NORTH SEA STUDY OCCASIONAL PAPER
No. 107

A Least-cost Optimisation Model for CO_2 Capture

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August, 2007 Price £25.00

DEPARTMENT OF ECONOMICS

ISSN 0143-022X

NORTH SEA ECONOMICS

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Contents Page

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Abstract

The cost of carbon capture and sequestration (CCS) is central to discussions on the cost of carbon abatement in the overall cost of climate change mitigation. Focusing on the capture stage of the CCS chain, it is observed that while most writers agree that power plants, being large point sources, obvious capture sites, a dearth of historical real life data makes it difficult to have equally authoritative carbon capture costs. The absence of authoritative CO_2 capture costs could hinder the deployment of carbon capture technology. The present study attempts to add relative realism to discussions on CO_2 capture costs and early carbon capture deployment in the UK. The starting point of the study's contribution is to combine the public domain-available data on the proposed carbon capture investment programmes of selected power plants in the UK with the relevant data available in the literature. Using these data, a least-cost optimisation model was formulated and solved with the linear programming algorithm available in GAMS. The major findings of the study include (a) the total cost in relation to output has three phases - rising, plateau, rising; (b) alternative capture technologies do not have permanent relative cost advantages or disadvantages; (c) increasing capture-generation ratio reduces system cost; (d) Government incentives encourage carbon capture and the avoidance of emission penalty charges; and (e) more vigorous tightening of the EU-ETS through increasingly stringent emission allocations rights is required to improve the universal profitability of carbon captures processes in the UK.

A Least-cost Optimisation Model for CO_2 Capture

I. Introduction

Several policy options have been proposed and/or implemented to meet the emission compliance targets inspired by the internationally-agreed Kyoto Protocol[1]. Thus, in the UK as in the rest of the European Union (EU), the Emissions Trading Scheme (or, EU-ETS for short) commenced operations in January 2005. The EU-ETS is a cap-and-trade scheme in which CO_2 emission limits are set for qualifying large emitters according to the National Allocation Plans (NAP) of member countries. Emission allowances[2] equal to the set emission limits are allocated free to each regulated emitter. Starting from April 2006, the allowances have to be "surrendered" or "delivered" in annual returns, in which the actual and traded CO_2 emission levels are compared with the amount allocated. The amount of the non-delivered emission (NDE) allowance, defined as:

NDE = "surrendered" emission – allocated emission

= (*actual emission + sold allowances – purchased allowances) – allocated emission*

must be zero at the time of filing a return. In other words, any excess or surplus emission allowance is expected to have been traded in the emerging CO_2 markets prior to filing the returns. If not, an emission penalty, currently fixed at €40 per tonne of CO_2, is payable for greater-than-zero NDE allowances.

While it may be too early to make definitive evaluative statements on the performance or effectiveness of the EU-ETS, the emerging consensus appears to be that the current NAP Allocations (2005-2007) are overly

[1] First commitment period 2008 to 2012.
[2] In units of one million tonnes of carbon dioxide.

generous[3] and have engendered (a) considerable carbon price volatility; and, (b) a generally low compliance cost that has neither significantly curbed carbon emissions nor seriously encouraged carbon capture and sequestration (CCS).

Thus, it is argued by (Berlin, 2007) and several other writers that more stringent emission caps are needed both to (a) raise the compliance cost; and, (b) increase the attractiveness of investments in CCS technologies.

Beyond advocacy, the emerging evidence points in the direction of stricter emission limits. Thus, the EU Commission reduced Germany's total allocation of CO_2 certificates from 495 mt/CO_2 per annum in NAP 1 (National Allocation Plan Phase 1) to 453 mt/CO_2 per annum in NAP 2 (a reduction of 8%). Correspondingly, the UK's total allocation was reduced by 4% from 246 to 237 mt/CO_2 while the country's electricity sector had a much bigger reduction of 20% (DEFRA, 2007).

The present study proposes a methodology for determining the least-cost options of introducing carbon capture technology[4] under the overarching assumption of increasingly stringent emission caps on fossil-fuelled power plants, which are universally recognised as large point sources of carbon emission. The approach entails formulating and solving an optimisation model with clearly stated goals, and, explicit provisions for the various regulatory, technological and market conditions which offer opportunities and/or restrict corporate decision-making and action-taking. The objective of the present study is to minimize the cost of CO_2 capture[5], using the well-tested optimizing techniques of linear

[3] Contexualising the "excessive generosity" of the emission allocations, it would be recalled that they were the unsurprising outcome of the intense political debate and compromise that gave birth to EU Directive 2003/87/EC establishing the EU-ETS.

[4] It should be pointed out at the onset that the present study deals only with the capture stage of the CCS (carbon capture and storage) value chain. The disposal, transportation, EOR and permanent storage stages of the value chain will be investigated in a subsequent study.

[5] That is, the cost of producing a "concentrated stream of CO_2 at high pressure that can readily be transported to a storage site" (IPCC, 2005).

programming to scan through all the possible cost-output combinations before selecting a particular combination as being the optimal. The model is applied to the UK but has a wider applicability.

II. A generalised model in brief

In a carbon abatement regime with sufficiently stringent emission caps, the power plants in a region or country would each face a multi-objective cost function to be optimized with respect to the average costs of electricity generation, pollution control, and carbon capture, subject to technical, market and regulatory constraints. For sectoral or industry-wide analysis, the individual objective functions would be aggregated.

II.1 the objective cost function

Presenting first the objective function, it is noted that the power plants, invariably using different power generation and CO_2 capture technologies, would seek to minimize the environomic cost function[6] in equation (1), subject to a number of constraints including those listed and discussed below.

$$C_t = \frac{k_t\left(\sum a_{it}x_{it} + \sum b_{it}u_{it}\right) + \sum\sum f_{it}y_{it} + \sum\sum e_{it}y_{it} + (\sum\sum m_{it}v_{it} - \sum\sum h_{it}q_{it}) - \sum\sum g_{it}(q_{it})}{(1+r)^t} \quad (1)$$

where:

k_t = capital recovery factor of plant type at time *t*

a_{it} = unit CAPEX of the core power generating plant type *i* at time *t*

x_{it} = effective electricity generating capacity of plant type *i* at time *t*

b_{it} = unit CAPEX of the CO_2 capture equipment of plant type *i* at time *t*

u_{it} = installed CO_2 capture capacity in plant type *i* at time *t*

[6] According to Pelster **et. al** (2001) the cost function is thermoeconomic because it combines thermodynamic (e.g. fuel costs) with economic (e.g. capital/investment costs) consideration. The inclusion of environmental considerations (carbon abatement) makes the cost model environomic.

f_{it} = unit fuel OPEX of plant type *i* at time *t*

y_{it} = the operating level (or output) of plant type *i* at time *t*

e_{it} = unit non-fuel OPEX of plant type i at time t

h_{it} = unit CO_2 capture OPEX

q_{it} = amount of CO_2 capture in plant type *i* at time *t*

m_{it} = unit emission penalty cost to plant type *i* at time *t*

v_{it} = excess CO_2 emission in plant type *i* at time *t*

g_{it} = unit Government intervention (tax or subsidy) rate in plant type *i* at time *t*

r = discount rate

t = time in years

The various components of the objective function are discussed below in section II.1.1 through II.1.4.

II.1.1 The capital investment

(a) The core generating plant

Four types of power plants – namely, Pulverized coal (PC), Combined Cycle Gas Turbine (CCGT), oxyfuel-based and Integrated Gas Combined Cycle (IGCC) – and two types of boilers (sub- and super-critical) are available for the deployment of CCS technology (IPCC, 2005).

Given particular electricity generation and carbon capture technologies, the investment cost of the i^{th} plant type at time *t* consists of the capital expenditures (CAPEX) incurred on generation (x_{it}) and CO_2 capture (u_{it}) capacities. Owing to the unavoidable barriers to full capacity utilisation, it is customary to distinguish between the nameplate (or notional) and effectively-used capacity of a power plant. Recent IEA GHG studies claim the levelised capacity factor is about 85 per cent (IEA-GHG, 2006). The capacity factor is likely to be further eroded by the anticipated efficiency losses due to the parasitic effect of CO_2 capture[7]. According to some estimates, the CO_2 capture process requires between 10 and 40 percent extra energy (or fuel) to produce the same net export energy as the equivalent without-capture reference plant[8]. These losses advocate the application of CCS technology only to high efficiency plants in which the efficiency penalties are lower and less costly (see Wall, 2007 and Drax, 2005).

In order to capture the required increase in the nameplate capacity needed to compensate for the efficiency losses, the cost of the effective generation capacity ($a_{it}\ x_{it}$) is defined in the present study as:

$$a_{it}x_{it} = a_{it}x_{it}^{'}\left(1+l_{it}\right)$$

(2)

where:

$x_{it}^{'}$ = the nameplate capacity of plant type *i* at time *t* (MW)

l_{it} = efficiency degradation due to CO_2 capture (%)

(b) the CO_2 capture capacity

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[7] Wall (2007) identified the following processes as the major contributors to efficiency losses: (a) solvent regeneration and CO_2 compression (in post-combustion capture); and, (b) oxygen production and CO_2 compression (in oxyfuel and pre-combustion capture). Theoretically, "using an ASU (air separation unit) the extra energy required to produce CO_2 is about 200 KWh per tonne of captured CO_2 and 30 KWh to compress CO_2 from 0.21 to 1 atm".

[8] According to IPCC, in order to capture 90 percent CO_2, using the best available technology would require the following additional amounts of energy and fuel for each plant type

new supercritical PC	24 to 40 %
new CCGT	11 to 22 %
new bituminous coal-based IGCC	14 to 25%

Source: IPCC, 2006 p. TS-13

A power plant desirous of adding CCS technology to its electricity generation process has a number of options. It can either invest in a new build power plant with integrated or built-in CO_2 capture facilities or, it can simply add-on a CO_2 capture system with retrofitted or re-built boilers and turbines which are designed to increase plant efficiency and output (Mitsui Babcock, 2006). There are three leading combustion technologies (oxyfuel, pre- and post- combustion) and one gasification technology often considered in the literature for CO_2 capture. These technologies are at different stages of development, deployment, and commercialization. Whichever option is chosen will result in capital expenditure (CAPEX ($b_{it}\ u_{it}$)) which is additional to those incurred in the core electricity generating plant.

(c) The capital recovery factor

The third element in the capital investment component of the objective function is the capital recovery factor (CRF) which is defined as:

$$k_t = \frac{r(1+r)^n}{(1+r)^n - 1}$$

(3)

where, in addition to previous definitions:

n = power plant lifetime

II.1.2 The OPEX

The OPEX (operating expenses) of the power plants comprise the fuel, non-fuel and CO_2 capture costs (excluding capital costs). The non-fuel OPEX includes items usually referred to as Operations and Maintenance (O + M) costs. At any given time, the aggregated fuel ($\sum\sum f_{it} y_{it}$) and non-fuel ($\sum\sum e_{it} y_{it}$) costs both depend on the amount of electricity (y_{it}) produced. In turn, power output is a function of the amount of fuel inputs

($\boldsymbol{f_{it}}$) as well as the load ($\boldsymbol{l}$) factor, which is determined by the level of plant availability[9] and the power price-marginal cost ratio. That is,

$$l_{it} = \varphi\left(A_{it}, \frac{P_{et}}{MC_{et}} \right)$$

(4)

with the condition that $P_{et} > MC_{et}$

where,

A_{it} = plant availability of plant type *i* at time *t*

P_{et} = price of electricity at time *t*

MC_{et} = marginal cost of electricity at time *t*

Plant availability (A_{it}) is the amount of time the plant is capable of generating electricity, after deducting planned and forced outages. The marginal cost of electricity (MC_{et}) comprises mainly of fuel, non-fuel and CO_2 capture costs. The profitability criterion ($P_{et} > MC_{et}$) is that the price of electricity must be greater than the marginal cost of electricity generation and CO_2 capture. In the medium term, both the price and marginal cost are expected to decline owing to the interplay of several factors including economies-of-scale and improvements in thermal efficiency, resulting from the "cumulative experience" or "learning by doing" effect. The potential of declining medium-term marginal cost induced by improvements in the plant thermal is proxied in the present study by assuming declining fuel cost per kilowatt-hour of electricity

[9] Defined as the amount of time the plant is capable of generating electricity after deducting planned and forced outages.

generated. This is consistent with the approach adopted by IEA-GHG (2006).

II.1.3. the Cost of Net Emission Reduction (NER)

A power plant whose carbon emissions at a given output level exceeds its allowance has the option of incurring either of the costs of (a) reducing emission to permissible levels through capture/abatement, or (b) purchasing allowances or (c) paying the emission penalty equal to the value of the excess emission. The rational power generator will choose the least-cost option.

Thus, it is clear that even though as an add-on to power generation, the CO_2 capture process naturally increases costs, these costs are offset either in part or completely by the emission penalty that the power plant would have been obliged to pay in the absence of the capture activity[10]. The aggregated net emission reduction (NER) cost of the power plants of a particular technology is the difference between their aggregated excess emission penalty costs and the cost saving through CO_2 capture. That is,

$$Net\,emission\,reduction\,\cos t = \sum\sum\ m_{it}v_{it} - \sum\sum h_{it}q_t \qquad (5)$$

The first term on the RHS above is the excess emission penalty cost, which is defined as:

excess emission penalty cost = excess emission x the unit penalty cost (6a)

where,

excess emission = net emission – allocated emission

[10] The importance of taking a holistic view of carbon capture cost was discussed in Kemp and Kasim (2006.)

$$= (actual\ emission - CO_2\ capture) - allocated\ emission \quad (6b)$$

Clearly, according to equation (6b), the excess emission penalty cost is positive (or incurred) only when the net emission is greater than the allocated emission allowances. Rearranging the terms in the equation sheds further light on the conditions for incurring or avoiding emission penalty costs. Specifically, emission penalty costs will be incurred whenever actual emission exceeds the sum of a plant's allocated emission allowances and the amount of CO_2 captured. That is,

$$actual\ emission > allocated\ emission + CO_2\ captured \quad (6c)$$

By contrast, emission penalty costs are avoided and the direction of the inequality sign changed whenever the actual emission is less than the sum of the allocated emission and CO_2 captured.

II.1.4. Government incentives

CCS technology is relatively new and its widespread deployment is hampered by market and regulatory uncertainties. The conventional wisdom is that some Government assistance or incentives are required to encourage the widespread introduction of the CCS technology.

