

Economic Assessment of the all-Island Potential for Carbon Capture and Storage in Ireland

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Summary

Aims and methodology

This report presents the results of a screening study of the economics of three carbon capture and storage (CCS) projects in Ireland.

Three source-to-sink scenarios are analysed. The sources are new build power plants at Moneypoint, Cork and Kilroot. We assume that Kinsale Head is used to store CO₂ from Money point and Cork and that the Portpatrick Basin is used to store CO₂ from Kilroot.

We estimate the capital, operating and abandonment costs, as well as the costs per tonne of CO₂ avoided for CO₂ separation, transport and injection. We also report the cost of electricity as € per MWh for projects with and without CCS. The costs are presented in €2008 terms. They are based on limited processing, cost and reservoir data and have a margin of error of ± 50%.

We estimate the cost of the CCS projects excluding tax effects and have not considered how the European Emissions Trading Scheme will affect the economics.

Cases examined

Table 1 – Summary of cases examined

Number	Power plant type	Source location	Sink	Sensitivity Analysis
Case 1A	900 MW _e pulverised coal	Moneypoint	Kinsale Head	Yes
Case 1B	900 MW _e pulverised coal	Moneypoint	Kinsale Head using alternative onshore route	No
Case 1C	900 MW _e IGCC	Moneypoint	Kinsale Head	No
Case 1D	900 MW _e pulverised coal and retrofit natural gas power plants	Moneypoint and Cork	Kinsale Head	No
Case 2A	900 MW _e pulverised coal	Cork	Kinsale Head	Yes
Case 2B	900 MW _e pulverised coal	Cork	Kinsale Head with alternative offshore route	No
Case 2C	900 MW _e plant	Cork	Kinsale Head	No
Case 2D	540 MW _e pulverised coal	Cork	Kinsale Head	No
Case 3A	540 MW _e pulverised coal	Kilroot	Portpatrick Basin	Yes

Case 1 – Moneypoint Power station to Kinsale Head Gas Field

CCS for a pulverised coal power station

This case examines the CCS costs of a new-build 900 MW_e sent-out pulverised coal power plant in the Shannon Estuary at Moneypoint. The total capacity of the power plant excluding the power required for auxiliaries is 1,160 MW. Of this total, 260 MW_e is used for CCS.

Table 2 – CCS costs for Moneypoint to Kinsale Head

Moneypoint to Kinsale Head	Reference power station without CCS (A)	Power station with CCS (B)	Incremental effect of CCS (B - A)
Capital Cost (€ million)	1,509	2,712	1,203
Annual operating cost (€ million/yr)	229	343	114
Abandonment cost (€ million)	0	101	101
Annual CO ₂ emissions (million tonnes)	5.41	0.70	(4.71) [#]
PV of costs (€ million)	3,480	5,601	2,121
PV of CO ₂ Avoided (Mt)	–	–	44.8
PV of Power Sent Out (TWh)	64	64	0.0
Cost of Net Electricity Sent Out (€/MWh)	54.6	87.9	33.3
Specific CCS Cost (€/t CO ₂ avoided)	–	–	47.4

[#] A total of 6.27 Mt is injected and 4.71 Mt is avoided each year

CO₂ is separated from the flue gas of the power plant using solvent absorption. The CO₂ is compressed, transported 185 km onshore and 50 km offshore. It is then injected at subcritical state into the subsurface into Kinsale Head depleted gas field. The amount of CO₂ avoided annually is 4.71 million tonnes.

The capital cost of the CCS project including the cost of the power plant is €2,712 million. The annual operating cost is over €343 million. Our best estimate of the specific cost of CCS is €47 per tonne CO₂ avoided.

The effect of changing the onshore pipeline route to include a 2.5 km water crossing at the Shannon Estuary and reducing the onshore distance from 185 km to 130 km is marginal.

Sensitivity analyses

The figure below gives a summary of the sensitivity of the base case estimates to changes in the exchange rate, coal price, capital costs and the number of injection wells.

The central cost estimates are most sensitive to changes in the capital cost. Doubling the capital cost can increase the CCS cost estimates by almost €35 per tonne CO₂ avoided

Reflecting uncertainties in injection conditions, we examine the effect of increasing the number of wells to take into account well interference and pressure build-up in the reservoir. Increasing the number of wells from an estimate of 1 to 65 increases the specific cost of CCS by over €25 per tonne CO₂ avoided.

Variations in the exchange rate and coal price increase the costs by, less than €20 and €10 per tonne CO₂ avoided respectively.

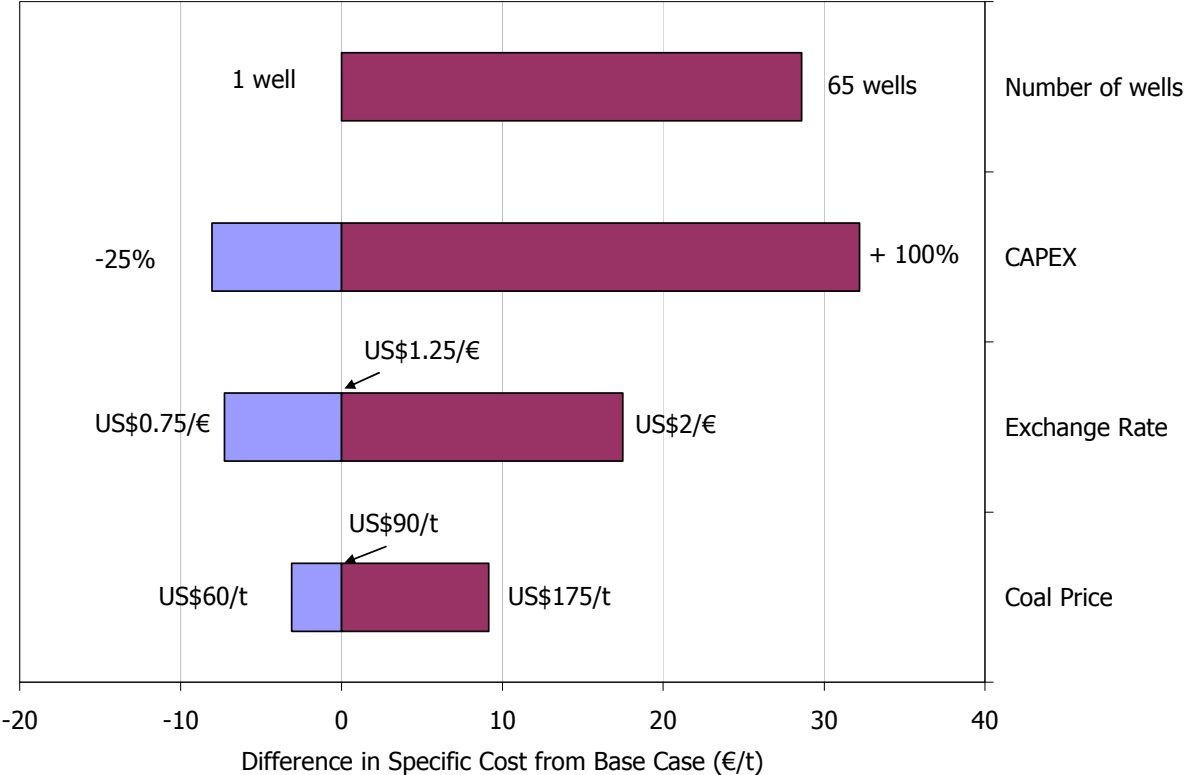


Figure 1 – Summary of sensitivity analyses for Case 1A

The costs set out above exclude the costs of appraising the injection site before the CCS project is established. Additional sensitivity analyses show that such costs increase the specific costs of CCS by less than €1 per tonne CO₂ avoided. This is small because evaluation costs are considerably smaller than the costs of CCS itself.

CCS for an Integrated Gasification Combined Cycle (IGCC) plant

We also estimate the specific cost of CCS for an IGCC power plant at Moneypoint. The total capacity is 980 MW_e, including the power required for CCS. The capital, operating and specific costs are estimated to be €2,656 million, €309 million per year and €31 per tonne CO₂ avoided respectively.

CO₂ is separated from the synthesis gas produced by the power plant. The CCS energy penalty is estimated to be 8%. With a higher energy penalty of 16%, the total capacity of the

power plant would be 1,090 MW_e and the specific cost of CO₂ avoided would be over €40 per tonne.

CCS for both Money Point and Cork

An additional possibility is establishing CCS at Moneypoint and at the two existing natural gas fired power plants at Cork. The costs of CCS for the combined projects are €3,680 million for capital costs, €400 million per year for annual operating costs and €162 million for abandonment costs. In other words, this adds approximately €970 to the total capital costs compared to CCS for Moneypoint alone. The specific cost of CCS increases to €56 per tonne CO₂ avoided.

Case 2 – Cork Power station to Kinsale Head Gas Field

CCS for a pulverised coal power station

Another potential CCS project involves capturing CO₂ from a new 900 MW_e sent out supercritical pulverised coal power plant at Cork. CO₂ is separated from flue gas, compressed and transported 6 km onshore followed by a 50 km offshore pipeline. The CO₂ is injected in a subcritical state at Kinsale Head.

The total capacity of the new power plant is 1,154 MW_e, with 254 MW_e consumed for CCS. The amount of CO₂ avoided is 4.7 million tonnes annually.

We estimate only the costs of establishing CCS facilities. We have not included the cost of increasing the transmission capacity from Cork or of constructing and operating a coal port.

Table 3 – CCS costs for Cork to Kinsale Head

Cork to Kinsale Head	Reference power station without CCS (A)	Power station with CCS (B)	Incremental effect of CCS (B - A)
Capital Cost (€ million)	1,507	2,516	1,009
Annual operating cost (€ million/yr)	228	340	112
Abandonment cost (€ million)	0	54	54
Annual CO ₂ emissions (million tonnes)	5.40	0.70	(4.70) ^{###}
PV of costs (€ million)	3,475	5,404	1,930
PV of CO ₂ Avoided (Mt)	–	–	44.7
PV of Power Sent Out (TWh)	64	64	0.0
Cost of Net Electricity Sent Out (€/MWh)	54.6	85.0	30.3
Specific CCS Cost (€/t CO ₂ avoided)	–	–	43.1

^{###} A total of 6.24 Mt is injected, and 4.70 Mt is avoided each year

The total capital cost of the project is €2,516 million including the cost of building the power plant. The operating costs are estimated to be €340 million per year and the specific cost of

CO₂ avoided is €43 per tonne. Constructing a new pulverise coal power plant at Cork saves €4per tonne CO₂ avoided compared to Moneypoint.

Changing the transport route and thereby increasing the offshore pipeline distance from 50km to 60 km does not significantly change the cost estimates.

Sensitivity analyses

The specific cost is again most sensitive to the capital cost estimates and the number of wells. If capital costs estimates are doubled, the cost of CO₂ avoided increases by almost €30 per tonne. Increasing the number of wells from 1 to 65 increases the specific cost of CO₂ avoided by more than €25 per tonne of CO₂ avoided compared to the base case.

The project is less sensitive to the exchange rate and coal price variations. If the US dollar exchange rate increases to \$US2 per €, the specific cost increases by almost €18 per tonne CO₂ avoided. If the coal price increases to \$175 from €90 per tonne, the CCS cost rises by €10 per tonne CO₂ avoided.

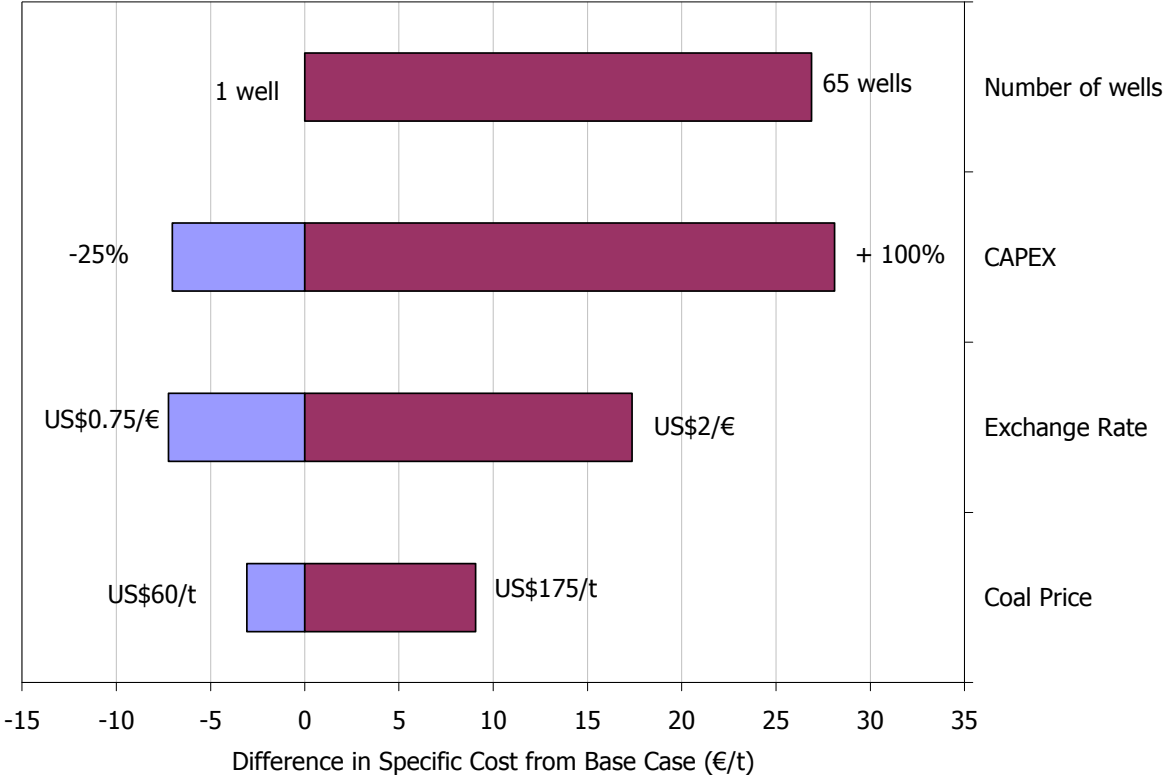


Figure 2 – Summary of sensitivity analyses for Case 2A

CCS for an Integrated Gasification Combined Cycle (IGCC) plant

The specific cost of CCS for a 900 MW_e sent out coal integrated gasification combined cycle (IGCC) power plant at Cork is estimated to be €28 per tonne CO₂ avoided. The total capital and annual operating costs are €2,497 million and €306 million respectively. The total capacity of the plant is 973 MW_e.

CCS for a 540 MW_e power plant at Cork

The capital, abandonment and annual operating costs for a new build 540 MW_e pulverised coal power at Cork are €1,665 million, €50 million and €208 million respectively. Compared to the base 900 MW_e power plant, the CCS and sent electricity costs increases by 5% to €45 per tonne CO₂ avoided and €89 per MWh respectively. The total capacity of the plant is 692 MW_e, including 152 MW_e for CCS.

Case 3 – Kilroot Power station to Portpatrick Basin

We also estimate the costs of CCS in Northern Ireland. We assume that the CO₂ is captured from a new power plant at Kilroot. The CO₂ is then compressed, transported 40 km offshore and injected into the subsurface in the Portpatrick Basin.

The total capacity of the new power plant at Kilroot is 698 MW_e including the power required for CCS. The power sent out is 540 MW_e, which is the power requirement without CCS.

Table 4 – CCS cost for Kilroot to Portpatrick

Kilroot to Portpatrick	Reference power station without CCS (A)	Power station with CCS (B)	Incremental effect of CCS (B - A)
Capital Cost (€ million)	978	1,908	930
Annual operating cost (€ million/yr)	136	209	73
Abandonment cost (€ million)	–	108	108
Annual CO ₂ emissions (million tonnes)	3.25	0.42	(2.83) ^{###}
PV of costs (€ million)	2,144	3,641	1,497
PV of tonnes avoided (Mt)	–	–	27
PV of power sent out (TWh)	38	38	0
Cost of Net Electricity Sent Out (€/MWh)	56.1	95.2	39.2
Specific CCS Cost (€/t CO ₂ avoided)	–	–	56

^{###} A total of 3.77 Mt is injected and 2.83 Mt is avoided each year

Sensitivity analyses

We analyse the effect of changes in the coal price, capital costs, reservoir permeability and project life on the cost of CO₂ avoided.

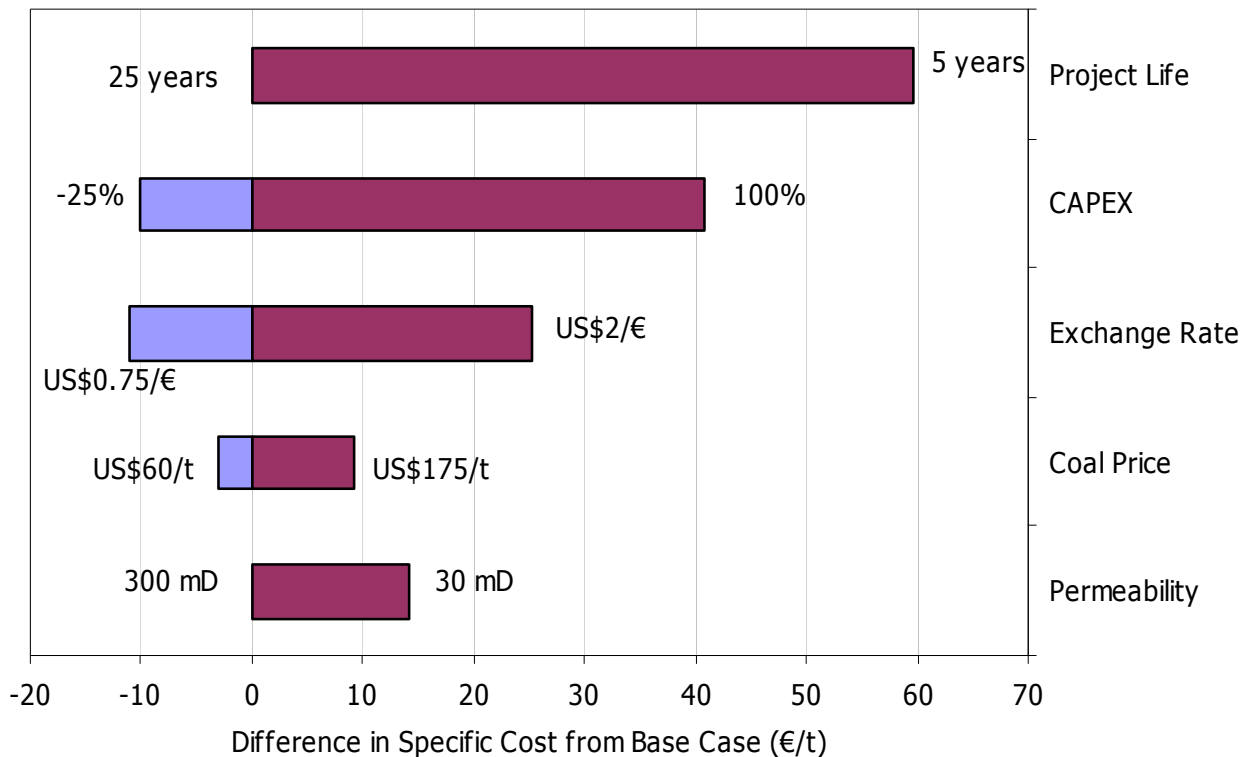


Figure 3 – Summary of sensitivity analyses for Case 3A

The storage capacity of the Portpatrick reservoir is uncertain. The costs in Table 4 assume that the reservoir has a capacity to inject over 100 million tonnes or 3.8 millions tonnes annually for 25 years. However this could be as low as 37 million tonnes. As far as the cost estimates are concerned, these uncertainties affect the injection period. If the injected period is reduced from 25 to 5 years, the specific cost of CC increases by €60 per tonne CO₂ avoided.

