elementenergy

Potential for the application of CCS to UK industry and natural gas power generation

for

Committee on Climate Change

Final Report

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Thanks

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Corus	Shell	UKPIA
Hydrogen Energy		

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Please note that views presented here are the sole responsibility of the authors and do not represent the views of the consultees.

Glossary of terms

ASU – Air separation unit

BAT – Best available technology

BF/BOF – Blast furnace/basic oxygen furnace, predominant steel production process globally and in the UK, in which molten iron flows directly from the blast furnace into a basic oxygen furnace from where carbon and impurities are removed.

Black start – Turbines used to start power stations in the event of an emergency

Bound site – A site of a power station surrounded (e.g. by buildings), leaving limited new access routes or room for expansion

CCR – Carbon Capture Ready

CCS – Carbon Capture and Storage

CDQ – Coke dry quenching

CCGT – Combined cycle gas turbine

CEPCI – Chemical Engineering Plant Cost Index

CHP – Combined Heat and Power

COREX process – a smelter reduction process for iron making (alternative technology option)

DUKES – Digest of UK Energy Statistics

ECRA – European Cement Research Academy

FGD – Flue gas desulphurisation

HRSG – Heat Recovery Steam Generator

IGCC – Integrated gasification combined cycle

LCOE – Levelised Cost of Energy

LCPD – Large Combustion Plant Directive

Load factor – the ratio of actual output of a plant to its specified capacity over a specified time period

MACC – Marginal abatement cost curve

NAP – National Allocation Plan (for the EU Emissions Trading Scheme)

NSBTF – North Sea Basin Task Force

OCGT – Open-cycle gas turbine

Re-powering – Here defined to be the replacement of the steam turbine, gas turbine, and HRSG

SMR – Steam methane reforming

TGR-BF – Top gas recycling blast furnace (an advanced iron-making process)

ULCOS – Ultra low CO_2 steel making programme

WACC –Weighted average cost of capital

Executive summary

Objectives of study

This study explores the technical and economic relevance of Carbon Capture and Storage (CCS) technologies to the UK industry and natural gas power sectors in the period up to 2050. For both sectors, the objectives of the study are to:

- Define technical potential for application of CCS.
- Project how this potential changes in the period to 2050.
- Estimate the costs associated with implementing capture at each facility, and associated transport and storage infrastructure.
- Confirm this data with a stakeholder survey, and develop a qualitative understanding of the main inputs and constraints around investing in capture.
- Use the above economic data and stakeholder feedback around investment criteria to assess likely uptake of CCS in the sector over the period to 2050.
- Explore competing low carbon technologies.

In addition the gas sector report examines:

- Technical and cost differences between integrated new build CCS plants, capture ready plants and retrofit of older plants.
- The impacts on flexible operation of gas power stations due to the application of CCS.

This analysis has been undertaken in the broader context of the Committee's recommendations for the level of the fourth carbon budget (2023-2027), to be published in late 2010. However, early advice regarding one aspect of the fourth budget recommendations – the potential for CCS on gas – was delivered to the Secretary of State in June 2010, supported by research contained within this report on the potential for CCS on gas-fired plant.

The sections of this report pertaining to the potential for CCS on industry will be combined with other analysis to develop broader scenarios for the decarbonisation of industry post-2020. Similarly, the role of gas CCS and unabated gas plant will be analysed in the context of overall power sector decarbonisation during the 2020s. These will be presented in full as part of the CCC's fourth budget advice in late 2010.

The scenarios presented here do not reflect the views of the Committee on Climate Change, but rather are an input to the formation of those views.

Industry Executive Summary

Direct emissions from industrial sources were around 125 $MtCO_2$ in 2008, equal to around 24% of total UK CO_2 emissions. Future emissions are projected to fall to around 109 $MtCO_2$ in 2050, based on the assumptions that energy efficiency and other BAT measures are increasingly deployed in industry, that UKCS production (and therefore offshore emissions) decrease to zero within the next few decades, and that there is no significant leakage of industry to other countries.

The fraction of direct emissions technically available for capture and storage was assessed via a quantitative filtering process. A capacity cut-off was introduced to filtering out smaller emitters (less than 50$ktCO_2$ for industrial CHP and 200$ktCO_2$ per annum for other sources): this reduced capture potential from 125 $MtCO_2$ to 73 $MtCO_2$ in 2008. This cut-off is made on the grounds of high costs associated with capture and the transport networks required to reach small, highly distributed emitters. Alternative means of CO_2 abatement, such as fuel switching to low carbon electricity, are likely to be both technically and economically preferable to these smaller industries[1].

The final filtered abatement potential also excludes those sectors where CCS development is considered technically difficult due to space restrictions (e.g. the offshore sector) and takes into account the percentage of emissions that can be captured at a given site and the capture plant efficiency.

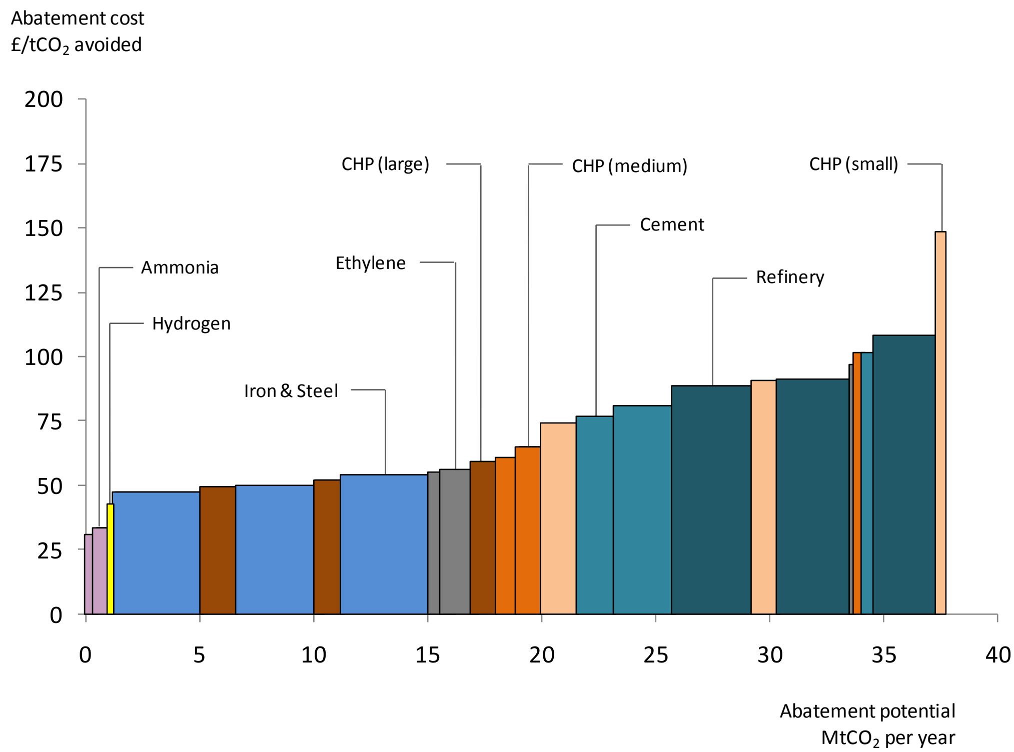
This analysis finds that CCS has the potential to address up to 38Mt of CO_2 emissions per annum in 2030 (decreasing to 37Mt by 2050) at costs of between £30 and £150 per tonne of CO_2 abated. The 'base case' capture and abatement costs assume that the capital cost of capture plant is discounted at a rate of 10% over twenty years and that some clustering of sources occurs for transport and storage of CO_2. Government projections of 'central' energy prices are also assumed.

Given DECC projections for CO_2 prices (£100-300/tCO_2 by 2050) we expect that, in all but the lowest CO_2 price scenario, the full CCS potential could be taken up cost-effectively by 2050. Investors, however, are likely to require a carbon price premium if the uptake is to be market- rather than regulation-driven, to cover investment in technologies outside their core competence and particularly if the carbon price is seen to be fluctuating or uncertain.

The level of abatement through deployment of CCS achievable by 2030 will be dependent on the date of technology availability, in turn driven by successful demonstration, and the incentives available. The share of the total potential considered economically feasible could be as high as 34 Mt CO_2 or as low as 1 Mt CO_2 per annum depending on the CO_2 price trajectory achieved. Limitations of build rates are however likely to hamper the ability to deliver by 2030 at the upper end of this spectrum.

Achieving 38 $MtCO_2$ of technical abatement potential would require deployment of capture to approximately 80 projects with the bulk of abatement achieved from iron and steel blast furnaces, refineries and cement kilns. These projects have been grouped into several cost categories in the marginal abatement cost curve shown below:

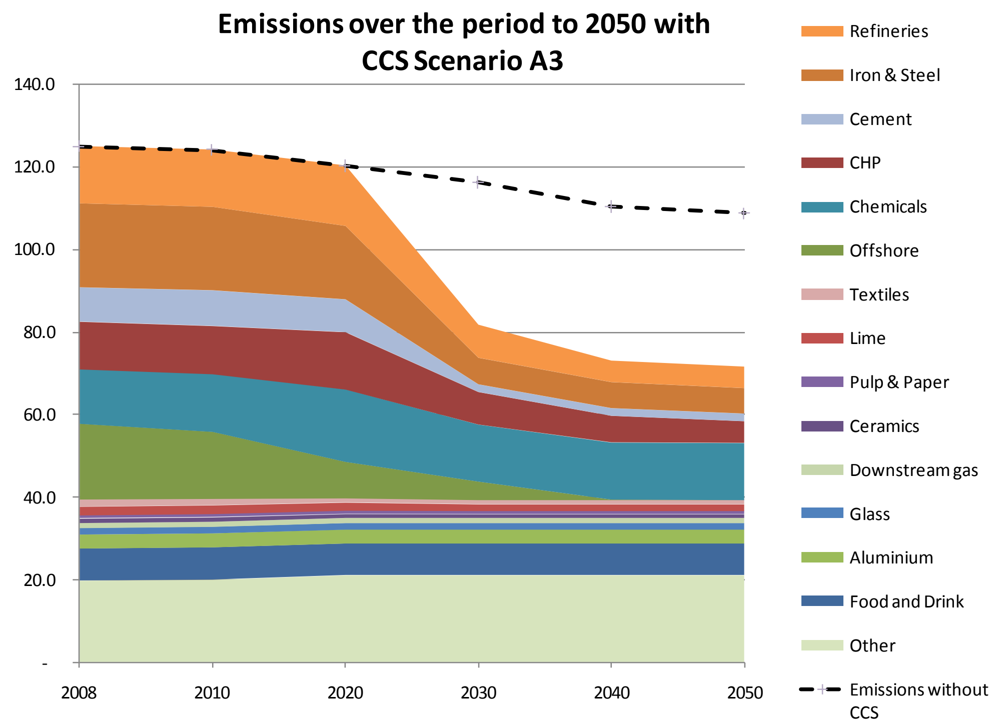
[1] Cost modelling assuming transport and storage savings due to clustering of sources was undertaken. It did not suggest revising the lower cut-off limit.



The lowest cost options for industry CCS consist of, in order of abatement potential: iron and steel blast furnaces, larger CHP facilities, and high purity CO_2 streams such as those produced from ammonia and hydrogen production plants. These can deliver the first 15Mt of CO_2 abatement below or around £50/tCO_2 abated.

Around 20 MtCO_2 of the remaining potential can be accessed at a cost of £100/tCO_2 or less. The shallow shape of the MACC ensures that there is a high sensitivity of the economic potential to the carbon price in the 2030 period. Under the DECC High CO_2 prices scenario, in 2050 all of the potential could be taken up cost-effectively. The remainder of emissions will be hard to access primarily due to the small size of the emitters.

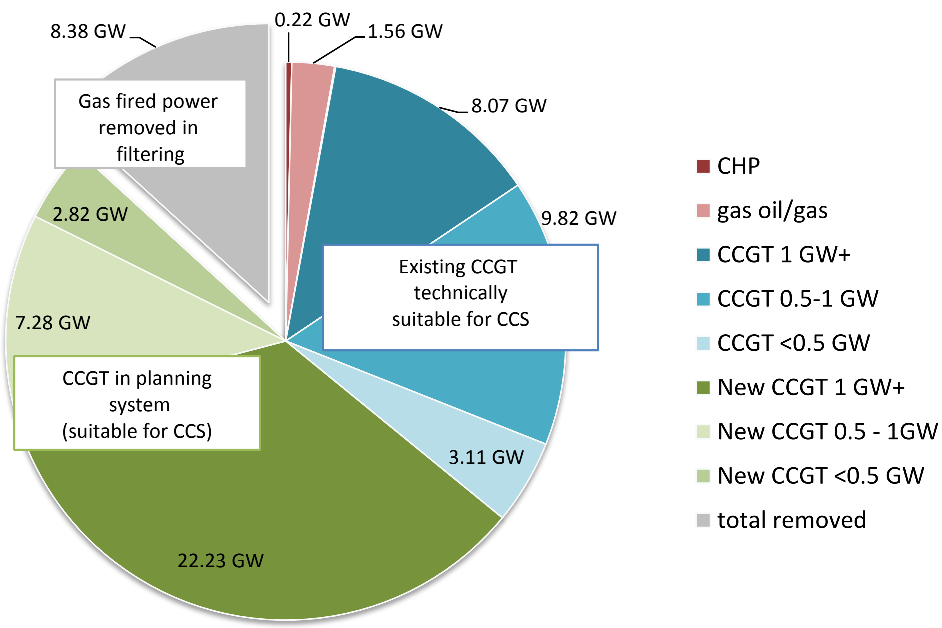
As a result of the filtering process, even with the highest DECC CO_2 price forecast and CCS deployment, much of the direct industry emissions remain unabated from CCS in 2050 (as shown below).


Emissions over the period to 2050 with CCS Scenario A3
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
2008
2010
2020
2030
2040
2050
Refineries
Iron & Steel
Cement
CHP
Chemicals
Offshore
Textiles
Lime
Pulp & Paper
Ceramics
Downstream gas
Glass
Aluminium
Food and Drink
Other
Emissions without CCS

Gas Power Executive Summary

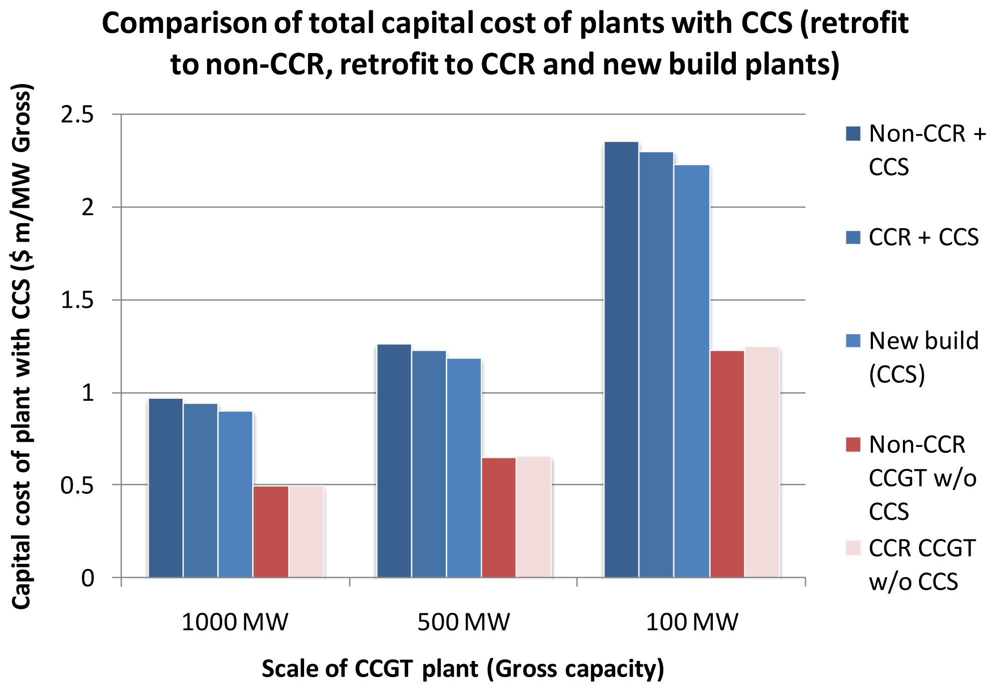
The UK natural gas power fleet is represented in this work as 31 GW existing (including 7.5GW of non-CCGT capacity) and 32 GW of new build currently in the planning system. Additional new build is added to the fleet to achieve indicative gas power capacity in 2050 of 40-45GW, defined as an input to the study by CCC based on previous modelling work.

Technology suitability, site constraints, and transport routes were examined as filtering criteria for the applicability of CCS. We estimate that over 85% of the existing CCGT fleet is technically capable of accepting CCS. All new build plants are required to be capture ready. A breakdown of the stock and its technical suitability for CCS is shown below. This study concentrates on assessing post-combustion capture for CCGT facilities. Many of the constraints considered (e.g. land availability, access), however, also apply to on-site pre-combustion capture and oxyfuel options. We recognise the potential in particular, for new facilities to fuel switch to coal gasification and pre-combustion capture and for the development of a hydrogen or syngas network. Detailed analysis of this option, as a clean-coal technology is outside the scope of this project and is recommended for further study.



The capital cost for the addition of post-combustion capture equipment to a CCGT facility whether capture ready or not, nearly doubles the total capital cost of the plant. The cost premium for retrofit of CCS to a non capture ready plant compared with a capture ready plant is small in comparison to the overall cost (a premium of $26,000-$57,000/MW compared to a cost of $ 0.9 million -2.2million/MW). This is also true for retrofit to a CCR plant compared to an integrated new build where the premium ranges from $42,000-70,000/MW.

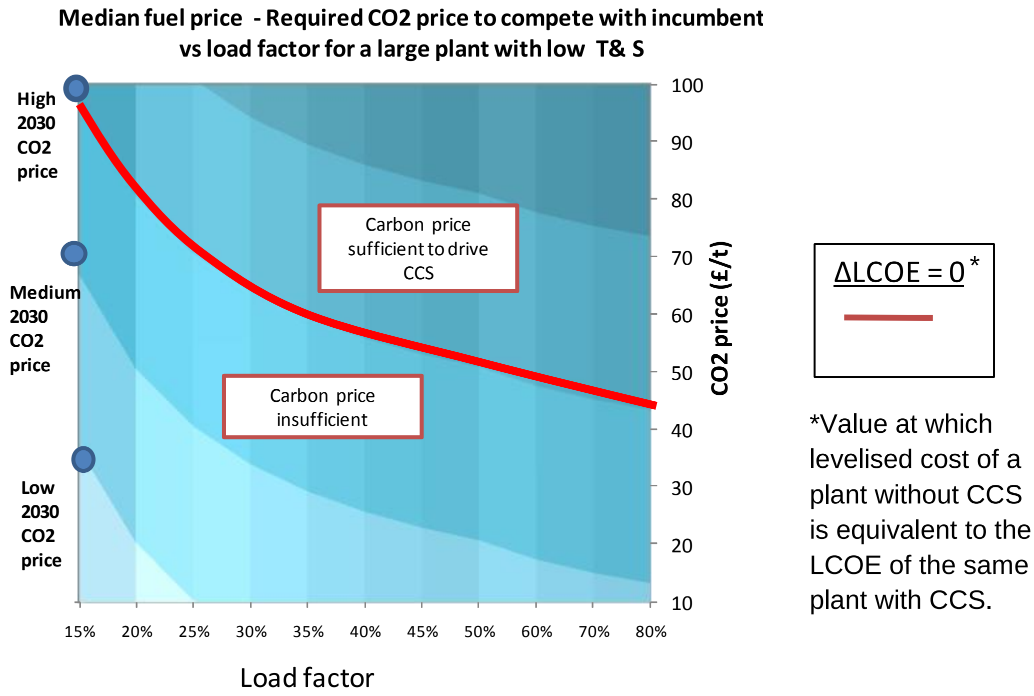
This capital cost analysis does not take into account the increased outage time for a non-CCR plant compared to a CCR facility (estimated here as an additional 1-5 weeks) and additional complications of gaining permission for a CO_2 pipeline route which, combined with other factors is likely to lengthen the overall build time, if not shut-down period.



For a CCGT, however, it is typically fuel costs that dominate the levelised cost of energy for a plant. As the CO_2 price increases over the period to 2050, this will become an increasingly large component of the LCOE.

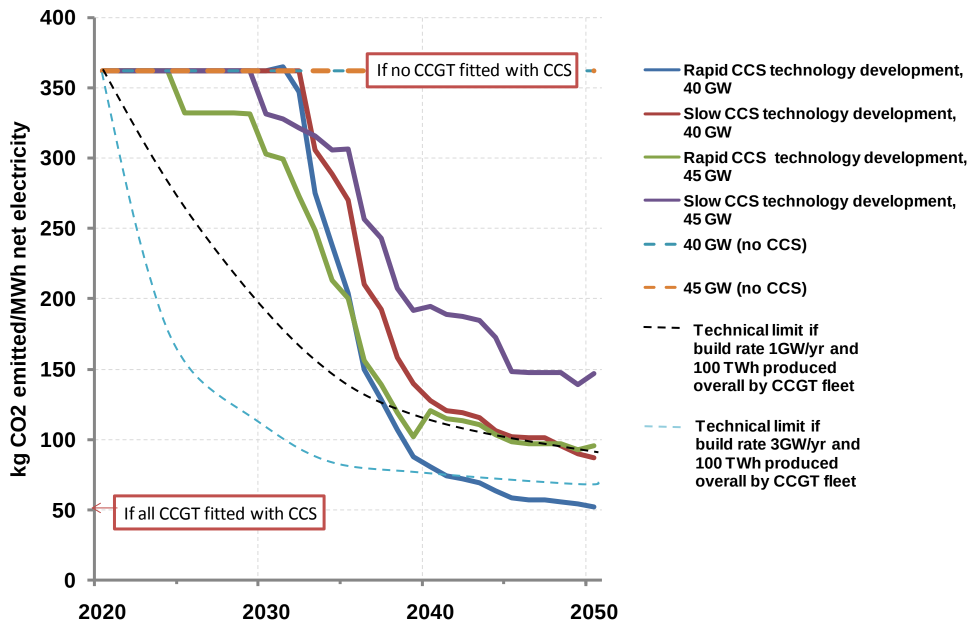
Financial viability of capture is strongly dependent on the load factor. Load factors vary considerably through the current fleet and, under high wind penetration there may be an increased requirement for lower load factor and peaking plant. If CO_2 price is high enough, (e.g. £100/tCO_2) the LCOE for operation of a CCGT plant retrofitted with capture can be lower than operation of the equivalent plant without capture, even at a low load factor of 15% (see below[2]).

2 LCOE accounts for capture, transport and storage.



The penetration of CCS through the gas fleet is clearly dependent on CO_2 price trajectory and load factors, but also to technology readiness. In fact, technology readiness may be the limiting step in adoption of capture in the 2020-2030 period. Following this, capture could be taken up by the fleet very quickly, under a variety of CO_2 price trajectories.

The rate of deployment of capture plants is unlikely to exceed 3GW per annum, and is likely to be closer to 1 GW per annum in the early years of commercialisation. This constrains the CO_2 intensity for the CCGT fleet is to 200g/kWh or above by 2030, even assuming plants with CCS run at higher load factors.



Flexibility is already an important concern for existing CCGT plant owners and operators and improving flexibility is a priority for suppliers as increased renewable generation joins the grid.

The ability to provide very fast response (< 5 minutes) is unlikely to be changed significantly with the addition of post combustion CCS to CCGT. There is some concern in relation to the ability of pre-combustion power stations to meet UK response requirements unless syngas buffers or co-firing can be deployed.

Post-combustion CCS does not prevent a power station from offering 4 hour ahead reserve services, although reduced ramp rates may make their offer less competitive in the marketplace.

The Maximum Generation Service and new offerings by the National Grid to encourage technology investment (such as their long term STOR launched last year), may offer alternate revenue streams for CCS to cover the impact of a reduction in net output and efficiency.

This study also identifies that if post-combustion capture is fully coupled to plant start-up (i.e. emissions during start up are captured), there is a potential for a slower ramp rate from a warm or cold start – resulting in at least 40 minute or hour delay respectively in reaching maximal load relative to an ‘uncoupled’ scenario where emissions in this period are not captured but instead are vented to the atmosphere. Reduction in ramp rates reduces the ability of a plant to take advantage of rapidly changing energy prices and may reduce competitiveness with non-CCS plants when offering reserve services.

The flexibility of CO_2 compression, individual pipelines and integrated pipeline networks, and storage facilities to manage variable throughput was outside the scope of this study and would require further analysis.

Contents

1 Introduction

1.1 Background

The UK has committed to ambitious CO_2 reduction targets for 2030 (34% reduction) and 2050 (80% reduction). This will require both substantial grid decarbonisation and reductions in emissions from industry which currently contribute c.24% of UK CO_2 emissions.

The Committee on Climate Change has indicated that in order to be on course to meet the 2050 target, the UK's power sector will need to be largely decarbonised by 2030, with a reduction in average emissions from the present level of around 560 gCO_2/kWh to below 100 g/kWh by 2030 and below 50 g/kWh by 2050. This requires contribution from various technology options including nuclear, renewables and carbon capture and storage.

Focus to date has been on the more carbon intensive coal-fired power stations as options for CCS. As the debate develops, however, it is important to understand the opportunity for CCS on natural gas fired power generation.

Industry has also received less attention to date in the literature (and from policy makers) although a growing number of studies and R&D programmes have assessed the technical and economic feasibility of capturing emissions from large industrial sources such as blast furnaces in integrated iron and steel works and clinker kilns in cement plants

This study considers the potential to reduce emissions across the natural gas power and industrial sectors through CCS. This is by no means the only method of major CO_2 reduction in these areas, where fuel switching or process change can also play a part, particularly for industry. Where competing options exist these will be noted, however, it is beyond the remit of this study to examine these technologies to the same level of detail.

This analysis has been undertaken in the broader context of the Committee's recommendations for the level of the fourth carbon budget (2023-2027), to be published in late 2010. However, early advice regarding one aspect of the fourth budget recommendations – the potential for CCS on gas – was delivered to the Secretary of State in June 2010, supported by research contained within this report on the potential for CCS on gas-fired plant.

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The scenarios presented here do not reflect the views of the Committee on Climate Change, but rather are an input to the formation of those views.

1.2 Introduction to CCS technologies

CCS brings together a diverse set of technologies for gas separation, compression, transport, injection and monitoring and management in reservoirs or equivalents. Individually these elements operate today within existing although largely disparate supply chains.

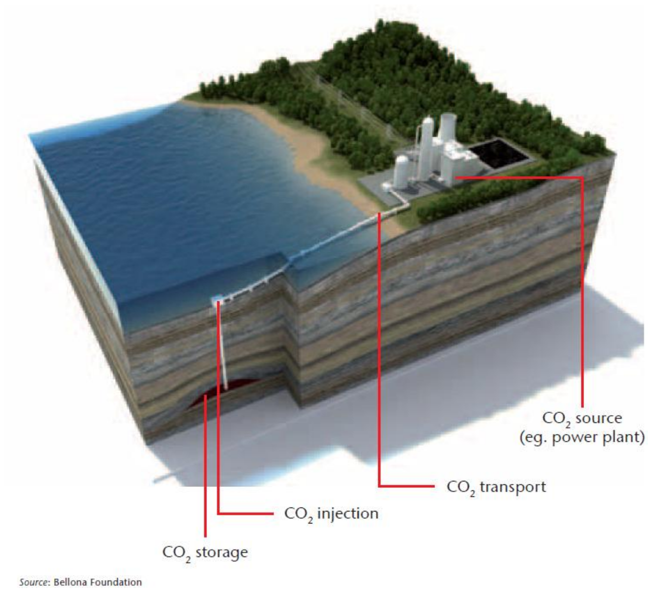

Figure 1 Idealised power station with capture, transport and storage (Image courtesy The Bellona Foundation).

CO_2 separation from other gases and compression together make-up the 'capture' process and tend to dominate costs and energy requirements of the complete system. Costs and energy requirements are expected to reduce over time through learning by doing, through volume production, and as breakthrough technologies emerge from laboratory trials into the marketplace.

Today three approaches - post-combustion, pre-combustion and oxyfuel – are envisaged to capture CO_2, as illustrated in Figure 2 and briefly described here. Further information can be found in the appendix, where each technology option is described in more detail along with potential future alternatives.

Within each of these approaches, there are a range of underlying technologies for CO_2 separation that are at different levels of commercial readiness. The technologies still in development are well described elsewhere[3].

[3] See for example, European Technology Platform for Zero Emission Fossil Fuel Power Plants Task Force (2009) Recommendations for the to support the deployment of CCS in Europe beyond 2020; and IEA (2008) Technology CO_2 capture and storage: A key abatement option (Energy Technology Analysis series)

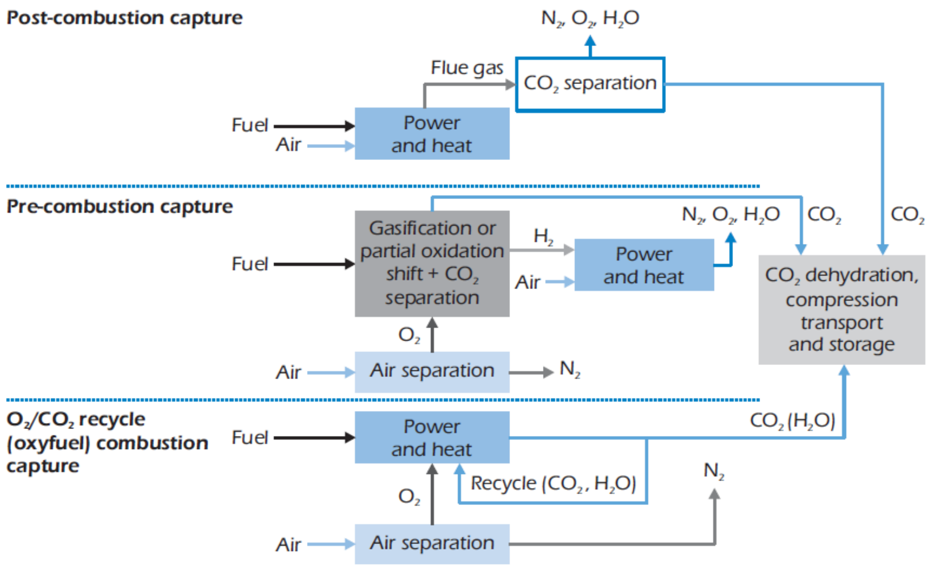

Figure 2 Dominant approaches to CO_2 capture (Image reproduced from IEA (2008) CO_2 capture and storage – a key abatement option).

Post-combustion capture using chemical (amine) solvents to separate CO_2 from gas mixtures, is a commercially available, mature technology. Upon heating, a high-purity CO_2 stream is produced which can be transported. However, the technology has yet to be fully demonstrated at commercial-scale with the flue gases from power plants. Although the post-combustion approach can be applied in principle to any source of CO_2, there are challenges for different sources – for example, of the requisite supply of steam may not be available at all sites.

In the future post-combustion capture can look to utilise more advanced amine solutions, ammonia and other solvents or move towards static bed adsorption or membrane technology. Oxyfuel systems involve combusting fossil fuels in recycled flue gas enriched with oxygen. This leads to the production of CO_2 and steam. Condensing the steam provides a high purity CO_2 stream. . Retrofitting oxyfuel technology requires the replacement of existing turbines as combustion in an oxygen atmosphere occurs at 3500°C, higher than a conventional gas turbine can accommodate. Additional space availability is also required for an Air Separation Unit. The use of an oxyfuel system technically removes the capture plant from the CCGT but the focus then falls on the Air Separation Unit and its flexibility and reliability.

Pre-combustion involves a partial conversion of hydrocarbon fuel into a hydrogen and CO mixture (or syngas) through gasification (for solid fuels such as coal or biomass) or steam methane reforming (SMR) (for natural gas), followed by a shift conversion of CO to CO_2. Separation of the CO_2 at this point means that the outputs from the combustion process are primarily steam and nitrogen. Flexibility and reliability concerns in this case fall on the ASU and gasification/SMR units.

Industry report

2 Technical potential for capture: Industry Sector

2.1 Industry sector CO_2 emissions

Direct emissions of CO_2 from fuel combustion and other processes in the industry sector accounted for 125 $MtCO_2$ in 2008, equal to around 24% of total UK domestic CO_2 emissions[4] (531 $MtCO_2$)[5]. Of this total, some 89 $MtCO_2$ of emissions were verified from over 630 installations covered by the EU ETS[6], of which good quality combined heat and power (CHP)[7] facilities accounted for around 12 $MtCO_2$[8]. The 36 $MtCO_2$ emitted from non-EU ETS activities represents a large number of typically small and diverse sources unsuited for capture, predominantly in the food and drink, chemicals, rubber and plastics, engineering and textiles sectors[9].