Incentives can be one or more of (a) fiscal; (b) market-driven; or, (c) physical. These incentives are not mutually exclusive and they sometimes overlap. Fiscal incentives will cover Government financial assistance in any form including investment tax credits, grants, loan/loan guarantees, and, rate-payer funded support. Market-driven assistance may be instituted in the form of CO_2 market price contracts. The long-term put option contract for carbon emissions proposed by Kemp and Swierzbinski (2007) is a good example of this kind of Government intervention. In addition, the authorities may incentivise carbon capture through the EU-ETS (or similar schemes outside Europe) by reducing emission allowances in NAP and triggering higher carbon prices. Direct physical government assistance may take many forms but would almost always work out as a price support scheme. Firstly, it may take the form of infrastructure support in which the Government by itself or, in partnership with others, finances the pipeline networks and other CO_2 infrastructure linking CO_2 producers to CO_2 end users and/or permanent storage sites. This kind of support is aimed at reducing the delivered cost of CO_2 to the end users, thereby boosting the demand and supply of the commodity. Secondly, Government direct support may be packaged in a cost-sharing scheme. This is the kind of support used in the present study to quantitatively ascertain the impact of Government assistance on carbon capture projects. It is a climate change price support scheme akin to existing incentives in the UK such as the Renewables Obligations (RO) and Climate Change Levy (CCL) exemptions, and Climate Change Agreements (CCAs) (DTI, 2004; HM Treasury, 2006).

Specifically, and purely for modelling purposes, the study assumes that a certain proportion of the investment and/or operating costs are borne by the government. That is,

$$G_{it} = \phi(q_{it})$$

II.2 The constraints

The corporate goals contained in the objective function in equation (1) will be minimized subject to the satisfaction of a number of constraints. The constraints are determined by demand, supply, technological and capacity factors. They can be summarized broadly into two sets of constraints namely,

Supply and/or maximum capacity constraints: $\sum s_{it} x_i \leq z_i$
Demand and/or minimum capacity constraints: $\sum d_{it} x_i \geq w_i$

Examples of the maximum (capacity) constraints are the requirements that:

a. electricity output and the quantity of CO_2 captured do not exceed their respective installed generating and capture capacities (i.e. power balance);

b. the amount of CO_2 capture does not exceed the quantity emitted;

c. investment does not exceed the limit announced by the investor.

Examples of minimum (capacity) constraints are the requirements that:

a. electricity output and the quantity captured of CO_2 must meet a specified minimum level of demand (i.e. demand balance);

b. a certain minimum proportion of carbon emissions is captured.

III. APPLICATION TO THE UK

III.1 Introduction

The model for CO_2 capture was applied to the UK. Many of the UK's fossil-fuelled and nuclear power plants are nearing the end of their productive lives. These plants may be re-powered or replaced with capture-ready (or with-capture) clean coal plants[11]. The selected plants in our sample either have announced such plans, or have publicly hinted at embracing CCS technology in the near term.

III.1.1 Time Horizon Assumptions

The planning horizon assumed is twenty five years, covering the period from 2008 to 2032. The period was divided into five-year expansion sub-periods, with snapshots taken in the median years. That is,

5-year expansion period	Median year
2008 – 2012	2010
2013 – 2017	2015
2018 – 2022	2020
2023 – 2027	2025
2028 – 2032	2030

III.1.2 Power Plants

The present study includes the power plants that have, to date, announced their plans to invest in CCS technology. Some other plants without publicly-announced carbon capture investments plans were included in the sample for regional representation, and the expectation that, being large emitters, they would eventually join the fold, especially if, as likely, more stringent emission limits are imposed. The selected major power plants and details of their CCS plans are presented below in Table 1.

Table 1: List of selected power plants with likely CCS schemes

[11] Progressive Energy (2005) forecast that 9000 MW of capacity will be required by 2010 to replace ageing coal-fired plants and decommissioned nuclear plants.

Owners	Town	Nominal capacity (MW)	Technology	Fuel	CO_2 capture ($MtCO_2$/yr)	Estimated capital cost £m	Estimated Start-up date	Year first commissioned
1. BP and partners[12]	Peterhead	475	CCGT	Natural gas	2	700	2009[13]	1980
2. Coastal Energy[14]	Teesside	850	PCSCFGD	Coal	5[15]	1,000	2010/2011	2010
3. E.ON UK[16]	Killingholme, Lincolnshire	450	IGCC	Coal	(2)[17]	550	(2012)	1992
4. RWE npower	Tilbury, London	1,000	PCSCFGD	Coal	(3)	800[18]	2016	1968
5. SSE[19]	Ferrybridge, West Yorkshire	500	PCSCFGD	Coal[20]	2[21]	350[22]	2011/2012	1966
6. E.ON UK[23]	Kingsnorth, Kent	800	PCSCFGD	Coal[24]	(5)[25]	1,000	2012	1970
7. Scottish Power	Longannet, Fife	2,304	PCSCFGD	Coal	(7)	(1,500)	(2012)	1970
8. Drax Holdings	Selby, North Yorkshire	3,960	PCSCFGD	Coal	(15)	(2,000)	(2012)	1974
	Total	10,339			44	7,900		

A number of important observations regarding the selected power plants in Table 1 require mention. Firstly, the plants, all of which are base load, are grouped into three power generation technologies namely, CCGT, IGCC and PCSCFGD (Pulverised Coal with Supercritical boiler and Flue Gas Desulphurisation)[26]. The categorization is necessary to capture the heterogeneity of the plants and fits neatly with that in the UK Phase 2

[12] BP pulled out of the scheme in May 2007 but it is included for comparative purposes.
[13] (a) captured CO_2 to be used from 15 to 20 years for Miller field life extension; (b) Pipeline length (Peterhead to Miller) = 240 km.
[14] Centrica and Renew Tees Valley Ltd. Source: Guardian Unlimited Wednesday November 8, 2006
[15] The company plans to capture 100 $MtCO_2$ over an assumed plant lifetime of 20 years.
[16] Press Release May 24 2006 and Annual Report 2006
[17] Authors own estimates in brackets.
[18] Source: http://www.ndtcabin.com/articles/power/0603014.php#art_k1x
[19] Project collaborators include Doosan (formerly Mitsui) Babcock Energy, UK Coal, Siemens and Heriot-Watt University (design and implementation of carbon capture technology). Source: Scottish and Southern Energy PLC, 2006, Powerful Opportunities, Annual Report 2006 p. 16
[20] To be sourced mainly from the nearby Kellingley mine.
[21] The supercritical plant/process would itself save 500,000 tonnes of carbon dioxide per annum (Press Release).
[22] Of which £250 million is for the supercritical plant and £100 million for the capture equipment (Source: SSE Press Release: "Plans for the UK's First Cleaner Coal Power Plant at Ferrybridge Power Station")
[23] Source: Press Releases: 11 October 2005; 11 December 2006.
[24] Co-generation envisaged (i.e. coal + energy crops)
[25] "The supercritical units could reduce CO2 emissions by up to 1.08m tones a year."
[26] There are clear indications that all the existing sub-critical units would be retrofitted to supercritical units through turbine modifications and replacement of boiler pressure (see for example, Mitsui Babcock, 2005).

NAP for EU-ETS. The NAP2 emission allocation methodology for Large Electricity Producers (LEP) is based on a benchmark formula in which each technology is assigned a standard load factor, efficiency and associated emissions factor (DEFRA, 2006). Secondly, the Peterhead-Miller project was retained in the study in spite of BP's announced withdrawal from the project because SSE, the owners of the Peterhead plant, still

> *"…retains an interest in developments in carbon capture and storage technologies and has potential opportunities at its gas-fired and coal-fired power stations"* (SSE, 2007).

Further, it is illuminating to examine the relative performance of the scheme.

Thirdly, the announcement in May 2007 by Scottish Power that two of its power plants in Scotland namely, Longannet and Cockenzie would convert to clean coal technology vindicates the inclusion of Longannet in the sample. According to Scottish Power (2007),

> *"If the proposal proceeds, construction could start in 2009 with operations beginning in 2012 …….the refitted stations will also be designed to incorporate carbon capture technology currently being developed at Longannet. The scheme involves pumping carbon emissions from the station into deep underground coal seams to drive out methane gas which can be used as a fuel. The carbon emissions remain trapped in the coal seams"*

Fourthly, it must be emphasized that the capital cost figures in Table 1 are indicative estimates only, as none of the power plants have carried out detailed techno-economic studies at the time of project announcement. With that major caveat in mind, it is observed that the estimated capital cost of deploying carbon capture in the selected plants is about £8 billion. With that level of investment the plants would capture about 44 mt/CO_2 per annum and have an installed generating capacity of about 11 GW.

III.1.3 Data sources

The data used in the study were obtained from the following sources:

1. Company data (public domain)
2. The National Grid
3. DTI
4. UKCCSC
5. IEA-GHG

Company data (public domain)

Data on electricity production, costs and relevant future plans were obtained from the selected companies' Annual Reports and Press Releases. Data aggregation was a problem as, apart from the single-plant Drax Holdings, the multi-plant operators in the sample typically aggregate their entire UK operations in their reports, making it difficult to glean the data on the performance and costs of individual power plants.

The National Grid

Data on the forecast electricity demand and the potential relative share of the output of the selected plants in meeting the demand (or the Transmission Entry Capacity) were obtained from the National Grid.

DTI

Fuel cost assumptions were obtained from DTI publications.

UKCCSC

Some data and/or assumptions notably on fuel costs were either agreed to at meetings of the CO2 Capture and Storage Consortium (CCSC) or obtained from earlier studies completed by members.

IEA-GHG

Data on electricity production and emission factors in 2005 were obtained from IEA-GHG.

III.2 THE MODEL

A least-cost optimization model for electricity generation and CO_2 capture was formulated and solved using the linear programming algorithm in the GAMS (General Algebraic Modeling Software) software application package. The solution technique is especially useful in determining the optimum energy mix because it permits a comprehensive costing and scanning of the alternative energy mixes for best results in each time period. The assumptions, parameters, decision variables, the model and its solution are as stated hereunder.

III.2.1 Model assumptions

The following are the model assumptions and their sources.

Table 2. Model assumptions

Variable	**Value**	**Source**
1. Full load hours	8000 hours	Gibbins, 2006a

2. Plant lifetime	25 years	Gibbins, 2006b
3. CO_2 capture OPEX	£11.20/tCO_2 (or \$20/tCO_2)	IPCC, 2006
4. Fuel cost: 500/750 MW supercritical plant	1.5p/KWh	Chalmers, 2006
5. Efficiency loss due to the parasitic effect of CO_2 capture	10 – 20 %	Leci (1996), BP (2006)
6. Levelised plant capacity factor	85%	IEA-GHG, 2006
7. Fuel costs	80% of OPEX	DTI
8. Excess emission penalty	€40 (or £26.85)/tCO_2	EU Commission
9. Annual increase in emission penalty	4%	Authors' own estimates
10. Emission allocation ratio[27]: PCSCFGD plants	70%[28]	Authors' own estimates
11. Emission allocation ratio: IGCC plants	80%[29]	Authors' own estimates
12. Emission allocation ratio: CCGT plants	90%	Authors' own estimates
13. Yearly reduction in the emission allocation ratio for all plant types.	5.5%	Authors' own estimates
14. Carbon price	€21 (or £14)/tCO_2	Point Carbon (2007)
15. Annual increase in carbon price	4%	Authors' own estimates
16. Improvements in plant efficiency reflected in the reduced cost of fuel per net KWh generated		IEA-GHG, 2006
17. A load duration curve divided into "peak" and "off-peak" loads		Authors' own estimates.

It is noteworthy that a fundamental assumption of the present study is that the cornerstone of the UK carbon abatement policy shall remain effectively contributing to a sustained tightening of the EU-ETS, through an increasing stringency in the emission allocation regime. Hence, a

[27] That is, emission allocation as a percentage of the historic amount of emission required to produce a given level of power output.
[28] This was the actual emission allocation ratio of Drax in 2005.
[29] The less polluting plants (i.e. IGCC and CCGT) are assumed to be allocated a higher proportion of their required emission rights than the more polluting PCSCFGD plants.

yearly reduction of about 6 percent in the emission allocation ratio is assumed as well as a 4 percent increase in the unit emission penalty cost.

III.2.2 Input variables

The following are the input variables and their symbols used in the analysis:

Table 3. Input variables

Symbol	Input variable
enitcap	levelised installed capacity (85% capacity factor) (electricity) (mtce)
cinitcap	levelised installed capacity (CO_2 capture) (mtce)
avail	Availability factor (%)
efflo	Power plant efficiency loss due to CO_2 capture (%)
life	power plant lifetime (years)
maxcap	maximum installed generation capacity (mtce)
edem	forecast UK annual electricity demand (mtce)
cdem	forecast UK CO_2 demand (mtce)
bud	annual CAPEX budget limit (£million)
call	EU-ETS allocated CO_2 emission rights (mtce)
allratio	emission allocation as percentage of power plant requirement (%)
intense	CO_2 usage intensity (or emission factor) (mtce)
ecapex	power plant unit CAPEX (electricity share) (£/mtce)
ccapex	power plant unit CAPEX (CO_2 capture share) in (£/mtce)
fuel	unit fuel cost (p/mtce)[30]
nfuel	non-fuel OPEX (p/mtce)
fuel-d	Annual rate of decrease of fuel OPEX (%)
nfuel-d	Annual rate of decrease of non-fuel OPEX (%)
ecapex-d	Annual rate of decrease of unit electricity CAPEX (%)
ccapex-d	Annual rate of decrease of unit CO_2 capture CAPEX (%)
copex	CO_2 unit capture OPEX in (p/mtce)
copex-d	Annual rate of LBD-induced reduction in OPEX (%)
allratio-d	Annual rate of reduction in the emission allocation ratio (%)
cem	CO_2 emission (mtce)
prod	electricity production in (mtce)

[30] Given in pence per KWh by Chalmers (2006)

