Carbon Capture and Storage:

Realising the Potential?

Work Package 3, Task 5 Working Paper Version 2.1

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I. Contents

List of Acronyms

ACCAT	Advisory Committee on Carbon Abatement Technologies
BETTA	British Electricity Trading and Transmission Arrangements
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCSA	Carbon Capture and Storage Association
CfD	Contract for Difference
CO_2	Carbon dioxide
CPF	Carbon Price Floor
CPFC	Carbon Price Floor Consultation
DECC	Department of Energy and Climate Change
ECCC	Energy and Climate Change Committee
EMR	Electricity Market Reform
EMRC	Electricity Market Reform Consultation
EMRI	Electricity Market Reform Inquiry
EPS	Emissions Performance Standard
EPSI	Emissions Performance Standard Inquiry
EU ETS	European Union Emissions Trading Scheme
FEED	Front End Engineering and Design
FiT	Feed-in Tariff
gCO_2/kWh	Grams of carbon dioxide per kilowatt-hour
GW	Gigawatt
HM Treasury	Her Majesty's Treasury
IEA	International Energy Agency
IRR	Internal Rate of Return
kWh	Kilowatt-hour
MARKAL	MARKet ALlocation
MSE	Market Sounding Exercise
MW	Megawatt
MWh	Megawatt-hour
NER	New Entrants Reserve
NPV	Net Present Value
SCPC	Super Critical Pulverised Coal
UKERC	UK Energy Research Centre

1.Introduction

This paper is an output from the UK Energy Research Centre (UKERC) Research Fund project 'Carbon Capture and Storage: Realising the potential?' (UKERC 2011). The project, led by the University of Sussex is undertaking an inter-disciplinary assessment of Carbon Capture and Storage (CCS) viability from now to 2030 involving a partnership from the Universities of Sussex, Edinburgh and Imperial College London (Markusson et al. 2011). The overall aims and objectives include helping policy makers understand the conditions for successful commercialisation of CCS and to contributing methodologies to inform policy decisions on whether CCS is 'proven'.

The project is focussed on CCS linked to electricity generation projects, not least because this suite of technologies is seen by many, including the UK Government, as having the potential to make a major contribution to meeting the UK's CO_2 reduction targets:

'*By 2020 well over half of the UK's electricity generation will still be fuelled by coal and gas. That is why CCS is such a crucial element of this Government's energy and climate change agenda. It is the only technology that can significantly reduce CO_2 emissions from fossil fuel power stations – by as much as 90%. IEA analysis has shown that without CCS, halving global emissions by 2050 will be 70 per cent more expensive. And it will play an important role in balancing the electricity system – underpinning intermittent and less flexible contributors like wind and nuclear.*' (DECC 2011e)

This working paper forms part of Work Package 3 ('Develop and analyse CCS pathways') of the UKERC project, and specifically, Task 5 'Analyse the UK investment climate'. The objectives are to: examine the current investment climate in the UK power sector; understand the range of CCS variants; explain how the UK policy context bears upon CCS; assess the impact on perceived risk and return for CCS investors; and draw conclusions about what this means for CCS 'financeability' and the conditions necessary for successful large-scale deployment of CCS by 2030. The paper also reviews a number of published CCS deployment scenarios to inform the 'pathways' of CCS deployment by 2030 required for Task 6 of the UKERC CCS project. Task 6 will develop a range of pathways, modified and analysed to take account of the 'dimensions of uncertainty' and the accompanying assessment framework identified and developed in earlier stages of the UKERC project.

2. Investment in electricity generation – theory and practice

Investment in theory

The traditional Net Present Value (NPV) approach to assessing potential investments relies on summing the discounted costs and revenues over the life the of the project. If the result is that the NPV is positive then in theory the project should go ahead. In practice, the NPV will need to be large enough to overcome the uncertainties in the projected income and cost streams, and to be larger than other competing projects within the organisation. The Internal Rate of Return (IRR) method is a development of NPV in that the IRR is the discount rate at which NPV=0. For firms, the choice of discount rate is driven by the weighted average cost of capital (weighted to reflect the percentage share of each source of capital) plus a risk premium to take into account project characteristics. The sum of the cost of capital and the risk premium translate into the investment hurdle rate. In a simplified example, a firm may have capital from shareholders (equity) and capital from debt (loans). The cost of equity capital is typically higher than debt finance to reflect the higher risk of equity because loan interest payments must be made before any returns are made to shareholders. It follows that the risks (and therefore required returns) for shareholders increase in very highly geared (high debt to equity ratio) capital structures as the earnings remaining after servicing debt are more at risk from any future fall in revenues. The cost of debt capital will also increase with very high levels of debt since debt holders will want to be compensated for the higher risk of debt default if profits decline. In theoretical terms: the value of the firm is sum of the market value of the debt and the market value of the equity, the weighted average of the cost of equity and debt can be defined for each debt/equity ratio, and the value of the firm will be maximised when the weighted average cost of capital is minimised. (Brewster 1997)

Dixit & Pindyck (1994) consider three generic characteristics of investment decisions and how these bear upon real-world investment. These are that: they are partially or completely irreversible; there is uncertainty over the future rewards that the investment may deliver; and there is a degree of flexibility in the timing of investment. They argue that the traditional NPV approach ignores the irreversibility of the investment and the value of the option that firms have in delaying making an investment. It is worth noting that these concerns may be particularly relevant to the electricity industry which typically has very large, very long lived capital assets, with considerable flexibility of the timing of investment. Dixit & Pindyck go on to use a 'Real Options' approach to explicitly value the option to delay investment (a value which is of course lost once the investment decision has been executed).

Box 1 Theories of the firm

Managerial theories of the firm attempt to address how a firm makes and executes decisions by recognising that an organisation can have a range of different objectives, and that these objectives may not be aligned either with each other or with a traditional, profit maximising view of the firm. The starting point for these theories is that in large organisations there may well be a separation of ownership and control, where ownership is widely distributed amongst a large number of shareholders and control of the organisation is concentrated in the hands of a relatively small number of managers. This separation allows the managers to pursue their own objectives, albeit bounded by an overall constraint (the need to be perceived to delivering value for shareholders). These management objectives may include e.g. increasing market share and/or company size, personal prestige, power, seniority, and salary. The 'principal-agent' theory lends weight to this view, in that the shareholders (as principals) employ managers (as agents) to act on their behalf – but there is an asymmetry of information because shareholders cannot monitor all the behaviour of the managers without significant costs. This allows managers considerable freedom to pursue their own objectives, provided of course that the observable outcomes are acceptable to shareholders (Brewster 1997). The concept of 'bounded rationality', introduced by (Simon 1957) is an attempt to recognise that even though individuals (in the firms case, managers or shareholders) want to act rationally they cannot do so perfectly because they cannot process all the information they have and/or they do not have access to complete information. In these circumstances, they will aim to achieve certain objectives (so called 'satisficing') rather than a theoretically optimal, utility maximising outcome.

The overall effect of these observations is that firms do not necessarily act in a perfectly rational, utility maximising way when considering investment. A further conclusion is that real world investment decisions are much more sensitive to the volatility of the economic environment than the orthodox theory would suggest, because such volatility results in a higher value being attached to waiting and delaying investment. Another key point that follows from the analysis is that there is a case for policy intervention if firms face a different value of waiting compared to society as a whole (i.e. a market failure associated with the decision process).

Investment in the UK's liberalised electricity market

Investment decisions in liberalised, competitive electricity markets such as the UK[1], must take account of a range of factors which bear upon costs and revenues (see Table 1 below). However it is not just the *quantum* of the costs and revenues that

[1] See Section 4 for a discussion of the changing UK energy policy landscape.

matters but also, for example the cost *profile* (i.e. the split between capital, operation & maintenance, and fuel costs) because market arrangements have tended to favour technologies with a particular cost profile, even if the long-run total costs are broadly similar to other technologies – the reasons for which we outline below.

Table 1 Risk factors affecting investment decisions, from (Gross et al. 2007)

	Price Risks	**Technical Risks**	**Financial Risks**
Cost	Fuel price CO_2 price	Capital cost Operating and maintenance cost Decommissioning and waste Regulation	Weighted cost of capital Credit risk
Revenues	Electricity price	Utilisation levels (and timing of utilisation, which can be important for price) Build time	Contractual risk

In Britain, electricity is bought and sold under a set of regulatory mechanisms known as BETTA (British Electricity Trading and Transmission Arrangements) which means that the market determines the 'merit order' of plants according to their operating and cost characteristics. Whilst strictly speaking there is no 'merit order' of plant in the UK electricity market because generators are free to trade in the market as they see fit, the term is a useful shorthand to describe what typically happens in the market, which is that high capital cost, low variable cost plant (such as renewable and nuclear power) will normally run whenever they are physically capable of doing so, and progressively higher variable cost plant will operate to follow seasonal and daily demand variation (Gross et al 2007; 2010).

This has important implications for prospective new plants because potential investors in those technologies with high capital costs will want to know that a plant will run at a high load factor i.e. have a high position in the merit order, and that long-run electricity prices (revenues) will be sufficient to cover all costs and provide a return on investment. Progressively lower capital cost plant can potentially generate sufficient returns even when running lower in the merit order, especially since such plants (usually fossil fuelled) are able to influence electricity prices and act as 'price makers', passing fuel cost fluctuations through to consumers – as evidenced by the increases in wholesale electricity prices in recent years, largely driven by rising wholesale gas prices (DECC 2011f).

These factors help to explain why new build in the UK has been dominated by Combined Cycle Gas Turbine (CCGT) stations. Such plants offer the low-risk combination of the lowest capital cost (£ per unit of capacity installed) of any major generating technology, and the ability to pass their relatively high and variable fuel costs through to consumers since in the current UK market structure electricity prices are typically set by CCGT generators. Around 30 GW[2] of CCGT plant has been built in the UK in the last two decades (DECC 2010c), with around 12 GWs either currently under construction or consented (ECCC 2011;NGET 2011). By comparison, no new coal-fired plant has been built in the UK since Drax was completed in 1974, and no new nuclear plant since Sizewell B was completed in 1995 (DECC 2010c). Around 4.5GW of wind power (high capital cost, very low marginal cost and zero fuel cost) *has* been installed since 2005 (RenewableUK 2011) but this has largely been driven by the strong policy support provided through the Renewables Obligation (RO) mechanism.

Technologies must also compete not just against each other in the UK market but also within individual organisations, each of which would typically have several potential projects under consideration at the same time. Because of the multinational structure of many of the generating companies involved in the UK electricity market, such competition may be across different countries but within the same company – which brings consideration of the different policy and regulatory environments to the forefront because such organisations will make their investment decisions based on which technologies in which markets can optimise the balance of risks and returns. Finance will tend to flow more readily to those countries which present the most attractive investment climate, which some suggest the UK does not at the moment (Ernst & Young 2010). In addition, there are concerns that the capital budgets of the electricity generating companies who operate in the UK are already under pressure (DECC 2010d).

[2] For comparison, current UK installed capacity is around 80GW and peak demand around 60GW.

