THE POTENTIAL FOR REDUCING THE COSTS OF CCS IN THE UK

INTERIM REPORT

PUBLISHED BY THE

UK CARBON CAPTURE AND STORAGE

COST REDUCTION TASK FORCE

NOVEMBER 2012

LONDON, UK

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EXECUTIVE SUMMARY

Introduction

Electricity generation in the UK is on the brink of a radical transition driven by the Government's ambitious carbon reduction targets, and retirement of ageing coal, nuclear and gas plant. A majority of the current base load generation fleet will require replacement before 2030, and if the UK is to reach its 80% GHG emissions reduction target by 2050, significant decarbonisation of the entire energy sector will be needed at the same time.

The twin requirement to replace ageing plant, and to reduce CO_2 emissions, can be turned into an advantageous infrastructure investment in Carbon Capture and Storage (CCS), to enable long-term use of fossil fuels in a carbon-constrained economy, alongside renewable and nuclear power, and to generate "Green Growth" for the UK economy.

Energy system modelling by the Energy Technologies Institute suggests that successful deployment of CCS would be a major prize for the UK economy, cutting the annual costs of meeting carbon targets by up to 1% of GDP (or around £42 billion per year) by 2050.

The availability and scale of high quality geological storage beneath the UK continental shelf in the North Sea and East Irish Sea, and the UK's well established offshore oil and gas expertise means that CCS represents an opportunity to drive UK economic growth, to retain and grow employment opportunities, to protect and grow the UK's manufacturing base and to gain significant competitive advantage in manufacturing costs over other countries in Europe. This gives the UK a unique position within Europe.

There is also an important and valuable opportunity to exploit the symbiosis between CCS and CO_2 EOR in the UKCS, adding significant revenues to a number of projects and extending the productive life of several UK oilfields. This is a key driver for CCS in the US and Canada, and it may be possible to achieve analogous benefits in the UK.

And in the longer term the UK might choose to sell a storage service to other EU countries to reduce their own emissions, and to export UK CCS-related services across the globe.

The Task Force

The CCS Cost Reduction Task Force was established in March 2012 by DECC to advise Government and Industry on the potential for reducing the costs of CCS, so that CCS power projects are financeable and competitive with other low carbon technologies in the early 2020s.

The Task Force comprises 30 members from the engineering, hydrocarbon, finance, project developer and academic sectors, representing a broad spectrum of UK and international organisations with deep experience in all aspects of CCS.

This Interim Report describes the work undertaken by the CCS Cost Reduction Task Force to date. The report describes the sources of potential cost reduction, along with the key enabling actions required to deliver them.

Key Conclusion

It is the conclusion of the Task Force that:

UK gas and coal power stations equipped with carbon capture, transport and storage have clear potential to be cost competitive with other forms of low-carbon power generation, delivering electricity at a levelised cost approaching £100/MWh by the early 2020s, and at a cost significantly below £100/MWh soon thereafter.

In essence, these costs of electricity can be achieved in the early 2020s through:

1 a. investment in large CO_2 storage clusters, supplying multiple CO_2 sites;

1 b. investment in large, shared pipelines, with high utilisation;

2. investment in large power stations with progressive improvements in CO_2 capture capability which should be available in the early 2020s;

3. a reduction in the cost of project capital through a set of measures to reduce risk and improve investor confidence in UK CCS projects; and

4. exploiting potential synergies with CO_2-based EOR in some Central North Sea oil fields

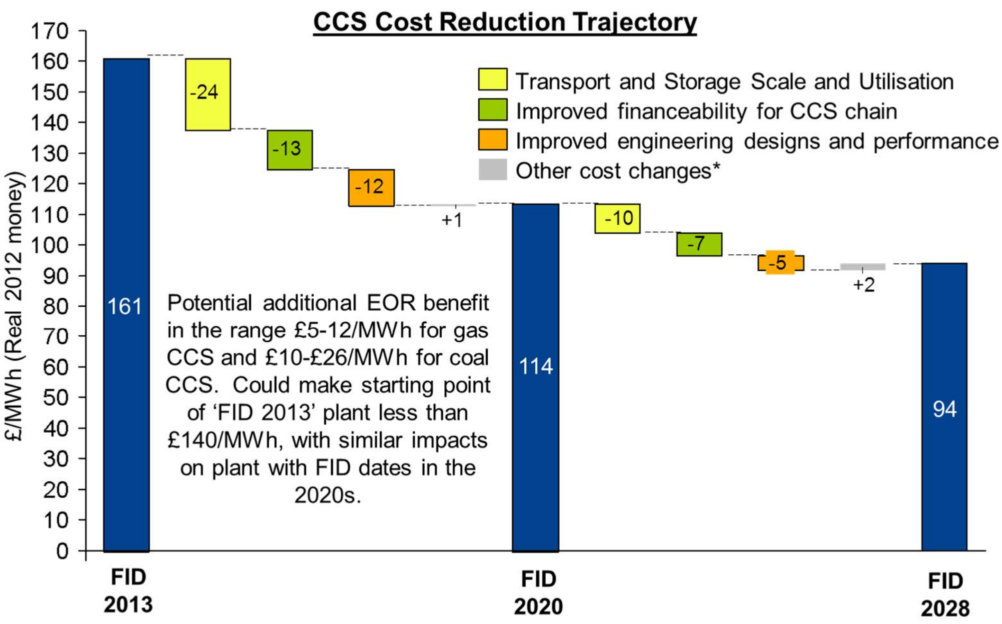
The cost reductions available in the early 2020s will be based on technologies that are already widely used at large scale, and that can be invested in with confidence and manageable risk. Further benefits from 'learning curve' effects, technology innovation, improved construction techniques, supply chain competition and the like will reduce costs further in the later 2020s.

These costs are potentially cheaper than alternative low-carbon generation technologies, without the system costs and drawbacks associated with supply intermittency or inflexibility.

Components of Cost Reduction

Early CCS-equipped power generation projects commissioned before 2020, will have higher costs because of their smaller size; relatively short lifetime if built on existing power plants; single point-to-point (capture-to-storage) full-chain configuration; engineering prudence; and risk averse commercial and financing arrangements. The Task Force anticipates that the first set of projects may have costs in the range of £150-200/MWh.

CCS costs in the 2020s will also depend on the specifics of each particular project. However an indication of the relative significance of the five key factors listed above is given in the graph below. The key conclusion of the Task Force is based on the underlying analysis summarised in this chart. The Task Force is reassured in this conclusion by similarities across capture technologies and the commercial development of analogous technologies such as Flue Gas Desulphurisation and Combined Cycle Gas Power Plant.



Note: Shows average costs across technologies. *E.G. Increasing CO_2 price, falling storage abandonment costs

The UK "CCS Landscape"

The Task Force is confident that the measures outlined in the five areas above will have the effect of reducing the costs of electricity produced by CCS-equipped power plants by the early 2020s. However, this can only happen if these measures are taken against the background of a landscape in the UK which is favourable to the development of CCS projects.

The following are the key characteristics required of that "CCS landscape":

Credible long-term UK government policy commitment to CCS

i. A continued view within industry that the UK government remains serious about encouraging CCS projects, and will provide the policy and financial support (e.g. through CfDs) to enable their development.

ii. A publically stated aspiration that CCS will be deployed at scale in the early 2020s, provided it can be cost competitive with renewables, would be most helpful.

iii. Equipment suppliers and supply chains have sufficient confidence in the commitment to a steady roll-out of CCS that they can commit to invest their energies in this industry to reduce costs and improve performance.

iv. The planning framework – in all its guises, including national and local planning, seabed usage planning, etc. – should have as its basis the presumption that CCS and associated infrastructure will be needed, rather than the view today that it may or may not be needed.

v. A coordinated plan for transport and storage, which allows for the development of infrastructure incrementally but with vision of the long-term.

vi. A suitable regulatory structure, and fiscal and policy framework to foster development of CCS at scale in the early 2020s.

vii. Clarity on the effective interpretation of the requirement that new gas plants be "CCS Ready".

viii. Continued government support for CCS R&D, to compliment investment from industry.

Multiple operating full-chain CCS projects:

ix. Successful development of the projects coming out of the UK CCS Commercialisation Programme before 2020 (and earlier if possible), with a view to building on the storage and transport infrastructure that they create;

x. On-going offer to future CCS projects, built into the EMR, of a CfD sufficient to make good projects financeable.

xi. Commitment to and frameworks for learning and knowledge sharing from projects and research in the UK and globally.

Continued engagement with the financial sector

xii. It is fundamentally important to maintain the current dialogue with the financial community so that its needs can be fed into policy development – responsibility for this engagement lies both with industry and with policy makers.

Underlying sources of cost reduction

The Task Force has confidence in this conclusion because it has examined in some depth the effect of opportunities for cost savings in five aspects of CCS projects:

Storage

- In order to finance full "economic-scale" CCS power stations, power station investors cannot be exposed to significant CO_2 storage risks. The transport and storage system must be very reliable, and its operating regime well matched to the intended operation of the power station.

  Uncertainty around the geological and operating behaviour of CO_2 storage sites means that reliable storage providers are likely to require access to more than one proven store, and to be capable of switching stores in order to provide back-up. This leads directly to the concept of proven 'storage hubs '.

  Through the correct configuration of the storage facilities in early projects it should be possible to structure a highly reliable storage service using storage hubs and multiple storage sites for follow on projects. This will make larger-scale generation and capture projects deliverable and financeable at costs in line with industry norms.

- A large part of the cost of CO_2 storage is set by the development costs of the surface facilities for the storage reservoir, which do not vary hugely with the rate of storage. Early projects with low CO_2 injection rates for storage will therefore incur high unit storage costs (unless they can share their storage).

  Storage will benefit significantly from scale. Multiple large generation plant supplying CO_2 to a hub will allow the storage development costs to be shared across large volumes of CO_2 stored.

The Task Force estimates that storage costs can be reduced from around £25/MWh in early projects to £5-10/MWh through investing in a CO_2 storage cluster supplying multiple CO_2 sites, which store volumes of around 5 million tonnes of CO_2 per annum. Lower costs per MWh could be seen in the longer-run, particular for gas based CCS, if higher volumes of CO_2 from multiple large capture plants feed into larger storage clusters.

Transport

- A well designed pipeline network is a key enabler of the storage hub. It allows new storage sites to join the network over time; it allows multiple storage sites to operate together; and it allows operational switching between storage sites when necessary. The configuration of the transport system for early projects should take into account the likely future development of the CO_2 pipeline network, in order to reduce future costs.

- The unit costs of transporting CO_2 by pipeline decreases as scale increases. Both utilisation and scale are important. This is supported by a key conclusion of the recent Mott MacDonald report, and endorsed by the Task Force, that leveraging early CO_2 infrastructure, if it designed correctly, can reduce the incremental cost of transport and storage substantially for later projects.

- CO_2 pipeline transport is a well-established technology and can be expected to have very high reliability, provided pumping reliability is given suitable attention.

The Task Force anticipates that transport costs could drop from around £21/MWh for early projects carrying 1-2 million tonnes of CO_2 p.a., to £5-10/MWh for large, well-used pipelines carrying 5-10 million tonnes of CO_2 p.a. Even lower costs per MWh could be seen in the longer-run, particular for gas based CCS, if still higher volumes of CO_2 from multiple large capture plants were feeding into an interconnected right-sized network.

Generation and Capture

- Early CCS projects developed in this decade are likely to be of modest size, in order to minimise risk across the full chain. Their levelised cost of electricity is therefore expected to be fairly high.

  Once CCS is established, significant reductions in electricity cost will be available through scaling up to plants sizes of around 1 GW, equivalent to unabated plants being installed elsewhere in the world.

  The Task Force has confidence that full scale plants with CO_2 capture will be available, operable and financeable in the early 2020s, and therefore that these economies of scale will be realised.

- CCS power generation and capture technology, although not new, is not yet fully mature. Significant, progressive improvements, particularly in CO_2 capture capability, and reductions in the energy penalty of capture can be foreseen for the early 2020s.

  In addition costs can confidently be predicted to fall further thereafter, once learning from early plants installed across the world becomes available.

- Suppliers of CCS power generation and capture plant technology continue to be aggressive in developing their technology, and competition is substantial. If they continue to be confident that this market will grow, increasing supply chain scale and price competition will drive prices downwards.

  Cost reductions will also come from reduced redundancy, appropriate process integration and use of improved materials.

The Task Force estimates that generation and capture costs could drop from an average of around £116/MWh for early projects to £96/MWh for projects in the early 2020s. Significant further reductions in generation and capture costs are possible by the late 2020s and beyond through continued improvements in capture technology.

Reduction in Cost of Capital / Achieving Affordable Finance

Early UK CCS projects' cost of capital will reflect their novel nature, their limited size, a lack of industry track record, Government's requirement to limit its exposure and the commercial risks inherent in the CfD FiT structure.

For example:

- No commercial scale projects yet exist from which financiers can gain confidence in the model and the business;

- Storage risks and uncertainties can be perceived as significant until the store is operational and well proven;

- The CfD mechanism does not take account of the project-on-project risk along the CCS chain, with each part of the chain exposed to on-going cost but no income if another part of the chain fails.

However, as the industry matures several developments are likely to reduce the cost of financing projects. In particular:

- De-risking the CCS chain, in particular through:
  - Providing a regulatory and policy structure that leads to financial security and insurance structures which allocate risk to those parties best able to manage them;
  - Creating an optimal contracting structure which balances contract standardisation to encourage financing with flexibility to adapt to project specific requirements;
  - Development of a storage solution which is 'proven' and demonstrably fit for purpose and robust to problems in any one store or well;
  - Building on the success of early projects to provide confidence in the operational performance of CO_2 capture equipment and the interaction with rest of the chain;
- Development of a suitable funding structure which caters for the full chain required by CCS projects, and incentivises them to provide flexible back-up to intermittent renewables in the future;
- Continued education and development of a critical mass of financial sector interest and involvement in CCS projects.

Estimating the individual contributions of each of these components is not straightforward, but informed members of the Task Force have suggested that the cost of capital (however raised) could fall from the "high teens" for early projects to around 10% or below by the early 2020s.

CO_2-based Enhanced Oil Recovery (EOR)

- CO_2 injection into oil fields is one method of recovering otherwise unrecoverable oil from mature oil fields, creating additional income to offset CCS costs, and deferring substantial decommissioning costs. The Central North Sea (CNS) oil province is mature with many fields set to close in the next decade.

  CCS and CO_2-based EOR fit together extremely well. Storage can be undertaken alongside EOR, and the revenue from additional oil production is a key reason for the development of many CCS projects in the US and Canada.

  A word of caution is needed when considering EOR, as not all Central North Sea fields are suitable for CO_2 EOR projects, technical and cost risk profiles are different from North America and there is no direct experience of offshore CO_2 EOR in the Central North Sea (CNS) or elsewhere. However, several oil companies are actively exploring the option of pursuing CO_2-based EOR on a number of fields in the CNS.
- Only a rough estimate can be made currently as to the value CO_2 may attract, if it were delivered, at pressure, to CNS oil field operators. Based on US experience this could well cover the cost of conventional CO_2 storage, and perhaps some of the transport costs as well. As a result this might decrease electricity costs by £5-12/MWh for gas CCS and £10-£26/MWh for coal CCS.
- It is the view of a number of informed Task Force members, and others who have been consulted, that EOR investments will be actively pursued, and probably sanctioned on some fields, as soon as there is confidence that CO_2 is being delivered to the Central North Sea (CNS); and that this will reduce the costs of electricity from some of the power project investments which are expected to be built in the early 2020s.

- In addition to reducing the cost of CO_2 transport and storage, CO_2 Enhanced Oil Recovery (EOR) in the UKCS, could extend the productive life of some UK oilfields significantly. The resulting benefits could include tax revenues, employment, delayed decommissioning, and enhanced UK balance of payments.

Other Applications of CCS

Development of CCS in the power sector could unlock the opportunity for a wide range of applications of CCS with broader benefits for the UK economy and its low carbon transition. These are not taken into account in simple comparisons of Levelised Cost of Electricity (LCOE) figures during the 2020s and include:

- Industrial applications, enabling emissions reductions at low incremental costs, helping to safeguard key UK industries against decarbonisation requirements;
- Future CCS applications (including those with bio energy and gasification technologies) which can potentially enable the use of a wider portfolio of low carbon energy technologies encouraging greater efficiency and flexibility in meeting 2050 targets.

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1. INTRODUCTION

In recent years, sustainability and security of supply objectives have become increasingly important for the energy sector. Energy policy and regulation objectives at European and UK levels have had to evolve in line with this change in direction. In its 2011 Electricity Market Reform white paper, the Department of Energy and Climate Change (DECC) summarised its policy objectives as:

- to ensure the future security of electricity supplies;
- to drive the decarbonisation of our electricity generation; and
- to minimise costs to the consumer.

The UK electricity generation sector is now on the brink of a radical transition to replace aging power plant capacity and to move to low carbon alternatives. Over the coming years, closure of existing coal, nuclear and gas plant will be driven by both the age of the existing generation fleet and by European environmental Directives. The requirement to replace this capacity could be turned into an advantageous infrastructure investment to enable continued use of fossil fuels in power and industry in a carbon-constrained economy. Gas and coal-fuelled generation fitted with Carbon Capture and Storage (CCS) is, alongside renewables and nuclear, a core option for this replacement plant. The ultimate size of the CCS generation tranche will be determined by its cost competitiveness compared to alternatives and the timescale of which cost competitive plant is available.

The CCS Cost Reduction Task Force was set up by DECC to advise Government and industry on the potential for reducing costs so that CCS generation projects are financeable and competitive with other low carbon technologies in the early 2020s. This interim report provides a summary of the initial findings of the Task Force. A final report will follow by April 2013.

1.1 Role of CCS in UK electricity generation mix

Several potential generation technologies are available to help achieve the decarbonisation goals. Some have negligible carbon emissions and some have much lower emissions than available from current technology. The approximate carbon intensity of generation from selected technologies is shown in Table 1 below.

Table 1 – Approximate emissions intensity of generation: Example technologies

Technology	Carbon intensity (gCO_2/kWh)
Conventional coal (unabated)	750-900
Conventional gas (CCGT) (unabated)	350-380
CCS coal	80-150
CCS gas	30-70
Dedicated biomass	Negligible net contribution
Nuclear, Wind, Marine	Negligible emissions
CCS biomass	Negative emissions

Note: The numbers above reflect emissions at the point of generation. Lifecycle emission analysis, including any requirement for additional 'back-up' generation for intermittent generation, would show a higher emissions intensity.

The prospects and timescales for deployment of low carbon generation vary for different types of technology. However, given the rates at which new low-carbon plant can be commissioned, and the attendant risks associated with all technologies, it is essential that a complementary mixture of technologies is deployed. Early deployment of coal- and/or gas-fuelled CCS will help to mitigate technical and economic uncertainty and will increase the likely contribution from these technologies in the future – this will be particularly helpful in progressing towards the additional decarbonisation required after 2020.

One peculiar aspect of wind power generation is that, being at the mercy of the weather systems passing through the UK, output will be highly variable over time. Over the next decade, the main new technology built to meet renewables and decarbonisation targets in the UK is likely to be wind generation, both onshore and offshore.