Industry sector CO_2 emissions have the potential to represent a large proportion of the UK's GHG emissions across all sectors in 2050 if industry output remains comparable and major action is not taken. The 2050 target of 80% of 1990 levels by 2050[10] equates to an overall budget of 159 $MtCO_2e$ across all sectors.

Figure 3 shows industry emissions for 2008 broken down by sector type, with emissions from industrial CHP facilities split out as a separate source. It can be seen that just four sectors (iron and steel, offshore, refining and chemicals production) accounted for over half of all emissions. Iron and steel was the largest contributor with over 20 $MtCO_2$ (primarily arising from fuel combustion in blast furnaces in large integrated iron and steel plants).These sectors are followed by fuel combustion in (predominantly gas-fired) CHP facilities and process and fuel emissions from cement kilns. Emissions from the remaining third were distributed across a wide range of sectors and processes not generally suitable for capture (due to small source sizes) including food and drink, textiles, lime, pulp and paper, and other sectors. The category indicated as 'other' accounted for around 20 $MtCO_2$ in 2008 and represents a large number of small and medium-sized industrial and manufacturing sites inside and outside of the EU ETS including e.g. vehicle and machinery production, electrical engineering, mining and quarrying, gypsum and plasterboard production and tyre manufacture.

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[4] All CO_2 emissions from within the UK, excluding international aviation and international shipping

[5] Updated Emission Projections (UEP), DECC 2009; 2008 figure is the sum of the industry and refining categories

[6] Verified emissions for 2008, EU Community Independent Transaction Log (CITL)

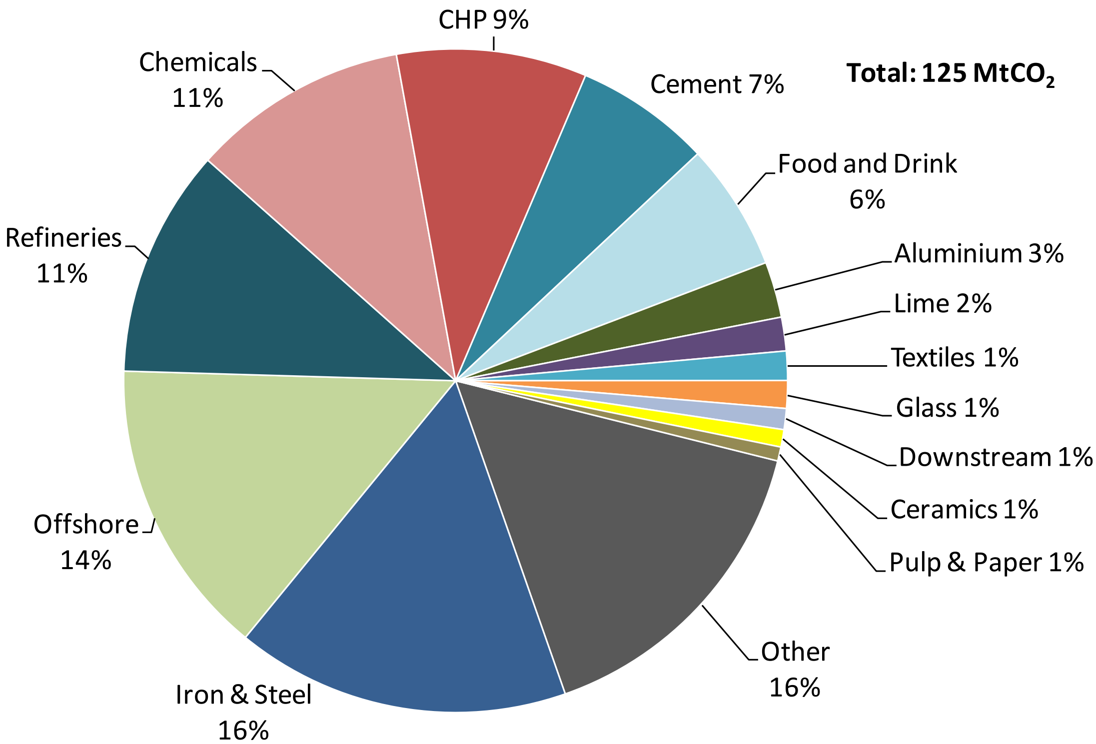
[7] For Good Quality CHP definition, see http://www.chpqa.com/html/notes.htm

[8] Based on analysis of UK National Allocation Plan Phase II, Annex I installation-level allocations CHP details table

[9] See 'Review and update of UK abatement cost curves for the industrial, domestic and non-domestic sectors' Final Report to the Committee on Climate Change, AEA, August 2008

[10] 119 $MtCO_2$ equal to an 80% reduction of 593 $MtCO_2$ (1990 UK CO_2 emissions)

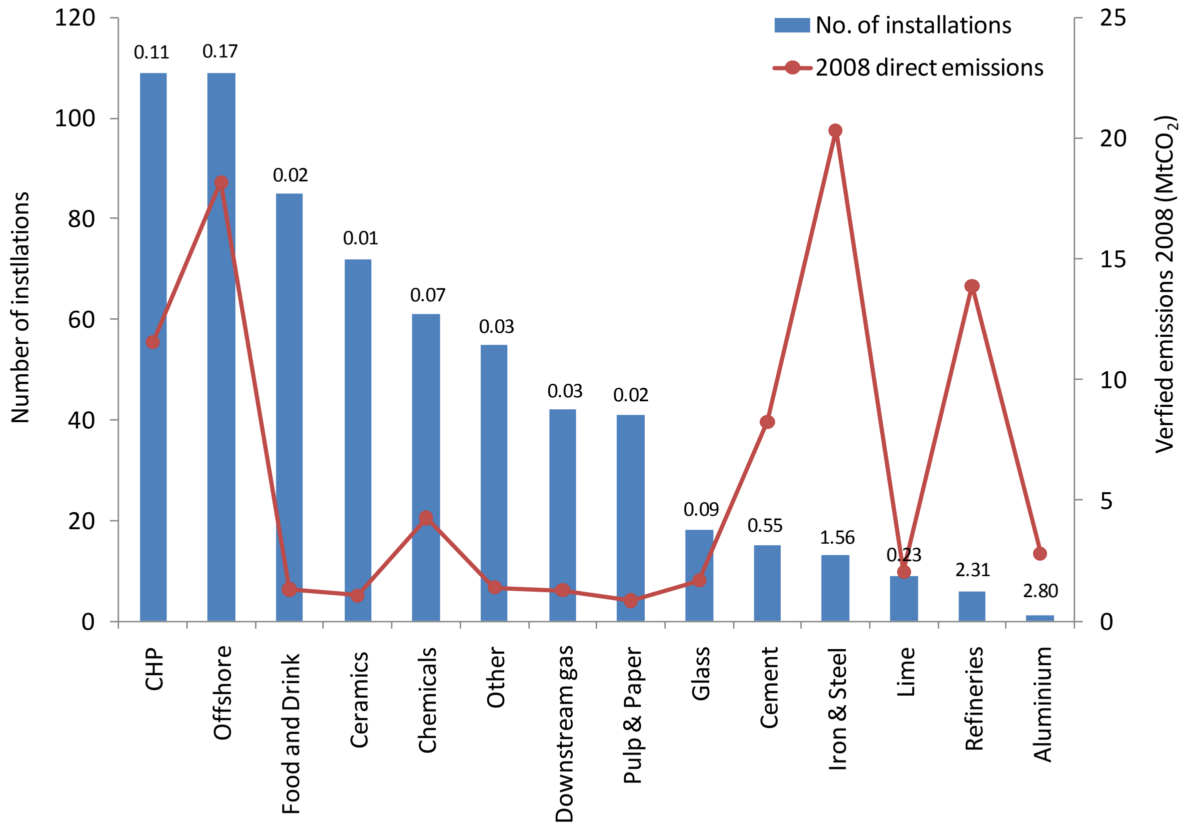
Figure 3: Industry direct CO_2 emissions in Great Britain, 2008



Source: UK Phase II NAP data & CITL data (for ETS emissions); AEA Technology, IEA GHG R&D, DECC (for non-ETS emissions)

Typical installation-level emission sizes vary considerably across industrial sectors. *Figure 4* shows the number of industrial installations within the EU ETS plotted against the total CO_2 emissions for each sector (with industrial CHP emissions split out as a separate category). Average installation-level CO_2 emissions are also indicated. It can be seen that a small number of sectors including iron and steel, cement and refining represent a relatively small number of point sources of CO_2 whilst accounting for a large share of the total CO_2 emissions from industry (i.e. per plant emissions of 500,000 tCO_2 per year or greater). Similarly, whilst sectors such as food and drink, ceramics and pulp and paper represent a much large number of installations, their typical plant size is much smaller and their contribution to total GB industrial emissions is relatively minor.

Figure 4: Great Britain industrial installations in the EU ETS, 2008



Note: figures shown above columns indicate average sector direct CO_2 emissions per installation in $MtCO_2$/yr
Source: UK Phase II NAP data (sector data includes CHP emissions)

Table 1 illustrates the distribution by source size of industry emissions in 2008 (including both ETS and non-ETS sources), across key sectors.

Heterogeneous sectors such as chemicals production, which represent a large number of processes and products, show a wide distribution of source sizes, as does industrial CHP which ranges from very small units of 5-10 MW capacity to large plants of over 300 MW. Sources of between 50,000 and 200,000 tCO_2 are dominated by CHP emissions, glass and offshore activities.

At an industry-wide level, the data indicates that around one third of emissions originated from very large sources emitting more than 1 $MtCO_2$ per year (iron and steel, cement kilns, refineries) and that around a third originated from very small emissions sources emitting less than 50,000 tCO_2 per year (comprising of a large range of activities including chemicals, food and drink production and various manufacturing and engineering activities).

Table 1: Industry direct CO_2 emissions in Great Britain, 2008; by source size

Sector	Direct emissions 2008 ($MtCO_2$)					
	> $1MtCO_2$	0.5 to 1 $MtCO_2$	0.2 to 0.5$MtCO_2$	0.05 to 0.2 $MtCO_2$	< 0.05 $MtCO_2$	TOTAL
Aluminium	2.80	-	0.59	-	-	3.39
Cement	1.15	4.68	2.43	-	-	8.26
Ceramics	-	-	-	0.14	0.92	1.06
Chemicals	-	3.75	0.77	1.58	7.10	13.20
CHP	2.26	2.06	2.63	3.44	1.19	11.57
Downstream gas	-	-	-	0.94	0.34	1.28
Food and Drink	-	-	-	0.16	7.58	7.74
Glass	-	-	-	1.56	0.12	1.68
Iron & Steel	20.02	-	-	0.16	0.16	20.34
Lime	-	-	1.57	0.47	0.01	2.05
Offshore	-	0.53	10.50	6.71	0.43	18.17
Pulp & Paper	-	-	-	0.35	0.51	0.85
Refineries	13.60	-	0.22	-	0.07	13.89
Textiles	-	-	-	-	1.78	1.78
Other	-	-	-	0.54	19.14	19.69
TOTAL	39.83	11.03	18.70	16.04	39.36	124.96
Share of total (%)	*32%*	*9%*	*15%*	*13%*	*31%*	*100%*

Note: The majority of Aluminium sector CO_2 emissions are represented by the Lynemouth Alcan coal-fired power station, which lies outside the scope of this study
Source: UK Phase II NAP data & CITL data (for ETS emissions); AEA Technology, IEA GHG R&D, DECC (for non-ETS emissions)

2.2 Industry CO_2 emissions forecast

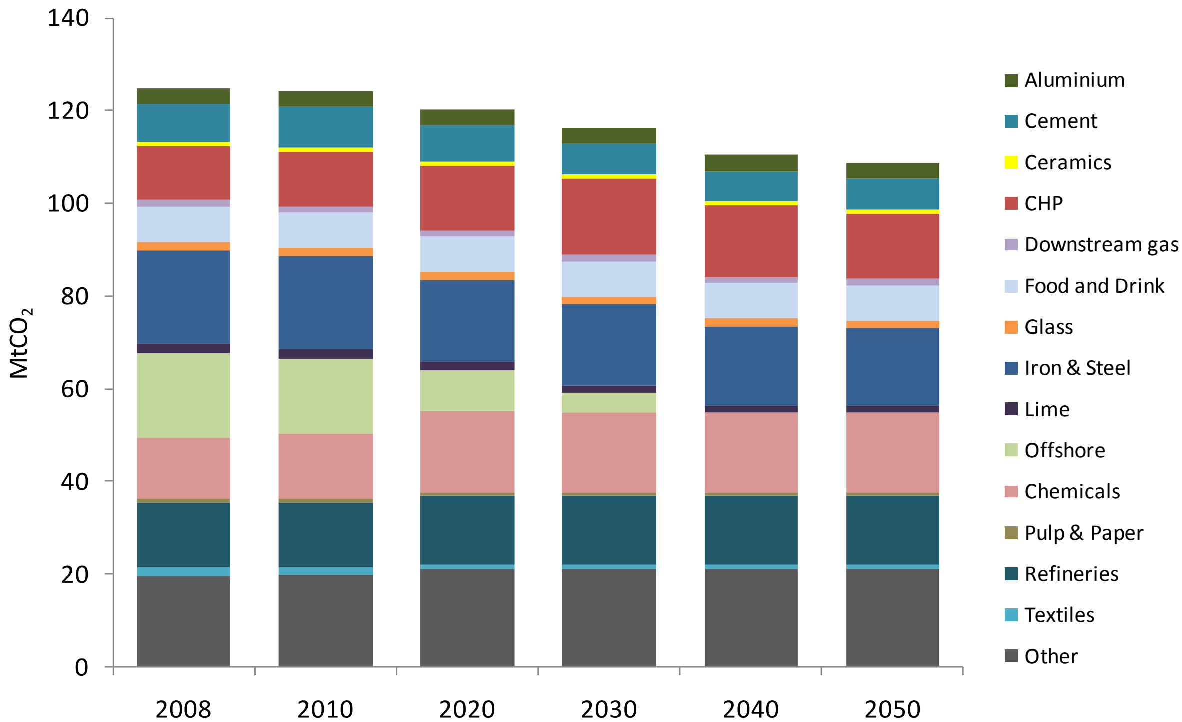
Figure 5 is a base case forecast of CO_2 emissions from industry to 2050. This provides the basis for further modelling and results presented in this study. In the absence of a robust set of long-term emissions projections for industry[11], the forecast has been derived from a large range of government and sector-specific industry information sources. The overall approach to calculating the forecast was largely based on the combination of two principal datasets:

1. *Projections of industrial output by sector* (e.g. SIC-code level output forecasts as used in the UK Energy White Paper 2007 analysis; recent BP and BERR data relating to existing and future UKCS oil and gas production; national targets for good quality CHP); and
2. *Projections of CO_2 intensity of output by sector* (e.g. estimates of BAT potential within industrial processes from the literature; industry, sector-wide and company-level targets for GHG reduction and energy use improvement; assumptions concerning existing potential for cost-effective energy efficiency improvements)

[11] Industry forecasts were being revised by DECC at the time of this study, however results were not available in time for inclusion in this analysis

The forecast is therefore a 'bottom-up' estimate of base case emissions reductions and is not constrained by CO_2 price projections and/or marginal abatement cost analysis. Importantly, the forecast is based upon the use of BAT and practices, *excluding* step changes in fuel use and new low-carbon industrial processes (e.g. substitution of electric arc furnace steel production based on recycled steel for fossil fuel-fired blast furnaces) and the use of CCS.

Figure 5: Forecast of industry direct CO_2 emissions in Great Britain, 2008-2050



The base case forecast projects CO_2 emissions from industry to fall from 125 $MtCO_2$ in 2008 to around 120 $MtCO_2$ in 2020 and 109 $MtCO_2$ in 2050, representing a decline of 13% over the period 2008-2050. The forecast compares against the UK Low Carbon Transition Plan 'central' projection of industry emissions including refining falling to 120 $MtCO_2$ in 2020[12].

The principal drivers behind the forecast CO_2 reduction include the decreasing carbon intensity within key large energy-using sectors such as cement and iron and steel, and also a significant decrease in UK offshore oil and gas production through 2050 (and to a lesser extent, a decline in textiles manufacture). Improvements in carbon intensity here reflect baseline assumptions concerning a range of sector-specific changes in energy use and production; for example increased use of materials blending and fuel switching (coke/coal to gas and biomass) in the cement sector and investment in energy efficiency equipment and use of BAT practises in the iron and steel sector. Note that the increases in absolute emissions forecasts for certain sectors (e.g. chemicals and other) are driven by strong

[12] UK Low Carbon Transition Plan, Table 1.2 (DECC, July 2009)

projected increases in output for certain SIC product categories including chemicals and man-made fibres, rubbers and plastics, non-metallic minerals, and vehicles.

2.2.1 Uncertainty in forecast emissions

In general, there is significant uncertainty concerning the forecast shown, as it is not based upon a systematic industry-wide analysis of quantified UK abatement potential.

The assumption regarding ongoing, constant, production levels represents an area of considerable uncertainty; for example, relevant (and unknown) factors which may result in permanent production loss and/or increased production include future changes in demand for products within the UK and elsewhere, demand-price elasticity effects, changes in the capital cost of plant and marginal cost of production (which in turn will be influenced by energy and carbon costs in addition to labour, insurance etc) and the competitiveness of UK industry compared to foreign production.

Predicting future industrial output was not the focus of this work, and the assumptions described above are consistent with previous government work including the Low Carbon Transition Plan.

In particular it should be noted that UK oil refining capacity is assumed to remain constant through 2050[13]. As with UKCS production, there necessarily exists considerable uncertainty regarding the future of both refining throughput and changes in demand for refined product. While demand for chemical feedstock may remain relatively robust, the demand for road fuels is likely to change substantially over the period as we move towards alternately fuelled vehicles.

Further discussion on the impact of this uncertainty on the resultant marginal abatement cost curve (MACC) can be found in section 3.4.2

2.3 Applying CO_2 capture to industry

Compared to fossil-fuelled power generation, the potential for CO_2 capture from industrial sources has received less attention in the literature (and from policy-makers). However, a growing number of studies and R&D programmes have assessed the technical and economic feasibility of capturing emissions from large industrial sources such as blast furnaces in integrated iron and steel works and clinker kilns in cement plants. In addition, the capture of high-purity CO_2 streams associated with the production of ammonia, hydrogen and ethylene oxide has been recognised and commercially undertaken for non-CCS purposes (e.g. in the production of urea).

CO_2 is currently captured from several industrial sites globally, including the removal of CO_2 from high-CO_2 natural gas at the Sleipner and Snøhvit fields (Norway) and In Salah (Algeria), and the capture of CO_2 from a coal-based synfuels plant at Weyburn (US) from where it is transported by pipeline to an oil field in Canada and injected to increase the oil recovery yield.

[13] See for example, Review of UK Oil Refining Capacity for the Department for Trade and Industry (Wood Mackenzie, May 2007) and PIU Energy Review, *Oil Initial Scoping Note* (PIU, August 2001)

Capture and injection from industrial sectors outside of the oil and gas industry, however, is not practised. Although there are currently no CCS projects capturing CO_2 from industrial sources in Great Britain, some companies in the iron and steel, refining and cement sectors are known to have undertaken initial (pre-FEED) assessments of capture technology and economics for certain sites. In addition, the Scottish Government and several of the Regional Development Agencies have assessed at a high level the capture potential from sites within key UK industrial areas as part of work undertaken to evaluate the role of regional CCS deployment[14].

This section draws upon the existing literature and consultation with UK industry to provide an overview of the potential applicability of capture technology to industrial sectors and sites in Great Britain.

For each sector we consider:

- Sector potential for CCS
- Other GHG abatement options
- Potential application to sites in Great Britain

Table 2: Summary of eligible GB industrial capture sites, 2008

Sector	Number of CCS eligible sites	Verified direct emissions 2008 ($MtCO_2$)	Share of total
Iron and steel	3	20.02	36%
Cement	14	8.00	14%
Refining	8	3.60	6%
Ammonia	2	1.43	3%
Hydrogen	1	0.30	1%
Ethylene	4	2.54	5%
CHP (large)	5	4.32	8%
CHP (medium)	8	2.41	4%
CHP (small)	32	13.44	24%
TOTAL industry	**77**	**56.06**	**100%**

2.3.1 Iron and Steel

2.3.1.1 Applicability of CCS technology options

Blast furnaces at iron and steel plants represent significant sources of CO_2 available for CCS, which can be captured either pre-combustion (using oxy-fuelling to generate a pure CO_2 off-gas) or post-combustion (using waste heat for chemical absorption). Neither approach

[14] Carbon Capture and Storage – A Roadmap for Scotland (Scottish Enterprise, 2010); Carbon Capture and Storage in North East England (One North East, 2009); A Carbon Capture and Storage Network for Yorkshire and Humber (Yorkshire Forward, 2009)

captures all of the CO_2 from integrated iron and steel plants, since large volumes are also emitted from non-core processes such as sinter plants, basic oxygen furnaces and rolling mills. However, CO_2 reductions in the core process could amount to 75% of total process emissions[15].

The application of post-combustion capture to iron and steel plants using chemical absorption would require the installation of CHP units to provide additional heat at most sites.

2.3.1.2 Existing/planned work on CO_2 reduction

In 2004 the European steel industry instigated the Ultra-low CO_2 Steel-making programme, ULCOS and work continues with the ULCOS II programme starting in 2010. Four iron-making processes along with CCS as the principle supporting technology, are being developed further in this programme. The consortium intends to carry out a major demonstration project that will include CCS during ULCOS II. Top gas recycling blast furnace (TGR-BF) is considered to be the most advanced iron-making process technology option under review, having already been piloted during ULCOS I at the LKAB experimental blast furnace in Sweden.

2.3.1.3 Other GHG abatement options

The carbon intensity of iron and steel production varies considerably between the major process types, ranging from around 0.4 tCO_2 per t steel (for electric arc furnace) to 2.5 tCO_2 per t steel (for coal-fired DRI process); in the UK where steel is produced using the most commonly used blast furnace/basic oxygen furnace route, carbon intensity is around 1.7-1.8 tCO_2 per t steel. Improved energy and materials consumption, and fuel and materials substitution, account for most of the abatement potential within the sector. A large range of BAT options exist for new build or retrofit to existing plant including the use of coke dry quenching (CDQ) heat recovery, top gas recycling blast furnace (TGR-BF)[16] and new coal-based reactor designs such as the COREX process. Fuel and materials substitution options include increased used of gas-fired DRI, increased use of biomass (mainly charcoal) and plastic waste injection.

The majority of abatement options available to an existing iron and steel plant would likely require a significant CO_2 price (i.e. greater than €25/tCO_2) to be incentivised, with only co-generation and some energy efficiency measures likely to be cost-effective in terms of energy savings alone. Most existing assessments of iron and steel abatement indicate that CCS represents the least cost-effective of available options (for both new build and retrofit).

2.3.1.4 Potential application of capture to sites in Great Britain

Verified emissions from a total of 13 iron and steel facilities (excluding CHP) were 20.4 $MtCO_2$ in 2008. Over 98% of this total was represented by the three large integrated iron and steel works operated by Corus, located at Port Talbot, Scunthorpe and Redcar, Teesside. All three plants produce steel according to the blast furnace-basic oxygen furnace (BF-BOF) production route and emitted 6-7 $MtCO_2$ each in 2008, representing the UK's largest emitters outside of the power sector. All three plants are considered technically available for capture from blast furnace emissions. The proximity of the Scunthorpe and Teesside plants to the depleted oil fields in the North Sea (and their location within the scope of planned regional CCS clusters)

[15] Energy technology Transitions for Industry (OECD/IEA, 2009)

[16] TGR-BF technology recycles gas to provide additional process heat, thereby resulting in more efficient use of coke and coal fuel inside the blast furnace than is possible with conventional operation.

suggests that they are particularly suitable for CCS project deployment, either through the retrofit of oxy-firing TGR-BF technology or post-combustion capture with CHP to raise additional steam requirements.

Although no decisions regarding project implementation or favoured capture technology have been made, it is understood that preliminary engineering and economic assessments have been carried out covering retrofit of TGR-BF technology to one of the four blast furnaces at the Scunthorpe plant based on the capture of the CO_2 using a combination of (vacuum) pressure swing adsorption and cryogenic technology, and transport from the site assuming that a suitable CO_2 network becomes established in the Yorkshire-Humber region. Initial assessments of CCS project potential are also planned at the Teesside and Port Talbot plants.

2.3.2 Cement

2.3.2.1 Sector potential for CCS

The cement sector is a major contributor to global CO_2 emissions. In 2005, direct emissions from global cement production accounted for 1,660 $MtCO_2$ - equal to around 6% of global CO_2 emissions[17]. The manufacture of cement involves the production of large volumes of CO_2 from fuel combustion and calcination of limestone in the kilns, offering potentially suitable sources for capture. A growing number of studies have assessed the applicability of capture technology at cement plants and the industry is becoming increasingly active in R&D efforts, for example through work recently undertaken by the European Cement Research Academy (ECRA)[18].

The applicability of pre-combustion capture is generally considered to be the least suitable capture technology to cement production as the CO_2 emissions produced from calcination of limestone (which typically account for around 60-70% of total plant emissions) would not be available for capture. Furthermore the explosive properties of hydrogen would entail significant modification to the clinker production process. The role of post-combustion technology has received more attention, and is considered potentially suitable for both new-build plants and retrofits. Chemical (amine) absorption is considered the most promising post-combustion capture process[19] with CHP providing the steam required for regeneration (unless sufficient waste heat were available from adjacent industrial facilities).

The use of oxy-fuelling to produce a pure CO_2 stream suitable for capture is also considered to be a potentially promising option for new-build cement kilns in the longer term, subsequent to successful demonstration in the power sector. From a technical point of view, post-combustion capture in the cement industry is not thought likely to become commercially available before 2020, with oxy-fuel technology deployed in 2025[20]. Significant R&D efforts and pilot projects are required over the next decade to demonstrate technology application and gain experience.

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[17] Energy Technology Perspectives 2008 - Scenarios and Strategies to 2050 (OECD/IEA, 2008)
[18] See www.ecra-online.org
[19] Cement Technology Roadmap 2009 (OECD/IEA, 2009)
[20] Cement Technology Roadmap 2009 (IEA/WBCSD 2009)

2.3.2.2 Other GHG abatement options

Emissions from clinker and cement production can be reduced principally through three established abatement measures: (1) energy efficiency improvements, notably in kiln technology; (2) Combustion of waste and biomass fuels in the kiln; and (3) increased use of clinker substitutes in cement blending. There is also significant R&D effort concerning the development of low-carbon cements, based on new production processes. Most studies of abatement potential within the cement sector indicate that, in contrast to CCS implementation, such options can be (and are) implemented at low or negative cost where possible. However, the increased use of alternative fuel and clinker substitutes faces a wide range of complex non-economic barriers typically outside the control of the cement and clinker industry, including limits to material availability, and existing product preferences and technical cement specifications.

Although the increased use of these abatement options may give rise to significant abatement within the sector, step change reductions in CO_2 emissions intensity are thought to be possible only with CCS deployment.[21]. This assumes production will continue to be based upon the current range of commonly used cement products. However, it must be noted that a number of low-carbon or carbon-negative cements (e.g. Novacem, Calera, Calix and geopolymer cements) are currently being developed which could potentially give rise to very significant sector reductions; there exist numerous barriers to their wider use and there is considerable uncertainty regarding their future adoption within the UK and elsewhere.

2.3.2.3 Potential application to sites in Great Britain

Verified emissions within the EU ETS for the cement sector (excluding CHP) were approximately 8 $MtCO_2$ in 2008, covering 14 cement plants including both dry and wet production process and ranging in production capacity size from around 250,000 t clinker (Barrington) to 1.8 Mt clinker per year (Rugby). Although kilns of less than 4,000 to 5,000 t clinker per day are considered unlikely to be candidates for CCS deployment on the basis of their having higher specific costs, retrofit of post-combustion capture technology can be considered technically feasible at all plants, subject to plant-specific space availability, and their continued operation in future years. However, a number of the largest cement plants (e.g. Rugby, Ketton, Hope) are situated inland at some distance from the coast and potentially suitable storage sites, and are located outside of identified potential CCS cluster regions. Such factors suggest significant barriers in terms of pipeline routing options and/or prohibitively high network connection costs.

2.3.3 Refining

2.3.3.1 Sector potential for CCS

CO_2 emissions from refineries account for about 4% of global CO_2 emissions, close to 1 billion metric tons of CO_2 per year[22] .Large oil refining complexes offer a number of CO_2 sources potentially suitable for post-combustion capture, including heaters, furnaces, boilers, crackers

[21] See Cement Technology Roadmap 2009 (OECD/IEA, 2009); 'Climate Change and the Cement Industry' (Cook, G. 2009); Low CO_2 Cements, Draft paper prepared for the UK Carbon Trust. Building Research Establishment Ltd 2007 BRE (2007),

[22] Gale, J., 2005. Sources of CO_2. In: Metz, B., Davidson, O., de Coninck, H., Loos, M., Meyer, L. (Eds.), Carbon Dioxide Capture and Storage. Intergovernmental Panel on Climate Change. Cambridge University Press, New York, pp. 75–104.

and utilities. Refineries are typically situated in coastal locations offering potentially close proximity to offshore storage sites, and are also often located within large industrial complexes where CCS clusters are more likely to develop over time.

Studies have been carried out on the application of post-combustion capture to refineries, and are described in detail in the appendix. This work has been reviewed and updated where possible by the authors based on consultation with industry.

2.3.3.2 Other GHG abatement options

Emissions at refineries can be reduced through a number of routes including the use of various cost-effective energy efficiency measures[23]. A number of examples of successful energy reduction schemes such as through the construction of cogeneration plants, the reduction of flaring and the use of alternative energy sources have been published[24]. Although the underlying trend of increasing energy efficiency in refining operations is likely to continue on an economic basis, in the absence of CCS deployment absolute global sector emissions are forecast to increase significantly with rising throughput (driven by growth in demand for oil products) and process complexity[25].

In a broader context, the increased use of synthetic fuels based on biomass feed-stocks is expected to result in significant emissions reductions from processes using refined energy products (transport, heating etc). Biofuel production leads to the formation of CO_2 from both combustion and process sources. The capture of CO_2 from these sources has the potential to create negative life-cycle emissions through the removal and permanent storage of carbon from the short-term biogenic cycle.

2.3.3.3 Potential application to sites in Great Britain

Verified emissions for the refining sector in 2008 (excluding CHP) were 13.9 $MtCO_2$, covering eight major oil refineries, all of which emitted over 200,000 tCO_2 per year. Three refineries had emissions of over 2 $MtCO_2$ each in 2008; these were the16 Mt ExxonMobil Fawley site, the 11 Mt Shell Stanlow site, and the 10.5 Mt Chevron Pembroke site. As shown below in Figure 6, all major refineries are located at industrial locations on the coast, offering potentially easy access to storage locations in the North Sea and Irish Sea (with the exception of Fawley, located on the South Coast).