3.Characterisation of CCS

CCS variants

A key factor in an assessment of CCS for power generation is the wide range of different technologies, fuels, potential operating approaches and build options which it encompasses. This is in marked contrast to the other major low-carbon generating options, such as nuclear power where only two designs of new plant (both pressurised water reactors) are undergoing the Generic Design Assessment (HSE 2011), and wind power, where the industry is currently settled on the three-bladed horizontal axis upwind turbine. As high capital cost, low variable cost technologies, nuclear and wind plants would expect to operate whenever they are physically able to do so (see Section 2), notwithstanding any technical flexibility of new nuclear plants or the possibility that either nuclear or wind plants may be forced to curtail output due to grid (or, in extremis, demand) constraints at some point in the future[3].

It must of course be recognised that both nuclear and wind power plants have experienced very significant costs rises in recent years (see Figure 1 below), and that some of the drivers behind these rises, such as higher raw material costs, are common to many technologies. Nevertheless, the relatively settled picture of new nuclear and wind power *designs and anticipated modes of operation* contrasts with a complex set of potential variants for the suite of Carbon Capture technologies. These variants can be characterised in the groups described in Table 2 below although it is important to recognise that there are elements of overlap, interconnection and interdependence. For example, some technologies may be more suitable for base load generation than others and some technologies are incompatible with partial CO_2 capture.

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[3] A future in which fossil-fired plants may be expected to provide a flexible generation role.

Table 2 Carbon Capture variants[4]

Technology	Fuel	Operation	Build
post-combustion, pre-combustion IGCC, oxyfuel	coal, gas, co-fired biomass, dedicated biomass	baseload, load following, CO_2 capture on/off	retrofit (and if so, to CCS-ready, or not, plant) , new build, partial CO_2 capture, installation phasing

From an engineering perspective, this wide range of variants may offer the opportunity to achieve the optimum variant for a particular project, depending for example on relative costs, availability of fuel supplies, anticipated mode of operation, and the generation mix (a company's own and the entire grid). There is certainly evidence that the opportunity to retrofit CCS to existing plants (where the remaining lifetime of the plant would play a key role in the investment decision), and the potential operational flexibility of CCS-equipped plant could have significant value, especially in a system with high penetrations of relatively inflexible nuclear and wind plant. In addition, whilst there is a complex interaction between CO_2 capture on/off options, carbon prices, and electricity prices, there is evidence to suggest that the ability to operate the *capture* process flexibly (as opposed the whole-plant flexibility described above) at certain times may be valuable to plant operators (Chalmers et al. 2009; 2011;Chalmers & Gibbins 2007;Gibbins et al. 2011;Husebye et al. 2011;Lucquiaud et al. 2009).

However, current analyses of the value of CCS to potential investors must make assumptions about the operating characteristics and costs of each variant under consideration, and at this stage, these cannot be known with certainty – indeed the aim of the demonstration programme (see Section 4), and in particular 'projects 2-4' is to address this uncertainty by gaining real experience from a range of the CCS technologies, see Annex 2, and (DECC 2010g). In the meantime, potential investors are faced with a very wide range of possible technology, fuel, operational and build options, with inevitably a great deal of uncertainty around each – apparently significantly more than would appear to be the case for other low-carbon generation options. We return to the possible impacts of these uncertainties on costs below.

CCS costs

Whilst costs are not the only factor that drives investment decisions in electricity generation (see Section 2), they remain of critical importance both to policymakers

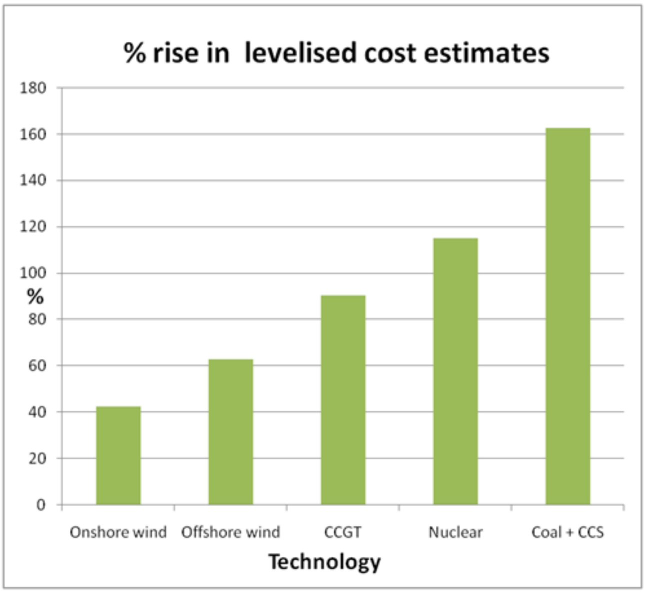
[4] The focus here is on carbon capture and associated power plant technologies, rather than the technologies required for the subsequent CO_2 transport, injection into storage sites, and subsequent monitoring.

and potential investors. In particular, policymakers require cost estimates to inform cost-benefit analyses carried out to determine whether a particular technology is deserving of support, in whatever form (e.g. Kennedy 2007), or as inputs for the type of energy system modelling commonly used to illustrate the range of potential deployment levels (see Section 4). Estimates of electricity generation costs abound in the literature (e.g. Gross et al 2007;IEA 2010;Mott MacDonald 2011) and in recent years estimated costs for CCS have emerged, see (IEA 2011) for a summary of recent international estimates and (Mott MacDonald 2010; 2011) for recent UK-specific estimates. One striking characteristic of these estimates is that costs for all major generation technologies have risen considerably in the last five years, as illustrated in Figure 1 below. Note that after allowing for any differences in discount rate, Mott MacDonald say that the costs estimates in their 2011 report for the Committee on Climate Change are consistent with those in their 2010 report for DECC.

Figure 1 suggests that cost estimates for CCS technologies have risen even more dramatically than for other generation options, perhaps as a result of 'appraisal optimism in the earlier estimates, but some commentators have suggested that for coal-fired CCS plant, the increases since the mid 2000s have mainly been driven by EPC (Engineering, Procurement, Construction) prices for the steam plant going up. It has also been suggested that it is difficult to be sure about these EPC prices because there is very little market activity in new coal plant in western Europe and that estimating capital costs for CCS out into the future is 'extremely uncertain' (Mott MacDonald 2011). Other commentators also contend that there is a significant degree of uncertainty surrounding cost estimates for CCS (Shackley et al. 2009).

Figure 1 Rise in levelised[5] costs for major technologies. From (DTI 2006;Mott MacDonald 2010), 2006 values inflation-adjusted to 2009

	2006 £/MWh	2009 £/MWh
CCGT	£42	£80
Coal + CCS	£54	£142
Nuclear	£46	£99
Onshore wind	£66	£94
Offshore wind	£99	£161



What is certain however is that these cost estimates, and those in (IEA 2011), assume that the CCS plant will be run for baseload generation. Whilst this may be a reasonable assumption, at least initially, there is recognition that it may not hold for all future CCS plant (Chapman 2011), indeed the flexibility of CCS plant is one of the reasons why the UK Government sees such a key role for it in the future generation mix (see Section 1). This implies that at least some CCS plants may run at reduced load factors as CCS competes with very low marginal cost renewables and nuclear power (Poyry 2009). Others have also expressed concern that a high penetration of renewable and nuclear power in the generation mix will squeeze thermal plant load factors (Steggals et al. 2011). This may be ameliorated to an extent if some of the future CCS plants are gas rather than coal fired as the lower capital cost element of CCGT-based plant would mean it was less affected by reductions in load factor. Indeed, the cost of electricity generated by gas fired CCS may be lower than coal-fired CCS anyway – according to (Mott MacDonald 2011), CCGT-based CCS is 'lower cost than coal-based CCS under all DECC published fuel price projections'. Note however, that coal-fired CCS is lower cost than gas-fired CCS on £/tonne of CO_2 abated basis, in large part because of the much higher carbon content of the fuel.

[5] The levelised cost metric captures the full lifetime costs of an electricity generating installation (e.g. capital costs, operational and maintenance costs, fuel costs), and allocates those costs over the lifetime electrical output, with both future costs and output discounted to present values. The result is expressed in cost per unit of output (such as £/MWh).

CCS investment challenges

The generic investment challenges faced by most low-carbon generation (see Section 2) are well understood. The combination of high capital costs and low operating costs means that such plant are typically 'price takers' with conventional gas and coal-fired plant being the 'price makers' that have the dominant influence over electricity prices (Gross et al. 2010). CCS introduces another set of challenges into the equation because it also carries relatively high fuel and operation and maintenance costs, a carbon cost for the residual CO_2 emissions which cannot be captured, and a potential long-term liability associated with the stored CO_2. The effects of these technical and price risks (see Table 1, Section 2), their characteristics and interaction with the policy, infrastructure and legal frameworks are identified below:

CCS cost and operational characteristics

The relatively high variable costs of CCS (when compared to nuclear or wind power for example) mean that CCS plants can generally be expected to have a lower position in the electricity market merit order (see Section 2), which may lead to lower load factors for some CCS plant (Gross et al 2010). This 'load following' role in the UK electricity market has typically been filled by a combination of relatively new, low capital cost CCGT plants, and coal plants whose build costs were sunk several decades ago. A notional[6] CCS plant in the current market may therefore be forced to occupy a rather uncomfortable position in the merit order, squeezed between low variable cost 'price takers' (nuclear and wind) and high variable cost 'price makers' (CCGT). Of course, conventional CCGT, whilst *lower* carbon than conventional coal, is still not *low*-carbon[7], which presents an opportunity for low-carbon, potentially load-following plant such as CCS. We discuss below whether policy options will attach sufficient value to such a role as to adequately reward potential CCS plants. Of course, depending on the contribution of nuclear and wind power to the generation mix, a proportion of any CCS fleet may be able to run at, or near, baseload, but the characteristics of CCS described above still present a significant challenge, particularly if, as some suggest, levelised costs for CCS are likely to show only small reductions over the next few decades as potential reductions in capital cost are offset by carbon price increases (Mott MacDonald 2011).

Whilst not strictly speaking an operating characteristic, another potential issue is that because CCS is sometimes considered as a 'bridging' technology on a path to an eventual almost zero-carbon electricity sector where CCS may not have a role because of residual CO_2 emissions (Anandarajah et al. 2009), it may change the way

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[6] 'notional' because no such plant exists yet

[7] According to (Hawkes 2010), the actual average gross CO_2 emissions of the UK coal and CCGT fleets in 2008 were 0.9kg/kWh and 0.4kg/kWh respectively.

potential investors view the technology. For example, organisations may be less willing to expend time, money and 'management overhead' developing CCS projects if the technology is not perceived as having a very long term future, particularly if the alternative is to expend those resources working with technologies which may be viewed as having a much longer term future such as renewables (and when potential CCS projects may be competing internally within an organisation for funding). On the other hand, if the bridging period is expected to last several decades, then this may not be a material disincentive to pursue CCS projects.