In addition, increases in the capital costs estimates can raise the specific cost of CCS by over €40 per tonne CO₂ avoided. Changes in the coal price and reservoir permeability also affect the costs, but to a lesser extent.

Again, evaluation costs were shown to have only a small effect on the estimate costs. Changes to the fracture gradient also have little effect.

Cost comparisons

This table shows the for all cases breakdown of the total base plus increment costs and the incremental specific costs per tonne CO₂ avoided.

Table 5 – Cost comparisons of project base cases

	Money-point PC	Money-point IGCC	Money-point with Cork Retrofit	Cork PC	Cork IGCC	Cork PC	Kilroot PC
Case Number	1A	1C	1D	2A	2C	2D	3A
Sent Out Power (MWe)	900	900	900	900	900	540	540
Total capital cost (€ million)	2,712	2,656	3,679	2,516	2,497	1,665	1,908
Annual operating cost (€ million/yr)	343	309	399	340	306	208	209
Abandonment cost (€ million)	101	87	162	54	50	50	108
Cost of Electricity Sent Out with CCS (€/MWh)	88	82	109	85	80	89	95
Specific Cost of CO ₂ avoided (€/t CO ₂ avoided)							
Separation	29.7	15.1	35.7	29.6	15.0	29.5	29.8
Transport	13.3	12.4	14.9	9.8	9.1	11.2	11.7
Injection	0.9	1.0	1.0	0.9	1.0	1.4	9.8
On Costs	3.5	2.9	4.5	2.9	2.4	3.3	4.5
Total	47.4	31.3	56.1	43.1	27.5	45.4	55.7

The lowest cost estimate of €28 per tonne CO₂ avoided is for CO₂ capture at an IGCC power at Cork, with storage in the Kinsale Head gas field. This reflects of the lower energy penalty associated with capturing CO₂ from the synthesis gas of the IGCC power plant and the short distance to Kinsale Head from Cork.

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1 Introduction

1.1 Aims and scope

This study is a preliminary assessment of the economics of CO₂ capture and storage (CCS) for selected potential CCS projects in Ireland. The analysis examines CO₂ capture from the flue gas of new power stations, followed by compression, pipeline transport and offshore storage in geological formations.

This study includes CCS cost estimates for the following cases –

- CO₂ captured from a 900 MW_e sent out pulverised coal power plant at Moneypoint, with storage at Kinsale Head depleted gas field (Case 1A).
- CO₂ captured from a 900 MW_e sent out pulverised coal power plant at Cork, with the CO₂ stored at Kinsale Head depleted gas field (Case 2A).
- CO₂ captured from a 540 MW_e sent out pulverised coal power plant at Kilroot, with the CO₂ stored at Portpatrick Basin (Case 3A).

For each case we estimate the capital, operating, abandonment, costs per tonne of CO₂ avoidance and per MWh of electricity supplied. The sensitivity of the estimates to changes in the US dollar - Euro exchange rate, pipeline routes, coal prices, capital costs, reservoir characteristics and evaluation costs of the each base case are also analysed.

In addition, we estimate –

- (a) the CCS costs of building a new integrated gasification combined cycle (IGCC) power plant at Moneypoint and Cork, with storage in Kinsale Head,
- (b) CCS costs of a new 540MW_e power station at Cork,
- (c) the cost of using alternative pipeline routes for the Moneypoint and Cork projects.

Table 6 summarises the cases evaluated.

Table 6 – Summary cases examined in report

Number	Source type	Source location	Sink	Sensitivity Analysis
Case 1A	900 MWe pulverised coal power plant	Moneypoint	Kinsale Head	Yes
Case 1B	900 MWe pulverised coal power plant	Moneypoint	Kinsale Head using alternative onshore route	No
Case 1C	900 MWe IGCC power plant	Moneypoint	Kinsale Head	No
Case 1D	900 MWe pulverised coal and retrofit natural gas power plants	Moneypoint and Cork	Kinsale Head	No
Case 2A	900 MWe pulverised coal power plant	Cork	Kinsale Head	Yes
Case 2B	900 MWe pulverised coal power plant	Cork	Kinsale Head with alternative offshore route	No
Case 2C	900 MWe IGCC power plant	Cork	Kinsale Head	No
Case 2D	540 MWe pulverised coal power plant	Cork	Kinsale Head	No
Case 3A	540 MWe pulverised coal power plant	Kilroot	Portpatrick Basin	Yes

Our report is a scoping analysis based on limited data. We have not carried out detailed process simulations of the capture process. Nor have we made reservoir simulations of the storage formations. Further information or more rigorous analysis might change the results presented in this report. Our economic analyses ignore the effect of tax and we have not analysed how CCS will be affected by the European Emissions Trading Scheme.

2 Methodology and assumptions

2.1 CO₂ avoided

The net reduction of CO₂ emissions as a result of CCS can be referred to as the amount of CO₂ avoided,

$$[\text{CO}_2 \text{ avoided}] = [\text{CO}_2 \text{ emitted without CCS}] - [\text{CO}_2 \text{ emitted with CCS}] \quad 1$$

The amount of CO₂ avoided is different from the amount of CO₂ stored, which represents the quantity of CO₂ that is injected into a geological reservoir.

Pictorially, the amount of CO₂ avoided and stored in million tonnes per year for the Kilroot project is shown in Figure 4.

A. Without CCS

CO ₂ generated	3.25 Mt/yr
CO ₂ captured and stored	0 Mt/yr
CO ₂ emitted	3.25 Mt/yr

B. With CCS

CO ₂ generated	4.19 Mt/yr
CO ₂ captured and stored	3.77 Mt/yr
CO ₂ emitted (CCS)	0.42 Mt/yr

C. Increment = (1) - (0)

CO ₂ generated	0.95 Mt/yr
CO ₂ captured and stored	3.7 Mt/yr
CO ₂ avoided	2.83 Mt/yr

Figure 4 - Mass of CO₂ avoided in the Kilroot to Portpatrick Basin Base Case Study

2.2 Process modelling

The cost and engineering estimates shown in this report are generated using a techno-economic model developed in-house at the University of New South Wales for the CO₂CRC.

The model determines the characteristics of the equipment, estimates the costs and the total energy consumption. We model the CO₂ separation, transport and injection phases of the CCS process. We do not model the power plant cycle.

As regards to CO₂ separation, we estimate the energy required for cooling and compressing the feed gas, pumping and regenerating the solvent.

The CO₂ compression and transport costs are influenced by a combination of the required down-hole injection pressure, the static head and frictional losses in the wells and flowlines.

For the Kilroot to Portpatrick Basin study we assume a minimum pressure of 86 bar (1,250 psia) and maximum pipeline pressure of 152 bar (2,200 psia). For the Moneypoint and Cork to Kinsale Head we assume a minimum pipeline pressure of 1 bar (15 psia) and a maximum pressure of 100 bar (1480 psia). The pipelines are made from X65 carbon-steel line pipe. We do not account for the effects of terrain and land use on pipeline construction costs.

In this analysis, many simplifications have been made. We have used short cut correlations and simplified process models. In addition we have not simulated the separation processes or the reservoir.

2.3 Economic modelling and assumptions

The techno-economic model estimates the individual equipment, operating, abandonment and the total costs of carbon capture and storage.

The main output from the model is the before-tax real specific cost of CO₂ avoided. This is defined as —

$$J = \frac{PV(\text{Capex}) + PV(\text{Opex}) + PV(\text{Abex})}{PV(\text{CO}_2 \text{ Avoided})} = \frac{PV(\text{Total Cost})}{PV(\text{CO}_2 \text{ Avoided})} \quad 2$$

where, PV represents the present value, of the capital cost or Capex in € million, operating costs or Opex € million, the abandonment costs or Abex in € million and the mass of CO₂ avoided.

The specific cost real cost of CCS for power plants can be calculated as:

$$J = \frac{\Delta COE}{\Delta EI_{CO_2}} = \frac{COE_{CCS} - COE_0}{EI_{CO_2,0} - EI_{CO_2,CCS}} \quad 3$$

where, COE is the cost of net electricity in € per MWh. EI represents the emission intensity of CO₂ in tonne per MWh. The subscripts 0 and CCS denote without and with CO₂ capture respectively.

We assume that the specific cost of CCS is the difference between the costs of a power plant with CCS and one without. This methodology reflects IEA and DOE guidelines¹. We have not included the effect of a carbon price from European Emissions Trading Scheme in

¹ The results presented in this report can be used to determine the CCS cost of CO₂ avoided in relation to different reference points. For example, the reference point could be a new best entrant power plant such as a CCGT plant without CCS. The CCGT plant has a COE of €60/MWh and an emission intensity of 0.4 ton/MWh CO₂. If we assume that a new power plant with CCS has a COE of €90/MWh and a CO₂ emission intensity of 0.1 ton/MWh, the specific cost of CCS can be calculated as (90-60) €/MWh ÷ (0.4-0.1)ton/MWh = €100/ t CO₂ avoided.

determining the cost of CCS or the sent out cost of electricity. Appendix 1 briefly describes how this can be calculated.

The change in cost of electricity can be calculated as:

$$\Delta COE = COE_{CCS} - COE_0 = \frac{PV(\text{Total Cost})_{CCS} - PV(\text{Total Cost})_0}{PV(\text{NESO})} \quad 4$$

NESO is the Net Electricity Sent Out (TWh). This is the same both with and without CCS.

We do not present the costs of CO₂ injected. However, this can be calculated using Equation 2 by replacing CO₂ avoided with the amount of CO₂ injected.

We assume that for the offshore component of CCS, the abandonment cost is 25% of the sum of capital costs of the CO₂ compressor, pipeline and injection wells and platforms. For the power plant and separation plant, we assume the abandonment costs are offset by the salvage value of the process equipment.

Table 7 lists the economic assumptions used in this analysis. The costs are in €2008 terms. The exchange rate is assumed to be 1.25 US per € based on the average daily exchange rate from January 2003 to May 2008.

Table 7 – Economic assumptions for base cases

Property	Value	Units
Cost year	2008	
Currency	Euro	€
Exchange rate	1.25	US\$ per €
Discount rate	7	% real
Project life (injection period)	25	Years
Construction period	2 (CCS) 3 (Power station)	Years
Capital cost phasing	40:60 (CCS) 20:45:35 (Power station)	%
Load factor	85	%
Fuel cost (bituminous coal)	90	US\$/tonne, equivalent to €2.5/GJ ² LHV ³
Fuel cost (natural gas)	10	\$/GJ, equivalent to €8/GJ
Unit power station capital cost (IEA-GHG, 2006)	1,560 pulverised coal 1,860 IGCC 890 CCGT	€/kW

² The cost of coal as \$ per tonne is converted to \$ per GJ assuming the thermal energy of bituminous coal is 27.9 GJ per tonne.

³ LHV represents the lower heating or calorific value, which is a measurement of the amount of heat released by burning a fuel at 25°C and returning the temperature of the product to 150 °C.

3 Moneypoint power station to Kinsale Head depleted gas field (Case 1)

3.1 Overview

3.1.1 Scope

This section discusses the cost of capturing CO₂ from a new power plant at Moneypoint, compressing it, transporting it 185 km onshore and 50 km and finally injecting it offshore into Kinsale Head. The CO₂ is injected at subcritical conditions into the Kinsale Head formation.

The proposed pipeline route is shown in Figure 5.



Figure 5 – Proposed pipeline route (Route A) from Moneypoint Power station to Kinsale Head depleted gas field

For the base case (Case 1A), we estimate the CCS costs of capturing CO₂ from the flue gas of a 900 MW_e sent out pulverised coal power plant. The total capacity of the plant is 1,160 MW_e including the power required for CCS. This does not include the power for auxiliaries.

We also estimate CCS costs of –

1. using an alternative overland pipeline route B (Case 1B) as shown in Figure 5;
2. recovering CO₂ from high pressure synthesis gas of an IGCC power plant (Case1C); and
3. CO₂ capture from the two existing natural gas power plants at Cork to the Moneypoint to Kinsale pipeline (Case 1D).

3.1.2 Separation

We assume that 90% of the CO₂ generated at the Moneypoint power plant is recovered.

For the base case (Case 1A), we assume that CO₂ is recovered from the flue gas of the supercritical pulverised coal power plant using Mitsubishi Heavy Industries' KS1 solvent. Studies by IEA GHG R&D and by Mitsubishi have shown the energy required for regeneration using this solvent is significantly less than that required by commercially available solvents such as MEA (Mimura et al., 1997; IEA-GHG, 2004; IEA-GHG, 2006). Based on the findings of Mimura et al. (2000), we assume that a proportion of the energy needed for regeneration is obtained from the waste heat of the flue gas cooling and CO₂ compression cycle.

For Case 1C, CO₂ is recovered from the synthesis gas of the gasification system in the IGCC power plant using Selexol solvent. The synthesis gas conditions are based on a Shell gasifier (Stork, 1999).

The feed gas conditions for both the supercritical pulverised coal and IGCC power plants are set out in Table 8. The flue gas conditions for the supercritical pulverised power plant are from the IEA GHG R&D Report No PH4/33 (IEA-GHG, 2004). The synthesis gas conditions are from the Stork Consultancy Report No 632300-008 (Stork, 1999).

Table 8 – Feed gas conditions of supercritical pulverised and IGCC power plants

Property	Supercritical pulverised coal power plant flue gas	Shell IGCC power plant synthesis gas
Power station without CCS thermal efficiency (% LHV)	38	39
Feed gas flowrate (kg/s)	1,345 (for 1160 MW _e plant)	190 (for 980 MW _e plant)
Feed gas temperature (°C)	110	37
Feed gas pressure (bar)	1	20
Molar/volumetric composition of feed gas		
CO ₂	13%	36%
CO	–	5.5%
H ₂	–	55%
N ₂ + Ar + traces	75%	3.5%
O ₂	5%	–
H ₂ O	7%	0
SO _x ppm	220 mg/m ³ (STP)	–
NO _x ppm	200 mg/m ³ (STP)	–
CO ₂ emissions (t/MWh)	0.807	0.71

3.1.3 Transport and injection

After leaving the separation process, the CO₂ gas is compressed for pipeline transport, onshore and offshore, followed by subcritical injection into Kinsale Head. CO₂ is injected at sub-critical temperature and pressure throughout the life of the project. We have not considered changes to the characteristics of CO₂ in the formation over time and if/or how it may influence the conditions for injection.

The pressure at the outlet of the CO₂ compressor is determined as a function of the required bottom-hole injection pressure, the static head and the frictional losses in the wells and pipeline.

We model subcritical injection using a steady-state analytical injectivity equation.

The properties of transport Route A and Kinsale Head are given in Table 9.

Table 9 – CO₂ storage transport for Case 1 and reservoir properties of Kinsale Head Gas Field

Property	SI units	Imperial units
Pipeline length onshore, (Route A)	185 km	115 mi
Pipeline length, offshore	50 km	31 mi
Pipeline length, Total	235 km	146 mi
Surface temperature	10°C	50 °F
Water depth	80 m	262 ft
Injection target depth (sub surface)	985 m	3,232 ft
Net pay	20 m	66 ft
Effective permeability	382 mD	–
Areal extent of reservoir	200 km ²	80 mi ²
Reservoir temperature	30 °C	86 °F
Reservoir pressure	7 bar	100 psi
Fracture pressure	177 bar	2,572 psi

3.2 Results – Case 1A

3.2.1 Economics

Our cost estimates for the base case (Case 1A) are shown in Table 10. In this table "PV" stands for present value.

Table 10 – Base case results for Moneypoint Power station to Kinsale Gas Field

	Reference Power station without CCS (A)	Power station with CCS (B)	Incremental effect of CCS (B - A)
Annual CO ₂ emissions (million tonnes)	5.41	0.7	(4.71) [#]
Capital Cost (€ million)			
Power station	1,282	1,590	308
Separation	–	372	372
CO ₂ compressor	–	74	74
Pipeline (onshore)	–	159	159
Pipeline (offshore)	–	72	72
Booster	–	0	0
Injection wells	–	11	11
Injection platforms	–	26	26
Owners' costs	90	161	72
Contingency	137	247	109
Total capital cost	1,509	2,712	1,203
Annual operating cost (€ million/yr)	229	343	114
Abandonment cost (€ million)	0	101	101
PV of capital costs (€ million)	1,306	2,325	1,019
PV of operating Costs (€ million)	2,174	3,262	1,088
PV of abandonment costs (€ million)	0	14	14
PV of all costs (€ million)	3,480	5,601	2,121
PV of CO ₂ avoided (Mt)	–	–	44.8
PV of power sent out (TWh)	64	64	0.0
Cost of net electricity sent out (€/MWh)	54.6	87.9	33.3
Specific CCS cost (€/t CO ₂ avoided)	–	–	47.4

[#]6.27 Mt is injected each year

The estimated cost of capturing CO₂ at a 900 MW_e sent-out power plant at Moneypoint and transporting 185 km onshore and storing it in Kinsale Head is €47 per tonne CO₂ avoided. Our best estimate of the total capital expenditure including the power plant is over €2,700.

The annual operating cost is estimated to be €343 million and the abandonment cost of the project is approximately €114 million.

The cost of electricity sent out for a power plant with CCS is over €88 per MWh. This is an increase of €33 per MWh or 60% compared to a power plant without CCS.

The amount of CO₂ avoided annually by capturing CO₂ at the Moneypoint power plant is 4.71 million tonnes.

3.2.2 Breakdown of cost estimates

Table 11 and Figure 6 give a breakdown of our cost estimates for the incremental effect of CCS.

