

The role of CCS in meeting climate policy targets

Understanding the potential contribution of CCS to a low carbon world, and the policies that may support that contribution

A report commissioned by the Global CCS Institute

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Executive Summary

Carbon capture and storage (CCS) refers to a set of technologies that may offer the potential for large-scale removal of CO₂ emissions from a range of processes – potentially including the generation of electricity and heat, industrial processes, and the production of hydrogen and synthetic fuels. CCS has both proponents and opponents. Like other emerging low carbon technologies, CCS is not without risks or uncertainties, and there are various challenges that would need to be overcome if it were to be widely deployed. Policy makers' decisions as to whether to pursue CCS should be based on a judgement as to whether the risks and uncertainties associated with attempting to deploy CCS outweigh the risks of not having it available as part of a portfolio of mitigation options, in future years.

On the basis of the available evidence, our headline conclusions are that:

- The risks of CCS not being available as part of a portfolio of mitigation options to address climate policy targets are greater than the risks associated with attempting to develop it.
- In particular CCS should be considered a critically important part of any strategy for limiting temperature rise to 2°C, and even more so for limiting temperature rise to 1.5°C.
- Pursuing CCS requires a whole-chain, innovation systems approach, including coordination of actors and infrastructure.
- There is an important active role for governments in such an approach.
- Legislative and regulatory frameworks are crucial, but CCS systems are still emerging – hence review and adaptation are important.
- The process of policy development and CCS implementation should be supported by robust and transparent risk management practices, reflecting and building on those employed to date, and by genuine public engagement. Critical issues include transparently verifying that CO₂ can be safely stored in any given project, and demonstrating the full life cycle sustainability of biomass used in BECCS applications, including with appropriate certification processes.
- CCS should be seen as an important component of a portfolio of mitigation strategies. Other low-carbon supply side technologies will also make critical contributions, and increasing energy and material efficiency is likely to be a key “no-regrets” option.

Our report examines policy issues in the deployment of CCS by attempting to draw lessons from case studies of other analogous technologies and technological systems; reviewing the current status of CCS systems and policies in a variety of countries; and providing analysis of integrated energy systems modelling (including our own scenarios) as evidence of the possible role of CCS in meeting climate policy targets.

The following lessons are drawn from our review of analogous technologies:

- Stimulating innovation in low carbon technologies requires an innovation systems approach that considers multiple feedbacks along the innovation chain, and the role of actors, institutions and networks in conditioning the process. This is especially the case for CCS, which is characterised by multi-actor supply chains, long-term liabilities and large shared infrastructures.
- As part of this approach, there will be a need for technology push policies – such as support for research, development and demonstration; and market pull policies – such as price support or carbon taxes; as well as coordination of actors, institutions and networks across the innovation system.
- Comparable large technological systems and infrastructures have in the past benefitted from some kind of whole-chain coordination and support, with governments often playing key enabling roles.
- It is unlikely that CCS will succeed without similar whole-chain coordination and support.
- Public engagement in the process of developing large scale technological systems like CCS, and the role they could play in the overall transition to sustainable energy systems, is critical.

Our review of the current status of CCS systems and policies finds that:

- CCS projects are in operation in various parts of the world, but such projects are typically cases where the addition of CCS is a relatively small incremental investment due to the nature of the existing process, or where captured CO₂ has a commercial value.
- For these kinds of projects, the economics are such that relatively modest policy incentives have provided sufficient additional incentive for companies to carry out geological sequestration of CO₂. However, policy drivers are not yet strong enough to bring about large-scale projects explicitly concerned with dedicated storage of CO₂ for climate mitigation purposes, where there is no other commercial value derived from the CO₂.
- Legal and regulatory frameworks for CCS are emerging in various jurisdictions, some adapting existing frameworks, others developing new frameworks. The design of a CCS legal and regulatory regime needs to incorporate effective review procedures and adaptation mechanisms in order to learn from developing scientific knowledge and technical experience.

In order to provide evidence of the potential future role of CCS in meeting climate policy objectives, and the potential risks to these objectives that may be incurred from not having CCS available, we analyse a range of future climate mitigation scenarios, comparing scenarios produced for this report with scenarios produced in other modeling exercises. This cross model analysis provides robust evidence that:

- If CCS were to become available on a large scale it could play an important role in meeting climate policy targets.

- The non-availability of CCS appears to make climate mitigation scenarios at best much higher cost, and at worst infeasible. In scenarios where CCS is not available, energy and material efficiency can help to reduce costs, and as such appears to be a key “no-regrets” option.
- In scenarios where it is available, CCS plays a significant but not dominant role in power sector decarbonisation – however its role appears much more critical in ‘hard-to-decarbonise’ sectors for which alternative mitigation options are very expensive or not available, such as heavy industry and manufacture of synthetic transport fuels for non-electrifiable transport modes.
- Bioenergy used in conjunction with CCS (BECCS) features significantly in a number of low carbon scenarios as a means of balancing carbon budgets with so-called ‘negative emissions’. Separate from the operation of CCS itself, the risks and uncertainties around the availability of large quantities of sustainable biomass is another key concern arising from this analysis.

1. Introductory and background issues

Key points:

- Carbon capture and storage (CCS) refers to a set of technologies that may offer the potential for large-scale removal of CO₂ emissions from a range of processes including the generation of electricity and heat, industrial processes, and from the production of hydrogen and synthetic fuels.
- CCS has both proponents and opponents. Like other emerging low carbon technologies, CCS is not without risks or uncertainties, and there are various challenges that would need to be overcome if it were to be widely deployed.
- Policy makers' decisions as to whether to pursue CCS should be based on a judgement as to whether the risks and uncertainties associated with attempting to deploy CCS outweigh the risks of not having it available as part of a portfolio of mitigation options, in future years.

Carbon capture and storage (CCS) has been proposed as a critical technology for the avoidance of future CO₂ emissions. This report explores the challenges and uncertainties of CCS, considers the evidence for its proposed critical role in future low carbon energy systems, and explores what contribution it could make, and the policies that would be needed to achieve this.

This introductory chapter sets out the background to CCS, and raises the issues and arguments that have been put forward both for and against the technologies it involves. The chapter also categorises the main uncertainties associated with CCS, and the challenges that it faces. In several cases the issues, arguments, challenges and uncertainties raised in this chapter are considered more fully, with the relevant evidence, in subsequent chapters. The purpose here is to present them in overview, in order to create a full context for the later, more detailed, discussion.

1.1. Overview of arguments for and against the deployment of CCS

CCS is a proposed method to reduce at large scale the CO₂ emissions from the continued use of fossil fuels. The urgent need to reduce global carbon emissions to atmosphere and ocean is therefore the overriding motivation in the case for pursuing CCS.

Fossil fuels currently meet more than 80% of global primary energy demand, and CO₂ from fossil fuel combustion accounts for over 90% of energy-related emissions (IEA, 2015a). The continued unabated use of fossil fuels is inconsistent with the commitment in the Paris Agreement to keep the global average temperature increase below 2°C, with an aspiration to limit it to 1.5°C. McGlade and Ekins (2015) find that

the total global fossil fuel reserves – resources that are recoverable under current economic conditions – would, if combusted, produce CO₂ emissions more than double the budget allowable to have a better-than-even chance of keeping temperature rise below 2°C, as calculated by the IPCC (McGlade and Ekins, 2015). CCS offers one means of producing low carbon electricity, along with other options such as nuclear and renewables. However, CCS could also provide a means of reducing emissions from industrial sectors, such as cement, steel, gas processing and fertilizer production, where other decarbonisation options are very limited, and allows for the possibility of ‘negative’ emissions from the sequestration of emissions from the combustion of biomass. The evidence from modelling studies concerning the role of CCS in delivering climate policy targets is reviewed in more detail in Chapter 4 of this report.

Other reasons for pursuing CCS in the context of an overall low carbon transition could arise from the opportunities it offers to maintain jobs and redeploy skills in the fossil fuel industry, and develop new industries, in a low carbon world. It has been estimated that the fossil fuel industry currently employs about 13 million people globally (WWF, 2015). Global decarbonisation towards a 2°C target without CCS would require a precipitate decline of this industry and a corresponding loss of employment. The large-scale deployment of CCS would be able to mitigate this job loss, as skills from the hydrocarbon industries, such as subsurface evaluation and offshore engineering, could be readily transferred to an emergent CCS industry. More generally, the required skills for CCS are already available in a range of countries to support a very large increase in CCS deployment. Coupled with the new job opportunities in the renewable energy sector (IRENA, 2015), employment from CCS could ease the transition of affected workers out of fossil fuel industries, and reduce the political resistance that its rapid decline would generate, allowing countries with fossil fuel extractive industries to continue to gain economic benefit and employment from these resources, even within a low carbon world.

As an example of this, in the IEA’s ‘450 Scenario’, in which by 2040 CCS in power and industry captures 5 Gt CO₂ per year, over the period to 2040 ‘facilities equipped with CCS in the power and industry sectors consume about 15 billion tonnes of coal equivalent that would be worth \$1.3 trillion and 4 000 billion cubic metres of natural gas worth about \$1.3 trillion at the prevailing fuel prices. ... Countries and companies with revenue streams from the extraction and processing of fossil fuels thus have a clear interest in supporting the development and deployment of CCS’ (IEA, 2015a).

As well as providing people with jobs, the fossil fuel industry is heavily invested in physical infrastructure. Even when fully depreciated, resistance to the loss of such assets before the end of their useful lives generates political resistance to decarbonisation. CCS systems have the potential to re-purpose or prolong the life of infrastructure associated with mining, power stations, pipelines and offshore platforms, avoiding the premature loss of such sunk investments. Moreover, reuse of legacy assets such as pipelines can also reduce the costs of transporting CO₂ from a source of capture to a sink for storage (Brownsort et al., 2016).

In addition, CCS could permit the development of new low carbon fuels and industries. Technological innovation in one field often affects other technologies or

has multiple applications, stimulating broader innovation dynamics. An example relevant to the development of CCS is the production of hydrogen through pre-combustion CCS processes. Hydrogen could have a pervasive role as a zero-carbon energy vector, for example as a clean road transport fuel through the use of fuel cells, as a heating fuel through combustion at the point of use, or as an alternative form of energy storage. The interaction of CCS with other technological systems including the production of synthetic transport fuels forms part of the discussion of Chapter 4.

However, as well as the above arguments in favour of developing CCS, concerns and criticisms have also been raised about CCS. Critics have questioned the technical viability of CCS systems (Greenpeace, 2016). The current status of CCS technologies and systems will be examined in more detail in Chapter 3.

Concerns have also been raised about the costs of CCS, relative to other low carbon options. As an 'end-of-pipe' addition to a fossil fuel based process, CCS inevitably entails an add-on cost to that of the original fossil fuel process. More generally, CCS, as a set of technologies dealing with disposal of CO₂, could struggle to compete on cost grounds with intrinsically low-carbon electricity generating technologies. As a result, it could be argued that even in the long-term, the carbon abatement cost of CCS could be higher than other low carbon technologies, such as solar, wind and geothermal. Some critics suggest that the argument from some companies that there should be a cap on the long-term commercial liability for CCS may indicate that they are not willing or able to bear the true long-term costs of CCS (Greenpeace, 2016). The costs of initial full-scale demonstrations have been high, particularly in the power sector (Banks and Boersma, 2015). The argument is sometimes made that CCS has failed to be deployed at scale despite already having received extensive public subsidy over a considerable period of time. Cost, coupled with the unwillingness of governments to provide the necessary subsidies, has certainly played a major role in a number of power generation demonstration projects, driven by purely low-carbon motivations, being stalled or cancelled in recent years. Such experiences will be explored further in Chapter 3. We also consider the different factors that can cause costs to rise or fall, both with reference to current CCS projects in Chapter 3, and through comparison to other technologies and technological infrastructures in Chapter 2. Variations in the cost of CCS are considered in the context of the overall costs of decarbonisation in Chapter 4.

Other concerns include whether CCS would in all cases achieve genuine overall emissions reductions. For example, in several of the projects which will be discussed in Chapter 3, captured CO₂ is being used for enhanced oil recovery (EOR) – the process of pumping CO₂ into the ground in order stimulate increased extraction of oil from declining oil wells. In such cases, even if the use of CO₂ for EOR does result in the sequestration of some CO₂, it has been used as a means of stimulating the production of another fossil fuel, which will then be consumed and its emissions released to the atmosphere. Thus, for some critics, this application of CCS does not count as a genuine CO₂ mitigation process, because it contributes to a system which still culminates in the production and unabated use of a fossil fuel (Greenpeace, 2016). The role of CO₂-EOR within the context of overall CO₂ mitigation will be discussed further in Section 1.2.2. Even when not used for EOR, critics argue that

CCS is not low carbon enough – residual emissions from CCS typically make capture about 90% efficient, although the oxyfuel process can increase this to 99%. Capture efficiencies less than 100% are amongst the technical parameters defined as inputs to the modelling described in Chapter 4 – hence the discussion of the role of CCS in this chapter will take account of this issue.

Another significant concern is the level of confidence around whether geological storage can securely sequester CO₂ without leakage, in perpetuity. Critics argue that no geological storage can be guaranteed never to leak. There is concern that a large scale leak would be the undoing of the main intention of the process by releasing CO₂ into the atmosphere; also in very high concentrations CO₂ is toxic to humans and animals (Greenpeace, 2016). These concerns would be especially relevant if CO₂ were to be stored at a large scale below inhabited areas. Evidence relating to the security of CO₂ storage is explored in Section 1.2.2.

Finally, for some critics, CCS is perceived as a means of perpetuating an outmoded addiction to fossil fuels, and that a true energy transition would be to make a much bolder leap towards new technologies, especially renewables. This is particularly the case when CCS is put forward by the coal industry, when it can be perceived as seeking to appease concerns about climate change while continuing with “business-as-usual”. In exploring public attitudes to energy system transitions in the UK, Parkhill et al (2013) uncovered a view that, if an energy system transition is needed, we should “do it right” – to make it a worthwhile change’. In this context, there was ambivalence around CCS. Parkhill et al report, ‘Whilst it is not true to say that publics are against CCS, we find significant concerns about its use. Negative attitudes towards CCS stem from the belief that it is not representative of progress; it is seen as a continuation of unsustainable practices associated with fossil fuels (i.e. this is another instance of perceived ‘non-transition’)’ (Parkhill et al., 2013). Other studies of public views of CCS suggest it is been negatively perceived as perpetuating reliance on waste disposal rather than waste prevention (Krämer, 2011). Parkhill et al suggest that the acceptability of controversial technologies such as CCS ‘is typically conditional upon other aspects of system change being realised’ (Parkhill et al., 2013). The importance of public deliberation around CCS is explored further in Section 1.2.7, in relation to other energy technologies in Chapter 2, and in relation to CCS case studies in Chapter 3.