Efficacy of policy support mechanisms

In the (relatively small) literature on CCS as an investment proposition, there appears to be something of a consensus emerging that the policy support mechanisms under consideration, both internationally and in the UK, are unlikely to deliver the level of CCS deployment that many suggest will be required (von Stechow et al. 2011). Some of the main observations are as follows:

In their 2009 paper (Abadie & Chamorro) concluded that in the face of the risks associated with uncertain returns, investment in CCS on coal plants will be delayed. They also concluded from a real-options based assessment that the CO_2 price required to overcome these risks and incentivise CCS investment was more than four times that which is suggested by a typical Net Present Value (NPV) method (see Section 2), and still more than three times even if the additional capital cost is covered by full subsidy (Abadie & Chamorro 2008). From their analysis of CCS investments in the US policy context, (Hamilton et al. 2009) suggest that given 'n^{th} of a kind' cost estimates available and the projected value of avoided carbon emissions under the then proposed US carbon cap and trade bills, Super Critical Pulverised Coal (SCPC) plant with CCS would not present a breakeven proposition until after 2030. In Canada, the TransAlta Corporation, who are planning a post-combustion CCS retrofit to their new Keephills 3 baseload coal plant, describe the economics of early CCS projects as 'extremely challenging' (TransAlta Corporation 2011).

(Osmundsen & Emhjellen) argue in their 2010 paper that CCS does not offer a profitable proposition and delivers CO_2 abatement at 'very high cost'. Others contend that the EU ETS on its own won't lead to large scale CCS deployment (Groenenberg & de Coninck 2008), a view that has some support from within the industry (Gaisford 2009). Flannery (2010) contends that 'CCS today lacks both an economically viable policy framework and a business model'. With a different analytical approach, Evar assessed stakeholder perceptions of the uncertainties over CCS technology development and whether support levels will be sufficient: He concluded that 'experts express certitude in the prospects for deploying large-scale CCS technology in the UK, all the while questioning several underlying technical and policy premises that are necessary to ensure this goal' (Evar 2011).

We return to the UK specific policy landscape, and in particular the impact of the Electricity Market Reform process, in Sections 4 and 5 below.

Infrastructure and legal frameworks

The two main issues here which appear to concern analysts are pipeline network sizing and the potential long term liability that CO_2 storage represents. It is argued by some stakeholders that with current policy there is a danger of a piece-meal build-up of pipelines, when a more coordinated approach might be more cost effective in the long run, see Annex 1 and (DECC 2010f), a view supported by (Chrysostomidis et al. 2009) who contend that:

'an integrated approach to pipeline infrastructure offers the lowest average cost on a per ton basis for operators over the life of the projects if sufficient capacity utilisation is achieved relatively early in the life of the pipeline. Integrated pipelines also reduce the barriers to entry and are more likely to lead to faster development and deployment of CCS. Without incentives to encourage the development of optimised networks project developers are likely to build point to point pipelines because they offer lower costs for the first movers and do not have the same capacity utilisation risk'

Since the effect of a sub-optimal pipeline network is to increase overall unit costs, the result is that the CO_2 transportation costs faced by projects may be higher than they could otherwise be.

Concerns over the long term liabilities associated with CO_2 storage are often raised in the context of the investment proposition of CCS (ERM 2010;Flannery 2010), whilst others question the degree to which the long term CO_2 storage liability is a commercially insurable risk (McKinsey 2008). On the other hand, the EU directive on CO_2 storage which Member States are required to transpose into law the this year, and seems likely to mandate a long term liability fund, may go some to way to addressing these concerns (EU 2009).

4. Policy landscape and CCS deployment scenarios

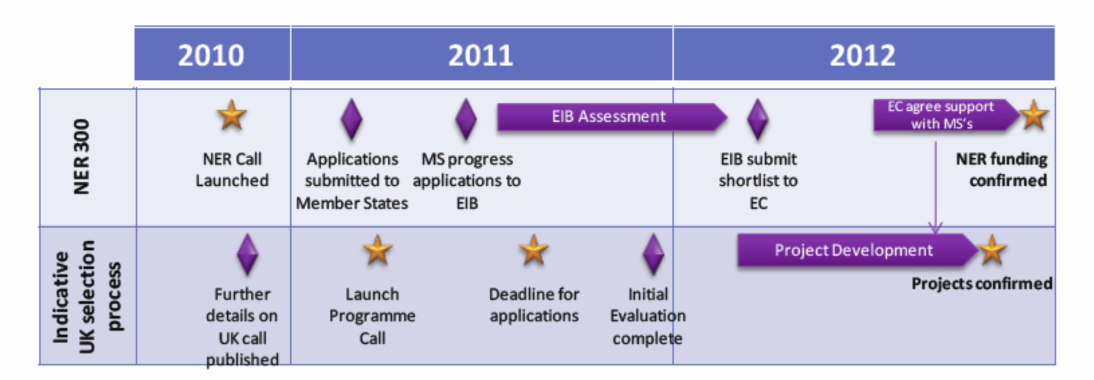
CCS Demonstration Programme

In November 2007 the UK Government launched a competition for demonstrating post-combustion capture on a coal-fired power station, to be operational by 2014, aiming to 'make the UK a world leader in this globally important technology'(DECC 2009;DTI 2007).Two of the applicants for the competition, Kingsnorth (E.ON) and Longannet (ScottishPower), were awarded funding for Front End Engineering and Design (FEED) work. The 2010 Spending Review confirmed that Government would provide up to £1bn for the successful project, but on the same day as this announcement was made, E.ON withdrew from the competition on the grounds that the economic conditions were not right, leaving ScottishPower as the only remaining competitor.

In 2010 the Government also reaffirmed its commitment to a further three CCS demonstration projects (known as projects 2-4), and completed a market sounding exercise to 'help the Department to explore workable options for the CCS demonstration project selection and funding processes, and learn about projects being considered by industry' (DECC 2010f). A key development was the decision to make gas fired generation eligible for the competition, following recommendations by the Committee on Climate Change (CCC 2011).

It was originally intended that funding for projects 2-4 would be financed by a CCS levy on consumer bills, but this levy was later shelved, and the CCS funding mechanism was bound up in the EMR process, discussed further below (HMT 2011). Funding for projects 2-4 was also tied up with the EU New Entrant Reserve funding (commonly referred to as the NER 300) that will be available from the EU-wide auctioning of 300 million EU ETS allowances, expected to raise between €4.5 and €9.0billion in total with two thirds of this available in the first call. DECC indicated their desire to 'harmonise' the timetable for projects 2-4 and the NER 300 process (DECC 2010g) but there were no guarantees that this would happen or that NER 300 winners would also get funding through the CCS 2-4 demonstration programme. The December 2010 guidance stated that priority would be given to NER funding applications that also have funding through the CCS demonstration programme: 'Projects that qualify for funding under the NER and meet the objectives of the UK demonstration programme are likely to present the best value for money to the UK' (DECC 2010b). See also Figure 2 below, from (DECC 2010g) for an overview of the then anticipated timelines of the two potential funding streams.

Figure 2 NER 300/UK CCS projects 2-4 competition timelines



DECC's aspiration was that the demonstration projects would facilitate CCS technologies being ready for commercial deployment by 2020, and in particular, that projects 2-4 would assist in the 'transition to commercial viability' after the 'initial demonstration at commercial scale' provided by the first project (DECC 2010g).

However, in October 2011, ScottishPower pulled out of the first demonstration plant competition, with DECC citing increased costs and the inability to reach a commercial agreement as the reasons. At the same time, DECC confirmed that the £1bn set aside for the first demonstration would be 'available for a new process' (DECC 2011d). Whilst it is not yet clear what that 'new process' will be, there is speculation that these funds may be available to co-fund winners of NER 300 funding (Littlecott 2011), thus, in effect, harmonising the two programmes (albeit with uncertainty over how many demonstration plants will actually now be taken forward.

Electricity Market Reform

In December 2010, the UK Government launched a consultation on Electricity Market Reform (EMR) which set out a proposed package of policies to 'ensure that low-carbon technologies become a more attractive choice for investors, and adequately reward back up capacity to ensure the lights stay on'. These reforms were driven by Government's belief that 'the current market will not deliver on the Government's objectives for decarbonisation, security of supply or affordability for consumers' (DECC 2010d). Whilst much of the detailed design of the package has yet to be announced, it is nonetheless clear that EMR will have significant implications for long-term CCS investment. The four key EMR mechanisms are explained further below, and their perceived impact on CCS is assessed below.

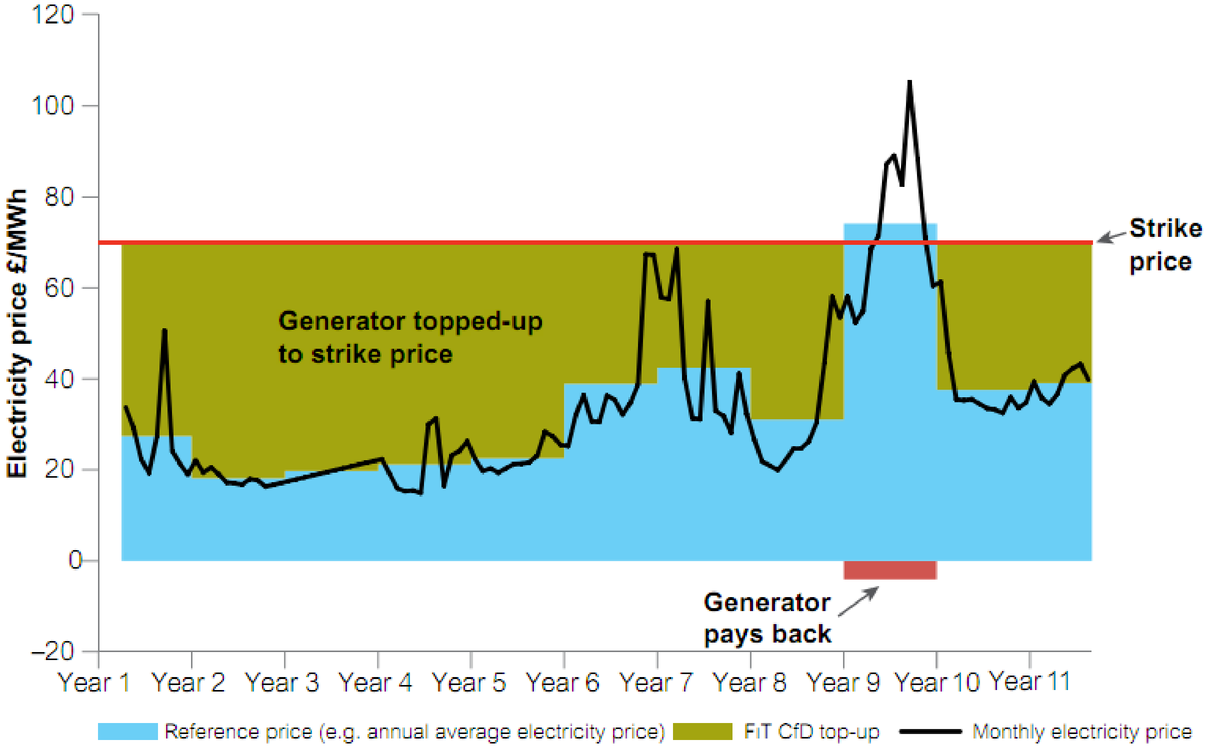
<u>Feed-in tariffs (FiT)</u>

At the heart of the EMR package are long-term contracts for low-carbon technologies such as CCS. The Government's proposals for a FiT aim to stabilise and top-up the revenues of low-carbon generators such as CCS, transferring electricity price risk from generators to consumers, through a Contract for Difference (CfD). The precise design of the CfD will evolve as CCS matures, moving from demonstration to commercial baseload deployment, and then potentially to flexible operation. This progression in financial support is summarised in Table 3 and discussed in further detail below.