Table 11 – Breakdown of CCS costs of Case 1A

	Capital costs (€ million)	Annual operating costs (€ million/year)	Abandonment costs (€ million)	Specific Cost of CO ₂ avoided (€/t CO ₂ avoided)
900MW _e Power station	1,509	229	0	–
1160MW _e Power station	1,829	292	0	–
Incremental effect of CCS				
Power station	308	63.7	0	19.5
Capture	372	44.7	0	16.5
CO ₂ compressor	74	3.0	19	2.1
Pipeline (onshore)	159	1.6	40	3.4
Pipeline (offshore)	72	0.7	18	1.6
CO ₂ booster	0	0.0	0	0.0
Injection wells	11	0.2	3	0.3
Injection platforms	26	0.5	6	0.6
Owners' costs	72	–	6	1.4
Contingency	109	–	9	2.1
Total incremental	1,203	114	101	47.4
Total	2,712	343	101	–

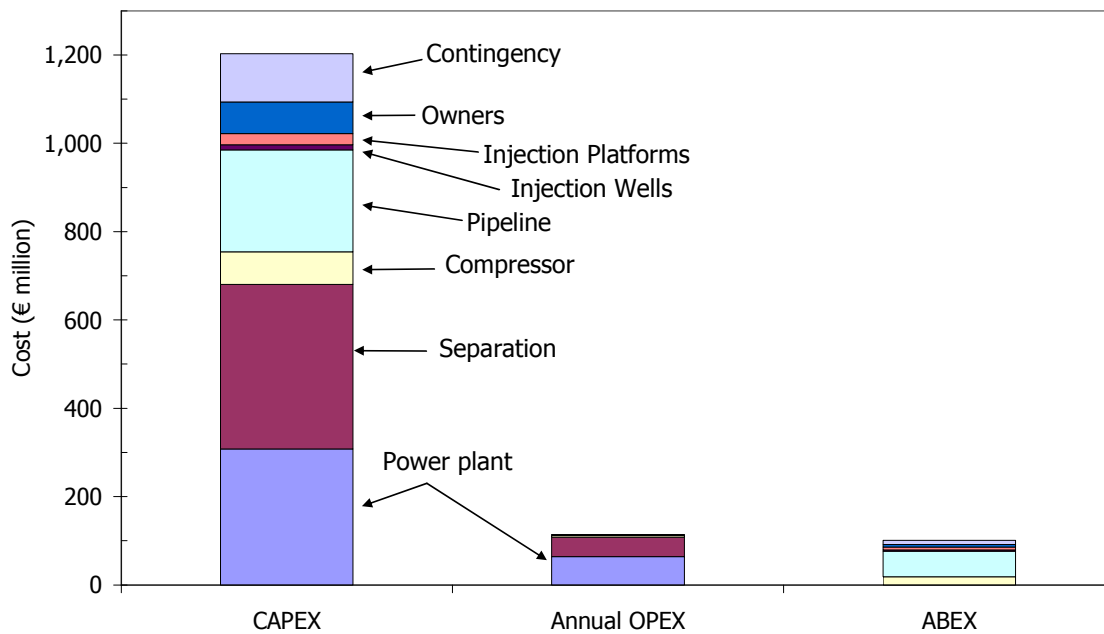


Figure 6 – Breakdown of the costs of CCS for Case 1A

Compared to a 900 MW_e power plant without CCS, the incremental capital and abandonment costs are €1,203 and €101 million respectively. The incremental operating cost is €114 million. Table 11 and Figure 6 show that the largest component for CCS is the cost of CO₂ separation. This accounts for over 30% of the total incremental capital costs. The second largest cost is for the power plant upgrade (26%), followed by the capital costs of transport pipelines (20%).

3.2.3 Engineering

Table 12 sets out the engineering design of the CCS process.

Table 12 – CCS engineering design for Case 1A

Property	SI units	Imperial units
Capture		
Number of absorption trains	5	–
Column height	35 m	155 ft
Column diameter	5.9 m	19 ft
Number of compressor trains	1	–
Total cooling water required	45 kt/d	100 million lb/d
Pipeline		
Nominal pipeline diameter	660 mm	26 in
Total line pipe steel required	39 kt	86 million lb
Injection		
Number of wells	2	–
Well Inner diameter	220 mm	86 in
Number of platforms	1	–
Pressure profile		
CO ₂ compressor inlet pressure	1 bar	14.7 psi
CO ₂ compressor discharge pressure and onshore pipeline inlet pressure	97 bar	1,400 psi
Onshore crossing pressure	80 bar	1,160 psi
Pipeline outlet pressure and top-of-well pressure	15 bar	1,090 psi
Bottom-of-well pressure	8 bar	120 psi

We do not require any booster pumps along the route of the 185 km onshore pipeline. This is because we have set a high maximum pipeline pressure. In optimising the transport cost, compressing the CO₂ to a high value at the start of the pipeline results in the lowest cost. We could set a lower maximum pipeline pressure, but this would require the use of booster pumps and probably a needless increase in the estimated costs. Increases in the formation pressure may also lead to the need for boosters, larger pipelines and/or more wells. This analysis is outside our scope.

Table 13 summarises the power plant performance. The total energy penalty for a power plant with CCS compared to one without is 22% or a loss of 8% LHV. The largest energy loss is associated with solvent regeneration, which is part of the CO₂ separation process. This accounts for over half of the total CCS energy penalty. The second largest energy loss is for CO₂ compression at the start of the transport pipeline.

Table 13 – Power Plant Performance for Case 1A

Property	Power (MW _e)	Thermal efficiency (LHV) %
Total net electricity generated	1,160	38
Equivalent electrical regenerator duty	137	
Pumping	5	
Blower	35	
CO ₂ compressor	83	
CO ₂ booster	0	
Total consumed by CCS	260	8
Net electricity sent out	900	30

3.3 Sensitivity analyses of Case 1A

The following describe analyses of the sensitivity of the economics of the 900 MW_e pulverised coal power plant at Money point to changes in –

1. US\$-€ exchange rate
2. coal price
3. capital costs
4. reservoir permeability
5. fracture gradient
6. number of injection wells
7. evaluation costs

3.3.1 Exchange rate

The US dollar - Euro exchange rate has fluctuated significantly since 1999 when the Euro started being traded. The exchange rate has been as low as 0.83 US\$ per € in October 2000, to as high as 1.6 US\$ per € in April 2008. The variation in the exchange rate affects the unit costs of imported equipment and other commodities. This in turn affects the costs of the CCS project.

Figure 7 shows the estimated cost of electricity with CCS and the specific cost of CO₂ avoided, as the US dollar to Euro varies from US\$0.75 to US\$2 per €. At a low US dollar exchange rate, the electricity cost is close to €135 per MWh and the specific CCS cost is over €65 per tonne CO₂ avoided. As the US dollar increases in value, the electricity cost and CCS costs falls to less than €70 per MWh and €40 per tonne CO₂ avoided respectively.

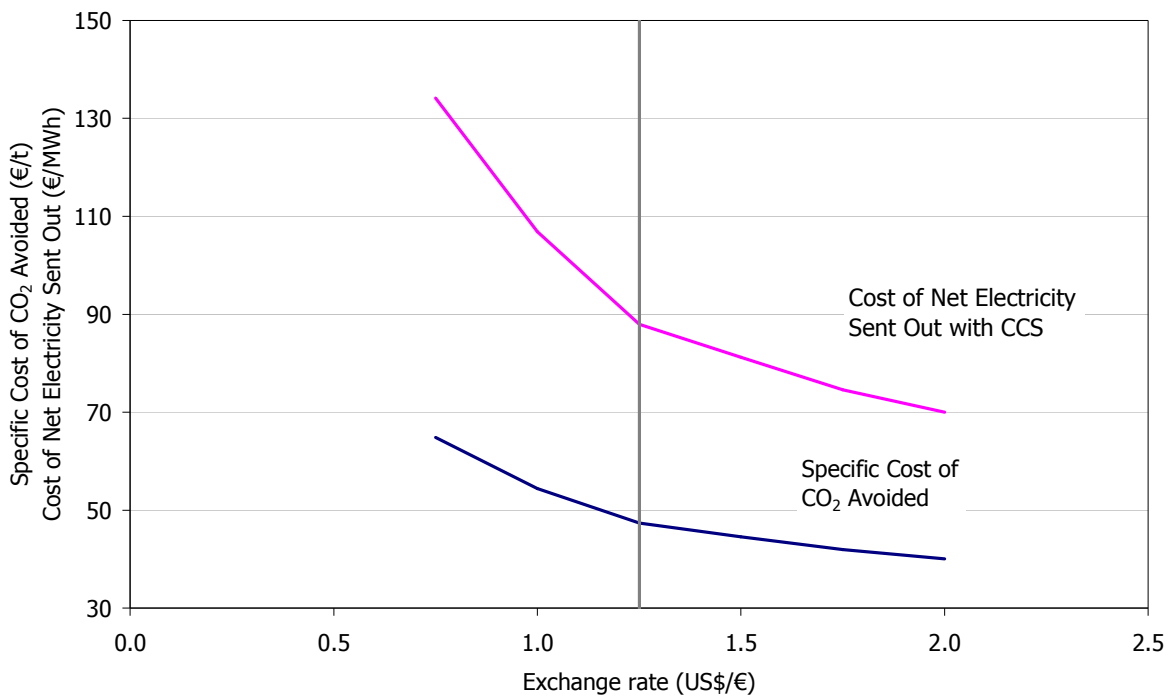


Figure 7 – Sensitivity of electricity and CCS costs of Case 1A with changes in the US exchange rate

3.3.2 Coal price

Changes in market conditions can cause significant fluctuations in the coal price. Figure 8 shows the change in cost of net electricity sent out and the specific cost of CO₂ avoided as the coal price varies between US\$60 and US\$175 per tonne. As the coal price increases from the base case assumption of US\$90 to US\$175 per tonne, there is a €30 per MWh increase in the cost of electricity. The corresponding specific cost of CO₂ avoided increases by more than €10 per tonne CO₂ avoided. The equivalent cost of coal in Euros is €48 to €14 per tonne.

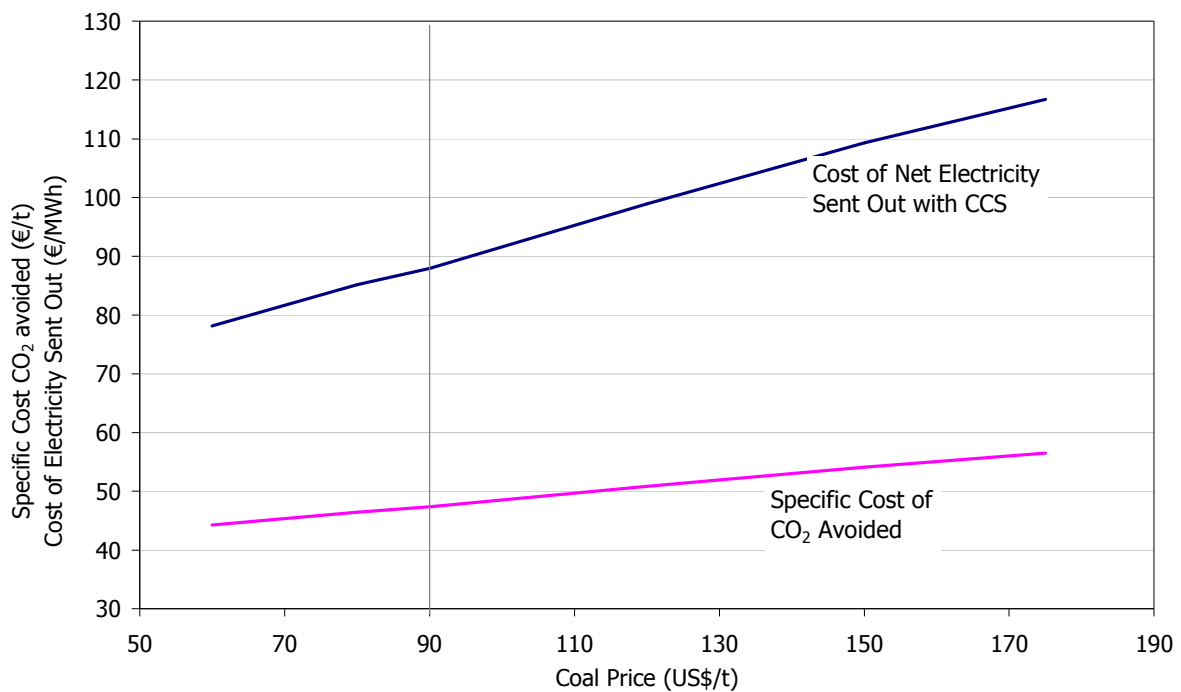


Figure 8 – Sensitivity of electricity and CCS costs of Case 1A with changes in the coal price

3.3.3 Capital costs

There are significant uncertainties in estimating capital costs. Figure 9 shows the changes in specific cost CO₂ avoided if we reduce the capital costs by 25% or increase it by 100% of our central estimates. With the highest capital costs, the cost of electricity sent out can be as large as €140 per MWh and the specific costs of CCS can be as much as €80 per tonne CO₂ avoided.

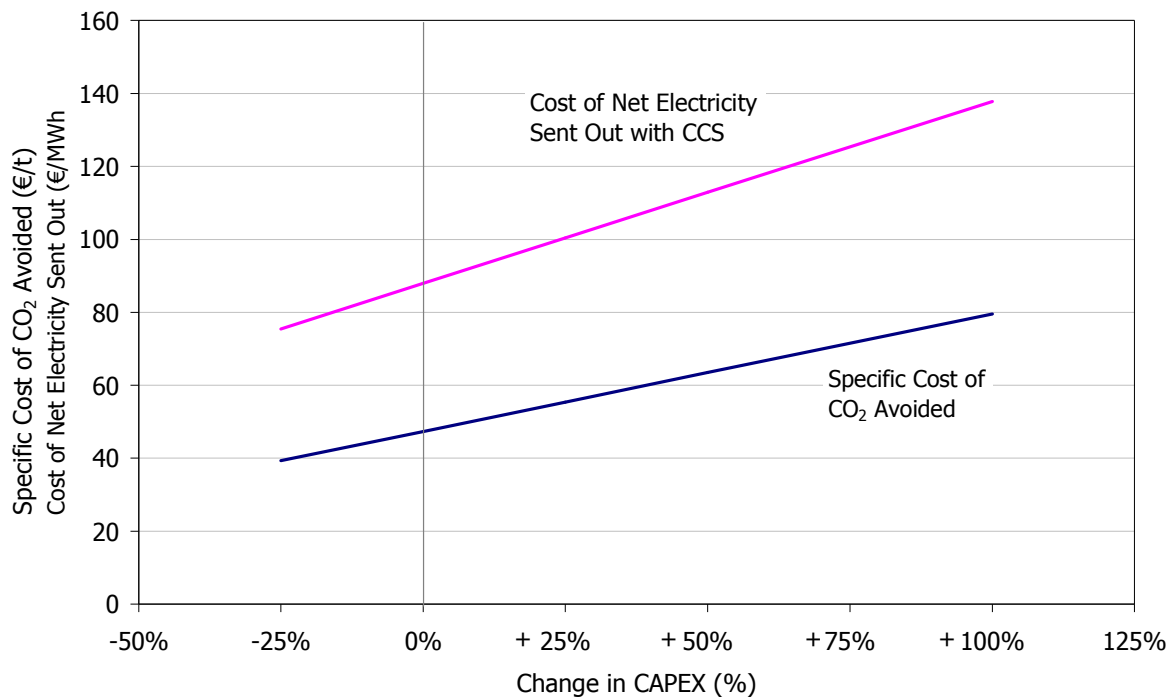


Figure 9 – Cost of electricity and specific cost of CCS with uncertainties in capital cost of case 1A

3.3.4 Reservoir permeability

In general, the number of injection wells required depends strongly on the reservoir bottom-hole pressure, which is inversely related to the permeability in the storage reservoir. A change in the permeability can therefore affect the capital cost and the overall specific cost of CO₂ avoided.

Figure 10 shows the effect of permeability on the cost of electricity and on the specific cost of CO₂ avoided. In fact, the figure shows that permeability has no impact on the cost. This is a different outcome to our analysis of the Kilroot-Portpatrick scenario (section **Error! Reference source not found.**). This is because we model the injection of subcritical CO₂ with an analytical injectivity equation that does not take into account pressure interference between wells nor pressure build-up in the formation. Because of these simplifying assumptions, the number of wells required for injection could be underestimated by at least an order of magnitude. We therefore analyse the effect on costs with increasing numbers of injection wells (section 3.12).

To remove the high degree of uncertainty in this analysis we recommend a comprehensive simulation of the reservoir.

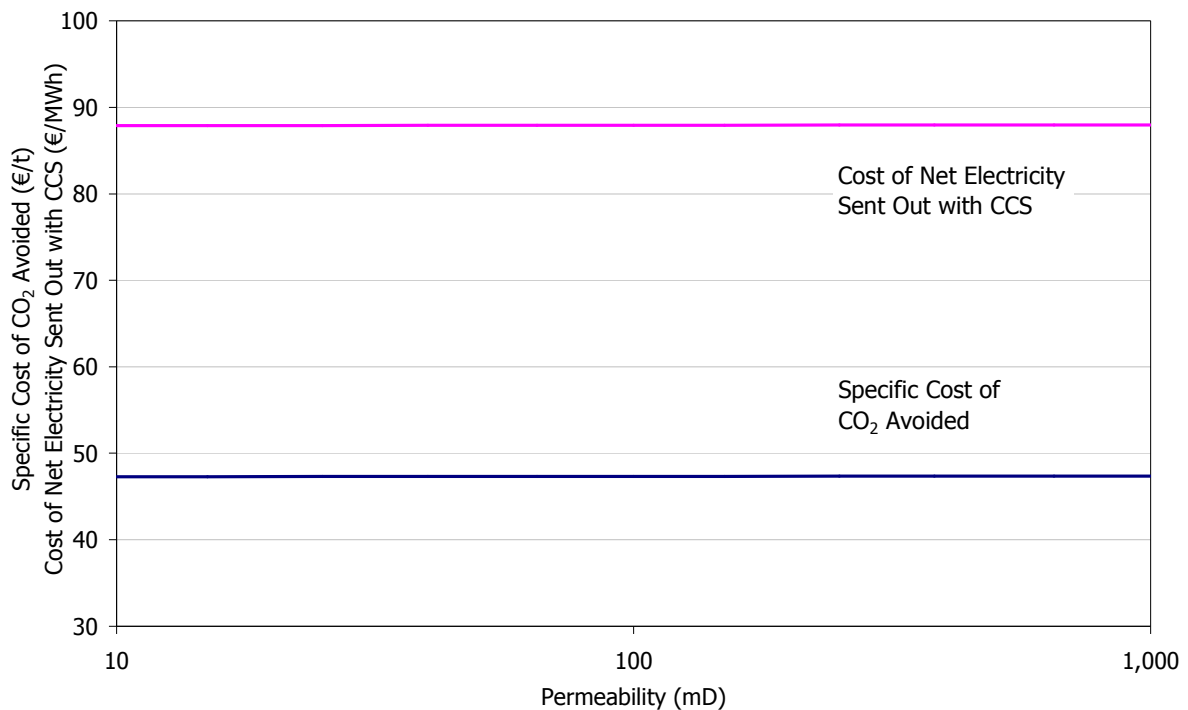


Figure 10 – Cost of electricity sent out and specific cost of CO₂ avoided for Case 1A using different permeabilities

3.3.5 Fracture gradient

We have limited information on fracture gradients in Kinsale Head and so have assumed a value of 177 bar (2,572 psi) for the fracture pressure based on our experience of other reservoirs. Figure 11 shows that there is no change in cost with increasing fracture gradient. As discussed in section 3.3.4, the effect of well interference and pressure build-up has been ignored. This is because we have used simplifying assumptions for CO₂ injectivity in our modelling.