Inevitably the intermittency of this new wind generation capacity will create additional challenges for the electricity market and system operation, as conventional generation has to be available to take over when there is little wind generation, and switched off when there is a lot of wind generation. There are therefore significant network management benefits in the longer-term to introducing alternative, potentially flexible, sources of low-carbon electricity such as abated coal and gas alongside intermittent renewable generation. By 'flexible' generation, we mean power stations whose output can be ramped up or ramped down in order to compensate for fluctuations in the power output from wind generators. Such plant flexibility is likely to be valuable even if it is only required in a relatively small number of time periods.

Fossil fuel generation with CCS is potentially able to operate in a flexible mode, increasing generation at times of high demand/low wind output and decreasing generation, even switching off, at times when it is not required. It therefore has the potential to provide much needed flexibility to the system and help avoid curtailment of wind generation.

1.2 Other opportunities and benefits associated with CCS

The benefits of the CCS Commercialisation Programme can extend well beyond the narrow confines of electricity generation. For example, CCS is an essential route to reducing carbon emissions for a number of UK industries; and the availability of transport and storage infrastructure will be critical to underpinning their economic health, and even their continued presence in the UK, beyond the early 2020s.

Furthermore, some CCS technologies under consideration for power applications involve the production of hydrogen in bulk, providing the opportunity to also decarbonise smaller CHP installations, provide feedstock for industry and, in the longer term, the opportunity to provide low carbon transport with reduced dependence on oil and also to enable partial decarbonisation of space heating. Availability of low carbon electricity production using CCS, can also promote fuel switching to electricity from gas, coal or oil for transport and heating.

There are also wider economic benefits to CCS which have been previously discussed by both DECC[1] and the Scottish Executive[2]. The Technology Innovation Needs Assessment (TINA)[3] stated that *"[CCS] Innovation could also help create a UK industry with the potential to contribute further economic value of £3-16bn to 2050."* Additionally

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1 http://tinyurl.com/bsf4g9q

2 http://tinyurl.com/5sgbgsu

3 http://tinyurl.com/bsg65wb

much valuable work has been undertaken by proponents of regional 'CCS clusters' in numerous locations around the UK. These benefits include:

- supporting regional development in:
  - regions where carbon capture can be deployed to large emitting power and industrial sources, helping to support the continued operation of those industries; and
  - regions where traditional offshore expertise can be utilised to develop CO_2 storage
- tens of thousands of new jobs in the CCS industry by 2030 as well as the protection of existing jobs in vulnerable industries;
- value creation from exporting CCS expertise to other geographical regions;
- long-term infrastructure development creating construction jobs as well as laying down valuable long-term strategic assets for the UK economy; and
- additional treasury revenue from increased taxation income where EOR allows further oil reserves to be exploited.

1.3 Composition of the Task Force

The CCS Cost Reduction Task Force was set up by DECC to advise government and industry. The Task Force comprises around 25 members, selected from the engineering, hydrocarbon, finance, project developer and academic sectors. A full list of Task Force members and the Terms of Reference of the Task Force can be found in Annex C.2.

1.4 Approach

Task Force methodology

The CCS Cost Reduction Task Force was established by DECC as part of the actions arising from the CCS Roadmap and is chaired by Dr Jeff Chapman, CEO of the CCSA and project managed by The Crown Estate. Three workstreams were established covering key potential areas of cost reduction with 'workstream champions' nominated as experts in the field to lead those discussions:

- Planning and Infrastructure: Mike Saunders (represented by Alastair Rennie), AMEC
- Commercial and Financial: Allan Baker, Societe Generale
- Generation and Capture: Leigh Hackett (represented by Thomas Stringer), Alstom

Task Force members were given the opportunity to:

- take part in a series of workshops in each workstream;
- provide written response to a questionnaire seeking detailed cost reduction opportunities and the impact each would have on a levelised cost of energy (LCOE) for CCS equipped CO_2 emitters; and
- provide detailed input via a one-to-one discussion / interview session.

The overall process was facilitated by Pöyry with additional key experts not included in the original task force also consulted where it was felt they could provide significant expert knowledge in particular areas.

The key conclusions from this process were then discussed by the entire Task Force with individual chapters of the report reviewed by workstream champions. Finally, the overall document was assessed by a core team of Task Force members and agreed to broadly reflect Task Force opinion (recognising the range of views on many subjects).

Modelling approach

Pöyry reviewed the model used in the DECC sponsored report by Mott Macdonald on potential cost reductions in CCS in the power sector[4]. Pöyry used the same general methodology and have taken Mott Macdonald data as a base for assumptions wherever possible. The model inputs were reviewed by the Task Force to establish a baseline from which to measure cost saving potential. This baseline is taken as a starting point when discussing cost reduction opportunities, and their impacts, within this report.

Cost savings for all four technology configurations covered in the Mott Macdonald report were examined:

- Post-combustion coal CCS;
- Post-combustion gas CCS;
- Oxy-combustion coal CCS; and
- Pre-combustion coal also known as Integrated Gasification Combined Cycle (IGCC) with CCS.

In places we refer to the technologies individually but we often show the average cost level across all technologies to simplify the message. Despite the differences in cost profile, the process has shown that the importance and magnitude of cost saving opportunities is broadly similar between the different technologies.

It should be recognised that:

- quantification of cost savings is difficult but the findings of this report appear broadly consistent with Mott Macdonald's analysis and findings in other similar studies once study-specific assumption have been accounted for; and
- forward-looking cost analysis is subject to uncertainty and there is potentially more work that can be done to provide further clarity on the modelled outputs and overall cost levels.

What this report IS

This report is a representation of the opinion of the Task Force members on the opportunities for reducing the costs of CCS in power generation and what impact the delivery of those options may have on the agreed baseline referred to above. The report broadly references a single LCOE path, however this path is for discussion purposes only and is used to highlight the degree of impact potential cost reduction opportunities may have on the overall LCOE of CCS equipped CO_2 emitters.

What this report IS NOT

This report is not a detailed model or representation of CCS project costs. It is also not a list of actions which have been assigned to industry, government or any other stakeholder. The report presents cost reduction opportunities. Further analysis is required to determine exact impacts and costs and agreement is required as to who may undertake identified candidate actions if and when they are adopted.

4 Potential cost reductions in CCS in the power sector, Discussion Paper, May 2012 http://tinyurl.com/c3cj9e8

2. CREATING A FAVOURABLE LANDSCAPE FOR CCS IN THE UK BY THE EARLY 2020s

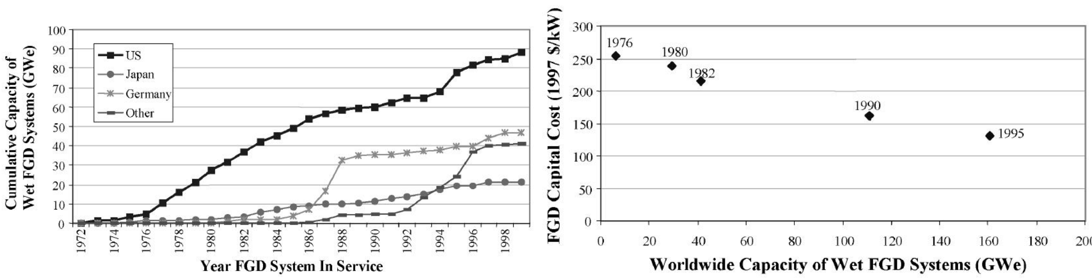
Like other technologies at an early stage of deployment CCS equipped power stations will have many opportunities for cost reductions as the deployment of the technology gathers pace.

Experience curves in a parallel technology: Flue Gas Desulphurisation (FGD)

Parallels can be drawn between the development of carbon capture and other emissions control technologies. This example is taken from a 2004 paper ‘Experience curves for power plant emission control technologies’ by E.S. Rubin et al.

From the 1970’s onwards progressively more stringent controls have been introduced in the US, Japan and Europe over sulphur emissions from power generation. Historically this has been most relevant to coal-fired power plants. The increasingly strict emissions limits have led to the widespread adoption of post-combustion control systems of sulphur emissions, otherwise known as FGD. The most prevalent of these is a ‘wet’ FGD system employing limestone or lime as a chemical reagent.

If we can compare the capital cost of contemporaneous FGD systems (in this case fitted to a 500MWe coal plant, 3.5% sulphur coal with 90% SO_2 removal) to the worldwide installed base of FGD we can extract the ‘experience curve’ for FGD, showing the relationship between technology cost and installed capacity.

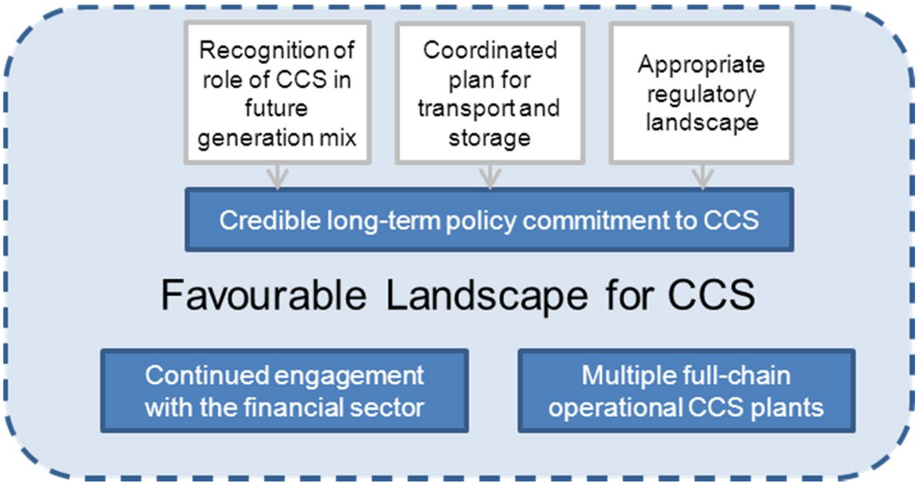


We can see that FGD costs exhibit significant declines over time. The view is that the costs reductions were largely the result of continued R&D activity although it is noted that competition between FGD vendors may also have contributed.

These experience curves are consistent with a large body of literature which examines a range of technologies.

However, cost reduction will only take place if a conducive ‘landscape’ engenders the transition from the early projects to a situation in which the application of CCS is viewed as ‘conventional’ in the same way CCGTs (or FGD systems – see box) are now. If such a landscape were to evolve then many of the cost saving measures will manifest themselves as a function of installed capacity, as commercial market drivers drive industry toward cost saving measures.

The key elements of such a landscape are described below.



2.1 A credible long-term policy commitment

Although the CCS industry is committed to continuing to play an active role in policy development, many of the most critical decisions to put in place the correct fundamental drivers are in the hands of policymakers. If the right conditions are created, then the Task Force firmly believes that CCS will be able to compete with other sources of low carbon generation. These key conditions include:

- recognition of the role of CCS in the future generation mix;
- working with industry to facilitate coordinated deployment of transport and storage infrastructure; and
- ensuring the regulatory landscape is fit-for-purpose and does not unintentionally block CCS projects.

We now discuss each of these in more detail.

2.1.1 Recognition of the role of CCS in the future generation mix

The Task Force recognises recent positive statements made by the government regarding the future role of CCS, as well as the funds made available through the CCS Commercialisation Programme. Nevertheless, some ambiguity remains in terms of the long-term pathways for decarbonising the UK economy, and for roll-out of CCS in particular. Making large-scale CCS power generation explicitly part of energy mix plans, provided it can be competitive with renewables, would help to resolve this uncertainty. It would also be helpful if the government were to recognise explicitly the potential cost effectiveness of CCS as part of emissions reduction and need for fossil fuels to back-up intermittent wind and loss of current nuclear fleet.

In order that equipment suppliers, project developers, financiers and other industry participants can make firm commitments to developing CCS in the UK, confidence in the long-term future of the industry is needed. In particular the development of the CCS supply chain, will require a perception that the UK will be undertaking a ‘steady-roll out of CCS’. This will create an on-going market for related products and services, without large boom and bust cycles of investment.

This recognition of the need for CCS, and the continuing need for CCS must also be present in the planning framework in all its guises, including national and local planning, and seabed usage planning. The planning and policy statements that influence those planning decisions, should have as their basis the presumption that CCS and associated infrastructure will be needed, rather than the view today that it may or may not be needed.

Candidate Action: Development of CCS could benefit from a planning framework that has an assumption that CCS will be needed, rather than that CCS might be needed.

2.1.2 Coordinated plan for transport and storage

The high-upfront costs of pipeline and storage infrastructure and the known large potential benefits from developing an optimal network of transport and storage suggest that potential cost savings could be realised if infrastructure is developed incrementally but with vision of the long-term.

Transport and storage developments are also linked as a well-designed pipeline network will also be a key enabler of storage hubs. So new storage sites will be able to join the network over time; multiple storage sites will operate together; and operational switching between storage sites will be simpler to execute when operational factors at any individual store require it to reduce capacity.

The Task Force believes that:

- Some form of long-term visibility of infrastructure plans would help project developers to plan suitably sized and located capture/storage sites. It is not yet clear whether this should extend as far as a centrally coordinated approach, or just an open and collaborative approach amongst project developers; and
- It would be advantageous if national planning framework/guidelines can be used to fast track consenting for storage and pipeline infrastructure.

It is currently unclear how much central planning is required to create a low-cost robust pipeline and storage network in the early 2020s and how much it is really a later stage issue.

Candidate Action: Consider work on an optimal strategy for locating CCS, to optimise fuel transport, electricity transport and CO_2 transport across the UK.

2.1.3 Appropriate regulatory landscape

The complex nature of CCS projects, with the likelihood of most of them having different companies involved in each of the capture, transport and storage elements, will require a unique approach to regulation in general and funding mechanisms in particular. Some projects are likely to develop as end-to-end CCS chains, whilst others are more likely to form or join clusters. Different elements of the chain may require different regulatory treatments. Some projects may include using the CO_2 for Enhanced Oil Recovery (EOR), whilst others will be simple storage. Regulations will have to be designed in a way that they retain their underlying drivers while also offering sufficient flexibility for a wide variety of project schemes.

More specifically, it is important that CCS is not artificially disadvantaged by the structure of funding mechanisms. There is some doubt within the Task Force as to whether the current EMR proposals will be fit for purpose for commercial scale CCS projects, and many members believe that unnecessary risks could unintentionally be introduced. The Task Force's views on funding mechanisms for projects reaching final investment decision in the early 2020s are discussed in detail in Section 5.2; it is also important that there is recognition that the unique features of CCS may necessitate a different treatment to other low-carbon generation in the next few years (i.e. at early stages of deployment).

Aside from the form of any support arrangements, it will also be important that Government can confirm that sufficient funds will be available to meet CCS and other low-carbon commitments, providing clarity around any funding limits applicable under the Levy Control Framework.

Industry and Government are already collaborating successfully on many areas of R&D in relation to CCS. The R&D requirement from both industry and Government is on-going to deliver low-cost CCS in the early 2020s and to keep costs on a continued downward trajectory.

There has also been discussion in the Task Force that additional clarity on the effective interpretation of the requirement that new gas plants be "CCS Ready" would be beneficial. As much of the infrastructure required for CO_2 transport and storage will need to be built with vision of the long-term, the potential future retrofit of gas plants with CCS could have a significant influence over shorter-term decisions for CCS infrastructure development.

Finally, the Task Force notes that excessively burdensome or overly prescriptive regulation is likely to stifle innovative solutions, and should be avoided.

2.2 Operational CCS plants

Demonstration of a variety of technologies and storage types/locations will be required to enable a full range of cost reductions to be realised in the 2020s and beyond. The Task Force considers that, for any given project, approximately three years' of successful operation is required for equipment suppliers and operators to 'learn' for the next wave of projects. This implies that in order for cost reductions to be achieved by the early 2020s a small number of projects must be deployed within the next five years.

The Task Force strongly supports the aims of the Government's Commercialisation Programme, and believes that this action will have the potential to kick-start a first wave of CCS projects in the UK. Delivery of this programme will be essential if the cost reduction opportunities outlined in this report are to be realised, as it can demonstrate that both the technical and commercial aspects of CCS are realisable (within each component in combination across the full chain). It will also raise public and investor confidence in what is still seen as a novel technology by those outside the industry.

A key aspect of the CCS Commercialisation Programme is to develop practical experience of the consenting and development process, which should in turn lower certain regulatory risks – not least, clarification around the long-term liabilities for CO_2 held in storage sites.

The Task Force also notes that CCS projects outside the UK have potential to provide useful information and experience that could be leveraged within the UK. Learning from other projects in Europe and beyond will be valuable and should be pursued wherever possible. Nevertheless, to stimulate development of supply chains and establish consenting processes a small number of projects will be required within the UK. These should have a track record of successful stakeholder engagement programmes which will help to avoid public acceptance concerns that would make planning more difficult.

2.3 Continued engagement with financial sector

Financing early commercial CCS projects is likely to be far more complicated than conventional power projects, because new financial structures need to be developed, and appropriate sources of funds brought in. Subject to suitable revenue streams being in place, some parts of the CCS chain may be financeable through conventional project financing, whilst others will require a more tailored approach. In particular, project finance for the storage sector is unlikely to be forthcoming without proven revenue certainty, which in turn will be extremely difficult for early projects.

These challenges dictate that the financial sector is able to adequately understand and assess the value drivers and risks associated with CCS projects. Conversely, policy must account for the real-world imperatives faced by banks and others involved in financing CCS projects.

The Task Force notes that realistically, there is likely to be limited active interest from commercial banks and other finance providers now, due to the lead times in developing commercial scale CCS projects. Nevertheless, it is fundamentally important to maintain the current dialogue with the financial community so that its needs can be fed into policy development. Failure to take account of these needs would be to risk the potential for 'bankable projects' in the 2020s.

The nature of this engagement is likely to require that a core number of 'experts' from the financial community remain involved in the debate – and that these individuals are drawn not only from the banking sector, but also the insurance industry and other related areas. The responsibility for this engagement lies both with industry and with policy makers.

2.4 Key conclusions

The landscape described above will not, by itself, guarantee that costs of CCS projects in the early 2020s can be reduced to a satisfactory level. However, it will enable a wide range of cost-reducing actions to be pursued. The most tangible ones can be grouped into three areas corresponding to the Task Force workstreams:

- **Planning and infrastructure developments** – focused on maximising transport and storage economies of scale.
- **Generation and capture technology development** through improved engineering designs and performance; and
- **Commercial and financial arrangement evolution** to achieve affordable finance for the CCS chain.

These three broad areas are discussed in the following sections of this report.

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3. MAXIMISING TRANSPORT AND STORAGE ECONOMIES OF SCALE AND SYSTEM EFFICIENCIES

Virtually all of the CCS projects proposed in the UK to date are based on isolated full chain schemes in which a single power station is connected via a single dedicated CO_2 pipeline to a storage site in the UK Continental Shelf (UKCS), generally a depleted oil and gas field (DOGF) or else a saline aquifer. Pipeline and storage costs in these early projects will be significant contributors to the LCOE with costs in the region of £30-50/MWh.

In the context of the landscape actions discussed in Section 2, a variety of cost saving routes were identified by the CRTF. This section will present the main findings for costs reductions from the Transport and Infrastructure Workstream.