Given their large annual CO_2 emissions and proximity to potential storage sites, capture from sources at all nine refineries is considered technically possible. The major technical barrier is likely to be space restriction on site, particularly in view of the extensive ducting network required if numerous sources are to be captured. As indicated by the Shell study, a large refinery complex offers a range of potential capture sources with different capture costs: these will necessarily vary on a site-by-site basis with capture from all significant CO_2 sources unlikely to be cost-effective even with very high CO_2 prices. The maximum share of site emissions considered technically and economically feasible for capture is estimated at around

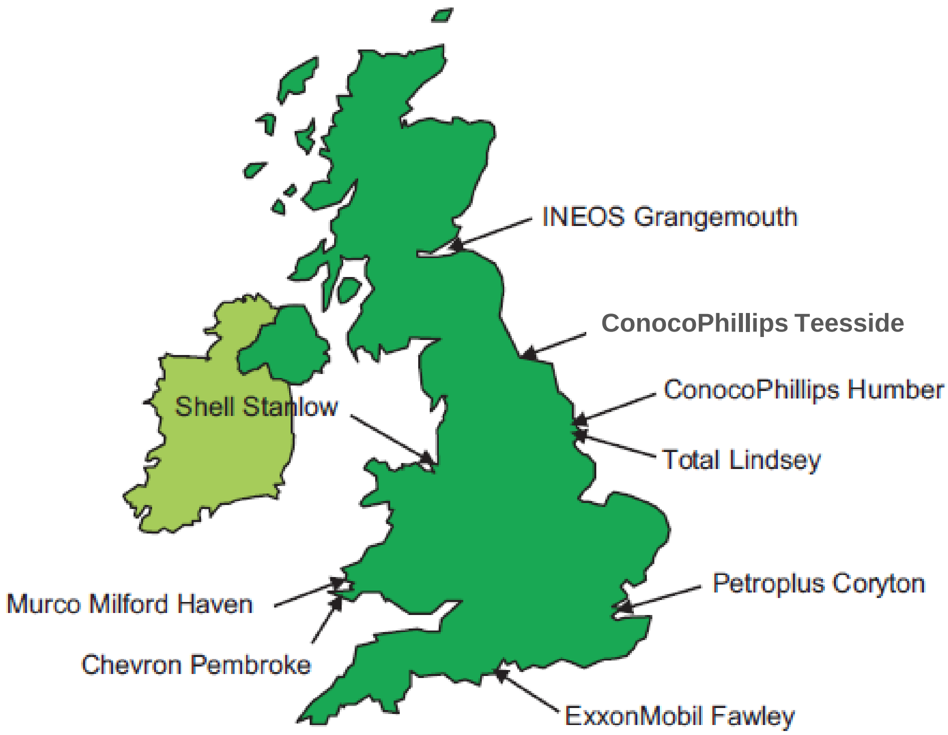
[23] For example, McKinsey (Pathway to a Low Carbon Economy, McKinsey & Company 2009) estimates around two-thirds of non-CCS abatement potential in downstream refining to be achievable at negative cost

[24] The Oil and Gas Industry and Climate Change. June 2007 (IPIECA, 2007). See http://www.ipieca.org/activities/climate_change/climate_about.php

[25] Global sector emissions are forecast to increase from 1.1 $GtCO_2e$ in 2005 to 1.5 $GtCO_2e$ in 2030; see Version 2 of the Global Greenhouse Gas Abatement Cost Curve (McKinsey & Company, 2009)

80%, and CCS would likely be applied to an increasing share of emissions sources (i.e. phased in) across a refinery complex on the basis of capture cost and economic incentive[26].

Figure 6: Major oil refineries in Great Britain



Source: UKPIA Statistical Review, 2009

2.3.4 Chemicals

2.3.4.1 Sector potential for CCS

Certain chemicals production processes which produce large flows of CO_2-rich flue gases may offer opportunities for relatively low cost post-combustion capture. These include the production of ammonia, hydrogen, ethanol, ethylene and ethylene oxide. Capture from large volume high-CO_2 concentration sources such as ammonia and SMR hydrogen plants can be achieved at relatively low cost as only compression and drying would be required as major additional equipment (as well as pumps, coolers and separators); absorption units and utilities to provide heat for amine regeneration would not be required.

Although application of post-combustion capture would not entail a major reconfiguration of plant process, the retrofit of equipment would likely be achieved at higher specific cost than that for an integrated design. The cost of capture from ethylene plants would likely be significantly higher due to the much lower CO_2 concentration in the flue gas (requiring

[26] Personal communication with senior representative for a UK refining company

chemical absorption units and steam for solvent regeneration). Details of literature costs can be found in section 3.

2.3.4.2 Other GHG abatement options

Given the diverse nature of the sector, an extremely wide range of abatement options exist depending upon the production process. The IEA identifies energy saving and best practice technologies within 57 chemicals and petrochemicals manufacturing processes. These include the use of process integration and waste heat, combined heat and power (CHP) and recycling and energy recovery[27]; significant potential for fuel switching (e.g. oil to gas and coal to biomass) also exists in certain processes. The implementation of such options in the short-term and of new technologies (including the production of bio-based plastics and chemicals) in the long-term would enable the sector to significantly reduce both its energy needs and its CO_2 intensity.

Existing studies indicate that implementing BAT practises such as fuel switching to less carbon intensive fuels and the use of CHP and other efficiency measures could be achieved at low or negative cost. However, a significant amount of abatement potential is thought to be potentially available at significantly higher cost through e.g. improvements in ethylene cracking and decomposition of non-CO_2 greenhouse gases. Analysis suggests that whilst requiring significant capital investment, such emissions reduction options are generally available at costs below that for CCS deployment.

2.3.4.3 Potential application to sites in Great Britain

Verified emissions for the chemicals sector with emissions in the EU ETS (excluding CHP) were 13.2 $MtCO_2$ in 2008, covering a total of 78 installations. The source size of most production facilities is medium or small scale; of the total 78 sites, 70 emit less than 200,000 tCO_2 per year and 58 less than 50,000 tCO_2. The sector covers a wide range of production processes and products.

Excluding CHP units, those installations considered potentially suitable for capture include:

- 2 ammonia plants (Billingham, Ince)
- 4 ethylene plans (Grangemouth, Wilton, Fife and Fawley)
- 1 hydrogen plant (Teesside)

These plants had combined direct emissions (excluding CHP) of 4.3 $MtCO_2$ in 2008, ranging from source sizes of 0.2 to 1 $MtCO_2$. All seven sites are located on or near the coast, of which five are located in close proximity to the North Sea (e.g. Billingham, Grangemouth, Fife, Teesside, and Wilton). In the absence of any known future plant retirement schedules or specific on-site technical limitations, CCS is considered to be potentially technically feasible at all seven installations. There is necessarily considerable uncertainty regarding the future lifetime of, and/or investment in new equipment at, these plants.

[27] Energy Technology Transitions for Industry; OECD/IEA (2009)

2.3.5 Combined Heat and Power

2.3.5.1 Sector potential for CCS

Post-combustion capture technology using chemical absorption can applied to a gas-fired combined heat and power (CHP) installation as with other gas-fired power plants (see earlier sections) at a capture rate of 85-90%. Economic and technical analysis carried out as part of this study has considered several illustrative emissions sizes of CHP plant in order to reflect scale economies.

The key cost assumptions and resulting capture cost ranges (across a range of Government gas price forecasts) are summarised in section 3. There is a significant decrease in capture costs with increased plant size, associated with capital cost scale economies.

2.3.5.2 Potential application to sites in Great Britain

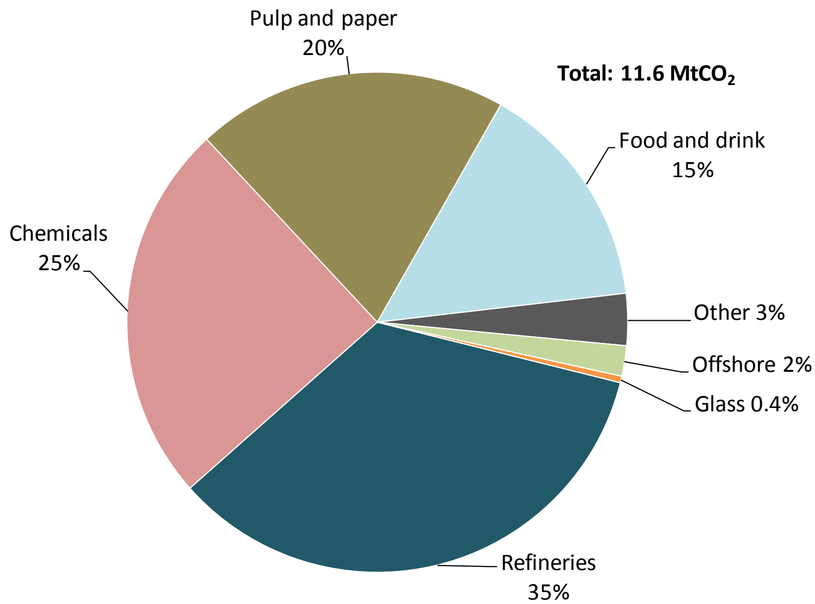
A total of 109 good quality CHP installations are included in the UK Phase II NAP and accounted for verified emissions of 11.6 $MtCO_2$ in 2008. According to the 2009 edition of the Digest of UK Energy Statistics, 71% of CHP capacity in 2008 was gas-fired[28]. Most industrial CHP units are relatively small in scale: of the total number, 95 emitted less than 200,000 tCO_2. Only five installations emitted over 500,000 tCO_2 (ExxonMobil Fawley, Shell Stanley, E.ON Winnington, INEOS Grangemouth and Fortum Grangemouth).

As shown in *Figure 7*, the oil refining and chemicals sectors accounted for around 60% of all industrial CHP emissions in 2008. In addition to those units located at refineries and chemical production plants, major CHP units are sited at food and drink facilities such as the British Sugar factories located at Bury St Edmunds in Suffolk and Wissington in Norfolk and at pulp and paper installations located in Aylesford and Kemsley in Kent.

Most large-scale CHP facilities in Great Britain are located within industrial sites, on or in close proximity to the coast. In addition to geographical and planning considerations, the major restriction to capture applicability to CHP units is considered to be plant size. Assuming that large-scale post-combustion capture within the power sector has been successfully demonstrated within the power sector by 2020, the capture size threshold for potential applicability to CHP in the period 2020-2030 is considered to be relatively low compared to other industrial emissions sources such as refineries (for the purposes of considering technical feasibility only) with all units emitting 50,000 tCO_2 or more per year considered applicable for CCS.

[28] Digest of UK Energy Statistics, Chapter 6: Combined heat and power (DECC, 2009). See http://www.decc.gov.uk/en/content/cms/statistics/publications/dukes/dukes.aspx

Figure 7: Direct CO_2 emissions from industrial Good Quality CHP in Great Britain, 2008



Source: based on UK Phase II NAP and CITL data (verified EU ETS emissions in 2008)

2.4 The technical capture potential

Direct CO_2 emissions from the industry sector were 125 $MtCO_2$ in 2008, and are forecast to decrease to around 120 $MtCO_2$ in 2020 and 109 $MtCO_2$ in 2050 (see earlier sections). The total technical capture potential in any given year through to 2050, however, will represent only a share of this total. The existing and future capture potential from GB industry has been calculated according to four basic steps, as follows:

- *Step 1: Eligible installation sizes*. Capture from very small emissions sources is considered unfeasible from both an economic and technical perspective. Below a certain volume of annual emissions, scale effects for both capture and transportation costs become dramatic (as similar sunk investment costs will be required for reduced capture volumes). A comparatively low threshold of 200,000 tCO_2 direct emissions per year has been chosen for most industrial sources[29]; a lower threshold of 50,000 tCO_2 has been chosen for CHP installations.
- *Step 2: Eligible sectors and processes*. Only certain industrial processes have been considered eligible for CCS, including iron and steel BF/BOF production, cement production, oil refining, industrial CHP and several chemical processes (ammonia, ethylene, hydrogen). In other industrial sectors, emissions sources are considered too diffuse across sites or else there is a lack of literature upon which to base capture cost estimates.

  Significant omissions include CO_2 from the aluminium sector (which in this context reflects a large coal-fired power plant outside of the study scope); lime production (for

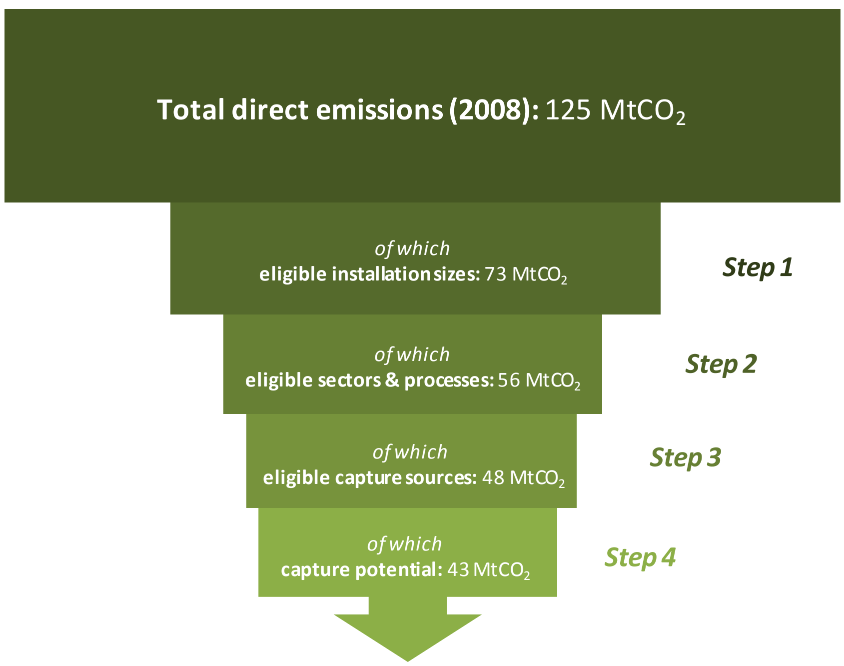
[29] Note that the choice of this threshold has the most significant effect upon offshore installation exclusion; however, these sources (offshore installations) are in any case excluded under Step 2.

which there is no known evidence in the public domain of CCS application having been considered, although post-combustion capture from quicklime kilns is considered to be technically possible) and offshore activities (the combined factors of dramatically declining production over coming decades and challenges of engineering and space availability suggest there will be very few significant CCS opportunities).

- *Step 3: Eligible capture source at site*. The share of on-site emissions which can be feasibly captured is difficult to quantify even at a high level, owing to plant-specific considerations and limitations in the literature considering CCS in industry. The maximum available share may range from 75-80% for iron and steel works and oil refineries up to 100% for CHP units. Sector specific percentages have been applied to candidate 'sites' in those sectors screened as eligible under Step 2, as detailed in the appendix.
- *Step 4: Application of capture rate*. The final step in calculating technical capture potential is the capture rate; a default rate of 90% has been applied in most cases unless alternative robust estimates are provided by the literature.

These four steps are illustrated in *Figure 8.* It can be seen that less than 40% of the total direct emissions in 2008 are considered technically feasible for capture i.e.43 $MtCO_2$[30].

Figure 8: Assessment of capture potential from industry, 2008



The sites identified as potential capture sites (i.e. Step 2) are shown in *Table 2*.Based on the above methodology, a forecast of technical capture potential (excluding capture from additional capture-related emissions) was calculated, as shown in *Figure 9*. Unless specific plant details were identified demonstrating 2008 emissions data to be unrepresentative, future

[30] Note that this excludes the additional CO_2 volumes associated with capture energy requirements which need to be included in calculation of transport and storage costs.

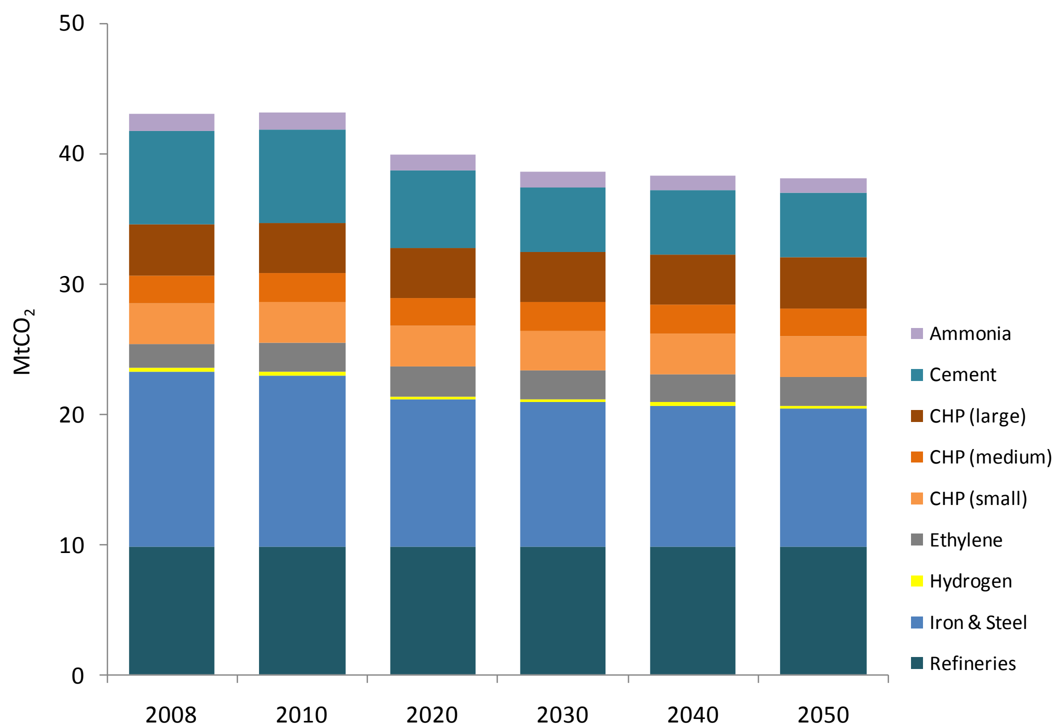
non-CCS emissions were based on projected 2008 base year data. This was carried out using similar sector-wide assumptions of future carbon intensity improvement to those made in forecasting GB industry CO_2 emissions as a whole.

No decision was taken regarding the possible future closure or change in output of plants; it was assumed that the 77 plants identified as possible capture projects remain operational throughout the forecast period (which may include major refurbishment/re-powering etc).

In the absence of modelling possible future scenarios of plant-by-plant retirement schedules and/or replacement, the analysis of capture potential and economics is rather based upon a simple assumption of CCS deployment at known existing brown-field industrial sites. See section 2.2 for further discussion.

The forecast indicates that the capture potential declines by around 10% by 2050 (from 43 to 38 $MtCO_2$), largely due to assumptions of marginal improvement in energy use, and implementation of BAT (predominantly in cement and iron & steel), see section 2.2. It can be seen that the iron and steel and refining sectors account for over half of the technical capture potential through 2050; these sources also represent the largest capture sources (including post-combustion capture from blast furnaces at the three large integrated iron and steel works of Port Talbot, Scunthorpe and Teesside and the major oil refineries). Capture from cement kilns and chemical production plants (ammonia, hydrogen and ethylene) represent a further 20 medium-sized capture sources accounting for a further quarter of the capture potential. CHP units located across a range of industrial sectors represent a total of 45 potential capture sites and account for the remaining quarter of capture potential.

Figure 9: Technical capture potential from industry, 2008 to 2050



3 CCS costs: Industry Sector

3.1 Methodology

The abatement costs (£ per tCO_2 avoided) associated with CCS deployment in industry have been calculated according to the following simple methodology:

1) *Calculation of capture costs.* Capture costs were calculated for nine representative industry capture project types, based on the existing literature and project team analysis. Technical assumptions and cost estimates were adjusted to current prices and modelled as far as possible using common economic assumptions e.g. financing assumptions and UK energy price forecasts to provide a reasonably comparable set of capture costs.
2) *Calculation of transport and storage (T&S) costs.* T&S costs were modelled on a plant-by-plant basis according to capture volume and location; the approach chosen assumed transport and storage of CO_2 to be operated by a different entity to the capture project operator(s) represented by a simple gate fee, and also the evolution of regional CCS clusters through to 2050.
3) *Calculation of CCS costs.* The cost of CCS has then been calculated by combining the capture and T&S costs for each of the 77 identified candidate sites. Both capture costs and avoided costs (by calculating annual tCO_2 abated compared to an equivalent non-CCS facility) have been modelled.

Cost-ordered marginal abatement cost curves (MACC) of CCS industry options were then generated for the years 2030 and 2050, based on the technical capture volume calculated (see Section 0) and the modelled abatement costs (£ per tCO_2 avoided) calculated for each identified candidate plant. Finally, several sensitivities were modelled, reflecting alternative forecasts of UK energy prices and possible project financing options.

This remainder of this section describes in further detail the above methodology and associated outputs.

3.2 Capture costs

Capture costs were calculated for each of the 77 identified installations by modelling costs for nine representative candidate project types.

Technical assumptions and estimates of capital and operational costs were derived from the literature, with costs adjusted to end of 2008 prices using the Chemical Engineering Plant Cost Index (CEPCI) and using one year average (2009) economic exchanges rates[31]. The same assumed rates of future capital cost reduction - associated with learning effects and increased manufacture – as those applied to post-combustion amine-based capture from CCGT plant were applied[32].

[31] EUR/GBP = 1.2329; USD/GBP = 1.56696

[32] i.e. 2030 capital cost = 0.68 x 2008 cost; 2050 capital cost = 0.54 x 2008 cost

In order to ensure a greater consistency across project type calculations, capture from additional CHP units (to produce heat for capture plant, where required) was included[33]. Fuel costs were calculated using the most recent Government forecasts of energy prices (see Appendix), using the 'central' price projections for the base case. For the base case, all capital costs were discounted at a (real) rate of 10% over a period of twenty years. The range of assumptions and capture costs are summarised in *Table 3* and *Figure 10*. More detailed descriptions of each project type and the data assumptions chosen are provided in the Appendix.

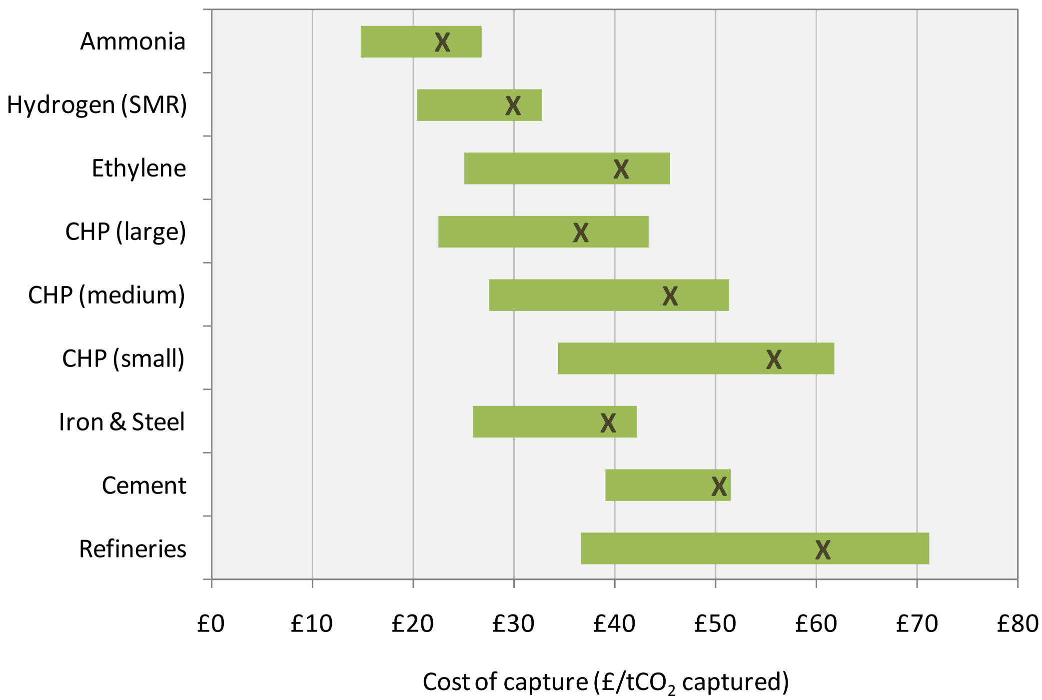
Table 3: Summary of project assumptions and capture costs

Plant type	Captured CO_2 ($MtCO_2$/yr)	Avoided CO_2 ($MtCO_2$/yr)	Add. Capex (£ million) 2030	Add. Opex (£ million/yr) 2030	Fuel requirement (GJ/tCO_2)	Capture cost (£/tCO_2 captured) 2030	Capture cost (£/tCO_2 avoided) 2030
Ammonia	0.800	0.736	88	2.25	1.42	15 - 27	16 - 29
Hydrogen (SMR)	0.285	0.268	56	1.79	1.06	20 - 33	22 - 35
Ethylene	0.932	0.785	171	4.36	2.81	25 - 46	30 - 54
CHP (large)	0.772	0.664	144	0.94	2.48	23 - 43	26 - 50
CHP (medium)	0.257	0.221	74	0.39	2.48	28 - 51	32 - 60
CHP (small)	0.103	0.089	43	0.25	2.48	34 - 62	40 - 72
Iron and steel	4.328	3.964	1185	30.25	1.50	26 - 42	28 - 46
Cement	0.862	0.633	200	16.96	2.77	39 - 52	53 - 70
Refineries	2.608	1.932	477	12.17	5.27	37 - 71	49 - 96

Note: capture costs do not include costs of transport and storage (T&S); capture cost ranges calculated based on 'low' 'central' and 'high' UK industrial energy price forecasts 2030-2050 (HMT, 2009)' costs apply financial discount rate of 3.5% and 10% over 20 years

[33] This is an assumption, and final decisions as to whether capture from additional power generation for gas separation and compression is likely to be made on a site by site basis

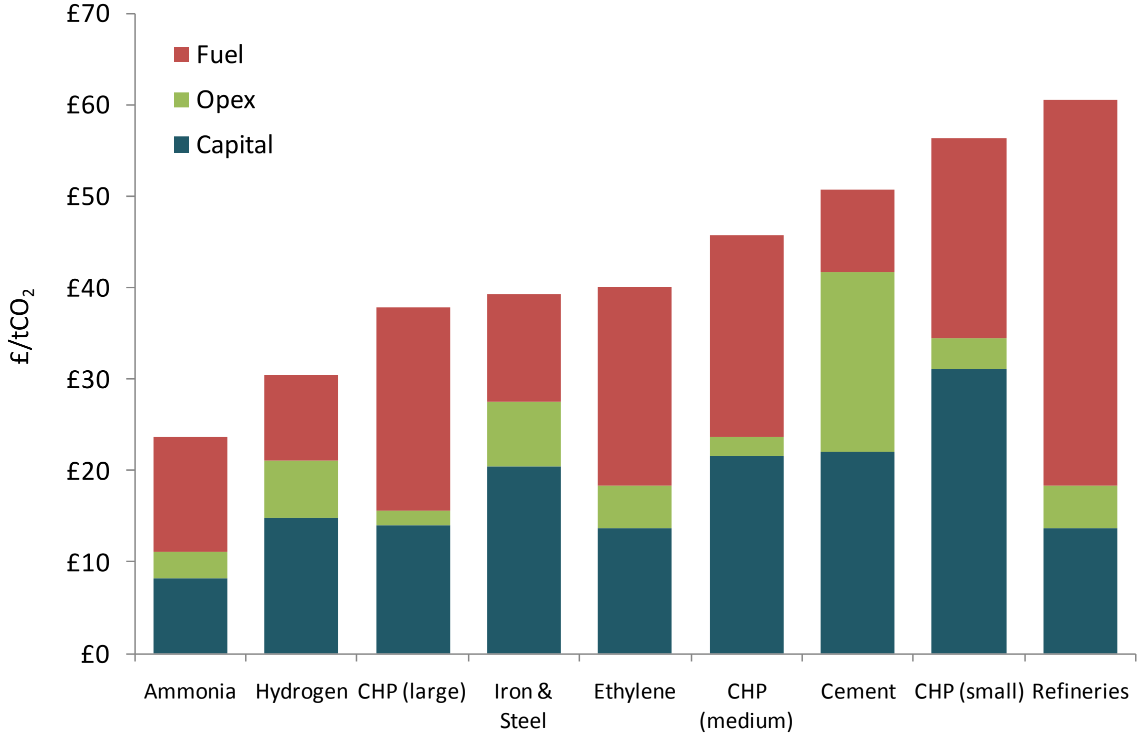
Figure 10: Range of modelled capture costs in 2030



Note: capture costs do not include costs of transport and storage (T&S); capture cost ranges calculated based on 'low' 'central' and 'high' UK industrial energy price forecasts 2030-2050 (HMT, 2009)' costs apply financial discount rate of 3.5% and 10% over 20 years. Base case costs are indicated by crosses; note that these values are located towards the upper end of the ranges shown because a discount rate of 10% i.e. a higher cost of capita than at 3.5% is assumed in the base case cost calculations.

The base case capture costs (£ per tCO_2 captured) calculated for each of the nine project types are shown in *Figure 11*, ordered by cost and broken down into their separate key cost components. The cost of capture is seen to vary significantly across the selection of candidate project types, ranging from around £25-30 per tCO_2 for those industrial sources involving high-CO_2 concentration capture streams with relatively simple capture equipment requirements (ammonia, hydrogen) to costs of £50-60 per tCO_2 where there are multiple lower CO_2-concentration sources (refinery complex) and/or smaller volumes available for capture (small-scale CHP). The graph also indicates variations in the relative share of different cost components, including for example comparatively high fuel (gas) costs associated with capture from a refinery complex - owing to the large energy requirement associated with capture from multiple CO_2 sources across the facility.

Figure 11: Capture cost components, 2030 (base case)



Note: capture costs do not include costs of transport and storage (T&S)

The costs have been generated using common assumptions for key cost factors as far as possible (e.g. energy prices, financial parameters, conversion to end 2008 prices; rates of future capital cost reduction, retrofit adjustments). However, as no robust comparative cost study of retrofit of CCS to industrial sources exists, the use of data drawn from the existing literature in order to compare costs across projects must necessarily be treated with some caution. For example, some cost estimates can be viewed as overly conservative (e.g. the cement opex data includes detailed and conservative estimates of plant fixed cost components for maintenance, labour, administration, insurance etc) whilst others exclude hidden costs or important project costs such as engineering and design costs and investment in civil works. Importantly, there is no quantification in the literature of the potential costs associated with reduced production during retrofit installation, although such estimates would clearly vary widely on a case-by-case basis.

Similarly, capital and operating costs will necessarily vary according to many process- and plant-specific considerations (plant size and configuration, on-site space availability, number of available capture sources etc). The range of capture costs presented above should therefore be viewed as first-order estimates only although it is worth noting that the figures produced fall within the range of existing cost estimates from the literature, summarised in *Table 4*.

Table 4: Summary of existing capture cost estimates

Sector	Cost	Source	Notes
Iron and steel	US$40-50/t$CO_2$	Borlee, J. (2007)	Capture cost (excl. T&S costs), based on post-combustion capture from blast furnance. Cost excludes any associated changes in blast furnace productivity
	€50/tCO_2	McKinsey (2009)	Avoided cost to society in 2030 incl. T&S costs; post-combustion capture from blast furnaces at large integrated iron and steel plant
	US$ 18/tCO_2	Gielen, D. (2003)	Capture cost (excl. T&S costs)
	US$ 25/tCO_2	OECD/IEA (2009a)	Low range CCS cost estimate from DRI production
	US$60-70/t$CO_2$	OECD/IEA (2009b)	Avoided cost incl. T&S costs ; post-combustion capture from blast furnaces at large integrated iron and steel plant
Cement	€20-75/tCO_2	IEA/WBCSD (2009)	Capture cost (excl. T&S costs) based on different capture technologies and cost factors
	US$75-100/t$CO_2$	OECD/IEA (2008)	Capture cost range, based on new and retrofit post-combustion
	€45-60/tCO_2	McKinsey (2009)	Avoided cost to society in 2030 incl. T&S costs; range reflects new build vs. retrofit
Refining	US$50-60/t$CO_2$	Simmonds, M. et al (2003)	Captured cost estimate based on retrofit of post-combustion capture from multiple sources at large UK refining complex not including CHP units
	€90-120/tCO_2	Stralen, J. et al (2010)	Captured cost estimate based on retrofit of post-combustion capture from range of sources at large European refinery complex, other than (low-cost) hydrogen production facilities
	US$130/t$CO_2$	Gerdes, K. (2009)	Capture cost (excl. T&S costs), based on retrofit post-combustion capture from refinery process heaters only
Chemicals	US$15/t$CO_2$	IPCC (2005)	Capture cost (incl. T&S costs) for post-combustion capture from hydrogen production plant
	€30/tCO_2	Stralen, J. et al (2010)	Capture cost estimate from hydrogen production facility at large European refinery complex
	< US$50/t$CO_2$	OECD/IEA (2009a)	Cost estimate for post-combustion capture from ammonia plants
	> US$50/t$CO_2$	OECD/IEA (2009a)	Cost estimate for post-combustion capture from ethylene plants
	US$ 25-30/tCO_2	OECD/IEA (2009b)	Avoided costs for early candidate high-CO_2 content capture sources (ammonia, hydrogen) incl. T&S costs
CHP (gas-fired)	US$ 37-74/tCO2	IPCC (2005)	Avoided cost range from the literature for post-combustion from gas-fired power based on existing technology
	US$ 53-66/tCO_2	OECD/IEA (2009b)	Avoided cost range for post-combustion from CCGT incl. T&S costs

Source: Borlee, J. (2007), "Low CO_2 Steels – ULCOS Project", ETP 2008 Workshop on Deploying Demand Side Energy Technologies, OECD/IEA, Paris (October 8-9); McKinsey & Company (2009) Version 2 of the Global Greenhouse Gas Abatement Cost Curve; Gielen, D. (2003), CO_2 removal in the iron and steel industry, Energy Conversion and Management; OECD/IEA (2009a), Energy Technology Transitions for Industry; OECD/IEA (2009b), Technology Roadmap: Carbon Capture and Storage; IEA/WBCSD (2009), Cement Technology Roadmap 2009; Simmonds, M., P. Hurst, M.B. Wilkinson, C. Watt and C.A. Roberts (2003), A Study of very large Scale Post Combustion CO_2 Capture at a Refinery and Petrochemical Complex; Stralen, J., Geuzebroek, F., Goodchild, N., Protopapas, G., Mahony, L. (2010), CO_2 Capture for Refineries, a Practical Approach. International Journal of Greenhouse Gas Control; Gerdes (2009) CO_2 Capture Overview – Scale of the Challenges, presentation by Karl Gerdes, Chevron Energy technology Company at IEA/CO_2 CRC CCS Summer School, 24 August 2009; IPCC (2005); Special Report on Carbon Dioxide Capture and Storage; OECD/IEA (2008), CO_2 Capture and Storage: A Key Carbon Abatement Option.