III.2.3 Decision variables

The following were the decision (or output) variables whose optimal values were determined in the model solution. The indices in the symbols can be interpreted as follows:

i = CCGT plants; j = IGCC plants; k = PCSCFGD plants

v = plant vintage (or time period); m = load block

Table 4. The decision variables

Symbol	**Decision variable**
ccgt(i,v)	capacity additions (electricity) CCGT plant *i* vintage *v*
igcc(j,v)	capacity additions (electricity) IGCC plant *j* vintage *v*
pcscfgd(k,v)	capacity additions (electricity) PCSCFGD plant *k* vintage *v*
uc(i,te)	capacity additions (CO_2) CCGT plant *i* vintage *v*
ug(j,te)	capacity additions (CO_2) CCGT plant *j* vintage *v*
up(k,te)	capacity additions (CO_2) CCGT plant *k* vintage *v*
yc(i,v,m,t)	electricity output CCGT plant *i* vintage *v* load *m* at time *t*
yg(j,v,m,t)	electricity output IGCC plant *j* vintage *v* load *m* at time *t*
yp(k,v,m,t)	electricity output PCSCFGD plant *k* vintage *v* load *m* at time *t*
ac(i,v,m,t)	amount of CO_2 captured by CCGT plant *i* vintage *v* load *m* at time *t*
ag(j,v,m,t)	amount of CO_2 captured by IGCC plant *j* vintage *v* load *m* at time *t*
ap(k,v,m,t)	amount of CO_2 captured by PCSCFGD plant *k* vintage *v* load *m* at time *t*
ic(i,v,m,t)	amount of government incentive to CCGT plant *i* of vintage *v* load *m* at time *t*
ig(j,v,m,t)	amount of government incentive to IGCC plant *j* of vintage *v* load *m* at time *t*
ip(k,v,m,t)	amount of government incentive to CCGT plant *k* of vintage *v* load *m* at time *t*
invc(i,t)	investment/CAPEX of CCGT plant *i* at time *t*
invg(j,t)	investment/CAPEX of IGCC plant *j* at time *t*
invp(k,t)	investment/CAPEX of CCGT plant *k* at time *t*

operac(i,v)	OPEX (electricity) of CCGT plant i vintage v
operag(j,v)	OPEX (electricity) IGCC plant j vintage v
operap(k,v)	OPEX (electricity) PCSCFGD plant k vintage v
coperac(i,v)	OPEX (CO_2 capture) CCGT plant i vintage v
coperag(j,v)	OPEX (CO_2 capture) IGCC plant j vintage v
coperap(k,v)	OPEX (CO_2 capture) PCSCFGD plant k vintage v
emipenc(i,v)	emission penalty cost CCGT plant i vintage v
emipeng(j,v)	emission penalty cost IGCC plant j vintage v
emipenp(k,v)	emission penalty PCSCFGD plant k vintage v
cost	total discounted cost

III.2.4 The Model Equations and Optimisation Constraints

Equations or expressions defining and/or setting limits to the following variables were specified:

Table 5. The model constraints

Equation	**Description**
7	The objective function (total discounted cost)
8a	capital charges constraint for CCGT plants at the median year of the expansion period
8b	Investment budget limit for CCGT plants at the median year of the expansion period
9a	Minimum (electricity) capacity constraint for CCGT plants at the median year of the expansion period
9b	Maximum (electricity) capacity constraint for CCGT plants at the median year of the expansion period
10	capacity constraint (power) on the i^{th} CCGT plant of vintage *v* at the median year of the expansion period

11	demand balance (electricity) of CCGT plants operating at load block *m* during the median year of the expansion period
12	OPEX (power) constraint for PCSCFGD plants at the median year of the expansion period
13a	Minimum (electricity) capacity constraint for CCGT plants at the median year of the expansion period
13b	Maximum (electricity) capacity constraint for CCGT plants at the median year of the expansion period
14	capacity constraint (power) on the i^{th} CCGT plant of vintage *v* at the median year of the expansion period
15a	demand balance (CO_2 capture) of CCGT plants operating at load block *m* during the median year of the expansion period
15b	demand balance (CO_2 capture) of CCGT plants operating at load block *m* during the median year of the expansion period
16	OPEX (CO_2 capture) constraint for PCSCFGD plants at the median year of the expansion period
17	The limit of Government incentive to CCGT plants at the median year of the expansion period
18	Emission limits
19a	emission penalty cost constraint for CCGT plants at the median year of the expansion period
19b	Excess emission
20	Emission-capture relationship

III.2.4.1 The objective function

At this capture stage of the CCS chain, the objective of the study is to choose the capacities and outputs of power generation and CO_2 capture which would minimize, over the period 2008 to 2032, the discounted aggregate cost of electricity generation and carbon dioxide capture. In the programming language of GAMS, the objective function is written as:

Minimise: *cost = sum((i,m), dsf(t+1)*(invc(i,t+1)+operac(i,m,t+1) +*
*emipenc(i,m,t+1) - 1.5*coperac(i,m,t+1))) +*
sum((j,m), dsf(t+1)(invg(j,t+1) + operag(j,m,t+1) +*
*emipeng(j,m,t+1) - 1.5*coperag(j,m,t+1))) +*
sum((k,m), dsf(t+1)(invp(k,t+1)+operap(k,m,t+1) +*
*emipenp(k,m,t+1) - 1.5*coperap(k,m,t+1)))*
(7)

where, in addition to previous definitions,

sum = the operand $\sum$

The objective is to minimize the system total discounted environomic cost where the total cost is defined as the addition of the costs of the three plant types. For each plant type, the discounted cost is the sum of its CAPEX, OPEX and emission penalty costs less 1.5 times the CO_2 capture OPEX, assuming the Government incentive amounts to 50% of the CO_2 capture OPEX.

The definitions and/or constraints of the various components of the objective function which constitute the remaining elements of the optimizing model are described below. To conserve space, the symbolic representation of only the CCGT (plant type *i*) definitions and constraints are presented below.

III.2.4.2 Joint Investment and Joint Products

As described in Kemp and Kasim (2006), CO_2 and electricity are joint products requiring joint investment. In the present study, two sets of equation or constraints were specified to determine the optimal level of investment in the selected power plants. Firstly, it was required that the level of investment be at least equal to the costs of expanding the plant's generation and CO_2 capture capacities (equation 8a).

Secondly, for each plant type, the size of investment was set equal to the estimated or actual levels announced by the power companies, plus the amount needed to compensate for efficiency losses. In GAMS programming language and using plant type *i* (i.e. the CCGT plant) as an example to save space, these constraints are written as:

Capital charges:

sum(i,invc(i,t+1)) $\geq$ *sum(i, crfc(i)*(sum(v, ecapexc(i,v,t+1)*ccgt(i,v) + ccapexc(i,v,t+1) * uc(i,v))))* (8a)

Investment budget limit:

sum (i, invc (i, t+1)) = $\left(\frac{1}{T}\right)$ **sum (i, dbccgt (i, "bud") * (1+dbccgt (i,"efflo")))*

(8b)

where, in addition to previous definitions,

T = number of investment periods over the planning horizon

It should be pointed out that *ecapexc* (power generation unit CAPEX) and *ccapexc* (capture equipment unit CAPEX) in the capital charges equation are assumed to decline over time at the relatively modest rates of 1% and 2% respectively. The former does so through the benefits of scale economies and technical progress while the latter is expected to reap the fruits of learning-by-doing (LBD)[31].

[31] Several writers including Yeh and Rubin (2007) have applied experience curve analysis to pulverised coal power plants' capital and operating costs data (USA and worldwide) and established that the observed reduced average price of electricity to the USA consumer was due to the effects of learning

III.2.4.3 Electricity generation

(i) minimum and maximum capacities

The minimum levelised installed capacity for plant type *i* at 85% capacity factor is described as:

minimum installed capacity:

sum(i,ccgt(i,t)) ≥ sum(i,
(dbccgt(i,"enitcap")(1+(dbccgt(i,"efflo")*0.5)))))* (9a)

That is, the effective minimum installed capacity must at least equal the product of the nameplate capacity and a factor equalling half of the estimated efficiency loss *plus* 1.

By contrast, the effective maximum levelised installed capacity must equal the product of the nameplate capacity and a factor equalling the full estimated efficiency loss *plus* 1.

maximum capacity:

sum(i,ccgt(i,t)) = sum(i, (dbccgt(i,"enitcap")(1+(dbccgt(i,"efflo")))))*
(9b)

(ii) power balance

The power balance constraint stipulates that the amount of electricity produced at time *t* by the plants of a given vintage *v* in any load block

by doing. Yeh and Rubin's calculated learning rate of 5.6% in the almost 60-year period (1942-1999), implies a reduction in costs of that magnitude for each doubling of installed capacity.

must not exceed the available capacity (which is the product of the installed capacity, the availability factor and efficiency loss). That is, production-capacity relationship:

*sum(m, dur(m)*yc(i,m,t)) ≤ dbccgt(i, "avail") *(1/(dbccgt(i,"efflo")))* (i,ccgt(i,t))* (10)

(iii) demand balance

There are two demand-output relationships or constraints in the model. Firstly, the total electricity output of the selected power plants was constrained to meet at least 10% of the forecast UK electricity demand[32].

power supply-demand relationship:

*(sum((i,m), dur(m)*yc(i,m,t)) + sum((j,m), dur(m)*yg(j,m,t)) + sum((k,m), dur(m)*yp(k,m,t))) ≥ 0.10*sum(m, dur(m)*edem(m,t))* (11a)

The demand constraint was informed by the National Grid projections in Table 6.

Table 6: UK Transmission Entry Capacity (2006-2013) (MW)

Power Station	Owner	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Killingholme 1	E.ON UK plc	900	900	900	900	900	900	900
Teesside	Teesside Power Ltd	1875	1875	1875	1875	1875	1875	1875
Drax	Drax Power Ltd	3885	3885	3885	3885	3885	3885	3885
Ferrybridge	Keadby Generation Ltd	1981	1981	1981	1981	1981	1981	1981
Kingsnorth	E.ON UK plc	1966	1966	1966	1966	1966	1966	1966
Tilbury	RWE Npower plc	1076	1076	1076	1076	1076	1076	1076
Peterhead	SSE Generation Ltd	1524	1524	1524	1524	1524	1524	1524
Longannet	Scottish Power Generation Ltd	2304	2304	2304	2304	2304	2304	2304
	Total (selected plants)	15511	15511	15511	15511	15511	15511	15511
	Total (UK)	76286	78294	87335	89270	91733	93923	94474
	Selected as % UK	20	20	18	17	17	17	16

[32] Drax satisfied about 7% of UK power demand in 2005 (Drax Annual Report, 2005)

Source: National Grid – Transmission Entry Capacity

The last row in Table 6 reveals that the market satisfaction capacities of the selected plants range between 20 and 16 percent. However, since only about 67% (i.e. 10339 MW)[33] of the total 1551 MW installed capacities would engage in carbon capture, the range of market satisfaction capabilities reduces to between 11 and 13 percent, hence the specified minimum 10% used in the study.

The second constraint was that the selected power plants, at least, maintained their individual market share (*emshare*). That is, for plant type *i:*

market share constraint:

*sum((i,m), dur(m)*yc(i,m,t)) ≥ sum((i,m), edem(m,t)*dbccgt(i,"emshare"))* (11b)

(iv) OPEX

For all vintages, plant types and times, the variable cost of power generation in a load block of duration *m* is expressed as the product of the level of electricity output during the period and the total (fuel and non-fuel) unit OPEX. The latter is comprised of the unit fuel and non-fuel costs per kilo-watt hour (*topexc*).

operating cost (electricity):

[33] See Table 1.

*sum((i,m), dur(m)*operac(i,m,t)) = sum((i,v), sum(m,dur(m)*yc(i,m,t))*sum(m, topexc(i,v,m,t)))* (12)

Following IEA-GHG (2006) and other writers, the total unit OPEX (*topexc*), too, is assumed to decline over time, with improvements in plant efficiency, fuel diversification and LBD. Thus, fuel and non-fuel costs are assumed to respectively decrease at the across-the-board annual rates of 1% and 0.8%.

III.2.4.4 CO_2 capture

(i) minimum and maximum capacities

Under the increasing emission stringency assumption, the upper limit of each power plant's capture capacity was set equal to their CO_2 emission level in 2005 (the first year of EU-ETS). The lower limit was set equal to 50% of this amount. That is,

minimum CO_2 capture capacity:

*sum(i, uc(i,t+1)) = 0.5*sum(i, dbccgt(i,"cem"))* (13a)

maximum CO_2 capture capacity:

sum(i, uc(i,t+1)) = sum(i, dbccgt(i,"cem")) (13b)

(ii) capture-capacity balance

At any given time and load block operational level, the amount of CO_2 captured is constrained to be no more than one and a half times the nominal capture capacity – that is, assuming a maximum 50% efficiency loss in the carbon capture process. For plant type *i*, this can be described as:

capture capacity constraint:

*sum(m, dur(m)*ac(i,m,t+1))* ≤ *1.5*uc(i,t+1)* (14)

(iii) demand balance

As with electricity output, there were two carbon demand-output constraints. Globally, the total amount of CO_2 captured in any given year was constrained to be at least equal to 10% of the total UK demand for CO_2, for both value- and non-value added uses[34].

CO_2 supply-demand constraint:

*(sum((i,m), dur(m)*ac(i,m,t+1)) + sum((j,m), dur(m)*ag(j,m,t+1)) + sum((k,m), dur(m)*ap(k,m,t+1)))* ≥ *0.10*sum(m,cdem(m,t))* (15)

(iv) OPEX (CO_2 capture)

The variable cost of CO_2 capture is defined as the product of the amount of CO_2 captured and the unit capture cost. Thus, the CO_2 capture OPEX for plant type *i*, given its CO_2 separation technology is defined as:

[34] The value-added uses would include CO_2-EOR (in oilfields) and ECBM (enhanced coal bed methane) (in coal mines). Non-value added applications would include permanent storage.

CO_2 capture OPEX:

$$sum((i,m), dur(m)*coperac(i,m,t+1))=sum((i,v), sum(m,dur(m)*ac(i,m,t+1))*sum(m, copexc(i,v,m,t+1))) \qquad (16)$$

Doosan Babcock (2006) identified the following CO_2 separation technologies:

(a) Post-combustion amine scrubbing
(b) Pre-combustion (physical solvent process) separation and/or oxyfuel firing.
(c) Membrane separation.

The cost differential of the separation technologies is reflected in their unit capture cost, *copexc (*in equation 16).

In the literature, the unit variable capture cost, *copexc*, is not only assumed to decline over time due to learning by doing but to do so faster than in the case of electricity generation, once a critical mass of understanding has been attained. This is because being relatively new, the learning rate of CCS technology and the attendant cost reductions are expected to be higher than the rest of the technologies deployed in power generation which are mature (see, for example, IEA-GHG, 2006 and Davison, 2006).

III.2.4.5 Government incentives

The issue of government incentives was discussed above briefly in general terms. In this section, closer attention is paid to the relevant UK Government's incentives.