3.1 Achieving optimal scale in transport and storage

Storage

A large part of the cost of CO_2 storage is associated with the development costs of the storage reservoir, which are incurred even for quite low volumes of CO_2 injection. As higher volumes of CO_2 are injected in a particular site, additional costs will be incurred (primarily more wells and additional monitoring) but the percentage cost increase will be small in comparison to the overall increase in volumes. Early projects with lower CO_2 volumes for storage will therefore incur higher unit storage costs (unless they can share their storage) but as with transport, storage will benefit significantly from scale.

The Task Force estimates that storage costs can be reduced from around £25/MWh in early projects to £5-10/MWh by investing in a CO_2 hub (or cluster), supplying multiple CO_2 sites, storing CO_2 volumes of around 5 million tonnes of CO_2 per annum. Lower per MWh costs could be seen in the longer-run, particular for gas based CCS, if higher volumes of CO_2 from multiple large capture plants were feeding into larger storage clusters.

In addition, if a storage cluster is developed so that there are multiple storage types and geologies, the reliability of the storage would be increased so lowering risks for developers in each element of the chain. This will be a key step in making full economic-scale generation and capture projects deliverable and financeable at costs in line with industry norms (see Section 3.2 and 5.1.3)[5].

For such storage hubs to be in development by the early 2020s, the Task Force believe that the current CCS Commercialisation Programme would need to deliver a number of projects which are structured to deliver a high reliability storage service to follow on projects which aim to operate in the early 2020s.

Candidate Action: Future projects need to build on opportunities created by early projects to achieve cost savings through storage hubs.

Candidate Action: Consider how to ensure contracts and licences can be structured flexibly enough to allow CO_2 to be injected into alternative stores by agreement between storage owners.

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5 Development of storage clusters has been discussed in some depth by Task Force members in the past in previous reports such as the Central North Sea – CO_2 Storage Hub report released in September 2012.

Transport

The unit cost of transporting CO_2 has the potential to decrease significantly at higher volumes because the costs of constructing and installing pipelines grow at a much slower rate than volumes they can transport. In an ideal world a single, very high capacity (over 10mt/year) source committing to fully use a pipeline for 25 to 40 years would give a low transport cost. However, the utilisation factor is also important because a large pipeline which has spare capacity for much of its lifespan would have higher unit transport costs than a smaller one which is full year on year.

Additional fundamental drivers of transport costs are pipeline distance, the crossing terrain (particularly onshore) and planning costs. It is therefore apparent that the lowest cost transport network will be one which:

- transports large amounts of CO_2 in appropriately sized pipelines;
- is cognisant of sizing of trunk line sections and feeder line sections to ensure high utilisation for the maximum period of the asset lifetime (average flow compared to maximum flow);
- minimises the distance CO_2 is transported (factored for terrain, shoreline crossings and planning constraints) restricted by decisions on the capture and storage sites; and
- minimises the need for building additional pipelines that would incur significant planning costs.

The Task Force anticipates that transport costs could drop from £18-23/MWh for early projects carrying 1-2 million tonnes of CO_2 p.a., to £5-10/MWh for large, full pipelines carrying 5-10 million tonnes of CO_2 p.a. Even lower per MWh costs could be seen in the longer-run, particular for gas based CCS, if even still higher volumes of CO_2 from multiple large capture plants were feeding into an interconnected right-sized network.

This is supported by a key conclusion of the recent Mott MacDonald report, and endorsed by the Task Force, that leveraging early CO_2 infrastructure, if it is designed correctly, can reduce the incremental cost of transport and storage substantially for later projects.

Candidate Action: Consider how to ensure that the configuration of the transport system for early projects takes into account likely future developments of the CO_2 pipeline network, in order to minimise long-run average costs.

3.2 Characterisation of storage

Site selection for storage is important to access low cost, low risk storage. Assessment of each particular storage site will depend on a number of factors:

- Geographical location of storage site;
- Timing of storage site availability (generally due to other activities at the site);
- Data availability, particularly for existing wells and seismic data, allowing development of a geological model and parameters for the rock and fluid properties; and
- Being able to build a sufficiently good storage reservoir model.

This then enables key features such as injectivity, well design, and capacity to be used with some confidence level in the business case for investment.

To some extent necessary data on potential storage sites is contained in public and private databases; this is particularly the case for depleted oil and gas fields. For other reservoir types, generally saline aquifers, significantly more characterisation work will be required (although it should be recognised that within these broad categories of storage type the level of data for individual sites can vary greatly).

Collecting and having access to reliable data on storage opportunities will:

- create additional confidence in general storage solutions, minimising the risk perception for CO_2 storage:
  - Enable the development of diverse storage options, so that (collectively) their storage capacity is "bankable" which ultimately requires several 'proven' stores that are equally accessible. This is referred to as a storage hub.
  - Financial institutions currently regard storage as the least well known element of the chain and public perception of storage is mixed – this is part of a general de-risking of the CCS chain as described in 3.1.3.
- maximise the ability of firms to select the most advantageous storage sites, reducing capital and operational costs, and the probability of selecting inappropriate sites.
  - Whilst the geo-science and CCS communities are both confident of overall storage potential in the North Sea, the suitability (with regard to 'average' injectivity and storable CO_2 volume) of individual sites is necessarily uncertain.
  - To some extent a site will be more favourable if there are other good potential injection sites nearby.
- attract a wider range of players into the storage business in the long-run, bringing competition and lowering costs.

However, there are significant costs involved in characterising storage. Key steps are typically: a desktop study of seismic and well data; the collection of new seismic data; drilling new data collection wells; drilling test injection wells and injecting water/CO_2.

The step-up in cost at each sequential stage of characterisation at an individual store is significant (up to 10's of £m at the top end). Whilst not as speculative as drilling for hydrocarbons it must be assumed that some test wells will prove that a storage formation is not suitable. Once a formation is selected for investment and is proven, it will be natural that additional capacity will be sought in the same formation and/or nearby because of better local knowledge, to minimise the risk of new negative information. Such new sites will then benefit from lower incremental transport and CO_2 test injection costs.

Given the likely high costs, one potential development model to manage the costs and risks for an individual hub would be as follows:

- Target the nearest potential hub location that has diverse storage options.
- Without new drilling, characterise options in the area, (using existing cores, seismic and regional data) select the lowest risk option for storage in the context of the business case for the hub.
- In the case where there is an available depleted oil & gas (DOGF) storage as an early, already highly characterised store it may be possible to avoid new drilling as at worse it may take the full CO_2 output of a single CCS project for only a limited number of years;
- Provide transport; use what capacity is available with existing pipelines or build a right sized hub trunk line connection.

- After a period of first injection characterise and test nearby opportunities in additional DOGF storage and/or saline aquifer storage to increase the storage capacity and flexibility of the hub. This is important as it de-risks there being unexpected problems with the first store. Hub spoke pipes are sized to suit the incremental capacity.
- Develop spoke pipelines to EOR opportunities as fields become available to create additional value for the CO_2 hub and lower the cost of CO_2 storage (see Section 6.1).

The commercial arrangements could become complex as store operators offset their service obligations by options to store with other operators, but being able to do that will benefit emitters, otherwise emitters will require multiple storage off take contracts to ensure their CCS asset utilisation.

The natural advantages from developing additional storage sites at a hub or next to an existing CO_2 pipeline mean that there are natural economic drivers to further expand it (as pipeline savings from shorter distances are likely to be outweighed by confidence of a proven storage reservoir). However, there may be significant value to establishing a new hub if there is very large storage capacity and it lowers storage and transport costs in the long-run.

Entirely new hubs will only be developed if there is a decent prospect of a step change in cost reduction because of the risks involved. Gaining access to the lower potential costs are one of the reasons that a strategic plan for transport and storage would make sense.

It should be noted that the UK is endowed with an enormous strategic asset in relation to the storage capacity in the UKCS and that the rights for carbon dioxide storage are vested within The Crown Estate[6].

Candidate Action: Consider further work to be undertaken to examine the options for a more or less coordinated approach to developing transport and storage of CO_2 in the Central and Southern North Sea, and to recommend a way forward

3.3 Regulatory framework and funding mechanism

Both the Task Force and the UK CCS Roadmap recognise that creating the right regulatory framework for CCS is crucial for the deployment of CCS. However, the lack of CCS projects in the UK means there is also a lack of experience in regulatory agencies and commercial entities of how regulatory systems would apply to CCS infrastructure. This increases the risk for the establishment of early CCS projects, driving up the costs of development.

A key aspect of the CCS Commercialisation Programme is to develop practical experience of the consenting and development process, which should in turn remove certain regulatory risks. Not least, clarification around the long-term liabilities for CO_2 held in storage sites.

Long-term liabilities associated with storage of CO_2 for very long timescales will need to be addressed in order for projects to be financeable. Commercial entities will find it extremely difficult to carry large and open-ended liabilities on their balance sheets, and will look to Government to take over responsibility at some point. The Task Force welcomes the progress on these issues that has been made as part of the Commercialisation Programme, but believes a robust and enduring solution will need to be put in place that is suitable for all projects, through the 2020s and beyond. This learning from operational projects forms part of our landscape as described in Section 2.

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6 http://www.thecrownestate.co.uk/energy/carbon-capture-and-storage/

In the longer-term, several concerns were raised by the Task Force regarding how the regulation and funding mechanisms for CO_2 transport and storage may change over time as the industry matures.

There are a wide range of options available for the future of the industry, in particular the level and extent of regulation that will be used in transport and storage sectors:

- Light-touch regulation whereby development of the transport and storage industry is market led with standard third-party access requirements in-line with current pipeline infrastructure; or
- Heavier regulation, such as defining a monopoly provider of transport and storage infrastructure in a region then applying regulation on the allowable rate of return.

Whilst developing a highly regulated sector would require significant regulatory changes before 2020, a stable regulatory framework in the 2020s will be critical for the deployment of low cost CCS. Wherever possible, the key principles governing the future regulation should be established as early as possible to reduce regulatory risks for participants.

Whilst the regulations are in place for third party access the guidance for this, particularly for storage access, has not yet been issued. Whilst third party access for storage is quite difficult to describe, some guiding principles can be defined. For example allowing cost recovery and enabling storage owners to agree options with other storage in hubs will help ensure that long-term emitters (who can access transport and agree a storage contract with a store owner) will be able to store their CO_2.

The funding mechanism that is applied to the transport and storage of CO_2 could also have a large impact on the costs of deployment. These options were discussed as part of the Planning and Infrastructure Workstream as well as in the Commercial and Finance Workstream. These funding options and the impact they have on costs is discussed further in Section 5.2.

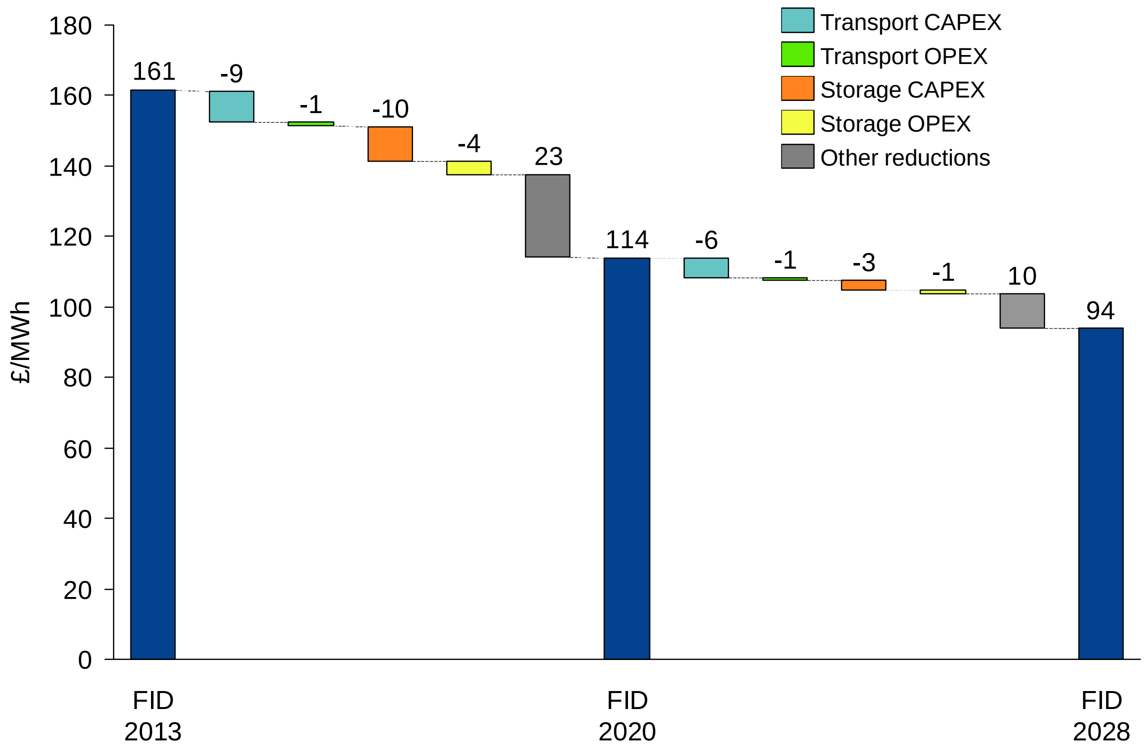
Candidate Action: Assess what future development of the regulatory regime is required to deliver CCS projects, including guidance on whether access by third parties to storage is required.

3.4 Conclusions: storage and transport cost reduction opportunities

All the routes described above effectively facilitate access to two general cost reduction mechanisms: reduced capex and reduced opex in both storage and transport sectors.

In summary, the potential for cost reduction that falls within these mechanisms is summarised in Figure 1. The 'Other reductions' category includes the cost reduction measures achievable by the other cost reduction pathways in this report. These are discussed in Chapters 4 and 5 below but it should be noted that the Commercial and Financial Workstream also included measures that impacted transport and storage costs.

Figure 1 – Potential cost reductions from maximising economies of scale and system efficiencies of transport and storage (real 2012 £/MWh)



Notes:
Diagram show technology average costs (i.e. average costs across all four technologies examined).
Results are presented on a £/MWh basis, the general pattern would be similar if presented in a £/tonne basis, however, future benefits would appear less favourable due to increased plant efficiencies (and consequently a declining CO_2 capture rate)

The Task Force anticipates that there is the potential for transport costs to drop from £18-23/MWh for early projects to £5-10/MWh for FID 2020 plants and £1-3MWh for plant reaching FID in the late 2020s. Additionally there is the potential for storage costs to drop from £22-26/MWh for early projects to £5-10/MWh for FID 2020 plants and £2-5/MWh for plant reaching FID in the late 2020s. A breakdown of modelling assumptions and costs is provided in Annex A.

The underlying driver of cost reductions in both transport and storage is the ability to facilitate increased throughput of CO_2 into the system (ultimately manifested by applying routes discussed in Section 3.1). Increasing the CO_2 throughput of the system incurs costs associated with the deployment of larger diameter pipes and longer pipe lengths (representing the facilitation of clusters); however, the increase in the equipment costs is significantly outweighed by cost savings associated with increased CO_2 throughput.

In the model, increased throughput is effected via an increase in pipe diameters. By FID 2020 pipe diameters have increased from 15” to 18” (coal plants) or from 10” to 15” (in the case of gas plants); this facilitates an increase in throughout from 2 to 4 mt/year and from 1 to 2 mt/year respectively.

By FID 2020, average onshore pipe length has also increased from 30 to 40 kilometres (we assume, in line with Mott MacDonald, that average offshore pipe length remains at 300km throughout the modelled period). These increases in throughput (and the pipeline diameters assumed) are in-line with capture volumes from larger single CCS projects on power stations – it may be that larger pipelines are being developed (for future CO_2 flows to feed into at a later date) but the potential positive impact of such a system is not included.

By FID 2028 the model assumes further increases in pipe diameter, reaching 36” (and assuming 15mt/year throughput) in all cases, representing increased economies of scale from clustering projects. However a 36” pipe has the potential to transport more than 15mt/year at higher pressures meaning that there is the potential for even greater economies of scale (above those assumed in the modelling to 2028) to be realised.

The capex reduction mechanisms discussed above are also expected to bring down the opex of projects (as annual opex is assumed to be 2% of capex throughout the modelled period, as per Mott MacDonald assumptions), opex therefore declines in proportion with capex.

3.4.1.1 Additional cost reductions in transport and storage

It should be noted that additional reductions in transport and storage costs can be accessed through financial mechanisms (in particular, by improving the financing terms available, see Section 5); these mechanisms should thus ultimately be considered together. Such financial benefits can only be exploited by reducing risks, particularly those associated with storage and regulation. This is in part facilitated by the measures discussed in Sections 3.1, 3.2 and 3.3.

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4. IMPROVING GENERATION AND CAPTURE ENGINEERING DESIGNS AND PERFORMANCE

CCS plant in general will have higher cost metrics than conventional thermal power stations because the process needs additional capital equipment to capture and compress the CO_2; additional energy is needed to run the separation and compression plant (thus affecting the net energy output of the plant[7]); and additional operating expenses are incurred due to consumption of solvents, chemical reagents, catalysts and formation of waste products.

Additional generation and capture costs for the first commercialisation phase projects suggests a range of costs from £35-46/MWh (after removing carbon cost impacts). However, there is clear scope to minimise the difference through lower:

- capital equipment costs;
- capture operating costs; and
- energy penalty (i.e. the difference between the net energy delivered to the grid in a CCS case and the net energy delivered to the grid in a non-CCS case[7]).

The main routes are described below.

4.1 Optimal scale of generation and capture unit size

Early CCS power projects developed in this decade are likely to be of modest size, in order to minimise risk capital across the full chain in the first developments. The levelised cost of electricity from these plants is therefore expected to be fairly high.

Once CCS is established, significant reductions in electricity cost will be made by scaling up to plants sizes to around 1 GW or more, equivalent to unabated plants being installed elsewhere in the world today. This will:

- improve efficiency in the base plant;
- lower capital costs and some operational costs at the base plant;
- allow additional economy of scale benefits in components of the capture units;
- allow additional economy of scale benefits in the transport and storage sectors (see Section 3.1).

To some extent “the bigger the better” with regard to the unit costs of capture components as potential economies of scale are regarded as significant. However, it should be noted that for several of the key equipment and systems required in a CCS plant, larger sizes are often not yet commercially available and therefore, the currently available size “breakpoints” will limit scale-ability. With the widespread introduction of CCS projects, industry will have the incentive to push the limits on such equipment and develop larger and more cost effective components. Examples of such equipment where economies of scale are expected to be significant include: ASU cold boxes, air compressors (for ASU’s), CO_2 compressors, pumps, heat exchangers, columns (distillation, absorbers, regenerators) and gasifiers. There are likely to be different

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7 Many observers use the term “energy penalty” to describe the extra energy costs of the CCS process compared to conventional plant. For convenience we use this terminology in this report, although it should be recognised that many aspects of this are identical to the thermal efficiency of any plant i.e. that there are energy losses.

optimal scales for different technologies but scale benefits on individual components could be of the order of 25% of capital costs for that particular component.

Although these larger sized components, once commercially available, ought to drive a lower capex for the CCS plant, there is likely to be a corresponding increase in single point failure risk. In this case, there will be a tendency toward potentially increasing contingency requirements and introducing limits to reasonable gains.