3.3 Transport and storage costs

Transport and storage of captured CO_2 are obviously essential elements of CCS projects. Though they are expected to make up less than a third of overall CCS costs, inadequate consideration to transport and storage could derail CCS projects. Locations for CO_2 storage may be highly sensitive to timing and political or commercial drivers over which the CO_2 source may have little control and may or may not be 'optimised' from the perspective of the source or wider society. Likewise a range of CO_2 transport solutions may be conceivable for connecting sources and sinks and the chosen solution may not be 'optimised' either from the perspective of the source or wider society.

3.3.1 Transport – key issues

Transport modes could potentially include pipelines or ships. Ship transport may be attractive when considerable flexibility is required (e.g. because of uncertainties in expected volumes, specification or over storage site location/suitability), or when project lifetimes are short. In general however where the locations of sources and storage sites are clear, then pipeline transport will be most economic, particularly for the larger sources. Pipeline design, routing and financing then become the key concerns.

CO_2 pipelines could operate at low pressure (with CO_2 in the gas phase) but operation at high pressures (with CO_2 in the dense or supercritical phase) is expected to be more economic because of the smaller pipeline diameters required[34]. However the limited experience of CO_2 pipelines in the UK could delay in implementation. In a few cases re-use of existing natural gas or oil pipelines may be possible, probably on an opportunistic basis.

3.3.2 Clustering

In several parts of the UK CO_2 sources are clustered together[35]. In these areas, integrated pipeline networks, with multiple branches to connect individual sources to a common hub and trunkline, might significantly reduce the disruption, and transaction costs and risks associated with permitting and installing multiple point point-to-point pipelines. Particularly for smaller sources, integrated pipelines could considerably reduce the costs of transport[36]. However there are major challenges in commercially financing CO_2 pipelines that are initially over-sized, particularly in the period before CCS is considered a mature commercial technology and before the locations, capacities, timing and technology choices of sources and sinks are fully understood. Commercial investors would price in the risk of low utilisation through a higher weighted average cost of capital (or complex penalty clauses), resulting in higher tariffs[36].

3.3.3 Storage – key issues

In studies led by the British Geological Survey and Scottish Centre for Carbon Storage the UK has more than sufficient 'theoretical' capacity to satisfy domestic demand for the foreseeable future. Much of this capacity has been insufficiently characterised to date, and therefore it is

[34] There is considerable experience worldwide of CO_2 transport in pipelines, for example in North America for enhanced oil recovery or offshore Norway for CO_2 storage at the Snohvit facility.

[35] Element Energy (2007) Development of a CO_2 transport and storage network in the North Sea: Report to the North Sea Basin Task Force, available at www.nsbtf.org

[36] Element Energy (in press) CO_2 pipeline Infrastructure: An global analysis of global challenges and opportunities for the International Energy Agency Greenhouse Gas Programme.

not clear exactly which sites are technically most suitable, which sites will be matured to a point that they are ready for storage, when these will be available, and what lifetime storage capacity will be allowed.

The matching of sources with sinks has been examined in a number of studies[37]. For this study, sources were linked with three broad regions of storage potential under (i) the Southern North Sea, (ii) Northern and Central North Sea, and (iii) the East Irish Sea. Other areas (e.g. south coast or south west coast) of the UK, may ultimately be demonstrated to have storage potential, but to date these are poorly studied. For these regions costs were based on the assumption that long offshore pipelines could be used to transport CO_2, although the viability of these or equivalent onshore connection to the Southern North Sea requires much further analysis.

Storage costs will at a minimum include site appraisal, capital and operating costs for physical infrastructure for injection (e.g. platforms and wells), ongoing CO_2 monitoring costs and additional costs to comply with regulations. The costs for CO_2 storage will vary between sites. For some locations, the potential to re-use of existing data, wells and platforms could reduce costs directly (or indirectly, through delayed decommissioning or enhanced oil recovery). For other sites the requirements to map in detail a large storage complex, provide new infrastructure, especially for facilities in deep water or for deeply buried storage units, or remediate a large amount of existing infrastructure could increase storage costs substantially. These factors can only be assessed on a site-by-site basis.

3.3.4 Transport and storage cost modelling

The diversity of transport and storage options implies a correspondingly wide range of transport and storage cost estimates. Furthermore, drawing on the same supply chains, these are exposed to the high price and currency volatility associated with international engineering markets. The pace of development of CO_2 transport and storage infrastructure can follow very different trajectories[38].

For the purpose of a UK-wide study of opportunities out to 2050, in-house models for transport and storage were adapted to work with a minimum number of inputs, consistent with the quality of data available.

With high fixed costs, there are significant economies of scale in transport and storage. Indeed the costs of individual transport and storage solutions for sources below a 1-2 Mt CO_2/year are likely to be prohibitively high, and therefore it is assumed that industrial sources would connect to a common CO_2 transport and storage network.

Transport costs were calculated for each site on the basis of predicted volumes, and site location (which is used to estimate distances onshore and offshore between source and sink) and utilisation rate. This was then multiplied by a factor according to the site's clustering potential as described below:

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[37] See for example Element Energy (2007) Development of a CO_2 transport and storage network in the North Sea: Report to the North Sea Basin Task Force, available at www.nsbtf.org; Yorkshire Forward (2008) A carbon capture and storage network for Yorkshire and Humber; E.On (2009) A vision for a CCS cluster in the South East; One North East (2010) Carbon capture and storage in North East England; Scottish Carbon Capture Consortium (2009) Opportunities for CO_2 storage around Scotland – an integrated research study; Element Energy *et al*. 'One North Sea' report for the North Sea Basin Task Force, Manuscript Accepted for Publication; Poyry, Element Energy and BGS for IEA Greenhouse Gas R&D Programme (2009) Role of Depleted Gasfields for CCS, available at www.ieaghg.org

[38] Element Energy *et al*. 'One North Sea' report for the North Sea Basin Task Force, Manuscript Accepted for Publication.

Source Size	Clustering Potential Level	Cost multiplier (relative to point-to-point)
All	Low	1
Tier 0 source (>1 Mt CO_2/year)	Medium	0.75
Tier 0 source (>1 Mt CO_2/year)	High	0.7
Tier 1 source (<1 Mt CO_2/year)	Medium	0.5
Tier 1 source (<1 Mt CO_2/year)	High	0.3

For storage, costs will depend strongly on site-specific issues. The requirement for multiple new wells and surface facilities, pressure boosting, remediation of existing infrastructure, extensive site development and monitoring would increase costs. Conversely the economic benefits from re-use of existing infrastructure, delayed decommissioning or enhanced oil recovery could reduce costs substantially. For this analysis a simple flat tariff of £3/t CO_2 was assumed for all sites. [39]

3.3.5 Assessment of costs

The analysis shows that 24 industrial sources can connect to transport and storage networks with tariffs below £5/t CO_2, and total of 53 sources, capturing 38 Mt CO_2/year in total can connect to transport and storage networks below £10/t CO_2.

The remainder (24 industrial sources, capturing 8 Mt CO_2/year) have transport and storage costs higher than £10/t CO_2, reflecting one or more of the following:

- Their smaller volumes, meaning they are unable to take advantages of economies of scale in transport .
- There large distance from potential storage sites.
- Sources that do not form part of a plausible CO_2 source cluster.

[39] See for example, McKinsey (2008) CCS - Assessing the Economics; Element Energy (2007) Development of a CO_2 transport and storage network in the North Sea: Report to the North Sea Basin Task Force, available at www.nsbtf.org; NOGEPA (2008) Potential for CO_2 storage in depleted gas fields on the Netherlands Continental Shelf Phase 2 – costs of transport and storage; van den Broek *et al* (2010) Feasibility of storing CO_2 in the Utsira formation as part of a long-term strategy for CCS in the Netherlands; International Journal of Greenhouse Gas Control Vol 4, Issue 2, 351-366.

Figure 12: Distribution of T&S costs for industrial sources in 2030 (cluster scenario)

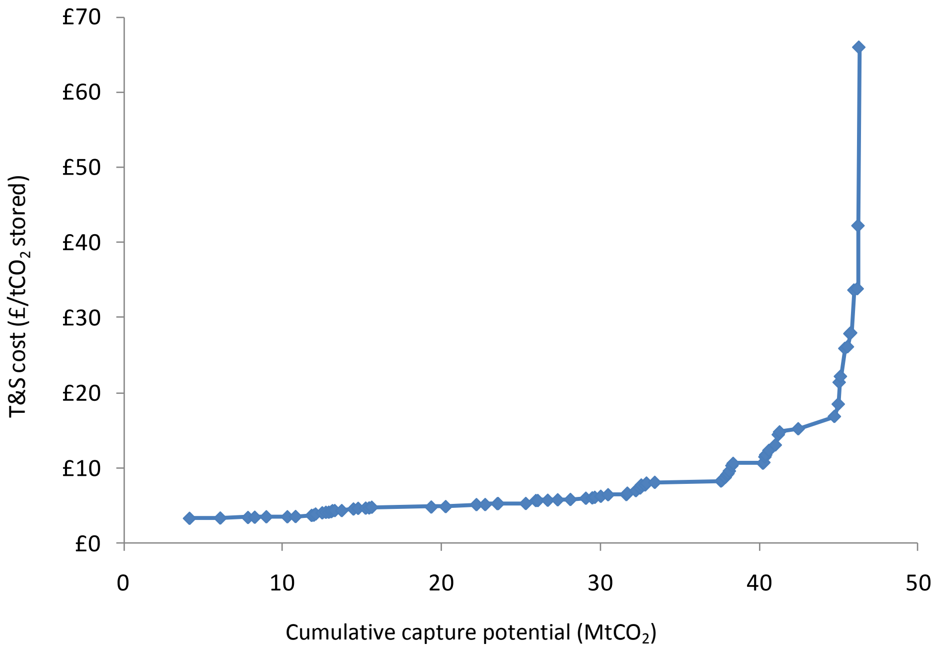


Table 5: Distribution of T&S costs in 2030 (cluster scenario)

2030	T&S cost (£/tCO_2 stored)					
	0 to 5	*5 to 10*	*10 to 20*	*20 to 40*	*> 40*	**TOTAL**
No. of sites	24	29	13	8	3	**77**
Volume ($MtCO_2$)	20.28	17.87	6.86	1.19	0.29	**46.50**
Share of total %	43.6%	38.4%	14.8%	2.6%	0.6%	**100%**

The table above shows the distribution of transport and storage costs calculated for each of the 77 potential capture sources identified. Note that the cumulative capture volume shown on the x-axis is greater than the capture potential shown earlier for 2030; this is due to the inclusion of additional CO_2 volumes captured from additional on-site utilities (for capture plant energy requirements).

The graph indicates that over 80% of the total potential CO_2 capture volume (covering 53 installations) could be transported and stored for a cost to the capture plant operator of £10 per tCO_2 or less; a further 17% of the total potential (covering 13 installations) is assumed to be available at a cost of £20 per tCO_2 or less. Only around 3% of the potential is assumed to have a cost greater than £20 per tCO_2 (covering 11 installations).

The costs shown are highly dependent upon both location and the size of potential CO_2 capture. The lowest costs within the range shown are associated with the largest emissions sources (iron and steel works, oil refineries, large-scale CHP plants) located at industrial sites on the coast with close proximity to offshore storage sites; the highest costs are associated with the smallest source sizes (small-scale CHP) located inland.

3.4 Marginal Abatement Cost Curves

3.4.1 Methodology

The capture costs were combined with the calculated T&S costs to arrive at CCS cost estimates for each of the 77 candidate installations identified. Marginal abatement cost curves (MACC) were then generated for 2030 and 2050 in order to illustrate a cost-ordered series of increasing abatement potential from CCS deployment in industry. Note that CCS MACC calculations are based upon avoided emissions, rather than captured emissions[40].

Avoided emissions take into account those emissions not captured, including the proportion of non-captured emissions from additional energy requirements (see appendix for further details)[41]. This relationship can be represented as follows[42]:

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

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

For ease of presentation, installations were grouped on an abatement cost basis: each of the 77 installations was allocated into one of three cost categories (A, B and C) assigned to each of the nine capture project types i.e. a maximum of 27 CCS cost categories. Note that in the case of iron and steel, each category therefore reflects an actual plant, and that also only two ammonia plants and one hydrogen plant were identified (see *Section 2.3* for details).

[40] The definition of abatement in the context of CCS is in terms of avoided emissions. This is the basis for CCS recognition under the EU ETS.
[41] Typically emissions from additional energy requirements (such as CHP) are assumed to be captured at a 90% rate
[42] CO_2 capture and storage: A Key Abatement Option (IEA.OECD, 2008)

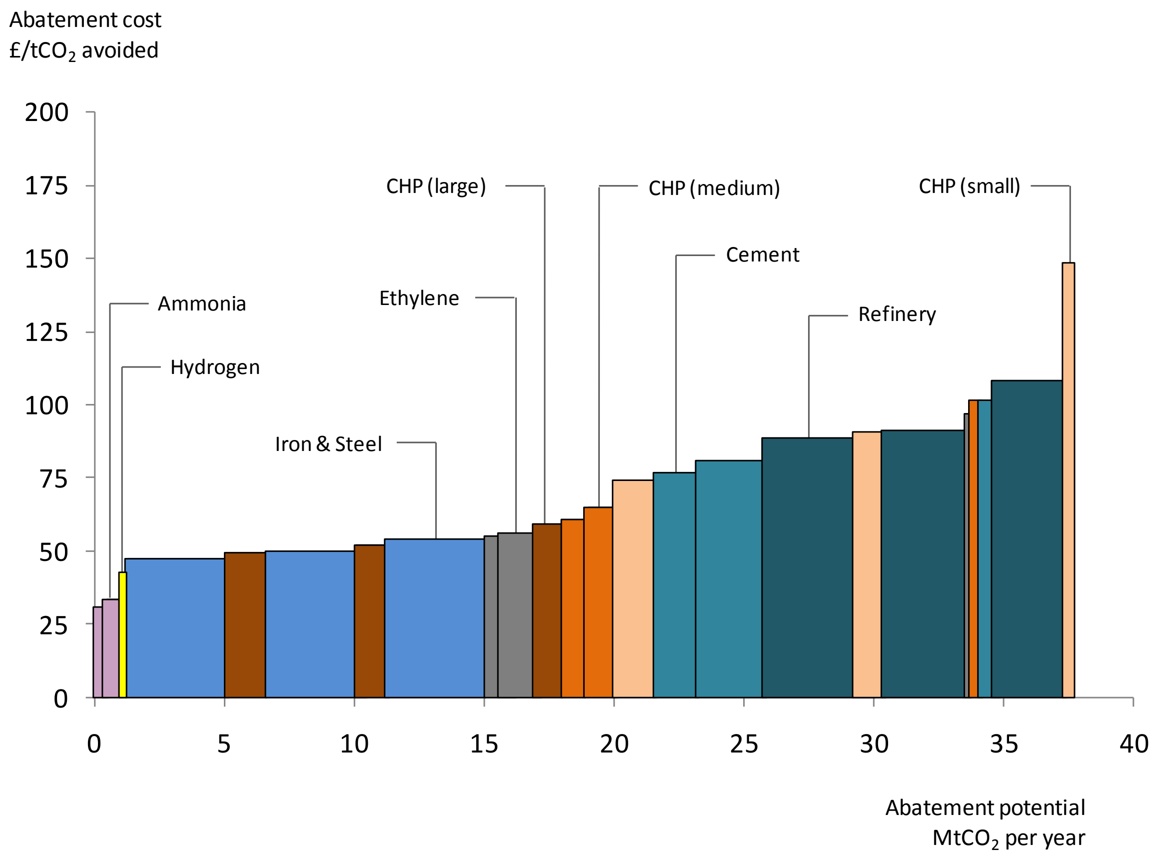
3.4.2 Results

3.4.2.1 Base case

Figure 13 presents a base case marginal abatement cost curve for CCS applied to industry in Great Britain for the year 2030. The corresponding data are provided in the Appendix.

The curve shows a total technical abatement potential of around 38 $MtCO_2$, available at a wide range of costs increasing from around £30 per tCO_2 (ammonia) to around £150 per tCO_2 (small-scale CHP). As described earlier, the capture cost elements reflect a variety of factors including capture equipment requirements based on flue gas CO_2 concentrations, energy penalty rates and scale-effect capital costs whereas the T&S cost elements reflect geographic factors as well as potential source capture volumes. The graph does not take into account technology readiness or likely deployment rates which will be considered as part of the uptake scenario analysis.

Figure 13: Marginal Abatement Cost Curve for Industry in 2030 (BASE CASE)



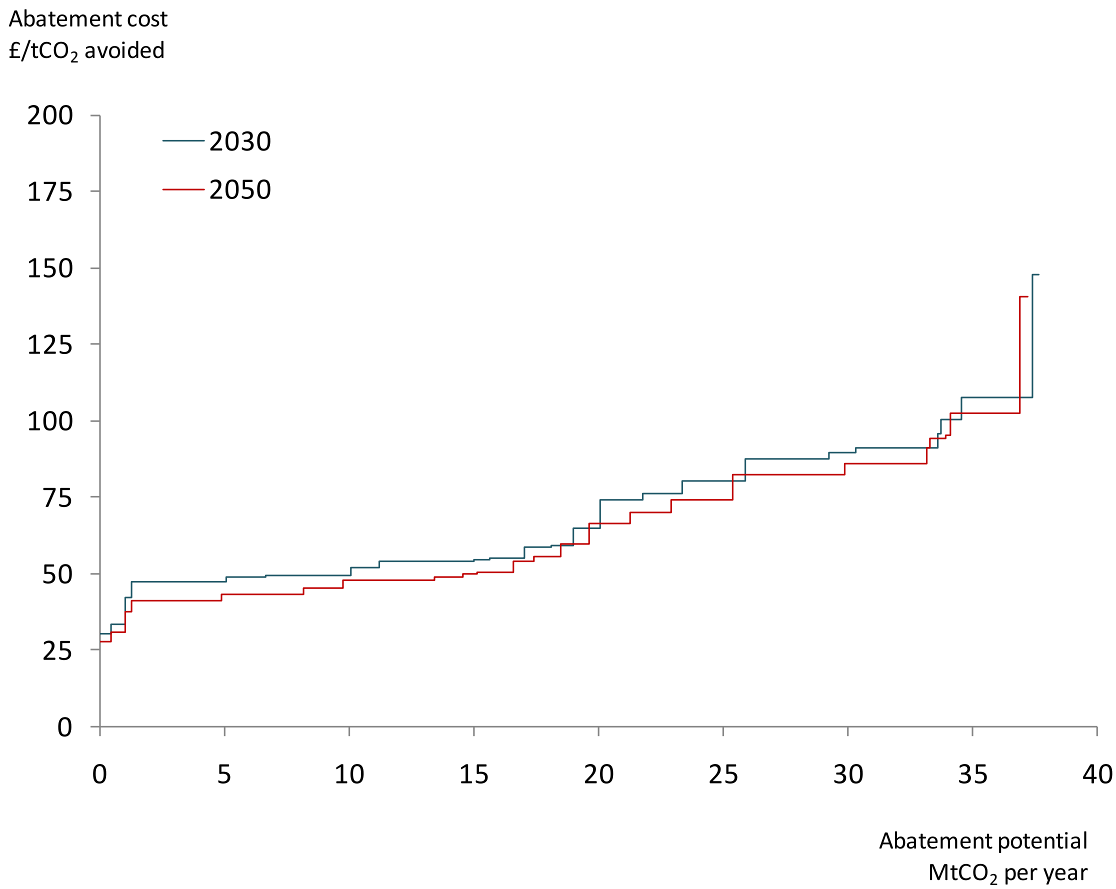
It can be seen that around one third of the abatement potential is estimated to be achievable at around £50 per tCO_2 or less and includes capture from high-CO_2 stream ammonia and hydrogen plants, the three integrated iron and steel works and the majority of large-scale industrial gas-fired CHP capacity). A further third of the potential is available for around £80 per tCO_2 or less (capture from ethylene plants and most medium-scale CHP units and cement kilns), and the remaining third at higher cost from oil refineries sector and certain other plants with high unit T&S costs (e.g. inland small-scale CHP units).

Note that the differences between tranches of the same sector (for example the three refinery tranches) stem from differences in plant output and therefore size of capture kit installed and differences in transport and storage costs based on plant location and emissions.

Figure 14 compares the MACCs calculated for 2030 and 2050. Although there is a noticable reduction in abatement costs associated with real capital cost reductions 2030-2050, the effect is not dramatic; it is assumed in the capital cost reduction rates chosen in the analysis that the most significant equipment cost reductions occur in the period 2010-2030 e.g. the demonstration and early commercial deployment stage[43]. Note also that there is a marginally smaller volume of total capture (and therefore abatement potential) in 2050 compared to 2030; this is attributable to assumptions of increased energy performance in certain sectors through 2050 (e.g. increased materials blending rates and energy efficiency in GB cement manufacture). The degree of uncertainty regarding both future capital cost reduction and CO_2 available for capture is clearly very high and will be dependent upon many factors highly international in nature, including for example the rate at which CCS technology is successfully deployed worldwide over the next decade and the future competitiveness of GB industry (which in turn will be influenced by a range of economic drivers, some of which are related to carbon costs).

[43] Note also that potential future improvements in capture energy requirements are not modelled

Figure 14: Marginal Abatement Cost Curve for Industry in 2030 and 2050 (BASE CASE)



3.4.2.2 Sensitivity analysis – uncertainty in fuel price and financing

In order to assess the potential range of abatement costs associated with CCS applied to industry sector, a sensitivity analysis was conducted by producing six alternative MACCs on the basis of the following economic scenarios:

- Low energy price forecast (using discount rates of 10% and 3.5%)
- Central energy price forecast (using discount rates of 10% and 3.5%)
- High energy price forecast (using discount rates of 10% and 3.5%)

Real discount rates of 10% and 3.5% were chosen to reflect typical illustrative rates within the private and public sectors respectively. These values have been used to reflect high- and low-risk investment decision making in MACC analysis presented in several recent Government studies[44]. A value of 10% was found to be in alignment with typical values for a real corporate weighted average cost of capital (WACC) suggested by industry through consultation, which ranged from 7-15% for large scale industrial projects implemented in the EU or UK. Clearly, the presence of high project risk associated with e.g. uncertain regulatory environment, CO_2

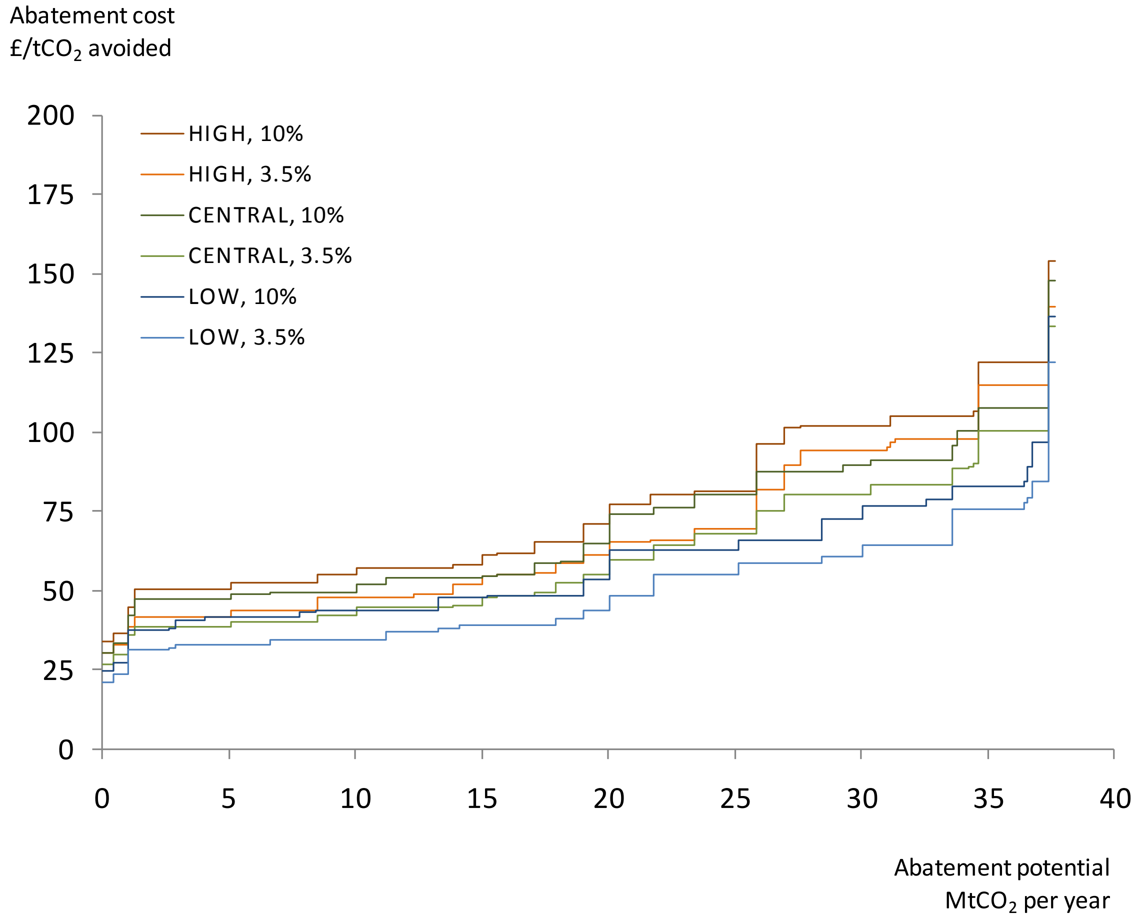
[44] See for example 'Building A Low Carbon Economy' (Climate Change Committee, 2008) Box. 3.6 and the 2007 UK Energy White Paper

price volatility, unproven technology etc would increase lending rates significantly. The MACC chosen as the base case was calculated using a commercial discount rate of 10% and the ‘central’ energy price forecast was used.

The resulting set of MACCs is shown in *Figure 15* for the year 2030. The sensitivity of CCS cost to both energy prices and financial discount rate is seen to be significant. For example, the increase in abatement cost between the ‘low’ and ‘high’ energy price scenarios is in the order of around 40%, the exact rate for each project being depending upon the share of fuel costs in the total CCS abatement cost (highest for oil refining). The increase in abatement cost between the application of 3.5% and 10% discount rates scenarios is in the order of around 20%, varying according to the relative contribution of capital cost in the overall CCS cost. The variability of these two factors between different project types can be seen in the fact that the relative (cost) order of some CCS options changes across the six curves.

To the extent that industrial CCS projects in Great Britain will only be incentivised by market CO_2 prices (i.e. EUAs), the potential rate of CCS deployment is likely to be highly sensitive to energy prices and/or the cost of capital. For example, under the most favourable MACC scenario presented here (low energy prices; discount rate of 3.5%) an EU ETS Phase III allowance price of £50 per tCO_2 would incentivise around 22 $MtCO_2$ of CCS abatement whereas the least favourable MACC scenario would incentivise less than 2 $MtCO_2$. This highlights the importance of CO_2 prices - and investor expectations of their future price changes - to potential CCS deployment within industry in the medium-long term.

Figure 15: Marginal Abatement Cost Curves for Industry in 2030



3.4.2.3 Sensitivity - industrial output projections

This MACCs produced are based upon the industrial emissions forecasts presented in section 2.2 . As discussed earlier, the emissions projections for those specific sites identified as potential captrue sources - i.e. a total of 77 instalations - reflect the (industrial output and CO_2 emission) forecasts made for each industrial sector fo the GB as a whole, except where alternative plant-level information is known. The emissions forecast of the CCS-eligible plants are therefore based upon a fairly constant GB industrial output projection (with the execption of certain sectors such as offshore O&G production and textiles). Future changes in GB industrial output are necessarliy highly uncertain and will be driven by a large range of macro-economic and site-specific factors including e.g. changes in demand for industrial products, national and international economic growth,and relative competitveness of GB industry (including potential impact from leakage impacts associated with differential carbon costs).

Future changes in industrial output will either:

- Reduce (or increase) the load factor for those plants currently operating; or
- Remove (or add) plants from the current fleet e.g. to meet falling (or increasing) demand

The latter case will essentially have the effect of removing the relevant tranches entirely from the MACC with little or no impact on the remaining tranches, except potentially to reduce the economic benefits available from developing local clusters of capture sources. In the former case, reducing load factors will both decrease the total volume of CO_2 potentially available for capture and increase the abatement cost of a given project (because with part-loading, the investment cost results in a relatively lower CO_2 saving over the project lifetime). The latter effect may in practise be differential across and between sectors and plants, depending on those technical and economic factors determining the marginal cost of capture.

3.4.2.4 Sensitivity – Filtering sites based on annual emissions

Filters applied earlier in the process restricted the application of CCS to sites with emissions greater than 200ktCO_2 per annum, or 50ktCO_2 per annum in the case of CHP. If sites are re-located to be in close proximity to other potential CCS sites (e.g. a power station or large cement works), there is opportunity to increase the overall abatement potential by merging streams prior to capture.

4 Industry CCS deployment scenarios

4.1 Primary sensitivities variables

Given the purpose of this study is to examine the likely deployment rate of capture technologies in industry and power sectors, we have identified key input sensitivities that have the greatest effect upon this outcome.

4.1.1 Technology readiness

Despite the maturity of CO_2 separation and “capture” in some industrial processes (the drinks industry is an example) the scale of capture here is at least an order of magnitude less than what would be required for “commercial deployment” i.e. at the 100MW – 1GW scale. As a result the industry standard view is that capture technology is not technically ready, and needs to be proven at the demo and pre-commercial scale before it achieves this status.

Moreover, “Best Available Technology” (BAT) is a commercialisation indicator used to indicate if a technology could (or should) be taken up by the market. In this context “available” requires the technology to have been demonstrated successfully at a commercial scale and in an economic environment which is similar enough to that of the target plant.

For industry and later for the gas sector, we use two example technology readiness dates:

- **Early**: Which reflect the earliest practicable availability given the requirement for demonstration and pre-commercial deployment phases. Typically this is in the time period 2020-2025.
- **Slow**: Which assumes that the pre-commercial deployment phases are more problematic and that capture reaches technology readiness ca. 10 years after the earliest date.

Technology readiness (TR) dates are used as a trigger for investments in capture. No investment in commercial deployment is allowed before the TR date, however we do allow decisions regarding capture to be taken immediately at the TR date. The asset specific construction time then defines when the asset, with capture, is on-line.

It is recognised that the choice of technology readiness does affect other variables within the model. Most important is the technology cost; specifically the assumptions about the learning rate for capture. Problems with deployment will interrupt the assumed cost reduction trajectory. For transparency we have assumed a single learning rate trajectory.

4.1.2 Economics

There has to be a viable business model to underpin investments in capture. Both the gas power and industry sector models utilise economic viability tests before permitting capture to be added to each facility.

The industry MACC curve identifies for each facility the price of CO_2 required to give the required return on investment. Three CO_2 price trajectories are taken from DECC projections, and these are used for comparison against the industry MACC curve to identify economic investments.

For the purposes of simplicity and transparency, investment in capture is triggered when the market CO_2 price is equal to or greater than the levelised cost of abatement in a given year (subject to technology readiness and the limits of technical availability). Implicit in this approach is the assumption that CO_2 prices in subsequent years would remain at the same level or increase; no foresight is assumed involving likely projections of CO_2 prices. In practise, it is understood that investment decisions and financing structures are more complex and will account for risk factors such as CO_2 price volatility and uncertainties concerning future policy support; such factors may result in an investment decision requiring needing a the prevailing market CO_2 price to be higher than the abatement by a certain margin; however, there is no robust data to determine this margin and such decisions commonly involve a range of complex economic and non-economic factors.

4.1.3 Other variables

WACC/discount rate: Set at a constant of 10%

Fuel price: DECC central price projections used.