1.2. Challenges and uncertainties of CCS

Debates around controversial technologies and technological systems can easily become polarised. On the one hand, advocates may fall into rejecting any concern as unimportant; on the other hand, opponents may seize on the existence of any risk or uncertainty as reason to reject the disputed technology entirely. However, a more constructive approach is likely to arise from an open and transparent assessment and balancing of risks and uncertainties, including consideration of whether and how such uncertainties can be reduced. Many of the issues raised in the summary of arguments above are identified by Watson et al (2014) as key uncertainties in relation to the prospects for the substantial commercial deployment of CCS. The uncertainties are listed as: the variety of pathways; the security of storage; the

possible scale and speed of development and deployment; the integration of CCS systems; future costs and financial risks; the vagaries of politics, policy and regulation; and public acceptance. These uncertainties were identified by reviewing the social science literature on CCS and the wider literature on innovation, as well as consulting with representatives from industry, policy and academia, and with technology stakeholder representatives. They therefore provide a robust entry point into the challenges that would need to be addressed if CCS were to achieve its potential for large scale carbon sequestration.

1.2.1 Variety of technology pathways

The three main distinctive technological varieties of carbon capture technology for the power sector can be summarised as post-combustion, pre-combustion and oxyfuel capture. Watson et al (2014) note that the variety of different technological options for CO₂ capture creates uncertainty for investors and policy makers.

In post-combustion capture, CO₂ is removed from the flue gas of a power plant or industry activity after normal combustion has taken place. This is typically done using a chemical process based on chemical solvents. After being removed from the flue gas the CO₂ can then be released from the solvent, typically by increasing the solvent temperature in a reboiler, and the solvent can be reused (Gibbins and Chalmers, 2010). Solvent technology has been applied at large scale for post-combustion capture. Other approaches, such as membranes or adsorbents are at different levels of development.

In pre-combustion capture, the primary fossil fuel is not combusted in its original form, instead undergoing high temperature gasification and partial oxidation with air/oxygen and steam to produce a syngas mixture of carbon monoxide (CO), hydrogen (H₂), H₂O and CO₂. Shift reactions are then used to convert CO to hydrogen and CO₂. Separation of the hydrogen from the CO₂ can use a physical solvent, membrane, or pressure swing process. The remaining hydrogen can then be combusted in a combined cycle gas turbine, used in a fuel cell to generate electricity, or potentially stored and used as chemical feedstock for other purposes – for example in oil refinery upgrading of hydrocarbons (Gibbins and Chalmers, 2010), for heating or for land transport.

Oxyfuel capture is a post-combustion capture process, however it differs from standard post-combustion capture in that the combustion of the primary fuel takes place in pure oxygen rather than air. Though this incurs an energy penalty to produce pure oxygen in an air separation unit, the advantage of doing so is that the flue gas from fuel combustion should contain no nitrogen. Separation of CO₂ from water can then be achieved by simple condensation, which makes it possible to avoid the more energy intensive chemical separation process in post-combustion capture (Gibbins and Chalmers, 2010).

There is some uncertainty about which of these technologies is more likely, and more cost-effective, to achieve full scale-up. There are also other characteristics of the technologies which could give further reasons for selecting one over the other, depending on technological application, geographic setting, or policy priorities. One

important issue is the suitability of the different technologies for post-combustion retrofits in the power sector. Given the long remaining lifespans of many existing coal-fired electricity plants, and the real possibility of many more unabated coal and gas electricity plants being built over the coming decades, especially in emerging economies, retrofitting of existing coal or gas power plant is likely to play an important role in any significant CCS contribution to decarbonisation. In order to stay below 2°C degrees, China and India will either have to close or retrofit a number of their newly installed coal fired power plants.

Inevitably, given the early stage of deployment, there are technological and cost uncertainties about each of the varieties of CCS. Post-combustion, oxyfuel and pre-combustion capture processes have all been demonstrated, however it is not straightforward to extrapolate from the costs of one-of-a-kind demonstrations to projected future costs of 'Nth-of-a-kind' commercialized plant.

Political decisions and challenges are inevitably linked to these technical challenges. CCS technologies of any kind require prolonged policy support if they are ever to scale up. Policy makers have options for doing this – as will be discussed further in Chapter 2 – but in doing so need to be aware of making or avoiding choices and trade-offs, such as whether to focus their support on one particular CCS technology option, and whether their support for CCS should or should not offset their support for other energy technologies. Different types of capture will anyway be required for different industrial sectors (e.g. gas processing, steel, cement), and transport and storage infrastructure, as a major source of cost and potentially of cost reduction whatever the capture technology, will require its own commercial models and incentives for deployment.

1.2.2 Security of storage offshore and onshore

In this section we consider the question of the security and integrity of geological CO₂ storage over long time frames. Before examining the issues around unintended leakages of CO₂ from geological storage, we first consider the specific issue of whether CO₂ injected for the purposes of enhanced oil recovery (CO₂-EOR) can be considered a genuinely effective way of reducing CO₂ emissions to the atmosphere. In CO₂-EOR, although CO₂ is sequestered, it is done for the purposes of stimulating the production of oil which is then combusted at a later stage, releasing CO₂. The downstream emissions arising from the combustion of the oil produced by the EOR process could be seen to erode the net reduction of CO₂ attributable to the whole process, perhaps entirely. For this reason some critics of CCS argue that CO₂-EOR “misses the entire supposed purpose of CCS because it likely has no climate benefit” (Greenpeace, 2016).

Most currently existing EOR is not done for the purpose of CO₂ mitigation, but for the commercial profit of increasing oil production. As such, commercial operators are not necessarily incentivised to maximise CO₂ storage, or even to ensure that the CO₂ will remain stored once it has served its purpose for EOR. Therefore, as a minimum condition for CO₂-EOR being a potential CO₂ mitigation option, adjustments to current typical EOR practice would need to be made to improve the CO₂ storage aspect. IEA (2015b) propose four key additional requirements for EOR to be a

climate mitigation tool: additional site characterisation and risk assessment; additional measurement of venting and fugitive emissions; monitoring and enhanced field surveillance; and changes to abandonment processes that help guarantee long-term containment of CO₂. These requirements would add costs for commercial operators, and so would probably need to be supported through policy measures. We discuss more about ongoing monitoring of CO₂ storage later in this section, and appropriate policy measures to incentivise CCS for CO₂ mitigation, later in the report.

However, even if the CO₂ is safely stored, there remains the issue that it is used to produce more fossil fuel, which could be seen to erode the CO₂ mitigation benefit. Life-cycle analysis (LCA) of the emissions of a CO₂-EOR system can shed some light on this question. Understanding and defining the overall CO₂ mitigation potential of CO₂-EOR through LCA crucially requires a definition of the boundaries of the system being analysed, and a definition of the baseline against which CO₂-EOR is being implemented – that is, what would have happened in the absence of the CO₂-EOR system. Two important questions to ask of LCAs of CO₂-EOR are therefore: does the LCA include the downstream emissions from the oil that is produced by the EOR; and if so, what fuel is it assumed that this EOR oil is displacing within the energy system?

For example, Hertwich et al (2008) present the results of an LCA of a proposed CO₂-EOR system on the west coast of Norway. The hypothetical system would consist of a combined cycle gas plant fitted with CO₂ capture, the CO₂ being used for EOR. In the LCA, the impacts of the capture of CO₂ are allocated to the electricity produced, and the impacts of the transport and storage of the CO₂ allocated to the oil produced. On the basis of this allocation, the per-kWh emissions from power production are reduced by 80% compared to IGCC without CCS; the per-m³ emissions associated with oil production are reduced by 30-90% compared to extracting the oil without EOR, mostly due to the increase in oil production. The LCA does not include the emissions from the downstream combustion of the oil. Thus this system would represent a significant reduction in emissions from electricity production compared to unabated fossil fuel power stations, at the same time as producing oil likely to have a lower life-cycle carbon footprint than some other comparable types of oil production. As such if this EOR oil was to displace a more carbon intensive type of oil, then it would deliver carbon reductions relative to that baseline.

The importance of what the EOR products are displacing is discussed by Jaramillo et al (2009). They carry out LCAs based on data from five EOR projects, including the emissions from the combustion of the final petroleum product. They find that net emissions from all projects are positive – in other words that the amount of CO₂ sequestered is less than the total emissions of CO₂ from the whole system, including the combustion of the petroleum product. However, this net positive result effectively assumes that the final consumption of the petroleum represents additional CO₂ to the atmosphere – the implicit assumption is that the petroleum-using activity would not have occurred anyway without the EOR system, using petroleum from other sources. In further analysis the authors compare the emissions of the CO₂-EOR system to those of alternative systems producing the same quantities of electricity and oil – in other words, these comparisons assume that the same quantities of oil would still be produced, by other means, even if the EOR system was not there to produce them.

This analysis reveals that the five CO₂-EOR systems would produce oil and electricity with lower overall emissions than alternative systems producing the same quantities of oil and electricity, if these other systems were based on current oil and electricity emissions, or on electricity from an IGCC plant and oil from Canadian synthetic crude oil. However, compared to electricity produced from low carbon sources and Saudi Arabian oil, four of the CO₂-EOR systems would not achieve significant emissions reductions, while one of them would result in a 5% increase in system emissions.

Stewart and Haszeldine (2015) undertake an LCA of a hypothetical CO₂-EOR in the North Sea. They find that the net CO₂ is negative if the system boundary includes only the production operations, but net positive if the boundary also includes the transportation and refining of the crude, and the end product use. In an alternative scenario in which injection of CO₂ is optimised for maximum CO₂ storage, not for oil production, the CO₂ balance remains net negative even including the emissions from transportation, refining and end use – however such a scenario would not be commercially optimal purely from the perspective of oil extraction, and would therefore evidently require additional policy inducements. Stewart and Haszeldine find the emissions intensity of the oil produced from the CO₂-EOR system to be 0.135-0.137 tCO₂e/bbl. The authors note that this value is somewhat higher than values given in other CO₂-EOR studies, in part due to their inclusion of emissions from flaring, venting and fugitive releases, associated with the production process. Comparing this estimate of the emissions intensity of CO₂-EOR oil, to that of oil produced by other means, is complicated by the wide ranges and uncertainties in such estimates in the literature. Cai et al (2015) cite 0.03 tCO₂e/bbl (4.4 gCO₂e/MJ) for US conventional crude oil recovery. Jacobs (2012) find for European refined crude oil a range of around 0.02-0.07 tCO₂e/bbl (4-12 CO₂e/MJ), depending on flaring. Burnham et al (2012) suggest embedded emissions for conventional crude oil production of 0.11-0.15 tCO₂e/bbl (20-25 CO₂e/MJ). Di Lullo et al (2016) find a range of results with well-to-tank (WTT) estimates ranging from 0.14 tCO₂e/bbl (24 gCO₂e/MJ) for gasoline from Saudi Arabian Arab Light crude, to 0.27 tCO₂e/bbl (46 gCO₂e/MJ) for gasoline from Venezuelan Vene crude. A comparison of these ranges with the LCA estimates of Stewart and Haszeldine suggests that the life cycle CO₂e emissions of CO₂-EOR oil are broadly in a range comparable with the life cycle emissions of conventional crude oils. Several analyses suggest that some conventional oils would have lower life cycle CO₂e emissions than CO₂-EOR oil. However, other work, in particular the analysis of Di Lullo et al (2016), suggests that CO₂-EOR oil could have lower life cycle emissions than the more energy intensive conventional oil processes. Comparison of LCAs of conventional and unconventional oil production within individual studies suggests that unconventional oil production is typically likely to entail greater life cycle CO₂e emissions than conventional oil (Burnham et al., 2012, Cai et al., 2015) – hence if CO₂-EOR were to displace unconventionally produced oil there is a reasonable likelihood that it would also deliver a net emissions benefit.

In other words it matters what the products of CO₂-EOR are offsetting. Assuming that the emissions reduction from the captured and stored CO₂ are allocated to the power plant – that is, the electricity is counted as low carbon because of the stored CO₂ –

whether the EOR-produced oil can be considered low carbon depends on what it is compared to. If the EOR-produced oil reduces the production of a more carbon intensive form of oil (conventional or unconventional) then it will constitute additional carbon reductions, whereas if it offsets an oil product of comparable CO₂ intensity then the savings will be negligible. However, if the EOR-produced oil offsets or displaces a less carbon intensive form of oil which would have otherwise been used, then it would constitute a net increase in emissions. Clearly the net emissions increase would be considerably greater still if the EOR-oil was displacing or preventing the introduction of a very low-carbon fuel, such as hydrogen, biofuels or low carbon electricity. Therefore, a key issue in relation to the role of CO₂-EOR as a climate mitigation tool, is the extent to which future low carbon pathways can still use oil at all. If oil is still being used in any case within the system, then the production of oil from CO₂-EOR would not constitute additional emissions, as long as the carbon intensity of its production was not greater than that of the conventional or unconventional oil it displaced. This question will be considered again in Chapter 4, in the light of the low carbon scenarios produced for this report.

We now turn to issues surrounding the security of long term geological storage of CO₂. Oil and gas can accumulate and remain in stable deposits over thousands and even millions of years. CCS is obviously best suited, and perhaps only suited, to locations with this type of geology. However, the 1,000 to 10,000 year long time scales over which CO₂ is anticipated to be stored, and the dynamic nature of parts of the earth's crust over such time scales, does mean that the security of CO₂ storage is subject to long-term uncertainties. How monitoring over these timescales should or could be carried out, and whether the risk calculation makes that necessary, is still debated. Three kinds of impact from a leak can be considered. One is the risk of CO₂ re-entering the atmosphere, thereby negating the primary rationale for CCS. A second issue is that a leak into existing oil and gas deposits could affect the chemical composition and economics of extracted reserves. Finally, a concentrated release of CO₂ in a particular area could have local environmental or health risks (Pollak and Wilson, 2009, Watson et al., 2014).