Recognising the existence of market failure in climate change mitigation, the UK Government has put in place a number of incentives targeted at reducing the emission and abatement costs of CO_2 and other pollutants. DEFRA (2006) grouped the incentivising policies into six types namely, regulation, fiscal charge, subsidy, market creation, information provision, and voluntary and negotiated agreement. Of the six types three directly influence the market price of anthropogenic substances. Thus environmental levies, charges, and taxes increase the price of an environmentally damaging good and raise public revenue. Subsidies are the opposite of public revenue-yielding policies, reducing the price (and public revenue) of an environmentally-friendly commodity or activity (such as carbon capture as opposed to carbon emission), through grants, lower taxes/tax rebates. Market creation policies fix a quantity such as emission limits and allow market forces to determine the appropriate price. The Renewables Obligation (RO)[35] and Climate Change Levy (CCL) are examples of the latter, and are similar to the cost-sharing concept of the present study. However, while ROs are fixed by the level of obligation[36] the cost-sharing incentives of the present study are load- (and, by extension) capture cost-related. Activity- level-related incentives (a) appropriately reward the carbon capture effort, and (b) add flexibility to the analysis since they provide the authorities with greater latitude, if so inclined, to apply different levels of support during peak and off-peak periods. Specifically, in the present study, purely for purposes of illustrating the effects of incentives on investor behaviour

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35 Succinctly described as requiring "electricity suppliers to deliver a stated proportion of their electricity from eligible renewable energy sources. Companies can meet their obligation by presenting Renewable Obligation Certificates (ROCs). ROCs are currently issued to renewable generators for each 1MWh of electricity generated, these are then bought by supply companies. Suppliers can also meet their obligation by paying a buy-out fund contribution per MWh or a combination of the two. Money from the buy-out fund is recycled pro-rata to companies presenting ROCs, hence the value of a ROC = buy-out price + money recycled from buy-out fund. The recycling mechanism gives suppliers an additional incentive to invest in renewables and acquire ROCs. (DEFRA, 2007)

36 leading, in the face of external constraints (such as delays in the planning process), to increased cost per tonne of carbon saved and hence offering poor value for money (OFGEM, 2007)

with respect to CO_2 capture, Government support equal to 50% of the OPEX relating to CO_2 capture in either load block was assumed for model illustrative purposes. For plant type *i* the Government incentive constraint is written as:

Government incentives:

*sum((i,m), dur(m)*ic(i,m,t+1)) = 0.5*sum((i,m), dur(m) * coperac(i,m,t+1))* (17)

That is, the amount of Government incentives during any load block is equal to half the block's CO_2 OPEX capture cost. The incentives may be given in a number of ways. Firstly, the Government may amend the RO and CCL exemptions by redefining renewables to include carbon capture. Administratively, this approach may well be the least expensive way to incentivise CO_2 capture since the Government already has the infrastructure and experience to administer both climate change policies. Alternatively, the Government may introduce a CO_2 capture feed-in tariff. The feed-in tariff may in implemented in such a way that OFGEM allows electricity generators not only to include CO_2 capture costs among their admissible costs but also to charge a factor above their CO_2 capture OPEX[37], for the electricity fed into the national grid.

III.2.4.6 Emission Constraints

(i) possible and probable emissions

A distinction was made in the study between possible and probable emissions. A power plant's possible emission is equivalent to the level of

[37] For example, one-and-a-half-times the CO_2 capture OPEX, as done in the present study.

emission that can be expected based on a rigid application of theoretical emission factors. On the other hand, the plant's probable emission levels are based on the more realistic assumption that in all likelihood the plant would not be tied rigidly to the static theoretic emissions factor as it decouples the production-emission relationship for a variety of reasons, including emission compliance requirements, deepening co-firing generation[38], and fuel diversification (biomass, energy crops, and petcoke). Given this possibility and the emerging evidence already pointing in that direction, the study imposed a constraint that the more flexible probable emission level must be less than the relatively static possible emission level, based on historic emission data. Thus, for plant type *i*, the emission limit is:

emission limit:

*emceq (t)..sum((i,m), dur(m)*emc(i,m,t)) ≤*
*sum((i,m),yc(i,m,t)*intensec(i,m,t))* (18)

The RHS of the inequality sign is the theoretical emission factor of a particular load block at time *t*.

(ii) net emission reduction cost constraint

As stated earlier, the net emission reduction (NER) cost is the difference between the emission penalty cost and the CO_2 capture cost. The constraint on the latter has already been described above. The former (i.e. emission penalty cost) is defined as the product of any excess emission and the unit emission penalty. That is,

emission penalty cost:

[38] The ROC Obligation size was 5.5% in 2005/06 and is scheduled to progressively increase to 15.4% by 2015/16, with a possible increase towards 20% thereafter (OFGEM, 2007).

*sum((i,m), dur(m)*emipenc(i,m,t)) = sum((i,v,m),*
*dur(m)*xec(i,m,t)*bet(t))*
(19a)

where excess emission (*xec)* is defined as:

excess emission:

*sum((i,m), dur(m)*xec(i,m,t)) = sum{((i,m,v), (dur(m)*emc(i,m,t) - dur(m)*ac(i,m,t))} - callc(i,v,t))* (19b)

Thus, excess emission is the net emission[39] less the amount of the allocated carbon allowance where, the net emission itself is the actual emission less the amount of CO_2 capture.

(iii) capture-emission relationship

The amount of CO_2 captured is constrained to be no more than the amount emitted at any point in time and, in any particular load block duration. For plant type *i* this can be written as:

CO_2 capture-emission relationship:

*sum((i,m), dur(m)*ac(i,m,t+1))* ≤ *sum((i,m), dur(m)*emc(i,m,t+1))*
(20)

IV Results

Because of the vital role generally ascribed to Government intervention in the development and deployment of CCS technology, the model was

[39] That is, the term within the bracket {}

optimized in two scenarios under two alternative assumptions of the presence or absence of government support. The results are presented in two sections below. The first section discusses the results of the original with-incentive model while key results of the two models (including zero Government support) are compared in the second section. Consistent with the focus of the present study on carbon capture, the discussion of the results focuses on the carbon capture side of the plant's operations.

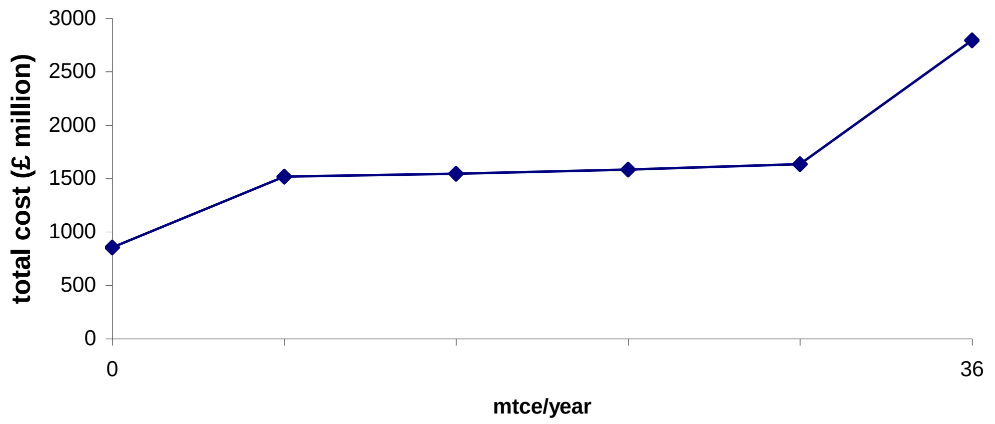
IV.1 Model solutions with government incentives

The assumption of this scenario is that the Government introduces a cost-sharing incentive scheme and the objective function (equation 1) and the accompanying constraints (equations 7 to 20) hold.

(a) the total cost curve

The optimal total cost curve of electricity generation and CO_2 capture is presented below. It is the aggregated supply function derived from the summation of the plant-level optimized least-cost options.

Fig. 1: Optimal cost curve of electricity generation and CO_2 capture in selected power plants



The chart shows three distinct phases. At the initial stages of commercializing carbon capture technology, it is plausible to expect rising costs due to a number of reasons, including "shortfalls in performance and reliability of early system designs" (see IEA-GHG, 2006 and Rubin **et.al**, 2007). However, in the medium term, the cost curve adopts the shape of a plateau, indicating that the fruits of learning by doing are being reaped, as it is possible to increase output without significantly increasing total costs. Eventually in the long-run, however, the cost-reducing advantages of learning by doing and other technological improvements appear to be overwhelmed by the increasing stringency of emission rights, leading (as shown below) to higher emission penalties and rising total cost function. This result, especially the cost-increasing impact of tightening emission rights, is consistent with the findings of several authors as reported in IEA-GHG (2006) to the effect that:

> *"... the real cost per kilowatt for constructing a power plant in the US continued to decline during the early to end mid-1960s then stabilized in the late 1960s, and climbed substantially during the 1970s and 1980s……Real construction cost increases were primarily due to new regulatory requirements such as environmental, health and safety standards….."*

To gain further insight into the nature and behaviour of the total cost curve a number of regression models were estimated to determine (i) the implied responsiveness or elasticity of total cost to changes in total output (i.e. of electricity and carbon capture); (ii) the responsiveness of total cost to varying CO_2 capture-power generation product mix; and, (iii) the responsiveness of total cost to varying power generation-CO_2 capture product mix.

The following simple regression model in logarithms (to the base *e*) was estimated to determine the total cost elasticity with respect to changes in total output:

$$C_t = \beta_0 + \beta_1 X_t + \varepsilon_t$$
(21)

where,

C_t = total cost of electricity generation and CO_2 capture (£ million)

X_t = total electricity production and CO_2 capture (mtce)

ε_t = regression error term

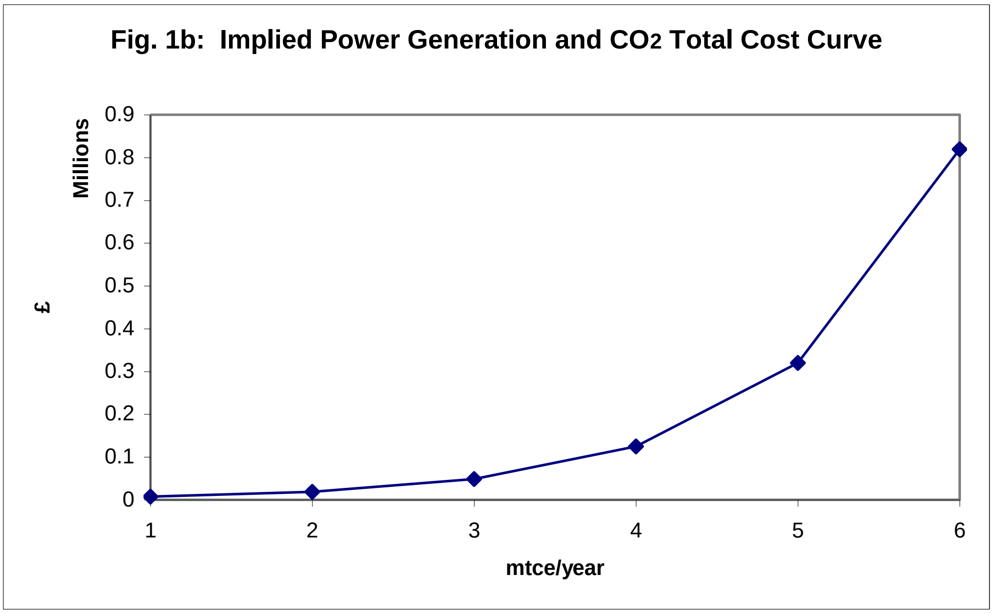
β_0 , β_1 are regression parameters

The regression result is summarized as follows:

Parameter	**Coefficient**	**t-statistic**	**Adjusted R-square**
β_0	4.20	5.26	0.75
β_1	0.94	3.97	

It is noteworthy that the estimated coefficient of β_1, the measure of the elasticity or responsiveness of total cost is less than unity. Precisely, the prediction is that a one percent increase in the production of electricity and the amount of CO_2 captured will engender 0.94 percent increase in total costs.

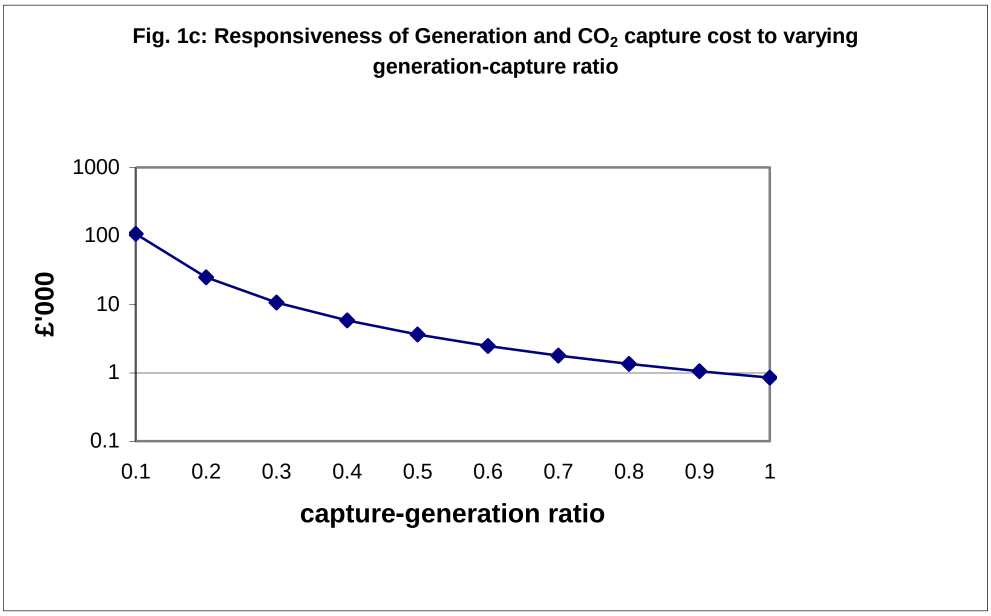
Fig. 1b shows the implied total cost curve in levels of the variables.



However, given the growing concern about climate change and the contribution of power generation to global warming it is conceivable that issues such as the amount of CO_2 captured per kilowatt-hour of electricity generated (or the CO_2 capture-generation ratio) will receive greater attention. To investigate the optimal course of action based on the present study's optimized model solution, the elasticity of total cost to the capture-generation ratio (β_{11}) was estimated by using the regression model in equation (21) while substituting the capture-generation ratio (x_{1t}) for total output (a_t) in that equation.