Even where there are limits to the scale of the component parts, there will be potential additional benefits from ordering more than one component from a single manufacturer. Benefits in the order of a 15% reduction in cost for a second component (compared to the first) are regarded as reasonable.

Over-capacity of critical components is often designed into a power train to ensure continuity of generation during outage, for example additional solvent feed pumps or ASU modules. Larger plants with more critical units may still require only one back-up unit. These kinds of impacts are discussed in more detail in Section 4.2 below.

The Task Force believe that full scale plants with CO_2 capture can be available, operable and financeable in the early 2020s if the landscape described in Section 2 is in place. There is therefore strong confidence that economies of scale associated with power plant scale-up will be available in the early 2020s.

A suite of early phase pre-commercial CCS projects in the size range 200-400 MW will provide industry with the incentive to push the existing envelopes and develop these offerings. Such projects, once operational will enable suitable testing opportunities and provide data on performance and availability that can be used to provide the guarantees likely to be required to make CCS financeable.

Candidate Action: Projects developed in the UK following those arising from the Commercialisation Programme should be of a size much closer to the full size unabated plants available in order to capture the economies of scale that should then be available.

4.2 Optimisation of early designs and reduction of engineering redundancies

In addition to the benefits of increased plant scale, some other costs associated with the first commercialisation phase projects are likely to fall during the second and third waves of projects without the need to assume technological advancements. Optimisation of processes, designs and a reduction in engineering redundancies has the potential to significantly reduce capture costs.

Reduced developer/design contingency

As the first wave of CCS plants deliver operational experience (described in the landscape) and larger plants are developed, plant designs should remove certain types of redundancy and design margin. Alongside optimised construction strategy, this reduced contingency should reduce ‘superfluous’ costs.

Balanced against the cost advantages of lower margins/redundancy, will be a reduced level of availability as the system will no longer contain such a high level of back-up. Designs can therefore be expected to optimise the ‘availability versus redundancy’ equation such that costs decrease and/or availability improves over time.

However, experience in other industries indicates that costs can actually increase from the first wave of projects to the second wave before then decreasing again with further deployment. It is often the case that this cost increase is driven by overly strict performance standards on the technology in the early stages of commercial deployment. CCS can avoid this pitfall (and must if it is to deliver low cost in the early 2020s) by ensuring that:

- market support allows plant to operate at less than baseload without CCS without having a distorting impact on plant returns;
  - E.g. If you impose an 80% availability requirement on a plant which, in its first year, only manages 79% then it could lose all revenue whereas in a market situation it would only be marginally affected.
- policy allows plant to operate at least some of the time partially without CCS without unduly affecting the plant returns; and
  - Lowering required capture rate for early years of operation.
- making sure that plant design margins and CO_2 quality standards are fit for purpose given the H&S implications.

It remains to be seen just how significant this process of reduced contingency can be as it will depend on the performance of the first commercial scale CCS projects, and future licensing and permitting requirements.

Candidate Action: Ensure that any constraints (e.g. CO_2 specifications), design requirements (e.g. capture percentage limits) or performance objectives (e.g. minimisation of cost of electricity generation) are set with the intended and unintended consequences of these limits clearly understood and agreed.

Candidate Action: A proper dialogue needs to occur between the project developer, plant designer and supplier of critical equipment to ensure that the optimal balance between scale risk, equipment redundancy, design margins and required availability is achieved.

Better integration of capture unit into generation plant

We could expect to see engineering designs improve the level of heat integration between the capture unit and the generation plant. By utilising steam/heat at the optimum temperature level (i.e. using the lowest grade heat possible from the power plant) you can minimise the energy penalty associated with the capture system. However this must be balanced against:

- the principal disadvantage of reduced flexibility/availability, for this reason, over-integration may prevent effective operation in future market; and,
- the need for reliability as a fundamental prerequisite for effective integration reduces the speed with which integration can be progressed.

To some extent early projects will already be aiming to maximise integration whilst still maintaining flexibility and reliability but the ‘optimal’ setup is uncertain and will depend on the evolution of the rest of the electricity market and other sources of value (see Section 6.4). Indeed some Task Force members questioned whether or not early plant designs may already be too integrated. For this reason, although there is perceived potential for increased integration into the plant, the scope is regarded as limited by the early 2020s.

Benefits in capital cost optimisation can be achieved through smart “physical” integration between the CCS plant and the power plant. This will be the case for a greenfield power plant with CCS which has considered the optimum layout of all physical components and minimizing interfaces such as duct work, utility piping, electrical tie-ins, etc.

Candidate Action: The benefits and downsides of integration should be examined from the experience of all early projects, worldwide, in order to incorporate this experience into future designs.

4.3 Evolution of current capture technologies

In general technological improvements will be a function of how many plants are deployed globally. Thus, the more plants in operation the faster the evolution. On the other hand, if only a few plants are developed before 2020 the rate of technological advancement would be slow.

In general significant improvements are expected in existing capture technologies between now and the early 2020s. All technologies should continue to improve during the 2020s as roll-out continues but over time we can expect the costs of these 'current generation' technologies to tend towards natural limits.

Capture process

There is a potential for current capture technologies to improve incrementally as experience grows between today and projects reaching FID in the early 2020s. These current capture technologies can be largely defined as:

- **Post-combustion**: Capturing CO_2 from the flue gas of a conventional gas or coal fired power plant using an absorption based process (utilising absorbents such as amines or ammonia);
- **Oxyfuel:** Coal is burned with oxygen (generated from an Air Separation Unit) rather than air resulting in a flue gas containing CO_2 and water (no nitrogen). CO_2 is then captured from the resulting flue gas.
- **Pre-combustion:** Gas or coal is converted in a gasifier into a mixture of hydrogen, CO and CO_2. In the case of power generation, the CO is further converted to CO_2 which is then captured from the resulting gas, generally using an absorption based technology. The remaining H_2 rich gas is then burned in a gas turbine to generate power.

There are a number of specific technology improvements that are at pilot-stage or very close to pilot, and as such these represent opportunities for cost saving by the early 2020s timespan. These include:

- solvent (e.g. amine) improvements;
  - There have already been considerable improvements made in the last 5 years as technology providers have shifted from using standard solvents such as monoethanolamine (MEA) to more advanced solvents tailored for post-combustion capture. As much as a 25% improvement has been realized to date by many technology providers. Further improvements can be expected, however, as these will likely mean tailored chemical solvents, the cost and supply chain considerations need to be traded off against the potential energy benefits.
- alternative solvents (i.e. alternatives to amine) that fit within similar overall flowsheet;
- absorption process improvements such as improved internal heat integration, external heat integration and overall process optimisation;
- improvements in physical absorption processes used in Pre-Combustion based systems;
  - Advances currently underway through the ETI technology programme;

- further improvements to IGCC as learning develops from the operational experience of IGCC projects worldwide;
- improvements in critical equipment performances such as column packing, heat exchangers and CO_2 compressors; and
- improvements in Air Separation technologies (process cycles optimised for oxy-combustion processes) resulting in low specific energy consumption.

It should be remembered that there is a theoretical lower threshold to the level of energy consumption required to extract CO_2 using any of the above technologies. Some technologies will ‘plateau’ earlier than others and it is currently unclear which technologies can ‘go further’ than others in the necessary time-frame.

The Task Force believes that there is no current obvious technology or fuel winner for CCS and developing a market for CCS in the long-run is the optimal way to drive improvements and lower costs.

The key question for each of these technologies is:

What can we do to make improvement in this area happen? What will drive technological improvement?

Improvements in materials of construction

Optimisation of materials of construction utilised within the capture plants has the potential to lower capital costs. Potential cost saving measures by the early 2020s include:

- using cheaper material (including a reduced dependence on steel) as a better understanding of material robustness and corrosion resistance is gained through operational experience. Examples include:
  - using more concrete (in absorbers in particular) could save up to 30+% of cost can be saved on the absorber; and
  - using lower cost steel or polymers;
- the use of off-site fabrication for certain components which may be more cost effective when large plants with multiple units are being constructed.

Improvements in flexibility of Power Generation with CCS

During the period between today and 2030, the UK’s power grid is expected to evolve toward a greater percentage of renewable power generation (e.g. wind power). This evolution means that fossil power generation with CCS will need to be flexible in order to efficiently match the demands of the grid (see Section 1.1 and Section 2.1.1.)

It is expected that the current capture technologies will be capable of enabling a sufficiently flexible CCS installation. However, the exact capabilities of CCS power will vary based on the actual technology employed and will need to be further proven through the early phase projects. The current views on system capabilities can be summarized as follows:

- Post-combustion: Absorption based processes can be made to follow the load of the host power plant through the use of advanced control systems. A key factor will be the specifications imposed on the capture plant performance. If the CO_2 recovery rate can drop below 90% (for example) for a short period of time during the ramping period, then it should be quite straightforward to achieve rapid ramping rates.

- OxyFuel: Ramping an oxyfuel CCS process will require load following of the ASU as well as the back-end CO_2 purification system. While dynamic ramping can be achieved through advanced controls, an oxyfuel system offers a unique approach to reacting to load. During periods of low load from the grid, the power plant can remain at a constant load and the extra electricity used to generate liquid oxygen from the ASU which is then stored. Then during periods of high electricity demand, the ASU can be turned down and the liquid oxygen used to supply O_2 to the process. In this way, the liquid oxygen serves as a form of energy storage.
- IGCC: Compared to a PC-Coal or NGCC plant, IGCC has a lower operational flexibility. While PC-Coal or NGCC plants have proven to reliably cycle down to low loads, the gasifiers associated with IGCC plants are best operated at a constant or near constant rate. However, flexibility can be achieved with an IGCC solution if there's an outlet for the syngas from the gasifier (or the H_2 rich gas normally sent to the turbine). In the case where the gasifier produces syngas for downstream chemicals production in addition to power production, then a balance between power generation and chemicals synthesis could provide the necessary flexibility.

Industry will continue to further drive improvements in all areas above providing a favourable landscape for CCS is in place, with a first wave of projects being developed and a clear vision of an on-going market developing closely behind the first wave.

4.4 Developing the CCS supply chain

Developing the supply chain for components of CCS has the potential to bring down the costs of components. The supply chain for CCS will develop as a favourable landscape for a CCS market is created and suppliers can foresee a smooth pipeline of projects. On the other hand if roll-out of CCS happens too quickly, it could mean that existing supply chains cannot cope with demand which perversely would increase costs for CCS project developers for bottle-neck components.

A developed supply chain will be one where:

- supply of all equipment (e.g. packings, heat exchangers, compressors, etc.) and related raw materials (e.g. steel) is possible within reasonable timescales to meet demand;
- a suitable level of competition between equipment suppliers drives efficiency, innovation and ultimately lower costs; and
- standardisation and significant volume of orders allows expansion by manufacturers towards a minimum efficient scale of production.

However there is a tension between providing incentives for equipment manufacturers to remain engaged in early projects, while bringing in competition in the longer term to lower costs. Standardisation too can be a double edged sword in that standardisation to the 'wrong' standard could limit the ability of a firm to export technology to wider global developers.

The extent to which supply chain effects will lower costs in the 2020s will depend on how rapidly the CCS supply chain can develop and how large a supply chain is required to significantly bring down component costs.

4.5 Next generation capture technologies

Beyond the current suite of capture technologies currently being deployed at pilot-scale around the world are the next generation of capture technologies, loosely classed as technologies at the laboratory- or bench-scale. These technologies have the potential to enable step changes in capture costs but are often based on very different processes to current capture technologies.

While opinions in the Task Force differ as to the timescales for development of these newer technologies it is generally viewed that they must go through at least two levels of scale-up before they would be ready for commercial deployment. For this reason they are really only suitable for inclusion on a wide scale from the late 2020s onwards.

There are many different technologies at this scale of development and it is not possible to say which of these will offer the greatest commercial attraction in the long-run.

Four example technologies discussed were:

- Alternative technologies suited for gas/CCGT post-combustion such as Flue Gas Recirculation.
- Advanced oxygen generation technologies (e.g. non-cryogenic, membrane) which have the potential to drive a step change reduction in the cost of oxygen and a corresponding reduction in oxyfuel CCS costs.
- Chemical looping which can be viewed as an advanced oxyfuel process whereby the ASU is eliminated.
- Advanced post-combustion capture such as the Regenerative Calcium Cycle (RCC) process which offers the possibility for a step change reduction in energy consumption – see box below.

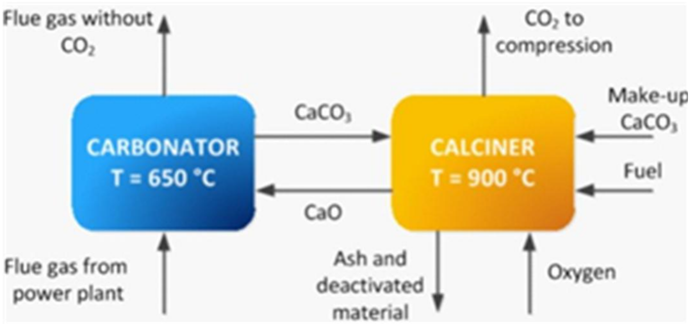
Candidate Action: R&D funding for future technologies should continue from all sides to create cost reductions beyond the incremental reductions available from existing technology.

Example Next Generation Technology: Regenerative Calcium Cycle (RCC)

The Regenerative Calcium cycle (RCC) is a post-combustion process that operates at high temperatures (600-750Deg C in the absorber) and (900 Deb C in the regenerator) and utilizes a solid absorbent, lime (CaO). In the RCC process, CaO absorbs the CO_2 from the flue gas, in a carbonator. The $CaCO_3$ formed is transferred to a calciner, where the CO_2 is released by increasing the temperature to approximately 900C. The stream of highly concentrated CO_2 is ready for compression and storage, whereas the regenerated CaO is transferred back to the carbonator closing the Ca-loop. The following chemical reaction describes the capture and release cycle for CO_2:

$$CaO\ (s) + CO_2\ (g) \rightleftarrows CaCO_3\ (s),\ \Delta H = -178\ kJ/mol.$$

Because the reactions take place at elevated temperatures, there is a great potential for optimization through efficient integration into a power plant or industrial plant (e.g. cement). A further evolution of the technology envisions the use of heat above the level of the power plant steam cycle through the integration of the calciner into the boiler thereby making use of "indirect calcination". Such a solution has the potential for a high rate of CO_2 capture with minimal energy penalty on the host power plant.

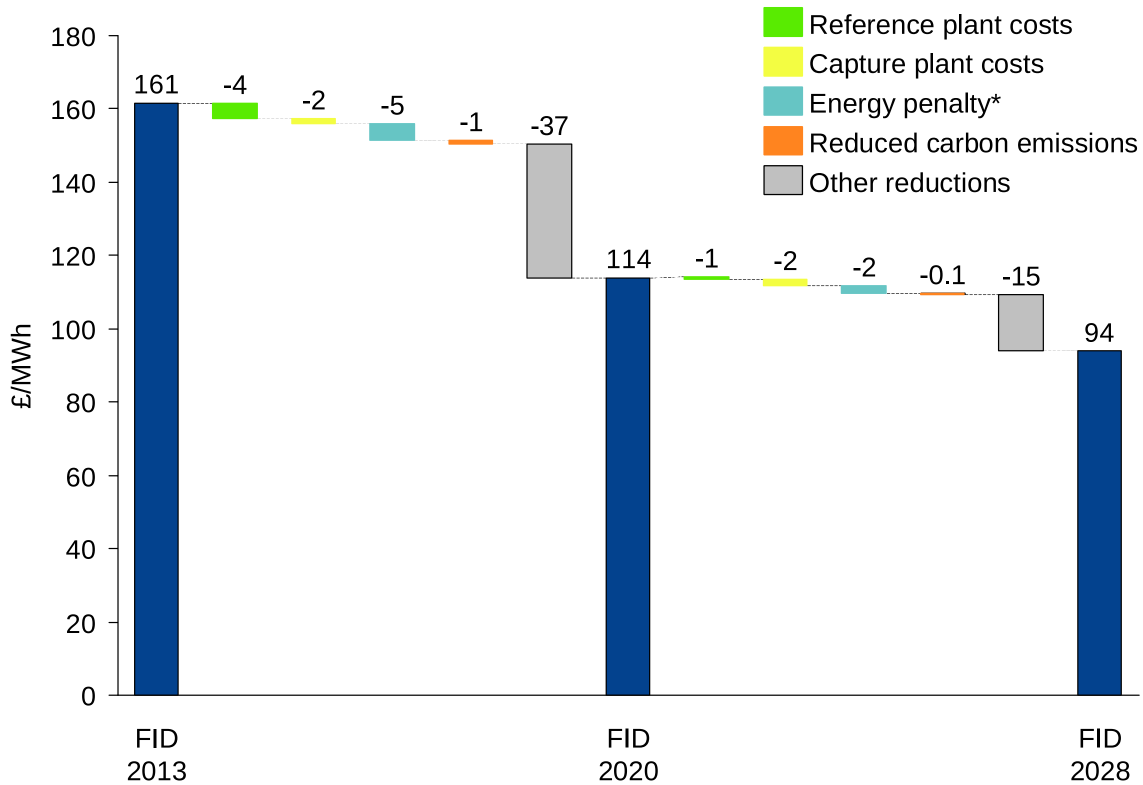


Development of new technologies such as RCC require continued R&D but have the potential to lead to significant longer term improvements in CCS technology beyond 2020.

4.6 Conclusions on generation and capture cost reduction opportunities

Figure 2 summarises the cost reductions that can be accessed through improved performance of capture technologies. The 'Other reductions' category includes the cost reduction measures achievable by the other cost reduction pathways in this report. These are discussed in Chapters 3 above and 5 below.

Figure 2 – Potential cost reduction mechanisms relating to improvements in capture technologies (real 2012 £/MWh)



* Includes host plant costs and additional fuel costs

The Task Force estimates that generation and capture costs could drop from £116/MWh (with a range of £104-125/MWh across technologies) for early projects reaching FID in 2013 to £96/MWh (£88-106/MWh) for plants reaching FID in 2020. In the late 2020s generation and capture costs could drop further to £87/MWh (£82-93/MWh). A breakdown of modelling assumptions and costs is provided in Annex A.

In line with Mott MacDonald low cost path assumptions, the model assumes continuing technological progress in the underlying Reference Plant, manifested through capex reductions:

- Post-combustion coal and oxy-combustion coal: £1,500/kW, £1,400/kW and £1,400/kW (in 2013, 2020 and 2028 respectively).
- Post-combustion gas: £550/kW, £500/kW and £500/kW (in 2013, 2020 and 2028 respectively).

- IGCC[8]: £2,200/kW, £2,000/kW and £1,900/kW (in 2013, 2020 and 2028 respectively).

In addition to Mott MacDonald assumptions, the model also assumes that reference power plant efficiencies also improve through time[9]:

- Coal Fired Power Plant: 43%, 45% and 45% (in 2013, 2020 and 2028 respectively).
- Combined Cycle Gas Plant: 54%, 56% and 56% (in 2013, 2020 and 2028 respectively).
- IGCC: 43%, 45% and 45% (in 2013, 2020 and 2028 respectively).