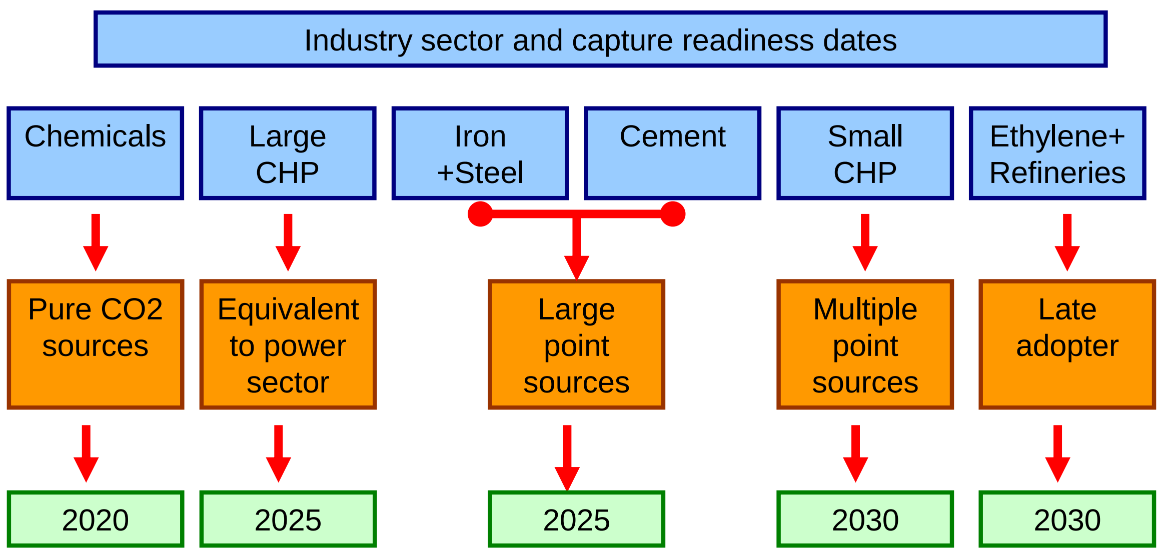
4.2 Summary of deployment scenarios

A summary of the industry deployment scenarios is show below.

Technology Readiness	CO_2 Price trajectory		
	Low	Medium	High
Early (2020)	A1	A2	A3
Late (2030)	B1	B2	B3

Some industrial processes are expected to be earlier adopters of capture technology, for reasons which include the purity of the CO_2 stream, and the number of individual CO_2 source emitters at a single facility. We reflect this within each TR scenario by allowing immediate take up of the technology in some sectors, and delaying it in others, see below.

Figure 16: Commercial technology readiness dates for scenario set A, across sectors



5 Potential for CCS: Industry Sector

The base-case MACC[45] is used to define the realistic potential for CCS over the period to 2050. For each installation:

1) The date at which the technology can be commercially applied at large-scale in the sector is defined according to the scenario as described above.

2) The abatement cost is compared to the CO_2 price in any given year, as defined by the scenario.

Uptake of CCS by a plant can therefore occur at any time beyond the technology readiness date provided the CO_2 price exceeds the abatement cost. In reality such uptake is likely to be tied to refurbishment schedules for some industry sectors. Consultation responses indicated the complexities and often modular nature of such schedules which prevented the application of over-arching assumptions across a sector/sectors to predict uptake.

Descriptions of the refurbishment cycles are summarised in the Appendix.

5.1 Results

5.1.1 Industry-wide analysis

Figure 17 highlights the impact on CCS potential in UK industry from CO_2 prices and the global rate of CCS development. The uptake profiles for the scenarios shown are a consequence of a relatively shallow baseline MACC (as shown in section 3.4) and steep trajectories for CO_2 price predicted by DECC.

In the most optimistic scenario (A3), where CCS is proven early and CO_2 prices are high, then the abatement potential reaches 35 Mt CO_2/year in 2030. Deployment occurs over a narrow timeframe reaching a maximum of 37.5 Mt CO_2/year by 2032. This corresponds to a capital investment of *ca*. £7.7 bn over the seven years from 2025 and 2032 (*Figure 17*).

Conversely, in scenarios A1 and B1, where CO_2 prices are low, uptake starts later and proceeds more slowly. Abatement is only *ca*. 1 Mt CO_2/year in 2030, rising to 34 Mt CO_2/year in 2050. . In these scenarios investment is delayed and is spread over a much longer period, i.e. £6 bn over 15 years.

By the time the CO_2 price has reached the medium case, the price is sufficient to drive investment at the rate shown by scenario A2. Technology development inhibits the equivalent case (B2) and scenario B3, causing an identical steep step-like trajectory. Uptake occurs as soon as technology becomes available as it is already economic to deploy.

Although CO_2 price and CCS development rates are important prior to 2035, after 2045, the annual abatement potential is similar across the six scenarios, i.e. differences in CO_2 price or impact on total abatement from an initial fast or slow rollout of CCS are small. This is a result of the minimum CO_2 price prediction from DECC of £100/t, which is sufficient to drive investment across the board.

[45] Central fuel prices, 10% real discount rate

Figure 17 CO_2 abatement in industry for different CCS development and CO_2 price scenarios.

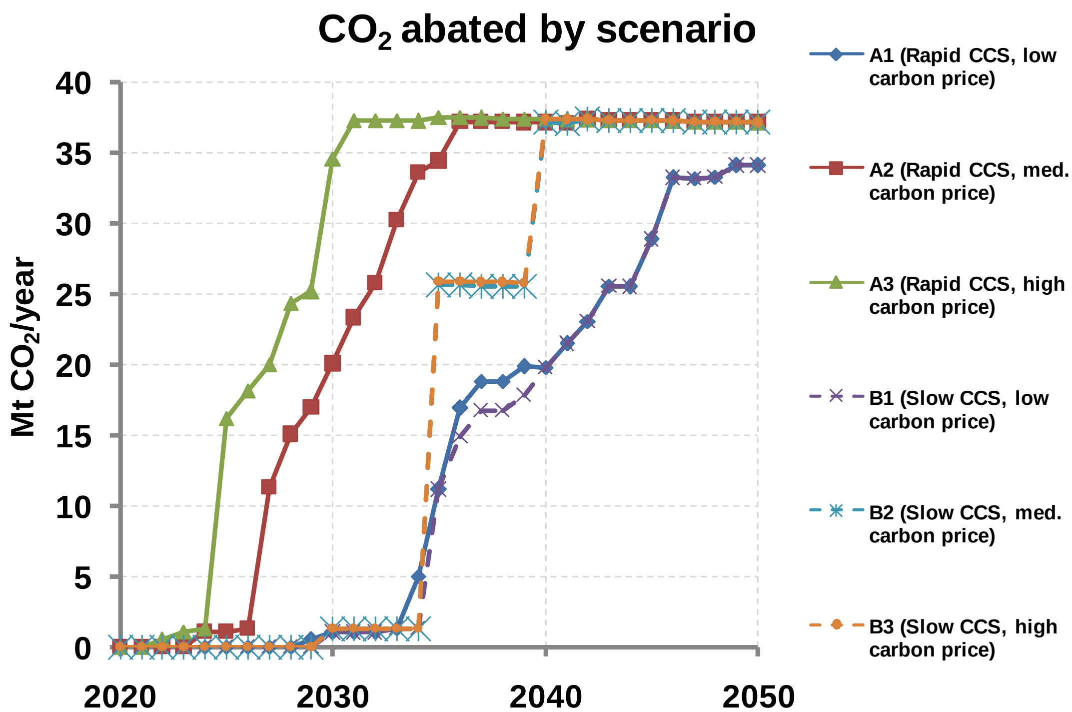
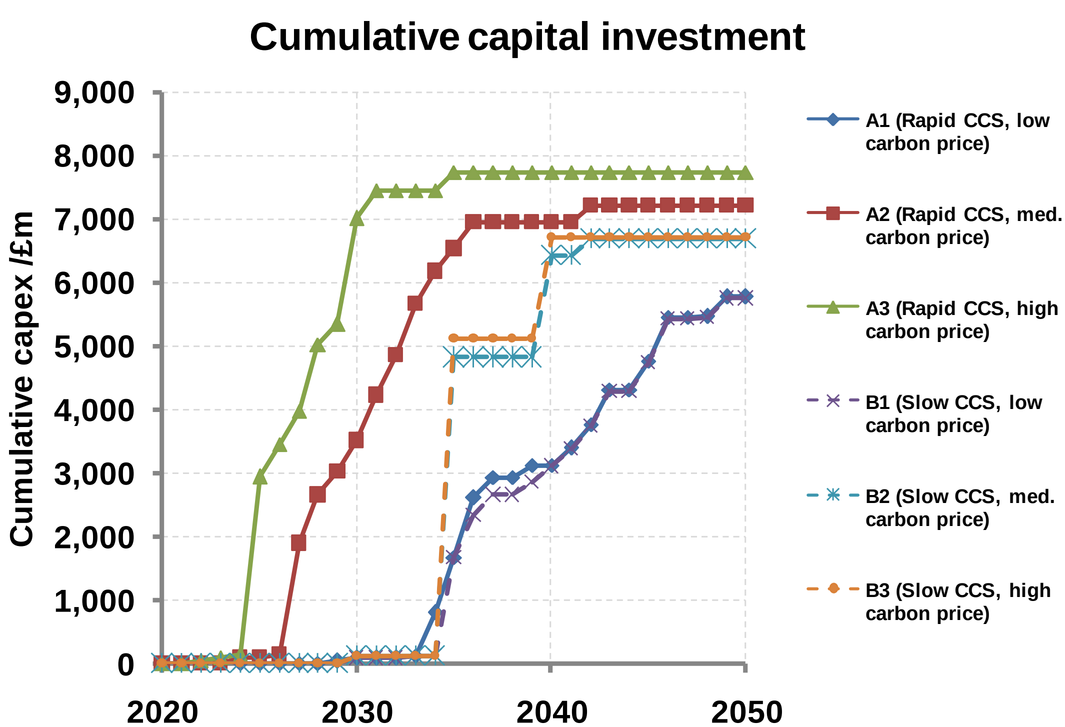


Figure 18 Capital investment profile for CCS in industry for the six scenarios.



5.1.2 Sectoral contributions to abatement and costs.

The sensitivity of the breakdown of the CCS projects by sector for the six scenarios has been analysed. For simplicity, the two extreme rates of CCS development are shown in Figure 19, i.e. scenarios A3 (most optimistic, i.e. high CO_2 prices and rapid CCS technology development) and B1 (most pessimistic, low CO_2 price and delayed CCS technology development).

Irrespective of scenario, iron and steel, CHP and refineries provide the dominant opportunities for CO_2 emissions abatement in 2050. Before this however, the absolute contribution from each sector is dependent on timing and the scenario. Capture from ammonia plant is available soonest but is of low magnitude. Capture in industrial CHP and iron and steel industries each provide material abatement in *ca*. 2030 in scenario A3 but in B1 this is delayed until *ca*. 2040. Capture at refineries, ethylene and the cement sectors begin to contribute in A3 from 2030, but are negligible even in 2040 in B1. Indeed refineries only contribute materially from 2045 in scenario B1.

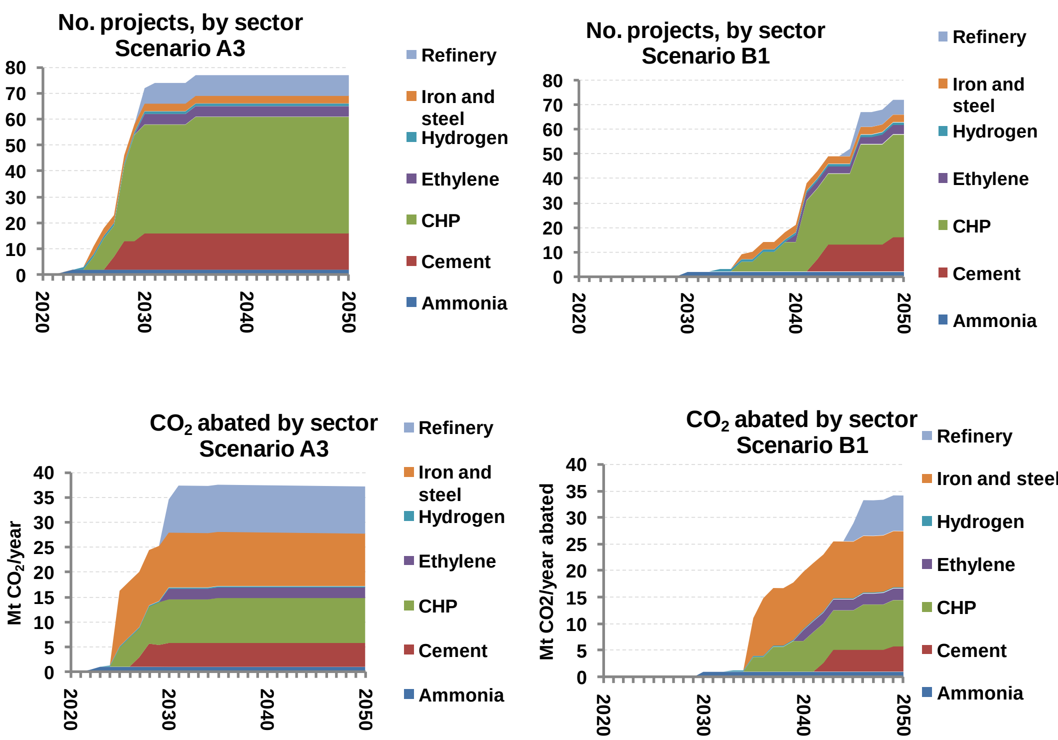
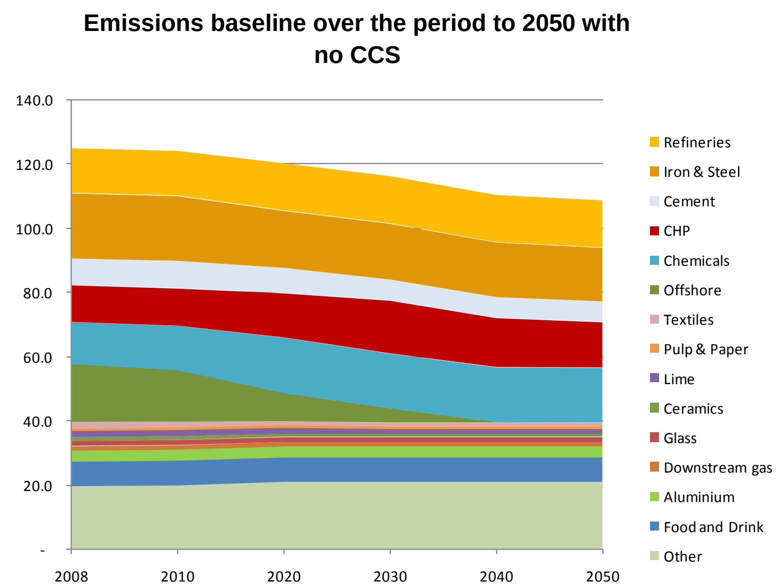


Figure 19: Contrast in the number (upper panels) and abatement potential (lower panels) of capture projects for the most optimistic (left hand panels) and most pessimistic (right hand panels) scenarios for CCS deployment in UK industry.

5.1.3 Emissions

The impact upon CO_2 emission levels, of these uptake trajectories, is shown in the two graphs below. The upper graph shows the baseline emission trajectory for the industry fleet, without CCS. The lower graph shows the lower emissions following scenario A3.



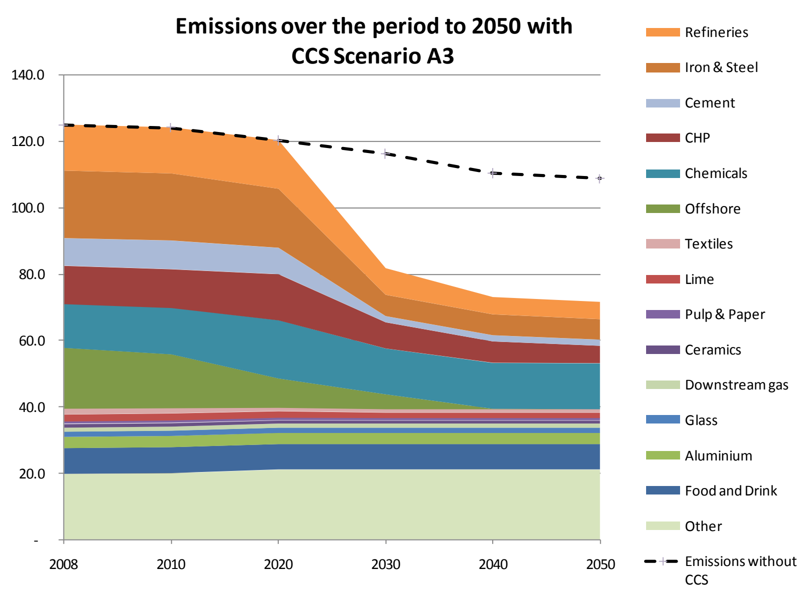


Figure 20: Industry direct emissions with and without CCS over the period 2008-2050

5.1.4 Summary

With very diverse assumptions on the rate of CCS technology development and CO_2 prices, the captureable emissions from industrial sources is estimated in the range 34-37 Mt CO_2/year in 2050, with capital investment in the region £6-8 bn.

The dominant contributions to abatement in 2050 come from the iron and steel, industrial CHP and refining sectors.

There is significant uncertainty over the economic potential of CCS in industry and relative contributions from different sectors in the period 2025 to 2045, with CCC's alternative CO_2 price forecasts resulting in very different CCS uptake levels. The rate of CCS technology development has a significant impact at higher CO_2 prices but has negligible impact under the lower CO_2 price forecasts.

With plausible uncertainties of *ca.* 10 years on when uptake becomes relevant, it will be challenging to engage industry in preparing for CCS. For cement and refining, the uncertainty in economic uptake exceeds 20 years.

Gas Report

6 CCS application to the gas power sector

6.1 Size and composition of the existing and planned gas fleet

Existing databases (including the Digest of UK Electricity Statistics 'DUKES', the National Allocation Plan for the ETS, and IEA emitters database) were used to develop a database listing the capacities, start dates and current emissions for the current fleet of gas-fired power generation. Current emissions are proportional to a number of factors, including plant load factors, efficiency and the type of gas-fired plant.

The current fleet in the database has a nominal rated capacity of 31.2 GW and comprises predominantly CCGT, a small number of OCGT, gas/oil, CHP and Cogeneration units, as shown in Figure 21. The current fleet is predominantly smaller, sub-1000MW units.

A database of future gas plant plans was developed using an in-house database of potential CCGTs and planned or proposed CCGTs that are in the planning process or have made a planning/section 36 application. The planned capacity is in excess of 30GW, however typically a number of proposed projects are likely to fail for financing or planning reasons. In particular, projects developed by independent developers are generally less successful than those developed by larger utilities. The recession has also impacted the demand for electricity, decreasing the likelihood that planned capacity will go ahead according to its original timescale. For completeness all proposed plants are considered here.

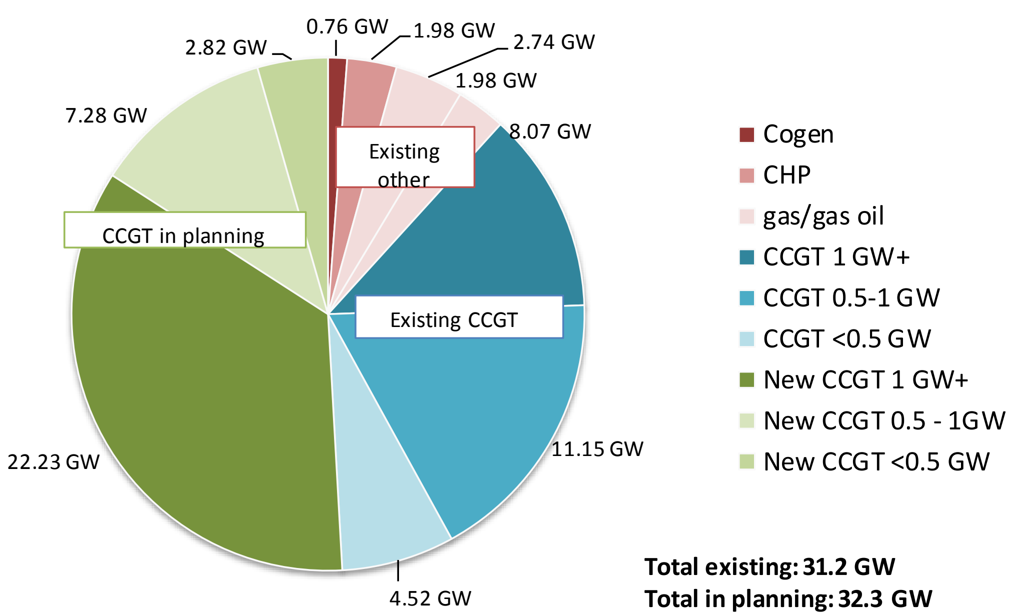


Figure 21: Current UK Gas-fired Generation 2009 (blue and red) and CCGT plant in planning, pending or under construction (green)

70% of planned CCGT capacity is in larger units each in excess of 1000 MW. This trend is likely to continue into the future as even larger plants (up to 1.8GW) join the grid in the future.

6.2 Repowering and replanting of existing fleet.

Plant age and refurbishment requirements determine operation and plant economics of a particular plant. Typically plant 're-powering', i.e. replacement of turbines and heat recovery steam generator (HRSG) occurs 20-30 years after construction. Repowering typically involves downtimes of several months. The extent of plant refurbishment during 'repowering' will depend on site-specific issues – such as compatibility of existing infrastructure with the new turbine(s). Future gas fleet potential capacity can be estimated using assumptions on repowering timelines and overall demand. A baseline assumption for this study is that, unless the site is mothballed, repowering can occur 20 years after plant construction to extend lifespan by 20 years. After 40 years it is assumed that a new plant can be built on site from scratch.

Please note that grid requirements determine the functioning of the system as a whole but in some locations impact operational parameters of plants. This is not considered further in this report as significant changes to the grid are expected by the 2030-2050 period.

6.3 Shortlisting sites for CCS relevance.

The gas fleet list contains plants that differ in their CCS relevance, based on plant type, annual plant emissions, plot availability for capture, site pipeline access, access to storage sites. Technology and market evolution may result in unexpected additional opportunities for capture from the gas power sector, but cannot be relied upon.

6.3.1 Plant type

The types of plant identified in the database include systems used solely to provide heat and/or power in industry, CHP/cogeneration plants, multi-fuel units, Open Cycle Gas Turbines (OCGT), black start power units as well as 'conventional' combined cycle gas turbines (CCGT).

Units used for industrial heat and/or power are excluded as their potential has been described in the preceding chapters.. With the exception of Peterhead power station for which gas with CCS has already been proposed by industry, multi-fuel, gas/oil and IGCC sites are excluded from the site shortlist which is focused on the gas power fleet. IGCC represents a fuel-switching option from natural gas fired power to coal gasification, rather than as gas-fired power generation with CCS and will therefore be treated accordingly.

Black start facilities (used to start power stations e.g. in the event of grid failure) are removed as these are viewed as part of the parent coal fired station and tend to be gas/oil units with very low load factors.

6.3.2 Plant size

The majority of the UK gas-fired power generation is above 50,000 t CO_2/year. Sources below this level of annual emissions are excluded as the costs and challenges of CO_2 transport are likely to rise significantly with smaller volumes[46]. Removing small generators removes 37 sources corresponding to emissions of 0.7 Mt CO_2/year.

6.3.3 Plant pipeline access

Unless a natural gas supply can be substituted by a hydrogen supply from elsewhere, and the existing gas pipeline and gas turbine adapted or replaced to ones that can run on hydrogen, on-site CO_2 capture requires access for a pipeline to transport CO_2 away for storage,. Even if ship transport is used offshore transport is still required away from the site to dockside.

For some power stations, there are residential, social or industrial developments adjacent to the sites. Some sites are “bound”, i.e. where the surroundings effectively barricade the site in question and no pipeline path is evident, without redevelopment. Consider the example of Enfield CCGT.

Figure 22: Enfield CCGT, example access problem

Here the site is almost fully bound. Access to the South, West and North is via industrial or residential areas severely limiting pipeline access. To the East is a reservoir. There is a very narrow route in the North-East.

For new sites the CCR requirements are such that the access to the site must be identified, and the degree to which rights of way are secured for use are under discussion.

6.3.4 Plot

The footprint for an onsite carbon capture plant, compressor and pipeline installation is significant and varies considerably on the technology involved and the operational requirements. The economies of scale and impacts of future technology development are potentially significant. The IEA report CO_2 Capture Ready Power Plants (2007/2) identifies the

[46] See for example, Amec and Gastec (2006) IEA Greenhouse Gas R&D Programme Report 2006-4.

footprint of a post-combustion capture facility for a 785 MWe CCGT as 250m x 150m, i.e. 47.8m²/MW.

Using this footprint estimate, an assessment is made for each site on available land adjacent to the power station. Land outside the site fence is considered unavailable. If hydrogen can be produced offsite and the facility can be converted to run on the new fuel, the plot restriction filter can be removed.

6.3.5 Storage

Access to storage is reflected in transport cost estimates but is also a minor element in the filtering of sources. The storage filter is an assessment of the ability to easily access storage for an emitter. The possible storage of CO_2 will take the form of deep saline formations, depleted oil and gas fields, and potentially sites for enhanced hydrocarbon recovery. The storage access assessment is based on simple metrics those sites with clear practical access to clusters and/or storage sites are preferred. Those tending to be inland score lower. Those sites in areas where no storage is foreseen are marked lowest.

A typical example of a poor storage potential site would be the new Marchwood CCGT. The site is located at the top of Southampton water and running a pipeline or shipping solution in the area would be technically challenging. In addition the location of a storage site nearby on the South Coast is unlikely, given current assessments, so overland pipelines or very long offshore pipelines are possibilities.

No sites are excluded at this stage on the basis of poor access to storage alone, as this is seen as an increased cost to the generator rather than technical limitation in most cases.

6.3.6 Filtered List

The filtering of the gas-fired plant for consideration is screened over a number of parameters to eliminate plants that may be unsuitable for consideration of CCS.

The filters applied are as follows:

- Removal of industrial Cogen/CHP which is considered in the accompanying industrial report and of black start facilities
- Removal of generation facilities with emissions less than 50ktCO_2 per annum (equivalent to an IEA tier 2 source and consistent with the industry report)
- Site assessment based upon plot availability, site access for the remaining sites (i.e. for the addition of a CO_2 pipeline

The top level of screening avoids duplication with the industrial sector analysis and other sectors. For example gas turbines used for support of or the black start of coal fired generation are viewed as coal sector plant. Capture of black start is assumed to be via any CCS solution added to the parent plant.

The overall effect of filtering is to take out a relatively small percentage of the fleet (8.38 GW in total and only 2.74 GW of CCGT fleet).

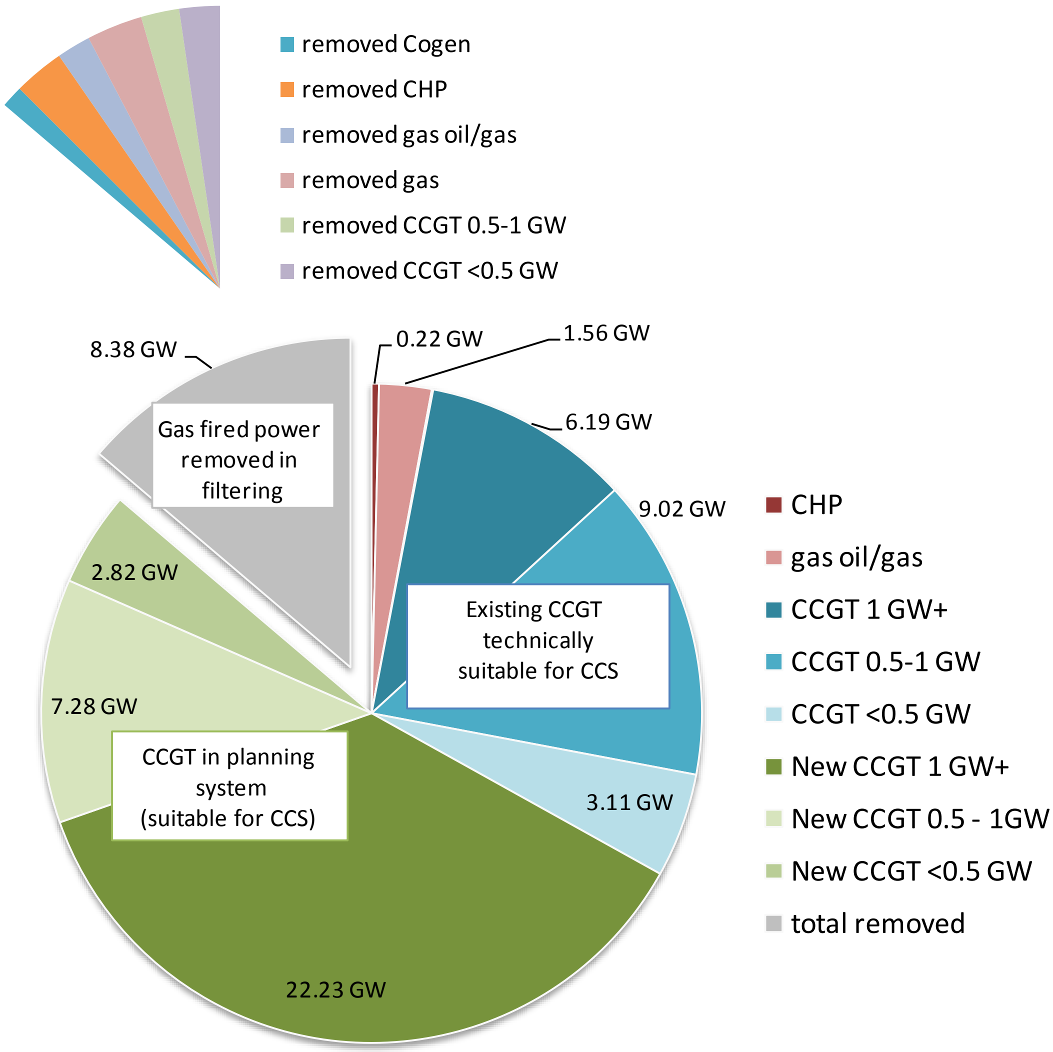


Figure 23: Distribution of plant types after filtering, and description of the wedge removed during the process (above)

6.4 Technology options for the natural gas sector

The technology options for CO_2 capture are described in the introductory section of the report and in the appendix and comprise of pre-combustion, oxyfuel and post-combustion technologies for the power sector.

6.5 Cost methodology overview

6.5.1 Cost Basis

The project team relied on three main sources of plant cost data: (1) programs with industry-validated data (2) in-house databases of costs and correlation factors and tools used in FEED studies and (3) public data in printed articles, journals, reports and books where the source data can be clearly verified.

Mid-range or typical range equipment sizes are used to provide baselines (i.e. plant costs without capture). The cost calculation therefore uses:

- Energy calculations based on AMEC's experience of acid gas sweetening and CCS
- Experienced base estimation of additional works
- Costing of additional works
- Calculation of systems costs.

Modification is made to a cost baseline of $2008, normalising the numbers using Chemical Engineering Plant Cost Index (CEPCI). We also include an 8% margin for Owners Engineer costs. The full breakdown of costs is tabulated in the Appendix, with an example shown below.

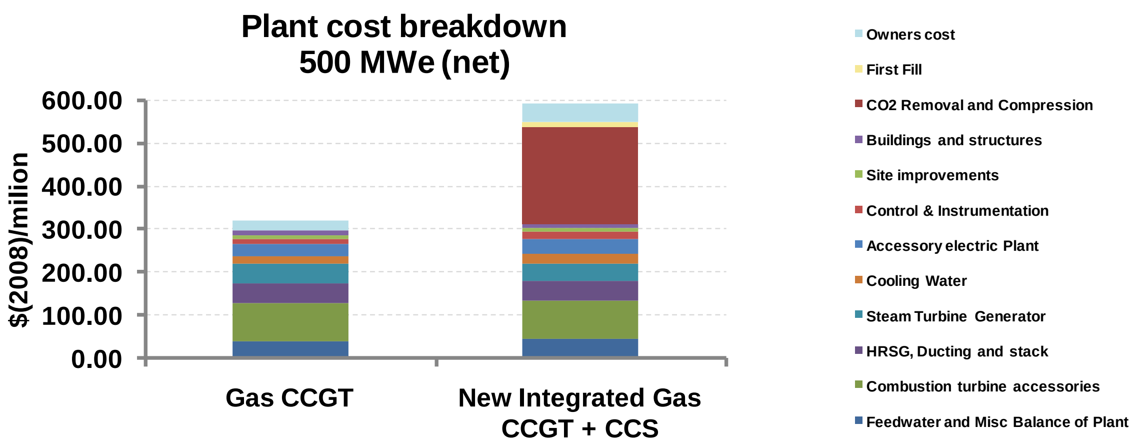


Figure 24: Illustrative capital cost breakdown for a new 500 MWe CCGT plant, and for the equivalent plant with integrated CCS

The OPEX costs are divided into fixed and variable. The fixed operating and maintenance costs are estimated using typical values from the chemical industry and for CCGT power generation and cover personnel costs and a 3% of CAPEX per annum maintenance materials charge, irrespective of load factor. Variable costs are estimated from the same sources and cover consumables (excluding natural gas) and charges for the plant and are based on typical metrics for carbon capture plants and CCGTs. Finally established tools predict the energy and parasitic power requirements with and without CCS.