Parameter	**Coefficient**	**t-statistic**	**Adjusted R-square**
β_{01}	6.74	21.84	0.56
β_{11}	-2.10	-2.46	

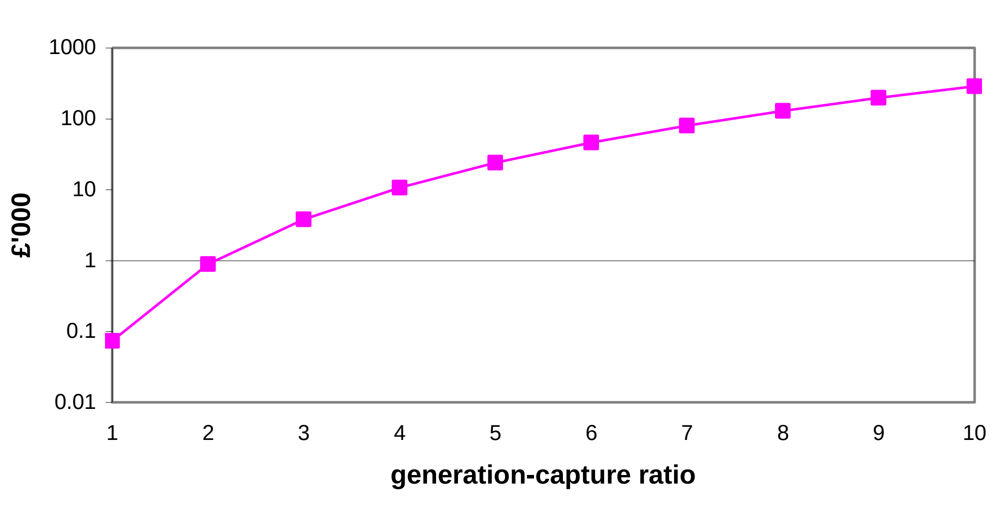
With $|\beta_{11}| > \beta_1$, that is, the absolute magnitude of the elasticity of total cost to changes in the capture-generation ratio being greater than that of changes to total output, it is clear that (a) the issue of product-mix in any capacity expansion programme is very important indeed and, (b) more specifically, to minimize total cost, greater amounts of CO_2 ought to be captured per kilowatt-hour of power generation. This is demonstrated in Fig 1c below.



As can be seen in Fig 1c, reducing the capture-generation ratio from 80 to 40 percent increases total from about £1 million to about £5 million. The conclusion, therefore, is that the most effective cost-reducing option in a climate of increasingly stringent emission allowances is to increase the amount of carbon capture in the electricity generation-CO_2 capture product mix.

Interestingly, the same conclusion is reached if the foregoing analysis had been approached from the flip side of the coin – that is, the generation-CO_2 capture ratio (or kilowatt-hour generation per tonne of CO_2 captured), as can be seen in Fig. 1d.

Fig. 1d: Responsiveness of Generation and CO_2 capture cost to varying generation-capture ratio



Reducing the factor by which power generation exceeds CO_2 capture from 8 to 4 (in Fig. 1d) substantially reduces the COE ***plus.*** The underlying cost elasticity to a change in the generation-capacity ratio is presented below:

Parameter	**Coefficient**	**t-statistic**	**Adjusted R-square**
β_{02}	4.30	3.40	0.57
β_{12}	3.60	2.52	

As with the capture-generation ratio, total cost is more responsive to the product-mix (generation-capture) than total production, with β_{12} (=3.60) > β_1 (=0.94).

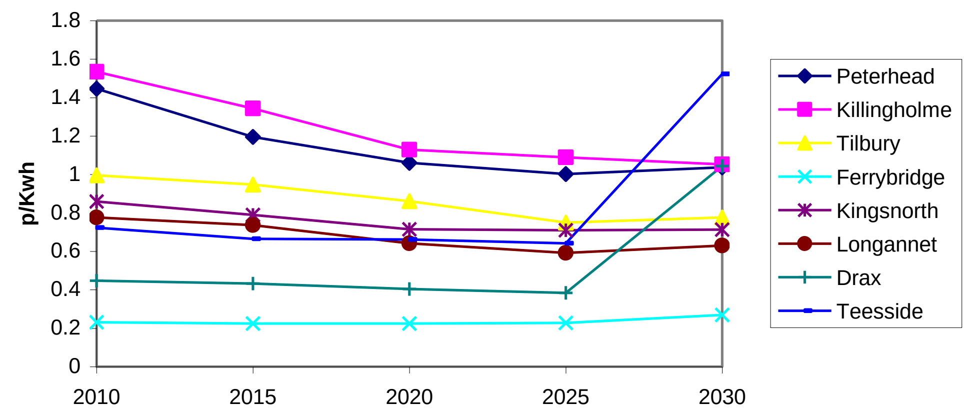
(b) Average cost: the cost of electricity and CO_2 capture

The cost of electricity and CO_2 capture (or, COE ***plus***, for short)[40] ranged from 0.22 p/KWh in 2015 at the Ferrybridge (a PCSCFGD) plant to 1.52

[40] Another short form that may be considered is the abbreviation COEAC (Cost of Electricity and carbon Capture). However, COE ***plus*** is preferred because it readily conveys the notion of the cost of an extra activity to be added to "COE" which is widely recognised as an abbreviation for the "cost of electricity generation" in the literature.

p/KWh in 2030 at the Teesside (PCSCFGD) plant. The results are summarized in Fig. 2 below.

Fig. 2: A ranking of the optimal costs of electricity generation and CO_2 capture of 3 technologies in selected power plants



In terms of the likely Government policy of picking a “winning” technology, the above chart conveys the message that, in a dynamic world, no plant type has a permanent cost advantage or disadvantage. Thus, while the CCGT (Peterhead) and IGCC (Killingholme) plants started out being ranked as the costliest providers in 2010, a PCSCFGD (Teesside) had overtaken them by 2027. Moreover, by 2030, COE ***plus*** of the two erstwhile costly plant types had fallen to the extent that they converged with that of Drax (PCSCFGD), which for 15 years (2010 - 2025) was the second least expensive plant. An insight into the switch in the cost relativities is provided by a close study of Table 8 and Figures 3 and 5. Fig. 3 shows that the optimal amounts of CO_2 captured in both PCSCFGD plants (Teesside and Drax) stabilized after 2025. However, Fig. 5 (especially the polynomial trend lines) and Table 8 show that almost simultaneously, the emission penalty charges incurred by the two plants increase dramatically, pushing up their COE ***plus*** by wide margins in Fig. 2. By contrast, the trajectories of the CO_2 capture efforts and incurred emission penalty charges at the Killingholme and Peterhead plants are seen to be moving, largely, in the opposite directions. Thus, in Fig. 3 one observes monotonously rising (albeit, gently) CO_2 capture effort curves of the two plants, while Fig 5 and Table 8 show that Killingholme avoids incurring emission penalty charges throughout and Peterhead incurs relatively small penalty charges in 2025 and 2030. The combination of increasing carbon capture effect and emission penalty avoidance results in lowering COE ***plus*** of Peterhead and Killingholme.

This is a very significant result as it demonstrates that the main driver of the switch in the cost relativities is excess emission penalty charges. The two PCSCFGD plants (Drax and Teesside) are less expensive than the higher efficiency, less carbon emitting plants (Peterhead and Killingholme) as long they avoid incurring heavy emission penalty charges. However, once carbon prices have risen high enough from 2025 onwards in the present study (i.e. minimum (a) penalty charge equals €57/tCO_2, and (b) carbon price equals €29/tCO_2) to force the incurrence of emission penalty charges by the relatively large emitters, the cost relativities switch in favour of the CCGT and IGCC plants. The result is another way to understand the advocacy of higher carbon prices in the literature to enhance the cost competitiveness of CCGT and IGCC plants (see for example, Berlin, 2007).

Ferrybridge (a PCSCFGD) was the least expensive throughout. The least-costly status could have been genuinely earned out of being the most efficient plant or, it might have arisen from a likely project cost underestimation. The latter appears to be the case. At the announced project capital cost of £350 million, this cost figure appears to be unrealistically low, a fact recently acknowledged by the company itself in one of its most recent reports, noting that:

> *"It was originally expected that installation of the Supercritical Boiler and related plant to meet all established environmental standards would require investment by SSE of around £250m*[41]*. Over the past year, costs across the power equipment sector have risen and the required level of investment may be significantly higher …."* SSE(2007)

Indeed, the foregoing statement is indicative of the strong health warning that must be attached to all the cost figures used in the present study. In virtually all the cases, the cost figures are preliminary as the final techno-economic studies had not been concluded at the time they were released in the public domain.

In addition to Ferrybridge, Drax (PCSCFGD) remained a low-cost carbon capture operator for a very long time. Several factors, including the fuel type, improvements in plant efficiency and scale economies might explain the short- to medium-term position of Drax as a low-cost plant.

(c) Amount of CO_2 captured

Fig. 3 shows the respective forecast optimal quantities of CO_2 captured at the power plants. The Drax 2005 actual emission was included in the chart to underscore the point that the present study's core assumption of increasing stringency of emission rights implies that the permissible emissions and CO_2 capture levels in 2008 to 2030 would not exceed the actual emission in 2005 (the commencement date of EU-ETS).

[41] The CO_2 capture equipment was estimated to add another £100m.

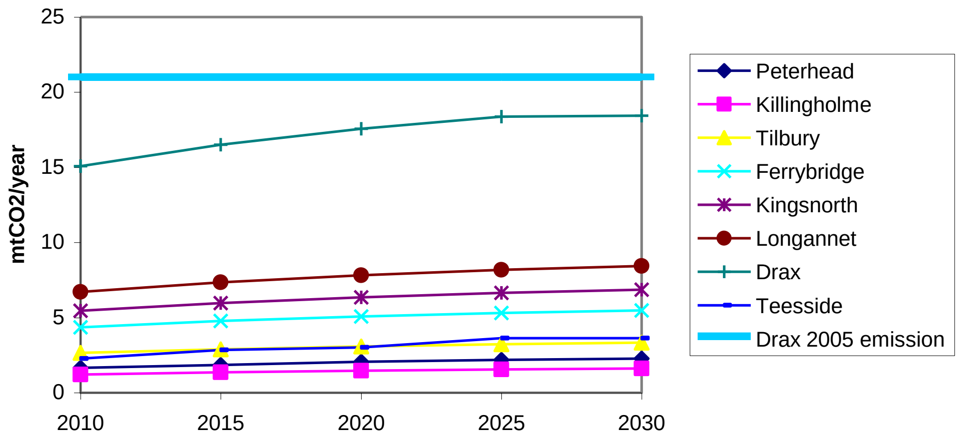


Fig. 3: A comparison of the optimal amount of CO_2 capture in selected power plants

Killingholme is projected to capture the least amount of CO_2, averaging about 1.43 $mtCO_2$/year at an average capture cost of about £16.52/tCO_2. Peterhead, a gas-fired plant comes second in the league of minimum carbon capture plants. Being respectively IGCC (high efficiency) and CCGT (gas, low CO_2 emission) plants, this result is not surprising but it highlights a potential conflict (not yet addressed in the literature) between the goals of improving plant efficiency and maximizing installed carbon capture capacity[42]. Again, unsurprisingly, Drax (a PCSCFGD) is projected to capture the largest amount of CO_2, averaging about 18 mtCO2/year at an average cost of £12.63/tCO_2.

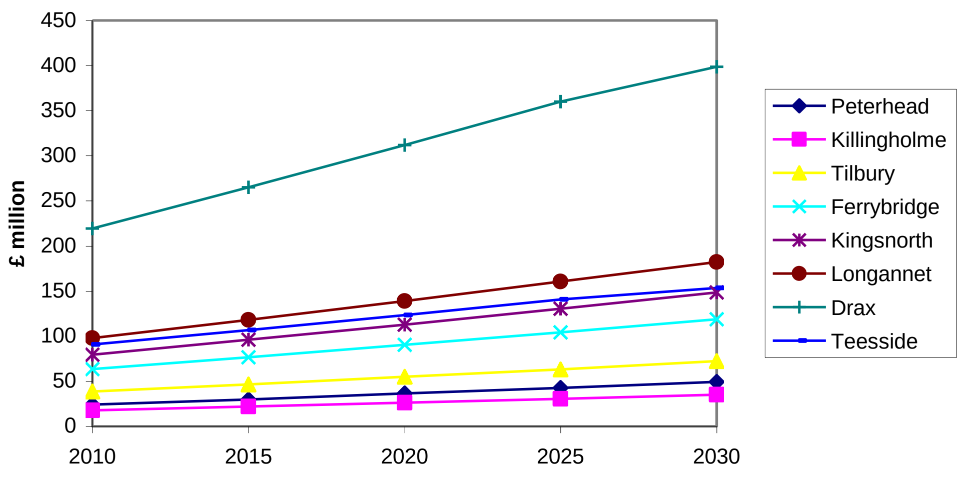
(d) The value of CO_2 captured

The value of the CO_2 captured is simply the product of the amount captured and the market price CO_2. Assuming a carbon market price of roughly £14/tCO_2 (or about €20/tCO_2 rising at the rate of 4% per annum,

[42] For example, Davison (2006) reported that the “costs per tonne of CO_2 are higher for the gas fired plants 48-102 \$/tCO_2, because less CO_2 emission is avoided per kWh of electricity generated”. However, in the final analysis, it is not only the fuel type but also, the much sought-after improvements in plant efficiency that will increasingly reduce the amount of CO_2 emission avoided, creating an overcapacity in the installed carbon capture capacity prior to the improvements in plant efficiency.

as emission allowances are tightened, the value of the CO_2 captured by the plants are as shown in Fig. 4.

Fig. 4: A comparison of the optimal values of captured CO_2



(e) The Emission Penalty Cost

As stated above, a power plant adding CO_2 capture to its operations would pay emission penalty charges only if its actual emission exceeded the sum of its emission rights and CO_2 capture.

The emission penalty costs of the selected power plants are presented below. In addition to the bars, polynomial trend lines were fitted to the data in Fig. 5 to capture the underlying trends in the irregular movements of the emission penalty cost variable.