Mott MacDonald low cost path cost-reduction rates have been considered by the Task Force and whilst there is uncertainty and a range of opinions over such numbers, they are considered as a valid assumption basis.

Whereas cost savings arising from improvements in reference plant technology are largely focused in the nearer term (before 2020), capture plant improvements are seen to have similar cost saving effects both pre- and post-2020. The costs assumptions assume that reduction occurs at different rates for different elements of the capture process, with average reductions in capture plant capex as follows:

- Post-combustion coal/gas: 10% before 2020 and a further 13% by 2028.
- Oxy-combustion coal: 10% before 2020 and a further 14% by 2028.
- IGCC: 2% before 2020 and a further 7% by 2028.

Concomitant with these capex improvements, we also assume a steady reduction in energy penalty (representing overall improvements in the capture process)[10]:

- Post-combustion coal and oxy-combustion coal: 25%, 18% and 15% (in 2013, 2020 and 2028 respectively); original Mott MacDonald low cost path efficiencies were 25%, 23% and 18%.
- Post-combustion gas: 19%, 14% and 11% (in 2013, 2020 and 2028 respectively); original Mott MacDonald low cost path efficiencies were 15%, 14% and 11%.
- IGCC: 17%, 16% and 12% (in 2013, 2020 and 2028 respectively).

Additionally, in line with Task Force recommendations, we assume an increase in CO_2 capture rates of the plants (increasing from 85% to 90% between 2013 and 2020).

The reduction in cost of capture technology is particularly difficult to predict because technological development, by definition, is not a known quantity. Also, the response of the supply chain to a substantial, competitive CCS market alongside other demand sectors is difficult to predict. Whilst this generates uncertainty in costs savings, many Task Force members think there is the potential for considerably greater savings than those above based on previous experience with other technologies.

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8 Estimates of IGCC capital costs vary greatly, and as such are they are regarded by the Task Force as subject to a greater range of uncertainty than the other technologies.

9 Mott MacDonald assumptions assumed constant efficiencies throughout the modelled period of 40% in coal plants and 53% in gas plants.

10 The energy penalty figures are dependent on the reference plant efficiency, therefore care must be taken when comparing such numbers from project to project.

5. ACHIEVING AFFORDABLE FINANCE FOR CCS CHAIN

This section presents the main findings for cost reductions from the Commercial and Finance Workstream.

All elements of the Carbon Capture and Storage chain are by nature capital intensive so the efficiency of the financing structure has a large influence on the overall LCOE.

In general there is significant interest in CCS from certain financial institutions but the overall perception is that risk is high which in turn constrains financing options and increases costs above those for conventional power projects.

Current large-scale CCS projects worldwide are generally funded via a mix of capital grants, equity, subsidised loans (from multinational development banks, export credit agencies etc.) and limited scope commercial loans. However, the nascent nature of the industry means that there are no standardised finance structures in place for CCS projects and the terms of future commercial loans are highly uncertain.

5.1 De-risking the CCS chain

One of the key mechanisms by which increased learning and experience will lower costs is through lower cost of capital, including financing for all elements of the CCS chain. The mechanism by which these costs reductions are realised is through:

- A reduction in the equity hurdle rate required by firms to invest in CCS as they better understand and price the particular risks of the industry;
- An increase in the equity value attributed to later years of an asset life (through greater perceived certainty in longer-term revenue streams and costs);
- An increase in the gearing available to projects as well as increasing debt liquidity available to CCS overall, leading to an improvement in the available terms of debt (margins, ratios, covenants etc.) as the perceived risks of the industry are better defined and understood through experience.

There is considerable overlap with the other workstreams for de-risking the CCS chain. However there are some specific routes by which cost saving can be achieved which were discussed by the Commercial and Finance Workstream.

5.1.1 Optimal industry structure for risk management

As the CCS landscape develops, the risks in the chain should be more efficiently allocated to those parties that are best able to manage them, thus reducing the overall cost of risk associated with CCS.

The ability of the industry to allocate the different risks will depend on many things, not least the regulatory and policy environment for CCS which will have a material bearing on the industry structures established. Different interventions can lead to a variety of industry structures, in particular in the CO_2 transport and CO_2 storage sectors of the chain, which could make risks more or less acceptable to different stakeholders.

Below we outline some potential industry model structures that were discussed as part of the workstream workshops. Appropriate industry structures for CCS equipped power stations are likely to change over time as the risk structure of the industry evolves.

Fully integrated (JV) model

This is a fully integrated (or Joint Venture (JV)) project structure where each 'full-chain' capture, transport and storage project is owned by a Special Purpose Vehicle (SPV). The SPV is set up and managed by JV partners who may be specialists in one particular aspect of the chain with SPV integrating the full chain.

This will be optimum in terms of risk sharing as many of the interface risks are internalised and profits and costs can be shared However, JV partners operating in different sectors can have very different approaches to business and more importantly risk/return expectations making this approach challenging to set up. From a financing perspective though, this could be an attractive structure if the JV partners were reputable and credit worthy entities and if the JV/shareholder agreement adequately addressed these differences to ensure risks were well managed.

A JV model is likely to be most applicable to single or related projects but could also be applicable to provision of transport and storage infrastructure to serve hubs of multiple capture projects.

Market led, disaggregated industry model

In this model, each component of the CCS chain is owned and operated by a different entity with the relationships governed by commercial contracts. These contracts could have a variety of forms including availability based, Take-or-Pay, Ship-or-Pay and variable charge payment mechanisms and would be regulated by standard Third Party Access (TPA) requirements.

This model would potentially provide the developers and operators of each chain element with the strongest incentives to manage their own construction and operational risks. However it also increases the potential for, and impact of, project-on-project type risks where individual elements of the chain may be unduly exposed to operational risk in other components of the chain. Whilst this can be mitigated with the contractual arrangements between the individual links, the negotiation of these contracts and the ability of the individual companies involved to honour their obligations is crucial to making the disaggregated model work.

It is not currently clear what the optimal approach would need to be to fund such a disaggregated model as a 'trickle-down' of revenue from capture to transport to storage combined with the other issues described above may make it difficult to finance some elements of the chain.

Regulated returns/revenues for transport & storage sector

Establishing a central or regional transport & storage entity could help to significantly lower the cost of capital and financing if based on a Regulated Asset Base or similar structure; examples being the gas and electricity grid and to a certain extent, the Offshore Transmission Owners (OFTOs) for offshore wind. Such a structure would enable socialisation of the costs of transporting and potentially storing the CO_2, leading to lower financing costs than the same transport sector which was funded on a purely commercial basis. However, the structure put in place would need to also encourage costs minimisation and ensure that the scale of the network was suitable to meet the expected development of the industry.

Additionally it is widely recognised that the UK government would not accept such an industry on its balance sheet so a private sector 'monopoly' provider would be required but examples do exist. The appropriateness of this type of model depend largely on the expectations for the wider development of the industry as this type of model will clearly be more appropriate for a more mature industry with hubs and multiple capture plants than single point to point projects that may emerge from the Commercialisation Programme.

Candidate Action: Consider how the business model for CCS in the UK should migrate away from early end-to-end full chain projects to projects more suited to cluster development.

5.1.2 Contracting structure

As the first CCS projects are developed as part of the CCS Commercialisation Programme, a commercial structure will be established governing parties' responsibilities. There is a clear opportunity for these early commercial agreements to form the template for subsequent projects, as was the case for the early CCGT power projects in the UK and Independent Water and Power Plant (IWPP) projects in the Middle East. The ability for CCS projects to look to these contracting structures as guidelines for new projects will improve the efficiency of executing subsequent projects and the Task Force believe that there are potentially significant financing benefits from defining an early robust 'copy-cat' model for commercial contracting and risk sharing which will contribute to the cost reductions in the industry on both development and financing.

Competing forces influence the desirability, in contracting terms, of separation of the chain into smaller individual components:

- Different elements of the chain (generation, capture, transport, use, storage) may require very different financing and contracting structures to make the business commercially viable. However;
- 'Project-on-project risk' (or the risk arising from interactions between sequential parties in an interdependent group – sometimes known as 'chain-risk') will increase as the number of links in the chain is increased. In other words, contingency is, in part, a function of the contractual interface and the more interfaces, the more the potential for layering of contingencies – other things being equal, reducing the number of contracts reduces this inefficiency in contingency costs.

To the extent possible, establishing a standardised commercial and financing model for CCS will be beneficial if it is appropriate for future CCS projects. However the model will need to be flexible enough to cope with unique features of individual projects, not least differing capture technologies and pipe-storage configurations.

5.1.3 Characterisation or 'proving' of storage

For financial institutions, generation is understood and CO_2 transport has been widely demonstrated in the US and elsewhere. In particular, CO_2 use and storage in the UK are much less familiar to financial institutions even if there is some precedent in other industries that use project finance services.

The Task Force believes that these storage risks are regarded by the finance community as being a major current issue for financing CCS. Without a low risk profile for the storage element of the chain, CCS projects will find it difficult to get low cost (or possibly any) external finance, thereby increasing costs and limiting the scale of any individual CCS power plant (further reducing potential costs savings from power plant scale – see Section 4.4).

Financeable CCS in the early 2020s therefore requires a storage solution that is generally regarded as 'proven' and demonstrably fit for purpose in order for financing to be raised, the focus of which will be:

- characterisation of storage sites and a track record of storage injectability and CO_2 dispersion behaviour as expected in key localised areas; and
- diverse storage options to provide contingency, so that (collectively) the probability is “bankable” which ultimately requires several ‘proven’ storage options.

Alternatively, storage will have less impact on overall financing if the financial performance of the rest of the chain is somehow insulated from the storage risk. This could be achieved by a separate storage entity assuming the storage risks although it is not clear which entity could perform that function at present.

The need to address storage risks has been highlighted by the Planning and Infrastructure Workstream as well as the Commercial and Financial Workstream. It is discussed in more detail in Section 3.2.

5.1.4 Demonstration of Capture technologies

The Task Force believes, in addition to the storage risks outlined in 5.1.3 above, Capture technologies at a scale required for application to power stations are still regarded as novel by the finance community and as such are regarded as a high risk element of the CCS chain for power stations. This risk perception for current capture processes currently creates an issue for financing CCS.

The Commercialisation Programme in the UK and capture projects elsewhere in the world have the opportunity to help mitigate these risks by the early 2020s through the successful deployment of operational CCS plants (as discussed in 2.2). Financeable CCS requires a capture process that is technically proven in order for financing to be raised, the focus of which will be:

- construction risk for the capture units; and
- technical performance of the capture process post commissioning (rate, costs etc.).

As technologies are tested at scale we would expect the risk perception on those technologies to decrease although the variety of options for each CCS project (such as geography, generation technology, fuel-type, other heat loads etc.) will mean that this de-risking process will take time.

As newer, ‘next generation’ capture technologies are developed over time these will also need to undergo a similar process of testing both at scale and in a variety of conditions to lower their technical risk and make them financeable.

5.2 Ensuring funding mechanisms are fit-for-purpose

A fit-for-purpose funding mechanism which matches the cost structure of the project and provides revenue certainty (subject to performance) will lower the perceived risk of the CCS project, lowering the hurdle rates for CCS projects and giving access to low cost finance (as described in the wider de-risking description – see Section 5.1).

Electricity Market Reform

The UK currently presents one of the most attractive potential investment environments in the world for CCS due to its geography, skills base and suite of potential support mechanisms for CCS. The EMR process has put in place potential long-term remuneration for CCS in line with other low carbon generation options through the CfD mechanism.

After the commercialisation programme the strike price, as provided by the CfD mechanism, is intended as the primary method of support for CCS. However the technical details of the CFD mechanism are still being decided and, the initial strike prices will be set by negotiation before becoming technology neutral in the 2020s.

The following key CfD features, some of which have already been discussed as part of the EMR process, have been highlighted by the Task Force as having the potential to offer value for consumers by making CCS more financeable without increasing the absolute costs to consumers:

- A mechanism to ensure the value of flexibility and firm-availability is rewarded (see Section 6.4);
- Allow renegotiation of CfD strike price after construction to remove construction risks from the project;
- Index the CfD strike price to fuel prices to remove fuel price risks; and
- Present a viable CfD counterparty so that counterparty risk is minimised.

Whatever funding mechanism is used for the CCS chain it will need to be simple enough for financial institutions to understand, model and be confident that the revenues flowing from it are stable, reliable and deliverable in the long-term. Whilst the outline of the EMR proposals are encouraging in this respect the detail will be crucial for the bankability or otherwise of CCS projects.

Candidate Action: Continue work to develop the CfD structure, and other relevant EMR instruments, with a view to their widespread use in CCS projects.

Separate funding mechanisms for T&S sectors

The current CfD funding proposals for CCS are focused on the power generation sector with the key metric being the delivery of low CO_2 power to the grid at the power station fence. Payment for the transport and storage of the CO_2 is expected to be covered by the CfD payment.

Where the entities that are transporting and storing the CO_2 are separate from the power generator, the current model is for payment for CO_2 transport and storage to be via a negotiated contractual relationship. The nature of these contracts will govern the risk profile of the individual elements of the CCS chain.

The CfD mechanism has good potential and, notwithstanding the above points, is regarded as a relatively good mechanism for addressing the risks and creating financeable generation and capture of CO_2. However, transport and storage have very different risk profiles:

- As the transport networks have a very high proportion of capital costs they will favour fixed annual payments – they will be particularly exposed to contracts which are based on a per unit fee for delivery of CO_2. The power station on the other hand would prefer all payments to be based on a per-unit delivery of CO_2;
- Storage operators may need to take speculative approaches to storage characterisation, investing significant sums of money in uncertain sites before a CO_2 flow is ensured. They will therefore require higher levels of compensation to account for the risk.
- Use of CO_2 for EOR raises another set of issues as the CO_2 user will require reliability of volumes when required but also technical flexibility related to the independent operation of the field utilising EOR.

5.3 Continued involvement from financial and insurance sectors

If, as expected, the perceived risks associated with CCS change positively in the medium term to improve the financeability of the industry, there will be increased competition, all else being equal, for the provision of project finance and other services to the CCS sector. This will clearly help to ensure that financing costs of CCS projects are reduced as the industry matures.

The role of the insurance sector should not be underestimated in improving the financing conditions for CCS as they will be best placed to deal with and mitigate certain risks which will still exist within the CCS chain.

On-going work within the CCSA and ClimateWise, the global insurance industry's leadership group to drive action on climate change risk, considers the role that insurance might be able to play in helping to manage the regulatory and commercial risks faced by CCS project developers[11].

Candidate Action: Keep a variety of financial institutions, analysts and insurance companies engaged in CCS such that they:

- **understand and gain comfort with the full chain of CCS, its technical characteristics and the financing mechanisms in place;**
- **can correctly analyse risks and risk mitigation options; and**
- **can work with the industry to provide the financial structuring expertise required to fund the anticipated growth of the industry in an efficient manner.**

5.4 Conclusions on commercial and financial cost reduction opportunities

From a modelling perspective, cost reduction mechanisms in this area are simulated by:

- Incorporating longer economic asset lives in later projects allowing longer term financing (increasing the assumed economic life from 15 years to 25 years between 2013 and 2020 in all sectors). By doing so we move to a figure more representative of (what in later years is expected to be) a more mature industry. Longer economic lives represent the impact of improved financing terms and the potential for progressive refinancing of debt, and serve to drive down costs by, in effect, allowing projects to recoup capital expenditure over an extended period of time.
- Reducing the cost of capital:
  - In capture and transport sectors, the cost of capital remains at 10%[12] until 2028 when it is assumed to drop to 8%.
  - In the storage sector the cost of capital is assumed to steadily decline from 15% to 14% to 12% in 2013, 2020 and 2028 respectively.

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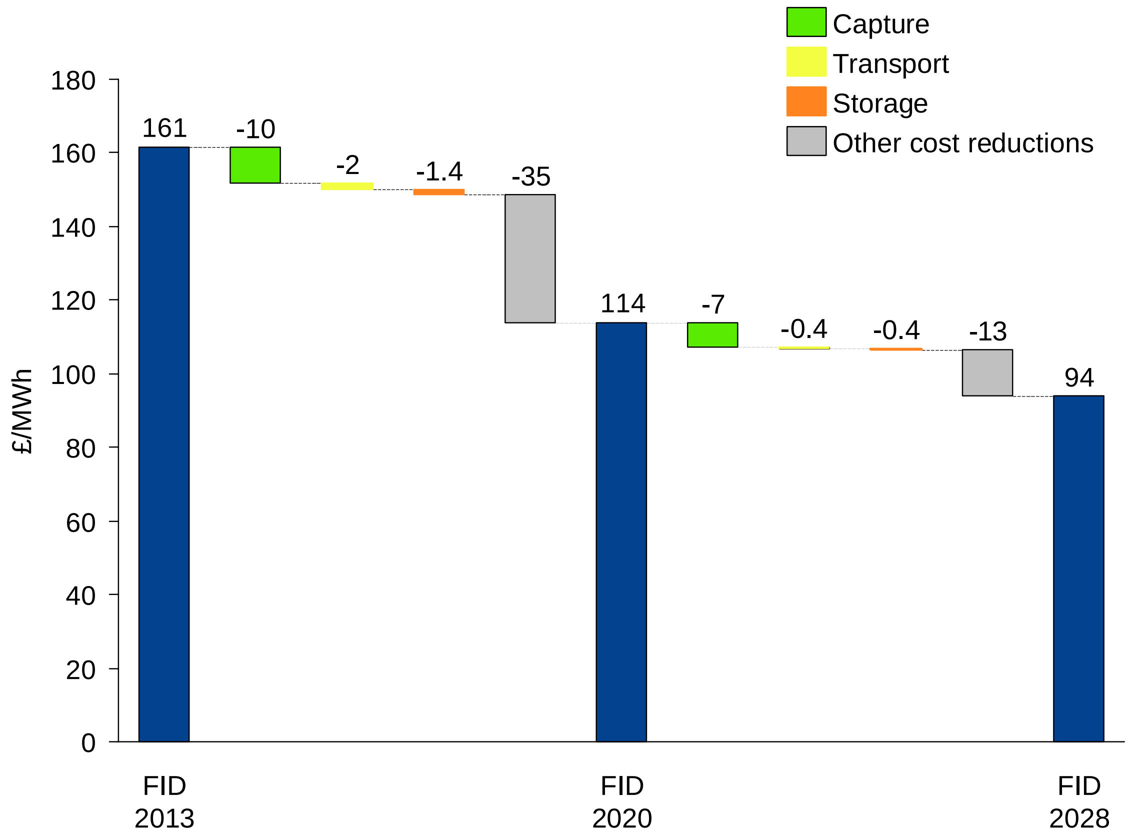
11 "ClimateWise (2012): Managing Carbon Capture and Storage Liabilities in Europe" http://www.climatewise.org.uk/

12 It is noted that the 'correct' cost of capital figure is uncertain even for established industries and differing assumptions can drive very different results for LCOE calculations. The numbers stated have taken the Mott Macdonald report as a starting point and are regarded by the Task Force as broadly appropriate for this kind of analysis. However, it should be recognised that individual Task Force members choose to use (sometime very) different numbers in their own internal analysis.