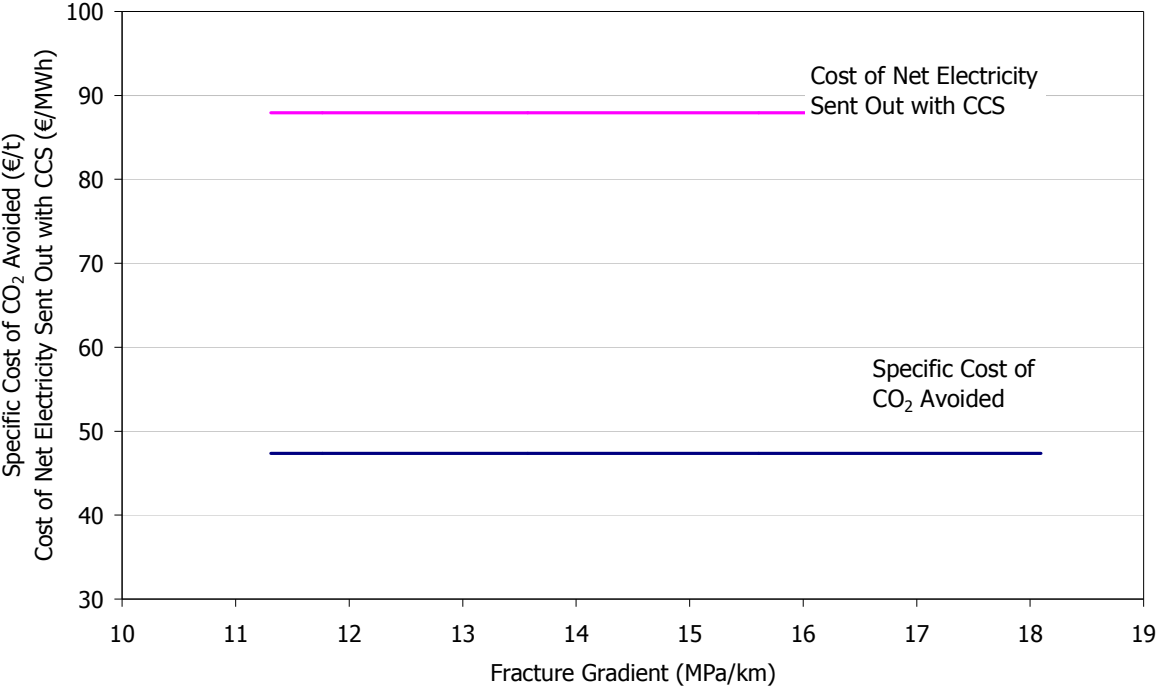


Figure 11 – Cost of net electricity sent out and specific cost of CO₂ avoided for Case 1A with fracture pressure

3.3.6 Number of injection wells

In our base case analysis, we estimate that one injection well is required. As mentioned above, there is significant uncertainty in this because we use a simple injectivity equation to model subcritical CO₂ injection. Figure 12 shows the change in the cost of electricity and specific CCS cost as the number of wells increases from 1 to 200.

Assuming that injection wells are spaced 2 km apart, the physical constraint for the maximum number of wells is over 60. At a spacing of 1 km, over 250 wells may be feasible. We have chosen a range of 1 to 200 wells in this analysis to demonstrate the change in costs when a project requires an exceptionally large number of wells (200).

For one injection well, the cost of electricity is over €88 per MWh and the specific cost of CCS is €50 per tonne CO₂ avoided. If the project requires 10 wells, the specific cost of CCS increases to €55 per tonne CO₂ avoided and the cost of electricity sent out with CCS is €92 per MWh. With 100 wells, the cost increases to over €100 per MWh and specific CCS cost is over €90 per tonne CO₂ avoided.

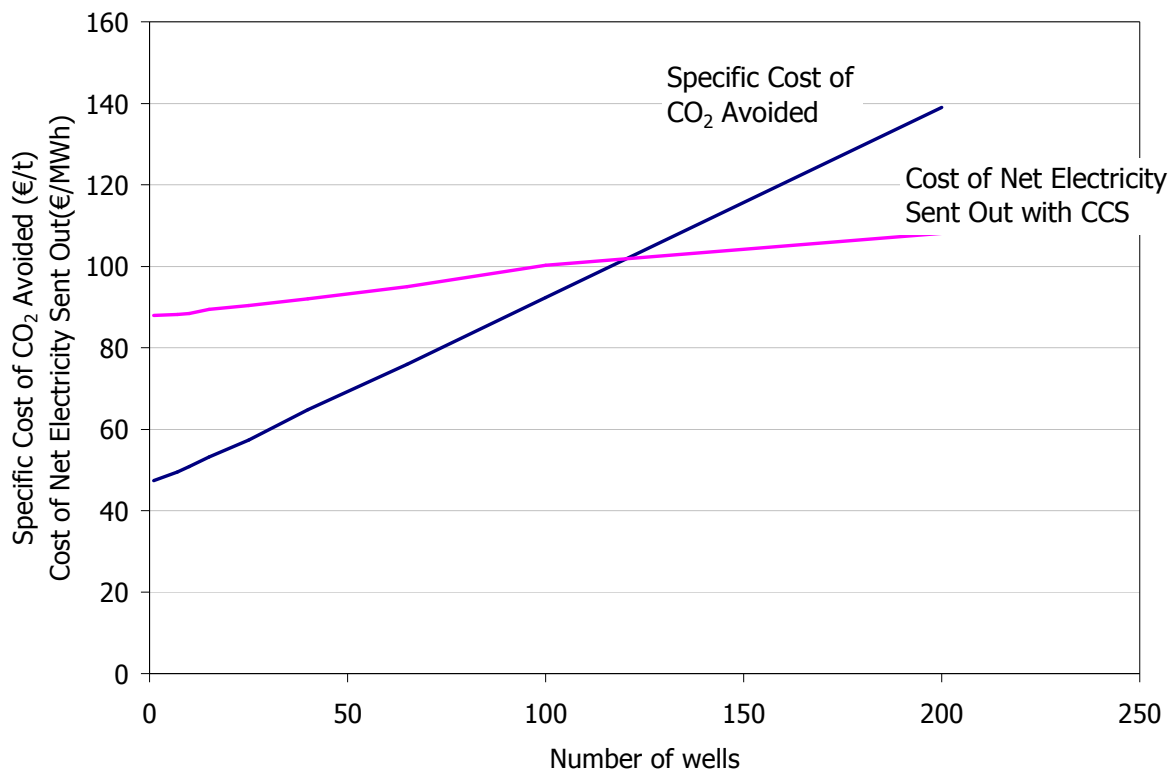


Figure 12 – CCS costs with increasing number of injection wells for Case 1A

3.3.7 Reservoir evaluation costs

The analyses above exclude the costs of evaluating the reservoir in assessing its suitability for CO₂ storage. Figure 13 shows the change in the cost of electricity and the specific CCS costs if the net present value (NPV) of evaluation costs is incorporated.

For example, if we assume drilling 5 wells over a 5 year period at cost of €16 million per well, then the NPV of the evaluation cost would be €65 million. From Figure 13, the cost of electricity for case 1A would increase from €88 to €89 per MWh and the specific cost of CCS would increase to more than €50 per tonne CO₂ avoided. These costs do not change significantly with increasing evaluation costs because the total project costs are an order of magnitude times larger.

The effect of evaluation costs would be more significant if we incorporated into the analysis the risk that the evaluation programme might not prove up the storage site. We do not attempt such an analysis in this report.

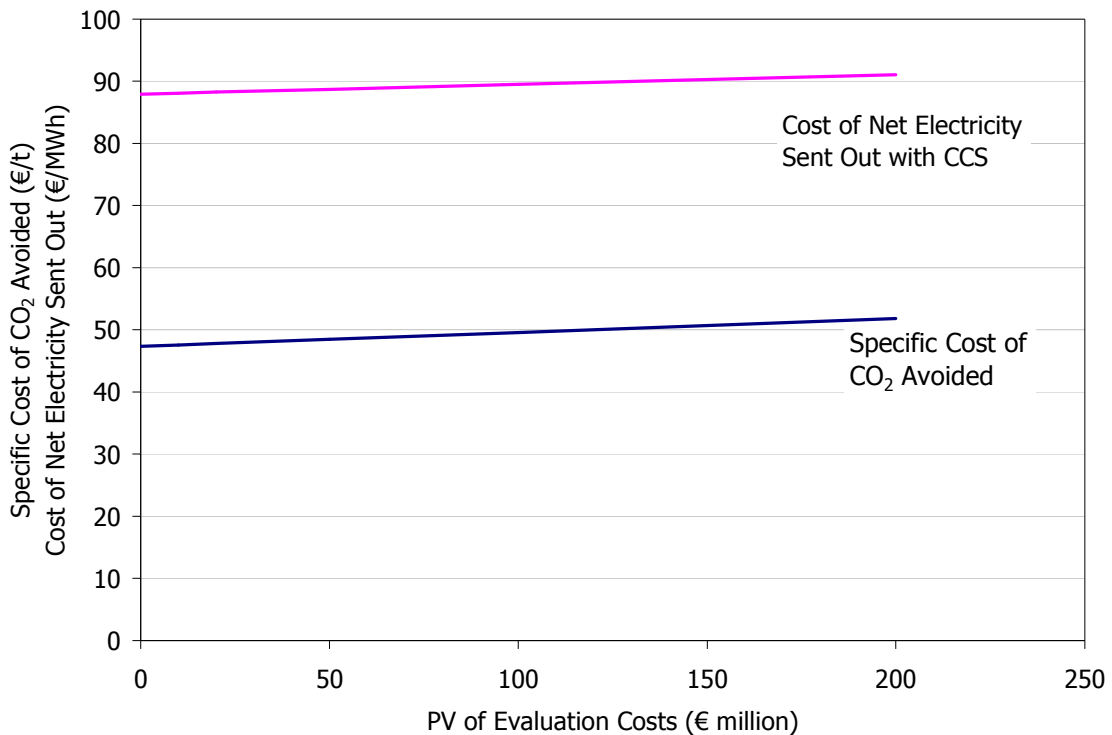


Figure 13 – Cost of net electricity sent out and specific cost of CO₂ avoided for Case 1A with evaluation costs

3.4 Alternative pipeline route (Case 1B)

Two pipeline routes have been proposed for transporting the compressed CO₂ from Moneypoint power station to the Kinsale Head gas field. In the base case, we analyse Route A. In this analysis, we examine the alternative route, Route B, shown in Figure 5.

Route B has a total length of 132.5 km including 2.5 km of water crossing at the Shannon Estuary. This route does not cross Cork Harbour. We estimate the cost of the water crossing using cost data for offshore pipelines. We recognise that the true cost will need to reflect local conditions.

Table 14 summarises the capital, operating and specific CCS costs if CO₂ is transported using route B.

Table 14 – Breakdown of CCS costs of Case 1B

	Capital costs (€ million)	Annual operating costs (€ million/year)	Abandonment costs (€ million)	Specific Cost of CCS (€/t CO ₂ avoided)
900 MW _e Power station	1,510	229	0	–
1160 MW _e Power station	1,874	293	0	–
Incremental effect of CCS				
Power station	309	63.9	0	19.5
Capture	373	44.8	0	16.5
CO ₂ compressor	74	3.0	19	2.1
Pipeline (water crossing)	37	0.4	9	0.8
Pipeline (onshore)	101	1.0	25	2.2
Pipeline (offshore)	70	0.7	17	1.5
CO ₂ booster	0	0.0	0	0.0
Injection wells	11	0.2	3	0.3
Injection platforms	26	0.5	6	0.6
Owners' costs	70	–	6	1.3
Contingency	107	–	9	2.1
Total Incremental	1,178	114	94	46.9
Total	2,688	343	94	–

The alternative route has similar costs to Route A (Table 11). The shorter distance of Route B reduces the total onshore pipeline cost from approximately €160 million to €100 million. However the water crossing at the Shannon Estuary adds €37 million to the total transport cost. Therefore, the total capital costs are similar.

3.5 IGCC Power Plant (Case 1C)

Table 15 shows the cost estimates for case 1C, CO₂ capture from an IGCC power plant at Moneypoint with CO₂ storage in Kinsale Head.

Table 15 – Breakdown of CCS costs of Case 1C, 900MW_e IGCC at Moneypoint

	Capital costs (€ million)	Annual operating costs (€ million/yr)	Abandonment costs (€ million)	Specific Cost of CCS (€/t CO ₂ avoided)	COE _{NESO} (€/MWh)
900 MW _e Power station	1,753	257	0	–	62.1
980 MW _e Power station	1,879	278	0	–	
Incremental effect of CCS					
Power station	107	20.8	0	7.2	
Capture	363	25.6	0	13.6	
CO ₂ compressor	65	2.6	16	2.0	
Pipeline(onshore)	128	1.3	32	3.1	
Pipeline(offshore)	67	0.7	17	1.6	
CO ₂ booster	0	0.0	0	0.0	
Injection wells	11	0.2	3	0.3	
Injection platforms	26	0.5	6	0.7	
Owners' costs	54	–	5	1.1	
Contingency	82	–	8	1.7	
Total Incremental	903	52	87	31.3	19.8
Total	2,656	309	87	–	81.9

In our best estimate, the capital cost of building a new 900 MW_e sent out IGCC power plant at Moneypoint is €1,753 million. Adding the cost of CO₂ capture, transport and storage, the total capital cost increases to €2,656 million. This capital cost is very similar to estimates for a new 900 MW_e sent out pulverised coal power plant with CCS (Table 10).

The cost of electricity from an IGCC power plant with CCS is €82 per MWh. This is less than for a pulverised coal with CCS (Case 1A). This is because CCS for IGCC technology is cheaper than that for post combustion technology.

CCS for IGCC is cheaper because the energy penalty of this system is significantly lower. For a capacity of 900 MW_e, an IGCC power plant requires 80 MW_e to recover and compress the CO₂. In comparison, pulverised coal CCS requires 260 MW_e (Table 13). The difference arises because CO₂ capture from the synthesis gas of the IGCC plant uses a physical solvent. This requires significantly less energy for solvent regeneration. The effect of this is that the

operating cost for IGCC with CCS is less - €309 million compared to €343 million per year for pulverised coal.

We have assumed that using Selexol physical solvent has a significant benefit. In addition, we have not simulated the water shift reaction nor modelled the power plant cycle. This might affect the total energy consumption. We estimate that the energy penalty of the CCS process is 8%.

Figure 14 shows the effect of changes in the energy penalty on CCS costs. If the energy penalty increases to 15%, the specific cost of CCS increases to €40 per tonne CO₂ avoided. If the CCS energy penalty is 22%, the specific cost of CCS for an IGCC with CCS is similar to the cost of capture from a supercritical pulverised coal power plant (Case 1A).

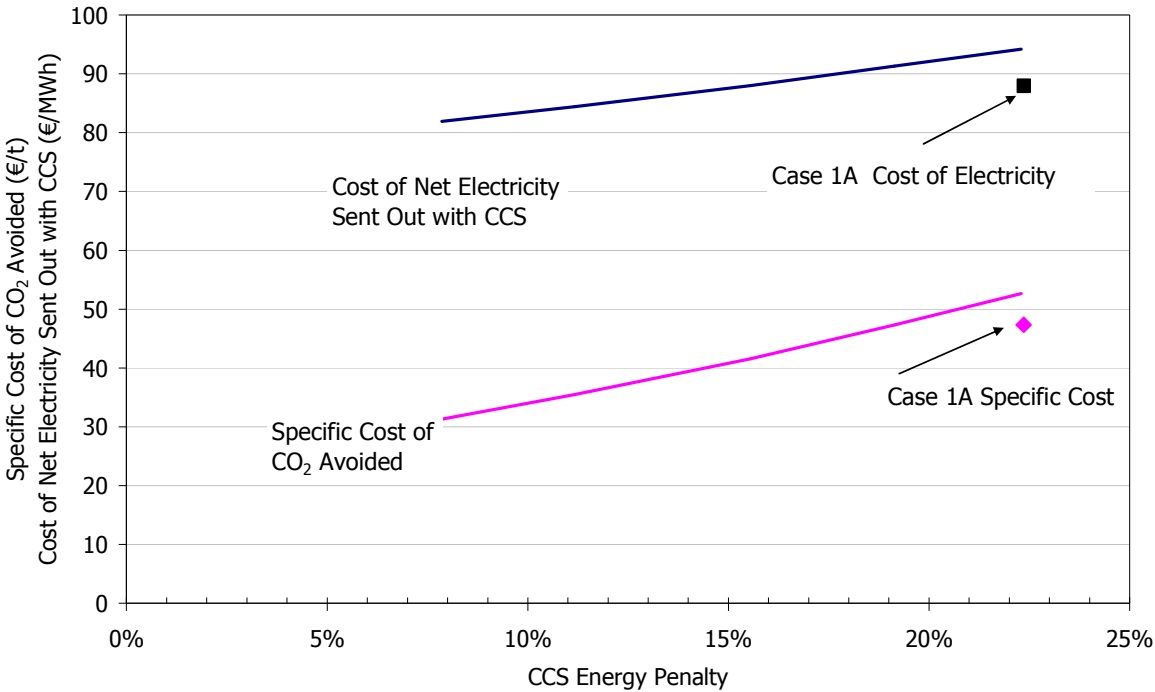


Figure 14 Change in of CCS and cost of electricity costs of IGCC with CCS with increasing CCS energy penalty

3.6 Retrofit CCS at Cork power stations (Case 1D)

The following analysis examines the cost of retrofitting CCS to two existing natural gas fired power stations at Cork. The combined annual CO₂ emission from these power plants is 2 million tonnes.

We assume that 90% of CO₂ emissions are recovered from the flue gas of the 445 MW_e and the 525 MW_e natural gas fired power stations. This is shown in Figure 15. CO₂ capture facilities are located at each power plant and use KS1 solvent technology. We have ignored heat integration for the CO₂ capture process because such opportunities might not be available at the existing power plants.

The CO₂ recovered at each site is compressed to a sub-critical condition. It is then piped onshore for 6 km in two pipelines before joining the CCS pipeline from Moneypoint power station at the shore crossing.

The energy for the capture and compressor facilities is provided by a purpose-built 65 MWe new gas fired power plant fitted with CCS. It is located at the next to the 445 MW_e power plant. We assume the new natural gas fired power plant costs €890 per MW and the cost for natural gas is €8 per GJ.