In this section we review currently available evidence on the security of CO₂ storage offshore and onshore. Concerns were raised by Greenpeace (2016) about the risks of leakage from CO₂ storage sites, based on evidence from monitoring at three sites: Sleipner, in the Norwegian North Sea; In Salah, in Algeria; and in Yazoo County, Mississippi. We consider evidence from each of these sites and regions.

As will be discussed in Section 3.2.6, the Sleipner CO₂ storage project has been capturing CO₂ since 1996. The CO₂ is stored in a formation above the Sleipner East field. The ECO₂ research project identified fractures in the sea bed above the Utsira formation, North Sea, with one large fracture in the sea bed 25 km away from the Sleipner injection well. Though the ECO₂ researchers state that the fractures would pose a risk of leaks if they were reached by the injected gases, there is no evidence of any connection between the Sleipner CO₂ plume and these fractures, which have a different and natural origin (Haszeldine et al., 2014). The CO₂ plume is contained as predicted in the Utsira formation, and remains a long distance from the largest of the fractures. No leaks have been recorded since injection began in 1996.

Even if a leak were to occur into shallow marine seas, initial tests suggest that its impact would be minimal. E_{CO₂} researchers injected 'up to 150 kilograms of CO₂ a day just above the sea floor near Sleipner. They found that the CO₂ completely dissolved within the lower few metres of water, rapidly converting to bicarbonate and dispersing. Only a small amount of the injected gas may have reached the atmosphere' (Monastersky, 2013). A controlled and monitored release of CO₂ into a shallow seabed typical of North Sea habitats was conducted offshore of Scotland. Most of the CO₂ was trapped by dissolution and dispersion in the seabed sediment. The 15% injected CO₂ which reached the seabed in this experiment (Blackford et al., 2014) was dispersed rapidly by tides and currents. Marine life was marginally affected for two days. Natural CO₂ vents in the Mediterranean Sea provide additional insight into long-duration seabed leakage. Researchers found 'that the gas, which acidifies nearby waters, kills off many organisms within a small, 10-metre zone around the vent and reduces species diversity within a radius of about 100 metres, but that effects beyond that distance are limited' (Monastersky, 2013).

The storage site at In Salah, Algeria, also referred to by Greenpeace (2016) was injected with approximately 4 million tonnes of CO₂ between 2004 and 2011. White et al (2014) report on observations that pressure, and probably CO₂, has migrated into the lower portion of the caprock. They suggest that the most likely explanation for this is the interaction of hydraulic fracturing, caused by the increased pressure as a result of the gas injection, with pre-existing fractures in the rock. Notwithstanding this likely migration of the gas into the lower portion of the caprock, White et al find that 'there are no indications... that the overall storage complex has been compromised, and several independent data sets demonstrate that CO₂ is contained in the confinement zone' (White et al., 2014). Thus, in this case monitoring from the surface provided adequate advance warning to take action by halting CO₂ injection, thereby eliminating risk of leakage to the surface. This project is also discussed in Section 3.2.9.

Examining natural occurrences of CO₂ onshore can provide insight into the impact of long duration leaks. Analogies are sometimes made with Lake Nyos in Cameroon, which is saturated with CO₂ of volcanic origin. In 1986, due to a disturbance to the bed of the lake, hundreds of thousands of tons of CO₂ were very suddenly released from the water and poured into neighbouring valleys, with catastrophic impacts on local populations. Clearly CCS storage sites would need to be verified as not being vulnerable to similar build up and sudden release of CO₂ (Socolow, 2005). However, there are very different natural processes, concentrations and rates of release involved in such rare and well-documented volcanic lakes, compared to common natural seeps of CO₂ onshore at cold springs. The latter conditions are more likely a better analogy for conditions around a human induced leak. Evidence gathered from sites of real historical CO₂ leaks, both natural and human-induced, suggests that in sites of leakage similar to CO₂ from an underground geological storage site, the gas is rapidly dispersed and mixed into the locally surrounding air mass. In Italy, where leakage from natural geological stores of volcanic CO₂ is historically well documented, the risk of premature death is calculated at 1 in 36 million of the affected population per year (Roberts et al., 2011).

Leakage potential through disused wells in the neighbourhood of CO₂ stores is a commonly identified high risk in geological CO₂ disposal. Examples in which leakage was likely induced by CO₂ injection engineering operations, occurred in Mississippi and Louisiana. The Mississippi case relates to the activities of an oil company, Denbury Resources, in pumping CO₂ into old oil fields in order to enhance oil recovery. Leaks occurred from 4 disused wells, in one case lasting for 37 days, and the company was forced to undertake remediation activities. The issues in this case seem to have arisen from the attempts to pump CO₂ into long-abandoned and improperly sealed wells, which were not able to withstand the resulting increased pressures (Mississippi Business Journal, 2016). The cases highlight the importance of carefully regulating and monitoring the activities of companies undertaking CO₂-EOR. However, they also suggest that, if leaks do occur, existing oil and gas technology can be deployed to shut down leaking wells and remediate them.

Verdon et al (2013) review and compare the effects of long term injection at Sleipner, In Salah, as well as Weyburn in Saskatchewan, Canada. They find that Sleipner has experienced little pore pressure increase during the period of injection, whereas In Salah has experienced increased pressure, resulting in some 'substantial microseismic activity'. In Weyburn, the long history of oil production substantially reduced pore pressures, before CO₂ injection increased pressures again – in combination leading to 'complicated, sometimes nonintuitive geomechanical deformation'. In general, 'the differences in the geomechanical responses of these sites emphasize the need for systematic geomechanical appraisal before injection in any potential storage site' (Verdon et al., 2013).

In summary, observations from existing CO₂ storage sites do not provide sufficient evidence to assert that the safe long-term geological storage of CO₂ is fundamentally and technically unviable. Observations thus far show that carefully selected, managed and monitored CO₂ storage sites are successfully containing CO₂. This is not to deny that the injection of CO₂ can give rise to geomechanical effects, as observed at In Salah, which will require close and careful monitoring. Neither could the risk of leakage ever be entirely rejected with absolute certainty. However, the evidence, especially from apparent leakage failures such as from Mississippi and Louisiana boreholes, suggests that the proportionate response to these uncertainties would be to undertake future CO₂ injection with appropriate caution and careful ongoing monitoring, rather than necessarily to forbid injection entirely. If a deviation from expected behaviour is apparent, or a leak occurs, then with existing monitoring and technology it should be possible to identify and deal with the problem rapidly and effectively. As with all technologies, the risk associated with it must be balanced against the consequences of not using it. In this case, that means considering the risk of CO₂ leakage against the impact on global emissions of not deploying CCS. The potential risk of disqualifying CCS from the portfolio of global decarbonisation technologies is one of the issues that will be explored in Chapter 4.

1.2.3 *Scaling up and speed of development and deployment*

If other technical and economic uncertainties associated with CCS were addressed, there would still be uncertainty around whether sufficient numbers of CO₂ capture

plants and their required associated infrastructure could be constructed in time to make a significant contribution to global-scale decarbonisation by mid-century. A step change in CCS deployment would be needed if CCS were to make a meaningful contribution to greenhouse gas mitigation (Scott et al., 2013). In the IEA's '450 Scenario' – which presents a pathway consistent with limiting temperature rise to 2°C – 'global CCS capacity in the power sector reaches 740 GW in 2040, 20% of fossil-fuelled power generation at that time' (IEA, 2015a). The rate of installation of CCS power plants in the scenario averages 20 GW per year in the 2020s, and over 50 GW per year in the 2030s (IEA, 2015a). Achieving such levels of capacity would clearly require quite phenomenal build rates in a number of countries. On the other hand, very high build rates of large scale technologies over sustained periods have been seen. Chapter 2 for example explores the example of the French nuclear programme, which installed over 50 GW of capacity in a little over fifteen years, while the market-driven development of oil and gas production and transportation capacity was also very rapid. As will be discussed in subsequent chapters, such levels of scale up for CCS would be dependent on a strong policy framework, including clear and long-term market signals, efforts to assist in the coordination of multiple actors over long supply chains, and the addressing of legal and regulatory issues, and barriers concerning financial risk. Such efforts would be considerable, but not impossible.

1.2.4 *Integration of different CCS technologies into a single system*

A major challenge to CCS will be the coordination of a multi-actor value chain. This will not emerge spontaneously in response to a clear market demand, and therefore is likely to require some government coordination. CCS infrastructure includes an integrated network of pipelines and storage sites. As such it faces the dilemma of scale, familiar in other examples of networked infrastructures. It would need to be built at an appropriately large size to benefit from economies of scale assuming multiple sources feeding in, and to avoid a highly expensive piecemeal approach to the infrastructure. However, the larger-scale the infrastructure that is built the greater the risk of wasted investments if the feeding-in sources – power plants and industrial facilities – are not built or do not connect to it. The coherent and cost-effective integration of a CCS system would therefore require a not inconsiderable amount of foresight, planning and coordination.

Oxburgh (2016) and Deloitte and Crown Estate (2016) identify precisely this problem. For Oxburgh (2016) the proposed remedy is state intervention in creating the first operational infrastructure networks, which then have sufficient value to enable routine and profitable investment in creating more capacity. It is further proposed by Oxburgh that long-term policy certainty can be improved by creating a market for CO₂ storage driven by storage mandates (Oxburgh, 2016). Deloitte and Crown Estate (2016) examined more flexible and varied models including public-private partnerships.

In Chapter 2, we consider historical examples of other networked industries, as well as the benefits of supply chain coordination in other energy technologies.

1.2.5 Economic and financial viability

As previously mentioned, a substantial challenge for CCS is that it must, inevitably, cost more than the equivalent CO₂-emitting process to which it is an add-on. Oxburgh (2016) and Deloitte and Crown Estate (2016) explore the different metrics that are required to evaluate economic viability in different sectors.

Reviewing estimated total costs for CO₂ capture, transport and storage systems in power generation, based on recent studies, Rubin et al (2015) find that the cost increase above reference plants for different CCS technology systems ranges between 26% and 114%. Natural gas processing and some other industrial applications where high purity CO₂ is already separated and captured in the existing waste stream can involve lower cost increases, these being just for compression, transport and storage. Such cost estimates indicate the incentive that will be required for private companies to deploy CCS. Whether such incentives are provided in turn depends on how badly policy makers want the technology to be deployed. The sensitivity of CCS deployment rates to cost is one of the issues explored in Chapter 4.

It is suggested that there is potential for reducing the fundamental technology costs, especially through improving the energy efficiency of the capture process. In particular it is possible that new low-energy solvents will emerge from university and investor-led innovation. Disruption could also occur in CO₂ separation – for example H₂-CO₂ separation using low energy pressure-swing is already operating at 1Mt CO₂/yr in the Port Arthur plant of the Valero refinery, Texas.

In addition to technology costs, Watson et al (2012) also draw attention to the issue of financial viability, which is related to how policies affect cash flows, investor confidence and network regulation. Watson et al suggest that ‘improving economic and financial viability is an important rationale for policy support’ (Watson et al., 2012). While the economics of specific technical components may be hard to predict, and dependent on successful R&D, financial viability is something over which policy could have significant influence, as will be explored further in case studies in Chapter 2.

Other studies point to the reduction in cost that might be expected with progressive development of CCS projects. The CCS Cost reduction Task Force in the UK (CRT, 2013) identified a cost reduction pathway from £140 to £85 per MWh electricity price. The progress along this pathway did not require significant technological innovation, but was largely driven by reducing the cost of infrastructure by cheaper construction, and especially by sharing of CO₂ gathering pipeline networks from captured sources on land, to large diameter common carrier pipes offshore, and co-located storage with shared facilities and monitoring.

Another approach to cost reduction through scale-up is proposed by the UK Oxburgh Report (Oxburgh, 2016). This proposes that, with controlled procurement of the different CCS components from competitive suppliers, it is possible to move directly to the £85/MWh electricity cost-efficiency identified by the Cost Reduction Task Force, from the first CCS project. A major difference in policy approach between

Oxburgh and previous UK policy is to create a government owned commercial company which takes the responsibility and risk of procuring and managing construction of the first CCS projects with infrastructure. Once the first projects are operating, the infrastructure has commercial value, and government can privatize the CCS Development Company to continue with normal low-risk commercial investment, retaining only the regulatory oversight.

1.2.6 Policy, politics and regulation

The increased costs that arise from adding CCS to any equivalent CO₂-emitting process mean that, from a private investor perspective, and in the absence of any policy driver, there is typically a very limited business case for CCS. The strength of policy driver required to make a CCS project commercially attractive may vary across different types of CCS projects. For example, as discussed in Section 1.2.2, the use of CO₂ for EOR can improve the economics of CCS due to the value of the increased production of fossil fuels it enables. However, even here, ensuring that the CO₂ that is injected for EOR is stored securely and for the long term – and thus that the system is an effective climate mitigation tool, and not only a method for increasing oil production – is likely to create additional costs for commercial operators, and therefore to require further policy inducements over existing EOR practices (IEA, 2015b). Also, as will be discussed in Chapter 3, there are some CCS projects in existence or under development where due to the nature of the primary process, the added cost of CCS was a relatively small increment. In such cases, the policy lever required to bring the projects into being was correspondingly modest – nonetheless some policy intervention was needed. In contrast, encouraging dedicated CCS in sectors where the additional costs above those of the existing process are much higher, would require a correspondingly stronger policy driver. Thus, CCS as a serious long-term CO₂ mitigation option is strongly dependent on the existence of policies, politics and regulations designed to create a demand for low carbon energy production, or for the removal of CO₂. To the extent that these aspects are uncertain, the future for CCS will be correspondingly uncertain. CCS requires clear policy signals about the value of low carbon energy, extending clearly into the future, to give investors the long term confidence they need to invest in the technology. It requires a supportive political environment which engenders the sense that the long term policy signals will not be reneged upon in the name of short term political expediency. It also requires regulation that provides a sound and comprehensible legal framework to allow investors and project developers to proceed with confidence. Strong and consistent political will is a vital pre-requisite for any CCS roll-out programme. Various precedents for these aspects in a range of energy and other technology examples will be explored in Chapter 2.