Fig. 5: A comparison of the excess emission penalty payable by selected power plants

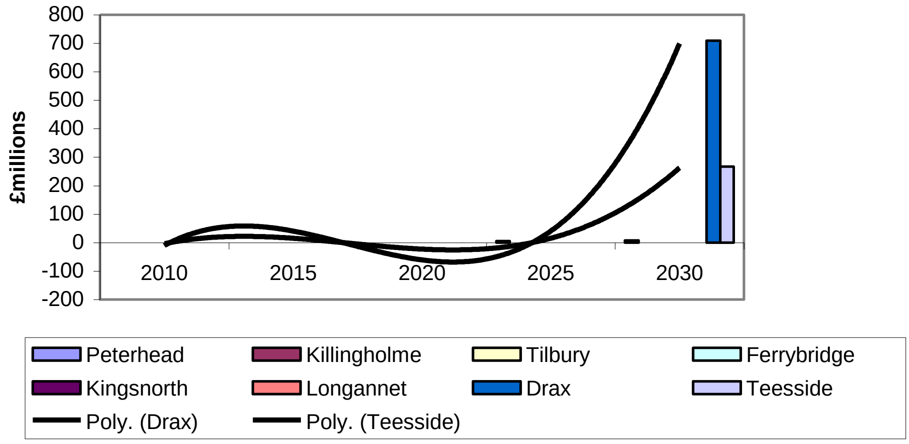


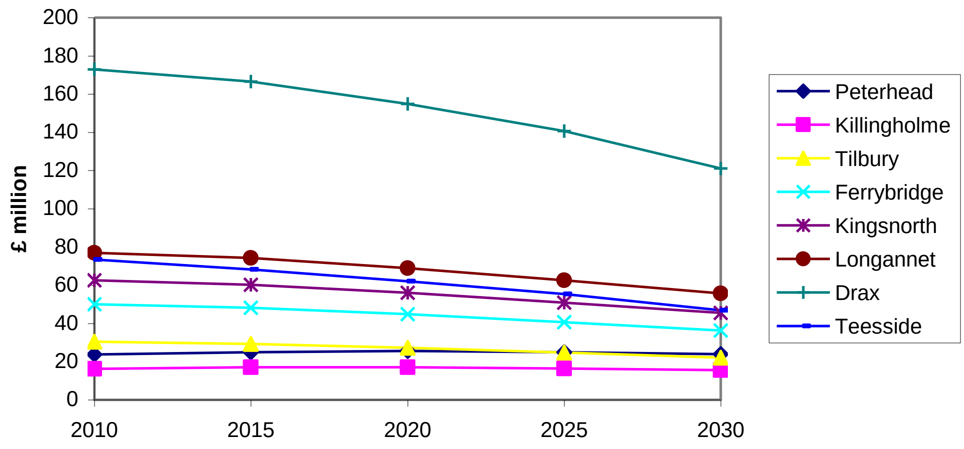
Fig. 5 shows that six of the eight selected plants virtually succeeded in avoiding emission penalty charges throughout the planning horizon, by keeping within the increasingly stringent emission limits. Indeed, as typified by the negative values in the polynomial trend lines fitted to the Drax and Teesside data, all the selected plants between 2010 and 2030 captured more CO_2 than required. The "extra" carbon capture creates an opportunity to trade in emission allowances (e.g. carbon offsets) in addition to trading in the CO_2 commodity itself.

However, in contrast to the six plants that avoided emission penalty charges throughout, Drax and Teesside incurred significant emission penalty costs in 2030, at the tail end of the plan period.

(f) Government incentives

The maximum yearly Government cost-sharing incentives in the form of grants, under the assumption that 50% of the OPEX capture cost would in effect be paid by the Government, range from £15.58 million (paid to the Killingholme plant in 2030), to about £173 million (paid to Drax in 2010).

Fig. 6: A comparison of the optimal values of government cost-sharing incentives to selected major power plants



As can be seen in Fig. 6, Drax and Killingholme stand at the opposite extremes of their requirement of Government incentives.

In addition, though high to begin with, the amounts of the incentives either remained flat or dropped slightly from one median year to the next. In all, the optimal cost-sharing arrangement amounted to about £2.2 billion between 2010 and 2030[43]. Table 7 below expresses the level of Government support in terms of pence per kilowatt-hour of electricity generated and carbon captured, based on the assumptions discussed above. The table is useful in comparing the level of Government support for carbon capture with those for alternative carbon abatement technologies such as ROs and CCL exemptions.

[43] This may be compared with (a) the £1billion being sought by UK's energy firms "to experiment with the potential benefits of carbon sequestration and capture…" Guardian (2007); (b) the £1 billion per year by 2010, which DTI estimated would be required to support the RO together with the exemption from CCL for electricity from renewables (DTI website, http://www.consumer.gov.uk/renewables/renew_2.2.1.htm)

Table 7: The cost of Government support

	Cost of Government support (p/KWh)								Aggregated
	Peterhead	Killingholme	Tilbury	Ferrybridge	Kingsnorth	Longannet	Drax	Teesside	total (£M)
2010	0.39	0.33	0.27	0.65	0.74	0.32	0.38	0.81	506.08
2015	0.26	0.22	0.16	0.27	0.29	0.17	0.21	0.29	488.65
2020	0.22	0.19	0.14	0.23	0.24	0.15	0.18	0.24	456.33
2025	0.20	0.16	0.12	0.19	0.19	0.12	0.15	0.20	416.18
2030	0.17	0.14	0.09	0.15	0.16	0.10	0.12	0.16	366.88

The level of Government price support ranges from 0.09p/KWh (Tilbury, 2030) to 0.81p/KWh (Teesside, 2010). Briefly, comparing the level of support in the table with the CCL exemptions and Climate Change Agreement (CCA) discount, it is clear that in most cases the required level of support is below:

(a) the current 0.43p/KWh CCL exemption enjoyed by eligible industrial electricity users (DTI, 2004), and,

(b) the 80% discount on the CCL (or 0.34p/KWh) granted to CCA signatories (HM Treasury, 2006).

IV.2 A brief Assessment of the impact of Government incentives

The importance of Government incentives to the development and deployment of carbon capture is investigated in two key areas, namely, on the time paths of COE ***plus*** and the profitability of operations. The investigation is conducted by comparing the trajectories of the two variables under two alternative scenarios namely, with- and without-Government incentives. It should be borne in mind that apart from the difference in the assumptions on incentives, every other assumption is the same in both scenarios.

(a) a comparison of COE *plus*

Graphical comparisons of the magnitude and time paths of the costs of electricity generation and carbon capture in the selected power plants are presented below in Figs. 7 to 14.

Fig. 7: Peterhead: A comparison of the optimal costs of electricity generation and CO_2 capture with- and without incentives

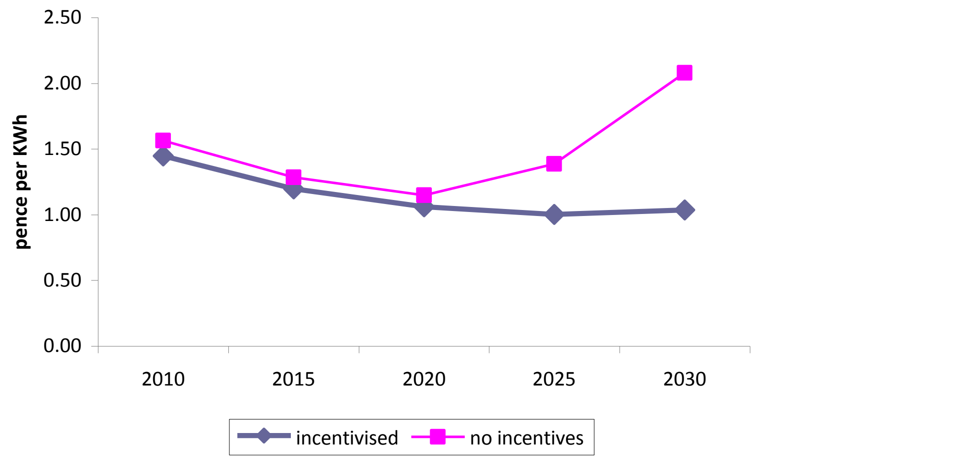


Fig. 8: Killingholme: A comparison of the optimal costs of electricity generation and CO_2 capture with- and without incentives

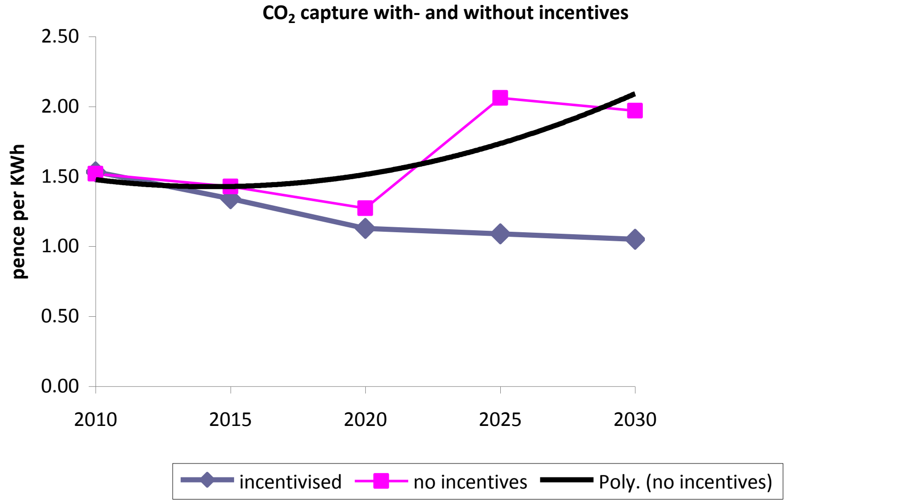


Fig. 9: Tilbury: A comparison of the optimal costs of electricity generation and CO_2 capture with- and without incentives

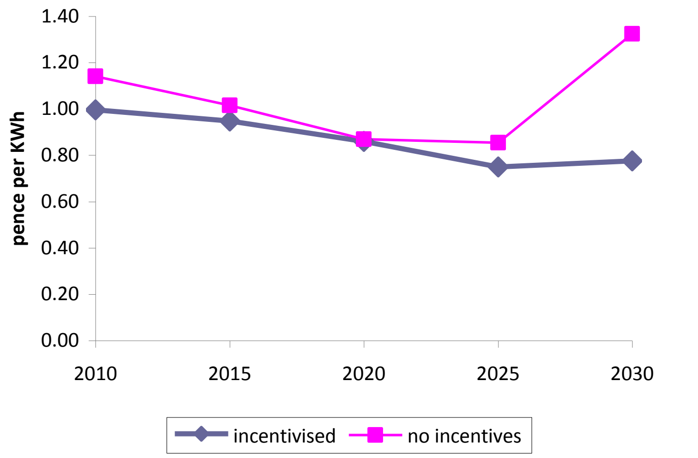
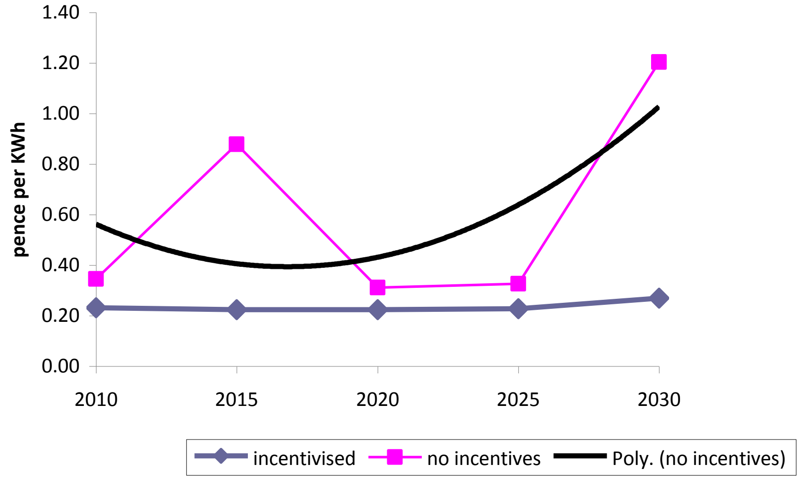


Fig. 10: Ferrybridge: A comparison of the optimal costs of electricity generation and CO_2 capture with- and without incentives



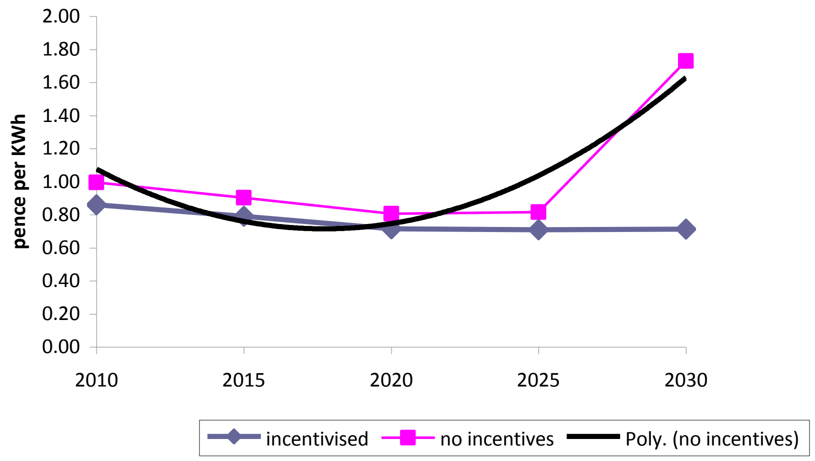


Fig. 11: Kingsnorth: A comparison of the optimal costs of electricity generation and CO_2 capture with- and without incentives

