	1.3%
Retrofitted peat plants – Pipeline – Storage in Corrib field	9-11	5-11	60	227	1,090	1.3%
Future IGCC[16] – No transport - Aquifer	**6-7**	**5-10**	**20-30**	**128**	**792[17]**	**6.2%**

As stated, the figures used in the previous SEI study are worldwide averages used for the purpose of obtaining rough figures for feasibility. More accurate cost figures for feasible technology options are needed if they are to be pursued.

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[14] At time of writing, the price of CO_2 was €16.50/tCO_2. Source: www.pointcarbon.com.

[15] Data reproduced from reference [9].

[16] IGCC: Integrated Gasification Combined Cycle, a power plant that employs coal gasification for fuelling a combined gas and steam turbine cycle.

[17] The *No CCS* emissions figure for this case study refers to a new supercritical pulverised coal combustion (PCC) plant.

Analysis of IGCC plants with CCS for Ireland

Overview

In order to gain an understanding of the costs involved in CCS projects, detailed cost/benefit analyses were performed for an IGCC plant with CCS and a PCC plant without CCS. To this end, an Excel-based spreadsheet model was developed. Power generation from a CCS-enabled plant has the following cost components:

- Power plant:
  - Capital cost
  - Operation and maintenance cost
  - Fuel
  - Emissions (if a carbon tax applies)
- CO_2 transport:
  - Capital cost
  - Operation and maintenance cost
- CO_2 storage:
  - Capital cost
  - Operation and maintenance cost

Each cost component was considered separately in this analysis. The levelised cost of electricity (COE) in terms of €c/kWh$_e$ was calculated for a plant and compared to non-CCS coal-fired options. The values of variable input parameters affect the COE, so sensitivity analysis was performed to determine the relative influences of these parameters. The variable input parameters are shown in Table 3.

Table 3 Variable input parameters for Irish CCS analysis

Variable input parameter	Units
Fuel cost	€/ton of coal
Carbon price	€/tCO_2
Onshore pipeline transport distance	km
Offshore pipeline transport distance	km
Tanker ship transport distance	km
CO_2 storage method (Aquifer, EOR, etc.)	
Cost/benefit of CO_2-enhanced recovery methods	\$/tCO_2 or €/tCO_2
Discount rate	%
Global IGCC capacity	GW$_e$
IGCC learning rate	%

Most of the parameters are self-explanatory, but some deserve further discussion. The cost/benefit of enhanced recovery refers to levelised cost per ton of CO_2 figures obtained from the literature. For the enhanced recovery considered in this work, no breakdown between capital and O&M was available, so a levelised aggregate cost was used. In some cases, the benefits derived from enhanced recovery through revenues more than offsets the costs of storage. This would give a negative cost component. The global IGCC capacity is used with the IGCC learning rate to determine the future cost of IGCC plants. The individual cost components (plant, transport and storage) are discussed in the following sections.

Power Plant and Capture

The term "IGCC" refers to a family of power plants, which employ coal gasification for fuelling a combined gas and steam turbine cycle. The specifications of IGCC plants depend on the individual plant configuration. In general, all IGCC plants with CCS have the following processes: coal cleaning and gasification, raw gas[18] cooling, carbon monoxide shift, H_2S scrubbing, CO_2 scrubbing and compression, gas turbine combustion, steam generation, steam turbine cycle, combustion product exhaust. Differences in configuration include:

- Gasification method: Temperature, pressure, oxidant, coal delivery method, and raw gas composition depend on the gasification method employed. Common methods include: Shell, E-Gas, Texaco, Winkler and high-temperature Winkler, British Coal, PRENFLO, Kellogg-Rust-Westinghouse (KRW).
- Raw gas cooling method: Quench cooling or radiative and convective cooling.
- Clean or raw gas CO shift: If H_2S is removed from the synthesis gas before the CO shift, the process is known as clean gas CO shift. If H_2S removal follows the CO shift, it is raw gas CO shift. H_2S is extremely corrosive and can lead to the formation of SO_x. The purpose of the CO shift is the convert CO present in the raw gas to CO_2. This increases the concentration of CO_2, making it easier to remove.
- Method of CO_2 removal: Due to the high concentration of carbon dioxide in synthesis gas after the CO shift, physical scrubbing is the most suitable separation method. In an absorber, a solvent bonds physically (as opposed to chemically) with the CO_2 and is removed to a regenerator, where it is cooled. The bond is broken and the CO_2 is compressed to the supercritical state or liquefied for transport. The solvent is then sent back to the absorber. Some processes remove both H_2S and CO_2 with the same solvent. Common physical solvents include: Selexol, Purisol, Rectisol and Glycol.
- Gas turbine combustion: The synthesis gas that reaches the gas turbine consists mostly of hydrogen. Oxygen is usually used as the oxidant in the gas turbine, which leads to very high temperatures. Most gas turbines cannot operate safely at such temperatures and so must employ extra cooling, which reduces overall efficiency. The next generation GE H-frame turbine is expected to be able to address this issue.

Due to the interest in IGCC and CCS there is a substantial amount of information available, however it is not always complete. Tables 4 and 5 show the data used in this analysis for IGCC and PCC plants. The data set name incorporates the type of power plant (IGCC or PCC). An 'n' in the data set name means CO_2 is not captured. For example, *IGCC1n* refers to an IGCC plant without CCS. It was assumed that an IGCC would not be built if carbon dioxide were not to be captured. However, data for IGCC plants without CCS was included for comparison. Two data sets, *IGCC9 2010* and *IGCC10 2020* [19], are projections for CCS-enabled IGCC plants in 2010 and 2020, hence their lower costs and higher capture rates. Where data is unavailable, '-' appears.

The data in Tables 4 and 5 provided the basis for the analysis. Specific investment costs were obtained from the relevant literature. Data was obtained in units of US\$/kW$_e$ and converted to 2005 €/kW$_e$ using appropriate exchange rates and consumer price indices (CPIs) as inflation rates. The figures given for IGCC plants with CCS include the cost of CO_2 compression to the supercritical state. It

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[18] Raw gas is the term given to synthesis gas before it has been cleaned of H_2S.

was assumed that any new plant would be built at or near the current site of Moneypoint to avail of the existing coal-handling and electricity transmission infrastructure.

Annual operation and maintenance costs for all plants were taken as being 4% of capital investment, similar to references [16] & [17]. When applied to PCC plants, this assumption agreed well with SEI's in-house levelised cost of electricity model.[19] No distinction was made between fixed and variable O&M, as such detail was unavailable in most of the literature surveyed.

Annual fuel costs were obtained from the following formula:

$$C_{fuel} = 8.760 \frac{c_{coal} P_{net} CF}{\eta_{LHV} LHV_{coal}}$$

$where:$

$C_{fuel} = \text{Annual fuel cost} = [€ / yr]$

$c_{coal} = \text{Cost per ton of coal} = [€ / ton]$

$P_{net} = \text{Net output} = [MW_e]$

$CF = \text{Capacity factor}$

$\eta_{LHV} = \text{Efficiency (LHV)}$

$LHV_{coal} = \text{Lower heating value of coal} = [kWh_f / ton]$

The cost of coal is a variable parameter, whose base value was taken as €56/ton [20]. Variations will be discussed in later sections. Net plant output and LHV efficiencies are given in Tables 4 and 5. The capacity factor of each plant was taken as 80% and the LHV of coal was taken as that of bituminous coal, 8,876 kWh_f/ton.