1.2.7 Public acceptance

CCS has the potential to generate public concern for a number of reasons. First it is a comparatively new and little-known technology, and in countries or regions with little experience of this or similar industrial processes, it may be viewed with suspicion. Second, it might viewed as a technology being promoted by a powerful incumbent fossil fuel industry, more concerned with prolonging their own existence

than enabling a genuine energy transition. The links between CCS and EOR could strengthen this perception. Reports of the geomechanical or seismic effects of CO₂ injection, as in the In Salah project (White et al., 2014), might also cause CCS to become associated with hydraulic fracturing (“fracking”), which has faced considerable public opposition in a number of countries for its own reasons.

More positively, and as noted above, is the possible positive perception of CCS as assisting in the survival and sustainability of industrial regions as deep decarbonization takes place.

The effect of public opinion on processes of developing and deploying technologies varies substantially between different countries, which have differing planning and consultation processes. However, in many countries, public deliberation is increasingly seen as a critical factor in the successful development of new technologies (Watson et al., 2012). As will be explored in Chapter 2, the views of citizens affected by the development of large-scale technologies and infrastructures have in several cases had significant impacts on their development. The right to engage in debates about technological deployment, and to have views heard, is increasingly being demanded as a part of democracy. In such circumstances, citizens are sceptical of tokenistic or disingenuous attempts at consultation (Crompton, 2015).

The ability of CCS to win public acceptance is therefore an important uncertainty. In Chapter 2 we explore lessons from other examples of public deliberation around large scale energy technologies and other infrastructures, and Chapter 3 also considers public acceptability issues in relation to proposed CCS programmes.

1.3. Conclusions

CCS is a controversial technology that has both proponents and opponents. In this introductory chapter we have summarised the main arguments that are typically marshalled in favour of scaling up and deploying CCS, as well as the arguments that critics of CCS have laid out in opposition to its further development.

We have suggested however that an overly binary approach to CCS is unlikely to be helpful. Rather than either simply attempting to dismiss risk entirely, or conversely to assume that any amount of risk however small is sufficient to reject CCS entirely, we suggest that a more constructive approach is likely to arise from open and transparent assessment and balancing of risks and uncertainties, including consideration of whether and how such uncertainties can be reduced. We have briefly reviewed key areas of uncertainty, and as indicated throughout this chapter, many of these areas will be explored in more detail in subsequent chapters.

In general we would suggest that no technology is without risk or uncertainty. Therefore the question in relation to CCS should not be whether all risks and uncertainties can be eliminated before it is possible to proceed, but rather to what extent such risks can be managed, and to what extent they may be outweighed by opposing risks that could arise as a result of not attempting to develop CCS.

In the remainder of this report we continue to explore risks and challenges both of deploying and not deploying CCS, and will finally present our own judgement on what we consider the appropriate balance between these various risks to be.

2. Understanding policy options through the experience of other technologies

Key points

- Stimulating innovation in low carbon technologies requires an innovation systems approach that considers multiple feedbacks along the innovation chain, and the role of actors, institutions and networks in conditioning the process. This is especially the case for CCS, which is characterised by multi-actor supply chains, long-term liabilities and large shared infrastructures.
- As part of this approach, there will be a need for technology push policies – such as support for research, development and demonstration; market pull policies – such as price support or carbon taxes; as well as coordination of actors, institutions and networks across the innovation system.
- Comparable large technological systems and infrastructures have in the past benefitted from some kind of whole-chain coordination and support, with governments often playing key enabling roles.
- It is unlikely that CCS will succeed without similar whole-chain coordination and support.
- Public engagement in the process of developing large scale technological systems like CCS, and the role they could play in the overall transition to sustainable energy systems, is critical.

2.1. Introduction

This chapter examines historical examples of energy technologies and other large infrastructures, and considers the role that policy making has played in affecting their deployment. The chapter first discusses some important context for the analysis of these examples. It discusses innovation systems approaches that have been developed to understand processes of innovation, and to inform policy frameworks that seek to support innovation in clean energy technologies. The chapter then focusses on the two renewable electricity generation technologies that have attracted most attention in terms of policy provision – wind and solar PV. It draws out cross-cutting lessons from the role of policy-making in relation to these two technologies, and considers to what extent these lessons may be applicable to the case of CCS. Bearing in mind that these particular examples are also in many ways quite different technologies to CCS, the chapter then casts a wider net to consider what lessons may be learned from other kinds of energy technologies or large infrastructures, that may be more closely analogous to CCS in certain respects. The chapter then draws conclusions from across the range of technologies considered, as to the most relevant lessons for CCS.

2.2. Background: rationales for government intervention, and objectives of policy support

2.2.1 Rationales for government intervention¹

In order to draw lessons from other technologies for the case of CCS, it is important to take into account what drives innovation in the energy sector, and the rationales for public policy intervention to support such innovation. The desire to develop, demonstrate and deploy CCS technologies to reduce emissions is part of a broader strategy which emphasises the role of innovation in new energy technologies. For the purposes of this report, we use a broad definition of innovation that encompasses a spectrum of activities – from early stage research and development (R&D) to demonstration and early commercialisation.

The literature and experience of innovation is that it is a continuous, complex process. To make sense of this complexity, a number of innovation systems frameworks have been developed that focus on specific contexts. These include frameworks that focus on national, regional, sectoral and technological innovation systems (Watson et al., 2015). A key insight from this literature is that innovation is not a linear process. Whilst early models of innovation and many contemporary policy discussions assume such a linear model, the evidence shows that there are usually important feedbacks between the ‘stages’ of innovation. Furthermore, innovation is shaped by a range of factors that go well beyond the preferences of consumers and the capabilities of producers. These include government policy frameworks, industrial and market structures, and broader macro-economic and institutional factors. Figure 2.1 depicts the contrast between a ‘linear’ model of innovation and a more ‘systematic’ model, the latter characterized by feedbacks between innovation stages, contextual factors, and the role of actors, networks and institutions in conditioning the process.

¹ This section draws extensively on a book chapter co-authored by one of the report authors (Watson et al., 2015).

² See, for example, Global Carbon Capture and Storage Institute Legal and Regulatory Indicator 2015, which provides a valuable summary and scorecard of the state of legislation

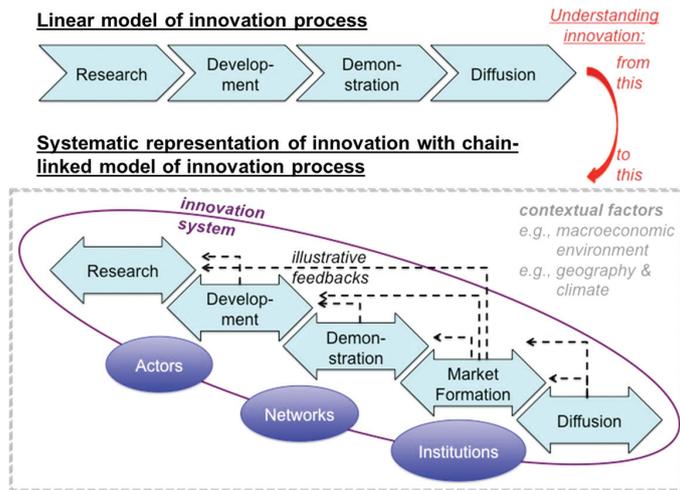


Figure 2.1: The evolution of thinking on innovation processes – moving from a ‘linear’ model to a ‘systematic’ model. Source: Grubler et al (2012)

For many economists, there are two standard rationales for governments to intervene to support cleaner energy technologies – including those that can reduce greenhouse gas emissions (Jaffe et al., 2005, Scott and Steyn, 2001). First, that the social costs of carbon emissions from the energy system are not fully internalized. This means that technologies that emit less carbon are at a disadvantage – and therefore carbon should be priced at an appropriate level. Second, the private sector tends to under-invest in R&D because individual firms cannot fully capture the returns from their investments. This provides a rationale for government to fund R&D.

This is where many policy prescriptions that are informed by neo-classical economics stop. However, innovation systems approaches suggest a number of additional rationales for intervention – particularly where the aim is to reduce costs to a point where low carbon technologies are more competitive with established technologies. Government technology policies often need to attend to other stages of the innovation process, and not just R&D. There has been an increasing focus on the ‘valley of death’ that faces developers as they try to move technologies from demonstration or prototype phase to incorporation in commercial products (DTI, 2004, Gallagher et al., 2006). This is the stage of innovation between ‘technology push’ and ‘market pull’. CCS is a classic case of a technology that faces this ‘valley of death’. Developers often need to commit increasing financial resources to technology development at a stage where the risks of failure remain high (Trezona, 2009).

There are further rationales for intervention that go beyond these market failures. An innovation systems perspective also focuses on wider system failures. Such system failures are particularly important for low-carbon technologies (Foxon, 2003, Stern, 2006). The adoption of some of these technologies often requires both technological change and institutional change. For example, the diffusion of smart metering technology is not just a simple technical challenge but also implies a new approach to information provision to energy consumers and new information technology

infrastructure. Others require new links between established but hitherto separate actors within the innovation system. For example, CCS technologies require new collaborations between utilities, oil and gas companies, and power equipment companies and can also require amendments to existing regulations (e.g. those that govern marine pollution or issues around liability).

One of the most important system failures for sustainable technologies is 'lock-in' (Unruh, 2000). The term lock-in was originally coined by Brian Arthur to explain how some technologies become widely adopted due to increasing returns to scale, even though they may not, objectively speaking, be the best technologies for a particular application (Arthur, 1989). This lock-in concept was subsequently scaled up to describe the pervasiveness of fossil fuels, and hence high carbon emissions, within modern industrialised economies (Unruh, 2000, Unruh, 2002). This means that if markets are left to themselves, energy systems tend to change slowly (Pearson and Fouquet, 2006).

The concept of lock-in is an important reminder that policies may have to do more than support low-carbon technologies so that they are more attractive and cost-effective. This is because many parts of high-carbon energy systems consist of long-lived capital assets including electricity grids, gas pipelines, and buildings. Furthermore, these assets are supported by interacting systems of rules, regulations, and institutions that coordinate energy flows, market relationships, and investment decisions. Therefore, policy interventions need to be mindful of the risks of lock in to more developed, but ultimately less successful technologies (Hoppmann et al., 2013). Technology neutral market pull policies such as carbon pricing tend to provide incentives for technologies that are closer to the market. This may be desirable in the short term, but it may be that there are other technologies which were less developed, and therefore expensive, at the time of implementing the policy instrument, but which would in the long term have delivered lower cost and better performance had they received financial support.

Given these insights, the policy prescriptions offered by neo-classical economics are often insufficient to drive the innovation required in a timely way. Whilst it is common for economists to argue that a policy approach based on carbon pricing and public funding for R&D is 'first best', innovation systems approaches suggest that these prescriptions are necessary, but are not likely to be sufficient. This general conclusion is reinforced by the slow progress with pricing carbon world-wide. Whilst many countries now have carbon pricing that covers some economic sectors, price levels tend to be too low and/or uncertain to drive new innovation.

As a result, many policy frameworks that are designed to support the development and deployment of low carbon technologies are more specific. Some of the most successful include a range of interventions that are designed to support technologies through different stages of the 'innovation chain' and/or create markets for these technologies. The German approach to supporting renewable energy is a good example, where specific 'market pull' support has been consistently provided by feed-in tariffs. But that support has been complemented by policies for priority market access, sharing of costs for consequential grid enforcement, and a wider enabling environment that has helped to provide project finance. Similarly, policies to support

new, low carbon vehicles do not rely on carbon pricing – but on a range of measures including standards, programmes to install electric vehicle charging points, grants for early adopters and exemptions from some taxes.

2.2.2 Objectives of policy support

When designing such ‘packages’ of interventions, it is also important to consider the desired outcomes. CCA (2015) identifies three principles: cost effectiveness; environmental effectiveness; and equity. Clearly it would be possible to rapidly incentivise the deployment of almost anything if money were no object. However, in reality government budgets are constrained and subject to numerous competing pressures, hence it is vitally important to deliver the desired technologies cost effectively. Environmental effectiveness is of course crucial, and this goes beyond the promotion of a technology that is ostensibly low carbon, towards ensuring that the low carbon condition holds over the life cycle of the technology, and that the technology can successfully operate within a whole system that is balanced and secure. Ensuring that any costs of support policies are equitably shared is an important social and political objective.

Balancing these principles is a key challenge of effective policy support. A policy must be sufficiently strong to create a response; conversely if it is stronger than it needs to be it risks lacking cost effectiveness; and if it is not paid for in a fair way this creates equity concerns. Such concerns lead some to point to the risks of more specific policy interventions. If they are too specific for too long, this may blunt more general market incentives such as carbon pricing or auctions for low carbon electricity generation that can help to deliver emissions reductions whilst minimizing costs to taxpayers and consumers. Specific interventions also lead to concerns about lobbying. Policy makers can also be put in the position of attempting to ‘guess’ what the correct subsidy needs to be for any given technology, which may be inefficient. To take these concerns into account, clear processes for policy review, evaluation and adjustment are required (Watson, 2008).

2.3. Review of policies applied to wind and solar PV

Having taken an overview, in the previous section, of the key rationales and objectives of low carbon technology support policies, this section examines particular support policies that have been enacted in various jurisdictions, focussing on wind power and solar PV.

This section first presents data on the globally installed capacities and recent deployment rates of both solar PV and wind. Following this, specific policies are discussed. For convenience, the discussion is structured according to different types of interventions that can be made at different stages along the innovation chain, depicted in Figure 2.1 – thus it reviews ‘technology push’ followed by ‘market pull’ strategies. However, it should throughout be recalled, as discussed in the previous section, that policies do not act in isolation, but rather as part of an overall innovation system.

In this section we focus on the effectiveness of policies in bringing about increased deployment and cost reduction of wind and solar PV, but we do not recount extensively for each policy that is mentioned, the social and political context and the wider political implications of its implementation. Clearly any policy which is strong enough to have its desired effect, may also have impacts on other sectors of society, depending on the way that the policy is funded, or which actors the policy targets. As such, the ability of a government to implement such a policy may be affected by political contextual factors such as the lobbying power of the actors potentially affected by the policy, the strength of the government's electoral mandate, and the treatment of the issue in the media. Such issues could affect the political feasibility of any of the policies mentioned below, and though we touch on such issues in some cases, it is beyond the scope of the current report to comment on them in detail for every policy. However, in general terms it can be stated that increasing the deployment of low carbon technologies, which may at least initially be more expensive than incumbent technologies or face other barriers, requires clear and consistent policy signals. As such, a clear commitment and strong political will to implement such policies with consistency, must be considered a pre-requisite to progress in this area, for any country. Later in this chapter in Section 2.6, our comparisons with other technological case studies discuss issues of political and public acceptability issues that may be of more specific relevance to CCS, and public acceptability issues are also discussed in relation to some of the CCS case studies presented in Chapter 3.