Table 3: Financial support for CCS following EMR. Adapted from (Jones 2011)

Period	Status/role	Form of funding
2010s	Demonstration projects '2-4'	Government currently undecided, but indicates that it could be a mix of fixed payments and CfD.
2020s	Commercial deployment, running at baseload	Two-way CfD, with the strike price being agreed between the energy agency and CCS generator. When the market price for electricity (the reference price) is below the strike price, the energy agency pays the generator a top-up. This top-up will equal the difference between the strike price and the average annual electricity price, and is represented by the darkest shaded area in Figure 3 below. However, when the market price for electricity is above the strike price, the generator pays the agency back the excess.
Late 2020s	Commercial deployment, operating flexibly	DECC envisages that once the baseload sector has been decarbonised in the late 2020s, a one-way CfD for flexible CCS plant may be required. This one-way CfD will incentivise CCS plant to respond to short-term market signals, such that it runs at times of high demand, but does not run when demand is low.

Figure 3: Two-way CfD for baseload operation (DECC 2011c)



Carbon price floor

The carbon price floor (CPF) is a fiscal instrument that aims to reduce uncertainty for investors and incentivise low-carbon generation by topping up the EU ETS carbon price. Enacted through reform of the Climate Change Levy, it is envisaged that the CPF will begin at around £15.70/tCO_2 in 2013, rising gradually to £30/tCO_2 in 2020, and then to £70/tCO_2 in 2030 (real 2009 prices). CO_2 that is captured and stored via CCS will be exempt from the tax (HMT 2011).

Emissions Performance Standard

The Emissions Performance Standard (EPS) is a regulatory backstop which puts an annual limit on the amount of CO_2 that a plant can emit, equivalent to 450gCO_2/kWh for plant operating at baseload. In this way, the EPS reinforces the Government's policy that no new coal plant can be built without demonstrating CCS, but does not prevent the construction of new unabated CCGT. Existing plants are fully grandfathered, meaning that they are not subject to the 450gCO_2/kWh level. Plants consented after the EPS comes into force will be subject to the 450gCO_2/kWh level, but will receive protection from future changes to the EPS for a limited period of time, with Government indicating that this period could be around twenty years. DECC signals that the EPS might be lowered in the future, as a means to requiring full CCS on new fossil fuel plant.

Capacity mechanism

The Government has indicated that a capacity mechanism will be introduced to target the problem of resource adequacy, i.e. how to secure sufficient reliable capacity to cover peak demand. However, a firm decision has not been made on its design; instead, the White Paper launches a further consultation on this instrument.

We return to the design and efficacy of these instruments in section 5 below.

CCS deployment scenarios

To inform the project team's discussions around Task 6 of the UKERC CCS project, in particular the development of the 'central pathway' of successful CCS deployment up to 2030, a review of the most recent major CCS deployment scenarios was undertaken. This review sought to understand the range of CCS deployment levels described by these scenarios, and to inform the development of the deployment pathways in Task 6 of the UKERC CCS project. The review relied upon the scenarios described in three major reports over the last two years, the UK Energy Research Centre Energy 2050 work, described in (Anandarajah et al 2009), the UK Department of Energy and Climate Change 2050 pathways analysis (DECC 2010a), and the work commissioned by the Committee on Climate Change for their 4th Carbon Budget report (Usher & Strachan 2010). A fourth view was provided by the modelling work that accompanied the EMR White Paper (see notes below for the document citations). The CCS deployment scenarios for 2030, or 2035 in the case of (Anandarajah et al 2009), in each of these reports are summarised in Table 4 below.

Table 4 CCS deployment scenarios

Report	CCS deployment (GW installed capacity)
UKERC Energy 2050	24 – 38GW
DECC 2050 Pathways	10 – 16.5GW
CCC 4th Carbon Budget report	15.2GW
Modelling accompanying EMR	10 GW

Notes:

UKERC Energy 2050 – Deployment levels are for 2035 with CCS 'taken up strongly' from 2020 onwards. All CCS is based on coal plant (i.e. no gas CCS). Numbers are for the 80% carbon reduction scenarios (other carbon reduction targets resulted in CCS deployment of between 12 and 37GW, with the lower number from a 90% carbon reduction scenario because the residual CO_2 emissions from CCS limit its use, and the higher number from a 60% carbon reduction scenario). The report recognised that the timescale to achieve these deployment levels was 'extremely tight' and that CCS uptake levels were 'optimistic'.

DECC 2050 Pathways – Deployment levels are for 2030, and based on the '8–20GW' described in (Poyry 2009), which was in turn based on modelling undertaken by the Committee on Climate Change. The Poyry analysis judged that to install 20GW of CCS by 2030 was 'only just plausible' so they describe a 'realistic maximum high deployment path' of 16.5GW, and suggest that even 10GW by 2030 is a 'considerable challenge'. These 10GW and 16.5GW levels correspond to the 'Level 2' and 'Level 3' trajectories in (DECC 2010a). Note that there is no explicit statement of whether this is envisaged to be all coal plant, gas or a mixture.

CCC 4th Carbon Budget report – Deployment levels are for 2030, under a 80% carbon reduction scenario. The total figure is made up of 7.7GW of coal CCS and 7.5GW of cofired biomass CCS, with no gas or pure biomass CCS installed. A number of other MARKAL model runs under a range of different assumptions and constraints were carried out as part of this work and are described in detail in (Usher & Strachan 2010). These resulted in coal CCS deployment levels of between zero and 5.4GW by 2030.
Modelling accompanying EMR – According to modelling accompanying the White Paper, the EMR package will lead to around 10GW of CCS by 2030; of this, around 9GW will be coal CCS, and around 1GW will be gas CCS. The driving force for this investment is the FiT CfD (DECC 2011a). The EPS has no impact (DECC 2011b), and the CPF is limited to ensuring the retrofit of Demonstration projects, rather than motivating CCS investments in additional plant (HMT 2010). In the absence of the four EMR policies, the only CCS investment would be in projects directly funded by the Demonstration Programme (DECC 2010e). It is important to note the limitations of these EMR projections. The modelling assumes that all four CCS demonstration projects are on coal-fired plant, despite the competition for Projects 2-4 being opened up to bids from gas CCS. Furthermore, the modelling is based on the decarbonisation target of an average grid carbon intensity of 100gCO_2/kWh by 2030, although it is possible that the Government might choose to lower this level to 50gCO_2/kWh, following recommendations by the Committee on Climate Change (CCC 2010).

The first three of these reports (UKERC Energy 2050, DECC 2050 Pathways, CCC 4th Carbon Budget report) drew their deployment levels, either directly or indirectly, from MARKAL model runs. However, the considerable uncertainties around the timing of CCS demonstration plant deployment and the cost estimates described above may suggest that characterising CCS in deterministic, cost optimisation energy system models is particularly challenging given that there are so many potential technology paths.

In addition, there is wide divergence in opinion about the potential for CCS demonstration until 2020, let alone deployment up to 2030. A report published last year (Ecofin & The Climate Group 2010) that canvassed opinions from ‘over 30 private sector capital providers’ concluded that, given the likely scale of funds available, having *two* CCS projects *across Europe* is realistic for the 2020s. At the other extreme, the Advisory Committee on Carbon Abatement Technologies explicitly aspired to around 5GW of capacity in the UK by 2020 (ACCAT 2009). These divergent perspectives might be rather crudely characterised as *cautious prospective financiers* on one side, and *optimistic engineers* on the other, and perhaps highlight the difference between a technology being .technically ready and being financeable. Yet with such disagreement on the potential for CCS demonstration by 2020 formulating scenarios for 2030 deployment is particularly challenging. It may also be prudent to adopt a conservative attitude regarding future CCS deployment in the UK because global CCS development appears to be falling short of initial expectations. Although the IEA’s CCS roadmap envisages 100 projects by 2020, the latest report by the Global CCS Institute indicates that the world is on track to have just twenty large-scale CCS projects operating by 2020 (Cundy 2011).

Notwithstanding this caveats, these scenarios and the EMR modelling do represent the deployment levels commonly seen in influential reports and as such appear to be a reasonable starting point for discussion of the ‘central pathway’ of Task 6 of the UKERC CCS project.

5.Stakeholder views

Introduction

This section presents the findings of seventeen semi-structured, non-standardised interviews conducted in June-August 2011. These interviews were originally conducted for research into the impact of EMR on CCS investment, see (Jones 2011). This Working Paper draws on findings in that report, and on the original interview notes made during the course of that research. Interviewees spanned a range of industry stakeholders, including technology providers, utilities, project developers and consultancies. Due to the sensitivity of the topics discussed, comments made during interviews are not directly attributed, though a full list of interviewees can be found in (Jones 2011).

The findings from interviews are supplemented by reference to recent consultation and inquiry responses (summarised in Table 5 below). Responses to the first four consultation/inquiry responses listed in the table were systematically analysed in (Jones 2011), and this Working Paper draws upon this analysis; however, the responses to DECC's Market Sounding Exercise were additionally studied to understand the more general concerns of CCS stakeholders (see Annex 1 for a list of the published responses).

Table 5: Adapted from (Jones 2011). See the Consultations and Enquiries Referencing section after Annex 2 for details of the citation system used for responses.

Consultation/inquiry	Organisation launching consultation/inquiry	Evidence-giving period
1. Electricity Market Reform Consultation (EMRC)	Department of Energy and Climate Change (DECC)	Dec 2010-March 2011
2. Carbon Price Floor Consultation (CPFC)	Her Majesty's Treasury (HM Treasury)	Dec 2010-Feb 2011
3. Electricity Market Reform Inquiry (EMRI)	Energy and Climate Change Committee (ECCC)	Nov 2010-Feb 2011
4. Emissions Performance Standards Inquiry (EPSI)	ECCC	July-Oct 2010
5. Market Sounding Exercise (MSE)	DECC	July-Sept 2010

The aim of the interviews and analysis of consultation/inquiry responses was to understand industry stakeholders' views on the following:

- The impact of EMR on investment in the CCS demonstration projects;
- The impact of EMR on investment in CCS deployment in the 2020s; and
- The EMR modelling's projection of 10GW of CCS (most of which is coal CCS) by 2030.

Since EMR will largely shape the UK CCS investment climate over the coming years, these interviews and consultation/inquiry responses provide an invaluable insight into industry stakeholders' perceptions of the risks and returns associated with investment in CCS in the UK. A disadvantage of this emphasis on EMR is that it led interviewees to focus on the carbon capture element of CCS, since this is the element of CCS most directly affected by changes to the electricity market. However, this shortcoming was mitigated by the inclusion of individuals directly involved with CO_2 transportation and storage in the list of interviewees, to understand broader impacts across the whole CCS chain.