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[19] This is a discounted cash flow model for assessing the levelised costs of electricity for a variety of power generation technologies.

Table 1 Data for IGCC power plants

Data set	Reference	Gasifier type	Oxidant	Syngas cooling	Scrubber	Gas turbine	Net Power MWe	CO_2 captured % of C in	Emissions g/kWh$_e$	Efficiency (LHV) %	Efficiency loss % points	Specific investment cost 2005 €/kW$_e$	Capital investment 2005 million €
						IGCC without CCS							
IGCC1n	[16],[17]	Texaco	O_2	Quench	Selexol	Siemens V94.3a	390.1	0.00%	751.8	42.95%	n/a	1,348	526
IGCC2n	[16],[17]	Texaco	O_2	Quench	Selexol	GE H frame	403.0	0.00%	719.8	44.87%	n/a	1,305	526
IGCC3n	[16],[17]	Texaco	O_2	Rad & conv	Selexol	Siemens V94.3a	422.3	0.00%	692.6	46.63%	n/a	1,570	663
IGCC4n	[18]	KRW	O_2	Rad & conv	Glycol (H_2S+CO_2)	GE F frame	411.1	0.00%	801.0	35.10%	n/a	1,407	578
IGCC5n	[18]	KRW	air	Rad & conv	Glycol (H_2S+CO_2)	GE F frame	441.3	0.00%	746.1	37.68%	n/a	1,323	584
						IGCC with CCS							
IGCC1	[16],[17]	Texaco	O_2	Quench	Selexol	Siemens V94.3a	361.9	91.28%	70.1	36.79%	6.16%	1,739	629
IGCC2	[16],[17]	Texaco	O_2	Quench	Selexol	GE H frame	371.4	91.28%	67.0	38.47%	6.40%	1,699	631
IGCC3	[16],[17]	Texaco	O_2	Rad & conv	Selexol	Siemens V94.3a	382.6	90.38%	73.4	39.12%	7.51%	1,986	760
IGCC4	[16],[17]	Texaco	O_2	Quench	Selexol (H_2S+CO_2)	Siemens V94.3a	359.8	94.93%	38.0	36.58%	6.37%	1,660	597
IGCC5	[16],[17]	Texaco	O_2	Quench	Selexol (H_2S+CO_2)	GE H frame	369.4	94.92%	36.4	38.27%	8.36%	1,623	599
IGCC6	[16],[17]	Texaco	O_2	Rad & conv	Selexol (H_2S+CO_2)	Siemens V94.3a	380.6	94.03%	43.3	38.91%	5.96%	1,914	728
IGCC7	[18]	KRW	O_2	Rad & conv	Glycol (H_2S+CO_2)	GE F frame	373.5	79.64%	178.0	31.88%	3.22%	1,782	665
IGCC8	[19]	Texaco	O_2	Rad & conv	Selexol	GE F frame	491.0	89.00%	95.8	32.83%	-	1,945	955
IGCC9 2010	[19]	Shell	O_2	Rad & conv	Selexol	GE FB frame	523.0	98.00%	12.1	40.03%	6.33%	1,616	845
IGCC10 2020	[19]	Shell	O_2	Rad & conv	Selexol	GE H frame	533.2	99.99%	0.1	57.31%	-	1,372	731
IGCC11	[7]	Shell	O_2	Rad & conv	Selexol	-	351.0	89.20%	87.0	40.10%	7.30%	2,578	905
IGCC12	[7]	E-gas	O_2	Rad & conv	Selexol	-	359.0	87.00%	105.0	40.10%	6.60%	2,154	773
IGCC13	[7]	Texaco	O_2	Quench	Selexol	-	457.0	89.00%	116.0	31.30%	7.80%	1,759	804
IGCC14	[7]	E-gas	O_2	Rad & conv	Selexol	-	404.0	91.00%	73.0	38.50%	6.30%	2,327	940
IGCC15	[7]	Texaco	O_2	Quench	Selexol	-	455.0	91.20%	65.0	39.00%	5.60%	2,609	1,187
IGCC16	[7]	Texaco	O_2	Quench	Selexol	-	730.0	85.00%	152.0	31.50%	6.50%	1,698	1,239
IGCC17	[7]	Texaco	O_2	Quench	Selexol	-	742.0	85.00%	151.0	32.00%	6.00%	1,606	1,192
IGCC18	[7]	Shell	O_2	Rad & conv	Selexol	-	676.0	85.00%	142.0	34.50%	8.60%	2,112	1,428
IGCC19	[7]	Texaco	O_2	Quench	Selexol	-	492.0	90.00%	97.0	33.80%	5.30%	2,191	1,078
IGCC20	[7]	Texaco	O_2	Quench	Selexol	-	492.0	90.00%	97.0	33.80%	5.30%	2,191	1,078

Table 4 Data for PCC power plants

Data set	Reference	Boiler type	Net Power MWe	Emissions g/kWh$_e$	Efficiency (LHV) %	Specific investment cost 2005 €/kW$_e$	Capital investment 2005 million €
PCC1n	[7]	Supercritical	462.0	774.0	42.20%	1,617	747
PCC2n	[7]	Ultra supercritical	506.0	736.0	44.80%	1,465	741
PCC3n	[7]	Ultra supercritical	520.0	760.0	44.50%	1,876	975
PCC4n	[7]	Ultra supercritical	758.0	743.0	44.00%	1,498	1,135
PCC5n	[7]	Ultra supercritical	754.0	747.0	43.70%	1,437	1,083
PCC6n	[7]	Supercritical	524.0	811.0	40.90%	1,369	717
PCC7n	[7]	Ultra supercritical	397.0	835.0	38.90%	1,440	572
PCC8n	[7]	Ultra supercritical	462.0	941.0	36.10%	1,560	721

Annual emissions costs were obtained from the following formula:

$$C_{emissions} = 8.760 \times 10^{-6} c_{CO_2} e_{CO_2} P_{net} CF$$

$where:$

$C_{emissions} = \text{Annual emissions cost} = [€ / yr]$

$c_{CO_2} = \text{CO}_2 \text{ cost} = [€ / ton]$

$P_{net} = \text{Net output} = [MW_e]$

$CF = \text{Capacity factor} = [\%]$

$e_{CO_2} = \text{Specific CO}_2 \text{ emissions} = [g / kWh_e]$

The CO_2 cost is a variable parameter, whose base value was taken as €17/ton.[20] Specific CO_2 emissions are given in Tables 4 and 5. Net plant outputs and capacity factors of each plant are the same as hose used in finding the annual fuel costs. The power plant base value cost components for each plant configuration are shown in Table 6. At this point it should be noted that for current CCS systems, costs associated with the power plant are by far the dominant component.