2.3.1 *Global deployment and cost reduction / learning rates of wind and solar PV*

As shown in Figure 2.2, at the end of 2015 the top five countries for installed capacity of wind were China, USA, Germany, India and Spain. As shown in Figure 2.3, the growth of installed capacity over the preceding decade had been strong, with China's high rate of growth particularly noticeable.

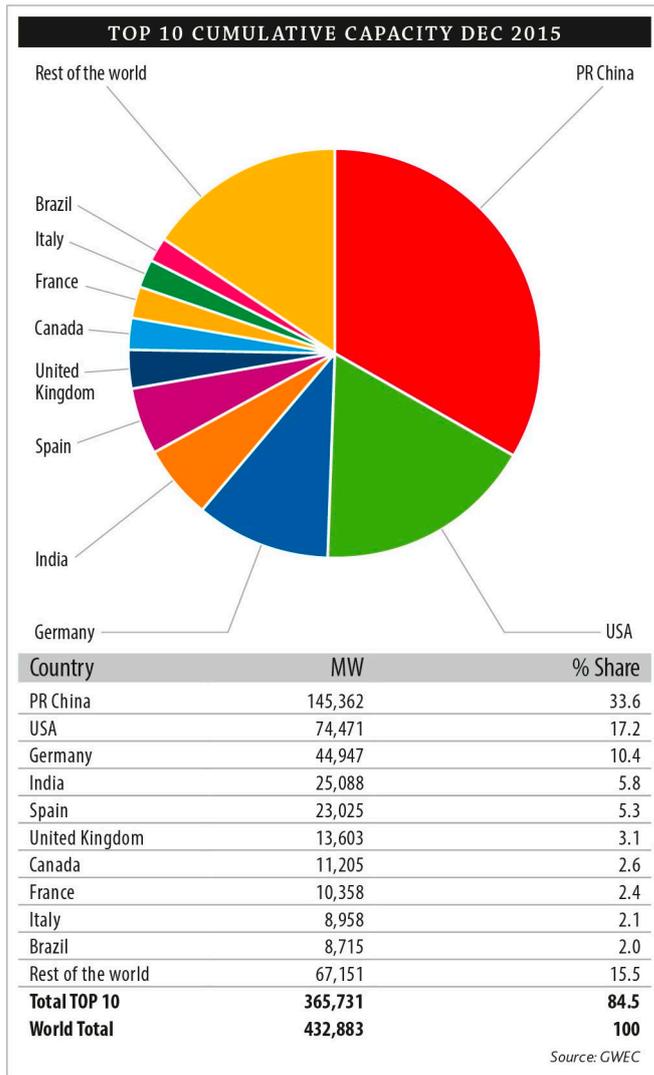


Figure 2.2: Top 10 cumulative wind capacity December 2015. Source: GWEC (2016)

Wind capacity

Gigawatts, cumulative installed capacity

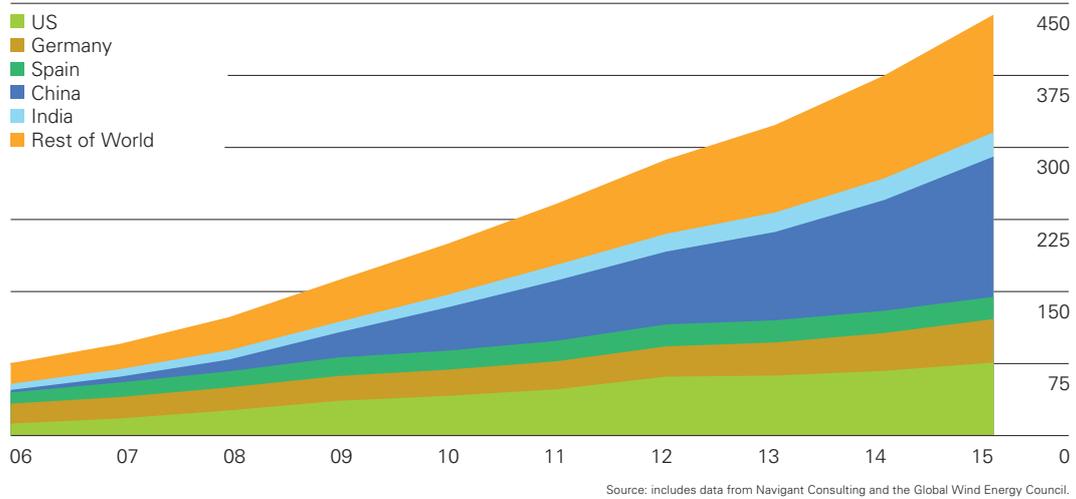


Figure 2.3: Cumulative installed wind capacity 2006-2015. Source: BP (2016)

As shown in Figure 2.4, the top five countries for installed capacity of solar PV were, at the end of 2015, China, Germany, Japan, US and Italy. China, Germany and Japan alone accounted for more than half of the world's installed capacity, and, as shown in Figure 2.5, were also the fastest growing in the preceding decade.

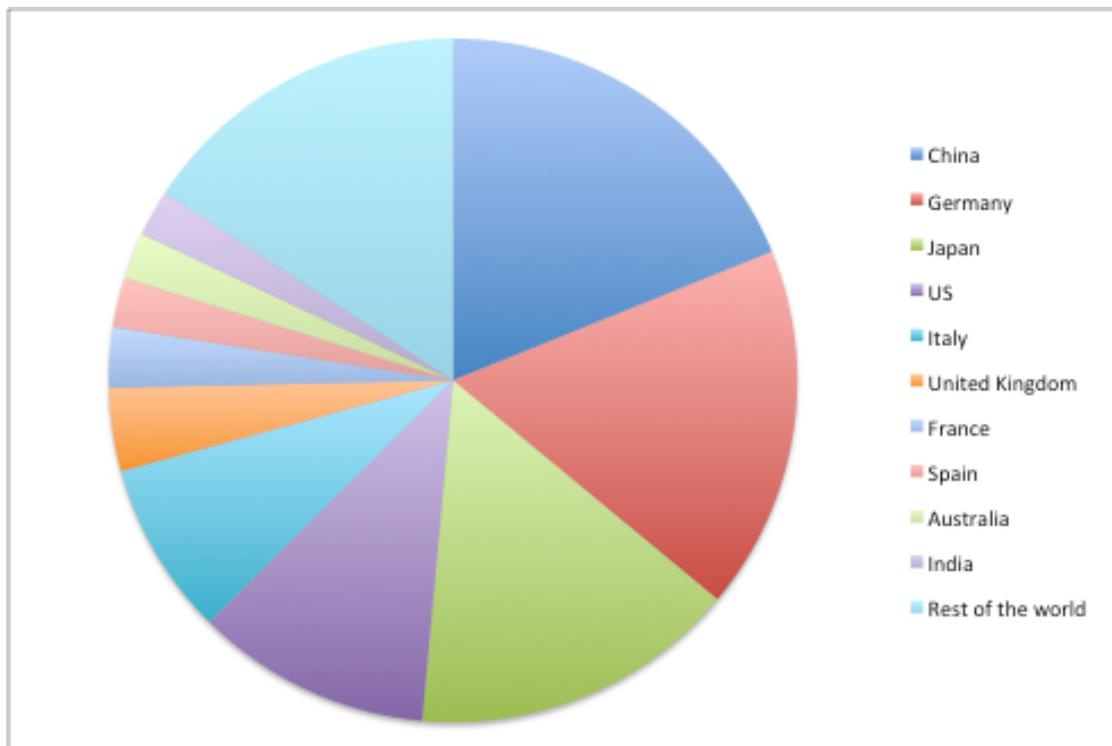


Figure 2.4: Top 10 cumulative solar PV capacity, 2015. Source: BP (2016)

Solar PV generation capacity

Gigawatts, cumulative installed capacity

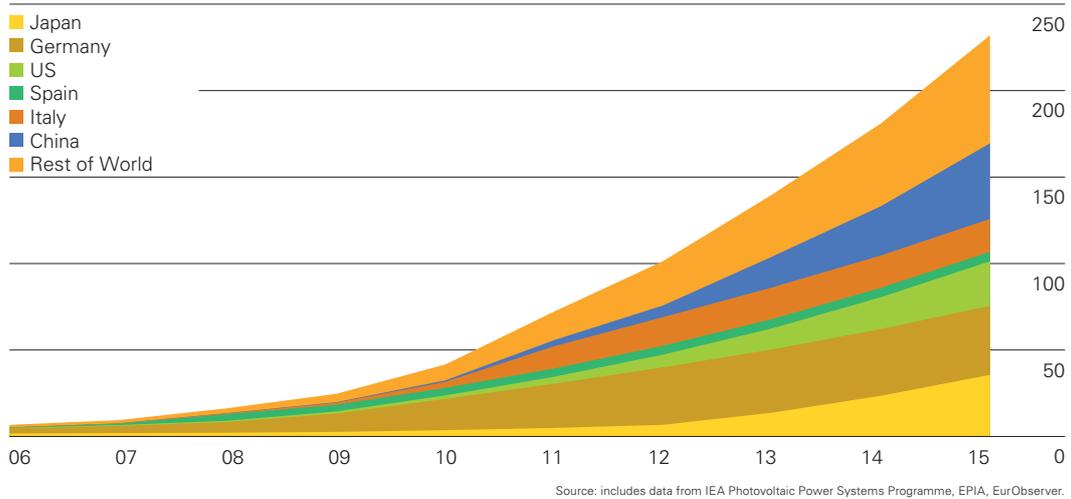


Figure 2.5: Installation of solar PV, 2006-2015. Source: BP (2016)

At the same time as these strong increases in cumulative installed capacity, both solar PV and wind have also seen noticeable decreases in cost in recent years. Figure 2.6, Figure 2.7 and Figure 2.8 show data for solar PV and onshore wind for the US. Figure 2.9 shows global costs for solar PV, and on- and offshore wind.

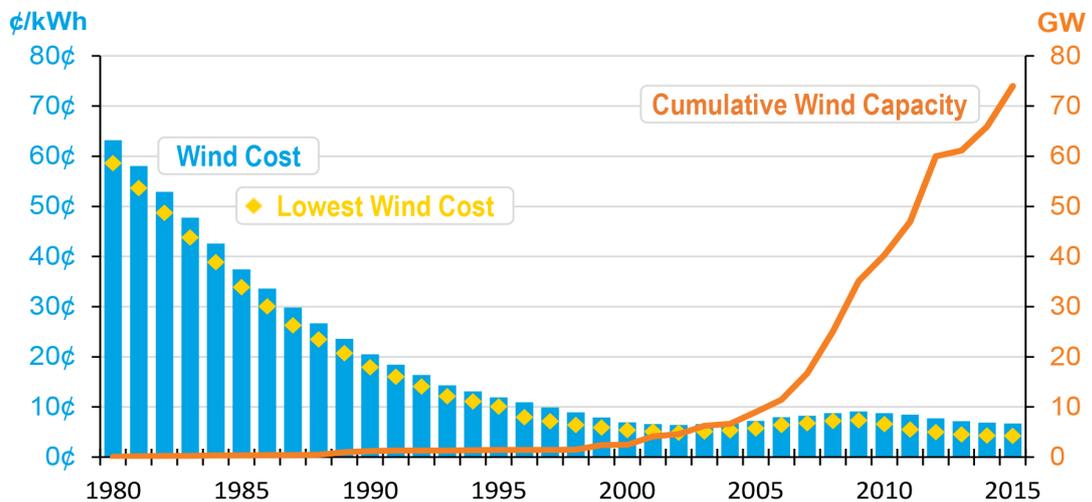


Figure 2.6: Onshore wind cumulative installed capacity and costs for the US, 1980-2015. Source: DOE (2016b)

Note on figure: Costs adjusted to dollar year 2015, excluding production tax credit. “Wind cost” data is levelised cost of energy from representative site. “Lowest wind cost” derived from power purchase agreements from good to excellent wind resource sites (DOE, 2016b).



Figure 2.7: Utility scale solar PV cumulative installed capacity and cost for the US, 2008-2015. Source: DOE (2016b)

Note on figure: costs shown are median costs, and exclude the effect of the Investment Tax Credit (DOE, 2016b).