6.5.2 Scaling with size of plant

The capital and operational costs are not uniform in cost per MW across the size range but rather change with plant scale. The list of CCGT plants indicates that 100, 500 and 1000MW are appropriate markers as example plants for calculation of costs per MW. For a given power station, the cost per MW of its identified size band can then be multiplied by its true gross capacity to more accurately determine cost for both the baseline plant and capture technology. The differences in costs

These sizes also allow the consideration of the complexity issues of working on large plants. This is discussed in the appropriate section.

6.5.3 Future costs of capture

Future capture costs are subject to considerable uncertainty, learning and experience of current technologies will lower the cost over time and new technology will reach maturity. Technology development will hopefully result in lower cost systems and systems with lower efficiency penalties, but cannot be guaranteed. More general market drivers, such as material and labour costs, exchange rates, competition within the market, new technology, site-specific issues, and whether the roll-out is commercially or regulatory driven will also influence costs. As an example, if regulation drives the requirement for CCS then costs may well stay robust in the face of an essentially captive market. Alternatively, positive political and economic signals may drive more suppliers to compete in the marketplace to deliver the technology, driving down costs.

The following learning rates were applied to capture technology , a description of their derivation can be found in the appendix.

Table 6: Learning rates applied to CCGT and CCS costs

Learning rate applied by year (% of 2008 cost in 2008 prices)	Capital cost of CCGT	Capital cost of CCS	Operational costs of CCGT and CCS
2030	86%	68%	96%
2050	58%	54%	89%

6.6 Retrofit to pre-2009 stock (non-CCR)

6.6.1 Technical application of CCS to non-CCR stock

The complexity of cutting into existing plant that was not designed for expansion or retrofit is well known. Experience in retrofitting of flue gas desulphurisation (FGD) under the Large Combustion Plant Directive has shown programme, cost and technology issues occur even with mature FGD technologies. Typical FGD programmes in some sources are indicated at relatively short programmes of 4-7 weeks. Practical experience however shows that the tie-in section of an FGD retrofit programme is 12 weeks, with commissioning following immediately. The impact of retrofit can be significant with major works in proximity to a live operational plant. Therefore executing enabling works during a planned shut down or alongside routine maintenance activity saves later programme complexity. Similarly, retrofit of capture plant to existing CCGT plants is expected to be technically challenging as these systems were not designed to accommodate a parallel process.

With retrofit the key issues become access to storage, access for pipelines, plot plan, density of equipment and pipe work, controls and instrument integration/expansion, electrical expansion, expansion of balance of plant systems, and provision of thermal energy.

The largest impact of retrofit is likely to be the provision of the thermal energy load to the capture plant. If the CCGT is to provide the steam for capture then the CCGT system will require modification and the operator accepts the loss in generation capacity and efficiency. One alternative is to fit independent steam provision and either capture the extra emissions or vent them and pay for the additional CO_2 emissions. The preferred option would be to capture the additional carbon dioxide.

6.6.2 Costs for non-CCR stock

In consideration of the impact of retrofit the cost the size of the CCGT has an effect. Larger installations become more integrated and complex but equally costs for components do not scale linearly with size and larger facilities can benefit from their scale.

Multiple units typically feed a smaller number of steam units common between gas turbines and integrate the ducts and stacks for example. To account for this a complexity factor is applied to the cut-in costs, increasing costs by 50% for 500MW plants and 100% for 1000MW, to the retrofit costs. These factors are derived from AMEC's experience of project delivery. The complexity factor is based on the level of access that is expected to exist, availability of pipe access and local lay down areas all need to be considered. Where access is restricted there is a penalty, rather than a saving that is incurred in the cost of tie-ins. Overall the cut-in cost increase for larger installations, however, is outweighed by the cost savings on major items which come with scale.

In costing the retrofit solution the enabling works for the project are based on typical retrofit factors applied by AMEC to retrofit of FGD and carbon capture to coal fired generation.

Operational costs for retrofit are in terms of additional resources and cost to an existing CCGT installation. The complexity factors are not applied to the retrofit of capture plant on capture ready designed CCGTs.

Table 7 Comparison of the costs of capture retrofit (non-CCR and the baseline non-CCR CCGT plant)

$2008	Gross Capacity (MW)	CAPEX($m)	Fixed OPEX ($m/year)	Variable OPEX ($m/year)
CCGT - CCS additional costs	1000	477.6	1.75	5.34
	500	306.6	0.94	2.67
	100	113.1	0.54	0.53
Baseline CCGT	1000	493.8	9.82	4.53
	500	324.2	5.78	2.27
	100	122.6	2.74	0.45
Total for plant with CCS	**1000**	971.4	11.57	9.87
	500	630.8	6.72	4.94
	100	235.7	3.28	0.98

6.6.3 Timing of retrofit for non-CCR stock

Retrofit of capture equipment will be disruptive to an operational site and require careful integration and management. The required construction time of a capture facility varies with size, however typically 12-18 months on site construction time. The overall project period is dependent on the design of the system, construction plan and the availability of both resources and equipment. Once physically complete and tested the tie-in of the capture plant is likely to be several months per unit, given physical tie-ins must be made, control and safety systems modified and pre-commissioning completed. Capture ready plants are likely, in contrast to be quicker as the tie-in points would have been located and more importantly allowed for during the permitting and design phases.

From the plant operator's perspectives the optimal timing for retrofit of capture equipment onto an existing plant will is likely to be when the plant is expected to be offline for major refurbishment anyway, and when the economics of the plant, and likely future operation (including load factor) are being reassessed (e.g. on repowering). By this stage, some of the original plant investment costs have been recovered (although costs for the new turbines and HRSG must be recouped over the remainder of the plant lifetime.

This offers an opportunity to introduce CCS to a plant, and could reduce downtime compared to retrofit at other periods if works were synchronised.

The existing stock is likely to have undergone a refurbishment cycle by 2030.

6.7 Capture ready stock

In general, measures can be implemented to facilitate the transition from conventional operation of a CO_2 emitter to a state in which the majority of the CO_2 can be captured, transported and stored when CCS ultimately is technically and commercially proven at the scale required.

A range of options to define readiness are technically available. Preparing for one technology option for CO_2 capture in detail may hamper a plant's ability to switch to an alternative option should this become preferable at a future date. Some preparations (e.g. through preparing site access and allowing additional space) remain valid irrespective of technology types. Consideration is also need for the plant refurbishment and normal maintenance programme and the ability to stage modifications during this period.

6.7.1 UK legal definition of Carbon Capture Ready

A capture ready plant is designed to be able to operate initially without capture equipment and later with capture equipment added. From April 2009 all power plants over 300MW in development or planning are required to be Carbon Capture Ready as defined by the Department of Energy and Climate Change. Legally, this involves demonstrating:

- that sufficient space is available on or near the site to accommodate carbon capture equipment in the future
- the technical feasibility of retrofitting their chosen carbon capture technology
- that a suitable area of deep geological storage offshore exists for the storage of captured CO_2 from the proposed power station
- the technical feasibility of transporting the captured CO_2 to the proposed storage area
- the likelihood that it will be economically feasible within the power station's lifetime, to link it to a full CCS chain, covering retrofitting of capture equipment, transport and storage
- make clear which CCS technology options are considered the most suitable for the proposed station

If planning is granted, the operator is required to;

- retain control over sufficient additional space on or near the site on which to install the for the carbon capture equipment, and the ability to do use it for that purpose;
- submit reports to the Secretary of State for DECC as to whether it remains technically feasible to retrofit CCS to the power station. These reports will be required within 3 months of the commercial operation date of the power station (so avoiding any burden on the operator with an unimplemented consent) and every **two** years thereafter until the plant moves to retrofit CCS.

In addition some enabling works are likely – as integrating the connection points and designing the system to accept CCS in the future is much more cost effective at the early design stage than modifying in the future.

Therefore when considering CCR-CCGT an allowance needs to be made for increased land area purchase, provision of technical studies as proof of concept documents and physical allowances in the plant.

Although difficult to assess the impact on costs, capture readiness may reduce the degrees of freedom available for plant design - and choices available for the design of a plant.

6.7.2 Costs of capture readiness

Different options for the level of pre-investment required in facilitating readiness are possible. Minimal pre-investment would involve selection of one or more potential capture technologies, preliminary design for capture facilities, allowing sufficient space, identifying approvals required. The highest pre-investment might additionally include very detailed examination of technical and economic operation with CCS with long-term agreements with potential suppliers, obtaining all consents (including for transport and storage), potentially sizing equipment for future demand, and possibly even some level of public engagement.

For this study, the costs associated with a capture ready plant and the intended fitting of the CCS portion are similar to that of the new integrated facility. Although the requirement to perform in two different configurations may reduce design choices and equipment procurement that may indirectly increase costs. The two major components, i.e. power and capture are largely identical, but the phasing of implementation means that some extra costs are associated with a CCR-CCGT unit. These are expected to include:

Table 8 Comparison of the costs of capture retrofit and the baseline capture ready plant, 100 MW plant*

	Initial cost incurred for CCR on CCGT construction (% of installed CCGT cost)	Cost of addition of capture plant in future (% of installed CCGT cost)
1. Provision for duct cut-in and diversion	Add an additional: 0.5% of capital cost for a 100MW CCGT plant (For larger systems multiply by correction factor to take into account increased complexity)	1.9%
2. Steam extraction		0.5%
3. Balance of Plant Enhancements		0.1%
4. Cooling Loops		0.5%
5. Control, Instrumentation & Electrical Integration		1.5%
6. Study work	Add £1,600,000 irrespective of system size	N/A

**The figures for a 500MW and 1000MW plant for the initial cost incurred and for the addition of the capture plant should be multiplied by factors of 1.5 and 2 respectively.*

The allowances for provisions 1-5 in the above table are made are simply the provision of space and equipment that allows expansion. In addition to this the requirements for study work under the CCR requirements. This would typically include land take, pipeline access study, safety case, consultation, constraint mapping – additional area, incremental increase of base station survey, ground survey – incremental increase on base station survey. For the additional works and the expansion of studies conducted as part of the CCGT parent plant, and allowance of £1,600,000 was made for each plant, independent of size.

Table 9 Comparison of the costs of capture retrofit and the baseline capture ready plant

$2008	Gross Capacity (MW)	CAPEX($m)	Fixed OPEX ($m/year)	Variable OPEX ($m/year)
CCR - CCS additional costs	1000	445	1.7	5.3
	500	286	0.9	2.7
	100	105	0.5	0.5
Baseline CCR CCGT	1000	500	9.8	4.5
	500	328	5.8	2.3
	100	125	2.7	0.45
Total costs for plant with CCS	**1000**	945	11.5	9.8
	500	614	6.7	5
	100	230	3.2	0.95

6.7.3 Implementation of capture retrofit to CCR

The fitting of capture plant to a CCR-CCGT should be significantly less complex than retrofitting to non-CCR stock.

The extent of carbon capture readiness can vary. Demonstrating capture readiness requires, space allowances, a series of technical considerations to be made and the capture ready case proven. The provision of space is the critical element in enabling fitting of a capture solution to a power station. The extent of further preparations at the initial build stage could also determine the ease of which capture could be fitted at a later stage. Physical tie-in points identified and engineered at the design stage allow ease of completion later or, civil works could be extended and provided to avoid re-work. These decisions whilst relatively minor could enable faster deployment of CCS.

Depending on the extent of preparation the programme for implementing capture plant can be shorter than for retrofit to non-CCR stock. Whilst the construction programme remains the same overall, preparation at an early stage would shorten the future programme. The major items, however, would still take significant time to construct, depending on technology.

Typically 12-18 months is expected to retrofit, dominated by the civil works and the delivery and construction of major plant equipment. Tie-in provisions are usually done in parallel in the construction phase for retrofit to minimise the construction period. The savings in programme come to the fore in the tie-in and pre-commissioning phases. For retrofit to non-CCR stations a period of 8-12 weeks is considered for tie-in related shut down with commissioning following on. For capture ready it would be less depending on the extent of pre-investment. Assuming just space has been allowed as required in the guidelines the tie-in schedule could decrease to 7–10 weeks.

From the plant operator’s perspective the optimal timing for fitting of capture equipment onto a CCR plant may still be to be at major refurbishment. However, the provision of CCR may allow earlier deployment as CCS as matures and becomes proven.

6.8 Integrated capture plant

6.8.1 Technical application of CCS

If the impacts of the CCS plant operating with the CCGT are considered from the first stages of design through to operation, it is assumed that the plant will have a high degree of heat recovery and heat integration to minimize the impact of the capture plant on the overall rated performance and flexibility of the CCGT.

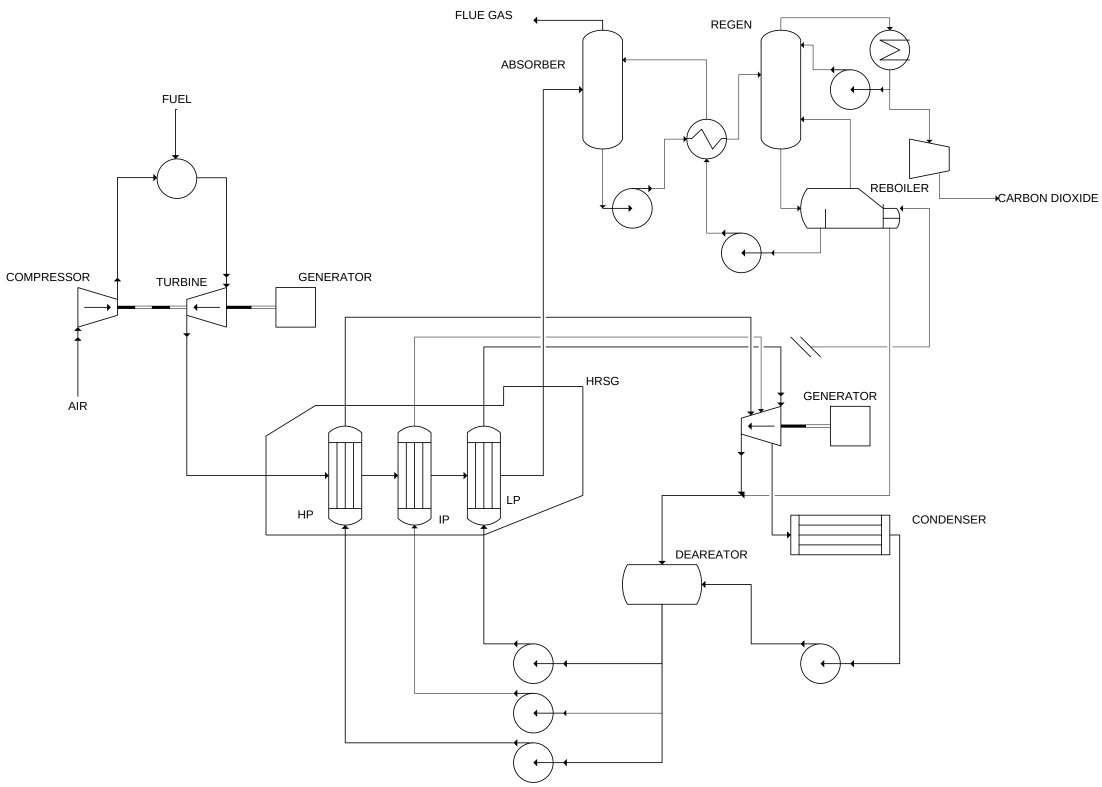


Figure 25 Engineering schematic for a CCGT facility equipped with post-combustion capture.

6.8.2 Costs

The basis for the costing of the integrated CCS and the component parts is the NETL study "Cost and Performance Baseline for Fossil Energy Plants"[47]. This study presented a robust breakdown of CAPEX and OPEX for an integrated solution, but also allows the component parts to be analysed and used to determine retrofit and CCR related costs. These costs, indexed to 2009 allow the costs associated with the other elements to be derived.

In terms of operational cost typical assessments for UK chemicals industry have been used in line with AMEC's experience. This includes the shift manning increment for a plant, plus required admin, support and maintenance personnel. This represents the fixed operational cost. The variable operational cost is derived as metrics based on the NETL report, energy consumptions are provided using assessment tools within AMEC.

Table 10 Integrated CCGT with CCS

Gross Capacity	CAPEX/$m	Fixed OPEX ($m/year)	Variable OPEX/ $m/year
1000MW	903	12	10
500MW	592	7	5
100MW	223	3	1

[47] DOE/NETL-2007/1281; Volume 1: Bituminous Coal and Natural Gas to Electricity - Final Report, Revision 1, August 2007.

6.9 Performance comparison

The impact of the addition of CCS on the performance of a CCGT plant is considered in this section. No differential is considered here between the performance offered by integrated new build facilities, CCR with CCS and retrofit of non CCR plants. In reality this is unlikely to be the case, however, no information was found to support quantification of these differences. The impact on flexibility of operation will be considered separately in section 9.

In any given year the electrical output of a power station is dependent on its gross capacity, any degradation of capacity that has occurred to date and a parasitic load. This parasitic load is increased by the addition of CCS equipment such as CO_2 compressors. The following diagram describes the potential impact of CCS addition on electrical output.

In addition the fuel required to produce this electricity is dependent on the system efficiency, which also degrades as the system ages. When a post-combustion CCS system is added to a facility, the overall system efficiency can be expected to fall as steam is used not generate power but to drive the capture plants regeneration section. Power provided to the capture and plant and the compression system also reduces that available to the grid for export, thus lessening the overall efficiency of the parent plant.

The calculation used to obtain the fuel required by a plant and subsequently the associated CO_2 emissions can be described by:

(Load factor x 8760 x net capacity)/ net efficiency = fuel requirement (MWh)

Fuel requirement x CO_2 intensity of fuel x (1-% emissions captured) = CO_2 emitted

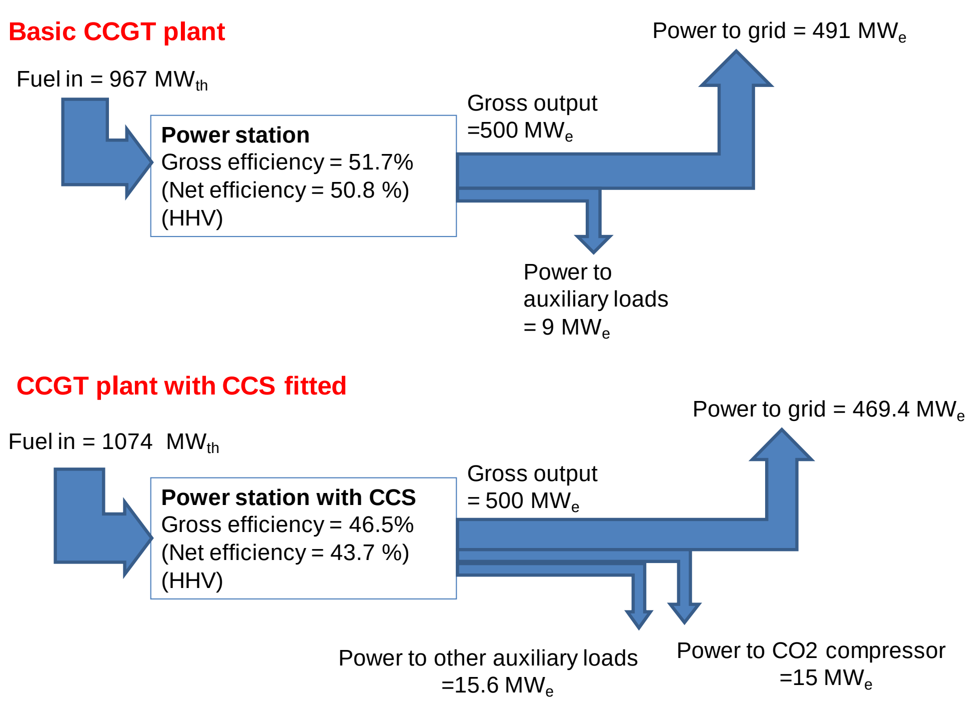


Figure 26 Sankey (energy flow) diagram for a power plant with and without CCS fitted

The following table summarises assumptions used in subsequent analysis:

Table 11 Summary of assumptions for performance characteristics

		Baseline CCGT	CCGT with capture
Generating efficiency, net of auxiliary power	% HHV	50.8%	43.70%
degradation of capacity	% per 8000 hrs of operation until overhaul every 3 yrs	0.8%	0.80%
Degradation of efficiency	% per 8000 hrs of operation	0.50%	0.5%
% of emissions captured	%	0%	90%
Parasitic load (Gross to net) per MW gross	MW parasitic per MW gross	0.018	0.06

6.10 Summary

A database of existing and planned gas power fleet was developed. (N.B. Industrial gas-CHP systems were considered in the industrial report and are not discussed further).

The remainder of the fleet comprises units which can be differentiated in terms of their CCS relevance. Once technical filters are applied, such as site suitability for capture and transport, and overall emissions, 53 existing and planned CCGT units remain relevant for CCS. Only 2.7GW of CCGT capacity was excluded during filtering.

The costs and performance of CO_2 capture remain will remain highly uncertain until after capture demonstration projects have been operating for a few years, and will also depend on overall market drivers for engineering and construction costs. Although various degrees of overall CCS readiness are technically possible, based on current UK legislation the additional investments required for capture readiness have been and will be relatively small.

Reference values for the prices and efficiency penalties of baseline CCGT plant, capture ready CCGT plant, retrofit of capture equipment to capture ready plant, and new build integrated CCGT plant are provided as well as assumptions surrounding performance characteristics.

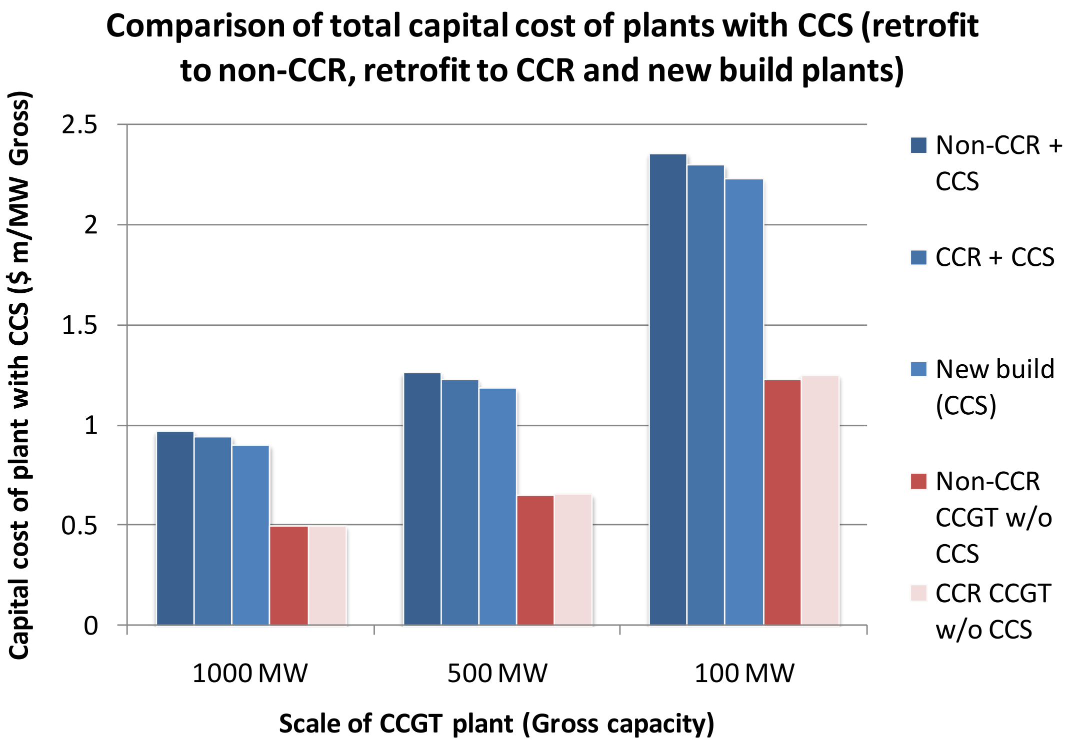


Figure 27 Comparison of total capital cost of plants without CCS, and with CCS

The difference between the original plant investment in a baseline CCGT plant and CCR CCGT plant is minor compared to the capital outlay for CCS. Overall the capital cost of CCS retrofit is comparable to the cost of the original plant investment in all cases. The slight additional cost on plant construction for a capture ready plant is offset by cost savings at the retrofit stage so there is a small net benefit to preparing for CCS in capital cost terms ($26,000-$57,000/MW). This assumes that appropriate preparation was made in the preliminary stages.

A new build plant, with integrated CCS also sees a small saving ($42,000-70,000/MW) compared to the retrofit alternatives.

7 Technical potential for CCS in the natural gas sector

7.1 Factors influencing technical potential

To simplify examination of the economic potential of CCS, it is helpful to first define a realistic technical potential. In this study, the technical potential is defined as the total potential after high level filters have been applied to exclude those sources in the database which are either not relevant or where CCS is not technically feasible. At this stage plant economics are not considered. The following factors impact the technical (and later analysis of the economic) potential.

7.1.1 Total CCGT fleet GW capacity requirement

The overall size (in GW) of the gas power sector[48] obviously dictates the technical potential. Therefore, the first sensitivity which has an effect on uptake in the power sector is the projected demand for growth in gas power fleet capacity. Here two scenarios are applied to the power sector modelling representing higher or lower total gas capacity by 2030. The behaviour of the system as a whole, and therefore demand for gas power is outside the scope of this project. The scenario total gas demand was therefore provided by CCC.

A second obvious driver is the rate of CCS technology development which, combined with the available gas fleet, defines the total technical potential for CCS in terms of GW of installation.

Models were developed of the gas fleet, accounting at high level for new build, refurbishment and mothballing at sites to meet an overall target capacity demand. These are described in section 7.2.

7.1.2 Technology readiness

A number of technologies for CO_2 separation are already commercially available, although mostly these are at smaller scales than would be required for capture from large power plants. There are intense efforts to develop demonstrate these capture technologies at large scale, develop capture technologies with improved performance (e.g. reduced efficiency penalty), and to demonstrate the full chain of capture from a power plant, transport and storage. CCS technology will need to be demonstrated at large scale on a CCGT facility before it achieves the status of 'proven' technology.

"Best Available Technology" (BAT) is a commercialisation indicator used to indicate if a technology could (or should) be adopted. In this context "available" requires the technology to have been demonstrated successfully at a commercial scale and in an economic environment which is similar enough to that of the target plant. Demonstration of CCS at commercial scale on coal plants will provide some increased security for the natural gas sector. The operational parameters of natural gas fired power stations are, however, different enough in terms of energy requirements, flue gas concentrations, and integration that a demonstration meeting these requirements on a gas plant will very likely required before the technology can be determined commercially ready.

For the gas sector, we use two example technology readiness dates:

[48] At the request of CCC, the future gas power fleet capacity is here treated as an input.

- **Early**: Which reflect the earliest practicable availability given the requirement for demonstration and pre-commercial deployment phases, not only of capture but also of suitable transport and storage routes. The commercialisation date for this scenario is assumed to be 2020, so that any capture ready or new build plant can be fitted with CCS after this date.

- **Slow**: This assumes that the pre-commercial deployment phases are more problematic and that capture, transport and storage reach commercial readiness ca. 10 years after the earliest date (i.e. 2030).

Technology readiness dates are used as a trigger for investments in capture. No investment in commercial deployment is allowed before the readiness date, however we do allow decisions regarding capture to be taken immediately at the readiness date. The asset specific construction time then defines when the asset, with capture, is on-line. There is assumed to be a minimum 5 year delay for the introduction of CCS on older non-CCR stock, as legislation filters through.

It is recognised that the choice of technology readiness does affect other variables within the model. Most important is the technology cost; specifically the assumptions about the learning rate for capture. Problems with deployment will interrupt the assumed cost reduction trajectory. For transparency we have assumed a single learning rate trajectory.

The CCGT capacity requirement and technology readiness parameters have been converted into CCGT with CCS deployment scenarios shown below:

	Gas power capacity	
Technology Readiness	Medium – 40GW in 2030 (high wind penetration)	High – 45GW in 2030 (medium wind penetration)
Early (2020)	Medium early	High early
Late (2030)	Medium late	High late

For each scenario, the technical potential is converted to an economic assessment of potential using CO_2 price trajectories and wholesale fuel prices provided by DECC[49]. A sensitivity regarding CO_2 prices and fuel price is also carried out.

7.1.3 Build rate

The technical potential will be constrained by the realistic build rates possible for capture, transport and storage infrastructure. This will be determined by many different factors including:

Technology and design development - Elimination of unnecessary or conservative design, troubleshooting on existing plants, and improving understanding of operational parameters will

[49] Communication on DECC Fossil Fuel Price Assumptions, update to spring 2008.

reduce construction and implementation time for each plant. This should allow build rate to increase through time if other factors do not constrain deployment.[50]

Engineering resource availability – Some stakeholders have voiced concern about the future availability of UK engineers with sufficient experience to deliver major projects such as CCS. This issue is not CCS-specific however and has been discussed throughout the power and chemicals industries. At present, the average age of engineers is on the rise, with an insufficient number of young people starting training to meet future power sector demand. Developing the skill base needs to be started a minimum of 10 years in advance (to allow for a university degree and generation of sufficient experience for an engineer to work on such a project). This issue is recognised in other power sectors such as the nuclear industry.

Many European companies, however, now have offshore or low-cost centre engineering centres in global locations to provide resource that is not available in the EU or US market places. We therefore see this factor having a minor effect on overall build rate.

Industrial capability to deliver equipment and materials – Lead times for major equipment can be as long as several years. An initial restriction of market capability to manufacture key items (packing, compressors, fans), may increase delivery times in a high deployment market, delaying jobs or adjusting the project length. This bottleneck may disappear if manufacturers have time to ramp up for demand and foresee a sustainable market.

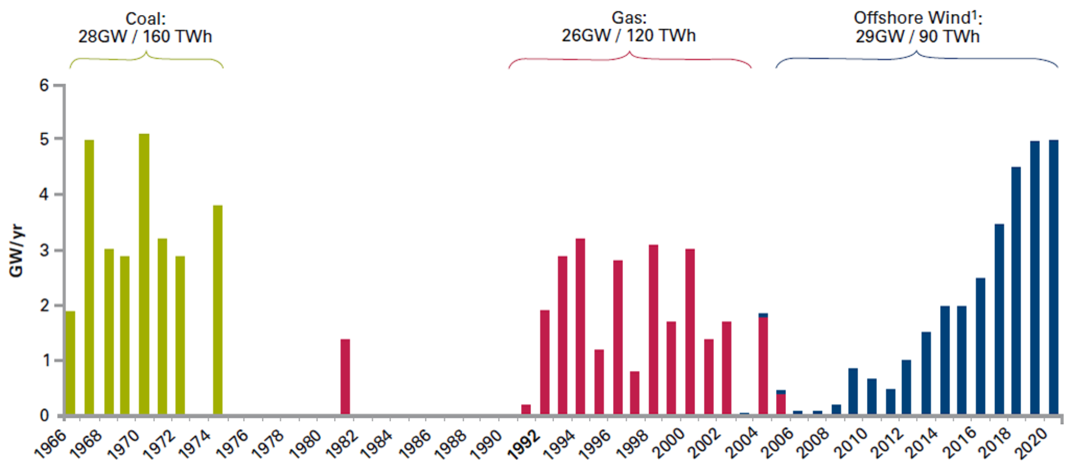
Modularisation/pre-assembly - deployment of technology in standard sets or licence packages reduces cost and increases efficiency of implementation, reducing build time per plant

Availability of finance – CCS infrastructure is highly capital intensive, and the ability to fund this will depend on the wider financial markets and the attractiveness of CCS investment relative to other investment strategies.

Overall the build rate for commercially proven CCS technology remains a significant uncertainty. In this study we use historical build rates of gas plants as a proxy for a maximum build rate, peaking at around 3GW per annum. Higher build rates observed for coal are partly representative of the larger typical installation size. As discussed previously, the average size (GW) of installation in the gas fleet is also predicted to increase in the coming years.

In the years after commercialisation, build rate capability is likely to be significantly below 3 GW per annum. Previous studies have assumed a 1 GW per annum build rate[51]. The CCC currently assumes 1 GW/yr to 2030 rising to 2GW/yr for the period to 2050 in internal modelling work.