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[20] www.pointcarbon.com

Table 5 Power plant cost summary

Data set	Net Power	Capital investment	Annual O&M	Annual fuel cost	Annual emissions cost
	MWe	2005 million €	2005 million €/yr	2005 million €/yr	2005 million €/yr
			IGCC without CCS		
IGCC1n	390.1	526	21.0	40.2	34.9
IGCC2n	403.0	526	21.0	39.7	34.6
IGCC3n	422.3	663	26.5	40.0	34.8
IGCC4n	411.1	578	23.1	51.8	39.2
IGCC5n	441.3	584	23.4	51.8	39.2
			IGCC with CCS		
IGCC1	361.9	629	25.2	43.5	3.0
IGCC2	371.4	631	25.2	42.7	3.0
IGCC3	382.6	760	30.4	43.2	3.3
IGCC4	359.8	597	23.9	43.5	1.6
IGCC5	369.4	599	24.0	42.7	1.6
IGCC6	380.6	728	29.1	43.2	2.0
IGCC7	373.5	665	26.6	51.8	7.9
IGCC8	491.0	955	38.2	66.1	5.6
IGCC9 2010	523.0	845	33.8	57.8	0.8
IGCC10 2020	533.2	731	29.3	41.1	0.0
IGCC11	351.0	905	36.2	38.7	3.6
IGCC12	359.0	773	30.9	39.6	4.5
IGCC13	457.0	804	32.2	64.6	6.3
IGCC14	404.0	940	37.6	46.4	3.5
IGCC15	455.0	1,187	47.5	51.6	3.5
IGCC16	730.0	1,239	49.6	102.5	13.2
IGCC17	742.0	1,192	47.7	102.5	13.3
IGCC18	676.0	1,428	57.1	86.6	11.4
IGCC19	492.0	1,078	43.1	64.4	5.7
IGCC20	492.0	1,078	43.1	64.4	5.7
			PCC without CCS		
PCC1n	462.0	747	29.9	48.4	42.6
PCC2n	506.0	741	29.7	49.9	44.4
PCC3n	520.0	975	39.0	51.7	47.1
PCC4n	758.0	1,135	45.4	76.2	67.1
PCC5n	754.0	1,083	43.3	76.3	67.1
PCC6n	524.0	717	28.7	56.6	50.6
PCC7n	397.0	572	22.9	45.1	39.5
PCC8n	462.0	721	28.8	56.6	51.8

In this section the cost components of power plants and CO_2 capture equipment were presented. Investment costs were found in the literature [7], [16]-[19] and presented in Tables 4 and 5. O&M, fuel and emissions costs were also calculated for each data set and presented in Table 6.

Transport

The costs associated with transportation are dependent not only on the amount of CO_2 being transported, but also on the distance it is moved and the transportation method employed. For large-scale transport, three options are considered: onshore pipeline, offshore pipeline, and tanker ship. Other options, such as road and rail transport, were studied in reference [21] and were disregarded in this study due to high costs.

As previously stated, CO_2 is piped as a supercritical fluid (i.e. its temperature is above 31.1 °C and pressure above 73 atmospheres). This is done to ensure high density and therefore high mass flow rate. The CO_2 must be pressurised to well above its critical point, to account for pressure drop due to viscous losses in the pipeline. Rather than make pipelines with huge diameters, pumps are used every 250 km to maintain pressure. For onshore pipelines, it is assumed the maximum and minimum allowed pressures are 110 atm and 80 atm, respectively. For offshore pipelines, the situation is different because pumping stations are not used. In addition, hydrostatic pressure at the seabed means that much higher pressures are obtainable. Here, we assume the maximum and minimum allowed pressures are 250 atm and 200 atm, respectively.

Cost functions for pipeline transport options were obtained from reference [21]. They are shown below.[21] No cost function for offshore pipeline O&M could be found, so the onshore function was used in its place. Likewise, no O&M function for the pumping stations was found, so 4% of investment cost per year was used. It should be noted that reference [21] reported that the pumping station investment cost function gives figures that are probably too high. However, this component represents a very small part of the overall project cost.

$$C_{onshore} = 0.0619L + 0.8529 + (0.00115L + 0.00001)D + (0.000299L + 0.00003)D^2$$

$$C_{offshore} = 0.4048L + 4.6946 + (0.00153L + 0.0113)D + (0.000511L + 0.000204)D^2$$

$$C_{onshoreO\&M} = 120{,}000 + 0.61(23{,}213D + 899L - 259{,}269) + 0.7(39{,}305D + 1{,}694L - 351{,}355) + 24{,}000$$

$$C_{pump} = 7.82P_{pump} + 0.46$$

where :

$C_{onshore}$ = Onshore pipeline investment cost = $[million\$]$

$C_{offshore}$ = Offshore pipeline investment cost = $[million\$]$

$C_{onshoreO\&M}$ = Onshore pipeline O & M cost = $[\$/yr]$

C_{pump} = Pumping station investment cost = $[million\$]$

L = Pipeline length = $[km]$

D = Pipeline diameter = $[inches]$

P_{pump} = Pumping station power requirement = $[MW_e] = \dfrac{\dot{m}_{CO_2}\left(P_{high}/\rho_{P_{high}} - P_{low}/\rho_{P_{low}}\right)}{\eta_{pump}}$

$\dot{m}_{CO_2}$ = CO_2 mass flow rate = $[kg/s]$

P_{high}, P_{low} = High and low pressures = $[MPa]$

$\rho_{P_{high}}, \rho_{P_{low}}$ = CO_2 density at high and low pressures = $[kg/m^3]$

η_{pump} = Pumping station efficiency

For a given CCS project, all of the variables in the cost functions were known or could be reasonably guessed, except for pipeline diameter. To obtain a diameter, pipeflow analysis was performed for each power plant data set. This was done iteratively, knowing the distance between pumping stations (250 km) and the average mass flow rate of CO_2 in the pipe (found from the CO_2 capture rate, plant capacity and capacity factor). First a diameter (D) was guessed, and from that the average pipe velocity (v_{ave}) and Reynolds number (Re_D) was found according to the following equations:

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[21] The cost function for onshore pipeline O&M includes both fixed and variable costs.

$$v_{ave} = \frac{4\dot{m}_{CO_2}}{\rho_{CO_2}\pi D^2}$$

$$\mathrm{Re}_D = \frac{\rho_{CO_2} v_{ave} D}{\mu_{CO_2}}$$

$where:$

$D = \text{Pipeline diameter} = [m]$

$\rho_{CO_2} = \text{Average CO}_2 \text{ density} = [kg/m^3]$

$\mu_{CO_2} = \text{Average CO}_2 \text{ dynamic viscosity} = [Pa.s]$

For practical systems, the flow is always turbulent in a rough-walled pipe, so the Haaland correlation was used to find a Darcy friction factor (f) [22].

$$\frac{1}{f^{1/2}} \approx -1.8\log\left[\frac{6.9}{\mathrm{Re}_D} + \left(\frac{\varepsilon / D}{3.7}\right)^{1.11}\right]$$

$where:$

$\varepsilon = \text{Pipe roughness} = [m]$

The guessed diameter was then checked against the diameter calculated by the pressure drop equation.

$$D = f\,\frac{1}{2}\,\frac{\rho_{CO_2} v_{ave}^2 L_p}{P_{high} - P_{low}}$$

$where:$

$L_p = \text{Distance between pumping stations} = [m]$

The correct diameter was found by iteration and eventual convergence. As the pressures involved in onshore and offshore pipelines are different, different onshore and offshore diameters were found for the same plant data set. The pipeline transport costs were found to correlate well with IPCC data in reference [7].

No cost functions exist for CO_2 tanker ships as they are not currently in use. They would however bear many resemblances to LNG tankers in terms of technology and economics. As with pipelines, the transport distance affects the cost of the project. The methodology used in this part of the study was the same as that used in [21] & [23].