Figure 15 – Proposed pipeline route from the retrofitted power stations at Cork to the main Moneypoint CCS pipeline

Table 16 – CCS costs of retrofitting existing power stations at Cork (Case 1D)

	Capital costs (€ million)	Annual operating costs (€ million/yr)	Abandonment costs (€ million)	Specific Cost of CCS (€/t CO ₂ avoided)	COE _{NESO} (€/MWh)
1,160 MW _e Power station with CCS at Moneypoint	2,712	343	101	47.4	88
900 MWe Reference power station with no CCS	1,511	229	0	–	54.6
1,220 MWe Power station with no CCS ⁴	1,968	329	0	–	–
Incremental effect of CCS					
Power Plant	388	100	0	20.8	
Separate compressor 1	903	61.2	0	21.6	
Pipeline (Cork onshore)	278	5.6	70	4.8	
Pipeline (onshore from Moneypoint)	4	0.0	1	0.1	
Pipeline (offshore) compressor 4	143	1.4	36	2.2	
Injection wells	70	0.7	17	1.1	
Injection platforms	0	0.0	0	0.0	
Owners	21	0.4	5	0.4	
Contingency	35	0.7	9	0.6	
Total incremental	129	–	10	1.8	
	197	–	15	2.7	
Total incremental	2,168	170	162	56.1	54.4
Total	3,679	399	162	–	109⁵

The costs of CCS add approximately €970 million to the total capital costs compared to capture at Moneypoint alone. The specific cost of CCS increases from €47 to €56 per tonne CO₂ avoided. The amount of CO₂ avoided increases from 4.7 to 6.5 million tonnes per year.

⁴ This is the sum of costs for building a new 1,155 MW_e pulverised coal power plant at Moneypoint and a new 65 MW_e natural gas fired power plant at Cork

⁵ This is the aggregated cost of electricity with CCS for the power plants at Cork and Moneypoint.

The total cost of the CCS project is €3,680 million. This includes the costs of building a new 1,160 MW_e power plant at Moneypoint and of building a new gas fired power plant to supply energy for CO₂ capture at Cork.

In this case, we capture more CO₂ than for the Case 1A. We might expect that by capturing more CO₂, there would be economies of scale. However, the specific CCS costs have increased by approximately €10 per tonne CO₂ avoided rather than decreased.

The costs of CO₂ separation and CO₂ compression for this case (Table 16) are more than for the base case (Table 11), whereas the costs of transport and injection are less. There are economies of scale in transporting a larger volume of CO₂ along the offshore pipeline. However, other costs increase because we are separating CO₂ at four different locations and need a new external power plant. The increased capital costs of separation are much higher than the reduced offshore pipeline costs and so the overall specific cost of CCS increases.

4 Cork power station to Kinsale Head depleted gas field (Case 2)

4.1 Overview

4.1.1 Scope

In this section we evaluate the cost of CO₂ capture from a new 900 MW_e sent-out pulverised coal power station at Cork. The CO₂ is compressed and transported 6 km onshore, followed by 50km offshore to be stored at Kinsale Head (Figure 16). The CO₂ is injected at subcritical conditions into Kinsale Head for the life of the project.

We have not included the costs of setting up new transmission lines. We have also excluded the cost of coal handling facilities in Cork Harbour.

The total power generated at the new base case (Case 2A) supercritical pulverised coal power plant is 1,150 MW_e excluding the power for auxiliaries. Of this total, 250 MW_e is required for CCS.

We also estimate CCS costs of –

1. using an pipeline route that is exclusively offshore (Case 2B) as shown in Figure 16;
2. recovering CO₂ recovered from high pressure synthesis gas of an IGCC power plant (Case 2C). The sent out power is 900 MW_e; and
3. capturing CO₂ from a 540 MW_e sent-out pulverised coal power plant at Cork with storage at Kinsale Head (Case 2D).



Figure 16 – Proposed pipeline route from the 900 MW_e power station at Cork to Kinsale Head gas field

4.1.2 Separation

We assume that 90% of the CO₂ emissions from a supercritical pulverised coal power plant is recovered using post-combustion KS1 solvent absorption (Case 2A and 2D).

For Case 2C, we model CO₂ recovery using Selexol physical solvent from the synthesis gas of a 970 MW_e IGCC power plant.

The flue gas conditions for the supercritical pulverised power plant are from the IEA GHG R&D Report No PH4/33 (IEA-GHG, 2004). The synthesis gas conditions are from the Stork Consultancy Report No 632300-008 (Stork, 1999). These are set out in Table 17.

Table 17 – Flue gas conditions for an 1150 MW_e pulverised coal power plant and 970 MW_e IGCC plant

Property	Supercritical pulverised coal power plant flue gas	Shell IGCC power plant synthesis gas
Power station thermal efficiency (without CCS) (% LHV)	38	39
Feed gas flowrate (kg/s)	1,330 kg/s (for 1150 MW _e plant)	190 kg/s (for 970 MW _e plant)
Feed gas temperature (°C)	110	37
Feed gas pressure (bar)	1	20
Molar/volumetric composition of flue gas		
CO ₂	13%	36%
N ₂ + Ar + traces	75%	5.5%
O ₂	5%	55%
H ₂ O	7%	3.5%
SO _x ppm	220 mg/m ³ (STP)	–
NO _x ppm	200 mg/m ³ (STP)	0
CO ₂ emissions	0.807 t/MWh	–

4.1.3 Transport and injection

After separation, the CO₂ is compressed for offshore transport. It is injected at subcritical conditions into Kinsale Head. We assume that CO₂ remains at subcritical conditions in the reservoir throughout the project. We have not accounted for changes in the characteristics of the CO₂ in the reservoir over time.

The transport and the properties of the Kinsale Head gas field are given in Table 18.

Table 18 – CO₂ storage transport for Cork and reservoir properties of Kinsale Head gas field

Property	SI units	Imperial units
Onshore pipeline length	6 km	4 mi
Offshore pipeline length	50 km	31 mi
Surface temperature	10°C	23 °F
Water depth	80 m	262 ft
Injection target depth (sub surface)	985 m	3,232 ft
Net pay	20 m	66 ft
Effective permeability	382 mD	–
Areal extent of reservoir	200 km ²	80 mi ²
Reservoir temperature	30 °C	86 °F
Reservoir pressure	7 bar	100 psi
Fracture pressure	177 bar	2,572 psi

4.2 Results - Case 2A

4.2.1 Economics

The estimated costs for Case 2A are shown in Table 19. In this table "PV" stands for present value.

Table 19 – Base case results for 900 MW_e Cork Power station to Kinsale Head Gas Field

	Reference Power station without CCS (A)	Power station with CCS (B)	Incremental effect of CCS (B - A)
Annual CO ₂ emissions (million tonnes)	5.40	0.70	(4.70) ^{##}
Capital Cost (€ million)			
Power station	1,280	1,584	304
Separation	–	371	371
CO ₂ compressor	–	74	74
Pipeline (onshore)	–	4	4
Pipeline (offshore)	–	67	67
Booster	–	0	0
Injection wells	–	11	11
Injection platforms	–	26	26
Owners' costs	90	150	60
Contingency	137	229	92
Total capital cost	1,507	2,516	1,009
Annual operating cost (€ million/yr)	228	340	112
Abandonment cost (€ million)	0	54	54
PV of capital costs (€ million)	1,304	2,161	857
PV of operating Costs (€ million)	2,170	3,235	1,065
PV of abandonment costs (€ million)	0	8	8
PV of all costs (€ million)	3,474	5,404	1,930
PV of CO ₂ avoided (Mt)	–	–	44.7
PV of power sent out (TWh)	64	64	0.0
Cost of net electricity sent out (€/MWh)	54.6	85.0	30.3
Specific CCS cost (€/t CO ₂ avoided)	–	–	43.1

^{##} 6.24 Mt of CO₂ is injected each year

The cost of capturing CO₂ at a power plant in Cork and storing at Kinsale Head is €43 per tonne CO₂ avoided. The total capital expenditure including the power plant is over €2,500. The annual operating cost is estimated to be €340 million and the abandonment cost is over €50 million. The cost of electricity with CCS is over €85 per MWh. The amount of CO₂

avoided annually for this CCS configuration is 4.74 million tonnes. The present value of CO₂ avoided over the project life is 45 million tonnes.

4.2.2 Breakdown of cost estimates

Table 20 gives a breakdown of our cost estimates. The figure shows the incremental capital, operating and abandonment cost of the base case 2A. The total incremental cost of CCS project from Cork to Kinsale Head is €1,010 million. Of the total capital costs, CO₂ separation accounts for 37%. The additional power plant required contributes 30% of the cost, while the cost of the CO₂ compressor and pipelines contribute approximately 7% each.

Table 20 – Breakdown of CCS costs of Case 2A

	Capital costs (€ million)	Annual operating costs (€ million/year)	Abandonment costs (€ million)	Specific Cost of CO ₂ avoided (€/t CO ₂ avoided)
900MW _e Power station	1,507	228	0	–
1155MW _e Power station	1,865	291	0	–
Incremental effect of CCS				
Power station	304	63.0	0	19.3
Capture	371	44.5	0	16.4
CO ₂ compressor	74	3.0	19	2.1
Pipeline (onshore)	4	0.0	1	0.1
Pipeline (offshore)	67	0.7	17	1.5
CO ₂ booster	0	0.0	0	0.0
Injection wells	11	0.2	3	0.3
Injection platforms	26	0.5	6	0.6
Owners' costs	60	–	3	1.1
Contingency	92	–	5	1.8
Total Incremental	1,009	112	54	43.1
Total	2,516	340	54	–

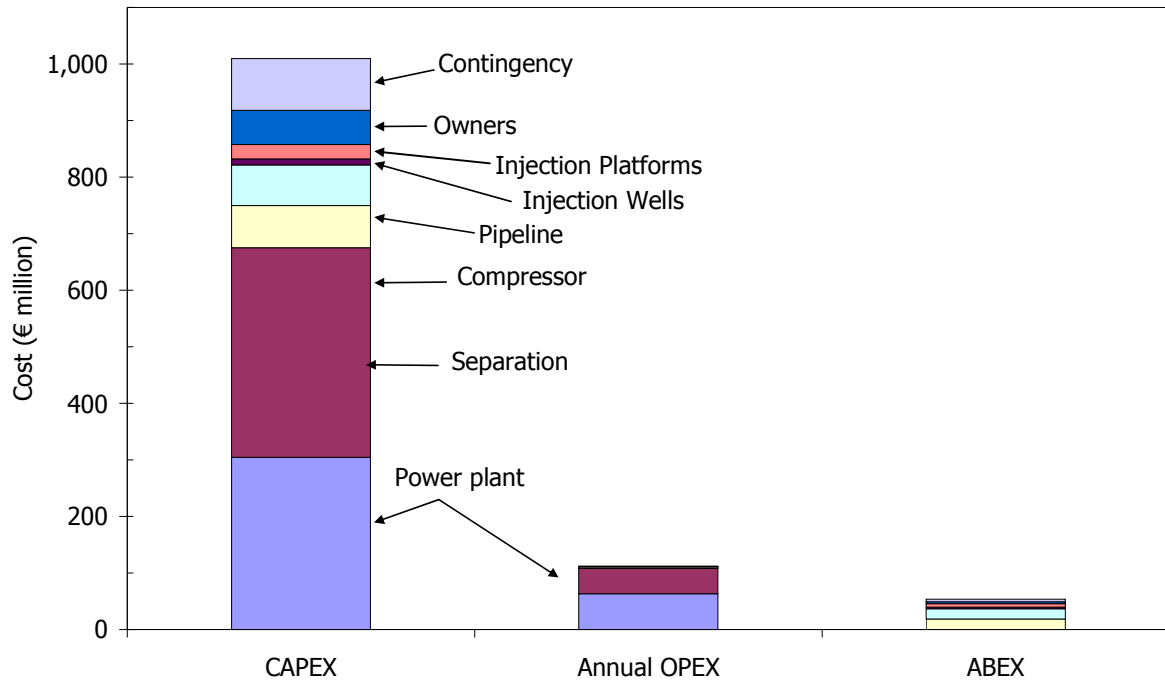


Figure 17 – Breakdown of the costs of CCS for Case 2A

4.2.3 Engineering

Table 21 sets out the engineering design of the CCS process from a 1,150 MW_e power plant at Cork to Kinsale Head.

Table 21 – CCS engineering design for Case 2A

Property	SI units	Imperial units
Capture		
Number of absorption trains	5	–
Column height	35 m	150 ft
Column diameter	5.9 m	19 ft
Number of compressor trains	1	–
Total cooling water required	45 kt/d	100 million lb/d
Pipeline		
Nominal pipeline diameter	560 mm	22 in
Total line pipe steel required	8 kt	3.7 million lb
Injection		
Number of wells	1	–
Well Inner diameter	22 mm	8.681 in
Number of platforms	1	–
Pressure profile		
CO ₂ compressor inlet pressure	1 bar	14.7 psi
CO ₂ compressor discharge pressure and onshore pipeline inlet pressure	87 bar	1,270 psi
Onshore crossing pressure	85 bar	1,250 psi
Pipeline outlet pressure and top-of-well pressure	75 bar	1,090 psi
Bottom-of-well pressure	8 bar	120 psi

Table 22 summarises the performance for the 1,150 MW_e power plant at Cork. The total equivalent electricity energy needed for CCS is 252 MW_e. The energy for solvent regeneration accounts for over half of this energy, with the energy for feed gas and CO₂ compression accounting for the remainder.

Table 22 – Power Plant Performance for Case 2A

Property	Power (MW _e)	Thermal efficiency (LHV) %
Total Net Generated	1,155	38
Equivalent Electrical Regenerator Duty	136	
Pumping	5	
Blower	33	
CO ₂ compressor	81	
CO ₂ booster	0	
Total Consumed by CCS	256	8
Net Sent Out	900	30

4.3 Sensitivity analyses of Case 2A

The following shows the sensitivity of the economics of the 900 MW_e pulverised coal power plant at Cork to changes in –

1. US\$ - € exchange rate
2. coal price
3. capital costs
4. number of injection wells
5. evaluation costs

4.3.1 Exchange rate

Figure 18 shows the costs as the exchange rate varies from US\$ 0.75 to US\$ 2 per €. At an exchange rate of \$US0.75 per €, the CCS cost increases to €60 per tonne of CO₂ avoided from the base case estimate of €43 per tonne of CO₂ avoided. As the value of the Euro increases, the CCS project and electricity costs falls to less than €40 per tonne CO₂ avoided and €70 per MWh respectively.

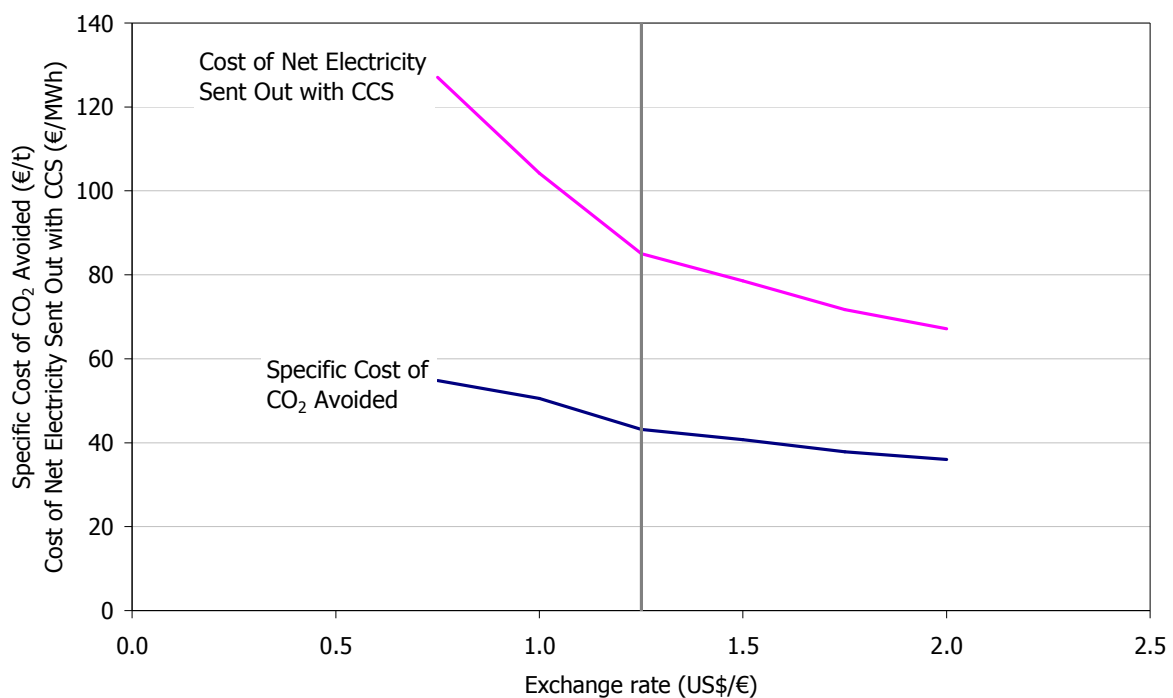


Figure 18 – Cost of electricity sent out and CCS costs of Case 2A with changes in the US exchange rate

4.3.2 Coal price

Changes in market conditions can cause significant fluctuations in the coal price. Figure 19 shows the change in cost of electricity and the cost of CCS as the coal price varies between US\$60 and US\$175 per tonne. As the coal price increases from the US\$90 to US\$175 per tonne, there is a €30 per MWh increase in the cost of electricity and a €50 per tonne increase in the cost of CCS.

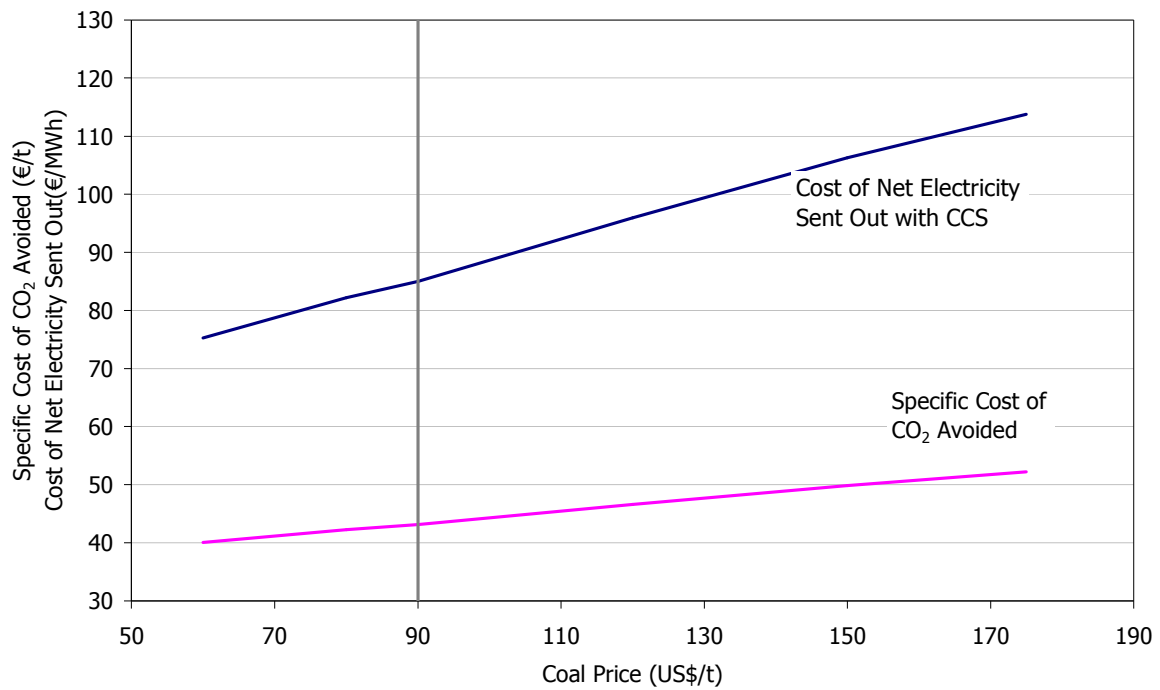


Figure 19 – Cost of electricity and specific cost of CO₂ avoided with changes in the coal price for Case 2A

4.3.3 Capital costs

There are significant uncertainties in estimating capital costs. Figure 20 shows the change in CCS cost estimates as capital costs vary between -25% and +100% of our central estimates. If the capital costs double, the cost of electricity can be as large as €140 per MWh and the specific costs of CCS can be almost €80 per tonne CO₂ avoided.