[50] Standardisation of infrastructure units and operational parameters may accelerate their approval by buyers, regulators and other stakeholders.
[51] Powering the Future, December 2009. Mapping our low-carbon path to 2050. PB Power



[1] Effective TWh of annual new offshore wind power is less than coal or gas due to lower load factor

Source: LEK Consulting, Renewable Energy Framework March 2006, BCG Analysis

Figure 28 Historic coal and gas capacity additions, and forecast offshore wind additions, courtesy of LEK Consulting©

7.2 Stock model

To quantify the changes in technical potential over time, a stock model was generated of existing and planned capacity, as described in the previous section. The extent of repowering and new build were selected to match the required GW of gas fleet demand over the period 2010-2050, according to the scenario, where scenario 1 reflects *ca.* 40GW of CCGT capacity and scenario 2 achieves *ca.* 45GW of capacity by 2030. It was assumed, for simplicity that:

- All plants have a 40 year life, with a refurbishment (i.e. replacing the combustion turbine, HRSG and steam turbine generator) after 20 years
- When new capacity is required, it is built upon a site where a gas power station has previously existed but since been closed. The new build has the same capacity as the previous power station.
- Where multiple sites are available to choose from, sites for larger power stations are preferentially selected. This is designed to reflect the move towards larger facilities on the network through time.

In reality the picture is more complex, for example, after 2019 legislation allows for larger systems and a wide range of factors will determine the fate of individual plants. It was not, however, feasible in this work to predict new site locations, or assume existing sites could accommodate additional capacity.

The resulting stock models are shown below:

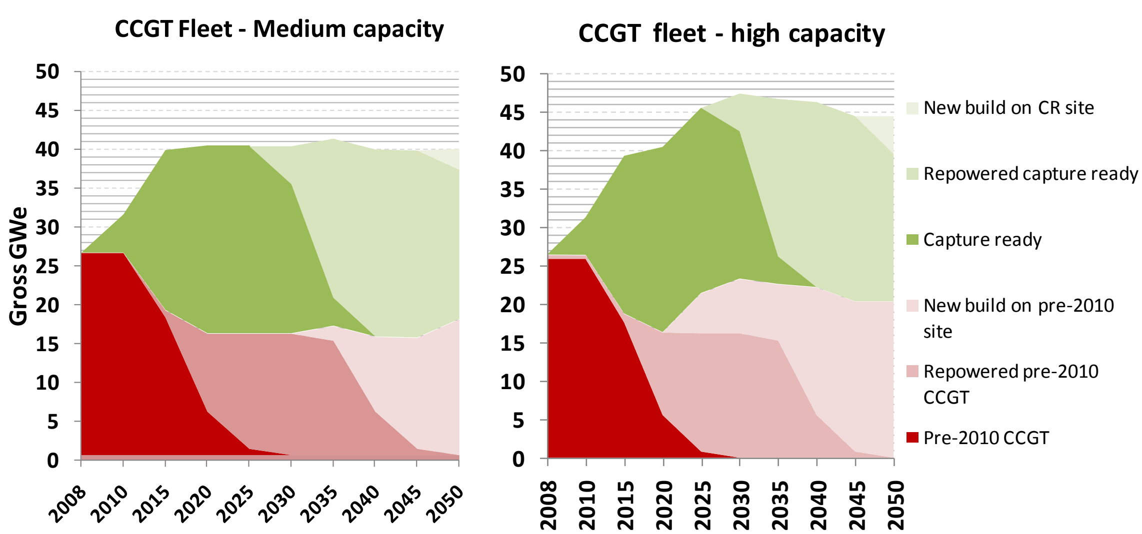


Figure 29 Stock model for high and low gas capacity scenarios.

The graphs above are taken as inputs to subsequent analysis.

7.3 Technical potential

This stock model can be translated into a maximum technical potential by applying a technology readiness date and build rate constraint as shown in the diagram below and by removing plants identified as unsuitable for CCS in Section 6. Only 2.7 GW of CCGT plant existing today was determined unfeasible for the addition of post-combustion capture kit on the grounds of space, access and storage[52] in the previous section. All such stock, however, is assumed to be removed from the system by 2050 and is likely to be operating at the lowest load factors over the 2030-2050 timescale.

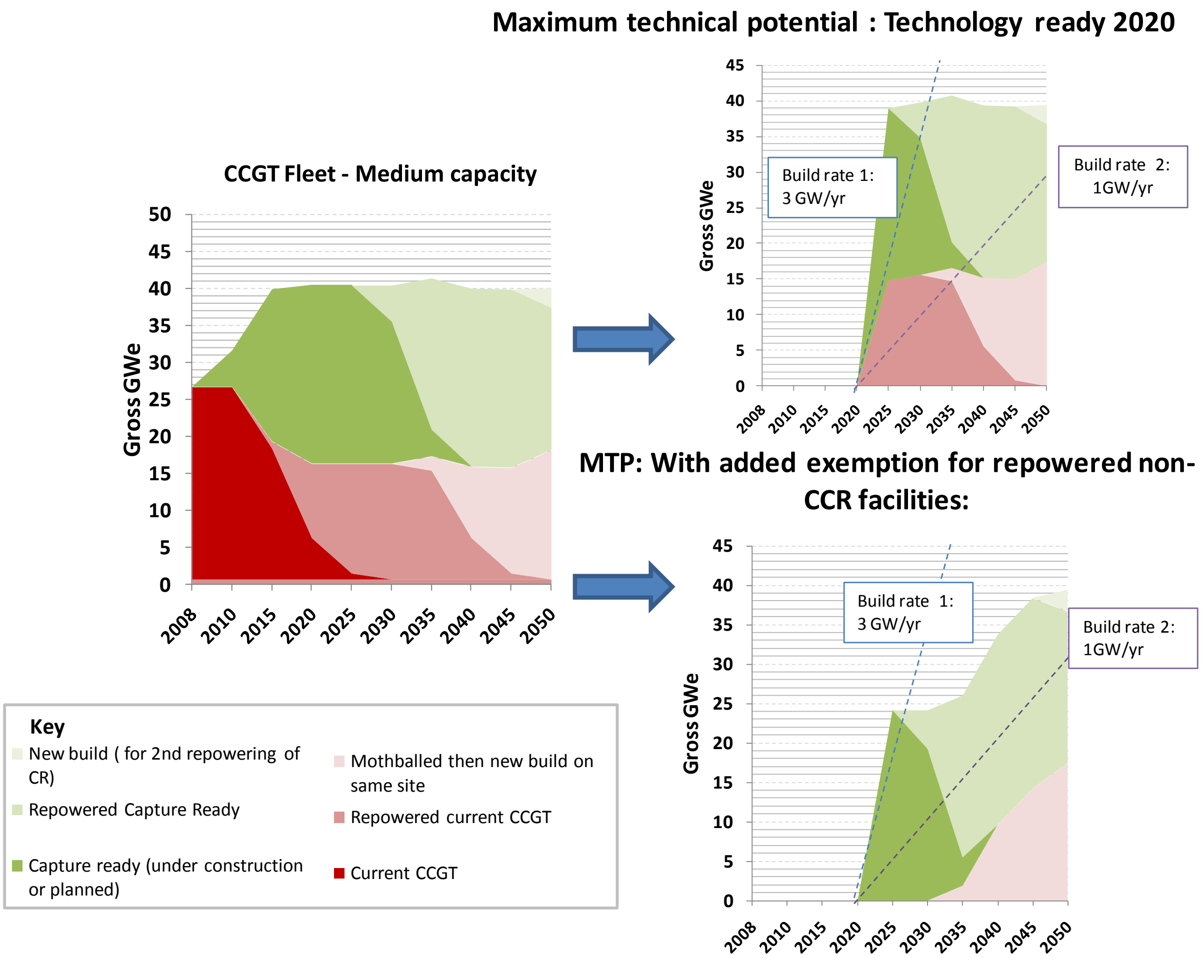


Figure 30 Estimating the maximum technical potential for CCS based on a technology readiness date of 2020.

By 2050 all stock is either re-powered capture ready plants or new build replacements (with the exception of a small amount of black start and similar facilities excluded from this model), and therefore technical potential approximately equates to the natural gas powered fleet at this time, if the build rate of 3 GW/year is achieved. At a lower build rate (1 GW/year) the technical potential corresponds to more than 75% of overall capacity.

[52] This plant could, however, still have potential to switch to operation on hydrogen, with off-site production and capture.

The technical potential for uptake in the period from 2020-2050 is entirely defined by the technology readiness date and build rate over the period.

8 Economic assessment of CCS

8.1 Methodology for economic analysis and key factors

A wide range of factors drive investment decisions for individual power plants and portfolio generators[53]. In this chapter we explore how the costs of electricity generation change on addition of CCS. We make the assumption that the vast majority of drivers and constraints remain the same between a CCGT plant and one fitted with CCS, and we do not consider issues such as risk management or portfolio balancing. Consistent with other analysis for the CCC, we have examined the levelised cost of electricity, i.e. used a simplified discounted cash flow for a CCS plant with and without CCS to establish potential for the market to adopt the technology and to assess, at high level, the likely impact on costs of electricity generation should CCS be adopted by the gas power sector. The discounted cash flow takes into account the following:

Table 12 Summary of assumptions for cash flow

Parameter	Comment
Capital costs	Specific to the size and type of plant and year of build, determined according to the methodology in section 4.
Build periods	Study assumes 1 year construction period for CCS during which there is a 12 week shut-down for non-CCR plants, and 10 week shut-down for CCR. CO_2 capture, for simplicity begins in year 2.
Fixed and variable operational costs	Specific to the size and type of plant and year of build and whether or not capture technology has been fitted.
Net capacity and efficiency degradation	As a plant ages, its net output capacity decreases through time. Here it is assumed to degrade at 0.8% per annum. As a plant ages it also faces a drop in efficiency from its systems until they are replaced at the time of refurbishment. This is assumed to occur at a rate of 0.5% per annum.
Refurbishment	Occurs after 20 years of operation, plant operates at a reduced load factor for the first year after refurbishment or major construction works.
Transport and storage costs	If capture technology is fitted, a charge specific to the plant is levied on captured emissions for transport and storage. See section 3.3

[53] See for example Eds. M. Grubb, T. Jamasb, and M. G. Pollitt (2008) Delivering a low carbon electricity system – technologies, economics and policy. Published by Cambridge University Press.

It is assumed that the overhaul schedule for maintenance is not affected by the addition of CCS and occurs every 25,000 hours of operation. The impacts of plant refinancing, taxes, depreciation, technology risk premium, and decommissioning requirements are not considered.

In addition the following variables are fixed, for a given scenario:

- **Load factor** for the chosen plant, fixed for a 20 year period
- **Fuel prices**, which vary through time according to DECC wholesale price predictions[54], see appendix, assuming HHV values.
- **A CO_2 price** for all non-captured emissions which varies through time according to the DECC CO_2 price trajectories[55]

These variables have a major impact on the levelised cost of energy from the plant (see Figure 32 and Figure 33). The levelised cost of energy is calculated using a weighted average cost of capital (WACC) or real discount rate of 10% and is determined over 20 years of operation (i.e. on refurbishment a plant's economics are assessed afresh)[56] for the plant with CCS[57]. This is compared to a similar plant without capture (i.e. applying the same load factor for the particular plant).

The levelised cost of energy is only one of many metrics used in power market investment appraisal decisions. The power purchase agreements and project risk profile will also be important for both independent power producers and portfolio generators. Portfolio generators will also consider the overall risk/reward profile of a *portfolio* of investments in different technologies[58].

The LCOE, however, provides a useful metric for policy makers to begin evaluation of the relative merits of generation investment. Notwithstanding issues on risk and portfolio management, investment in capture can be modelled as occurring when the LCOE of the plant with capture is lower than the equivalent plant without, assuming no change in load factor for the particular plant. The CO_2 price in the year the investment decision is made is used to calculate the LCOE of the asset in the baseline[59]. This represents a lack of foresight from the decision-maker, who must also account for the risk of the CO_2 price trajectory decreasing, rather than increasing over the period.

8.1.1 Impact of load factor and fuel price on LCOE

For a conventional gas plant the levelised cost of energy is dominated by the cost of fuel for the plant. The load factor of operation has a key impact on the overall LCOE and in our analysis, as it decreases the LCOE is driven upwards as the fixed costs (i.e. capital and fixed operational costs) become an increasingly large component of the overall cost (see Figure

[54] Communication on DECC Fossil Fuel Price Assumptions, update to spring 2008.
[55] In accordance with the industry report
[56] In this analysis both the cash flow and MWh have been discounted.
[57] The same discount rate is used for CCGT with and without CCS, for consistency with the assumption of commercial maturity.
[58] F.A. Roques (2007) Technology Choices for New Entrants in Liberalised Markets: The value of operating flexibility and contractual arrangements, for the International Energy Agency.
[59] Note the fuel price is flat over the period 2030 to 2050 in forecasts provided by DECC so there is no impact of foresight.

31). The absolute fixed costs remain the same, however they must be split over a reduced number of MWh.

In addition, low load factors increase the difference between the baseline plant and the equivalent plant with added capture technology as the additional capital cost for the latter becomes increasingly important. For a given CO_2 price, CCS may be economic over the baseline at high load factors, however, this is likely to reverse as load factor decreases.

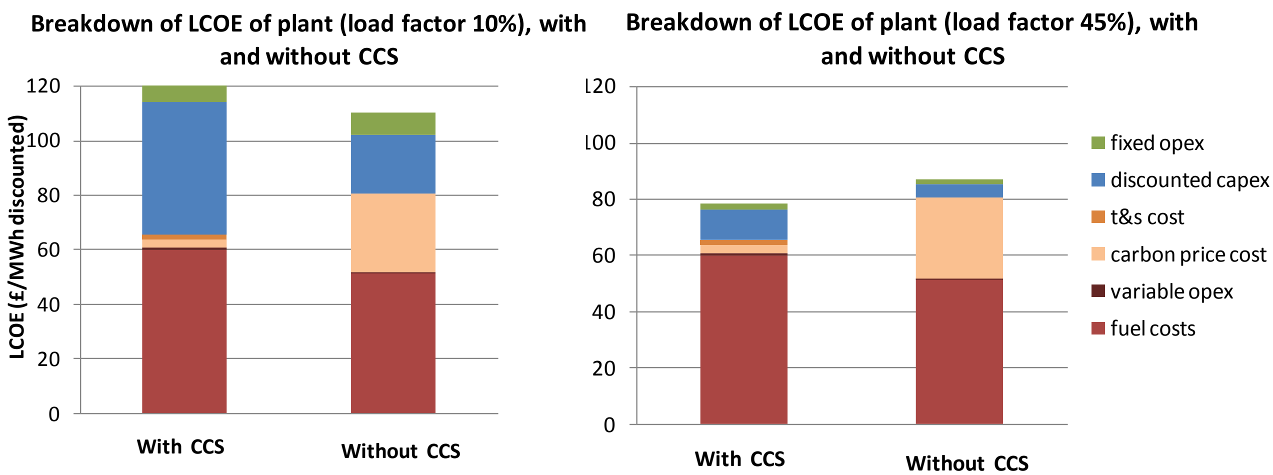


Figure 31 Breakdown of levelised costs of energy for a refurbished plant with and without CCS, under two different load factors. Carbon price £76/tonne.

The fuel cost section remains the same in both load factor scenarios as this is expressed in cost per MWh produced.

Under DECC scenarios out to 2050 CO_2 prices also have the potential to become a large part of the levelised cost of energy for CCGT plants without CCS. CO_2 prices between £100 and £300/tCO_2 will drive investors to build any new CCGT plant with integrated CCS, or to refit a capture-ready plant with capture.

The figure below shows the strong dependence on the LCOE for CCGT plant with and without CCS on the load factor and CO_2 price in the period around 2030. At a low price of carbon, the economics are insufficient for investment in CCS to occur. As the CO_2 price increases to the medium 2030 value of £70/t, all plants with CCS with load factors above 25% have a *lower* LCOE compared to plants without CCS. At the high 2030 CO_2 price, all plants with a load factor above 15% could install the technology.

Until the CO_2 price exceeds a value whereby CCS is preferable at all load factors, the number and locations where CCS is economically favoured will depend on the distribution of load factors.

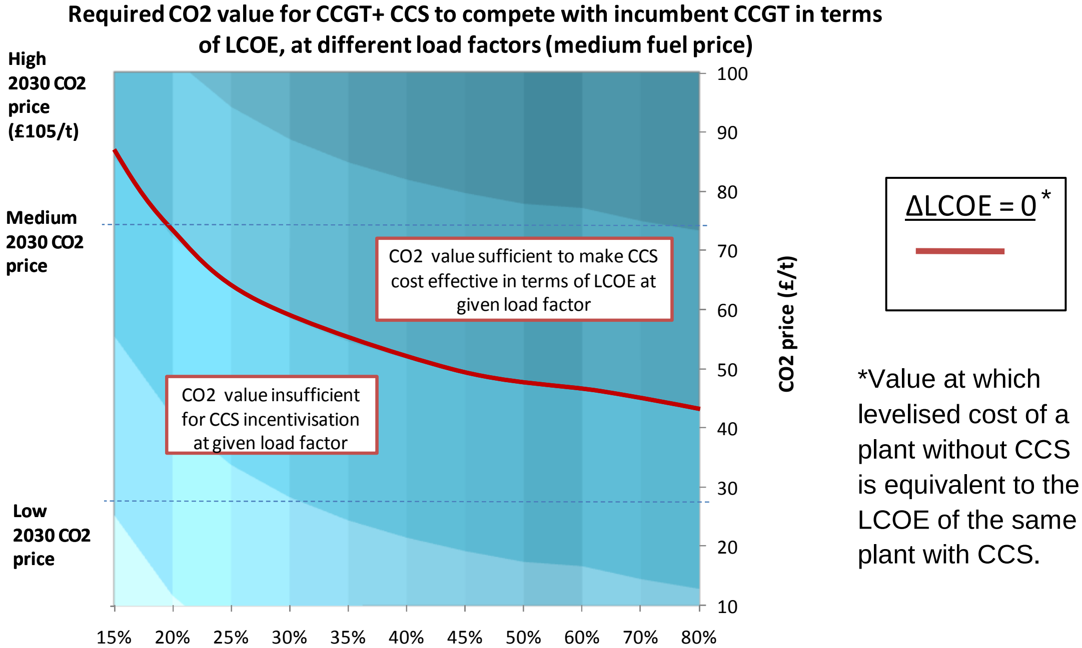


Figure 32 CO_2 value required for the LCOE of a refurbished plant with CCS to equal that of a plant without, for a given load factor.

Clearly the position of the curve is sensitive to the modelling assumptions. A lower fuel price reduces the CO_2 value required for a plant with a given load factor to have equal levelised costs of energy, with and without CCS.

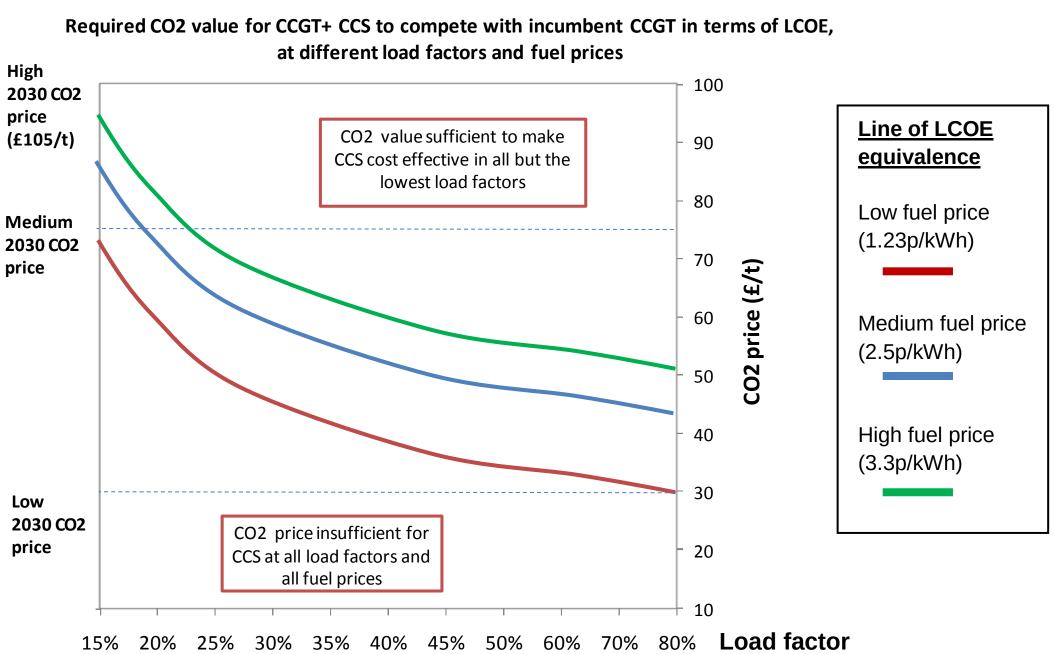


Figure 33 The impact of fossil fuel price on the CO_2 value required for the LCOE of a refurbished plant with CCS to equal that of a plant without, for a given load factor

8.2 Load factor distribution among the stock

The distribution of load factors throughout the stock in 2030 was provided by CCC for use in the project and is shown by the curve below:

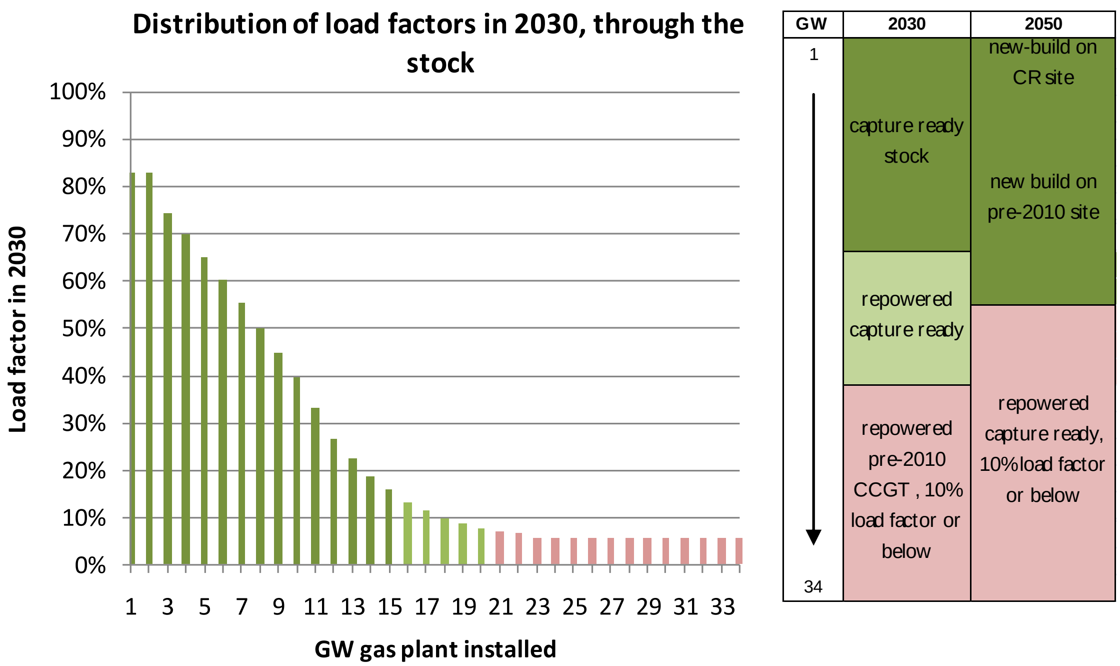


Figure 34 Load factor distribution amongst the 2030 and 2050 stock

Load factors are distributed among the stock according to the age of the plants concerned (i.e. the most recently constructed plants operate at the highest load factor, with recently repowered plants taking the next tranche and the oldest repowered stock assuming the lowest load factor of 10%). The load factors were distributed at random to facilities within each of the categories shown. This work represents a preliminary analysis and is an area where further study is recommended.

Due to the lack of data, we have assumed that the distribution profile of load factors in 2050 is assumed to be the same as that in 2030. This is a major assumption, however, it is beyond the scope of this project to predict load factors in 2050.

It is assumed, to simplify the analysis, that a plant operates at constant load factor across each 20 year section of its life. In reality new stock is continually appearing and readjustments are likely to occur in order to deliver the same TWh energy demand. Plants repowered in the interval 2030-2050 move into the 10% load factor category, and are replaced by new build to keep overall TWh as constant as possible.

8.3 Applying economics across the fleet

Uptake of CCS by a plant is assumed to be cost effective on plant refurbishment at any time beyond the technology readiness date provided the CO_2 price and fuel price ensure the LCOE for CCS is lower than without.

The following graph represents 21 capture ready plants, arranged in order of load factor (increasing from left to right) and shows the difference between the LCOE of the same plant with and without CCS.

The load factor distribution across the fleet is the primary factor driving the differences between the plants. In addition, the size of plant also has an impact, with smaller plants requiring higher load factors to achieve an equal LCOE, due to their higher capital costs per MW (see section 6.10). Finally this graph includes a charge to the power station for transport and storage of CO_2 specific to the plant's location, on all plants with an LCOE.

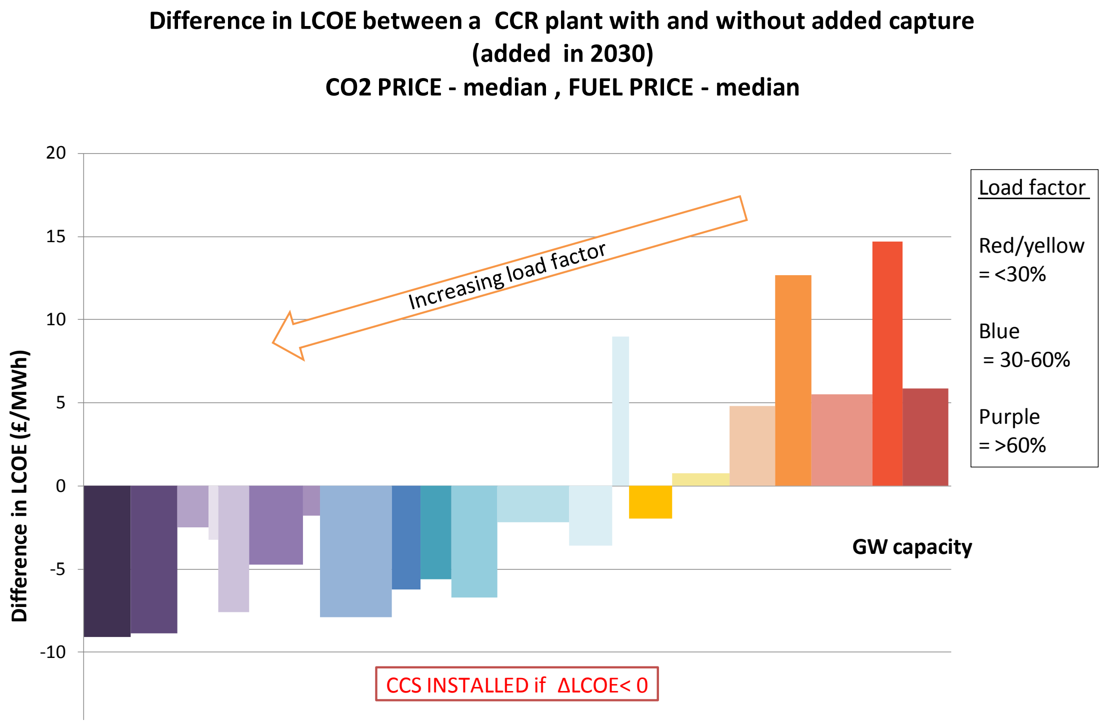


Figure 35 Difference between LCOE of plants with and without CCS for 21 capture ready plants, arranged in order of load factor.

8.3.1 Case – decisions made on refurbishment/construction

It is recognised that on CCR plants in particular, uptake of CCS may occur prior to refurbishment, however, here we review the use of refurbishment as a trigger for a re-evaluation of a plant's business model, and a decision whether or not to install CCS. This represents a case designed to stagger uptake and reflect aversion from the industry to installing a technology outside their core area of business.

In this case, on refurbishment or on construction for new build, the LCOE for the plant with CCS is compared to the LCOE of the plant without CCS, and the lowest cost option is selected.

The following graph shows the difference in LCOE at the time of refurbishment (labelled) for all repowered capture ready fleet. All plants above the line do not install CCS as the LCOE for a plant with CCS is greater than for a plant without, conversely, all plants below the line do install CCS.

Note that plant owners are not assumed to have foresight of CO_2 prices in the baseline (i.e. the CO_2 price in the year of refurbishment is used to calculate the LCOE) and fuel prices are assumed flat over the period 2030-2050 in accordance with figures from DECC. This results in the difference between the figure below and Figure 36. A sensitivity analysis allowing foresight of CO_2 price has been run, which results in the installation of CCS on refurbishment becoming cost effective for all plants shown below on the basis of LCOE over their 20 year lifetime.

The graph below is based upon medium CO_2 price and fuel price trajectories. Through time the load factor required for CCS installation drops as the carbon price increases.

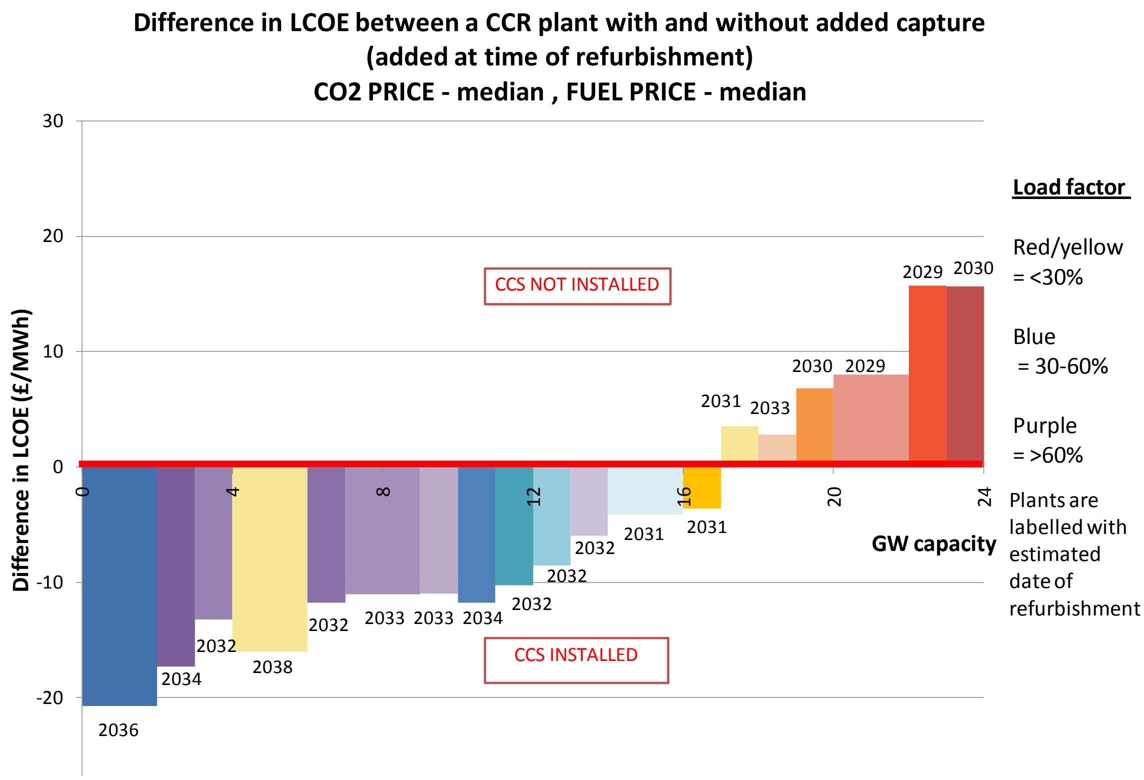


Figure 36 Difference in LCOE for CCR plants with and without capture, at time of refurbishment.

Differences between the plants are therefore generated due to the aforementioned factors, (i)load factor, (ii)size of plant and (iii) plant location shown in Figure 36 and (iv) by the plant refurbishment date and CO_2 price at that time which influences Figure 36 .

In the baseline scenario (medium early) where technology is commercially ready in 2020, all plants on the above graph could install CCS. In the case of the late scenario, where the refurbishment or build date precedes technology readiness (2030) for some plants, a plant is assumed to continue without installing capture technology until the next time a decision is made. In this case it will continue its life without CCS at a low load factor.

8.4 Economic uptake from scenarios for deployment

The following section analyses uptake of CCS if decisions are made on refurbishment (i.e. assuming uptake is driven by adoption of technology with the lowest LCOE, which takes into account CO_2 price).

Results are presented for the four scenarios as described in section 7 assuming the medium fuel price and CO_2 price assumptions.