The following assumptions were made about CO_2 tanker ships:

- The ships themselves are leased at a rate of \$25,000/day [7],
- The rest of the required infrastructure (port, short term storage, offshore platform) are built at a cost of \$335 million [23],
- Tanker capacity is 25,140 tCO_2 [23],
- Loading time is 24 hours [21],
- Average speed is 33 km/hr (18 knots) [23],
- Unloading time is 6 hours [23],
- 1% of the transported CO_2 boils off and is released to the atmosphere [23],
- Tanker O&M costs are 5.6% of the tanker capital cost [23],
- Fuel costs are 16.5% of tanker O&M costs [23],
- Non-tanker O&M costs are 0.02% of non-tanker capital costs [23].

The calculated transportation cost per ton was found to closely match IPCC figures [7]. The costs of the various transport methods are presented in Table 7. As previously stated, tankers typically operate over longer distances than pipelines, hence the units used for comparison in the table. It should be noted that these figures depend significantly on the discount rate employed, which has been identified as a variable input parameter. However they are useful for comparison purposes.

Table 6 Transport cost summary

Data set	**Annual transport** MtCO₂/yr	**Onshore pipeline cost** 2005 €/tCO₂/250km	**Offshore pipeline cost** 2005 €/tCO₂/250km	**Tanker ship cost** 2005 €/tCO₂/5,000km
		IGCC without CCS		
IGCC1n	0	0	0	0
IGCC2n	0	0	0	0
IGCC3n	0	0	0	0
IGCC4n	0	0	0	0
IGCC5n	0	0	0	0
		IGCC with CCS		
IGCC1	1.86	4.13	12.32	37.45
IGCC2	1.83	4.17	12.40	38.18
IGCC3	1.85	4.15	12.35	37.70
IGCC4	1.79	4.21	12.74	38.85
IGCC5	1.76	4.25	12.83	39.58
IGCC6	1.82	4.18	12.42	38.31
IGCC7	1.82	4.19	12.41	38.25
IGCC8	2.67	3.41	9.22	32.53
IGCC9 2010	2.17	3.83	10.86	36.00
IGCC10 2020	3.74	2.96	7.18	25.54
IGCC11	1.77	4.26	12.81	39.43
IGCC12	1.77	4.26	12.81	39.42
IGCC13	3.01	3.29	8.41	28.89
IGCC14	2.09	3.91	11.13	37.42
IGCC15	2.15	3.81	11.04	36.41
IGCC16	4.41	2.73	6.39	23.60
IGCC17	4.45	2.75	6.39	23.38
IGCC18	3.81	3.01	7.01	25.03
IGCC19	3.01	3.17	8.41	28.85
IGCC20	3.01	3.17	8.41	28.85
		PCC without CCS		
PCC1n	0	0	0	0
PCC2n	0	0	0	0
PCC3n	0	0	0	0
PCC4n	0	0	0	0
PCC5n	0	0	0	0
PCC6n	0	0	0	0
PCC7n	0	0	0	0
PCC8n	0	0	0	0

In this section the cost components of various CO_2 transport systems, onshore pipelines, offshore pipelines and tanker ships, were presented. Investment, leasing and O&M costs were found in the literature [7], [21], [23] and presented in Table 7. Specific costs per ton of carbon dioxide transported over a given distance were calculated.

Storage

Geological storage of carbon is not the most expensive step in CCS, but it is certainly the step about which least is known. Storage may be in deep aquifers (at depths of ~1,000 m or more), or depleted oil or gas fields. CO_2 may also be used in enhanced oil recovery (EOR), after pressure-driven flow and water-enhanced EOR. This is carried out at many sites around the world, but not with long term CO_2 storage in mind. Only at Weyburn in Canada is this done. CO_2-enhanced gas recovery (EGR) and CO_2-enhanced coalbed methane recovery (ECBM) are also under examination. However, these techniques may take decades or more to mature, if they ever do. Opinions vary on the feasibility of these options [7], [23]. As opposed to the capture step of CCS, storage is highly geographically and geologically dependent, so sites relevant to Ireland must be examined.

To date no survey of Ireland's deep geology has been undertaken. This means that we are currently unaware of any suitable aquifers in existence in Ireland or Irish territorial waters. However, there are large-scale gas production projects being carried out in Ireland, currently at Kinsale off the south coast, and in the near future at Corrib off the west. Sizeable oil and gas reserves have also been discovered and may soon be developed by two consortia of ExxonMobil, Providence Resources and Sosina over 200 km off the west coast.[22] The prospects are known as Spanish Point and Dunquin. The storage options considered in this study were:

- Storage in an imaginary aquifer discovered directly beneath the new IGCC plant,
- Storage in the depleted areas of the Kinsale gas fields,
- Storage in the Corrib gas field, which will eventually deplete,
- EOR in the Spanish Point oil field 200 km off the west coast.

EGR and ECBM were not considered in this study for the following reasons: they are both largely unproven technologies for storage, as opposed to aquifer, depleted field and EOR storage, and there is no data available for offshore EGR and ECBM projects. The second point is especially important since all the known major Irish oil and gas prospects are offshore, which would lead to increased costs relative to onshore projects. Therefore estimates for onshore projects would not be useful.

Costing data for aquifers was obtained from the Sleipner project and is shown in Table 8 [24]. Data was unavailable for storage in offshore oil or gas fields, so the aquifer data was also used for these cases. In the Sleipner project CO_2 is compressed from near atmospheric pressure to 80 bars. This is why the compressors are so expensive. This study has already included the cost of compression in either the power plant component (if there is no transport) or the transport component (if there is transport). Therefore, the compressor cost and the fuel and emissions cost are neglected. The cost of monitoring the storage was found to be €2.1million/yr [25]. The Sleipner project stores 1 $MtCO_2$ per year, so the costs on Table 8 are normalised to a 'per one million tons basis'.

Table 7 Cost data for aquifer and depleted oil/gas field storage[23]

Cost component	**Investment costs** 1996 million$	**Operational costs** 1996 million$/yr
Site characterisation	1.9	
Compressor trains	79	
Injection well	15	
Total investment cost	**95.9**	
Fuel and emissions		15
Total operational costs		**15**

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[22] http://www.providenceresources.com/html/porcupine_operations.html

[23] Data reproduced from reference [24].

The cost of offshore EOR was found to range from -\$10.5/tCO_2 to +\$21/tCO_2 [7]. It is expressed in terms of a levelised cost per ton stored, and can be negative to reflect the revenues generated from the sale of recovered oil. The midpoint value +\$5.25/tCO_2 is converted to €/tCO_2 and taken as the base value. The effect of this range is discussed in the section on sensitivity analysis. Table 9 summarises the storage cost components of the project for each power plant data set.