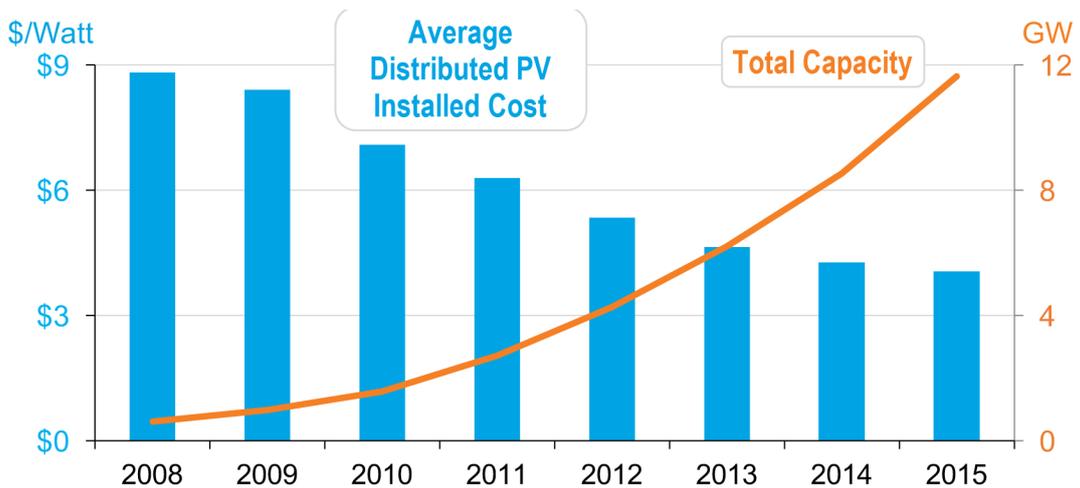


Figure 2.8: Distributed Solar PV cumulative installed capacity and average installed cost for the US, 2008-2015. Source: DOE (2016b)

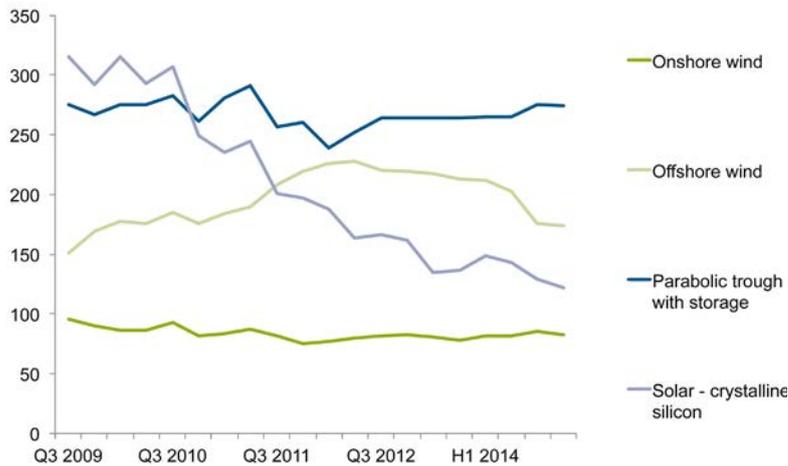


Figure 2.9: Global average levelised cost of electricity for wind and solar, Q3 2009 to H2 2015, \$ per MWh. Source: Bloomberg New Energy Finance. Figure from Frankfurt School-UNEP Centre and BNEF (2016)

These figures show that costs have fallen for solar PV and wind, albeit at very different rates. Figure 2.6, which focusses on US onshore wind, shows steep declines in levelised costs until the early 2000s, after which time costs plateaued and have recently fallen rather more slowly. Figure 2.9 also shows a very slow decline in global onshore wind costs since 2009. The market for onshore wind is relatively mature, which explains the slower rate of cost reductions. By contrast, PV costs have fallen much more rapidly. Figure 2.7, Figure 2.8 and Figure 2.9 show that from 2009 to 2015 the levelised cost of PV both in the US and globally was cut by almost two thirds. Key drivers of this rapid fall in price from 2009 included market pull policies such as feed-in-tariffs in Germany, UK and other countries, that increased global demand, reinforced by manufacturing focussed technology push policies in China, which became the largest global manufacturer of cells – already representing 29% of global production in 2007. This flooded the market, driving down costs. In countries such as Germany the combination of attractive subsidies and falling prices caused a rapid uptake in solar cells, followed by a government reaction of reducing the feed-in-tariff; as a result of which several German manufacturers went out of business (Yu et al., 2016).

Figure 2.9 illustrates an important difference between onshore and offshore wind. Whereas onshore wind is now a relatively mature technology, meaning that further cost reductions may be expected to be less rapid, offshore wind is less mature. The time period of Figure 2.9 begins when offshore wind was at a comparatively early stage of deployment – and that explains the trend of cost increases, followed by more recent signs that costs are now starting to decline due to learning by doing and economies of scale.

2.3.2 Examples of policy frameworks used in various countries, and how these have affected the deployment rates of wind and solar

At the outset, it is important to acknowledge that there are a wide range of reasons why countries choose to support renewable energy or other low carbon technologies. These reasons are often driven by wider policy goals – including the desire to reduce the environmental impact of energy systems and the opportunities for job creation and industrial development. The extent to which countries support these technologies is also shaped by geography, which affects the availability of renewable resources. Broader political and cultural factors also have a role to play. For example, the early support for renewables in Denmark is partly due to a national policy of shifting away from an oil-based energy system; whereas in Germany, this is closely linked to the strength of social movements against nuclear power (Jacobsson and Lauber, 2006). For CCS too, politics have played a decisive role in the extent of government support in those countries that have prioritised CCS technologies – and how this has manifested itself (Meadowcroft and Langhelle, 2009).

REN21 (2016) summarises the range of policies that are currently enacted globally in relation to renewable power technologies, noting the prominence of solar PV and wind power as the main targets of these. They find that at the end of 2015, the policy mechanism most frequently used to promote renewable energy was the feed-in tariff, having been adopted by 110 states, provinces or countries. Tendering is also growing in adoption – by the end of 2015, 64 countries had held tendering rounds for renewable technologies (REN21, 2016), with noticeably low prices for solar PV being achieved in countries such as Mexico and Chile (Levey and Martin, 2016). 52 countries had used net metering or net billing policies, which allow owners of renewable installations to receive payment for the power they generate in excess of their own use. This mechanism is of particular relevance to domestically installed solar PV, but it has also been used to support a range of other renewable technologies at large and small scales. REN21 also reports that fiscal policies such as ‘grants, loans and tax incentives’ continue to be important, and that many countries use a combination of the above policies (REN21, 2016).

Specific policy options pursued in different countries in relation to wind and solar PV, will now be explored, considering first ‘technology push’ policies, then ‘market pull’ policies.

2.3.2.1 *Technology push – R&D funding, government coordination*

In Germany technology-push support for solar PV focussed for a number of years on driving down the cost of the technology through technological innovation and increased efficiency of cells. The context for this support, which started in the 1970s, was the oil price shocks of the 1970s, coupled with increasing controversy about nuclear power – particularly after the Chernobyl accident in 1986 (Jacobsson and Lauber, 2006). The R&D programme for solar PV was undertaken with the combined involvement of research centres, universities and industry. Arising from the focus on technology improvement and efficiency gains, as well as complementary ‘market pull’ policies (primarily the feed-in tariff), production costs decreased from \$6.8 /Wp in 1992 to \$2.9 /Wp in 2008. Funding was provided from both Federal and State-level governments, and industry support instruments included: grants or cash incentives; reduced interest loans, and public guarantees to secure bank loans (Yu et al., 2016).

China's approach to PV technology for most of the 2000s was production based and export driven – it exported 97.5% of its modules in 2006 and 96% in 2009. It supported PV manufacturing through innovation funds, regional investment support policies, loans and 'easy credit'. Low labour and energy costs also reduced production costs. China's focus was on labour intensive downstream manufacturing, rather than R&D (Yu et al., 2016).

Japan was a major early supporter of solar PV R&D, which was consistently funded by central government from the 1970s. As was the case in Germany and other countries, impetus for this was provided by the oil shocks. A vertically integrated industry across the supply chain was developed. The price of modules was reduced from \$8.3/Wp in 1992 to \$3.7/Wp in 2002.

Denmark was a location for early pioneering efforts in wind turbine design, with a number of companies and individuals active in their development from the early 1970s onwards, catalysed by the oil crisis and an explicit desire to develop alternatives to oil. An important role was played by the Risø test laboratory, which had been established in 1958 primarily as a nuclear power testing centre, and which now moved into wind turbine testing. Its tests were rigorous and independent, and crucially the results were made publically available, creating a new source of information and proliferating the most successful designs (Grubb et al., 2014, Maegaard et al., 2013).

In the UK, the Carbon Trust has played an important role as a broker between research and R&D stages, and the need of investors for greater understanding and testing of the products involved. The Carbon Trust's 'Offshore Wind Accelerator' brought together the major project developers with the aim of reducing the costs of offshore wind by 10% - a significant reduction in the context of the uncertain cost trajectory of offshore wind, as shown in Figure 2.9. The process focussed on a range of aspects of the supply chain, including designs of foundations and site access systems. These were products and services that all of the convened project developers used, but did not provide themselves – hence all of the convened developers were not competing with each other on the technologies under discussion. Rather the companies in the group were able to clarify their needs to other potential providers, with each participant leveraging their own investment by many times due to the contributions of the other participants, and to establish a clear market demand for the products required, at a desired cost (Grubb et al., 2014). The UK is now the global leader in offshore wind.

2.3.2.2 Market pull – Feed in tariffs

The German feed-in tariff is often discussed as an early example of market creation policies for renewable energy (Jacobsson and Lauber, 2006). It was introduced in 1990, after several years of development and debate. It had cross party political support, despite opposition from within the government economics ministry to the provision of subsidies. The policy was reformed in 2000 with the implementation of the Renewable Energy Sources Act in 2000. This was also controversial – with some in government expressing a preference for a quota system, and opposition from established industrial groups. A rapid fall in the cost of PV modules took place – as

indicated at the global level in Figure 2.9. This resulted in a rapid uptake of installations in Germany, as shown in Figure 2.10. In response to the falling costs in 2008 a new law introduced a degression rate so that the 20 year fixed tariffs now decrease year on year. From 2009, the degression rate was adjusted according to the annual installed capacity (Polo and Haas, 2014).

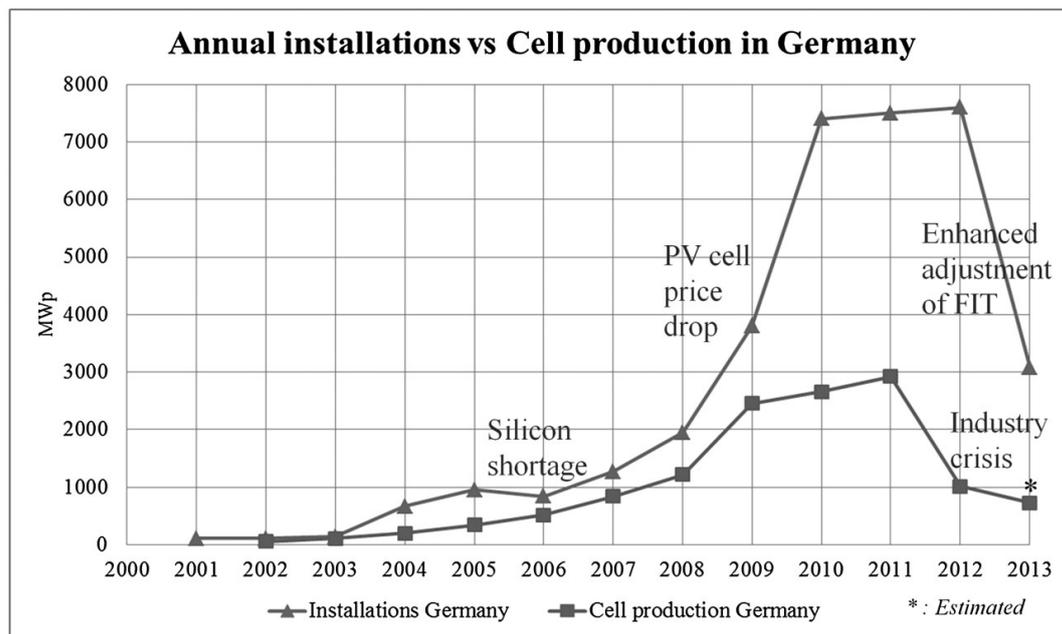


Figure 2.10: Annual installations and cell production in Germany, 2000-2013. Source: Yu et al (2016)

In China, after its initial focus on production, from the late 2000s, with the decline of demand from European markets, it began to focus more on stimulating domestic demand. Several subsidy programmes were introduced in 2009, and from 2011 a national FIT scheme started to support PV (Yu et al., 2016). The effect of this can be seen in Figure 2.11.

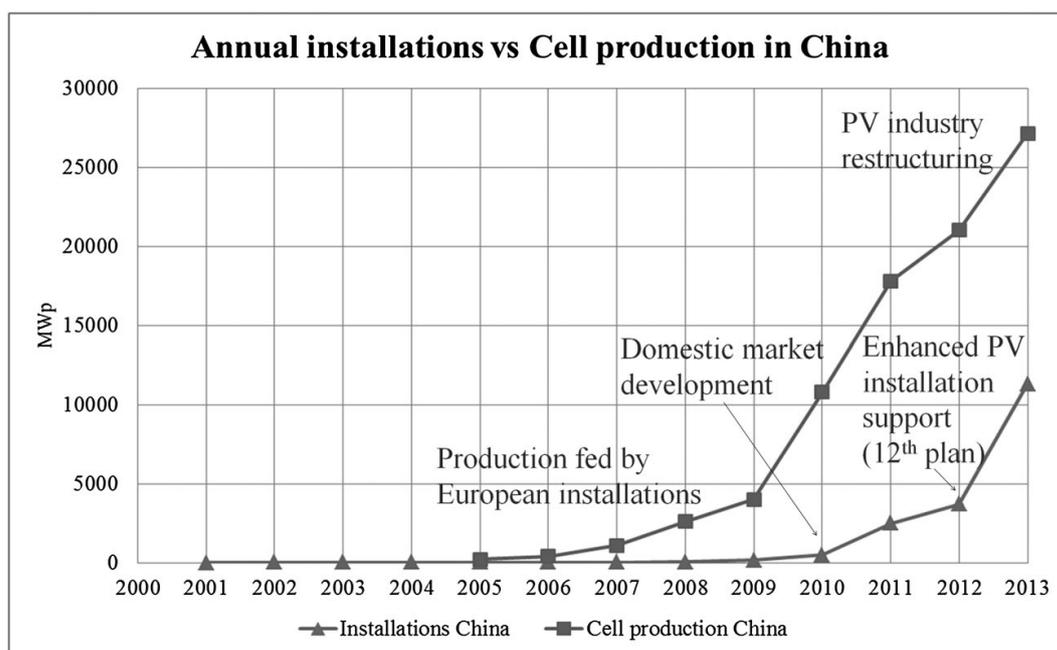


Figure 2.11: Annual PV cell production and installation in China, 2001-2013. Source: Yu et al (2016)

In 2012 Japan introduced a FIT scheme for installations over 10kW. Following its introduction installations increased dramatically in 2013 as shown in Figure 2.12 (Yu et al., 2016). However, in Japan domestic cell production appeared to track the spike in demand for installations more strongly than in other countries, for example Germany. Yu et al suggest that, at least up to 2012, Japan's market was more closed to foreign competitors than Germany's, because of complicated institutional barriers, such as performance and certification standards. Yu et al comment that in 2012 Japanese modules and systems were substantially more expensive than those in Germany and China. On the other hand due to the sustained and coordinated investment in R&D and production, Japan's PV manufacturing industry was well placed to track the boom in sales following the introduction of the FIT in 2012 – although some imports were required to meet demand (Yu et al., 2016).