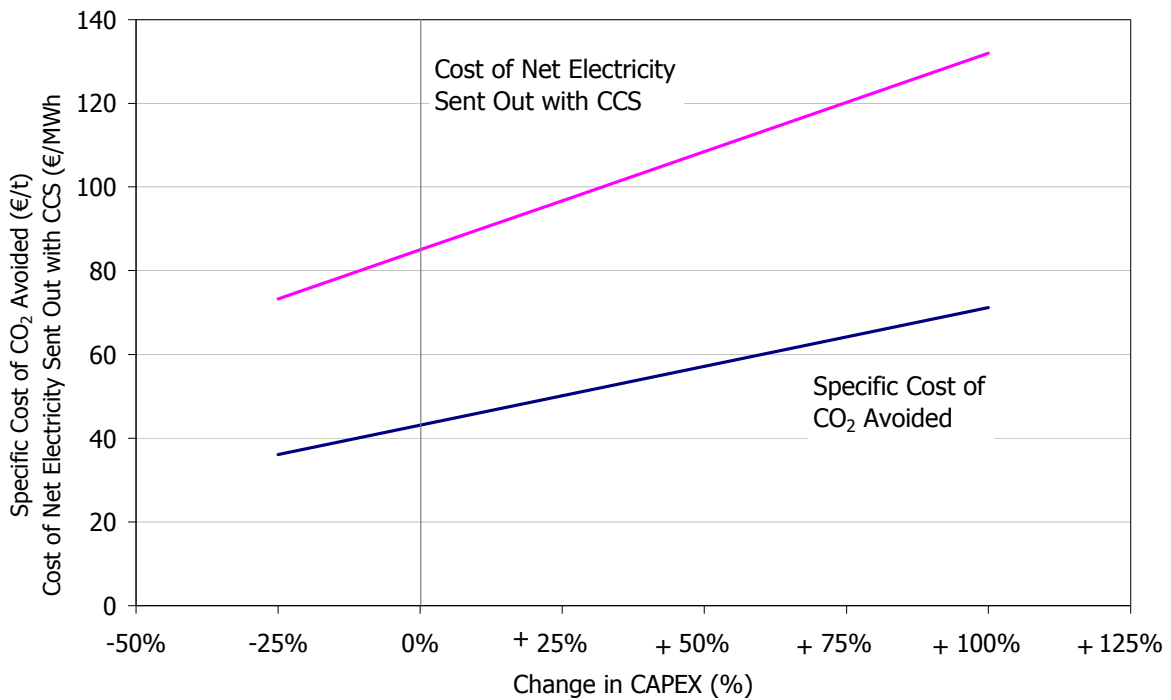


Figure 20 – Cost of electricity and specific cost of CO₂ avoided with changes in capital cost of Case 2A

4.3.4 Number of injection wells

As discussed in sections **Error! Reference source not found.** and section **Error! Reference source not found.**, we have used a simple CO₂ injectivity equation to model subcritical CO₂ injection into Kinsale Head. This method neglects the effects of well interference and pressure build-up in the formation. Therefore, variations in permeability and fracture gradient do not affect the number of wells required.

However, the number of wells required is strongly dependent on the bottom-hole pressure, which is inversely related to the permeability. In addition, the fracture gradient influences the pressure range within which injection is possible. As the fracture gradient falls, this injection window narrows and more wells are required

Figure 21 shows how the costs of capture at Cork vary with the number of wells. Increasing the number of wells from 1 to 10 raises the cost of electricity to more than €85 per MWh. The cost of CCS is approximately €45 per tonne CO₂ avoided. If there are over 150 wells, the cost of electricity and specific costs of CCS are over €130 per MWh and €110 per tonne CO₂ avoided.

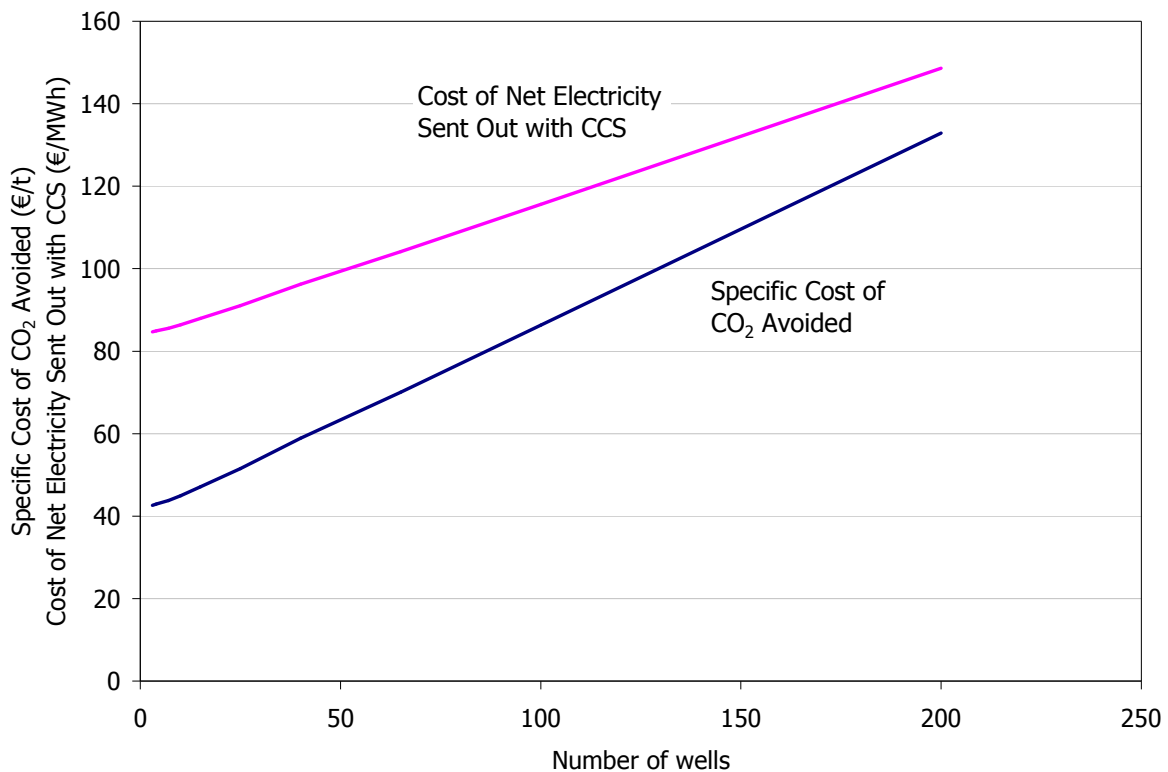


Figure 21 – Cost of electricity and specific cost of CO₂ avoided for Case 2A with increasing number of wells

4.3.5 Reservoir evaluation costs

Figure 22 shows how the cost of electricity and the CCS costs are affected by evaluation costs.. If the present value of an evaluation programme has a cost of €75 million, the cost of electricity increases from €85 to €86 per MWh and the specific cost of CCS would increase to €50 per tonne CO₂ avoided. Adding the evaluation costs has only a small impact on the total costs of CCS.

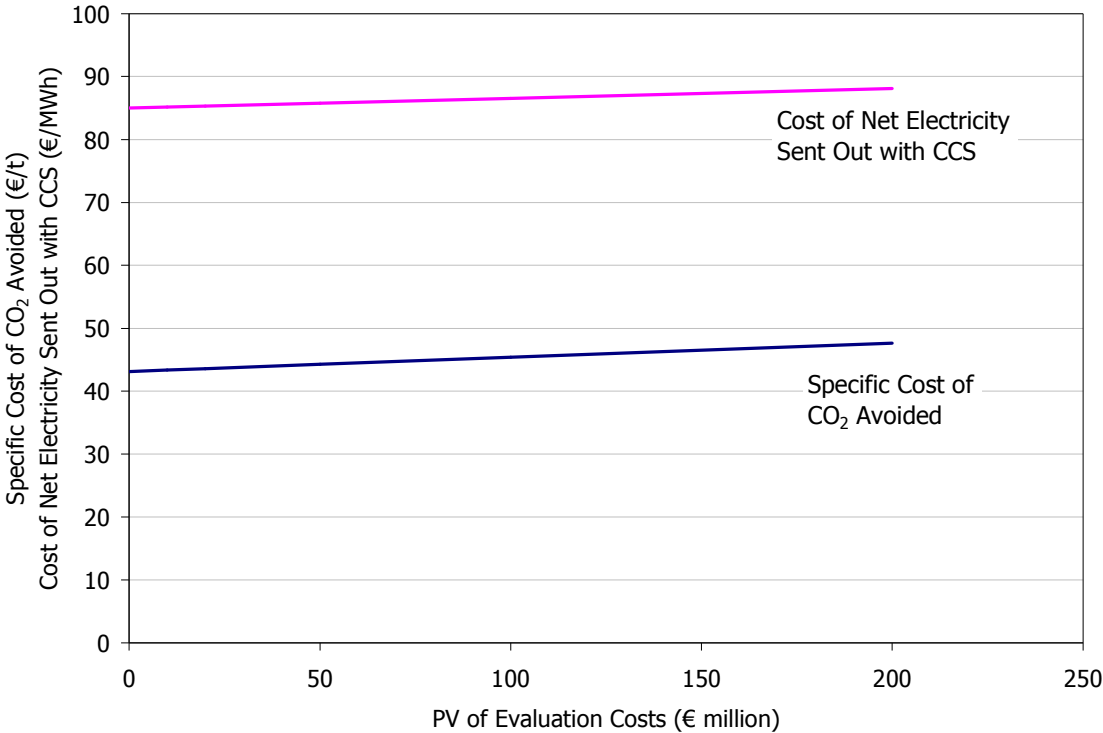


Figure 22 – Cost of net electricity and specific cost of CO₂ avoided with evaluation costs of Case 2A

The effect of evaluation costs would be more significant if we incorporated into the analysis the risk that the evaluation programme might not prove up the storage site. We do not attempt such an analysis in this report.

4.4 Alternative offshore pipeline route (Case 2B)

In the base case, the CO₂ is transported 6 km onshore and 50 km offshore. The following sensitivity examines the costs of CCS if the compressed CO₂ is piped 60 km offshore from Cork to Kinsale gas field. Table 23 summarises the capital, operating and specific CCS costs.

The capital and specific costs of CCS for the alternative route are similar to those for the base case 2A (Table 19).

Table 23 – Breakdown of CCS costs of 900 MW_e at Cork, followed by 56 km offshore transport

	Capital costs (€ million)	Annual operating costs (€ million/year)	Abandonment costs (€ million)	Specific Cost of CCS (€/t CO ₂ avoided)
900MW _e Power station	1,505	228	0	–
1,150MW _e Power station	1,863	291	0	–
Incremental effect of CCS				
Power station	304	62.9	0	19.3
Capture	370	44.5	0	16.4
CO ₂ compressor	74	3.0	19	2.1
Pipeline (offshore)	74	0.7	18	1.6
CO ₂ booster	0	0.0	0	0.0
Injection wells	11	0.2	3	0.3
Injection platforms	26	0.5	6	0.6
Owners' costs	60	–	3	1.2
Contingency	92	–	5	1.8
Total Incremental	1,011	112	54	43.2
Total	2,516	340	54	–

4.5 IGCC power plant (Case 2C)

The estimated costs for Case 2C, are in Table 24.

Table 24 – Breakdown of CCS costs of an IGCC power station at Cork with CCS

	Capital costs (€ million)	Annual operating costs (€ million/yr)	Abandonment costs (€ million)	Specific Cost of CCS (€/t CO ₂ avoided)	COE _{NESO} (€/MWh)
900 MW _e Power station	1,750	256	0	-	62.1
970 MW _e Power station	1,871	276	0	-	
Incremental effect of CCS					
Power station	103	20.0	0	6.9	
Capture	361	25.5	0	13.5	
CO ₂ compressor	65	2.6	16	2.0	
Pipeline (onshore)	4	0.0	1	0.	
Pipeline(offshore)	65	0.7	16	1.6	
CO ₂ booster	0	0.0	0	0.0	
Injection wells	11	0.2	3	0.3	
Injection platforms	26	0.5	6	0.7	
Owners' costs	44	–	3	0.9	
Contingency	68	–	5	1.4	
Total Incremental	747	50	50	27.5	17.4
Total	2,497	306	50	–	79.5

The specific cost of CO₂ avoided is €28 per tonne. The total capital cost including the cost of the new IGCC power plant is approximately €2,500 million. Compared to an IGCC power plant without CCS, the incremental capital cost is almost €750 million.

The cost of CCS for an IGCC power plant with CCS at Cork is €15 per tonne CO₂ avoided less than the cost of CCS at a pulverised coal power plant (Table 20). This is because of the smaller energy penalty.

4.6 540 MW_e power plant at Cork (Case 2D)

Our estimates for Case 2D are shown in Table 25.

Table 25 – Breakdown of CCS costs of an IGCC power station at Cork with CCS

	Capital costs (€ million)	Annual operating costs (€ million/yr)	Abandonment costs (€ million)	Specific Cost of CCS (€/t CO ₂ avoided)	COE _{NESO} (€/MWh)
543 MW _e Power station	982	140	–	–	56.8
692 MW _e Power station	1,207	177	–	–	–
Incremental effect of CCS					
Power station	191	37.2	0	19.2	
Capture	218	26.4	0	16.0	
CO ₂ compressor	65	2.6	16	3.0	
Pipeline 1	4	0.0	1	0.1	
Pipeline 2 (offshore)	65	0.7	16	2.3	
CO ₂ booster	0	0.0	0	0.0	
Injection wells	11	0.2	3	0.4	
Injection platforms	26	0.5	6	1.0	
Owners' costs	41	–	3	1.3	
Contingency	62	–	5	2.0	
Total Incremental	683	68	50	45.4	32.0
Total	1,665	208	50	–	88.8

The total capital costs for building a new 540 MW_e sent out pulverised coal power plant with CCS at Cork is €1,665 million. The cost of electricity is €89 per MWh and the cost of CCS is approximately €45 per tonne CO₂ avoided. The cost of building a new 540 MW_e power plant with CCS is almost €850 million less than the cost of a 900 MW_e power plant with CCS (Table 19). The cost of electricity and CCS increases by 5%.

5 Kilroot power station to Portpatrick Basin (Case 3)

5.1 Overview

5.1.1 Scope

This section is an assessment of the economics of CO₂ capture and storage (CCS) from a new supercritical bituminous power station located on the coast at Kilroot, Northern Ireland. The captured CO₂ is compressed and piped 40km offshore to the Portpatrick Basin for geological storage.

The net power sent out to the grid from the power station is 540 MW_e. All energy requirements for the CCS configuration (capture, transport and storage) are assumed to be provided by the same plant. The total capacity of the power station is 697 MW including the power required for CCS.



Figure 23 – Proposed pipeline route from Kilroot Power station to Portpatrick Basin

5.1.2 Separation

We assume that 90% of the CO₂ emissions from the Kilroot supercritical pulverised coal power plant are recovered using post-combustion solvent absorption. We assume that the separation plant uses Mitsubishi Heavy Industries' KS1 solvent with heat integration for the solvent regeneration system (Mimura et al., 2000).

The flue gas conditions for the supercritical pulverised power plant are from the IEA GHG R&D Report No PH4/33 (IEA-GHG, 2004) and are outlined in Table 26.

Table 26 – Flue gas conditions for a 700 MW_e pulverised coal power plant

Property	SI units	Imperial units
Power station Thermal Efficiency (without CCS)	38 % LHV	–
Flue gas flowrate (for 700 MW _e plant)	810 kg/s	1,786 lb/s
Flue gas temperature	110°C	230°F
Flue gas pressure	1 bar	14.5 psi
Molar/volumetric composition of flue gas		
CO ₂		13%
N ₂ + Ar + traces		75%
O ₂		5%
H ₂ O		7%
SO _x ppm		220 mg/m ³ (STP)
NO _x ppm		200 mg/m ³ (STP)
CO ₂ emissions		0.807 t/MWh

5.1.3 Transport and injection

After separation, the CO₂ is compressed to a supercritical state for transport and injection. We assume that the CO₂ remains in a supercritical state in the reservoir.

The compressor discharge pressure is a function of the required bottom-hole injection pressure, the static head and the frictional losses in the wells and pipeline. We assume a minimum pressure of 86 bar (1,250 psia) and a maximum pressure of 152 bar (2,200 psia). The pipeline is made from X65 carbon-steel line pipe. We model supercritical CO₂ injection using an unsteady-state numerical injectivity equation.

For the base case, we assume that the Portpatrick Basin has the capacity to store at least 25 years of injected CO₂ at rate of 3.8 million tonnes per year.

The properties of the Portpatrick reservoir are given in Table 27.

Table 27 – CO₂ storage transport and reservoir properties of Portpatrick Basin

Property	SI units	Imperial units
Pipeline length	40 km	25 mi
Surface temperature	10°C	50°F
Water depth	160 m	525 ft
Injection target depth (sub surface)	910 m	2,986 ft
Net pay	609 m	1,998 ft
Effective permeability	300 mD	–
Areal extent of reservoir	1100 km ²	430 mi ²
Reservoir temperature	51°C	124°F
Reservoir pressure	79 bar	1,146 psi
Fracture pressure	142 bar	2,060 psi

5.2 Results - Case 3A

5.2.1 Economics

Our cost estimates for the base case at the Kilroot power plant are shown in Table 28. In this table "PV" stands for present value.

Table 28 – Base case results for 540 MW_e sent out power plant at Kilroot

	Reference Power station without CCS (A)	Power station with CCS (B)	Incremental effect of CCS (B - A)
Annual CO ₂ emissions (million tonnes)	3.25	0.42	(2.83)###
Capital Cost (€ million)			
Power station	831	1,033	202
Separation	–	220	220
Compressor	–	65	65
Pipeline	–	57	57
Booster	–	0	0
Injection wells	–	34	34
Injection platforms	–	212	212
Owners' costs	58	113	55
Contingency	89	174	85
Total capital cost	978	1,908	930
Annual operating cost (€ million/yr)	136	209	73
Abandonment cost (€ million)	0	108	108
PV of capital costs (€ million)	847	1,634	787
PV of operating Costs (€ million)	1,297	1,992	695
PV of abandonment costs (€ million)	0	15	15
PV of all costs (€ million)	2,144	3,641	1,497
PV of CO ₂ avoided (Mt)	–	27	27
PV of power sent out (TWh)	38	38	–
Cost of net electricity sent out (€/MWh)	56.1	95.2	39.1
Specific CCS cost (€/t CO ₂ avoided)	–	–	56

3.77 Mt of CO₂ is injected each year

5.3 Breakdown of cost estimates

Table 29 and Figure 24 give breakdown details of our cost estimates. They show that the largest cost is the cost of CO₂ separation (almost 25%). The cost of CO₂ injection in deep water and the cost of upgrading the base power plant also account for a significant percentage of the total capital costs - approximately 20% each.