Figure 3 shows cost reduction mechanisms from accessing affordable finance for the CCs chain. The 'Other reductions' category includes the cost reduction measures achievable by the other cost reduction pathways in this report. These are discussed in Chapters 3 and 4 above.

Figure 3 – Potential cost reduction mechanisms relating to improved financeability (real 2012 £/MWh)



Modelling results indicate that the capture section of the chain has the most to gain from mechanisms that improve financeability; this is to be expected because it retains the largest cost elements.

The cost reduction shown here is actually relatively small for the Transport and Storage sectors. This is because this shows only financial and commercial impacts in isolation. The greatest savings in these sectors are harnessed from the economies of scale discussed in Section 3. In reality the de-risking of the sector as discussed in Section 5.1, will be essential to the financing and building of large scale infrastructure. As such the combined impact of **not** undertaking the cost saving routes discussed in this Chapter would be much greater than Figure 3 indicates due to their necessity for other aspects of cost saving.

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6. LEVERAGING THE BENEFITS OF CCS

Developing a CCS industry in the UK has the potential to create significant value not only through low cost power production but also within the Oil and Gas sector and by stimulating other areas of the economy. Many of these benefits are cross-workstream so we discuss them separately here.

6.1 Encouraging EOR

CO_2 injection into oil fields is one method of recovering otherwise unrecoverable oil from mature oil fields, creating additional income to offset CCS costs, and deferring oil and gasfield decommissioning costs. The Central North Sea (CNS) oil province is mature with many fields set to close in the next decade and therefore suitable for EOR developments. However, developing CO_2 led EOR will also require capital investment in new equipment at each field of the order of £1bn.

CCS and CO_2-based EOR could fit together extremely well; use of CO_2 for EOR provides a way of monetising a waste product, and permanently disposing of the CO_2 at the same time. This is a key reason for the financial success of many CCS projects in the USA and Canada.

A word of caution is needed, as not all CNS fields are suitable for CO_2 EOR campaigns, and there is no direct experience of offshore CO_2 EOR in the CNS or elsewhere. However, several oil companies are actively exploring the option of pursuing CO_2-based EOR on a number of fields in the CNS.

Recent work on the overall value of EOR opportunities such as the Scottish Enterprise Study on the 'Economic Impacts of CO_2-enhanced oil recovery for Scotland' and the University of Aberdeen's Occasional Paper on the 'Economics of CO_2-EOR in the UK Central North Sea' add testimony to this view.

However neither of the above papers takes the step of looking at the potential impact for LCOE of CCS power projects. Only a rough estimate can be made currently of the value that CO_2 may attract if it were delivered at pressure to CNS oil field operators. There is uncertainty in both the overall EOR value and the likely split of value between government, CO_2 provider and EOR developer. Indeed, these values are likely to vary significantly according to the features of each field/project. However, based on US experience the value could well cover the cost of conventional CO_2 storage, and perhaps some of the transport costs as well. As a result this might decrease electricity costs by £5-12/MWh for gas CCS and £10-26/MWh for coal CCS.

It is the view of informed Task Force members, and others who have been consulted, that EOR investments will be actively pursued, and probably sanctioned on some fields, as soon as there is confidence that CO_2 is being delivered to the CNS; and that this will reduce the cost of electricity from some of the power project investments which are expected to be built in the early 2020s. This can act as a stimulus to:

- maintain or extend existing and future offshore infrastructure;
- provide high-quality employment as well as protecting the existing offshore service industry; and
- provide oil and gas tax revenues.

Candidate Action: Stakeholders to work together to consider what measures could encourage CO_2 EOR in the UK.

6.2 Industrial CCS

Only around 40% of UK GHG emissions originate from the energy supply sector. If CCS is developed for the power sector, there is potential significant further opportunity to leverage the benefits of symbiosis between CO_2 capture from power stations with CO_2 capture from industrial sources.

In the absence of an existing CO_2 transport and storage network the low volumes of CO_2 generated at individual sites are unlikely to make underground storage of CO_2 a viable option for non-power industrial CO_2 sources. The large economies of scale associated with CO_2 storage and transport simply make it uneconomic.

However, the industrial processes are such that often CO_2 can be captured at a reasonably high purity for relatively low unit cost. If this CO_2 can be fed into already existing transport and storage networks then the incremental cost of the additional CO_2 saving would be very low.

Whilst the decarbonisation benefits may be attractive from a UK perspective industrial CCS is not necessarily economic to industrial emitters. As the CO_2 price faced by industrial emitters under the European Union Emission Trading Scheme (EU ETS) is so low – averaging around €8/tCO_2 in 2012 to date – abatement from these sources is not currently economic even though it may be significantly less costly than power sector decarbonisation.

This situation is expected to change as the EU ETS price increases during Phase III and Phase IV but the timing and extent of this rise is currently unclear. If industrial sectors faced higher costs of emissions earlier (as is the case for the power sector with a Carbon Price Floor) we would expect to see industrial CCS becoming more attractive.

The Task Force believe that encouraging industrial CCS would further reduce UK GHG emissions but also help to safeguard the competitiveness of UK industries as the costs of emitting CO_2 under schemes such as the EU ETS increases over time.

Candidate Action: Investigate options to incentive the development of industrial CCS projects.

6.3 Additional hydrogen value

IGCCs involve a process that produces decarbonised hydrogen in bulk that is then transported and combusted to produce low-CO_2 power. There is scope for the hydrogen to be fed into higher value uses and harder to access carbon abatement areas and not only in direct large-scale power generation facilities. This includes:

- providing feedstock for industry (as is currently the case on Teesside, Merseyside and elsewhere);
- smaller CHP installations;
- in the longer term, the opportunity to provide low carbon transport; and
- remote decarbonisation of CCGT power plant through a wider hydrogen network.

Banking of gasifiers would provide economies of scale benefits and produce sufficient volumes of hydrogen to feed into multiple processes. Whilst appropriate technology for such a system is under development, it would require a high level of integration of the source and use of hydrogen to achieve a viable financial proposition.

6.4 Wider Energy System Benefits

Energy system modelling by the Energy Technologies Institute suggests that successful deployment of CCS would be a major prize for the UK economy, cutting the annual costs of meeting carbon targets by up to 1% of GDP (or around £42 billion per year) by 2050.

Section 1.1 describes the important role that CCS is envisaged to play in a decarbonised UK electricity mix. There are significant network management benefits to introducing alternative, potentially flexible, sources of low-carbon electricity especially when it is installed alongside intermittent generation.

DECC's Technology Innovation Need Assessment released in August 2012 highlights the potential role of CCS in the UK's energy system:

- Having CCS available (compared to an energy system without CCS) is estimated to save the UK hundreds of billions of GBP in cumulative value between 2010 and 2050. Nevertheless, considerable work remains to demonstrate CCS at large scale and across the entire chain.
- CCS offers many benefits to a low-carbon energy and economic system as it allows the flexibility and energy security benefits of fossil fuel combustion with near-zero GHG emissions.

Therefore not only will CCS provide low carbon generation to the grid, alongside other low carbon options such as renewables and nuclear, it can also provide two additional services:

- Provision of secure power – unlike intermittent forms of generation, CCS can be scheduled so that it has a very high level of availability at times of peak demand on the grid; and
- Provision of flexibility – the electricity system must be balanced instantaneously by the System Operator to maintain the necessary level of electricity supply stability. CCS has the capability to both increase and decrease generation levels relatively quickly (compared to many other forms of low carbon generation).

We have loosely grouped these as the additional 'energy system' value of CCS. As the proportion of intermittent generation on the grid increases it is likely that the value of these services will increase.

It is not currently clear how these benefits will be rewarded for CCS plants under current market arrangements.

Candidate Action: Develop work to examine how CCS can operate to deliver flexible rather than base-load electricity generation.

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7. CONCLUSIONS

The Cost Reduction Task Force's objective was to examine the long-term outlook for generation costs from power stations that capture and store their carbon dioxide emissions. Many scenarios suggest that CCS power stations are likely to be a major component of the British decarbonisation targets for 2050. Indeed the flexibility of operation that gas- and coal-fired CCS power stations can offer may be essential in complementing the intermittent output of the wind generation fleet.

At this early stage of deployment, with even the few reference points of the costs of operation being largely based on technical studies rather than operation, this exercise has required members of the Task Force to use their experience to forecast the costs as the industry reaches maturity. Such an exercise has required:

- combining expertise from a technical point of view for the generation and capture part;
- understanding of the impact of developing a major infrastructure for the transport and storage part; as well as; and
- projecting the complex way in which commercial and financial arrangements grow from those appropriate to early projects those expected of a well-established industry.

With the collected experience of 30 members and contributors directly involved in all aspects of CCS project development, this Task Force is well-qualified to address the above issues.

Having the right landscape…

It is clear from the previous sections of this Report that significant cost reductions are to be expected provided the right landscape engenders them.

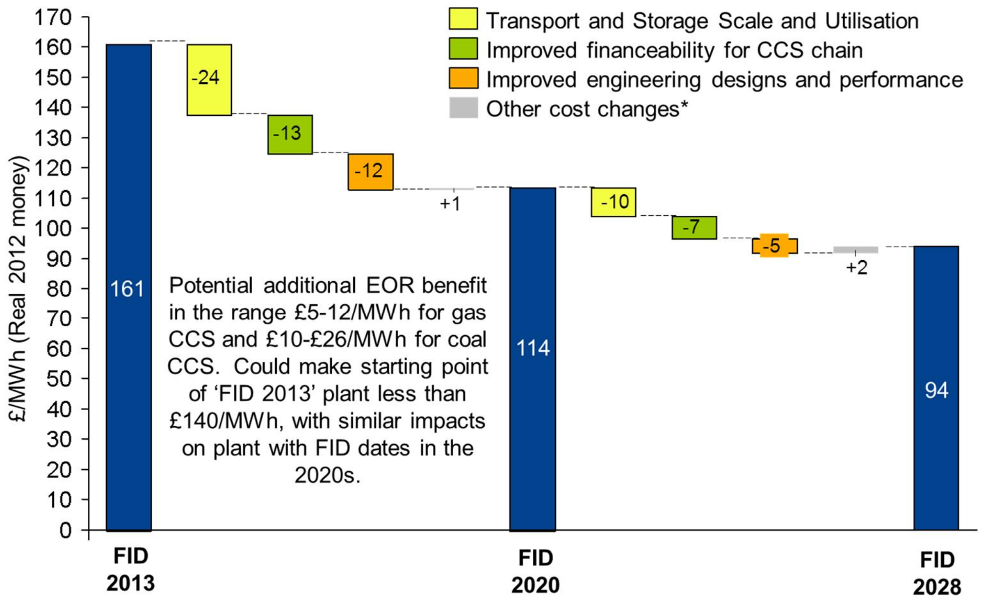
Key components of the right landscape are as follows:

- Credible and long-term UK commitment to CCS by government and industry which includes a recognition of the role of CCS in the future generation mix, as well as a coordinated plan for transport and storage and an appropriate underpinning regulatory landscape;
- Multiple operating full-chain CCS plants that build on the current commercialisation programme; and
- Continued engagement with the financial sector, so that the industry and government jointly create access to low cost finance for CCS.

…delivering the cost reductions

With this landscape in place, the overall cost reduction path for baseload CCS generation is shown in Figure 4, which translates the cost savings identified in Chapters 3, 4 and 5 – expressing them in terms of LCOE. For simplicity the diagram averages costs from the different technical approaches to capture, and takes as its starting point the baseline of a hypothetical full scale CCS-equipped power station reaching FID in 2013.

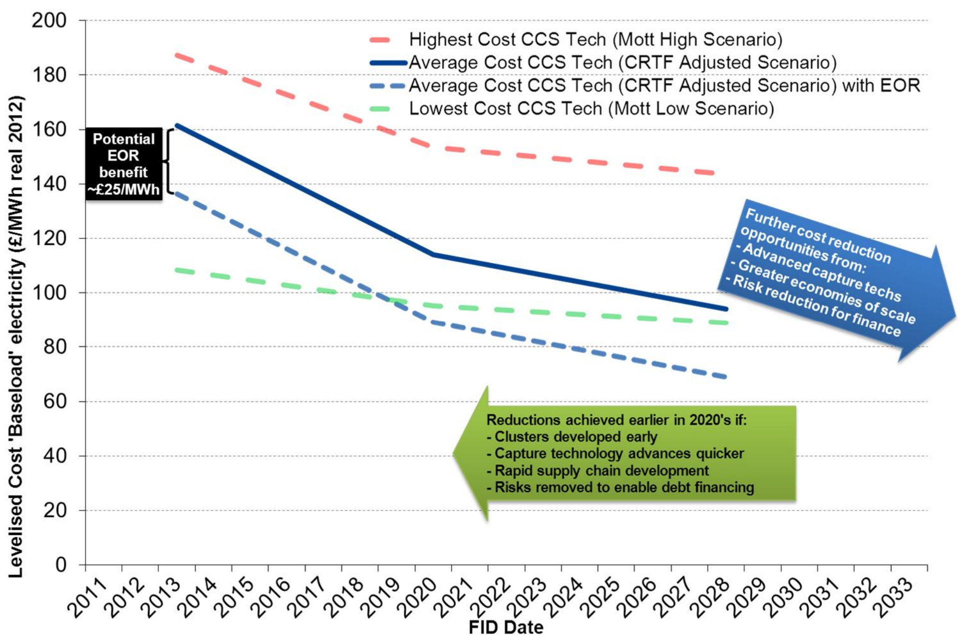
Figure 4 – Potential cost reduction mechanisms for CCS between plants reaching FID in 2013, 2020 and 2028 (technology average, 2012 £/MWh)



Note: Shows average costs across technologies. *E.G. Increasing CO_2 price, falling storage abandonment costs

If we take into account realistic ranges in both the overall costs of different technical approaches, and also in the range of cost reductions, we see a very significant downward trend. Figure 5 illustrates the trend for a baseload electricity station. The material potential for further reducing costs by incorporating EOR projects is also shown in this diagram.

Figure 5 – Range of cost reduction opportunities for CCS



…generating at costs comparable to other low carbon technologies

Several recent reports have suggested that offshore wind generation has the potential to reach LCOE of the order of £100/MWh, and this seems to be gradually being adopted as a benchmark for all low-carbon technologies.

It is clear that Carbon Capture and Storage will be a direct economic competitor with more traditional 'renewables' – and even more so when its ability to back-up wind intermittency is taken into account.

Still significant challenges ahead

It is by no means a given that these low cost levels will be reached: both Government and Industry will need to play their part, and while there are some clear policy gaps in the current CCS policy framework, industry has a significant contribution to make.

The Task Force is confident that this future is possible.

Note

As an interim report, the above conclusions may be modified somewhat as final packages of analysis are completed.

Additional programme of work to be included in the final report

In the six months since the Task Force was convened a great deal of very intensive work has been undertaken to prepare this interim report. The purpose of preparing an interim report was to take stock of the accumulated knowledge and understanding of this highly complex subject. The report will inform the Minister on the thinking of the Task Force to date at an important time of energy policy development and will establish a baseline on which the Task Force can base its on-going programme of work.

Throughout the report there are recommended candidate actions that may place an onus on the various different stakeholders to put in place measures that will ultimately lead to CCS cost reductions. It should be recognised that many of these actions are already in progress such as for example various policy matters already under developments as well as on-going technical R&D being undertaken by all stakeholders.

The next meeting of the Task Force to be convened soon after the publication will have its objective to examine the conclusions of the report and its candidate actions, to isolate and prioritise those actions that would otherwise not happen and to recommend or to allocate actions to ensure fulfilment of the cost reduction objective.

It is intended that a final report will be delivered to the Minister in Spring 2013.

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ANNEX A – BASIS OF MODELLING ASSUMPTIONS

The baseline agreed for this work is a derivative of estimated costs outlined in the DECC report by Mott Macdonald 2012. These costs were modelled in detail using the supporting information provided by Mott MacDonald.

Examining the "Mott High" and "Mott Low" scenarios, the opinions of the Task Force (on the sub-set of information contained in that model) were used to form a new baseline. This Baseline is titled the "Cost Reduction Task Force Adjusted Path" and is referenced when discussing cost reduction opportunities, and their impacts, within this report.

A.1 Summary of cost outputs for CRTF adjusted path

In general the cost assumptions made in the Mott Low Cost pathway were supported by the Task Force as achievable given the actions and recommendations in this report. The high cost pathway was regarded as representative of a world where the cost reduction opportunities presented here were not exploited (and was therefore not appropriate from the perspective of cost reduction opportunities).

The following is a brief description of the plant types and CCS industry position from which the adjusted cost path was derived. Where aspects are highlighted in red they have been adjusted compared to the Mott Macdonald Low Cost Pathway. Fuel prices have been kept equal to those contained in the Mott Macdonald report (based on 2011 DECC central case) to ensure results are comparable. As with the Mott Macdonald work, the cost estimates include costs for a base (or host) plant and as such are focused on newly constructed CCS projects rather than the retrofit of CCS to existing power stations.

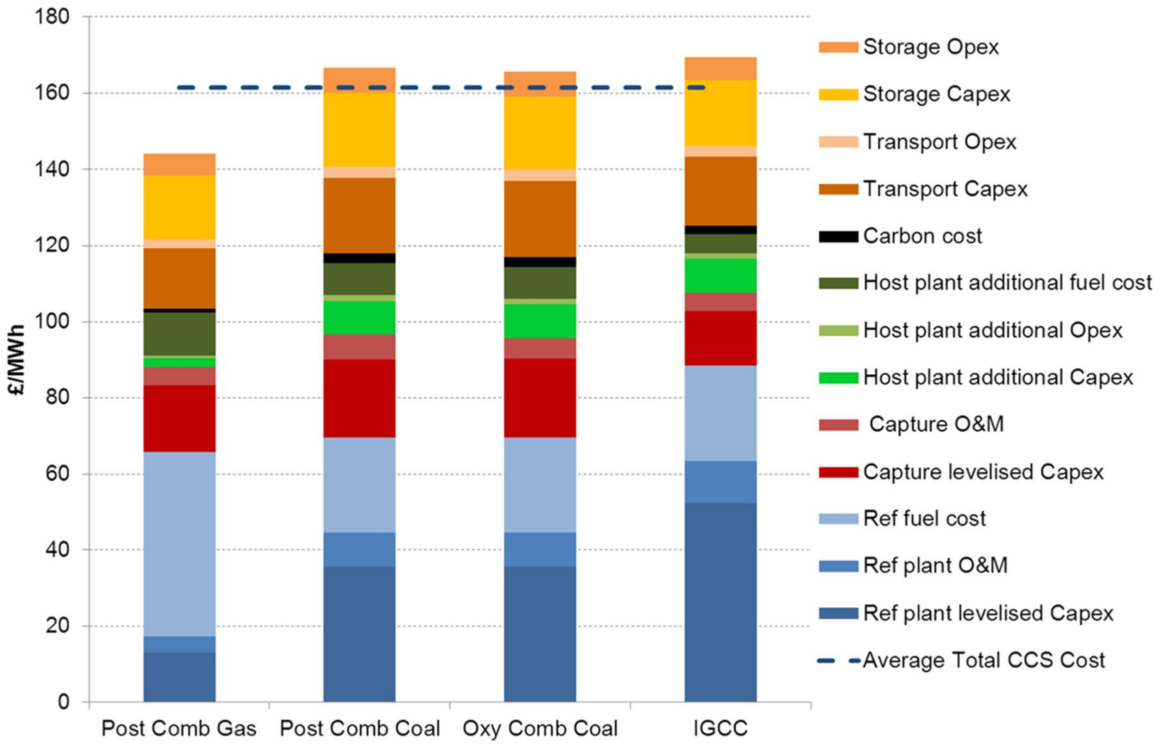
It should be recognised that the levelised cost of electricity from CCS will be partially driven by aspects unrelated to the cost reductions in this report. In particular these aspects include intentionally-driven commodity prices and, in some circumstances, the eventual load factor of the plants.