Results for the most and least favourable combinations of fuel price and CO_2 price (low fuel price/high CO_2 price and high fuel price/low CO_2 price) can be found in the appendix.

8.4.1 GW capacity

In the following results table early commercial technology readiness for capture, transport and storage (TR) is assumed to be 2020 and late 2030. The technical limit is defined by the build rate limit (set as 3 GW/year in line with historical CCGT build) and by the technology readiness date.

CCS deployment (GW)	Year	Technical limit (early)	Technical limit (late)	Early TR, 40 GW	Late TR, 40 GW	Early TR, > 45 GW	Late TR, > 45 GW
Total GW deployed under medium fuel price, medium CO_2 price	2030	30	0	0	0	5.1	
	2040	40-45	30	14.9	14.905	31.1	15.8
	2050	40-45	40-45	40	26.508	39.7	22.6
Implied build rate (GW/yr)	2030-2040	3	3	1.5	1.5	2.6	1.2
	2040-2050	1.5	1.5	2.6	1.2	0.9	0.9

Table 13 Summary of uptake if refurbishment acts as trigger, under different scenarios.

8.4.2 Emissions profiles

Emissions profiles corresponding to the GW of capacity installed in each scenario have been calculated and are shown on the next page. The difference between emissions with and without CCS represents the amount of CO_2 abated in a given scenario. The remaining emissions are a combination of:

- Plant without CCS fitted where energy generated has an average CO_2 intensity of 0.358 kg/kWh
- Plant with CCS fitted where energy generated has an average CO_2 intensity of c.0.05 kg/kWh (based on a 43.7% net efficiency and 90% capture rate)

The load factor of operation of each plant type determines overall CO_2 emissions from the fleet.

Table 14 Summary of CCC grid CO_2 intensity targets

TARGET DATE	Target Grid CO2 intensity	Worst Case gas fleet intensity	Best case
Present	560 g/kWh	358 g/kWh	358 g/kWh
2030	<100 g/kWh	358 g/kWh	300 g/kWh
2050	<50g/kWh	200 g/kWh	50 g/kWh

The following graph shows the average CO_2 intensity of energy generated from the gas fleet through time as a result of this analysis, for different scenarios under the medium fuel price, medium CO_2 price setting. The technical potential is also displayed to indicate the lower bound for emissions per MWh generated.

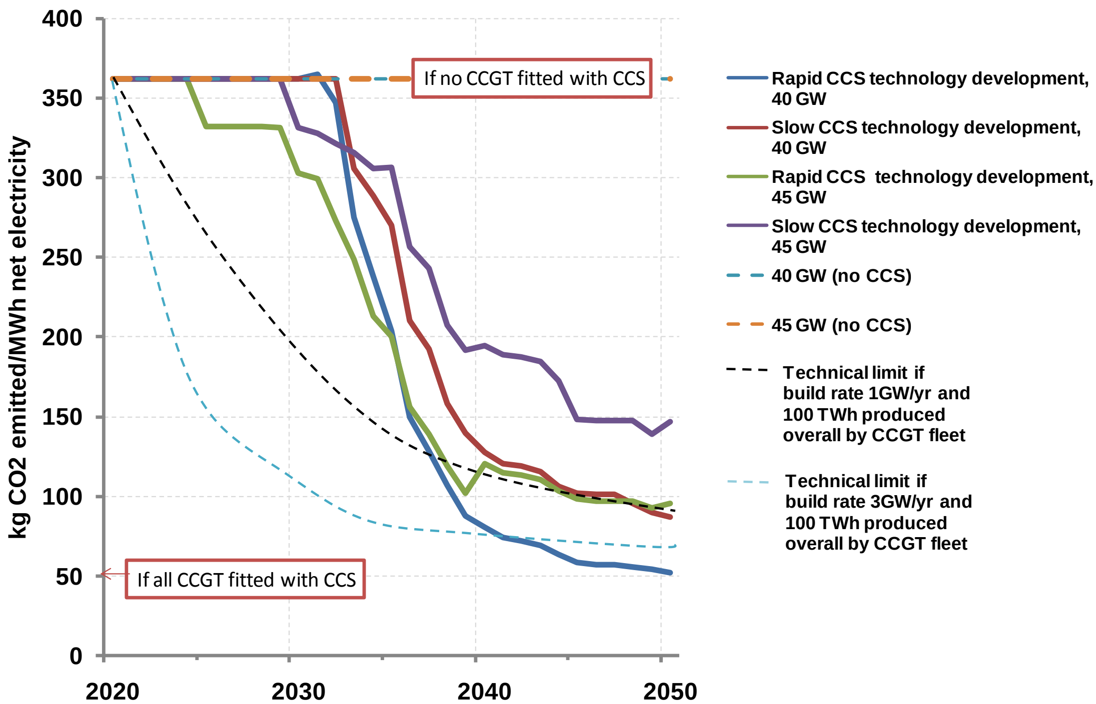


Figure 37 CO_2 intensity of energy generated from the gas fleet through time, under various scenarios. The technical limit for technology readiness in 2020 is also shown.

Average intensity from the gas fleet approaches the minimum (i.e. c.0.05kg/kWh) in the 40GW, early deployment scenario, generating only 5 $MtCO_2$ emissions from the entire fleet for c.100TWh, compared with emissions of 38 $MtCO_2$. In the worst case, (i.e. late deployment/high GW scenario) average intensity only reaches 150 kg/kWh by 2050

Overall the scenarios presented are consistent with the historical build rates of CCGT and estimated technical limits for build rate.

9 Flexibility

One important dimension to power plant flexibility is the ability to respond within a short, defined timeframe, to scheduled or unforeseen changes in demand and/or supply. These may result from:

- Consumer demand variation (e.g. daily and seasonal variation)
- Renewable resource variation (e.g. wind strength)
- Power station outages and emergency situations

In this section we discuss, at high level, the increasing need for flexibility in the grid system (including from natural gas fired power generation), and how the ability to deliver such flexibility is impacted by the addition of carbon capture kit to a plant. We examine the impact of flexible operation on capture, transport and storage of CO_2, particularly where there is a trade-off to be made between energy generation and CO_2 removal.

Flexibility can also be used to describe other parameters, such as the ability for a plant to switch fuel. Where CCS has a direct impact, these are discussed at the end of the chapter.

9.1 Operational need for flexibility

At the plant level, generators must ramp up and down to match scheduled bilateral energy contract obligations which promise to deliver energy from specified time, for a defined duration based on predicted demand. The following image shows an illustrative example of the output of one gas plant over a particular day:

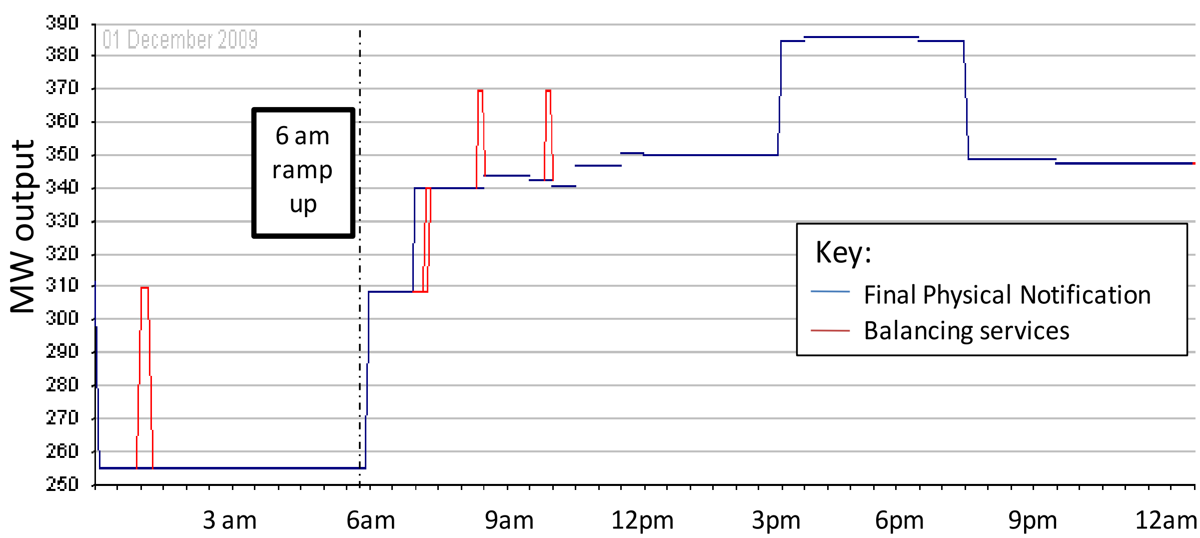


Figure 38 Example output of a gas power station module across 1 day, including the final expected output (FPN) in the absence of the balancing mechanism and output including balancing services required (shown in red).

The morning increase in demand for example is a regular occurrence and occurs from 6 am on a weekday (although only some of the fleet will be deployed to deliver it). According to National Grid, the increase in demand can be 14GW at a rate of 80-100MW per minute[60].

As shown in the graph above, CCGTs are able to ramp rapidly (e.g. in the example above the plant ramps at 11MW/minute). At peak times, a large amount of generation ramps at its maximum rate. The addition of more wind generation capacity on the system can also result in high ramp rates for remaining plant (for example as turbines are switched off during a storm). National Grid anticipates ramp rates of up to 11GW/h in 2020 on rare occasions. The ability of the fleet with CCS to deliver predicted ramp rates from regular or anticipated demand or generation changes should therefore be considered as well as the ability for the fleet to deliver balancing services required by National Grid. Impact on ramp rates of an individual power station is examined in section 8.4.

Self-despatched energy generation ramps to meet predicted half-hourly profiles and National Grid then ensures generation meets minute by minute demand

In general terms, the network operator's requirements can be sub-divided into:

- **Response requirements** (delivered within 30 seconds) designed to maintain frequency within a narrow band (49.5-50.5 Hz) as far as possible as total generation changes
- **Reserve requirements**,(delivered within minutes to hours) sources of extra power (either generation or demand reduction) to deal with unanticipated changes in demand or generation.
- **Emergency requirements–** including a fast start service (i.e. to start in an emergency from cold) and the maximum generation service whereby National Grid gains access to capacity outside the generator's normal operating range

An operator may be paid to be available over a certain timeframe (paid in £/MW per hour available) and if the service is utilized (in £/MWh delivered).

In practical terms a plant's ability to offer balancing services or to deliver its contract obligations is affected by its ramp up and ramp down rate and by economics of operating around its stable export limit (i.e. the minimum operating output for a given power station). In addition a plant has a specified notice to deviate from zero (NDZ), which is the notification time for a unit to start importing or exporting electricity). Provided it takes less than 90 minutes to produce the first MWh of electricity, no special dispensation is needed for the station[61].

In the current market, a plant may over or under-generate compared to their contracts, in which case a plant is paid the system sell price (SSP) or is billed the system buy price (SBP) by Elexon. A plant owner may choose to over-generate if constrained by technical limitations (e.g. begin ramping earlier if the plant has a lower ramp rate) in order to meet its requirements in subsequent periods, provided the system sell price is sufficient to cover the cost of fuel and variable maintenance.

Future requirements

[60] Operating the Electricity Transmission Networks in 2020

[61] BM start up is required for plants whose NDZ is greater than 90 minutes, for example some cold start oil power stations

The balancing services requirements will change over the period to 2050 with:

- greater penetration of variable renewable generation, particularly wind power
- changes in demand and demand forecast error (e.g. through the addition of electric vehicles to the system or through changes in user behaviour)
- and changes in plants(losses and gains, system size)

The following describes National Grid's predictions for their system requirements in 2025, assuming 34GW of wind on the system (as part of their "Gone Green Scenario"[62]).

Table 15 Summary of balancing services and estimated requirement from National Grid

Category	Service	Delivery timescale	Capacity required in 2009/10	Average capacity required in 2025
Response	Primary	Increase in generation within 10 seconds	631 MW	1111 MW
	Secondary	Increase within 30s	1021 MW	1583 MW
	High	Decrease within 10s	422 MW	434 MW
Reserve	Fast	Start within 2 minutes, ramp rate >25MW/min		
	STORR	4 hour ahead increase in generation, at least 3MW	4300 MW	7734MW

National Grid foresees a step change increase in *response* requirements as a result of the introduction of larger power stations (1800MW) in 2019. There is also a slight increase (particularly for the maximum requirement) in relation to the addition of wind on the system as system inertia decreases.

The increase in 4 hour ahead operating *reserve* requirement (STORR) from 4.3GW today to an average of 7.7GW and maximum of 17GW by 2025 is more dramatic and occurs primarily as a result of increased wind capacity in the system with an additional slight step change as larger plants are introduced in 2019. STORR is set such that there is a 1 in 365 chance that demand could exceed available generation.

9.2 Flexibility of capture technologies

The flexibility of capture plant is dependent on the capture technology choices, which we consider here in turn. For all technologies, CO_2 compressors and other such parasitic loads are required. The turn down of compressors with electric drives is likely to be possible. Arrangement of multiple compressors would allow turn down as low as 20% of designed throughput (see appendix).

In all cases, there will be a trade off between cycling the equipment to match demand and shortening its lifetime with associated increasing maintenance costs.

[62] The future Severn Barrage development also has potential to significantly impact future requirements of Balancing Services but is not included here.

Post-combustion

The application of post-combustion CCS will affect some aspects of a power plant's technical performance but not others. About two thirds of the CCGT's power stems from the gas turbine, whilst the remainder stems from the steam turbine and heat recovery steam generator (HRSG). The gas turbine is able to start-up rapidly and is not impacted by the addition of capture and therefore the addition of CCS would not affect the NDZ of a plant or the ramp-up rate in the very early stages. It will also not affect the stable export limit of the plant. The steam cycle, however, is directly affected by CCS, particularly when the plant is in a transient state. Steam is extracted from the cycle and the capture fluid and regeneration column need to be warmed and brought to temperature. We will therefore consider the impact of CCS on ramp rates and start up later in this section by reviewing a worst case scenario of start-up from cold.

Once the plant has reached steady state, as mentioned above, parasitic loads could be reduced or the capture plant could be turned off completely; in the latter case with no extraction from the steam cycle, plant efficiency and output will increase.

In terms of the performance of the post-combustion capture plant, there are operational issues surrounding flexibility, and the percentage of emissions captured varying as the power plant passes from one state to another. The current post combustion technology comprises two circulating fluid columns. There are operational limits on the turn down for such equipment items and start-up issues, although these are well understood in the process industry. Residence times are also critical but more at the upper limit of operation than at the lower operating regime. As it stands for flexibility at operational rates the columns require little alteration, for larger swings in emission flow rates the flow through the unit may be altered, but for efficiency rather than operational reasons. A critical issue is the balance of the gas and liquid flow rates to ensure smooth build up to operational flow and output stream quality.

The other flexibility option for capture plants is to design the system as a split capture plant in process trains. Splitting the capture plant costs increase but so does flexibility in that flow can be diverted to one train only, whilst the other is dormant and brought on line only when the flow exceeds a single train's capacity. This may add cost but gives greater ability to deal with lower flow ranges and the flexibility that may come from CCGT's that employ multiple GT units.

Future technology developments

Ideally a static system, one that does not rely on the parent power plant for a process driver, such as thermal energy, may prove to be the best enabler. Such systems as solid absorbents operating in temperature or pressure swing operation would likely have a low impact on the CCGT start-up times. These systems are used currently in dehydration applications in natural gas plants, and are virtually instantly available at full load.

Pre-combustion

Overall the flexibility of pre-combustion capture with natural gas on-site is limited by the production of syngas from the steam methane reforming and shift reactions. Without syngas storage mechanisms a pre-combustion plant is limited to options such as load shedding and changes in firing (e.g. reduction of post-firing of syngas in the steam cycle or co-firing with natural gas). Start up of syngas production could severely limit flexibility, but the facility can be kept operational if a market can be found for the hydrogen when not required by the power facility. In addition, availability of the SMR and ASU units may be lower than that of the power station, also resulting in the need for storage facilities, unless natural gas firing is allowed for limited periods. Provision for natural gas firing must be made at the stage of turbine selection if this is to be used as an option for flexibility as different turbines have varying specifications for the combinations of hydrogen and natural gas they are able to accept.

Flexibility options for syngas production include allowing the syngas production to approximately follow the load profile of the plant, or to provide a buffer to allow for daily variations. The ramp rates for syngas production will limit the ability to match the load of the power plant.

Consideration also needs to be taken into account of health and safety issues surrounding the storage of CO/H_2 laden syngas in large quantities.

Where hydrogen is produced off-site, transport storage mechanisms (such as line packing) can be implemented.

Oxy-firing

For oxy-firing, flexibility is limited by the Air Separation Unit supplying the oxygen. In the absence of an oxygen store or ability to run on air instead of oxygen, start up times are a concern. Initially commercial oxy-fired units are likely to be provided with the ability to switch to air-firing if required to reduce risk, alternatively liquid oxygen could be stored to aid ramp up or for unplanned outages of the ASU. Switching to air-firing could allow a power station to increase output as the production of oxygen is a major energy requirement of the cycle.

After switching back from air firing, demonstration experiments show CO_2 concentrations returning to oxy-firing levels after approximately 1 hour.

9.3 Flexibility - sub-minute level (Response)

At present all power stations are required to offer 10% of their capacity as response in the UK. This is more than most generators would wish to provide, and approximately 80% of the stock is compliant. Wind, nuclear and some “technically broken” power stations are exempt at present, though there has been some success with wind offering primary and secondary response delivery on the continent.

Response requirements are at present c. 600MW over the year, which represents less than the 10% requirement. This is delivered by, in order of preference, coal, large (over 300MW) pumped storage sites (Dinorwig and Ffestiniog, Foyers and Ben Cruachan), and CCGT. Wind has not to date provided primary and secondary response in the UK, although there has been some success on the continent.

It is unlikely that any further pumped storage units will be constructed in the UK, and therefore if current exemptions continue, more response must be delivered by the fossil fuel fleet. The magnitude of this requirement is small, however, it is worth examining whether the fleet with CCS would be able to deliver the service requirements in the same manner as it does today.

Impact of CCS on delivery

Typical factors that affect a CCGT when it is not operating at design specification (e.g. during transient states) include ambient air temperature and pressure, humidity, cooling medium temperature, electrical corrections and part load and are known as offload design issues. Such issues are not likely to affect the performance of a capture plant over very short time periods (i.e. seconds) due to the inertia of the chemical plant.

Ambient air temperature and cooling water temperature would directly impact on post-combustion, but would normally be designed into the plant. Variations in the CCGT performance caused by these factors typically affect the performance of a CCGT by a few percentage points from rated behaviour. At such a deviation capture processes are unlikely to be affected.

Therefore a capture plant, or the addition of it to a CCGT, is unlikely to affect the ability to respond to frequency response or short term conditional changes relative to the baseline CCGT plant.

Impact of response on CO_2 captured

Short term changes in the output from a plant are likely to be dampened by the inertia of the chemical plant system. If they are of significant duration (i.e. minutes to hours) these may be reflected in the capture rate of the plant.

9.4 Flexibility minutes to hours (Reserve requirements and normal ramp up/down to deliver contracts)]

Turning off capture kit from steady state

It is important to note at this stage that power price volatility occurs over short timescales, which is not matched by volatility in CO_2 price. Prices during peak periods may therefore be such that, on economic grounds a generator may for example, plan to switch off capture kit or shed load (e.g. from CO_2 compressors) for a particular half-hourly period unless legislation mandates otherwise. From a simple economic cost basis capture kit will be switched off if:

Electricity revenue (utilization price for balancing services) > CO_2 payment + fuel price + variable opex costs

In this study, the electricity price would, for example, need to exceed £75/MWh in the 2030 half-hourly period, and £122/MWh in the 2050 half hourly period, under the medium fuel price and fossil fuel price scenario[63].

In addition storage mechanisms may permit a generator to for example, store solvent generated at times of peak demand to be stripped later to allow load to be reduced during peak periods. This comes at a price requiring additional land, solvent, containers and equipment and viability depends on the value of offering this service. Finally there are health and safety issues surrounding storage of high volumes of amines which will need to be resolved is significant buffers are to be implemented.

[63] Analysis on this topic has also been carried out by Haines and Davidson, using the system sell prices from Elexon. Designing Carbon Capture power plants to assist in meeting peak power demand (2009).

It is possible that a generator may be able to capture value from the ability to deploy this additional capacity without turning off capture kit or resorting to energy storage mechanisms by offering a maximum generation or similar service. The Maximum Generation Service is defined as the ability to deploy capacity outside normal operational limits and is valued highly by the network operator. In an emergency case, it is estimated that a crash-stop of the capture system would be possible within 5 minutes, allowing an extra 56 MW of output from a 400 MW plant.

Recently National Grid also invited tenders for long term reserve services, allowing generators to submit offers for 15 years of delivery. This is a new service aimed at encouraging investment and no bids have been received thus far.

Ramp up/ramp down

The addition of CCS may impact the typical ramp up and ramp down rates of a plant, depending on the thermal state of the system.

There are essentially three start-up modes that a CCGT may have to endure:

- Hot – where a plant has been idle for 8 hours or less
- Warm – where a plant has been idle for 48 hours
- Cold – where a plant has been idle for 120 hours or more.

The colder the start, the more thermal cycling and stress on the equipment.

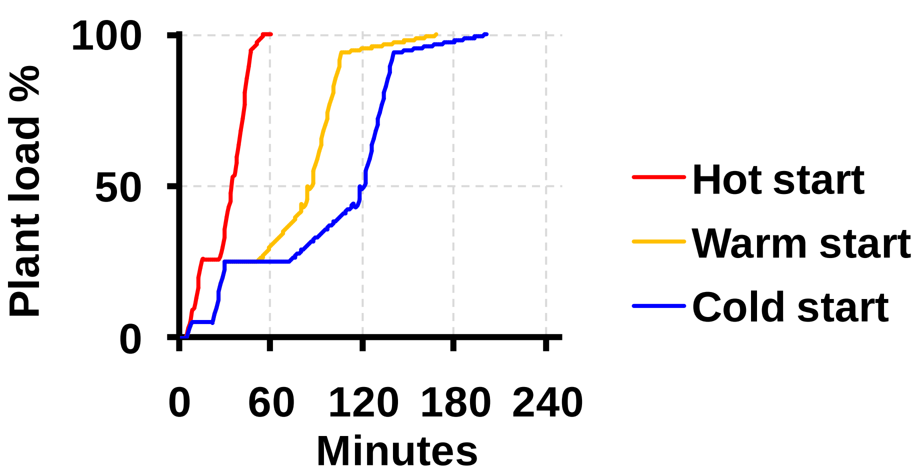


Figure 39 Impact of start type (hot, warm, cold) vs. time to maximum load for basic CCGT systems.

Table 16 Start up characteristics

	Time to working temperature	Occurs today	Starts before extensive maintenance
Hot	40-60 minutes	e.g. Within weekdays	8000
Warm	80-120 minutes	At the end of a weekend	2200
Cold	120-170 minutes	After planned and unplanned outages	<800

The cold start represents the worst case scenario for understanding the impact of CCS. In cold start the chemical plant also starts from cold and reduces the complexity of the dynamics. During start-up like the CCGT steam turbine and HRSG, the capture fluid and regeneration column need to be warmed and brought to temperature. Throughout operation the use of amine scrubbers requires significant thermal energy for the regeneration step.

The impact of CO_2 capture equipment on start-up is complex and unproven. There is intense academic and industrial research on how to minimise possible impacts[64] and this work therefore represents preliminary analysis.

We consider two options for start-up:

1) The capture unit can be brought online at the same time and pace as the CCGT, abating carbon dioxide from start. This 'coupled' approach will draw steam as it thermal energy source away from the steam turbine and HRSG, delaying warming, prolonging the start up period. CO_2 is then captured during start up, although the percentage of CO_2 captured may be lower than when the system is at full capacity.

2) The capture unit offline ('uncoupled') until the CCGT has completed its normal start-up cycle. Once at load the capture plant is brought online. This allows the generation side to react quickly to peak load, then lose steam to the capture plant. This delays the capture of CO_2 and no capture occurs until the plant reaches the required load.

A further option of solvent storage could allow a capture system to capture CO_2 without the regeneration column operating. This ability of the solvent to load CO_2 may require additional storage and increased equipment investment. The solvent can then be processed when the system is at full load and the grid requirement is decreasing. This would have cost implications, and potentially health, safety and operational issues.

The following graph considers options 1 (coupled) and 2 (uncoupled), and the CO_2 penalty or energy penalties associated with each.

[64] See for example, The IEA Greenhouse Gas R&D Programme on operating flexibility of power plants with CCS, available at : http://www.ieaghg.org/index.php?/20100113168/workshop-on-operating-flexibility-of-power-plants-with-ccs.html

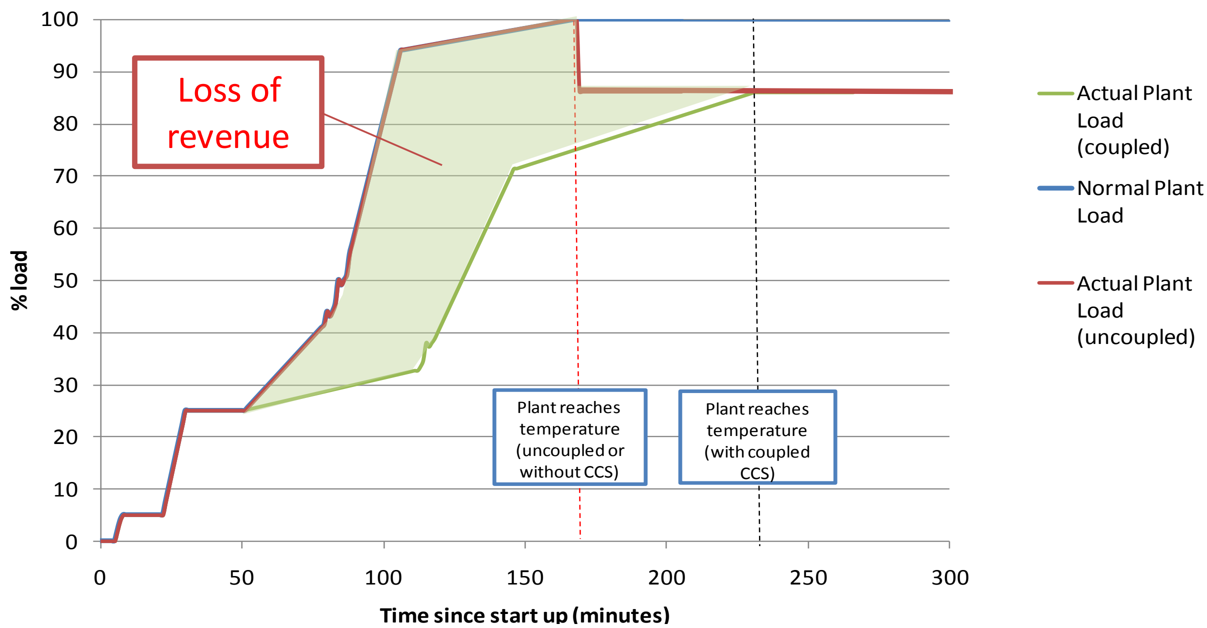


Figure 40 Cold start-up post-combustion capture plant with and without coupling.

In the uncoupled case, up to an additional 70 tCO_2 are released over the start up period at a cost of £4900 in 2030 (medium CO_2 price), however, an extra 250 MWh are generated and ramp up rates[65] after the first 25% are higher (an average of 3.75 MW/minute over the remaining period in the uncoupled case versus less than 0.5 MW/minute for the next hour and then average of 2.7MW/minute for the coupled scenario). Where cold or warm start-up is common, i.e. for peaking power plant, the proportion of CO_2 vented at low load factors could be significant, and undermine the economic case for CCS. This represents an upper bound as it does not take into account reduced capture rates at the start as the stripper is not at temperature.

In the simplest case, the CO_2 price must be sufficient to cover the cost of the lost MWh of generation, however, where the value of reaching peak output as quickly as a non-abated station has significant value in the market place that offsets the cost of emitting. Factors such as the reduced ramp-rate, limit the competitiveness of the plant for ancillary services. In addition CO_2 captured, may be of a reduced purity during the start-up phase of the plant.

Some stakeholders consulted during this report expect regulators are unlikely to allow start-up without capture, however, there is a precedent in Europe for the start-up of plants without flue gas desulphurisation.

CO_2 capture rates

Work has been done to date to attempt to understand the performance of capture under part load operation of coal plants. Further work is required to understand the implications of part-load operation of a CCGT plant on performance.

[65] A generator can define 3 ramp up rates during start up, and no rate can be zero.

9.5 Flexibility - Transport and storage

Although there is some concern over transport and storage flexibility it is important to note that the hydrocarbon industry already deals with large seasonal variation in demand. We therefore consider points specific to the transport and storage of CO_2, and experience related to this. It is important to note, however, that any system must be sized to meet a set level of demand, flexibility will result in under-utilisation of this capacity. This is likely to be detrimental to the economics of the pipeline or storage infrastructure unless users are required to pay for capacity in advance, irrespective of use.

Transport

The ability of the transport system to accommodate changes in CO_2 captured (whether changes in volume, pressure or purity) must also be considered. CO_2 has limited compressibility, limiting the option to linepack[66]. If the CO_2 is being transported by pipeline, then the pressure of the system must be maintained in order to keep the CO_2 in the specified (i.e. typically dense or supercritical) phase. Impurities impact the pressure and temperature conditions required to reach the supercritical phase and therefore are also of primary concern for CO_2 flow, as well as for the general maintenance of the pipelines themselves.

As the capture plant starts up capture and regeneration will not run efficiently to deliver CO_2 with an appropriate entry specification for transport systems until the correct temperature profile is reached. If this impurity level is of significant concern, it may result in CO_2 not being captured during the initial start-up of the capture plant.

There is also concern over mixing capture streams from different processes and plants (i.e. post combustion, pre-combustion and oxy-firing) which may have different impurities and water content. The entry specifications of a pipeline network must be carefully constructed.

Storage

Experience from the In Salah CO_2 injection facility in Algeria gained from 2004 to present, suggests that storage sites are able to accommodate variation in injection rates of CO_2. The site is injecting into a saline formation in carboniferous sandstone, similar to the sandstones found in the southern North Sea and has seen injection rates in wells vary from less than 200 mmscf per month to around 900 mmscf per month.

There is no evidence to date that variations in injection rate impact the final storage available in a given reservoir, although further work is required in this area.

9.6 Fuel flexibility

Gas turbines currently run on uniform standard natural gas in the UK from the National Transmission System. Depending on specification and warranty agreements, some turbines can operate on syngas, a mixture of methane, hydrogen and carbon monoxide often from refinery or gasification processes or some types of oils. Modern IGCC systems will operate on hydrogen-based syngas with the carbon dioxide removed for example.

[66] See for example, Element Energy (in press) for IEA Greenhouse Gas R&D Programme: CO_2 infrastructure – global analysis.

Repowering or the construction of a facility brings an opportunity to allow for future fuel flexibility for a power station, allowing turbines to be selected that would be capable of running on syngas in the future. The type of turbine selected becomes important, as different turbines are able to accept different blends of syngas and natural gas. The equipment must be specified to accommodate different firing conditions, as well as the imposed limits on availability due to higher levels of washing, inspection and maintenance. Firing on heavy oils for example will lead to faster soot fouling and hence an increased maintenance tempo. Firing on hydrogen brings different issue to the fore such as the high temperature and low energy output per kilogram.

9.7 Flexibility Summary

Flexibility is already an important concern for existing CCGT plant owners and operators and improving flexibility is a priority for suppliers as increased renewable generation joins the grid.

The ability to provide very fast response (< 5 minutes) is unlikely to be changed significantly between CCGT and CCGT with post combustion CCS. There is some concern in relation to the ability of pre-combustion power station to meet UK response requirements unless syngas buffers or co-firing can be deployed.

Post-combustion CCS does not prevent a power station from offering 4 hour ahead reserve services, although reduced ramp rates may make their offer less competitive in the marketplace.

The Maximum Generation Service and new offerings by the National Grid to encourage technology investment (such as their long term STOR launched last year), may offer alternate revenue streams for CCS to cover the impact of a reduction in net output and efficiency.

This study also identifies that if post-combustion capture is fully coupled to plant start-up (i.e. all emissions during start up are captured), there is a potential for a slower ramp rate from a warm or cold start – resulting in at least 40 minute or hour delay respectively in reaching maximal load relative to an ‘uncoupled’ scenario where emissions in this period are not captured but instead are vented to the atmosphere. Reduction in ramp rates reduces the ability of a plant to take advantage of rapidly changing energy prices and may reduce competitiveness with non-CCS plants when offering reserve services.

The flexibility of CO_2 compression, individual pipelines and integrated pipeline networks, and storage facilities to manage variable throughput requires further analysis. However evidence to date suggests that these can be designed for.