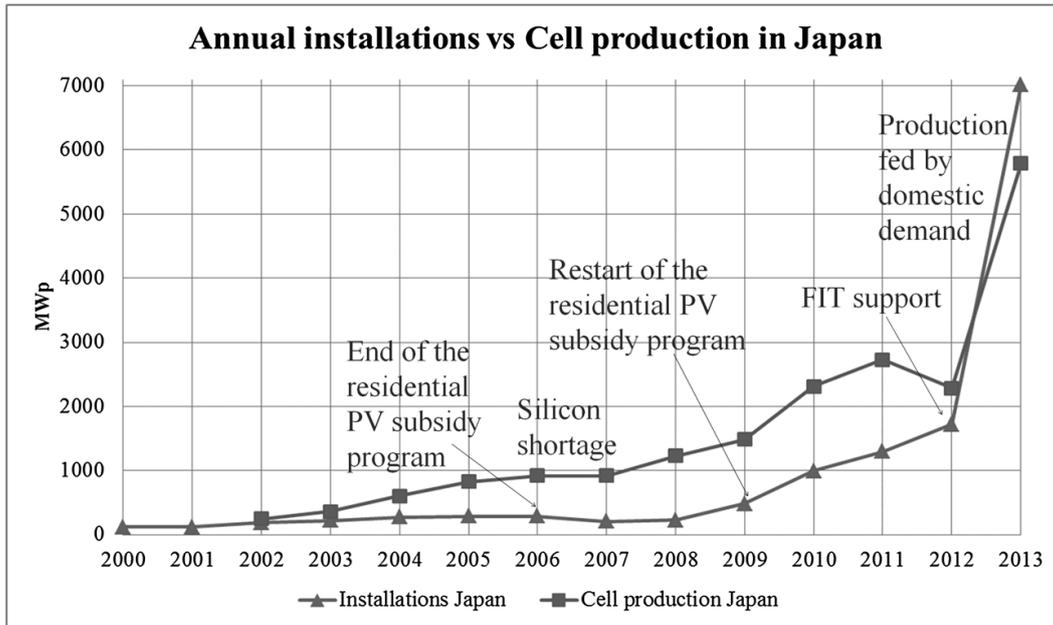


Figure 2.12: Annual installations and cell production, Japan, 2000-2013. Source: Yu et al (2016).

Spain offered a feed-in-tariff from 2004. According to Polo and Haas, a specific PV tariff was introduced in Spain from 2007. This led to rapid growth peaking in 2008, when an annual cap was set (Polo and Haas, 2014). In 2008, the FITs were guaranteed for 25 years, and subject to an annual capacity cap. Tariffs are recalculated each year (Polo and Haas, 2014). This was followed by a collapse in PV installations in 2009 (Figure 2.13). In January 2012 a 1-year moratorium on renewables development was introduced (Dent, 2013).

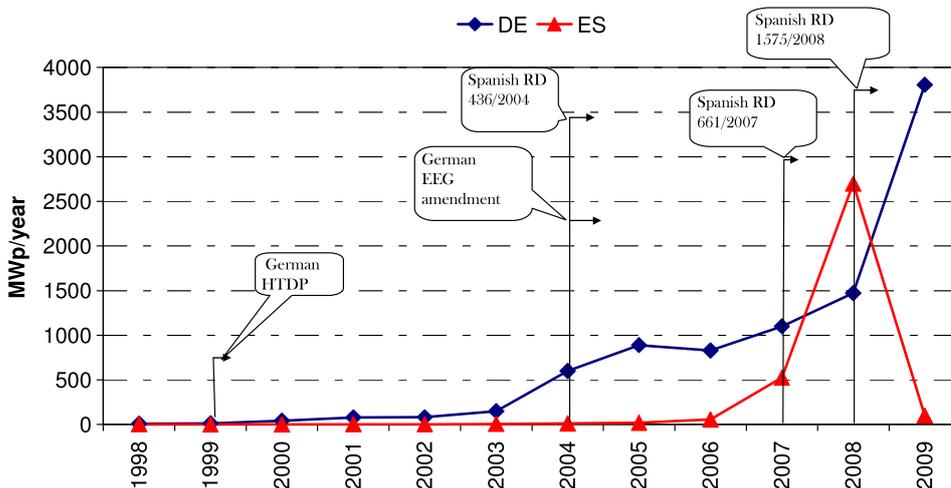


Figure 2.13: Annual grid installed PV capacity in Germany (DE) and Spain (ES), MWp / year, 1998-2009

The French feed in tariff is corrected annually in line with inflation rates. From 2012, an annual 10% degeneration rate for new projects was introduced. Higher rates are offered for building-integrated systems (Polo and Haas, 2014).

In the UK a feed in tariff for domestic solar PV was introduced in April 2010. The starting rate of 41.3 p/kWh was intended to deliver a return on investment of 5%. However, this calculation had not accounted for the rapidly falling costs of modules (as shown in Figure 2.9). As a result of the fall in capital costs, the return on investment on the basis of the tariff offered was much higher, and uptake of the tariff was much greater than expected, meaning that the pay-out on the tariff looked set to be much higher than had been budgeted. The Department of Energy and Climate Change (DECC) then made several downward-revisions of the tariff, arriving in August 2012 at a rate of 16 p/kWh, and with a sliding scale in place to allow downwards revision of the tariff every three months, depending on and linked to uptake in those three months. Domestic PV owners also received an export tariff of around 5 p/kWh for power exported to the grid (Contemporary Energy, 2016) – a form of ‘net metering’ (see below). Whilst these changes to tariffs were justified on the grounds of falling solar PV costs, some of them were on a faster timetable than previously announced. This led to investor uncertainty, and a successful high court challenge to one of the rate reductions (Watson, 2012).

However, this scheme was closed in January 2016, and a new scheme launched in February 2016, with substantially reduced tariffs (GOV.UK, 2016). The domestic rate was reduced to around 4 p/kWh with a declining rate set out to 2019. The export tariff was to remain fixed at just under 5 p/kWh (Ofgem, 2016). Reports suggested that in the two months following the introduction of the new scheme, the capacity of domestic scale PV installed had reduced by 74% compared with the same period in 2015 (Vaughan, 2016).

In 2013 the UK’s Energy Act created the framework for a variant of feed-in-tariffs to be made available to large-scale low carbon generators. The first contracts were awarded administratively, without competition, in early 2015. This feed-in-tariff system is based on a ‘contract for difference’, where the difference between the market price of electricity and the agreed ‘strike price’ is provided to the generator when the market price is below the strike price; conversely, if the market price goes above the strike price, the generator is committed to refunding this difference. The result is a fixed (inflation-linked) revenue stream, for the contract period of 15 years. Following initial administered contracts, renewable CFDs were awarded using an auctioning process. Newbery (2016) calculates that this competitive auctioning process was successful in driving down the costs of these contracts for the government, and thus for bill payers. The case of the nuclear CFD for Hinkley Point C was somewhat different, not least because the government was negotiating with only one provider, so no competition or auction was possible.

2.3.2.3 Market pull – renewable energy tendering

From 2003 to 2007, China operated a national bidding system for wind farm projects, the winners of which would receive a predefined electricity price. The period saw the installation of 2.6 GW of wind capacity. Wind farm projects in China have also received support through the Clean Development Mechanism (Koseoglu et al., 2013). Renewable energy tendering is also growing in popularity across the world (REN21, 2016). Notable successes of this type of approach appear to have emerged from countries including Mexico and Chile, whose tendering rounds delivered

remarkably low prices for solar PV (Levey and Martin, 2016). As discussed in the previous section, the integration of an auctioning element in the UK's allocation of prices for renewable energy CFDs has been considered to be successful in driving down costs (Newbery, 2016).

2.3.2.4 Market pull – net metering

In Japan, some utilities offered buy-back for excess solar power generated, at household electricity prices, in a voluntary agreement between 1994 and October 2004. In November 2009, an Excess PV Purchase Scheme was introduced, guaranteed for 10 years (Polo and Haas, 2014). Net metering has also been used in several US states.

2.3.2.5 Market pull – subsidies

In Germany targeted subsidy schemes were rolled out in the 1990s and early 2000s (Yu et al., 2016). The first PV investment subsidy scheme – the 1000 Rooftop Programme – was launched in 1989 (Polo and Haas, 2014). The 100,000 Roofs Programme lasted from 1999-2003. This programme offered 'soft loans' – initially at 0% interest, for payback over 10 years. The take up was initially disappointing, until broadened to include installations above 1 kW. Yu et al suggest these were responsible for a rapid increase in installations in the early 2000s (Yu et al., 2016). Subsidy programmes were also introduced in China in 2009 (Yu et al., 2016).

Japan offered subsidies for residential installations from 1994 onwards. This has produced slow but steady increases in installations (Yu et al., 2016). The Residential PV System Dissemination Program, 1994-2005, combined subsidy with low-interest loans, education and awareness raising (Polo and Haas, 2014). The scheme was reduced in 2005 and then closed down, to encourage producers to reduce costs. However, as installation rates fell, the scheme was reintroduced in 2009 (Yu et al., 2016).

The US Federal Energy Policy of 2005 provides for tax credits amounting to 30% of the total cost of a solar system. For homeowners, credit is limited to \$2000 per system (Polo and Haas, 2014).

2.3.2.6 Market pull – portfolio standards, supply obligations and tradable certificates

In 2002 the UK introduced a renewables obligation system – similarly to portfolio standards, this system mandated suppliers to source a minimum percentage of their total generation from renewables. They could do this either by buying renewable generation directly, for which they would receive a Renewables Obligation Certificate (ROC), or by trading in the market for ROCs. The system was initially intended to be technology-neutral, so that power produced from any renewable technology would be eligible for the same ROC credit. A price cap was set on the ROCs to assuage fears of high costs. The effect of the system was to reward those renewable technologies already closest to market – mainly onshore wind and biomass co-firing. It did little to stimulate innovation and development of other renewable technologies, and delivered little capacity overall. In 2006, the government introduced a 'banding' system, under which technologies would receive different multiples of ROCs for the same amount of energy produced, with the multiple reflecting the market-readiness

of the technology. A measure was introduced to ensure ROC values would be supported if the minimum mandated level of renewable generation was exceeded, in order to provide clearer price certainty for investors. The measures were successful in that the UK's renewable capacity began to expand, especially offshore wind. However, Grubb et al comment, 'the UK had in effect been dragged into the messiest and most complicated way of delivering feed-in tariffs yet conceived' (Grubb et al., 2014).

Korea also introduced a renewable portfolio standard from 2012 – in addition to a solar FIT and investment subsidies (Polo and Haas, 2014).

2.3.2.7 Other kinds of market incentives – carbon pricing and emissions trading schemes

The effectiveness of carbon pricing or taxation mechanisms, or emissions trading schemes – which, by creating a limited number of tradable permits to pollute, effectively create a carbon price – depends on the level at which the carbon price, or the emissions ceiling, is set. As with any market intervention that can create winners and losers, such schemes can be politically difficult to implement, especially at the kind of levels that would be necessary to stimulate major transitions from fossil fuel to low carbon technologies and infrastructure. Furthermore, even if carbon prices were higher and more stable, they would not necessarily be a sufficient incentive for the scale and speed of innovation required to meet climate change targets. Carbon prices have been observed to have an impact on CCS in cases where the removal of CO₂ can be achieved at a relatively small incremental cost, as will be discussed in Chapter 3.

The EU ETS has not succeeded in generating a high carbon price, due to over-allocation of permits. In response, in the UK, another mechanism to emerge from the electricity market reform (EMR) process which also generated the CfDs, discussed above, was the carbon price support (CPS), also known as the carbon price floor. This is a tax, applying to fossil fuel electricity generators, which bolsters the price of carbon delivered from the ETS to a pre-determined level, which was intended to increase over time, in order to give a stronger and more predictable price of carbon to the power sector. The CPS is now at a level that is much higher than prices within the EU ETS, though plans to increase its level further have been put on hold.

2.4. Discussion – the effectiveness of policies applied to wind and solar PV

2.4.1 Market pull policies

One notable observation to emerge from an examination of policies applied to wind and solar PV is the apparent effectiveness of the feed-in tariff type of policy, which guarantees generators a fixed price over the period of a long-term contract. The introduction of feed-in tariffs have been associated in several jurisdictions with a sharp pick up in installation rates, especially in the case of solar PV. In comparison, measures that support the capital cost of investment, but without supporting the

revenue of the project during its lifetime, seem to be less successful in stimulating investment.

It seems therefore that investors are attracted by the long-term certainty of income that feed-in tariffs provide. Although capital subsidies may provide strong incentives, they still leave the investor with uncertainty about future revenues – and that may impact their required rate of return, and therefore the costs of a particular policy.

The fixed revenues from FITs, when combined with a situation in which technology capital costs are falling, can create spikes in installation rates. This is because the falling capital costs with fixed revenues result in very favourable returns, and a sharp increase in investment.

It might be thought that this logic might only work for companies, whereas for individuals in residential applications, the capital grant or subsidy would be more effective. However, the role of intermediary companies that can take on the capital cost on behalf of customers – as well as dramatically declining costs of PV – seem to have helped to make the FIT attractive to residential consumers too.

Thus, although FITs can be highly effective policies in stimulating fast deployment, they also entail risk for the counter-party of the contract – the government that funds it, or ultimately, bill-payers. If the investment cost of a technology falls rapidly, a given FIT rate can be rendered more generous than would have been required, resulting in higher than necessary costs for the government or bill-payers. The impact of feed-in tariffs on consumer bills has been the subject of some controversy in the UK. Although the costs involved have been relatively small as a proportion of household bills, the availability of financial support has been reduced or abolished (in the case of onshore wind) for political reasons. In the last few years, the rapid growth of feed-in tariff costs has also sparked some discussion in Germany. This has led to pressure for policy reforms, but has not undermined the overall case for the feed-in tariff policy.

It should of course be recognised that the sudden and rapid fall in the cost of solar PV was to a large degree influenced by the specific situation of a government-supported manufacturing drive in China, with a combination of relatively cheap labour and mass production enabling the production of modules at considerably lower cost, with an over-supply of the market resulting. Whilst the depth and speed of the solar price fall may therefore be at least in part due to characteristics specific to solar – such as its modularity and resulting suitability for mass-production and export – nonetheless the possibility of relatively quick and unexpected falls in capital costs remains for other technologies, resulting in FITs becoming over-generous. This is a risk of the FIT approach.