Table 8 Storage cost summary

Data set	Annual storage MtCO₂/yr	Offshore aquifer/oil/gas field storage 2005 €/tCO₂	Offshore EOR & storage 2005 €/tCO₂
	IGCC without CCS		
IGCC1n	0	0	0
IGCC2n	0	0	0
IGCC3n	0	0	0
IGCC4n	0	0	0
IGCC5n	0	0	0
	IGCC with CCS		
IGCC1	1.86	4.77	-11.9 to +23.8
IGCC2	1.83	4.77	-11.9 to +23.8
IGCC3	1.85	4.77	-11.9 to +23.8
IGCC4	1.79	4.77	-11.9 to +23.8
IGCC5	1.76	4.77	-11.9 to +23.8
IGCC6	1.82	4.77	-11.9 to +23.8
IGCC7	1.82	4.77	-11.9 to +23.8
IGCC8	2.67	4.77	-11.9 to +23.8
IGCC9 2010	2.17	4.77	-11.9 to +23.8
IGCC10 2020	3.74	4.77	-11.9 to +23.8
IGCC11	1.77	4.77	-11.9 to +23.8
IGCC12	1.77	4.77	-11.9 to +23.8
IGCC13	3.01	4.77	-11.9 to +23.8
IGCC14	2.09	4.77	-11.9 to +23.8
IGCC15	2.15	4.77	-11.9 to +23.8
IGCC16	4.41	4.77	-11.9 to +23.8
IGCC17	4.45	4.77	-11.9 to +23.8
IGCC18	3.81	4.77	-11.9 to +23.8
IGCC19	3.01	4.77	-11.9 to +23.8
IGCC20	3.01	4.77	-11.9 to +23.8
	PCC without CCS		
PCC1n	0	0	0
PCC2n	0	0	0
PCC3n	0	0	0
PCC4n	0	0	0
PCC5n	0	0	0
PCC6n	0	0	0
PCC7n	0	0	0
PCC8n	0	0	0

In this section the cost components of CO_2 storage methods were presented. Investment and O&M costs were found for aquifer storage in the literature [24] and presented in Tables 8 and 9. A range of levelised specific costs per ton of CO_2 used for EOR was found [7] and presented in Table 9.

Scenarios

Ten scenarios for CCS deployment, shown in Table 10, were considered for analysis. All of the scenarios assumed that any IGCC plant would be built at the existing Moneypoint site. The *PCC* scenario represents a new build pulverised coal plant without CCS. Figure 2 shows the location of the proposed capture sites, transportation routes and storage sites. Capture is performed at the Moneypoint site (the green point). The red points mark where CO_2 could be stored in aquifers or depleted oil or gas fields, while the black indicates where EOR could be carried out. The pipeline routes to the Kinsale and Corrib fields follow the routes of existing or planned natural gas pipelines.

Table 9 Scenarios for CCS deployment in Ireland

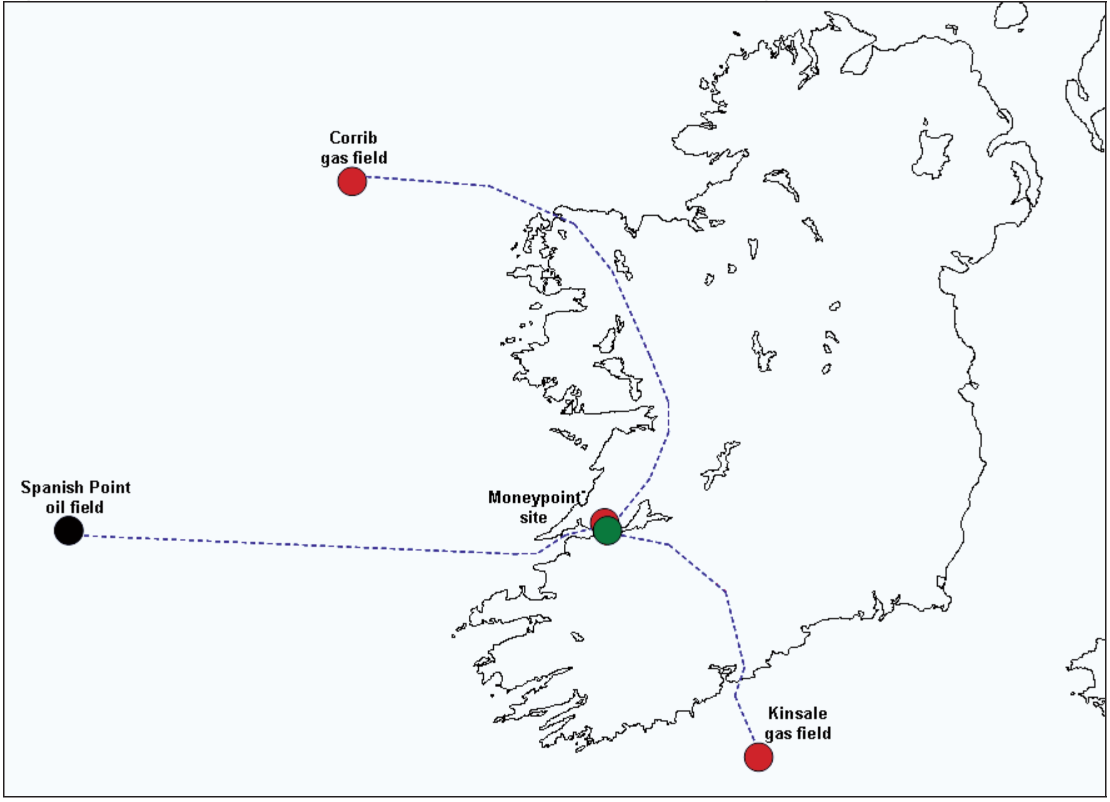
Scenario	Year	IGCC site	Transport method	Transport distance Onshore km	Transport distance Offshore km	Storage
PCC	All	Moneypoint site	n/a	n/a	n/a	n/a
MMA-2005	2005	Moneypoint site	None	0	0	Imaginary aquifer under Moneypoint site
MKD-2005	2005	Moneypoint site	Pipeline	144	59	Depleted Kinsale field
MMA-2020	2020	Moneypoint site	None	0	0	Imaginary aquifer under Moneypoint site
MKD-2020	2020	Moneypoint site	Pipeline	144	59	Depleted Kinsale field
MCD-2020	2020	Moneypoint site	Pipeline	216	92	Depleted Corrib field
MMA-2050	2050	Moneypoint site	None	0	0	Imaginary aquifer under Moneypoint site
MKD-2050	2050	Moneypoint site	Pipeline	144	59	Depleted Kinsale field
MCD-2050	2050	Moneypoint site	Pipeline	216	92	Depleted Corrib field
MSE-2050	2050	Moneypoint site	Pipeline	0	250	EOR in Spanish Point

Two scenarios were considered for the present day (2005), three for 2020, and four for 2050, and the cost of electricity (COE) was calculated for each in terms of 2005 €c/kWh$_e$. The *PCC* scenario applies to any timeframe as technology learning has very little effect on the cost of PCC plants. This is discussed in the next section. For IGCC with CCS, the COEs of all the individual data sets were averaged, and the standard deviation found. The standard deviation was used to establish a range of possible COEs over the data sets shown in Table 4. The same method was used for the cost of electricity from PCC plants.

It was assumed that the Kinsale gas field can be used now for CO_2 storage, as it is mostly depleted. The Corrib gas field has not yet begun production, but was assumed to be substantially depleted by 2020. Due to its location and current lack of development, Spanish Point was assumed to be ready for EOR by 2050.

As previously stated, each scenario has variable input parameters. Some of these are dependent on the level of development of the relevant technologies. Currently, CCS projects are considered high risk, as they are an unproven investment. Therefore a discount rate of 11.28% was used for projects in 2006 and 2020, as it is expected there will still be a relatively small amount of IGCC and CCS plants operating worldwide [26]. For 2050, a discount rate of 7.03% was used to indicate growing confidence in the technology. These discount rates are used in SEI's in-house levelised cost of electricity model for high and low risk technologies, respectively.