Stakeholder comments on CCS demonstration

Four key areas of concern emerged during interviews regarding the impact of EMR on investment in CCS demonstration:

- Progress of the Demonstration Programme;
- The suitability of performance-based support;
- The viability of post-combustion coal CCS demonstration; and
- CO_2 transportation and storage barriers.

These concerns are now discussed in turn.

<u>Progress of the Demonstration Programme</u>[8]

A commonly expressed view during interviews was the possibility of further delays to the Demonstration Programme. There appears to be a concern amongst industry stakeholders that Projects 2-4 will follow the precedent of Project 1, which Jeff Chapman has argued 'turned out to be a process of attrition rather than competition' (EMRI:Q282). Indeed, when asked whether the EMR package had any key omissions in relation to CCS, one interviewee replied: 'a sense of urgency'. In particular, interviewees expressed concerns that the incorporation of CCS demonstration funding within the EMR framework – via the use of CfDs – is exacerbating delays.

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[8] Note that the stakeholder interviews were conducted before the announcement that the Longannet project was not going to proceed.

Furthermore, the majority of interviewees expressed concerns about where funding for Projects 2-4 will come from, given the Treasury's decision to shelve the CCS levy. This levy had promised ring-fenced money for CCS, and so interviews expressed strong disappointment that it has been dismissed by Treasury, and fear that further delays in the Demonstration Programme may result. In his evidence to the Energy and Climate Change Committee (ECCC), David Kennedy, of the Committee on Climate Change (CCC), indicated that the demonstration projects could each cost around £1 billion, adding: 'given the current fiscal situation, without the levy, you have to question where would that come from?' (EPSI:Q17). Thus, overall industry stakeholders expressed strong concern that the uncertainty over funding for Projects 2-4, especially in the current financial climate, could lead to further delays in CCS demonstration.

One industry interviewee suggested that such policy delays were an expected phenomenon in policymaking, with Government timetables often being pushed back. However, most interviewees were more critical of Government progress, claiming that delays had been particularly prolonged in relation to CCS, and arguing that they will have three negative impacts on CCS investment, explained below.

Firstly, one interviewee expressed their 'grave concern' that the Government's decisions on funding the demonstration projects will come too late for UK CCS project developers to compete for the first, largest tranche of European NER300 funding. Another industry stakeholder explained that 'Government timetables slip all of the time', and this view was repeated by others in later interviews. Although one industry interviewee suggested that DECC might be able to renegotiate the NER300 deadlines – since the UK dominates the bids for CCS funding – this was disputed by another interviewee.

The second reason for concern about delays amongst interviewees is that CCS projects have long lead times, meaning that demonstration projects need to go ahead as soon as possible in order for CCS to be commercially deployable by the 2020s. As John McElroy, Director at RWE npower, explained in his evidence to the ECCC, 'to get on the path to 2030 we have got to get CCS demonstration up and running' (EPSI:Q110). One interviewee explained that 'we need action now' in order for CCS to be commercially ready by the early 2020s.

Thirdly, there are fears that if the Government delays further, industry will simply lose interest in CCS and take its money elsewhere. Interviews revealed a strong and widespread sense of frustration at the 'gap between rhetoric and action' on CCS policy. Two interviewees even indicated that industry was starting to doubt the Government's commitment to CCS.

Suitability of performance-based support

Another concern commonly expressed by interviewees was that the CfD funding structure proposed by Government was unsuitable for supporting demonstration projects. Most (though not all) interviewees favoured a capital grant approach over CfD, on the grounds that CCS is less technologically mature than other technologies, and this could result in uncertain revenue streams under production-based support mechanisms. This view was also expressed in some Market Sounding responses – such as by B9 Coal and EDF Energy. Interviewees argued that the CfD structure is targeted at mitigating price risk, whereas the key barrier to CCS investment is not price risk but rather construction and technology risk. This argument is supported by E.ON's response to the EMR Consultation. When discussing different models of FiTs, E.ON stated that '[n]one of these mechanisms removes development, construction and operational risks which are major factors' (EMRC).

Overall, stakeholder views appear to be that the performance-based CfD support could constrain investment in the Demonstration Programme, since it fails to address the risks associated with the technological immaturity of CCS.

Viability of post-combustion coal CCS projects

A particular concern raised by some interviewees in respect of coal CCS projects relates to the impact of the carbon price floor. As the World Coal Association (CPFC) has highlighted, the carbon price floor could negatively affect the economic viability of partial post-combustion coal CCS projects. This is because in some proposed demonstration projects CCS will only be fitted to a fraction of plants due to the limited funding available, meaning that the majority of these plant will continue to run unabated. This larger unabated portion of the power station would be subject to the carbon price floor, which could make the power station as a whole uneconomic to run. This problem particularly affects coal rather than gas projects due to the higher carbon intensity of coal, meaning that unabated coal-fired generation is liable to pay higher carbon cost relative to gas-fired generation.

Indeed, the Scottish Resources Group suggests that the increase in operating costs associated with the carbon price floor 'will massively, perhaps fatally, increase uncertainty for the participation of coal-fired plant in that [Demonstration] programme' (CPFC). In its response to the Carbon Price Floor Consultation, ScottishPower, at the time the only remaining competitor for funding for demonstration project 1, expressed concern at the possible impact on its Longannet coal-fired power station, where it hoped to retrofit CCS. Overall, there is a concern that the carbon price floor might undermine the case for investment in post-combustion coal CCS demonstration plants, and potentially lead to withdrawals from the Demonstration Programme, due to the impact on the unabated portions of these plants.

CO$_2$ transportation and storage

The EMR White Paper is focused on electricity markets, thus leading to an emphasis on the carbon capture element of CCS; CO_2 transportation and storage are outside its scope. However, interviewees from a range of backgrounds stressed the need for these areas of infrastructure development to be addressed. Indeed, in its evidence to the Energy and Climate Change Committee, technology provider GE Energy listed many barriers to CCS investment:

> 'The most significant barriers to CCS at present are upfront cost, technology and regulatory uncertainty surrounding issues of planning, shared infrastructure and CO_2 liability' (EPSI:Evw68).

It should be noted that only one of these barriers - upfront cost - is directly addressed by EMR. Many of these concerns were similarly expressed in responses to DECC's Market Sounding Exercise. Key concerns included:

- The need to develop CO_2 transportation and storage infrastructure (Progressive Energy, MSE);
- The need for Government to take a cluster-based approach and encourage co-operation between projects (One North East, MSE);
- Lack of support for oversizing the CO_2 pipeline network (CO2 Sense, MSE);
- Restrictions on plant size (Powerfuel Power, MSE);
- The need to identify and develop storage sites (BP, MSE);
- Planning delays (E.ON, MSE); and
- The potential disincentive of knowledge sharing requirements (Alstom, MSE).

Thus, due to the limited scope of EMR, industry stakeholders suggest that there are outstanding infrastructural constraints which EMR does not address, and which could limit or delay investment in the Demonstration Programme if action is not taken.

Summary

Overall, CCS stakeholders expressed a range of concerns about how EMR could negatively affect investment in CCS demonstration. Many industry representatives have stressed the importance of starting the demonstration projects as soon as possible and appear to be frustrated that progress on CCS demonstration remains slow. The performance-based support of a CfD appears unsuitable for immature technologies, the carbon price floor has negative implications for partial post-combustion coal CCS demonstration projects, and additional CO_2 transportation and storage barriers remain.

Stakeholder comments on post-demonstration CCS deployment

In general, interviewees' views on CCS deployment in the 2020s under EMR were less developed than those on demonstration, with one interviewee explaining that industry had focused its analysis on nearer term challenges.

Interviewees were asked about the impact of each of the four EMR policy instruments on investment in CCS deployment:

- Feed-in tariffs with contract for difference (FiT CfD);
- Carbon price floor (CPF);
- Emissions Performance Standards; and
- A capacity mechanism.

These are discussed in turn below.

<u>Feed-in tariffs</u>
The contractual commitment embodied in the FiT CfD was widely endorsed during interviews, with one interviewee stating that 'a guaranteed price does help to attract finance'. In his evidence to the ECCC, Chris Huhne, Secretary of State for Energy and Climate Change, explained the appeal of FiTs, stating that 'a contract is something that you can rely on and take to a court of law' (EMRI:Q385). Indeed, this legal status is believed to be more bankable than a tax (Association of Electricity Producers, EMRC) and stakeholders suggested that the stable revenues provided by FiTs should help to reduce the cost of capital of CCS projects.

Nonetheless, interviewees expressed unease about the precise design of the FiT CfD for CCS, discussed below:

- Fuel price risk; and
- The level of uplift in the CfD strike price.

Firstly, industry is concerned by the Government's indecision on whether to link the two-way CfD strike price to fuel prices. As interviewees explained, in the absence of a two-way CfD, plant have a natural hedge against rising fuel prices, since the electricity price tends to move in line with the price of gas (or coal). A two-way CfD would remove this hedge, since the constant strike price would prevent CCS plant from being able to recover costs if fuel prices rise, leading to exposure to fuel price risk. There was a strong consensus amongst interviewees that if a two-way CfD is used, it must be index-linked to fuel prices, or otherwise the cost of capital of CCS investments may increase. RWE npower suggests that locking into a 20-year two-way CfD when fuel prices are expected to be variable is 'likely to deter investment in CCS further' (EMRI:Ev142).

One interviewee highlighted that these concerns regarding fuel price risk do not apply to the same extent to a one-way CfD. This is because the strike price in a one-way CfD is the short run marginal cost, which includes fuel costs, and thus the strike price will vary with the price reference used for fuel. To the extent that the CCS operator is able to buy its fuel close to the level implied in the strike price, fuel price risk will be minimised. This prevents an adverse impact on the CCS investment proposition.

Secondly, the impact of the CfD depends on the level of subsidy encapsulated in the FiT CfD (CCSA, EMRC). The nuclear technology provider Westinghouse makes this general point:

> 'The extent to which the [EMR] mechanisms are sufficient to impact on [investment] decision making will depend not just on the shape of the mechanisms but on the associated numerical values' (EMRI:Evw15).

DECC has stated a preference for deciding CfD strike prices via technology-specific auctions/tenders from the late 2010s. However, it is unclear whether this will be adequate to ensure an appropriate uplift in the strike price, with consultation responses indicating widespread industry scepticism on these auction-based processes (Energy Institute, EMRC; Pöyry, EMRC). Yet the level of uplift in the CfD strike price will be crucial to motivating investment, especially since, as interviewees highlighted, it is unlikely that four demonstration projects[9] will be sufficient to get costs down to a level where CCS is deemed 'commercially deployable' (see stakeholder comments on 2030 deployment scenarios below).

Carbon price floor

Due to the economic signals it sends about decarbonisation, the Carbon Capture and Storage Association (CCSA) suggested that the CPF might be able to 'bring more certainty to investment in CCS' (EMRI:Ev129) and interviewees argued that a high carbon price is crucial to incentivising CCS investment over unabated fossil fuel power generation in the long run. However, the thrust of interviews and written responses was that the CPF, as proposed by the Treasury, would not succeed in stimulating substantial CCS investment. Indeed, one interviewee argued that the carbon price floor was 'redundant' since demonstration plant retrofits would have arguably occurred via the CfD even if the CPF was not in place.