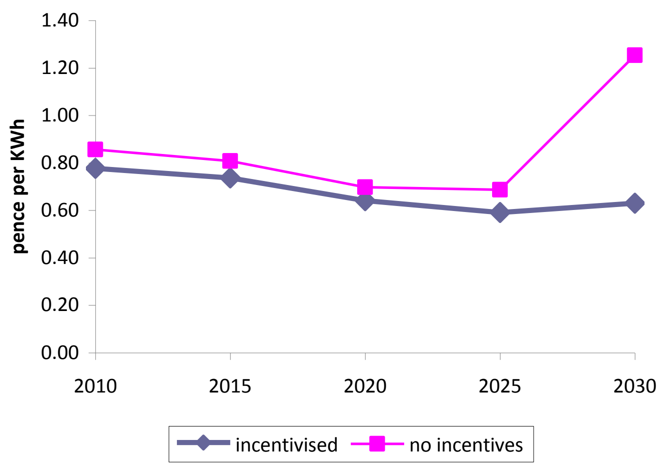
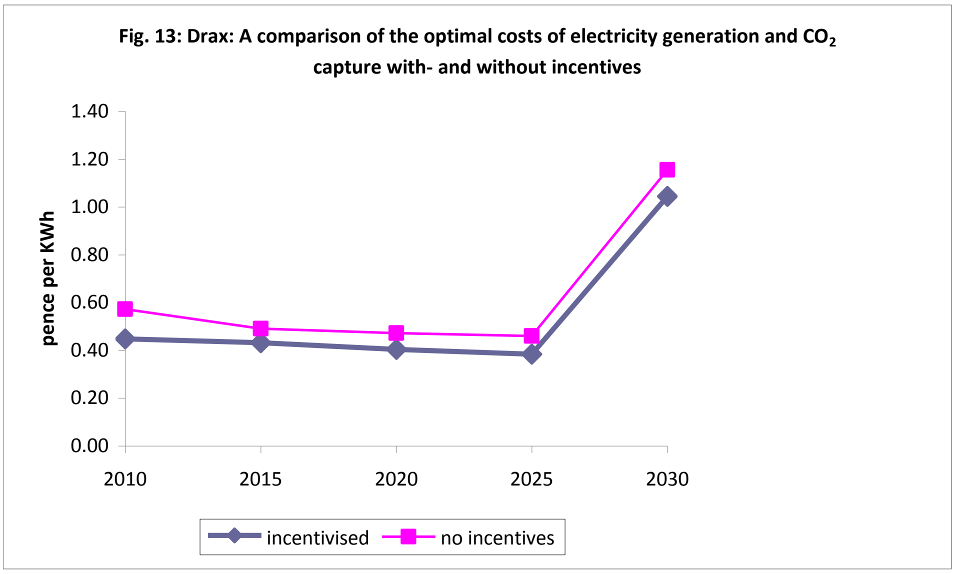
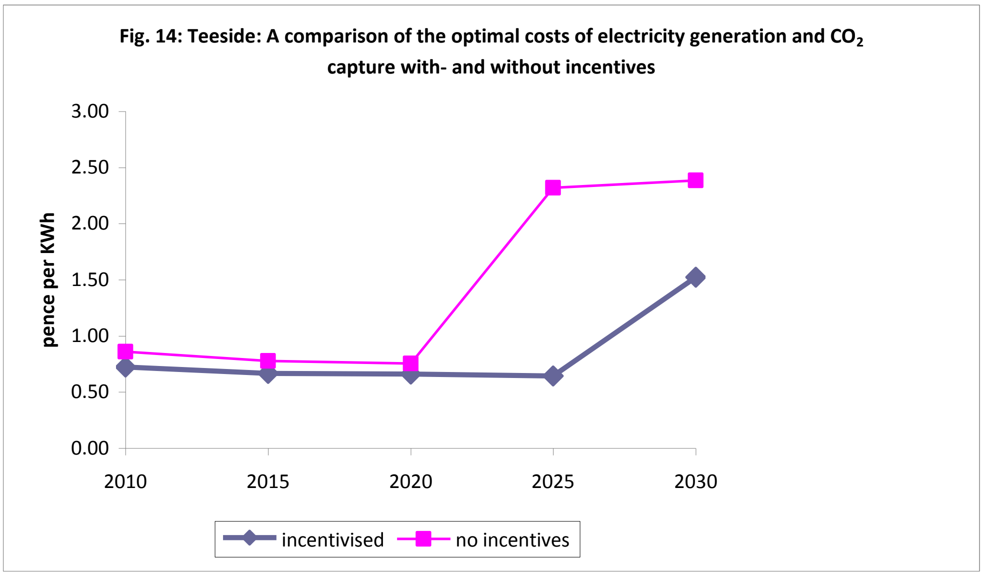


Fig. 12: Longannet: A comparison of the optimal costs of electricity generation and CO_2 capture with- and without incentives





A number of observations can be made about the comparisons in the foregoing charts. First, in general, the COE ***plus*** in the absence of government incentives are higher in all the power plants. Secondly, the gap between the two costs appears to be small in the short- to medium-term but widens in the long-term. Thirdly, the without-support COE ***plus*** displays a greater degree of variability over time.

Naturally, lacking the cushioning effects of Government cost-sharing incentives, the COE ***plus*** of the without-incentives plants are higher, albeit only marginally so in the medium term, because of the model's in-built assumption that Government support is limited to 50% of the CO_2 capture OPEX (i.e. excluding the capital cost).

Nonetheless, the absence of incentives discourages carbon capture. Thus, at the same level of electricity production a without-incentives power plant would capture less CO_2. However, capturing less CO_2 puts the plant at a double disadvantage, since according to Davison (2006) reducing the percentage of CO_2 captured increases costs[44], and thus exposes the plant to the risk of incurring higher excess emission penalty charges. The cumulative combined consequences of the reduction in carbon capture and higher emission penalty explain the divergence in the two costs, especially towards the end of the planning horizon. Table 8 shows the anticipated levels of excess emission penalty in the selected plants. It is useful to mention that:

(a) some cells in the table have two emission penalty values, one of which is in a bracket. A single-value cell instance is when the excess emission penalty of the two scenarios is the same while a two-entry instance is when the penalties diverge with each entry representing the penalty of a scenario; and,

(b) the figures in the brackets are the emission penalties incurred in the without-incentive scenario.

Table 8: Excess emission penalties in selected power plants (£ million)

	Peterhead	**Killingholme**	**Tilbury**	**Ferrybridge**	**Kingsnorth**	**Longannet**	**Drax**	**Teesside**
2010	0	0	0	0	0	0	0	0
2015	0	0	0	0(104)	0	0	0	0
2020	0	0	0	0	0	0	0	0

[44] As reported in Davison (2006), IEA-GHG had established that "... increasing the percentage CO_2 capture in coal-based post-combustion capture from 85-95% …. reduce the cost per tonne of CO_2 captured by 2%".

2025	6(48)	0(49)	0	0	0	0	0	0(223)
2030	8(82)	0(60)	0(124)	0(204)	0(256)	0(315)	709	266

Lastly, the without-incentive scenario shows greater volatility in the aforementioned Figures 7 to 14. An attempt was made to capture the long-term trend of the irregular movements by adding polynomial trend lines to the most volatile cases. It was found that though not well defined in most cases, the underlying trend is that of U-shaped COE ***plus*** curves, indicating a succession of falling, stable and rising costs[45]. However, the phases are of neither equal duration nor intensity. Thus, the predominant phase appears to be the rising cost segment. By contrast, the predominant phase in the with-incentive scenario (with the exception of Drax and Teesside in 2030) is the downward sloping or falling cost segment.

(b) the impact of government incentives on the profitability of operations

A comparative breakeven analysis of the with- and without government support scenarios for each of the power plants was conducted. The approach entails matching the market value of the captured CO_2 in each scenario against the sum of the power plant's CAPEX, and CO_2 capture OPEX. It should be pointed out that the analysis is partial because it excludes the revenues and costs of power generation. The partial analysis can be justified because (a) the focus of the study is on carbon capture, and, (b) each production unit in a power plant ought to be self-sustaining.

The projected carbon price and unit emission penalty charge used in the analysis are set out in Table 9. There are uncertainties about the future values of the two variables, including whether or not they would move in tandem over time. The convenient approach adopted in constructing the

[45] Which have been explained above in terms relative strengths of the cost-reducing effects of learning-by-doing and cost-increasing effects of higher emission penalties consequent upon increasingly stringent emission allocations.

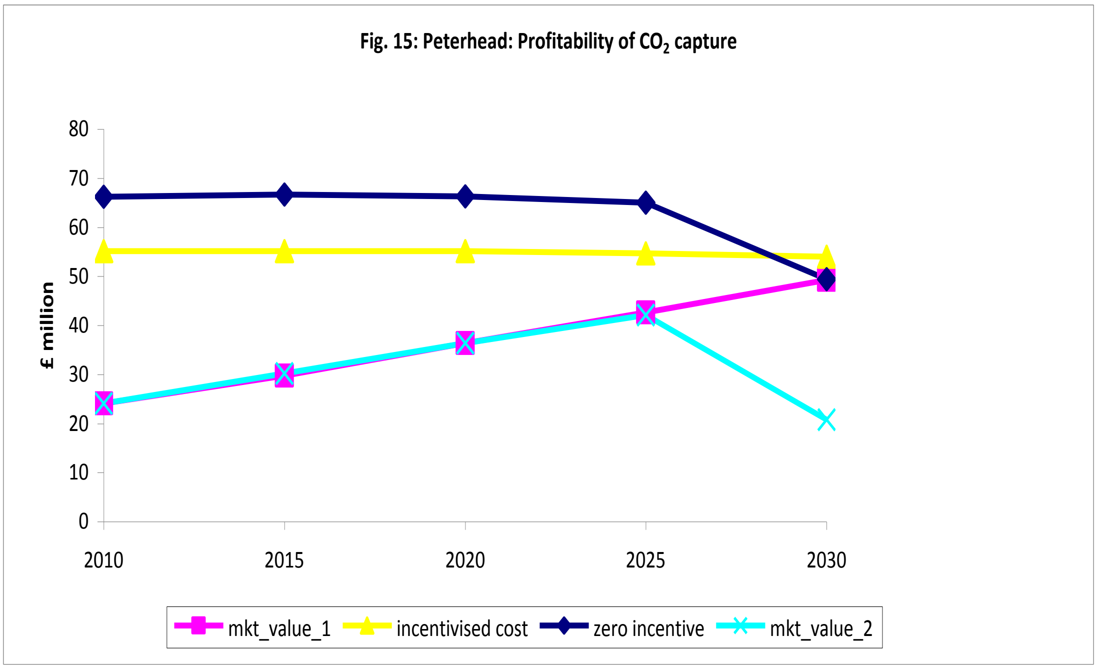
table was to assume (a) that, consistent with the assumption of tightening emission rights, both variables would increase over time; and, (b) that both variables grow at the same rate of 4% annum per annum.

Table 9: Projected carbon price and unit emission penalty cost[46]

Item	2008	2010	2015	2020	2025	2030
£/tCO_2	27 (14)	28 (15)	31 (16)	35 (18)	38 (20)	42 (22)
€/tCO_2	41 (21)	42 (22)	47 (24)	52 (26)	57 (29)	63 (32)

Sources: (a) Base year data, EU Commission (b) Authors' own projections

In Figures 15 to 22, "mkt_value_1" is the market value of the volume of CO_2 captured with Government incentives while "mkt_value_2" is the market value with zero incentives. The corresponding costs are "incentivised cost" and "zero incentive" respectively.



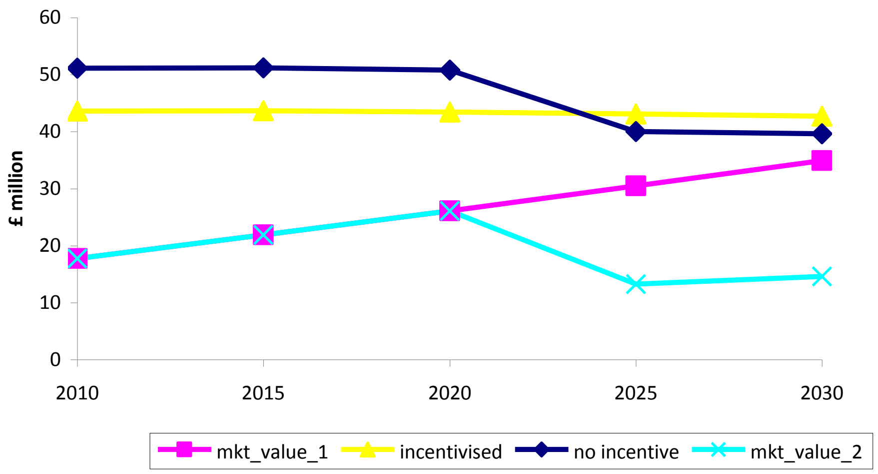
As can be seen in Fig. 15, although there is a virtual convergence of costs and potential revenue in 2030 in the with-incentive scenario, Peterhead

[46] Carbon prices are in brackets

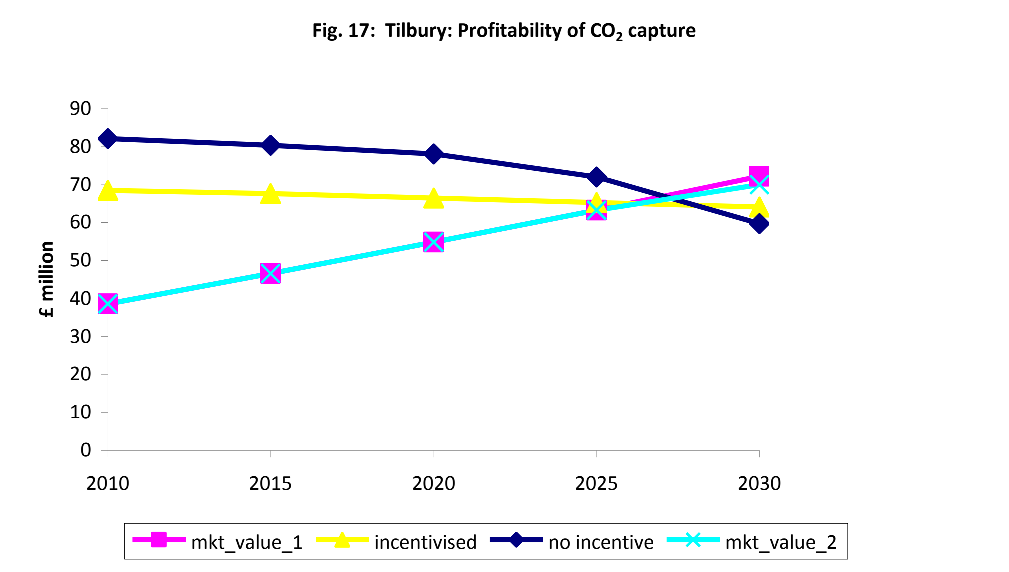
(CCGT) would not break even with or without Government incentive during the plan period. It is noteworthy that (a) the losses are bigger without Government incentives, and (b) while there is a virtual elimination of the long-term cost-revenue gap in the with-incentive scenario, a similar near convergence is absent in the without-incentive scenario.

The inability of potential revenue to cover costs suggests the need for further remedial action and/or policies that would shift the cost curves downwards and/or the revenue curves upwards until the two converge. Such remedial measures would include, but not be limited to, one or a combination of (a) deepening the cost-sharing ratio or subsidy; or, (b) cross-subsidisation from power generation and sales; or (c) realizing higher carbon prices through EU-ETS, by further tightening the limits on emission allowances; or, (d) accelerating the learning-by-doing rate, perhaps through enhanced R&D.