Figure 2 Proposed capture sites, transportation routes and storage sites



Technology Learning

Technology learning also affects the costs involved in a project, especially when a new technology is being employed. Two areas of CCS for which technology learning could be applied are the cost of the IGCC plant with CO_2 capture and the cost of drilling injection wells [7]. Learning-by-doing rates were defined for these technologies: 15% for IGCC [27][24], and 25% for well drilling [30]. This means that for each doubling of worldwide IGCC capacity, costs reduce by 15%. For comparison, a learning rate of 3% was used for PCC plants [27]. It was found that since IGCC costs dominate the COE, and oil and gas drilling is a widely-employed technology, the drilling learning rate had very little bearing on the outcome.

In order to apply these learning rates, worldwide capacity must be known. Current installed global capacity of IGCC plants was found to be 1 GW (recall that only four plants now operate), while the figure for PCC plants was 1,125 GW [26]. Similarly to well drilling, the already-large capacity of PCC plants means that learning has little bearing on the COE of PCC. Global installed capacity for IGCC in 2020 was estimated at 5 GW. The figure for 2050, 700 GW, was obtained from data in reference [26].

When these learning rates are applied to the investment costs of the respective technologies, future costs can be estimated. Figure 3 shows the technology learning curves (on a log-log plot) that were obtained by applying the above learning rates to the capital investment costs from Tables 4 and 5. There is very little room for improvement for PCC plants, while the cost of IGCC plants can be greatly reduced.

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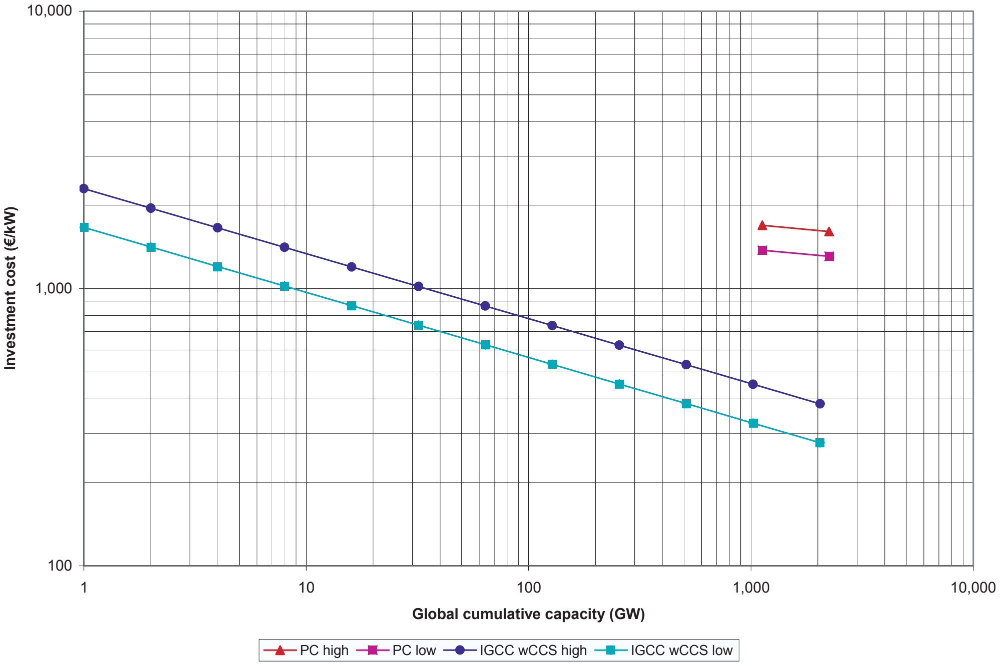
[24] References [28] and [29] used learning rates of 13% and 12% respectively. These are assumed to apply only to post-combustion CO_2 capture systems.

Figure 3 Learning rates for IGCC with CO_2 capture, and PCC investment costs



Sensitivity Analysis

Sensitivity analysis was performed on each of the scenarios to determine the relative importance of the variable parameters. The cost of electricity (COE) was found for each scenario, using reasonable base values of the input parameters. Each variable parameter within a scenario was then varied in turn along a reasonable range, while the others were kept constant. The variable input parameters and ranges are shown in Table 11. The change to the COE was observed, enabling the relative importance of each variable to be seen. Sensitivity analysis was also performed on a PCC as its costs are dependent upon the cost of fuel and the carbon cost. The results of the sensitivity analysis are presented in the appendices in the form of "spider graphs". The steeper the curve of a particular parameter, the greater its importance.

From this analysis, it was found that for IGCCs built now, the most important parameter is fuel cost. For future IGCCs, fuel cost and learning rate are of roughly the same importance. For conventional PCC plants, sensitivity analysis showed that fuel cost and carbon cost are of almost equal importance. For projects involving EOR, the cost or benefit of EOR, which is strongly dependent on the price of oil [7], is the most important factor.

Table 10 Variable input parameters and ranges for scenarios

Scenario	Transport distance Onshore km	 Offshore km	 Tanker km	Storage method	Discount rate %	Global capacity GW	Case	Fuel cost €/ton	Carbon cost €/tCO_2	Cost/ benefit of EOR €/tCO_2	IGCC learning rate %
PCC	n/a	n/a	n/a	n/a	7.03%	1,125	Base	56	17	n/a	3%[25]
							Low	36	7		
							High	76	27		
MMA-2005	0	0	0	Aquifer	11.28%	1	Base	56	17	n/a	n/a
							Low	36	7		
							High	76	27		
MKD-2005	144	59	0	Gas field	11.28%	1	Base	56	17	n/a	n/a
							Low	36	7		
							High	76	27		
MMA-2020	0	0	0	Aquifer	11.28%	5	Base	56	17	n/a	15%
							Low	36	7		10%
							High	76	27		20%
MKD-2020	144	59	0	Gas field	11.28%	5	Base	56	17	n/a	15%
							Low	36	7		10%
							High	76	27		20%
MCD-2020	216	92	0	Gas field	11.28%	5	Base	56	17	n/a	15%
							Low	36	7		10%
							High	76	27		20%
MMA-2050	0	0	0	Aquifer	7.03%	700	Base	56	17	n/a	15%
							Low	36	7		10%
							High	76	27		20%
MKD-2050	144	59	0	Gas field	7.03%	700	Base	56	17	n/a	15%
							Low	36	7		10%
							High	76	27		20%
MCD-2050	216	92	0	Gas field	7.03%	700	Base	56	17	n/a	15%
							Low	36	7		10%
							High	76	27		20%
MSE-2050	0	250	0	EOR	7.03%	700	Base	56	17	5.95	15%
							Low	36	7	-11.9	10%
							High	76	27	23.8	20%