Table 29 – Breakdown of CCS costs of Case 3A

	Capital costs (€ million)	Annual operating costs (€ million/year)	Abandonment costs (€ million)	Specific Cost of CO ₂ avoided (€/t CO ₂ avoided)
540 MW _e Power station	978	136	0	–
697 MW _e Power station	1,180	175	0	–
Incremental effect of CCS				
Power station	202	38.4	0	20.1
Capture	220	26.6	0	16.3
CO ₂ compressor	65	2.6	16	3.0
Pipeline	57	0.6	14	2.1
CO ₂ booster	0	0.0	0	0.0
Injection wells	34	0.7	9	1.3
Injection platforms	212	4.2	53	8.4
Owners' costs	55	–	6	1.8
Contingency	85	–	10	2.7
Total Incremental	930	73.1	108	–
Total	1,908	209	108	55.7

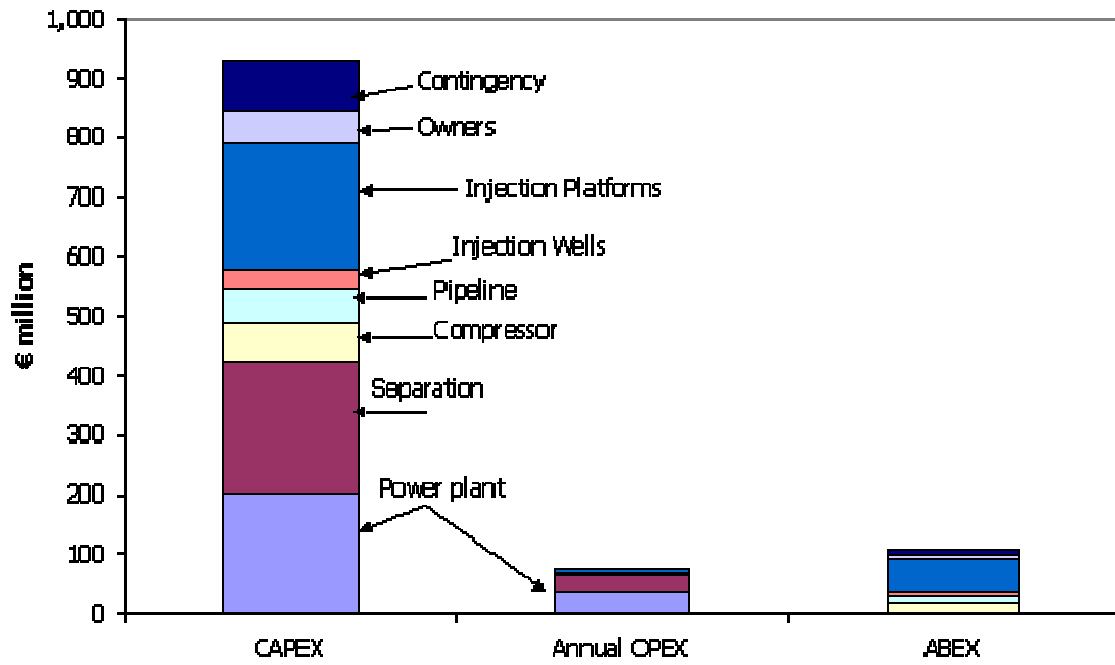


Figure 24 – Breakdown of the costs of CCS for Case 3A

5.3.1 Engineering

Table 30 sets out the engineering design of the CCS process.

Table 30 – CCS engineering design for Case 3A

Property	SI units	Imperial units
Capture		
Number of absorption trains	4	–
Column height	32 m	105 ft
Column diameter	5.7 m	19 ft
Number of compressor trains	1	–
Total cooling water required	27 kt/d	60 million lb/d
Pipeline		
Nominal pipeline diameter	457 mm	18 in
Total line pipe steel required	6 kt	13 million lb
Injection		
Number of wells	2	–
Well Inner diameter	101 mm	3.958 in
Number of platforms	1	–
Pressure profile		
CO ₂ compressor inlet pressure	1 bar	14.7 psi
CO ₂ compressor discharge pressure and onshore pipeline inlet pressure	112 bar	1,620 psi
Onshore crossing pressure	103 bar	1,487 psi
Pipeline outlet pressure and top-of-well pressure	99 bar	1,436 psi

Table 31 summarises the power plant performance. The total energy penalty for CCS is approximately 160 MW_e. Of this total, the energy for solvent regeneration accounts for half. The energy needed for CO₂ compression to a supercritical state is 52 MW_e.

Table 31 – Power Plant Performance for Case 3A

Property	Power (MW _e)	Thermal efficiency (LHV) %
Total Net Generated	697	38
Equivalent Electrical Regenerator Duty	82	
Pumping	3	
Blower	20	
CO ₂ compressor	52	
CO ₂ booster	0	
Total Consumed by CCS	157	9
Net Sent Out	540	29

5.4 Sensitivity analyses of Case 3A

The following section discusses the sensitivity of the costs to changes in –

1. US\$-€ exchange rate
2. coal price
3. capital costs
4. reservoir permeability
5. fracture gradient
6. evaluation costs
7. project life

5.4.1 Exchange rate

Figure 25 shows the effect of exchange rate fluctuations on the specific costs of CO₂ avoided and the cost of electricity. Changes in the exchange rate mainly affect the cost of equipment and fuel. If the exchange rate changes from the central estimate of US\$1.25 per € to \$US2 per €, the specific cost falls to less than €50 per tonne CO₂ avoided. However, if the exchange rate is less than \$US1 per €, the specific cost increases to over €65 per tonne CO₂ avoided.

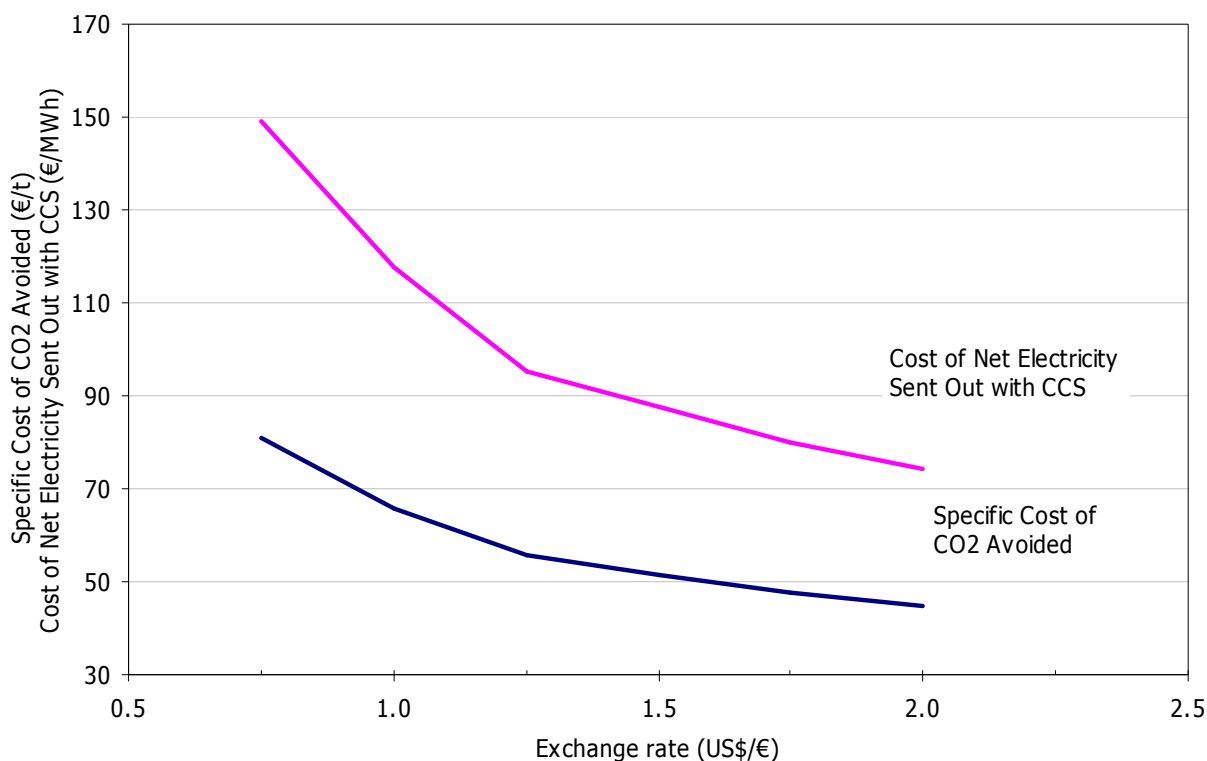


Figure 25 – Cost of electricity and the specific cost of CCS with changes in the US Euro exchange rate for Case 3A

5.4.2 Coal price

Changes in market conditions can cause significant fluctuations in the coal price. Figure 26 shows the change in cost of electricity and the specific cost of CO₂ avoided. We vary the coal price between US\$60 and US\$175 per tonne (equivalent to €47 per tonne or €1.7 per GJ LHV and €140 per tonne or €5.02 per GJ LHV respectively). As the coal price increases from US\$90 to US\$175 per tonne, the cost of electricity increases to €125 per MWh and the specific cost of CO₂ avoided increases to €65 per tonne. The coal price affects only the operating costs, which have a small effect on the total costs of CCS..

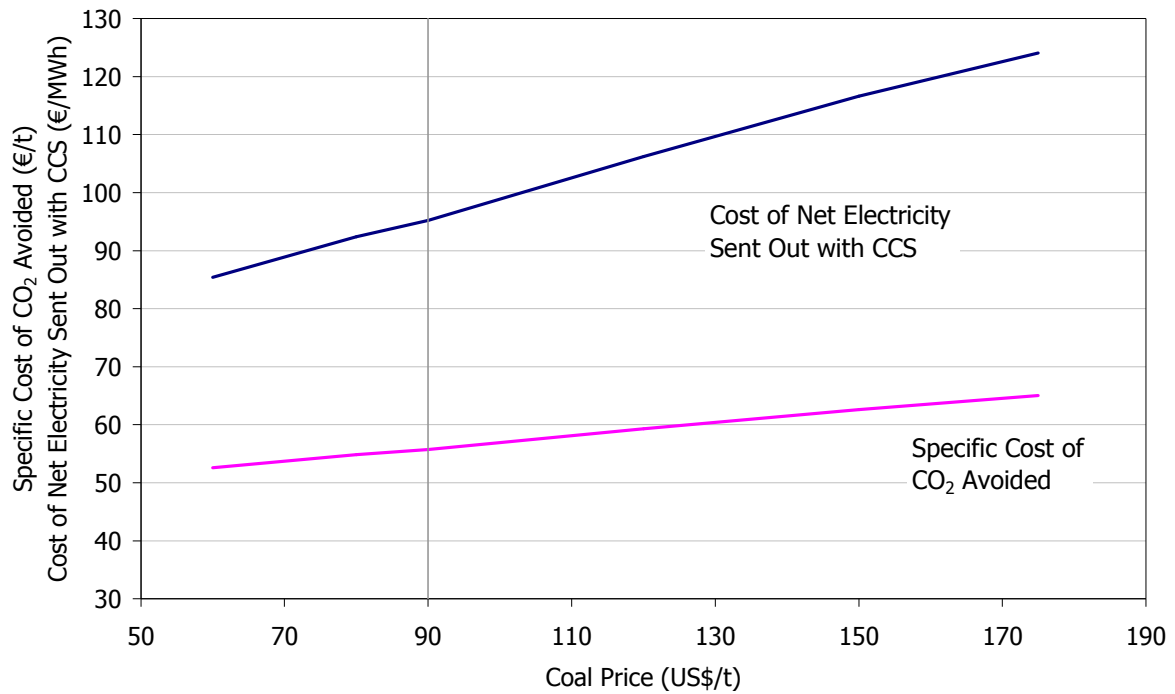


Figure 26 – Cost of net electricity and CCS costs with changes in the coal price for Case 3A

5.4.3 Capital costs

There are significant uncertainties in estimating capital costs. Variations in equipment prices reflect changes in commodity prices, labour costs and exchange rates. Figure 27 shows the changes in specific cost CO₂ avoided if the capital costs vary between -25% and +100% of our central estimates. With the highest capital costs, the cost of electricity sent out can be as large as €160 per MWh and the specific costs of CCS can be as much as €100 per tonne CO₂ avoided.

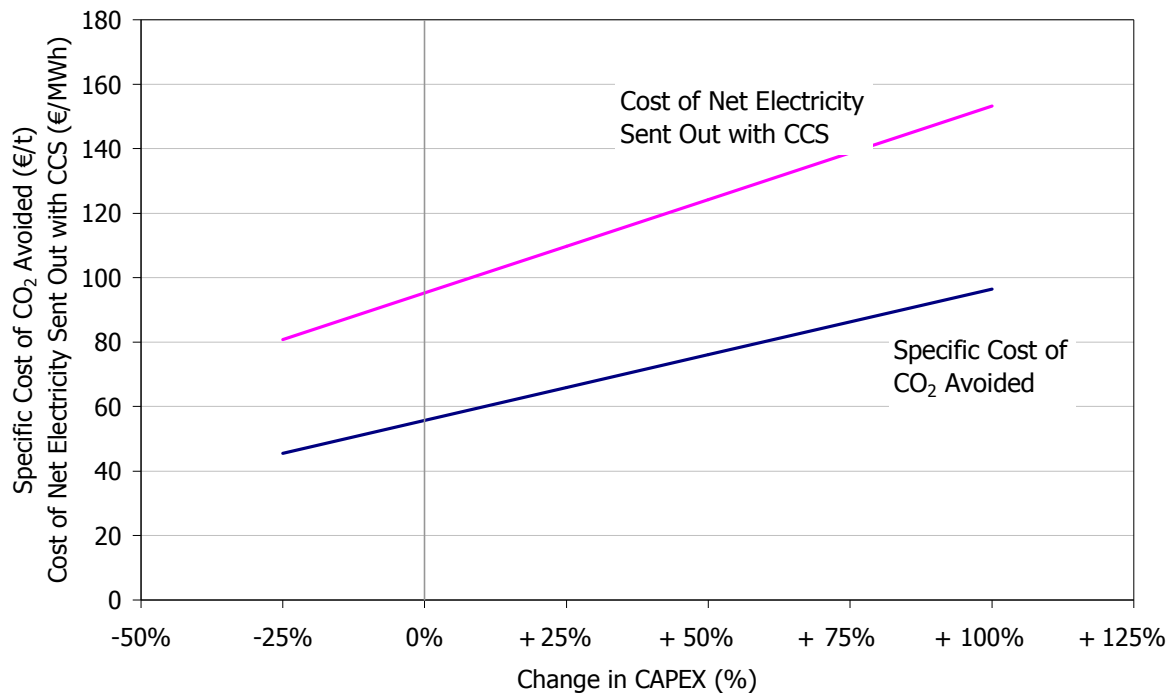


Figure 27 – Cost of net electricity and specific cost of CO₂ avoided with uncertainties in capital cost of Case 3A

5.4.4 Reservoir permeability

Figure 28 shows the effect of permeability on the cost of electricity and on the specific cost of CO₂ avoided. For this case, we model the effect of well interference and pressure build-up in the formation.

Over the range 85 mD to 1,000 mD the costs of CCS and the cost of electricity are relatively insensitive to changes in permeability. This is because with these high permeabilities there are few wells and varying the permeability affects only the operating costs.

However below approximately 85 mD, the number of wells required and the cost increases rapidly. The minimum permeability is 30mD, for which 18 wells are required. At this minimum permeability, the cost of electricity is over €100 per MWh and the specific cost is €70 per tonne CO₂ avoided.

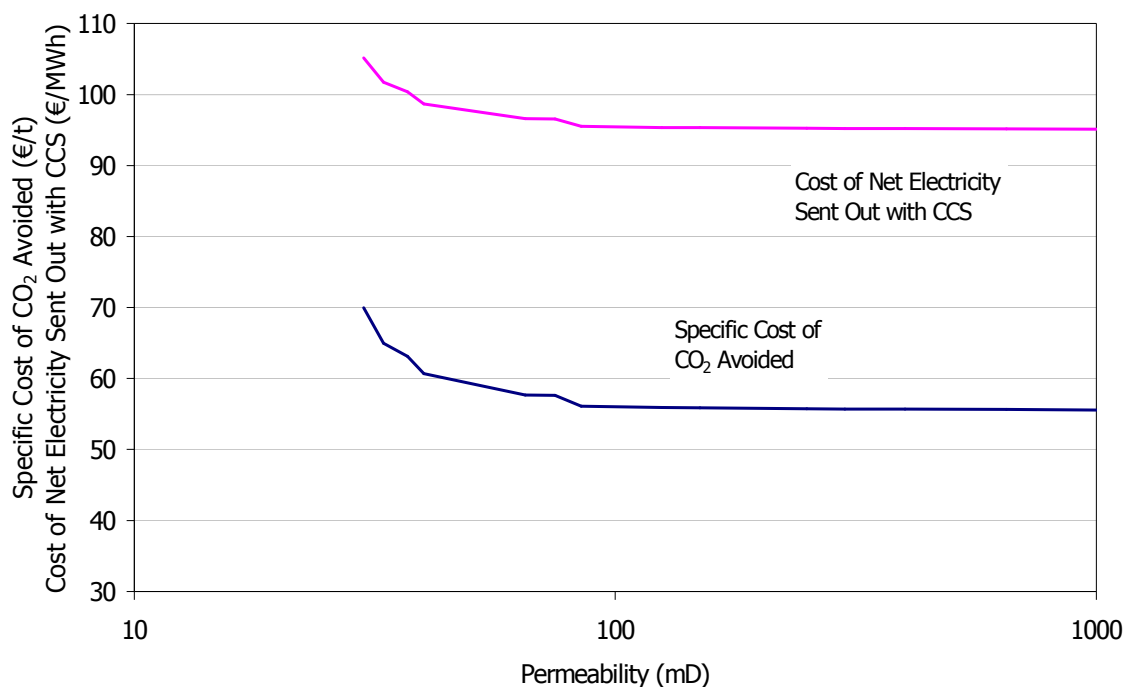


Figure 28 – Cost of net electricity sent out and specific cost of CO₂ avoided using different permeabilities for Case 3A

5.4.5 Fracture gradient

We have no information on fracture gradients in the Portpatrick Basin. Therefore we assume a fracture gradient of 15.6 MPa per km (0.69 psi/ft) based on our Australian experience.

Figure 29 shows that at the base case permeability of 300mD, changes in fracture gradient have a negligible impact on the cost of electricity and the cost of CCS. We expect that for lower permeabilities, changes in the fracture gradient will have an increasingly significant effect.