Moreover, as one interviewee highlighted, the ability of the CPF to incentivise investment in CCS depends on industry having confidence in the levels and longevity of this instrument – confidence which is lacking. A number of interviewees from industry suggested that the CPF levels were too high to be sustainable, due to their negative impact on the competitiveness of British manufacturing industry and consumers.

[9] Of course, progress with CCS in other countries may drive down costs irrespective of progress in the UK.

More significantly, interviewees lacked confidence in the CPF due to its status as a fiscal instrument. The Low Carbon Finance Group argues that in the short term, this tax-based mechanism can be trusted as relatively reliable due to the Government's need to increase revenues under the budget deficit (CPFC). However, in the longer term there are concerns about the reliability of this fiscal instrument. Numerous consultation responses highlighted that the prospect of future Governments changing tax levels exacerbated investor uncertainty (Drax, CPFC; Fichtner, CPFC; National Grid, CPFC; RWE npower, CPFC). Even Chris Huhne admitted that 'what one Chancellor says is going to be the carbon price over the next five years may be reversed by another Chancellor' (EMRI.Q385). Overall, interviewees argued that this lack of confidence in the CPF would limit its ability to incentivise CCS investment.

Far from stimulating investment, industry stakeholders argued that the CPF in fact poses a threat to investment in CCS deployment. There was a consensus amongst interviewees that the CPF would make the economics of unabated coal-fired power generation more difficult, which in turn could lead to the premature closure of existing coal plant, rather than their retrofit with CCS. Indeed, one interviewee suggested that by the time that CCS is ready for deployment, there will be no coal plant left to retrofit. In its written evidence to the EMR Inquiry, technology provider Alstom claimed that this smaller potential market would likely have the consequence 'that industry would reduce its investment in CCS' (EMRI:Ev202).

There will also potentially be a negative impact on the coal supply chain. The coal industry has argued in consultation responses that during the transition to CCS deployment, unabated coal-fired production needs to remain viable in order to maintain the infrastructure and expertise needed for CCS development (Coal Forum, CPFC; CoalImp, CPFC). The industry claims that by making unabated coal less viable, the CPF potentially undermines this coal supply chain, with adverse implications for coal CCS.

Overall, there is unease that the CPF will lead to the 'worst of both worlds'. On the one hand, industry stakeholders lack confidence in the longevity of this fiscal instrument, meaning that the CPF is inadequate to stimulate investment in CCS. On the other hand, the CPF levels are high enough to hit unabated coal and thus indirectly threaten coal CCS investment - through potentially making some coal CCS demonstration projects unviable, through reducing the number of coal plant to retrofit, and through undermining the coal supply chain. In this respect, CCS differs from other low-carbon technologies in that it is vulnerable to secondary impacts of the carbon price floor, which could deter investment in coal CCS.

Emissions Performance Standard

One interviewee argued that the EPS sent a 'positive' signal about the need for CCS in the future and technology provider GE Energy suggested that an EPS might be able to give confidence to invest in technology development and supply chains ready for future CCS deployment (EMRI:Ev210). However, the consensus of interviews was that the proposed EPS would be ineffective at driving CCS before 2030. The points made by interviewees on this matter largely broke into two lines of argument; one concerning CCS retrofits (where a plant is constructed and runs unabated, and then CCS is fitted at a later date) and the other concerning CCS integrated new builds (where CCS is fitted when the plant is constructed). By teasing out the arguments put forward in interviews, it was possible to further subdivide to explain how the EPS affects four types of CCS investment categories, discussed below.

CCS retrofit:

- CCS retrofits on plant consented before the EPS comes into force: A number of interviewees highlighted the Government's commitment to grandfathering, which means that plants consented before the EPS is legislated will not be subject to the 450gCO_2/kWh level. As a result, the EPS does not require CCS retrofit investments on this existing plant.
- CCS retrofits on plant consented after the EPS comes into force: One other interviewee further highlighted that new plants consented after the EPS comes into force will be grandfathered at the 450gCO_2/kWh level, receiving protection from future changes in the EPS for c. 20 years. This means that investments in unabated gas plant can go ahead and CCS retrofit investment will not be required for c. 20 years.

CCS new build:

- CCS on new plant consented after the EPS comes into force: CCS is not required on new gas plant, since unabated gas plant falls below the 450gCO_2/kWh level, a point noted by many interviewees. New coal plant would be required to be partially fitted with CCS, yet most industry stakeholders argue that it is flawed logic to argue that banning new unabated coal plant will necessarily drive CCS investment. This is because there are numerous other generation technologies which fall under the EPS limit; these include unabated gas, nuclear and wind power. Indeed, one interviewee described the EPS as 'a green light for unabated gas', a view supported by written evidence (Alstom, EMRI:Ev202; National Grid, EPSI:Evw13). Coal CCS still has to compete with these technologies for investors' attention. The key point is that investment in coal CCS is not *required* by the EPS as it stands.

- CCS on new plant consented after the EPS level has been reduced: It is difficult to see how this would directly drive CCS, since 'CCS is not the only low carbon generation technology available' and would still have to compete with nuclear and wind for investors' attention (UKCCSC & UKERC, EPSI:Evw27). Even at this lower level, an EPS does not directly require investment in CCS-fitted plant, since investors could opt to invest in nuclear or wind power instead – or indeed, not at all.

To summarise, although the EPS might send indirect 'signals' about the need for investment in low-carbon technologies such as CCS in the long-term, the consensus amongst industry stakeholders is that it has no immediate direct impact on CCS investment. Indeed, DECC's Impact Assessment states that the 450gCO_2/kWh level 'does not impact on modelled trajectories for investment in electricity generation' (DECC 2011b).

Capacity mechanism

It is difficult to assess the impact of a capacity mechanism on CCS investment since the Government has not announced firm decisions on its design; however, broadly speaking the capacity mechanism will provide support for plant/technologies that ensure resource adequacy, i.e. that there is sufficient capacity to meet peak demand. Although one interviewee strongly argued that CCS will be required to operate flexibly from the early 2020s onwards, the consensus amongst interviewees was that CCS is not expected to operate flexibly until at least the late 2020s onwards. Thus, the capacity mechanism seems unlikely to affect CCS investment decisions until the late 2020s.

Interviewees explained that industry analysis of how EMR will affect CCS has focused on factors with more immediate effects; as such, their thoughts on the capacity mechanism were less developed than that on other instruments. Nonetheless, there was a broad consensus about the need for capacity payments for CCS if it is running at low load factors. The CCSA (EMRC) and supplier Doosan Power Systems (EMRC) argue that in such circumstances, due to the capital intensity of CCS plant, investors will require capacity payments in order to ensure that capital costs are recovered.

Overall, the key finding from interviews and consultation/inquiry responses was that a capacity mechanism could serve a positive role in helping to reassure CCS investors concerned about load factor risk from the late 2020s onwards. However, the flexibility of CCS needs to be better understood and the Government's response to the consultation is needed before firm conclusions can be made.

Summary

The overall impact of EMR on investment in CCS deployment is mixed. The contractual commitment to low-carbon generation embodied in the FiT CfD is welcomed by CCS stakeholders and initial responses to the concept of a capacity mechanism are positive. The EPS has no direct impact on CCS investment, and the CPF is likely to be unable to significantly affect investment in CCS in the near-term because industry stakeholders lack confidence in fiscal instruments. However, there are concerns about the FiT CfD's potential exacerbation of fuel price risk, and the level of uplift in the strike price. Moreover, the CPF could potentially weaken investment in coal CCS through reducing the number of coal plant to retrofit, and through undermining the coal supply chain.

Stakeholder comments on CCS deployment by 2030

As outlined in Section 4, modelling accompanying the EMR proposals suggested that under the proposed market reforms, there would be investment in around 10GW of CCS by 2030, the majority of which would be in coal CCS. Interviewees were asked both about this market size and the relative mix of investment.

Market size

Conversations with interviewees indicate that the CCS industry has aspirations for 20-30GW of CCS by 2030, which is substantially higher than the 10GW of the modelling accompanying the EMR White Paper. One interviewee responded to the modelling results by stating that 10GW was too small a market to motivate company interest in CCS – they suggested that companies might respond by investing elsewhere in other technologies, resulting in insufficient competition to drive down CCS costs. In other words, an unambitious scenario by Government could be self-fulfilling – technology providers and investors would see the small projected market size, and as a result decide not to make significant investments in CCS, and so the small market size would become a reality. However, another interviewee argued to the contrary that Government was right to avoid ambitious CCS projections until the technology had been demonstrated and proven.

One interviewee suggested that the low CCS forecasts are the result of CCS being seen as the 'meat in the sandwich' between renewables and nuclear; whereas the renewables industry has ambitious European targets, and nuclear has been supported in National Policy Statements, the vision for CCS is less clear, leaving it squeezed. Another interviewee suggested that if Government adopts the CCC's (2010) recent recommendation of lowering the decarbonisation level to around 50gCO_2/kWh by 2030, this could boost CCS investment in the late 2020s.

A further finding was scepticism amongst a range of interviewees regarding whether CCS would be 'ready for commercial deployment' by 2020. Between them, interviewees provided a number of reasons why it was likely that four demonstration projects would not be sufficient to achieve commercial readiness:

- Four demonstration projects will be insufficient to remove all of the first-of-a-kind costs for CCS infrastructure, since the CO_2 transportation network will still require further development (especially in the absence of support for funding oversized pipelines).
- It is likely that each CCS variant will be demonstrated only once, i.e. there will likely be one post-combustion coal project, one gas-fired project, one pre-combustion coal project, and perhaps one oxyfuel project. One project for each variant is likely to be insufficient to fully bring costs down to a competitive level.
- The global rate of progress on CCS in the last two years has been slower than initially hoped for.

The timing of commercial readiness is crucial because, as interviews highlighted, the market size of CCS in 2030 will be significantly impacted by how soon CCS is deemed cost-competitive and commercially deployable.

<u>Relative mix of coal CCS and gas CCS</u>

Interviewees expressed strong and divergent views on the modelling's suggestion that EMR will lead mostly to growth in coal CCS, with there being just 1GW of gas CCS by 2030. Some interviewees and written evidence agreed with the modelling that coal CCS was likely to dominate due to its lower cost per tonne of CO_2 abated. Other interviewees and responses argued to the contrary that gas CCS might have a considerable role in future CCS deployment. In support of this, it was argued that there will be substantial CCS-ready gas-fired capacity suitable for retrofit; the CCC also argued that gas CCS had a competitive levelised cost and could be particularly competitive at lower load factors due to its lower capital intensity (EPSI:Ev47). However, the CCC's viewpoint was challenged by E.ON and one interviewee, who highlighted that the CCC's levelised cost calculations are particularly dependent on assumptions about the relative price of gas and coal; they also argued that the capital cost of gas CCS had been underestimated (EPSI:Evw39).