A.1.1 2013

- FID in 2013
- ~300MW net electrical output for both coal and gas plants, single projects
  - Not a specific design but using BAT technology
- Assumptions on all capex & opex from the Mott 2013 Low scenario
  - Host gas plant 54% HHV & £550/kW; Host post-comb coal plant 43% HHV & £1400/kW; Host oxy-comb coal plant 43% HHV & £1500/kW; IGCC 43% HHV & £2200/kW.
  - Energy penalty 25% for PC Coal & Oxy Coal, 17% for IGCC and 19% for PC Gas
- Plants capture 85% of the CO_2 produced and run at 80% load factor
- CO_2 transported 30km onshore and then 300km offshore in appropriate scale pipes (10'' for gas [1mtpa], 15'' for coal [2mtpa]) in dense phase and then stored in a DOGF
- We assume a 15 year economic lifetime for all components (inc. base plant, capture, transport and storage) with no terminal value
  - Shorter than standard due to the current lack of maturity of technology, assumed to increase to 25 years in the 2020s

- Pre-tax real Weighted Average Cost of Capital (WACC) assumption is 10% on the generation and capture, 10% on the transport pipeline infrastructure and 15% on the Storage
- Developer contingency included as a 10% uplift on all capital costs (supplier contingency is assumed to be contained in the capital cost estimates)

Figure 6 – LCOE of FID 2013 CCS technologies (£/MWh 2012 money)

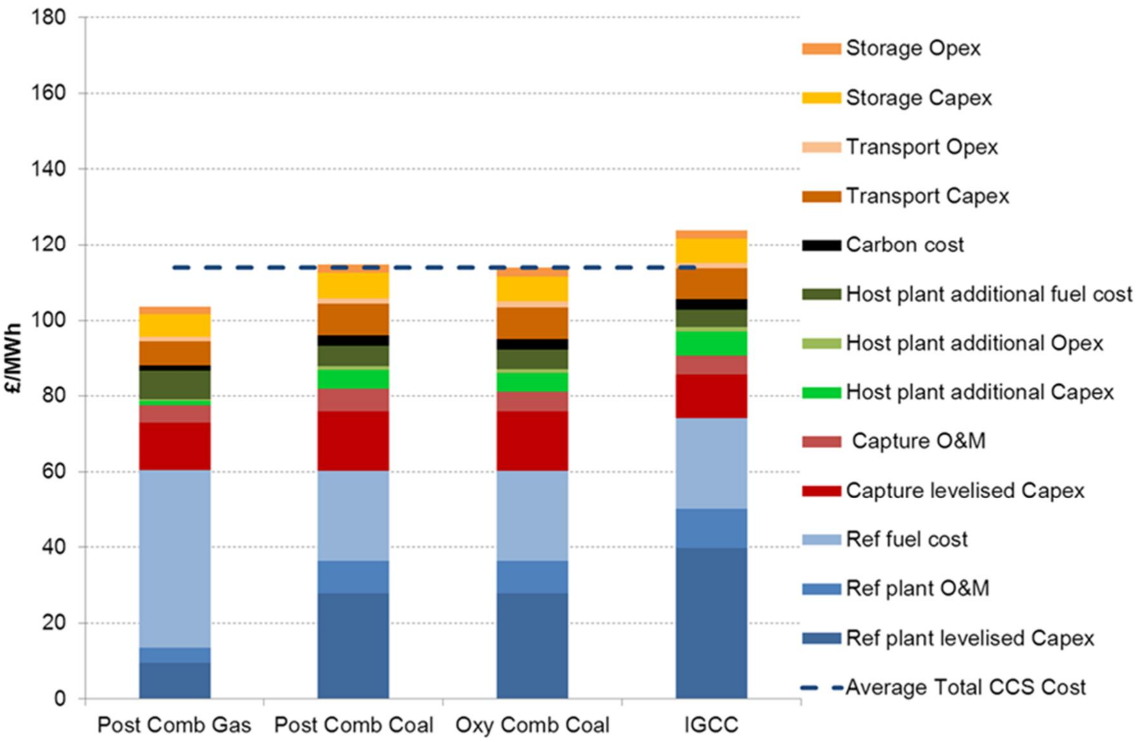


£/MWh	Post Comb Gas	Post Comb Coal	Oxy Comb Coal	IGCC
Ref plant levelised Capex	13.1	35.6	35.6	52.2
Ref plant O&M	4.2	8.9	8.9	11.1
Ref fuel cost	48.7	25.1	25.1	25.1
Capture levelised Capex	17.3	20.5	20.6	14.2
Host plant additional Capex	2.5	8.9	8.9	8.9
Host plant additional Opex	0.4	1.5	1.5	1.5
Capture O&M	4.9	6.4	5.4	4.9
Host plant additional fuel cost	11.4	8.4	8.4	5.1
Carbon cost	1.1	2.5	2.5	2.3
Transport Capex	15.8	20.0	20.0	18.1
Transport Opex	2.4	3.0	3.0	2.7
Storage Capex	16.8	19.2	19.2	17.3
Storage Opex	5.7	6.5	6.5	5.9
Total	144.1	166.5	165.6	169.3
Average Total CCS Cost	**161.4**	**161.4**	**161.4**	**161.4**

A.1.2 2020

- FID in 2020
- ~800MW net electrical output for coal, ~600MW for gas, single projects
- Full commercial scale brings significant economies of scale benefits in capture, transport and storage
- Projects benefit from partial economies of scale in transport & storage but not yet part of large, well utilised clusters
- Not a specific design but using BAT technology
- Assumptions on all capex and opex from Mott 2020 Low (recognising potential range)
- Host gas plant 56% HHV & £500/kW; post-combustion coal plant 45% HHV & £1400/kW; oxyfuel coal plant 45% HHV & £1400/kW ; IGCC 45% HHV & £2000/kW
- Energy penalty 18% for PC Coal & Oxy Coal, 16% for IGCC and 14% for PC Gas
- Plants capture 90% of the CO_2 produced and run at 80% load factor
- CO_2 transported 40km onshore and then 300km offshore in appropriately scaled pipes (15'' for gas [2mtpa], 18'' for coal [4mtpa]) in dense phase and then stored in a DOGF
- We assume a 25 year economic lifetime for all components (inc. base plant, capture, transport and storage) with no terminal value
- Pre-tax real WACC assumption is 10% on the generation and capture, 10% on the transport pipeline infrastructure and 14% on the Storage
  - 1% lower than 2013 as risk perception lowered on storage component (still 4% higher than Mott Low Cost path assumption)
- Developer contingency included as a 10% uplift on all capital costs (supplier contingency is assumed to be contained in the capital cost estimates).

Figure 7 – LCOE of FID 2020 CCS technologies (£/MWh 2012 money)

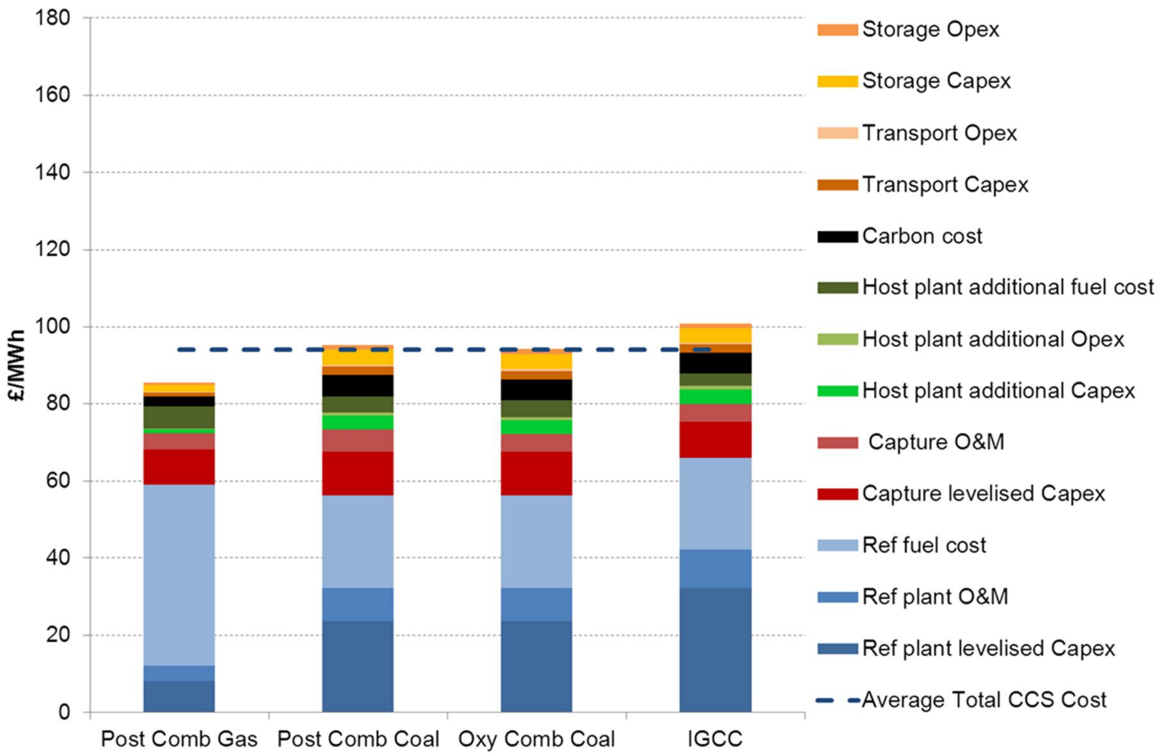


£/MWh	Post Comb Gas	Post Comb Coal	Oxy Comb Coal	IGCC
Ref plant levelised Capex	9.5	27.8	27.8	39.8
Ref plant O&M	4.0	8.5	8.5	10.3
Ref fuel cost	46.9	24.0	24.0	24.0
Capture levelised Capex	12.5	15.5	15.6	11.7
Host plant additional Capex	1.3	5.0	5.0	6.4
Host plant additional Opex	0.3	1.0	1.0	1.3
Capture O&M	4.6	6.1	5.1	4.8
Host plant additional fuel cost	7.6	5.3	5.3	4.6
Carbon cost	1.3	2.8	2.8	2.7
Transport Capex	6.4	8.3	8.3	8.1
Transport Opex	1.2	1.5	1.5	1.5
Storage Capex	6.0	6.7	6.7	6.5
Storage Opex	2.1	2.3	2.3	2.2
Total	103.7	114.7	113.9	123.8
Average Total CCS Cost	**114.0**	**114.0**	**114.0**	**114.0**

A.1.3 2028

- FID in 2028
- ~800MW+ net electrical output for coal, ~600MW+ for gas
  - Clusters allow for higher CO_2 flow than from the single station – 15mpta through the network
- Not a specific design but using BAT technology
- Assumptions on all capex and opex from Mott 2028 Low figures
- Host gas plant 56% HHV & £500/kW; post-combustion coal plant 45% HHV & £1400/kW; oxyfuel coal plant 45% HHV & £1400/kW ; IGCC 45% HHV & £1900/kW
- Energy penalty 15% for PC Coal & Oxy Coal, 12% for IGCC and 11% for PC Gas
- Plants capture 90% of the CO_2 produced and run at 80% load factor
- CO_2 transported 40 km onshore and then 300km offshore in appropriate scale pipes (36'' for both gas and coal - 15mtpa) in dense phase and then stored in a DOGF
- We assume a 25 year economic lifetime for all components (inc. base plant, capture, transport and storage) with no terminal value
- Pre-tax real WACC assumption is 8% on the generation and capture, 8% on the transport pipeline infrastructure and 12% on the Storage
  - Fall of 2-3% from 2013 as some risk has been removed from due to 'landscape' actions and project finance is now available for at least certain aspects. Storage WACC still 2% higher than Mott assumption.
- Developer contingency included as a 10% uplift on all capital costs (supplier contingency is assumed to be contained in the capital cost estimates).

Figure 8 – LCOE of FID 2028 CCS technologies (£/MWh 2012 money)



£/MWh	Post Comb Gas	Post Comb Coal	Oxy Comb Coal	IGCC
Ref plant levelised Capex	8.1	23.7	23.7	32.1
Ref plant O&M	4.0	8.5	8.5	10.0
Ref fuel cost	46.9	24.0	24.0	24.0
Capture levelised Capex	9.2	11.5	11.4	9.2
Host plant additional Capex	0.9	3.6	3.6	3.9
Host plant additional Opex	0.2	0.8	0.8	0.9
Capture O&M	4.2	5.7	4.7	4.6
Host plant additional fuel cost	5.8	4.2	4.2	3.3
Carbon cost	2.5	5.5	5.5	5.3
Transport Capex	1.0	2.2	2.2	2.1
Transport Opex	0.2	0.5	0.5	0.4
Storage Capex	1.9	3.9	3.9	3.7
Storage Opex	0.6	1.4	1.4	1.3
Total	85.6	95.3	94.2	100.8
Average Total CCS Cost	**94.0**	**94.0**	**94.0**	**94.0**

A.2 Generation and capture assumptions

A.2.1 Post-combustion coal

Post Combustion Coal			Low cost path				High cost path				Adjusted path		
			2013	2020	2028	2040	2013	2020	2028	2040	2013	2020	2028
Capture	ACF	%	80%	80%	80%	80%	60%	60%	60%	60%	80%	80%	80%
Capture	WACC	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	8%
Capture	Plant life	Years	15	30	30	30	15	20	25	30	15	25	25
Capture	Energy penalty	%	25%	23%	18%	13%	26%	24%	22%	18%	25%	18%	15%
Both	Energy cost	£/GJ	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Capture	Tech. component: Dev.etc	£/kW	67	63	60	57	77	77	74	71	67	63	60
Capture	Tech. component: Absorbers	£/kW	350	304	256	226	403	398	375	353	350	304	256
Capture	Tech. component: Regen.	£/kW	125	113	97	88	144	141	133	127	125	113	97
Capture	Tech. component: Compres.	£/kW	216	203	180	158	248	239	229	220	216	203	180
Capture	Tech. component: Host plant	£/kW	375	322	252	182	442	384	352	288	375	322	252
Capture	Tech. component: BoP	£/kW	108	98	87	77	124	123	118	111	108	98	87
Capture	VOM (CCS)	% capex	3.00	3.00	3.00	3.00	4.00	4.00	4.00	4.00	3.00	3.00	3.00
Ref	Specific Capex (Ref Plant)	£/kW	1500	1400	1400	1400	1700	1600	1600	1600	1500	1400	1400
Ref	ACF (Ref Plant)	%	80%	80%	80%	80%	60%	60%	60%	60%	80%	80%	80%
Ref	WACC (Ref Plant)	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	8%
Ref	Plant life (Ref Plant)	Years	30	30	30	30	25	25	25	30	15	25	25
Ref	VOM (Ref Plant)	% capex	3.0	3.0	3.0	3.0	4.0	4.0	4.0	4.0	3.0	3.0	3.0
Both	Carbon cost	£/tCO2	16	30	62	110	16	30	62	110	16	30	62
Both	% Carbon stored	%	85%	85%	85%	85%	85%	85%	85%	85%	85%	90%	90%
Both	Implied IDC %	%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Both	CO2 content of fuel	tCO2/tFuel	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341
Capture	Efficiency of plant (CCS)	%	30%	31%	33%	35%	30%	30%	31%	33%	32%	37%	38%
Ref	Efficiency of plant (Ref)	%	40%	40%	40%	40%	40%	40%	40%	40%	43%	45%	45%
Both	FOM %	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
All (inc. T&S)	Developer contingency	%	0%	0%	0%	0%	0%	0%	0%	0%	10%	10%	10%

A.2.2 Post-combustion gas

Post Combustion Gas			Low cost path				High cost path				Adjusted path		
			2013	2020	2028	2040	2013	2020	2028	2040	2013	2020	2028
Capture	ACF	%	80%	80%	80%	80%	60%	60%	60%	60%	80%	80%	80%
Capture	WACC	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	8%
Capture	Plant life	Years	15	30	30	30	15	20	25	30	15	25	25
Capture	Energy penalty	%	15%	14%	11%	7%	16%	15%	13%	10%	19%	14%	11%
Both	Energy cost	£/GJ	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
Capture	Tech. component: Dev.etc	£/kW	55	52	50	47	66	66	64	61	55	52	50
Capture	Tech. component: Absorbers	£/kW	310	269	226	200	372	368	347	326	310	269	226
Capture	Tech. component: Regen.	£/kW	120	108	93	84	144	141	133	128	120	108	93
Capture	Tech. component: Compres.	£/kW	150	141	125	110	180	173	166	160	150	141	125
Capture	Tech. component: Host plant	£/kW	83	70	55	35	88	83	72	55	83	70	55
Capture	Tech. component: BoP	£/kW	95	86	77	67	114	113	108	102	95	86	77
Capture	VOM (CCS)	% capex	2.00	2.00	2.00	2.00	3.00	3.00	3.00	3.00	2.00	2.00	2.00
Ref	Specific Capex (Ref Plant)	£/kW	550	500	500	500	550	550	550	550	550	500	500
Ref	ACF (Ref Plant)	%	80%	80%	80%	80%	60%	60%	60%	60%	80%	80%	80%
Ref	WACC (Ref Plant)	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	8%
Ref	Plant life (Ref Plant)	Years	25	30	30	30	20	20	25	30	15	25	25
Ref	VOM (Ref Plant)	% capex	2.0	2.0	2.0	2.0	3.0	3.0	3.0	3.0	2.0	2.0	2.0
Both	Carbon cost	£/tCO2	16	30	62	110	16	30	62	110	16	30	62
Both	% Carbon stored	%	85%	85%	85%	85%	85%	85%	85%	85%	85%	90%	90%
Both	Implied IDC %	%	10%	10%	10%	10%	10%	10%	10%	10%	15%	10%	10%
Both	CO2 content of fuel	tCO2/tFuel	0.202	0.202	0.202	0.202	0.202	0.202	0.202	0.202	0.202	0.202	0.202
Capture	Efficiency of plant (CCS)	%	46%	46%	48%	50%	45%	45%	46%	48%	44%	48%	50%
Ref	Efficiency of plant (Ref)	%	54%	54%	54%	54%	53%	53%	53%	53%	54%	56%	56%
Both	FOM %	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
All (inc. T&S)	Developer contingency	%	0%	0%	0%	0%	0%	0%	0%	0%	10%	10%	10%