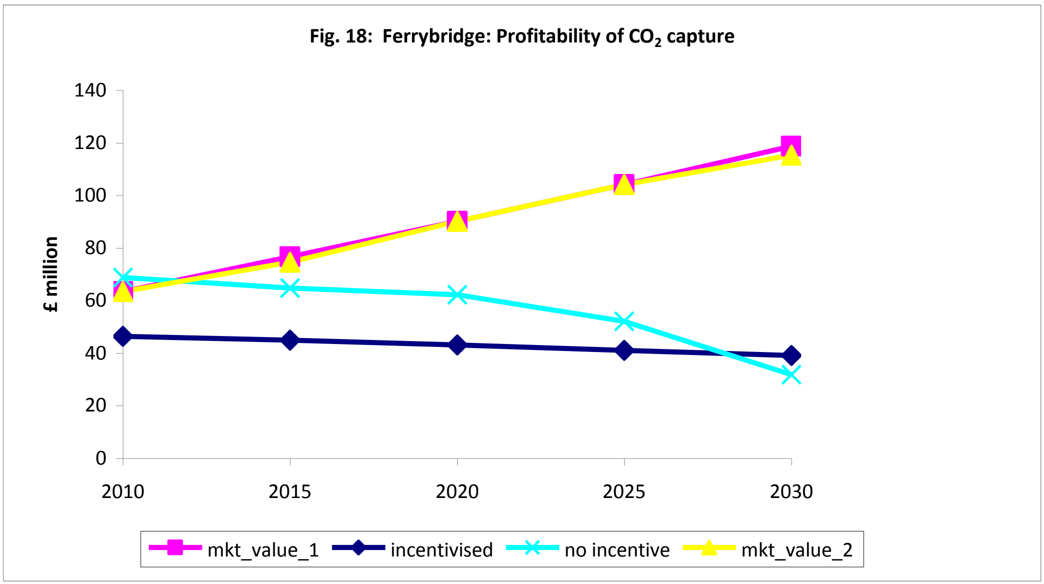
Fig. 16: Killingholme: Profitability of CO_2 capture



The Killingholme (IGCC) plant, too, would fail to cover its carbon capture-related costs throughout, with or without Government support. As with Peterhead, additional corrective measures would be needed to break even. It is useful to point out that the observed post-2025 lower costs of the without-incentive case (in this and other plants) was due to the lower volume of CO_2 captured.

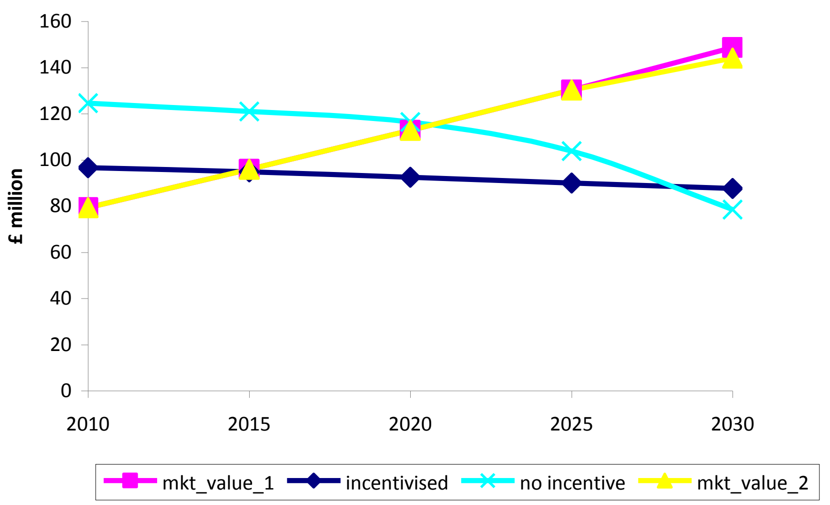


Tilbury (PCSCFGD) would breakeven with- or without Government incentives. First to break even in 2025 is the with-incentive scenario. Breakeven is attained a year later in 2026 without Government incentives.



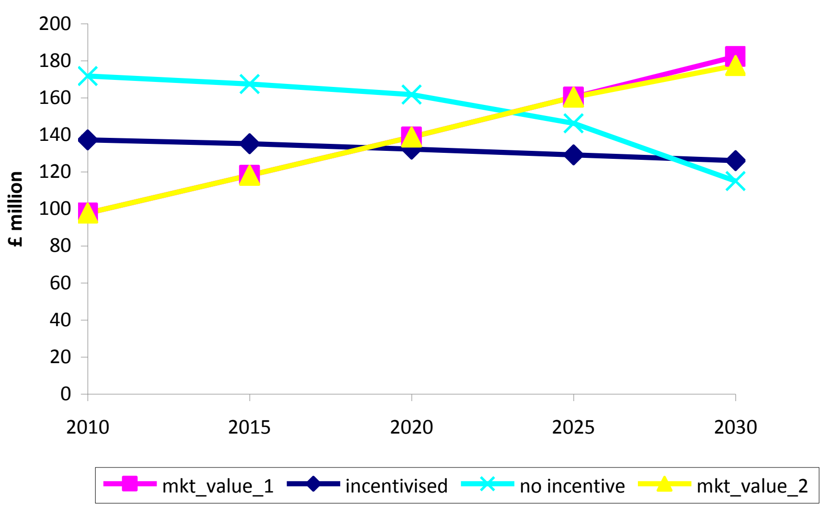
With the cost-reducing Government incentives in place, the Ferrybridge (PCSCFGD) plant would cover its carbon capture-related costs from the onset. However, without the incentives the breakeven point is delayed until 2012.

Fig. 19: Kingsnorth: Profitability of CO_2 capture

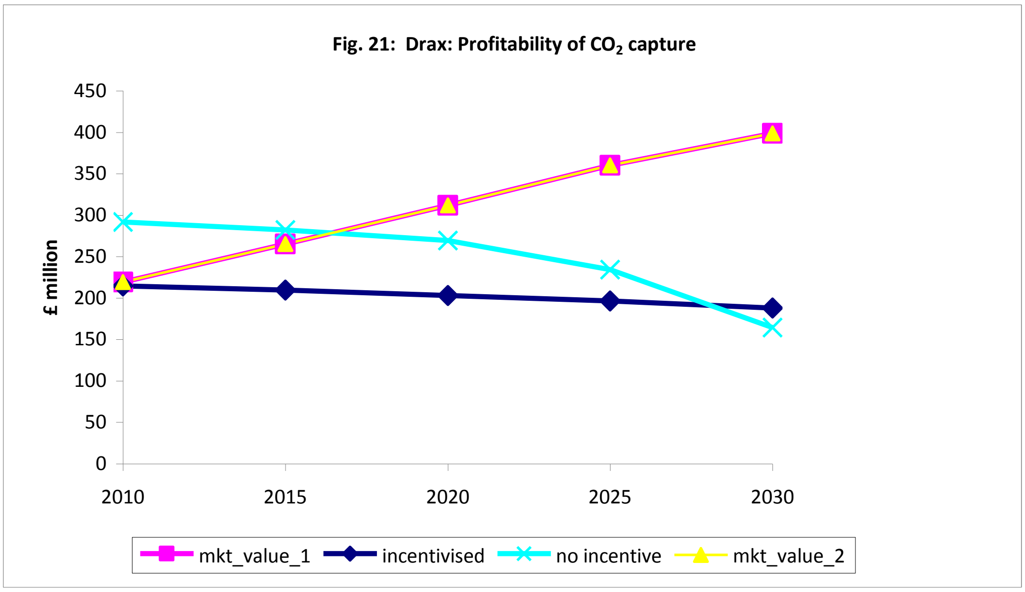


At the anticipated levels of Government support, carbon capture costs and market value, Kingsnorth (PCSCFGD) would breakeven around 2015. Without the incentives, breakeven would not be attained until about five years later in 2020.

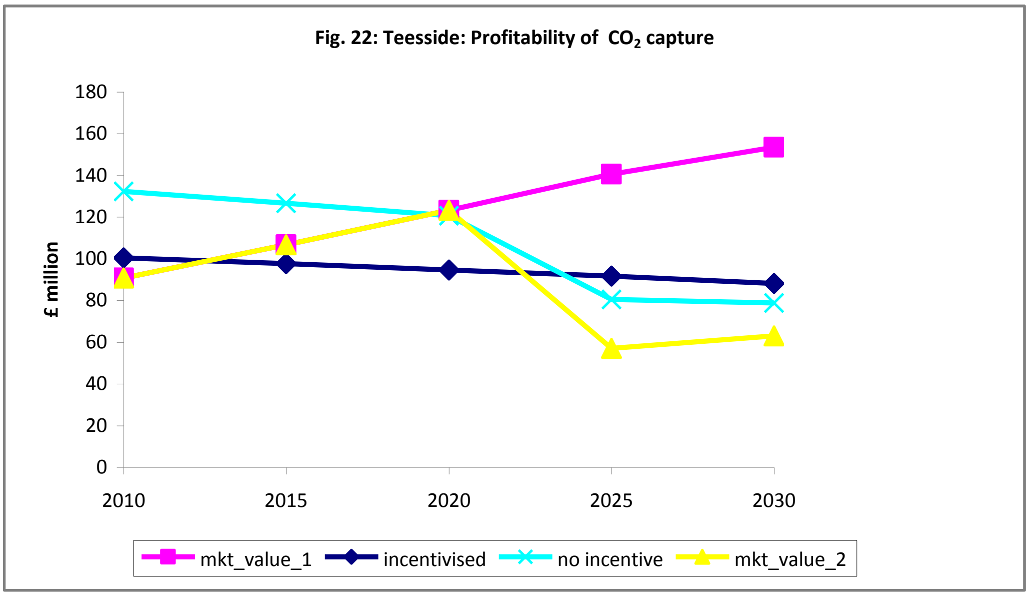
Fig. 20: Longannet: Profitability of CO_2 capture



With the aid of the incentives, Longannet (PCSCFGD) is expected to break even around 2018. Without incentives, breakeven occurs five years later in 2023.



At the given level of Government support and carbon price, Drax like Ferrybridge and Tilbury (all of which are PCSCFGD plants) would break even from the onset in 2010. However, without Government incentive the breakeven point would be delayed for six years, being attained around 2016.



Lastly, with government support, Teesside (PCSCFGD) would breakeven around 2012. Without the support, there would be a brief equalization of carbon capture costs and potential revenue in 2020. However, the shock of the emission penalty in 2025 would increase the costs more than the anticipated increase in the market value of CO_2.

V. Conclusion

In conclusion, of the eight power plants considered only two (Tilbury, Ferrybridge and Drax) would cover their carbon capture-related costs as from 2010. Two of the plants – the gas-fired Peterhead and relatively high efficiency integrated gasification Killingholme - would not break even throughout without putting in place one or a combination of the remedial actions outlined above. The remedial measures would include, but not be limited to, realizing higher carbon prices through EU-ETS, by further tightening the limits on emission allowances. Other measures that may be considered are (a) accelerating the learning-by-doing rate, perhaps through enhanced R&D; (b) deepening the Government-plant cost-sharing ratio or subsidy; or, (c) cross-subsidisation from power generation and sales.

The cost-revenue gap in three power plants (Kingsnorth, Longannet and Teesside) would eventually converge with government incentive, though not always without it.

The foregoing analysis underscores the point that to be universally profitable and readily adopted, carbon capture deployment would require more vigorous growth rates in the EU-ETS emission penalties and carbon prices as well as Government support.

APPENDIX 1: The model parameters

The model parameters are set out below.

Symbol	Description
length(time)	distance from base year
edem(m,te)	electricity demand by block (mtce)
cdem(m,te)	CO2 demand by block (mtce)
fuelc(i,v,t)	fuel OPEX cost for all CCGT plants
fuelg(j,v,t)	fuel OPEX for all IGCC plants
fuelp(k,v,t)	fuel OPEX for all PCSCFGD plants
fuel(i,v,t)	total fuel OPEX
nfuelc(i,v,t)	non-fuel OPEX cost for all CCGT plants
nfuel(j,v,t)	non-fuel OPEX for all IGCC plants
nfuelp(k,v,t)	non-fuel OPEX for all PCSCFGD plants
nfuel(i,v,t)	total non-fuel OPEX
copexc(i,v,t)	CO2 capture OPEX cost for all CCGT plants
copexg(j,v,t)	CO2 capture OPEX for all IGCC plants
copexp(k,v,t)	CO2 capture OPEX for all PCSCFGD plants
copex(i,v,t)	total CO2 capture OPEX
topexc(i,v,t)	total OPEX in CCGT plants
topexg(j,v,t)	total OPEX in IGCC plants
topexp(k,v,t)	total OPEX in PCSCFGD plants
ecapexc(i,v,t)	CAPEX (electricity share) for all CCGT plants
ecapexg(j,v,t)	CAPEX (electricity share) for all IGCC plants
ecapexp(k,v,t)	CAPEX (electricity share) for all PCSCFGD plants
ecapex(i,v,t)	total CAPEX (electricity)
ccapexc(i,v,t)	CAPEX (CO2 capture share) for all CCGT plants
ccapexg(j,v,t)	CAPEX (CO2 capture share) for all IGCC plants
ccapexp(k,v,t)	CAPEX (CO2 capture share) for all PCSCFGD plants
allratioc(i,v,t)	emission allocation ratio for CCGT plant
allratiog(j,v,t)	emission allocation ratio for IGCC plant
allratiop(k,v,t)	emission allocation ratio for PCSCFGD plant
noratioc(i,v,t)	Excess emission ratio CCGT plants
noratiog(j,v,t)	Excess emission ratio IGCC plants
noratiop(k,v,t)	Excess emission ratio PCSCFGD plants
vi(t,v)	vintage time matrix
initec(i,v)	initial capacity (electricity) CCGT plants
initeg(j,v)	initial capacity (electricity) IGCC plants
initep(k,v)	initial capacity (electricity) PCSCFGD plants
initcc(i,v)	initial capacity (CO2 capture) CCGT plants
initcg(j,v)	initial capacity (CO2 capture) IGCC plants
initcp(k,v)	initial capacity (CO2 capture) PCSCFGD plants

crfc(i)	capital recovery factor for CCGT plant type
crfg(j)	capital recovery factor for IGCC plant type
crfp(k)	capital recovery factor for PCSCFGD plant type
dsf(t)	discount factor
mx	(m, m) load order matrix;

Key Parameters used in the study

(a) Forecast UK electricity demand (in mtce)

Load	2008	2010	2015	2020	2025	2030
Peak	21	22	25	29	32	36
Off-peak	32	33	38	43	49	55
Total	53	55	63	72	81	91

Sources: (i) The National Grid; (ii) Authors' own estimates

(c) Forecast UK CO_2 demand for value- and non-value added uses (in mtce)

Load	2008	2010	2015	2020	2025	2030
Peak	20	21	24	27	30	34
Off-peak	30	31	35	40	45	51
Total	**50**	**52**	**59**	**67**	**75**	**85**

(e) Forecast EU-ETS unit emission penalty cost

Emission penalty	2008	2010	2015	2020	2025	2030
£/mtce	100.42	104.48	115.35	127.36	140.61	155.25
£/tCO_2	27.38	28.49	31.46	34.73	38.34	42.34
€/tCO_2	40.72	42.37	46.77	51.65	57.02	62.95

Sources: (i) Base year, EU Commission (2003); (ii) Authors' own projections

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