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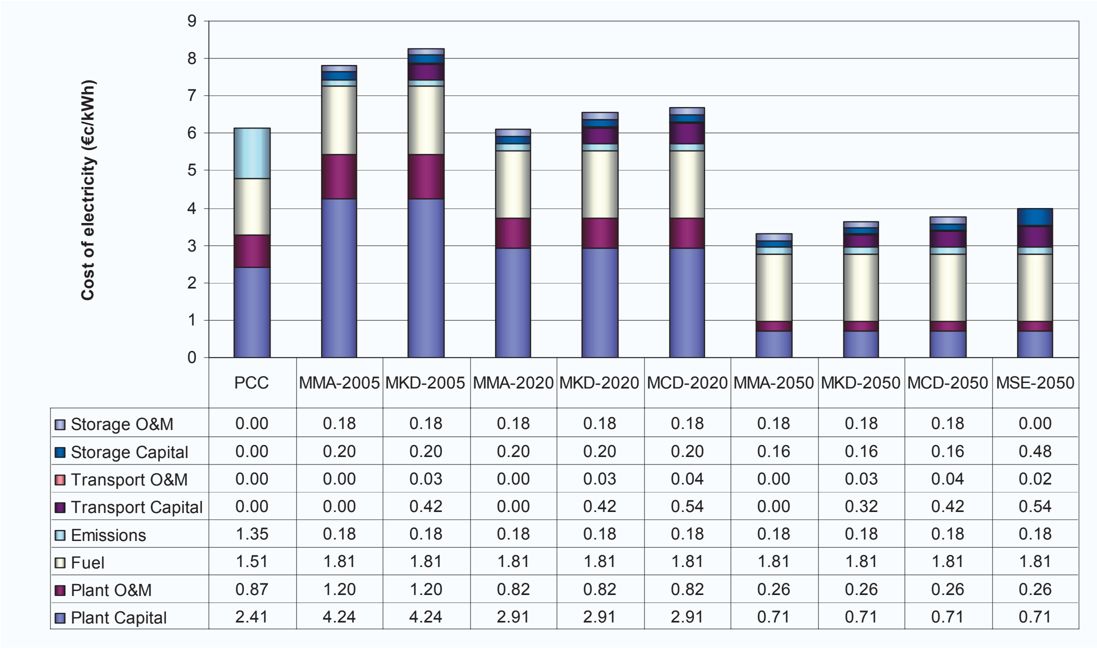
[25] This is the learning rate for PCC, not IGCC.

Results

Cost of Electricity

For a given scenario, the costs of electricity for the *IGCC with CCS* data sets, as shown on Table 4, were averaged, as were those for PCC plants without CCS. The standard deviations of these categories reflect the range of input data. Figure 4 shows the average COE breakdowns for all the scenario base cases, as shown in Table 11. Note that no error or ranges are shown in this graph.

Figure 4 COE breakdowns for the base case of each scenario[26]



	PCC	MMA-2005	MKD-2005	MMA-2020	MKD-2020	MCD-2020	MMA-2050	MKD-2050	MCD-2050	MSE-2050
Storage O&M	0.00	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.00
Storage Capital	0.00	0.20	0.20	0.20	0.20	0.20	0.16	0.16	0.16	0.48
Transport O&M	0.00	0.00	0.03	0.00	0.03	0.04	0.00	0.03	0.04	0.02
Transport Capital	0.00	0.00	0.42	0.00	0.42	0.54	0.00	0.32	0.42	0.54
Emissions	1.35	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Fuel	1.51	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81
Plant O&M	0.87	1.20	1.20	0.82	0.82	0.82	0.26	0.26	0.26	0.26
Plant Capital	2.41	4.24	4.24	2.91	2.91	2.91	0.71	0.71	0.71	0.71

It is interesting to note that the average COE breakdown for the base cases becomes less capital-intensive and more fuel-intensive in the future, resembling a gas-fired power plant. Note that for the *MSE-2050* scenario, no breakdown between capital and O&M was available for storage costs. Therefore, for the purpose of overall comparison, all EOR storage costs are shown as capital costs. Due to the fact that there was a data spread and variable input parameters for each scenario, the range of possible COEs is important. Figure 5 shows the total COE and range of COEs for each scenario. The range takes into account both the spread due to using multiple data sets, as well as the uncertainty due to the presence of variable parameters.

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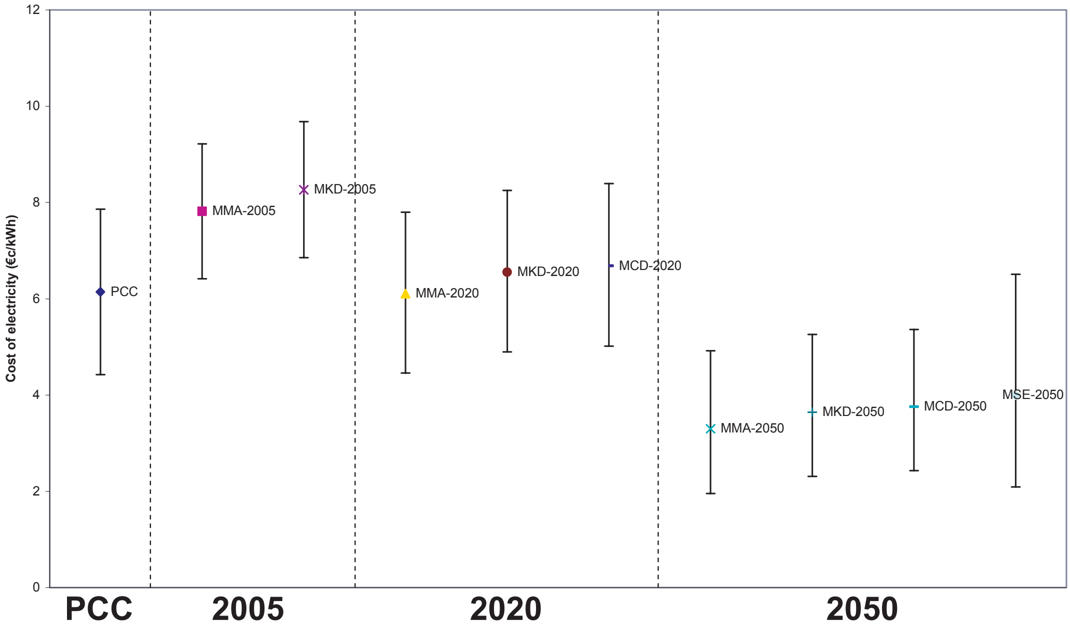
[26] Note that for the *MSE-2050* scenario no breakdown of storage costs was available. Therefore all EOR storage costs are shown as capital for this graph.

Figure 5 Range of COEs for each scenario



The EOR scenario, *MSE-2050*, has the largest range of electricity costs due to the uncertain nature of the techniques involved. In figures 4 and 5, an obvious decrease in costs over time can be observed. However the exact position of each scenario within its range is not known. This requires more precise knowledge of the costs involved. Table 12 summarises the potential COEs for CCS projects in Ireland. The COEs are in the range €c6.42-9.68/kWh for 2005, €c4.46-8.39/kWh for 2020, and €c1.96-6.21/kWh for 2050.

Table 11 Summary of COEs for each scenario

Scenario	Cost of electricity Low €c/kWh	 Base €c/kWh	 High €c/kWh
PCC	4.42	6.14	7.86
MMA-2005	6.42	7.82	9.22
MKD-2005	6.85	8.27	9.68
MMA-2020	4.46	6.11	7.80
MKD-2020	4.89	6.55	8.26
MCD-2020	5.02	6.69	8.39
MMA-2050	1.96	3.30	4.92
MKD-2050	2.31	3.65	5.26
MCD-2050	2.43	3.76	5.36
MSE-2050	2.16	4.00	6.21

Figure 5 and Table 12 show that while CCS-generated electricity is currently more expensive than conventional coal-generated electricity, costs of electricity could be similar by 2020. By 2050, IGCC plants with CCS could generate electricity 35% cheaper than PCC plants.