<u>Summary</u>

Most industry interviewees stated that the 10GW scenario was lower than industry had hoped for, and it was suggested that EMR's projections could become self-fulfilling by undermining industry investment confidence. Interviews also revealed uncertainty about when CCS could be considered commercially deployable, and highlighted that this could impact the deployment trajectory of CCS in the 2020s. There was no consensus on the likely relative mix of coal CCS and gas CCS investment under EMR.

Conclusions and links with wider literature

Three broad points emerge from the interviews and consultation/inquiry responses regarding the UK CCS investment climate. These relate to:

- Delivering the CCS Demonstration Programme;
- Addressing CCS-specific investment characteristics; and
- Achieving commercial readiness.

Delivering the Demonstration Programme
Firstly, and most importantly, interviews indicated that the strongest investment concerns of the CCS stakeholder community relate to delays and barriers to the UK Demonstration Programme. This slow progress on demonstration has the effect of undermining the confidence of the CCS investment community in the Government's plans for CCS. It further pushes back the date by which CCS could be considered 'commercially deployable', could put applications for NER300 funding in jeopardy, and exacerbates concerns about the suitability of production-based support.

This finding is supported by recent literature. Concerns over the prolonged nature of the Demonstration Programme and the need for action to maintain momentum in CCS demonstration were a strong theme in the CCSA's recent report, *A Strategy for CCS in the UK and Beyond* (CCSA 2011). Recent articles suggest that delays and difficulties with CCS demonstration are not just being experienced in the UK, but occurring globally (Watts 2011;Wells & Elgin 2011).

Addressing CCS-specific investment characteristics
Secondly, the interviews and consultation/inquiry responses raise a number of investment concerns about applying generic policy support mechanisms to CCS technologies, which have different investment characteristics from those of key competing technologies such as nuclear power. Specific concerns include:

- The variable operating costs of CCS: the prospect of rising fuel prices leads to concern about the loss of a natural market hedge via the introduction of the FiT.
- The unique relationship of CCS with unabated fossil fuels: during the demonstration phase, partial post-combustion coal CCS projects have a unique relationship of dependency on the economic viability of unabated coal generation, which could constitute the larger portion of a CCS-fitted plant. Future coal CCS deployment is also partially dependent on there being coal plant to retrofit, and a coal supply chain, leading to concerns about the impact of the carbon price floor.

These concerns are also raised elsewhere, with the (Energy and Climate Change Select Committee 2011) suggesting that CCS might require a different FiT design from that used to support other technologies due to its high and variable fuel costs. Meanwhile, (Meadowcroft & Langhelle 2009) have discussed the unique relationship of CCS with unabated fossil fuels, whilst others draw attention to the uncertainty created by the concurrency of the unresolved funding mechanism for later demonstration plants and the EMR consultation (SEG 2011). Overall, it seems that EMR could threaten CCS investment – during both demonstration and deployment – by not recognising its unique characteristics.

Achieving commercial readiness

Thirdly and finally, interviews revealed high levels of uncertainty about CCS deployment scenarios, with there being a wide divergence between EMR modelling projections and industry aspirations. In particular, there appears to be a lack of clarity about when CCS will become 'commercially deployable'. Interviews suggest that the Demonstration Programme in itself will be insufficient to get CCS to a stage where it is commercially deployable by 2020, especially since demonstration plants must be constructed and successfully operated for a sufficiently long period of time to give equipment suppliers, utilities and financiers confidence in future costs and reliability.

A key finding is thus that EMR proposals appear to be based on the assumption that CCS will be ready for commercial deployment sooner than seems likely. This could potentially lead to investment hiatus in the early 2020s if there is no bridge between demonstration and commercial plants. This view is supported by Gibbins & Chalmers's (2008) argument that a second tranche of demonstration projects are needed to reach commercial deployability. However, it should be noted that the UK Government is not the only Government to assume the commercial readiness of CCS by 2020s, with the latest CCS roadmap from the US Department of Energy similarly suggesting that '1st generation' technologies may be ready for deployment by 2020 and '2nd generation' by 2030 (DoE/NETL 2010).

6. Discussion

This section draws upon analysis of the characteristics of CCS that bear upon potential investors, the policy landscape, and stakeholder views to summarise the factors affecting CCS 'financeability'. These factors are categorised and then used to draw conclusions about the conditions necessary for the successful deployment of CCS over the next two decades.

Factors affecting CCS 'financeability'

Most decarbonisation scenarios assign a significant role to CCS in the future energy mix, yet CCS is still to be demonstrated at a commercial scale in the UK, and a number of high-profile CCS projects abroad have recently been postponed. In addition to challenges associated with the current financial climate, this Working Paper has discussed a number of factors limiting CCS 'financeability' in the UK. These are summarised below:

1. Technology and construction risk: Stakeholder interviews (Section 5) revealed technology and construction risk to be a particularly important factor deterring investment at present. The multiplicity of CCS technologies, each of which has differing technological characteristics, makes this factor especially difficult to tackle. Stakeholders expressed concerns that delays to the Demonstration Programme and the EMR's emphasis on performance-related support are exacerbating this risk.

2. High capital cost: CCS has high up-front capital costs, as explained in Section 3, and these estimates are also associated with significant uncertainty due to CCS's status as a new technology. The importance of this factor to stakeholders is reflected in their concerns about the level of uplift in the CfD strike price, and emphasis on securing NER 300 co-funding for demonstration projects.

3. Infrastructure constraints: Stakeholders discussed a number of infrastructural barriers to CCS investment. These include widespread first-of-a-kind costs associated with developing a CO_2 transportation network, and the lack of a systematic approach to optimising the network through a coordinated approach and pipeline oversizing. There are also more general uncertainties about the legal liabilities of CO_2 storage.

4. Fuel price risk: CCS has significant and variable fuel-related operating costs. As discussed in Section 2 fossil fuel plants are typically 'price makers', with the ability to pass fuel price increases on to consumers. However, Section 5 revealed stakeholders concerns that the FiT CfD support mechanism may remove this natural hedge of CCS to rising fuel prices.

5. Relationship with unabated fossil fuels (particularly coal CCS): Stakeholders with expertise in coal CCS argued that the EMR's negative impact on unabated coal-fired generation could indirectly undermine investment in coal CCS, due to the dependency of coal CCS on the continued existence of a strong coal supply chain, and the impact on coal CCS demonstration projects that involve only partial CO_2 capture.

6. Load factor risk: CCS has relatively high operating and fuel costs, which may mean that load factor risk could become important by the late 2020s. In particular, CCS plant might be required to operate flexibly when there is increased penetration of very low marginal cost nuclear and wind power plants. This has the potential to increase the unit costs of CCS generation, thus undermining the attractiveness of CCS investments. This risk is potentially greater for coal CCS than gas CCS, due to the higher capital intensity of coal plant (see Section 3).

Taken together, these factors may constrain the investment required for CCS projects. For utility companies considering very large investments in very long-lived assets, a number of the issues discussed above are not attractive characteristics, especially when any potential CCS projects must compete both internally within a company, and internationally, for funds (see Section 2). It is interesting to note that only two of the 'big six' vertically integrated companies in the UK electricity market are leading bids for UK CCS project funding through the NER 300 competition.

Categorising investment factors

On closer inspection, it becomes apparent that the investment factors limiting CCS 'financeability' discussed in this Working Paper broadly fall into two groups, discussed further below:

- Factors relating to CCS being an early-stage technology; and
- Factors relating to CCS-specific characteristics, which persist even when CCS is mature.

<u>Early-stage investment factors</u>

Firstly, CCS investors are faced with a number of risks and barriers that stem from the status of CCS as a relatively new suite of technologies. These factors include:

1. Technology and construction risk;
2. High capital cost; and
3. Infrastructure constraints.

The propensity of these factors to limit CCS investment decisions is inversely proportional to the number of CCS projects in successful operation. In other words, as the number of successful commercial-scale CCS plants increase, the salience of the three investment concerns listed above may decrease, and the CCS investment proposition may improve. For instance, as more CCS plants are constructed, the capital costs associated with CCS could be expected to decrease; indeed, this is a common phenomenon in technology innovation, with other technologies that were initially high cost going on to provide cost-effective performance (Greenacre et al. 2010).

Stakeholder interviews highlighted that together these investment concerns relating to the early-stage nature of CCS are the factors with the biggest impact on CCS 'financeability' at present. These factors put CCS stakeholders in a 'Catch 22' position: investors are hesitant to invest in CCS due to the presence of these factors, yet the only way to reduce the impact of these factors is for more CCS plant to be constructed and successfully operated.

<u>CCS-specific investment factors</u>

Secondly, CCS investors are faced with additional challenges that are unrelated to the early-stage nature of CCS development. These factors instead stem from CCS-specific features which are expected to persist over time. They include:

1. Fuel price risk;
2. Relationship with unabated fossil fuels (particularly coal CCS); and
3. Load factor risk.

Broadly speaking, these factors are relatively distinctive CCS investment characteristics, referring to areas where CCS diverges to some extent from other low-carbon technologies in the electricity market. Whilst these factors are currently less important to CCS investors than those relating to the early-stage nature of CCS, they have significant long-term implications, and may considerably shape CCS deployment by 2030, depending on the extent to which they are addressed by policymakers.

CCS deployment to 2030

Whilst there is a wide range of potential CCS deployment described in recent analyses, an indicative level of 10-15 GW by 2030 is consistent with much of the available literature. This suggests that the CCS suite of technologies have the potential (some would argue they are required) to play a key role in the UK's move to a low-carbon electricity system over the next few decades.

It is difficult, however, not to reach the conclusion that achieving the levels of eventual CCS deployment described above will require a considerably more concerted approach than has been the case to date. Reaching these deployment levels will require a number of conditions to be met. The first set of conditions, which are the priority in the short-medium term, are targeted at removing investment concerns related to the early-stage nature of CCS. The second set of conditions, which will become increasingly important over time, are targeted at removing investment concerns related to CCS-specific investment features.

Conditions to mitigate early-stage investment barriers

There are two conditions to be satisfied in order to reduce the investment barriers associated with the early-stage nature of CCS. The first condition is timely progress with the UK Demonstration Programme, which could substantially reduce the investment concerns relating to technology and construction risk. This Demonstration Programme will also be required to have a credible, strategic approach to infrastructure development. It is therefore particularly unfortunate that the first planned demonstration project will not now go ahead.

The second condition is that the Demonstration Programme is followed by adequate support for '2nd tranche' projects. Further post-demonstration projects will be needed before early-stage investment factors are diminished to the extent that CCS could be considered fully 'commercially deployable'; this is due to the multiplicity of the CCS variants that need to be demonstrated and the extent of infrastructural first-of-a-kind costs.

Conditions to mitigate CCS-specific investment barriers

Widespread CCS deployment also requires that policymakers demonstrate sensitivity to the specific techno-economic features of CCS. Although these are not the primary concerns of CCS stakeholders at present, they have been raised as significant factors for longer term deployment. This leads to three conditions for widespread CCS deployment in the 2020s. Firstly, CCS investors require a mechanism which allows them to either preserve the natural hedge of CCS to fuel price rises, or which is directly linked to fuel prices to mitigate this risk. A second condition is that there is a smooth transition from unabated coal-fired generation, so that the coal supply chain is maintained for future coal CCS projects, and so that partial post-combustion coal CCS projects are not threatened.