A.2.3 Oxyfuel combustion coal

Oxy-Combustion Coal			Low cost path				High cost path				Adjusted path		
			2013	2020	2028	2040	2013	2020	2028	2040	2013	2020	2028
Capture	ACF	%	80%	80%	80%	80%	60%	60%	60%	60%	80%	80%	80%
Capture	WACC	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	8%
Capture	Plant life	Years	15	30	30	30	15	20	25	30	15	25	25
Capture	Energy penalty	%	25%	22%	16%	11%	26%	24%	21%	17%	25%	18%	15%
Both	Energy cost	£/GJ	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Capture	Tech. component: Dev.etc	£/kW	67	63	60	57	80	80	78	74	67	63	60
Capture	Tech. component: Air Sep.	£/kW	280	243	200	177	336	329	301	283	280	243	200
Capture	Tech. component: Conditioning	£/kW	200	181	152	136	240	233	213	204	200	181	152
Capture	Tech. component: Compres.	£/kW	216	203	176	155	259	246	237	227	216	203	176
Capture	Tech. component: Host plant	£/kW	375	308	224	154	442	384	336	272	375	308	224
Capture	Tech. component: BoP	£/kW	107	97	87	76	128	127	122	115	107	97	87
Capture	VOM (CCS)	% capex	2.00	2.00	2.00	2.00	3.00	3.00	3.00	3.00	2.00	2.00	2.00
Ref	Specific Capex (Ref Plant)	£/kW	1500	1400	1400	1400	1700	1600	1600	1600	1500	1400	1400
Ref	ACF (Ref Plant)	%	80%	80%	80%	80%	60%	60%	60%	60%	80%	80%	80%
Ref	WACC (Ref Plant)	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	8%
Ref	Plant life (Ref Plant)	Years	30	30	30	30	25	25	25	30	15	25	25
Ref	VOM (Ref Plant)	% capex	3.0	3.0	3.0	3.0	4.0	4.0	4.0	4.0	3.0	3.0	3.0
Both	Carbon cost	£/tCO2	16	30	62	110	16	30	62	110	16	30	62
Both	% Carbon stored	%	85%	85%	85%	85%	85%	85%	85%	85%	85%	90%	90%
Both	Implied IDC %	%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Both	CO2 content of fuel	tCO2/tFuel	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341
Capture	Efficiency of plant (CCS)	%	30%	31%	34%	36%	30%	30%	32%	33%	32%	37%	38%
Ref	Efficiency of plant (Ref)	%	40%	40%	40%	40%	40%	40%	40%	40%	43%	45%	45%
Both	FOM %	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
All (inc. T&S)	Developer contingency	%	0%	0%	0%	0%	0%	0%	0%	0%	10%	10%	10%

A.2.4 IGCC

IGCC			Low cost path				High cost path				Adjusted path		
			2013	2020	2028	2040	2013	2020	2028	2040	2013	2020	2028
Capture	ACF	%	80%	75%	70%	65%	60%	55%	50%	45%	80%	80%	80%
Capture	WACC	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	8%
Capture	Plant life	Years	15	30	30	30	15	20	25	30	15	25	25
Capture	Energy penalty	%	17%	16%	12%	10%	20%	19%	17%	15%	17%	16%	12%
Both	Energy cost	£/GJ	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Capture	Tech. component: Dev.etc	£/kW	60	59	58	56	72	72	71	71	60	59	58
Capture	Tech. component: Water shift	£/kW	200	198	183	165	240	242	242	238	200	198	183
Capture	Tech. component: Conditioning	£/kW	160	155	140	131	192	192	192	188	160	155	140
Capture	Tech. component: Compres.	£/kW	80	78	72	65	96	94	94	94	80	78	72
Capture	Tech. component: Host plant	£/kW	374	320	228	180	500	456	391	330	374	320	228
Capture	Tech. component: BoP	£/kW	100	96	90	83	120	121	119	119	100	96	90
Capture	VOM (CCS)	% capex	2.50	2.50	2.50	2.50	3.00	3.00	3.00	3.00	2.50	2.50	2.50
Ref	Specific Capex (Ref Plant)	£/kW	2200	2000	1900	1800	2500	2400	2300	2200	2200	2000	1900
Ref	ACF (Ref Plant)	%	80%	80%	80%	80%	60%	60%	60%	60%	80%	80%	80%
Ref	WACC (Ref Plant)	%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	8%
Ref	Plant life (Ref Plant)	Years	30	30	30	30	20	20	25	30	15	25	25
Ref	VOM (Ref Plant)	% capex	2.5	2.5	2.5	2.5	3.0	3.0	3.0	3.0	2.5	2.5	2.5
Both	Carbon cost	£/tCO2	16	30	62	110	16	30	62	110	16	30	62
Both	% Carbon stored	%	85%	85%	85%	85%	85%	85%	85%	85%	85%	90%	90%
Both	Implied IDC %	%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Both	CO2 content of fuel	tCO2/tFuel	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341
Capture	Efficiency of plant (CCS)	%	33%	34%	35%	36%	32%	32%	33%	34%	36%	38%	40%
Ref	Efficiency of plant (Ref)	%	40%	40%	40%	40%	40%	40%	40%	40%	43%	45%	45%
Both	FOM %	%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
All (inc. T&S)	Developer contingency	%	0%	0%	0%	0%	0%	0%	0%	0%	10%	10%	10%

A.3 Transport Assumptions

Transport capital and operational cost assumptions have been taken from the Mott Macdonald report. Only minor adjustments have been made for the CRTF adjusted scenario at this point, largely regarding the assumed throughput of CO_2 and pipeline diameters in FID 2013 and 2020 gas projects. The amortisation rate and period applied to the capital expenditure has also been adjusted to better reflect Task Force estimates. It should be recognised that the simplified approach taken in these kinds of LCOE calculations can only partially reflect real-world financial arrangements.

Common assumptions			**2013**	**2020**	**2028**	**2040**
Subsea	Subsea Capex 10"	£/km	0.77	0.69	0.66	0.63
Subsea	Subsea Capex 15"	£/km	0.85	0.77	0.73	0.69
Subsea	Subsea Capex 18"	£/km	1.00	0.90	0.86	0.81
Subsea	Subsea Capex 36"	£/km	1.25	1.13	1.07	1.02
Subsea	Subsea Opex %	%	2.0%	2.0%	2.0%	2.0%
Subsea & onshore	Throughput 10"	mtpa	1	1	1	1
Subsea & onshore	Throughput 15"	mtpa	2	2	2	3
Subsea & onshore	Throughput 18"	mtpa	2	4	4	5
Subsea & onshore	Throughput 36"	mtpa	2	10	15	18
Onshore	Onshore Capex 10"	£/km	0.39	0.35	0.33	0.31
Onshore	Onshore Capex 15"	£/km	0.43	0.38	0.36	0.35
Onshore	Onshore Capex 18"	£/km	0.50	0.45	0.43	0.41
Onshore	Onshore Capex 36"	£/km	0.63	0.56	0.53	0.51
Onshore	Onshore opex %	%	1.5%	1.5%	1.5%	1.5%
Pipe diameters			**2013**	**2020**	**2028**	**2040**
Subsea	Low gas subsea pipe diameter	"	15	18	36	36
Subsea	High gas subsea pipe diameter	"	10	15	15	15
Subsea	Adjusted gas subsea pipe diameter	"	10	15	36	
Subsea	Low coal subsea pipe diameter	"	15	18	36	36
Subsea	High coal subsea pipe diameter	"	10	15	15	15
Subsea	Adjusted coal subsea pipe diameter	"	15	18	36	
Onshore	Low gas onshore pipe diameter	"	15	18	36	36
Onshore	High gas onshore pipe diameter	"	10	15	15	15
Onshore	Adjusted gas onshore pipe diameter	"	10	15	36	
Onshore	Low coal onshore pipe diameter	"	15	18	36	36
Onshore	High coal onshore pipe diameter	"	10	15	15	15
Onshore	Adjusted coal onshore pipe diameter	"	15	18	36	
Amortisation life			**2013**	**2020**	**2028**	**2040**
Subsea & onshore	Low gas amortisation life (onshore & offshore)	years	25	30	35	40
Subsea & onshore	High gas amortisation life (onshore & offshore)	years	25	30	35	40
Subsea & onshore	Adjusted gas amortisation life (onshore & offshore)	years	15	25	25	
Subsea & onshore	Low coal amortisation life (onshore & offshore)	years	25	30	35	40
Subsea & onshore	High coal amortisation life (onshore & offshore)	years	25	30	35	40
Subsea & onshore	Adjusted coal amortisation life (onshore & offshore)	years	15	25	25	
PMT rate			**2013**	**2020**	**2028**	**2040**
Subsea & onshore	Low gas PMT rate (onshore & offshore)	%	10%	10%	10%	10%
Subsea & onshore	High gas PMT rate (onshore & offshore)	%	10%	10%	10%	10%
Subsea & onshore	Adjusted gas PMT rate (onshore & offshore)	%	10%	10%	8%	
Subsea & onshore	Low coal PMT rate (onshore & offshore)	%	10%	10%	10%	10%
Subsea & onshore	High coal PMT rate (onshore & offshore)	%	10%	10%	10%	10%
Subsea & onshore	Adjusted coal PMT rate (onshore & offshore)	%	10%	10%	8%	
Average pipe lengths						
Onshore	Low gas onshore pipe length	km	30	50	80	80
Onshore	High gas onshore pipe length	km	30	30	30	30
Onshore	Adjusted gas onshore pipe length	km	30	40	40	
Onshore	Low coal onshore pipe length	km	30	50	80	80
Onshore	High coal onshore pipe length	km	30	30	30	30
Onshore	Adjusted coal onshore pipe length	km	30	40	40	
Subsea	Subsea pipe length	km	300	300	300	300

A.4 Storage assumptions

Storage capital and operational cost assumptions have been taken from Mott Macdonald report. Only minor adjustments have been made for the CRTF adjusted scenario at this point, largely regarding the assumed throughput of CO_2 in FID 2013 and 2020 projects and the amortisation rate and period applied to the capital expenditure (labelled as PMT rate below).

DOGF: Low path coal		2013	2020	2028	2040
Pre-FID	£m	19.20	19.20	19.20	19.20
Pipelines	£m	6.00	5.36	4.54	3.86
Platforms	£m	124.00	110.84	93.86	79.70
Wells	£m	41.00	36.65	31.03	25.56
MMV	£m	0.00	0.00	0.00	0.00
Abandonment	£m	75.00	58.93	46.30	37.25
Throughput CO2	mtpa	2	4	5	5
Amortisation period	years	20	25	30	35
Annual OPEX%	%	6.0%	5.0%	4.5%	4.0%
PMT rate	%	10%	10%	10%	10%
IDC %	%	15%	15%	15%	15%

DOGF: Low path gas	2013	2020	2028	2040
Pre-FID	19.20	19.20	19.20	19.20
Pipelines	6.00	5.36	4.54	3.86
Platforms	124.00	110.84	93.86	79.70
Wells	41.00	36.65	31.03	25.56
MMV	0.00	0.00	0.00	0.00
Abandonment	75.00	58.93	46.30	37.25
Throughput CO2	2	4	5	5
Amortisation period	20	25	30	35
Annual OPEX%	6.0%	5.0%	4.5%	4.0%
PMT rate	10%	10%	10%	10%
IDC %	15%	15%	15%	15%

DOGF: High path coal		2013	2020	2028	2040
Pre-FID	£m	22.08	22.08	22.08	22.08
Pipelines	£m	6.90	6.70	6.36	5.99
Platforms	£m	142.60	138.36	131.54	123.81
Wells	£m	47.15	45.75	43.49	40.53
MMV	£m	0.00	0.00	0.00	0.00
Abandonment	£m	86.25	77.06	65.23	54.66
Throughput CO2	mtpa	2.00	3.00	4.00	4.00
Amortisation period	years	15	25	39	40
Annual OPEX%	%	6.0%	5.0%	4.5%	4.5%
PMT rate	%	10%	10%	10%	10%
IDC %	%	15%	15%	15%	15%

DOGF: High path gas	2013	2020	2028	2040
Pre-FID	22.08	22.08	22.08	22.08
Pipelines	6.90	6.70	6.36	5.99
Platforms	142.60	138.36	131.54	123.81
Wells	47.15	45.75	43.49	40.53
MMV	0.00	0.00	0.00	0.00
Abandonment	86.25	77.06	65.23	54.66
Throughput CO2	2.00	3.00	4.00	4.00
Amortisation period	15	25	39	40
Annual OPEX%	6.0%	5.0%	4.5%	4.5%
PMT rate	10%	10%	10%	10%
IDC %	15%	15%	15%	15%

DOGF: Adjusted coal		2013	2020	2028	2040
Pre-FID	£m	19.20	19.20	19.20	
Pipelines	£m	6.00	5.36	4.54	
Platforms	£m	124.00	110.84	93.86	
Wells	£m	41.00	36.65	31.03	
MMV	£m	0.00	0.00	0.00	
Abandonment	£m	75.00	58.93	46.30	
Throughput CO2	mtpa	2	4	5	
Amortisation period	years	15	25	25	
Annual OPEX%	%	6.0%	5.0%	4.5%	
PMT rate	%	15%	14%	12%	
IDC %	%	15%	15%	15%	

DOGF: Adjusted gas	2013	2020	2028	2040
Pre-FID	19.20	19.20	19.20	
Pipelines	6.00	5.36	4.54	
Platforms	124.00	110.84	93.86	
Wells	41.00	36.65	31.03	
MMV	0.00	0.00	0.00	
Abandonment	75.00	58.93	46.30	
Throughput CO2	1	2	5	
Amortisation period	15	25	25	
Annual OPEX%	6.0%	5.0%	4.5%	
PMT rate	15%	14%	13%	
IDC %	15%	15%	15%	

ANNEX B – CONSOLIDATED LIST OF CANDIDATE ACTIONS

B.1 Section 2.1: Landscape

- Development of CCS could benefit from a planning framework that has an assumption that CCS will be needed, rather than that CCS might be needed.
- Consider work on an optimal strategy for locating CCS, to optimise fuel transport, electricity transport and CO_2 transport across the UK.

B.2 Section 3.1: Optimal scale in transport and storage

- Consider how to ensure that the configuration of the transport system for early projects takes into account likely future developments of the CO_2 pipeline network, in order to minimise long-run average costs.
- Future projects need to build on opportunities created by early projects to achieve cost savings through storage hubs.
- Consider how to ensure contracts and licences can be structured flexibly enough to allow CO_2 to be injected into alternative stores by agreement between storage owners.

B.3 Section 3.2: Characterisation of storage

- Consider further work to be undertaken to examine the options for a more or less coordinated approach to developing transport and storage of CO_2 in the Central and Southern North Sea, and to recommend a way forward.

B.4 Section 3.3: Regulatory framework

- Assess what future development of the regulatory regime is required to deliver CCS projects, including guidance on whether access by third parties to storage is required.

B.5 Section 4.1: Optimal scale of generation and capture unit size

- Projects developed in the UK following those arising from the Commercialisation Programme should be of a size much closer to the full size unabated plants available, in order to capture the economies of scale that should then be available.

B.6 Section 4.2: Optimisation of early designs and reducing engineering redundancies

- Ensure that any constraints (e.g. CO_2 specifications), design requirements (e.g. capture percentage limits) or performance objectives (e.g. minimisation of cost of electricity generation) are set with the intended and unintended consequences of these limits clearly understood and agreed.
- A proper dialogue needs to occur between the project developer, plant designer and supplier of critical equipment to ensure that the optimal balance between scale risk, equipment redundancy, design margins and required availability is achieved.
- The benefits and downsides of integration should be examined from the experience of all early projects, worldwide, in order to incorporate this experience into future designs.

B.7 Section 4.5: Next generation capture technologies

- R&D funding for future technologies should continue from all sides to create cost reductions beyond the incremental reductions available from existing technology.

B.8 Section 5.1: De-risking the CCS chain

- Consider how the business model for CCS in the UK should migrate away from early end-to-end full chain projects to projects more suited to cluster development.

B.9 Section 5.2: Ensuring funding mechanisms are fit for purpose

- Continue work to develop the CfD structure, and other relevant EMR instruments, with a view to their widespread use in CCS projects.

B.10 Section 5.3: Continued involvement from financial and insurance sectors

- Keep a variety of financial institutions, analysts and insurance companies engaged in CCS such that they:
  - understand and gain comfort with the full chain of CCS, its technical characteristics and the financing mechanisms in place;
  - can correctly analyse risks and risk mitigation options; and
  - can work with the industry to provide the financial structuring expertise required to fund the anticipated growth of the industry in an efficient manner.

B.11 Section 6.1: Encouraging EOR

- Stakeholders to work together to consider what measures could encourage CO_2 EOR in the UK.

B.12 Section 6.2: Industrial CCS

- Investigate options to incentive the development of industrial CCS projects.

B.13 Section 6.4: Wider Energy System Benefits

- Develop work to examine how CCS can operate to deliver flexible rather than base-load electricity generation.

ANNEX C – COST REDUCTION TASK FORCE

C.1 Task Force Membership

- Alstom
- Air Liquide
- AMEC
- CCSA
- CCS TLM
- CO_2DeepStore
- Costain
- E.On
- Ecofin
- ETI
- Gassnova
- National Grid Carbon
- Norton Rose
- Progressive Energy
- SSE
- Scottish Government
- Scottish Enterprise/IPA
- SCCS
- Shell
- Societe Generale
- Statoil
- TCM
- The Crown Estate

Additional Task Force Contributions

- Zurich
- Element Energy
- BGS
- 2CO
- BNP Paribas
- RBS
- Doosan Babcock

Report Sponsors

- The Crown Estate
- CCSA
- DECC

C.2 Task Force Terms of Reference

The Carbon Capture and Storage (CCS) Cost Reduction Task Force is an industry-led joint task force established by Government to assist with the challenge of making CCS commercially available for operation by the early 2020s.

The Government is reforming the electricity market with the aim of providing a framework that will facilitate low carbon investment, including in CCS. The Government's objective is to have competition between low carbon generation technologies in the 2020s with the market deciding which of the competing technologies delivers the most cost-effective mix of supply and ensures a balanced electricity system. If CCS-equipped power stations are to play a significant role in the electricity market they will need to be cost-competitive with these other technologies.

In the industrial sector CCS provides one of the main opportunities for significant emissions reduction to mitigate the increasing cost of carbon. Cost reduction is essential to ensure that the UK industrial sector can be decarbonised at least cost and remains competitive.

The Government has launched a CCS Commercialisation Programme with £1bn in capital funding which aims to support practical experience in the design, construction and operation of commercial scale CCS. To avoid any conflicts of interest the Task Force will not advise the Government on development of that programme.

Objective

The objective of the Task Force is to publish a report to advise Government and industry on reducing the cost of CCS so that projects are financeable and competitive with other low carbon technologies in the early 2020s.

Key Activities

The Task Force will:

A. identify and quantify the key cost components of CCS and the key cost reduction opportunities;

B. describe routes to realising these cost reductions and the actions required from industry and Government;

C. seek commitment from industry on initiatives to reduce cost and the steps Government could take to establish the right market framework and incentives to encourage industry to invest; and

D. Present to DECC Ministers:

    i. Interim findings, by Autumn 2012, setting out the opportunity and the planned programme of work; and

    ii. A final report, in early 2013, setting out findings and recommendations for action by Government and industry.