Emissions

Moneypoint currently emits 5.9 $MtCO_2$/yr, amounting to 8.6% of Ireland's national emissions of 69 $MtCO_2$/yr. Replacement of Moneypoint with an identically-sized state-of-the-art PCC plant would cut emissions to 5.2 $MtCO_2$/yr, or 7.6% of national emissions. Replacement of Moneypoint with an identically-sized IGCC plant with CCS would cut emissions to 0.6 $MtCO_2$/yr, or 0.9% of national emissions. This equates to a 7.7% cut in total Irish CO_2 emissions. This represents 66% of the emissions reductions needed to meet Ireland's Kyoto commitment [8].

Conclusions and Recommendations

Generation of electricity by IGCC with CCS may not currently be able to compete economically with conventional coal-fired generation in Ireland. However, it is competitive with the 2007 best new entrant (BNE) price of 8.64 €c/kWh [33].[27] By 2020 it could be competitive with pulverised coal-fired generation, and by 2050 it could be much more cost effective. In addition, CO_2 emissions from an IGCC plant with CO_2 capture and storage could be up to 88% lower than for a similarly-sized pulverised coal plant (see Tables 4 and 5). If an IGCC plant with CCS to replace Moneypoint, Irish CO_2 emissions would be reduced by 7.7%. With these points in mind, CCS should be viewed as a medium term option in Ireland's GHG emissions reduction strategy. Increased use of renewables and energy efficiency are more likely to be effective in the short term.

For the development of CCS in Ireland to proceed, it is vitally import that surveys of Ireland's deep geology and potential CO_2 storage sites are carried out. The Geological Survey of Ireland (GSI) has identified the assessment of CO_2 storage sites as a priority [32]. Surveys of this type have been carried out in Australia and Canada, as well as ranking of potential storage sites. Similar work in Ireland would be of great benefit [34], [35]. For certain scenarios, this study assumed the existence of a suitable aquifer beneath the site of the Moneypoint power plant. This may or may not be true, and until the country's storage capacity is known, little can be done beyond analysis of scenarios, similar to this study. Other issues that need to be resolved include safety, legal and public perception concerns surrounding pipeline transport and in particular geological storage.

In addition to assessing the country's storage capacity, Ireland should consider joining international collaborations in the area of CCS technology and applications. The IEA Greenhouse Gas R&D Program (IEAGHG)[28], the IEA Clean Coal Centre (IEACCC)[29], the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEFFPP)[30] and the Carbon Sequestration Leadership Forum (CSLF)[31] appear to be the most relevant to Ireland's current position. By joining one or more of these collaborations, the country may be able to build on the scientific and engineering research currently being carried out in relative isolation in Ireland. With an identified storage site, a pilot-scale demonstration plant could be built. For example, CO_2 from flue gas of a single existing generating unit could be captured and stored. This would give the opportunity to gain operating experience, and data on the performance and permanence of the storage facility.

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[27] BNE refers to the cost of CCGT-generated electricity.

[28] See website at http://www.ieagreen.org.uk/.

[29] See website at http://www.iea-coal.org.uk/site/ieaccc/home.

[30] See website at http://ec.europa.eu/research/energy/nn/nn_rt/nn_rt_co/article_2268_en.htm.

[31] See website at http://www.cslforum.org/.

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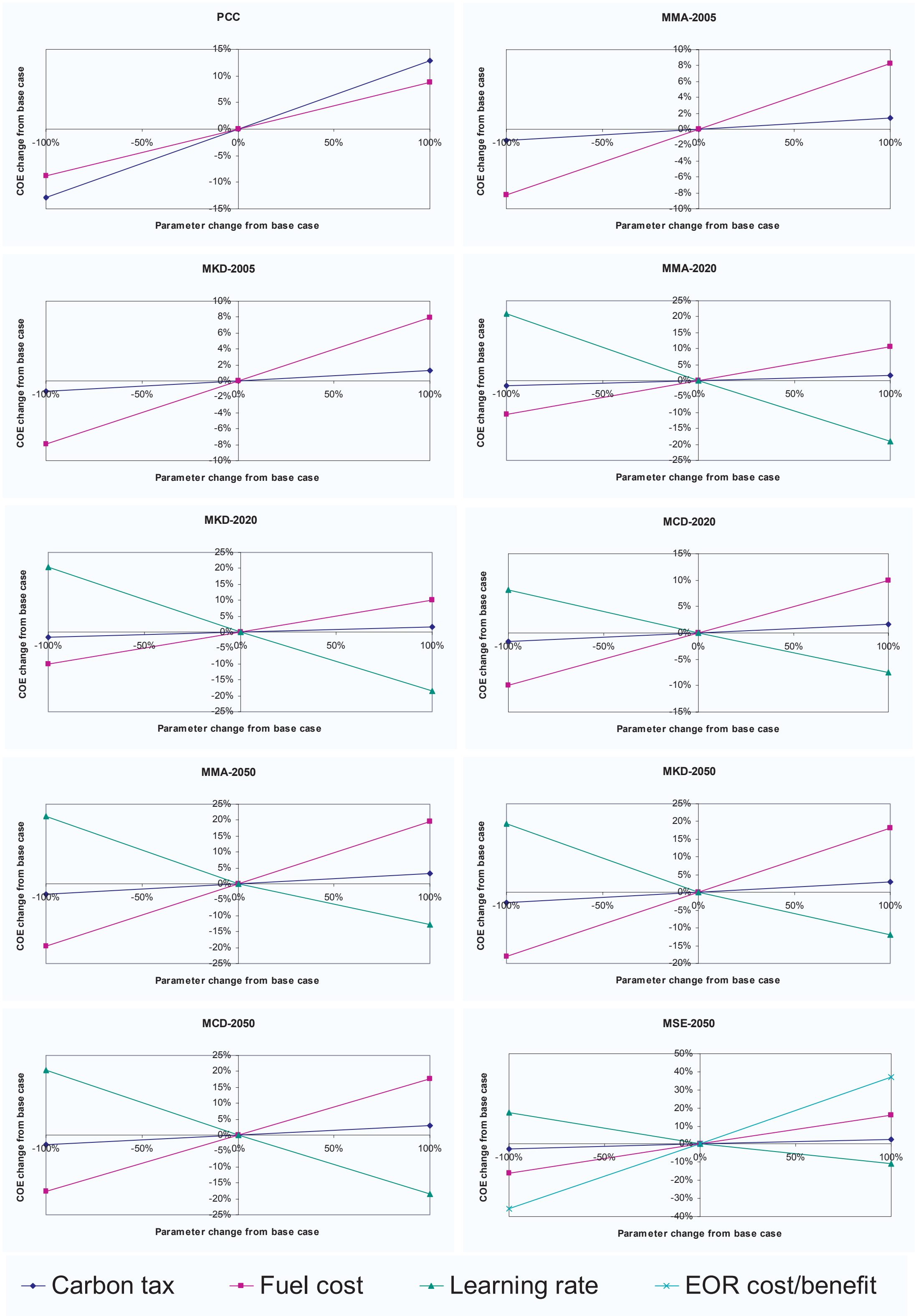
Appendices

Spider Graphs for Sensitivity Analysis



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