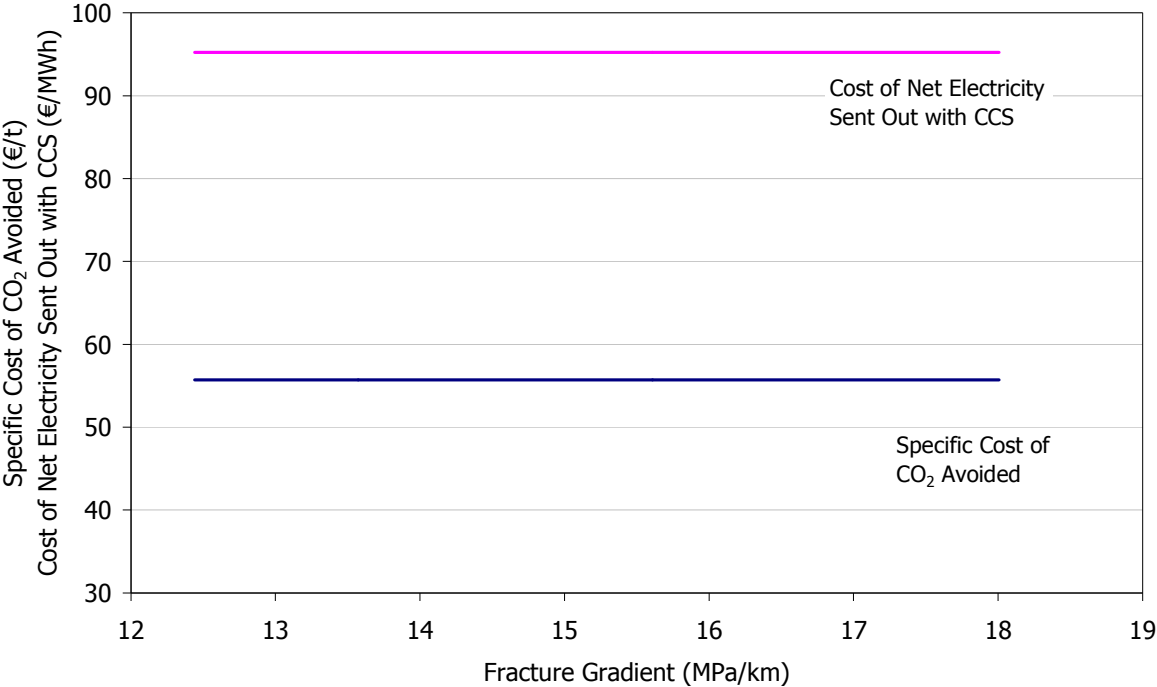


Figure 29 – Cost of net electricity sent out and specific cost of CO₂ avoided with fracture pressure for Case 3A

5.4.6 Reservoir evaluation costs

Figure 30 shows the effect increasing evaluation costs on the costs of CCS and the cost of electricity with CCS for the 540 MW_e power plant at Kilroot with. If the present value of evaluation costs is €100 million, then the specific cost of CO₂ avoided increases to €60 per tonne and the cost of electricity sent out with CCS increases to almost €100 per MWh.

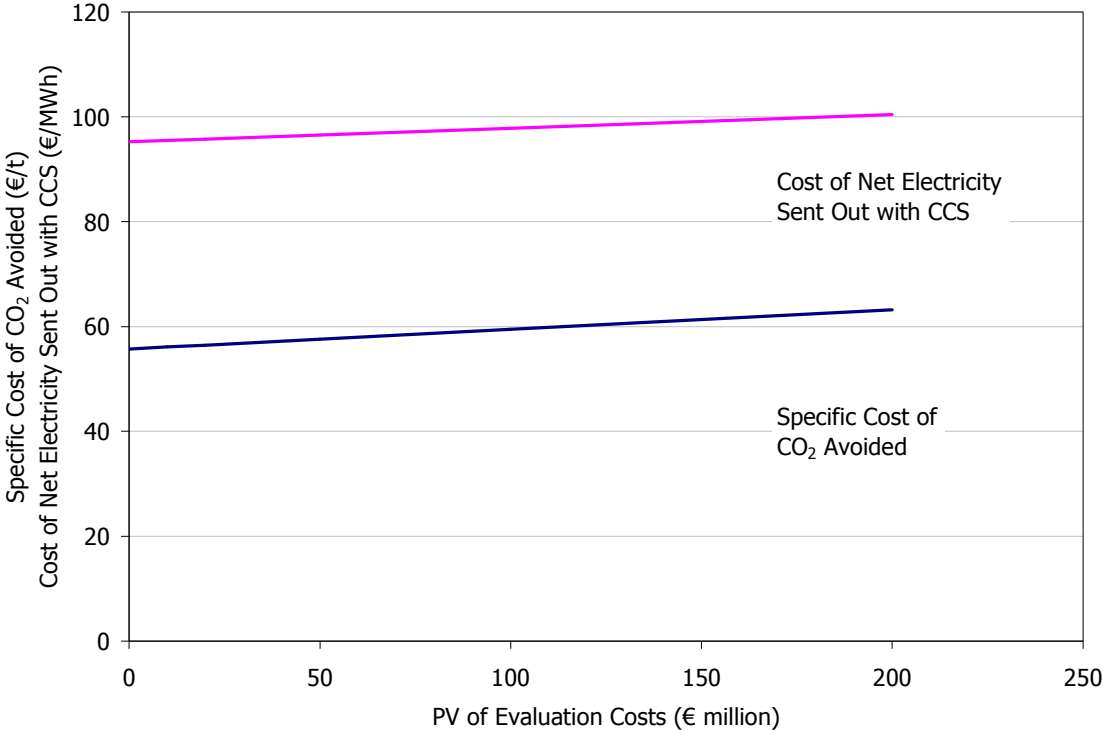


Figure 30 – Cost of electricity sent out and specific cost of CO₂ avoided with PV of evaluation costs included for Case 3A

The effect of evaluation costs would be more significant if we incorporated the risk that the evaluation programme might not prove up the storage site. We do not attempt such an analysis in this report.

5.4.7 Project life

In our base case, we assume that the reservoir has capacity to store CO₂ for 25 years, giving a total CO₂ storage of 95 million tonnes. However, if the capacity of the reservoir is smaller, then the costs of CCS increase. Figure 31 shows changes in the cost of electricity and cost of CCS for changes in the project life between 5 and 25 years. As the project life decreases, the cost increases because the costs are defrayed over fewer tonnes of CO₂ avoided and fewer MWh sent out.

If we assume that the capacity of the Portpatrick Basin is 37 million tonnes, then at an annual injection rate of 3.8 million tonnes of CO₂, the project life is approximately 10 years. For this project life the cost of CCS is €77 per tonne CO₂ avoided.

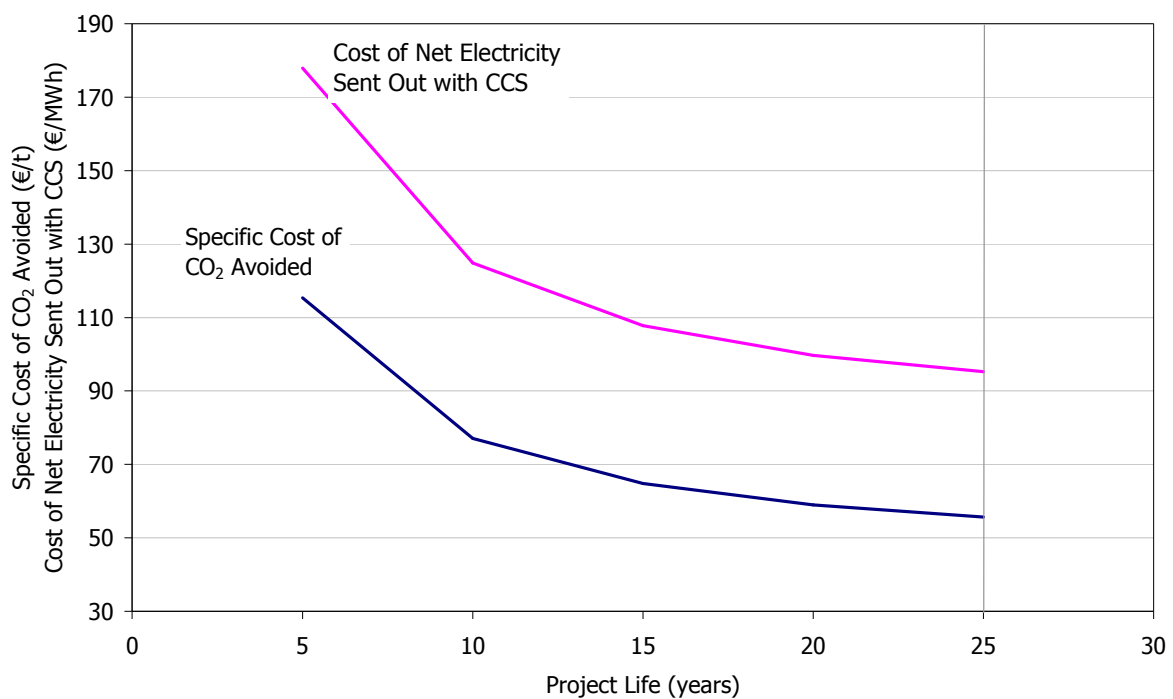


Figure 31 – Cost of electricity and specific CCS cost with changes in the project life for Case 3A

6 Cost comparisons

Table 32 summarises the capital, operating and abandonment costs of the cases examined in this report. Table 33 shows the breakdown of the costs of CCS into the components for CO₂ separation, transport, injection and on costs.

The lowest cost estimate of €28 per tonne CO₂ avoided is for an IGCC power plant with CCS at Cork with storage in Kinsale Head. This cost is up to €30 per tonne CO₂ avoided less than the other source - sink combinations.

The costs of CCS for IGCC power plants are approximately €15 per tonne less than those for pulverised coal power plants. This reflects the lower energy penalty of recovering CO₂ from high pressure gasification systems, reducing the operating costs of the power plant and the amount of total CO₂ generated.

The project with the lowest capital and operating costs is the 540 MW_e pulverised coal power plant with CCS at Cork with storage in Kinsale Head. This is because the power plant is smaller and the transport distance is shorter. CCS for Kilroot to Portpatrick has slightly higher capital costs, even though the size of the power plants and the transport distances are similar. The higher capital cost reflects the more expensive platform costs for deep water. This increases the specific cost to €56 from €43 per tonne CO₂ avoided.

The project with the highest cost is retrofitting the existing natural gas fired power plants at Cork for CCS and connecting it to the CCS project from Moneypoint power plant to Kinsale Head (Case 1D). The capital costs are larger than the other projects because of the costs for separating CO₂ at four different power plants. The operating costs per MWh are also higher for this project because using natural gas is three times more expensive than coal. Although economies of scale are achieved for transporting a large volume of CO₂ in the offshore pipeline, the high costs of the four separate CO₂ recovery processes and the large operating costs result in a high CCS project cost.

Table 32 – CCS Cost Estimate Summary

	Money - point 900 MW _e PC	Money-point 900 MW _e PC Route B	Money- point 900 MW _e IGCC	Money-point and Cork Retrofit	Cork 900 MW _e PC	Cork 900 MW _e PC Offshore Pipe	Cork 900 MW _e IGCC	Cork 540 MW _e PC	Kilroot 540 MW _e PC
Case number	1A	1B	1C	1D	2A	2B	2C	2D	3A
Annual CO2 avoided (million tonnes)	4.71	4.71	4.25	6.50	4.70	4.70	4.25	2.85	2.83
PV of CO2 avoided (Mt)	45	45	40	62	45	45	40	27	27
Total capital cost (€ million)	2,712	2,688	2,656	3,679	2,516	2,516	2,497	1,665	1,908
Operating Cost (€ million)	343	343	309	399	340	340	306	208	209
Abandonment cost (€ million)	101	94	87	162	54	54	50	50	108
PV of capital costs (€ million)	2,325	2,305	2,279	3,139	2,161	2,161	2,145	1,429	1,634
PV of operating costs (€ million)	3,262	3,265	2,935	3,795	3,235	3,235	2,909	1,975	1,992
PV of abandonment costs (€ million)	14	13	12	23	8	8	7	7	15
PV of power generated (TWh)	64	64	64	64	64	64	64	38	38
Cost of electricity sent out with CCS (€/MWh)	88	88	82	109*	85	85	80	89	95

*This is the aggregated cost of electricity for four power plants.

Table 33 – Breakdown of CCS cost for all Case Studies

Specific Cost of CO ₂ avoided (€/t CO ₂ avoided)	Money-point 900 MW _e PC	Money-point 900 MW _e PC Route B	Money-point 900 MW _e IGCC	Money-point with Cork Retrofit	Cork 900 MW _e PC	Cork 900 MW _e PC Offshore Pipe	Cork 900 MW _e IGCC	Cork 540 MW _e PC	Kilroot 540 MW _e PC
Separation	29.7	29.7	15.1	35.8	29.6	29.6	15.0	29.5	29.8
Transport	13.3	12.9	12.4	14.9	9.8	9.8	9.1	11.2	11.7
Injection	0.9	0.9	1.0	1.0	0.9	0.9	1.0	1.4	9.8
On Costs	3.5	3.4	2.9	4.5	2.9	2.9	2.4	3.3	4.5
Total	47.4	46.9	31.3	56.1	43.1	43.2	27.5	45.4	55.7

7 Conclusion and recommendations

	Moneypoint 900 MWe PC	Moneypoint 900 MWe IGCC	Cork 900 MWe PC	Cork 900 MWe IGCC	Cork 540 MWe PC	Kilroot 540 MWe PC
Total capital cost (€ million)	2,712	2,656	2,516	2,497	1,665	1,908
Annual operating cost (€ million/yr)	343	309	340	306	208	209
Abandonment cost (€ million)	101	87	54	50	50	108
Cost of electricity sent out with CCS (€/MWh)	88	82	85	80	89	95
Specific cost of CO ₂ avoided (€/t CO ₂ avoided)	47.4	31.3	43.1	27.5	45.4	55.7

The costs of CCS range from €28 to over €56 per tonne CO₂ avoided. The costs are highly dependent on the source of CO₂ and the conditions and location of the storage reservoirs.

The cost of electricity sent out with CCS for new build pulverised coal power plants is €85 to €95 per MWh. For IGCC power plants with CCS, the cost of electricity sent out is €80 to €82 per MWh.

The source to sink combination with the lowest cost (€28 per tonne CO₂ avoided) involves capturing CO₂ from a 900 MWe IGCC located at Cork, with subsequent storage in Kinsale Head. CCS from an IGCC power plant located at Moneypoint with storage in Kinsale Head has a slightly higher cost (€31 per tonne CO₂ avoided). The costs of capturing CO₂ from pulverised coal power plants at the same location is approximately €16 per tonne CO₂ avoided higher. We estimate a cost of €56 per tonne CO₂ avoided for capturing CO₂ from at Kilroot with storage in the Portpatrick Basin.

The sensitivity results show that cost estimates are strongly affected by capital cost estimates. Doubling the capital costs increases the specific cost of CCS by €30 to €40 per tonne CO₂ avoided. The CCS costs are also affected by reservoir and fluid behaviour uncertainties, which in turn affect the number of wells required. The cost estimates increase by up to €30 per tonne CO₂ avoided if the number of wells increase from 1 to 65. Changes in the US dollar to Euro exchange rate and the coal price have a smaller impact increasing the costs of CCS by up to €20 per tonne CO₂ avoided. Site evaluation costs have a small effect on the total costs.

Our report is a preliminary analysis based on limited process and cost data. We have used rules of thumb and simple equations to model the cases. We have not carried out detailed

process or reservoir simulations. As such, the results of this report are indicative with a margin of error of $\pm 50\%$. Furthermore, we have excluded the effect of tax and any effects of the European Emissions Trading Scheme. We recommend that –

- More reservoir data be acquired to assist in characterising the storage sites;
- The geological modelling of the Kinsale and Portpatrick Basin formations be expanded;
- Detailed and comprehensive reservoir simulations are carried out for each storage site;
- The behaviour of the CO₂ injected at Kinsale over time is modelled in detail;
- Local vendor quotes for capital and operating expenses be obtained; and
- Process simulation of the power plant cycle is carried out, in particular for the IGCC power plant.

An economic feasibility assessment, including full engineering design and costing should be undertaken to address the uncertainties identified in this report.

8 References

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Appendix 1. Cost of electricity with carbon credits

The cost of electricity including the cost of carbon credits, with and without CCS, for nine of cases is reported in Table 34. In this analysis we assume a carbon credit price of €35/t.

Table 34 – Cost of electricity including the cost for carbon at a price of €35/t

	Money-point 900 MW _e PC	Money-point 900 MW _e IGCC	Money-point PC with Cork Retrofit	Cork 900 MW _e PC	Cork 900 MW _e IGCC	Cork 540 MW _e PC	Kilroot 900 MW _e PC
Reference power plant without CCS (A)							
PV of all costs (€MM)	3,480	3,961	3,487	3,475	3,952	2,182	2,144
PV of CO ₂ emitted (Mt)	51.4	45.4	70.6	51.3	45.3	31.0	30.9
PV of electricity sent out (TWh)	64	64	64	64	64	38	38
COE with no carbon price (€/MWh)	54.6	62.1	54.6	54.6	62.1	56.8	56.1
PV of carbon credits (€MM)	1,800	1,588	2,472	1,797	1,584	1,086	1,081
PV of costs incl. carbon (€MM)	5,280	5,548	5,958	5,272	5,536	3,268	3,224
COE with carbon price (€/MWh)	82.9	86.9	93.4	82.9	87.0	85.0	84.3
Power plant with CCS (B)							
PV of all costs (€MM)	5,601	5,226	6,958	5,404	5,061	3,411	3,641
PV of CO ₂ emitted (Mt)	6.6	4.9	8.7	6.6	4.9	4.0	4.0
PV of electricity sent out (TWh)	64	64	64	64	64	38	38
COE with no carbon price (€/MWh)	87.9	81.9	109.0	85.0	79.5	88.8	95.2
PV of carbon credits (€MM)	232	173	305	231	172	139	140
PV of costs incl. carbon (€MM)	5,833	5,399	7,262	5,635	5,233	3,550	3,781
COE with carbon price (€/MWh)	91.6	84.6	113.8	88.6	82.2	92.4	98.9
Incremental effect of CCS (B-A)							
PV of all costs (€MM)	2,121	1,266	3,471	1,929	1,109	1,229	1,498
PV of CO ₂ emitted (Mt)	-44.8	-40.4	-61.9	-44.7	-40.4	-27.1	-26.9
PV of electricity sent out (TWh)	0	0	0	0	0	0	0
COE with no carbon price (€/MWh)	33.3	19.8	54.4	30.3	17.4	32.0	39.2
PV of carbon credits (€MM)	-1,568	-1,415	-2,167	-1,566	-1,412	-947	-941
PV of costs incl. carbon (€MM)	553	-149	1,304	364	-303	281	557
COE with carbon price (€/MWh)	8.7	-2.3	20.4	5.7	-4.8	7.3	14.6

* The PV of all costs is the sum of the PV of project capital, operating and abandonment costs.