Thirdly, in the longer term – perhaps in the late 2020s or early 2030s – a key condition for widespread CCS deployment will be that its potential for flexible generation is adequately rewarded. The capacity mechanism could help to address this, but details of its design in the EMR White Paper were insufficient for industry stakeholders to fully assess this instrument. Whilst policymakers and the UK electricity market have had sufficient time to become relatively comfortable with the premise that low-carbon generation has a premium value, up until now the market has largely valued flexible generation implicitly rather than explicitly, because the 'price-making' generation provides most of the required system flexibility. The challenge for CCS in the future will be how the market can be structured, *when required*, to adequately reward *flexible* low-carbon generation.

Conclusion

It is certainly possible that 10-15GW of CCS could be deployed in the UK power sector by 2030, providing that a number of conditions are met. Over the long-term, investors will require that fuel price risk and load factor risk are addressed, and coal CCS may be partially dependent on the continuity of the coal supply chain. Yet the crucial factors limiting CCS 'financeability' at present relate to the early-stage nature of CCS; in particular, technology and construction risk, capital cost, and infrastructural constraints are the key barriers to investment. Thus, the most important conditions in the near-term are (1) that CCS is successfully demonstrated at commercial scale, and (2) that '2nd tranche' projects receive support in the transition to commercial readiness.

On paper, it would seem that these two most significant conditions are being addressed. The CCS Demonstration Programme should help to reduce technology risks, to provide greater certainty over capital costs, and develop infrastructure, via commercial-scale projects. Following this, EMR should provide the necessary bridge for '2nd tranche' projects, assuming that there is an appropriate uplift in the CfD strike price. The basic framework for widespread CCS deployment by 2030 is thus in place. Yet the CCS investment climate remains fragile. Investors are dependent on Government support to co-fund CCS demonstration, and are concerned that in the current challenging financial environment, funding might be constrained or postponed. These concerns are particularly high following the shelving of the CCS levy, the delays in the Demonstration Programme (now made much more acute as a result of the failure to proceed with the Longannet project), and the precedent set by postponed projects abroad.

The key omission at present, then, is not so much an adequate policy framework, but rather the confidence that this framework will be implemented with mechanisms that recognise the *unique characteristics* of CCS and within the *timescales required*. As one industry stakeholder explained, what is lacking is 'a sense of urgency'[10]. Given that the extent of CCS deployment in the 2020s depends on the pace of demonstration in the 2010s, these concerns could have significant implications for future decarbonisation.

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[10] This resonates with a much earlier observation which, although not specifically aimed at investment in CCS, seems particularly apt: *'If governments wish to stimulate investment, perhaps the worst thing they can do is to spend a long time discussing the right way to do so'.* (Dixit & Pindyck 1994)

Annex 1: Summary of responses to DECC CCS Market Sounding Exercise

Respondent	Brief commentary on what was said, see (DECC 2010f) for full details
2CoEnergy	Focus on CCS linked to EOR. Their view is that knowledge sharing can be made consistent with IP protection. Support funding via a levy and a CfD based on CO_2 abated, paid to the generator. Would like NER 300 funding to be available to support the FEED stage.
Air Liquide	No published response, just press release on their proposed Rotterdam project.
Alstom	Not happy with the proposed support mechanism because they say it exposes project developers to too much upfront cost and risk against a backdrop of uncertain regulation, policy and public acceptance. Also make the point that new coal, even without CCS is not currently viable. Say that they are 'on course for a commercial offer by 2015'. Strong statements about the benefits of oxy-fuel although recognition that it is not cost competitive for demonstration plant as partial CO_2 capture is not possible. Seem wary of knowledge sharing.
B9 Coal	Mostly covers a description of their proposed project (oxy-fuel linked to fuel cells or hydrogen turbine). Would want an 'upfront payment schedule'.

BP	Emphasise the need to identify and develop storage sites (they suggest that this has not had the priority it needs). Their view on the proposed support mechanism is that it will increase the cost of developing CCS and that whatever process is used to select projects 2-4 should not require developers to fund extensive FEED work before the selection process is complete (they are clearly frustrated that they spent $60m on the Peterhead project which did not come to fruition).
CO2Sense (Yorkshire Forward)	Argues the case for a pipeline infrastructure sized to accommodate the large point sources in the region. Suggest that this will be much cheaper than point-to-point pipelines, and that this still holds even if the 'spare' capacity is not used for over a decade. Strongly support co-location of sites.
Corus	No comment on support mechanism, main point is to clarify the eligibility for industrial plants, and the need to develop the supporting CO_2 pipeline infrastructure.
EDF Energy	Subsidy must be restricted to the demonstration plants only, and concerned that the payment mechanism does not significantly distort the wholesale electricity market – suggest that capital grant support may be more appropriate and less likely to distort the market, with CfD based support for the additional operating costs of CCS only. Do not support the funding of oversized pipelines. Happy for gas plant to be eligible for the competition. Longer term support must only be through appropriate carbon pricing. Supportive of knowledge sharing although would prefer this is through existing programmes.

E.ON	Concerns over the impact of planning delays on project proposals, consistency with NER 300 competition requirements, that costs should not be modeled on very high load factors (because these cannot be assumed). They suggest that the proposed funding mechanism will lead to higher costs because proposers will need to cost in an additional risk premium, which would not be required if support was through a grant. Cautious about knowledge sharing requirements. Unconvinced of the need to demonstrate CCS on gas at this stage.
Global CCS Institute	Mostly a summary of (WorleyParsons 2009) main points, with emphasis on the risks posed by the high cost of CCS, and lack of strong policy support and funding.
One North East	RDA submission focused on the specific benefits of creating a CCS cluster in north-east England.
Powerfuel Power	Opposed to the size restriction (up to 500MW), presumably because it is not compatible with an IGCC project, and point at the incompatibility with the European Energy Programme for Recovery (EEPR) CCS competition rules (from which Powerfuel secured £165m in funding). Concerned that the competition may favour incumbent utility companies. Argue that whilst the proposed funding mechanism may work, it will be more costly because of the additional risk premium. Do not support the inclusion of gas plant in the competition.

Progressive Energy Ltd	Focus on the need to develop the CO_2 transportation and storage infrastructure. Opposed to the size restriction, presumably because it is not compatible with an IGCC project. Also oppose allowing any new build with a major fraction unabated. Argue the case for pre-combustion technologies. Do not support the inclusion of gas plant in the competition. Concerned that knowledge sharing requirements may compromise supplier's IP.
Rio Tinto Alcan	Coal gasification retrofit project (Lynemouth). Do not support the inclusion of gas plant in the competition unless it demonstrates a new technology.
RWE Npower	Competition should focus on coal (on cost per ton of CO_2 abated grounds, and that it would otherwise lead to earlier mandating of CCS on gas which would hamper investment in new gas plant). Seem comfortable with the proposed funding mechanism but caution that it should only be used to fund the demonstration plants, not retrofitting of any other plants (the costs for which should be provided through the mechanisms that emerge from the current electricity market reform).

SSE	Strongly support inclusion of gas plant in the competition (they refer to a number of 3rd party reports, including (Mott MacDonald 2010) which suggest it will be cheaper per MWh, especially in their view at lower load factors) linked to their post-combustion Peterhead proposal. Argue that a pure output-based funding mechanism will attract very high risk premiums and will therefore not deliver value for money. If some element of funding is output based, should be per MWh, not per ton CO_2. They propose funding on a regulated asset basis would give best value and greatest wider benefits. Highlight the problems of integrating (and protecting revenue streams) across the full production chain. Competition should not require the FEED to be completed before winners are announced.
UK Coal Mining Limited	Opposed to the size restriction (up to 500MW) and inclusion of gas in the competition. Concerned that the knowledge sharing requirement does not compromise IP. Strongly support co-location and suggest that DECC should be more prescriptive with suggested regions.
Westec Environmental Solutions	Mainly just a pitch for their absorber technology and a plea for DECC to assist in linking them with other players.
WWF/RSPB	Strongly favour retrofit for demonstration plants as it would deliver net CO_2 reductions from day 1 (as opposed to partial capture from a new coal fired plant), and that any new coal build (including major repowering of exiting plant) must have mandatory capture for the entire plant.

Annex 2: UK CCS NER 300 applicants submitted for EIB review

Applicant name	Description
Alstom Limited (Consortium)	New supercritical coal-fired power station (oxyfuel technology) on the Drax site, North Yorkshire.
C.GEN	New supercritical coal-fired power station (post-combustion amine capture technology) in Ayrshire, Scotland.
Don Valley Power Project (formerly known as the Hatfield Project)	New IGCC power station in Stainforth, Yorkshire
Peel Energy	New super critical coal and biomass plant with post-combustion capture at Hunterston, Scotland
Progressive Energy Ltd (consortium)	Pre-combustion coal gasification project in Teesside, North East England.
Scottish Power Generation Limited	Post-combustion amine capture retrofitted to an existing subcritical coal-fired power station at Longannet, Scotland
SSE Generation Limited	Post-combustion capture retrofitted to an existing CCGT power station at Peterhead, Scotland

Note that there were a total of 12 UK applications for NER 300 funding selected by DECC for submission to the European Investment Bank (EIB) i.e. the seven CCS projects described above plus five renewable energy projects. Up to three projects per Member State can be supported. A total of nine CCS projects were initially submitted to DECC, with two projects subsequently being withdrawn by the Project Sponsors.

The EIB is tasked with checking applications from Member States to assess their ‘financial and technical deliverability’. The European Commission will then ‘verify the eligibility criteria assessment and re-confirm with Member States the public funding contribution for Recommended Projects, before making its Award Decisions’ (DECC 2011e).

Consultation and inquiry citations and references

Standard referencing conventions were not appropriate for citing written and oral evidence to consultations and inquiries. This was due to the need for the citation to concisely and clearly convey the organisation which had submitted the response (rather than the organisation which had collated the responses), and the consultation/inquiry to which they had responded.

Consultation responses

Consultation responses typically lack page numbers, hence in-text citations are presented as in the following examples:

(Alstom, EMRC)	Alstom's response to the Electricity Market Reform consultation.
(EDF, MSE)	EDF's response to the Market Sounding Exercise.
(Consumer Focus, CPFC)	Consumer Focus's response to the Carbon Price Floor consultation.

Inquiry responses

The Energy and Climate Change Committee adopts the following code for citing evidence, which is followed in this working paper:

Q – Question number in oral evidence to inquiry

Ev – Printed written evidence

Evw – Additional written evidence

Hence, in-text citations are presented as in the following examples:

(Joan MacNaughton, EMRI:Q226)	Question 226 of oral evidence to the Electricity Market Reform Inquiry, by Joan MacNaughton.
(GE Energy, EMRI:Ev210)	Page 210 of printed written evidence to the Electricity Market Reform Inquiry, submitted by GE Energy.
(National Grid, EPSI:Evw14)	Page 14 of additional written evidence to the Emissions Performance Standards Inquiry, submitted by National Grid.

See table 5 in Section 5 for a full list of consultation and enquiry abbreviations.

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