Governments must face the challenge of addressing this risk, but without entirely removing the attraction of the FIT – its clear and guaranteed price over the long term. In several countries, government responses to the realisation that declining capital costs were leaving a previously established FIT rate exposed, were strenuous and sudden, including very substantial reductions in the FIT rate, or in some cases complete suspension of the programme. Polo and Haas (2014) suggest also a cap

placed on volumes in Spain resulted in over-supply in other European markets, further reduced costs, and a resulting additional installation spike in Germany (Figure 2.13).

The difficulty with such rapid government responses is that they create a boom-and-bust dynamic within the industry, and make it difficult for manufacturers to plan for the future, and in some cases to survive. Increasingly, FITs have ‘capacity corridors’ built in, providing for a degeneration rate in the level of the FIT offered that is linked to the total capacities installed (Polo and Haas, 2014). Such measures should allow less dramatic and more predictable adjustments to the level of FIT offered. Another successful way of reducing price risk for the government or bill payer is to allocate the contracts through competitive auction– this has been successful in UK and Mexico, albeit for much larger PV installations.

2.4.2 *Technology push policies*

Technology push policies can focus on technological R&D and innovation. In Denmark, Japan and Germany, R&D programmes have involved the coordination of commercial companies, research institutes and universities. The role of an independent research and testing centre for wind turbines, whose findings were made publically available, was particularly notable in Denmark.

China’s approach in the 2000s was to provide incentives to encourage companies to engage in mass downstream manufacturing. Without focussing on basic R&D this approach nonetheless delivered significant cost reductions in the downstream processes.

2.4.3 *R&D versus learning by doing*

Cost reductions can be expected from R&D, as well as learning by doing. As suggested above, both of these effects have been observed for solar, with a particularly strong reduction in costs from a manufacturing-led drive particularly from China. Once again the characteristics of solar PV modules have to be acknowledged to play a role in this – small, modular units which can be exported, and then typically installed in relatively unchallenging conditions, whether ground mounted or roof mounted. These characteristics are conducive for discovering cost reductions from mass production.

The cost-reduction effects of learning by doing are sometimes less clear for wind (Figure 2.9). This may be because of the larger and less modular characteristics of large-scale wind turbines, and the predominance of local conditions in affecting the overall costs of projects, with transportation of the turbines to remote locations, or the challenges of installing offshore subsea foundations. With such technologies, achieving economies of scale and the cost reductions of replication may arrive less readily, as before a critical number of projects have been completed, the possibility of meeting new and unforeseen challenging conditions in each new project is greater.

2.4.4 Promoting the current market leader versus the longer term research portfolio

One of the challenges of providing market-based incentives for emerging technologies is whether incentives given to a current version or generation of the technology risks crowding out investment in next-generation models, that could have provided ultimately lower cost or better performance, had research into them continued. Deployment policies that are not technology neutral inevitably carry a risk 'picking the wrong winner' (Hoppmann et al., 2013). As a cross-technology issue, this was found to be a concern during the operation of the Renewables Obligation (RO) system in the UK, where incentives were found to be adequate for the installation of the lowest-cost technologies at the time – onshore wind and biomass co-firing –but not for ongoing R&D of the emerging renewable technologies that were less close to market. This concern led to ROC banding – allowing different technologies to be awarded different multiples of ROCs, in reflection of their market readiness – and eventually to the replacement of the RO system with a technology specific FIT-based system.

However, the introduction of a technology specific FIT does not entirely resolve the problem. Hoppmann et al identify a similar issue within a technology class, but in relation to different generational innovations of the technology. At any given time it is possible that a subsequent generation of a technology, which may be still at an early research or development stage, may ultimately have better prospects than the technology generation that happens to be closest to market. Thus Hoppmann et al argue that deployment policies should be complemented by R&D and venture support, such as R&D subsidies or R&D tax credits, to help guard against ultimately unhelpful technological lock-in (Hoppmann et al., 2013).

However, a clear and long-term deployment policy can also have benefits for longer term R&D. In interviews with representatives of industry, Hoppmann et al (2013) find that strong market pull policies can be supportive of R&D, both by virtue of increasing the availability of cash flow which can feed back into increased R&D, and because the presence of a strong deployment policy helps to secure the interest of venture capitalists in investing in the next generation of the technology. Thus, policy-driven market growth can help to increase investment in R&D. This confirms earlier research suggesting that R&D investment increases in proportion to sales (Hall, 1987). However, there is an important distinction between sales driven purely by market forces and sales driven by policy – in the latter case the dependence of sales on the existence of policy can be a source of uncertainty, if it is not clear that the policy will be maintained. Indeed, Hoppmann et al find that policy uncertainty reduces investments in both R&D relating to future technologies, and exploitation of current ones (Hoppmann et al., 2013). This provides another reason for the importance of consistent and clear long-term policies, which are credible for industry and investors.

Providing this long term future clarity needs to be balanced with the abovementioned risk of over-promising on mechanisms such as FITs. The use of capacity corridors and degression rates may be appropriate. Also a longer-term forward commitment to provide technology neutral low-carbon FITs, at a specified declining percentage

above market price, could provide technology developers with the incentive to continue developing next generation products.

2.5. Lessons from solar and wind

Incentives which guarantee a future revenue stream tend to be most successful in speeding up deployment – at times extremely sharply. They can induce a higher pick-up than capital grants or investment incentives, as in these cases the price risk remains with the developer. Long-term price clarity is important, as is evidence of long-term policy commitment on the direction of travel.

However, giving this long-term signal while avoiding price risk remains a challenge. Degression rates, and promising long-term future FITs on an increasingly technology neutral basis, based on a declining percentage above market price, may be means to resolve this. Auctioning of contracts has also been shown to be successful, though this has only been used for larger projects – and is not considered to be practical for smaller installations, including PV for households.

The issue of who pays for the policies is important. The costs of FITs and other market pull policies are typically spread across electricity bills, which is essentially regressive. An alternative could be to fund policies through general taxation, but this would make the policy vulnerable to annual changes in government budgets. Carbon pricing may be theoretically the most efficient option for reducing emissions according to neo-classical economics, but it is far from easy to implement – and it is not clear that it is sufficient, on its own, to foster the innovation required.

Though strong market pull policies can feed back into longer term R&D, policies which support R&D and demonstration of technologies further up the innovation chain are also important. Grants and financial incentives for manufacturers have been shown to be effective in some jurisdictions in scaling up manufacturing. In general, an innovation systems approach that uses well coordinated policy packages, rather than individual policies considered in isolation, is likely to achieve greater success. Such an approach includes support for R&D, the coordination of research and industry supply chains, with independent testing and public availability of outcomes, as well policies aimed at creating markets for the new technologies.

2.6. Comparisons with other technological case studies

The previous sections of this chapter explored the deployment and effectiveness of policies relating to wind and solar. In some aspects experience with these technologies provides useful analogues for CCS. In other aspects CCS is quite different, for example:

- scale and modularity – whereas wind and particularly solar can be deployed at either small or large scale, and have modular qualities, the limited modularity of CCS may present different challenges
- infrastructure requirements – as well as requiring access to the electricity grid, CCS also requires a pipeline or shipping infrastructure. Whether this

infrastructure is provided new, or whether it involves re-deployment of existing oil or gas infrastructure, this entails substantial planning, regulatory and engineering activity.

- Legal and regulatory issues concerning long term geological storage of CO₂ and the interaction of CCS with the environment, and with other activities and sectors.
- Whole chain business risks and pricing for CCS often rely on multiple actors, attempting to discover new methods of working together. The ease, or difficulty, of these business relationships may be strongly affected by policy. CCS is also characterised by different types of investor to wind and solar. Whereas CCS investors tend to be large industrial companies, wind and solar technologies are deployed by a range of different investors – including households, communities and companies. This makes the political economy of wind and solar very different from the political economy of CCS.
- Public debates and deliberation around CCS will also have a different quality to those around wind and solar, due to its large scale, the requirement for long term storage and other issues.

This section discusses these aspects in some more detail, drawing on alternative historical analogies.

2.6.1 Scale and modularity

The previous sections found that rapid falls in the costs of solar PV modules were in part related to their modular characteristics, which facilitated mass production. Cost reductions were less straightforward for wind, with each unit being somewhat larger, and with often challenging installation conditions, which may frequently have been novel in the early stages of the industry. Particularly for offshore wind, there was evidence that costs were actually rising in the early years of the industry (Gross et al., 2010).

Thus the unit-size of a technology can have a relationship to cost reduction, in that for larger scale technologies it takes longer before the number of installed units can bring benefits from learning by doing.

Rai et al present historical examples of large scale technologies that exhibited rising costs in the early stages – US nuclear power plants (Figure 2.14) and natural gas liquefaction plants (Figure 2.15).

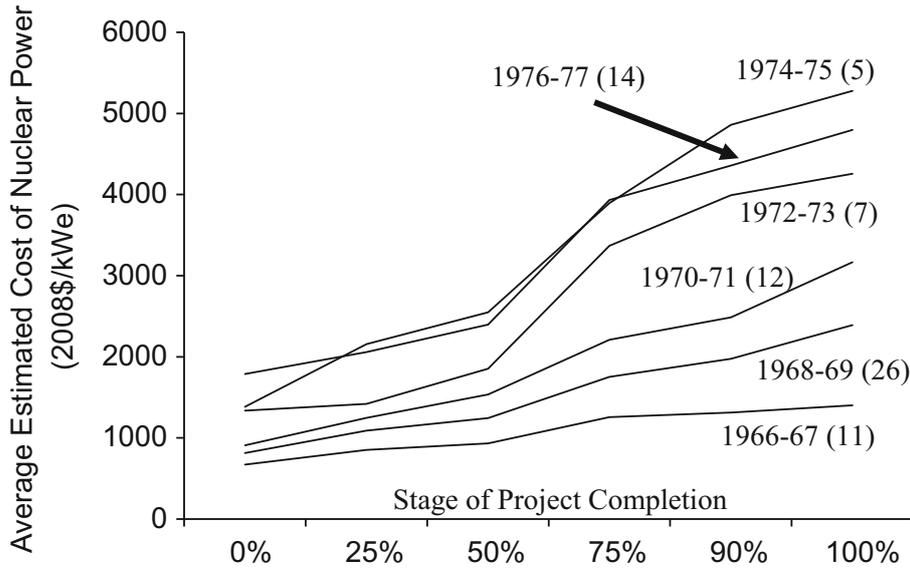


Figure 2.14: Average estimated capital cost of US nuclear plants at different stages of project, and at project completion. Number of projects begun during each time period given in parentheses. Source: Rai et al (2010)

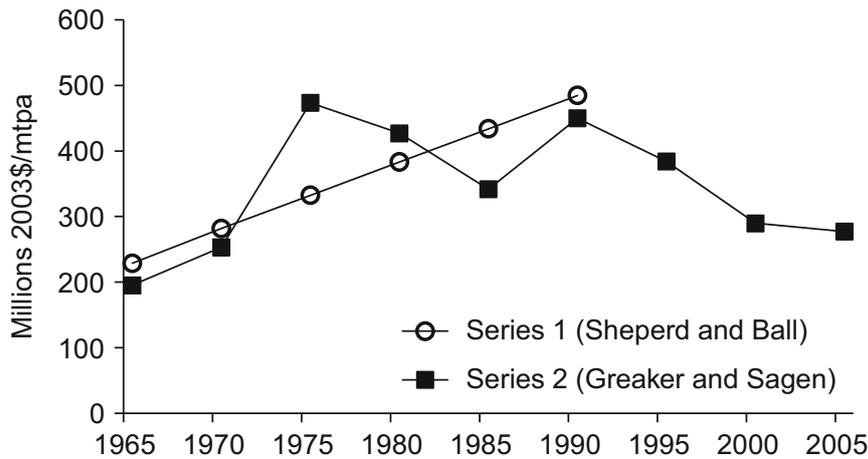


Figure 2.15: Historical unit cost of natural gas liquefaction plants. Source: Rai et al (2010)

One issue is that industries based around large scale technologies tend to become dominated by relatively few large actors, and hence become vulnerable to market power. Rai et al suggest that the inflating cost of LNG plants from the mid-1960s to the 1990s may have been related to a market structure in which there was almost no competition in technology, very few construction contractors, and only one dominant customer – Japan – that was ‘willing to pay premium prices’ (Rai et al., 2010). A similar observation could be made about the manner in which the total cost estimates of the UK’s planned new nuclear power plant, Hinkley Point C, have grown over the years in which it has been in planning. The UK government too is in a situation of negotiating with one large supplier.

Another issue is the way in which learning can transfer and disseminate amongst projects of individually very large size. An additional hypothesis offered by Rai et al for the early rising costs of LNG plants was the relatively small number – only 20 – of liquefaction terminals built globally between 1960 and 1995; distant from each other both geographically and in time. The physical and temporal separation of the individual units may have impeded the possibility of learning by doing (Rai et al., 2010). Conversely, even in a period of relatively rapid and intense roll out of projects, a large scale unit technology can still experience a lack of learning by doing if there are a large number of possible designs in use. Rai et al suggest this was the case in relation to the rising costs of nuclear projects in the US in the 1960s and 1970s, as illustrated in Figure 2.14. ‘The competition was so fierce that reactor manufacturers were constantly changing design to offer customers ever-increasing reactor capacities... Constantly changing design precluded the standardization that would have led to economies of scale... rapid parallel deployment robbed the industry of the opportunity to apply learning from a tranche of projects to the next series of projects’ (Rai et al., 2010).

Efforts to move more quickly towards technological standardization characterize the more state-led nuclear programmes, such as in France and the UK. The French programme began in the 1950s developing a gas-cooled graphite design, but subsequently moved to the Westinghouse PWR design. From the 1960s onwards the government strongly supported this design, leading to standardization, learning effects, and the development of domestic industrial capability around this design (Watson et al., 2014). In 1974, following the oil crisis of the previous year, a central government directed programme was launched (the ‘Messmer Plan’) aimed at producing most of the country’s power from nuclear reactors. Over the next 15 years 54 reactors were built, all based on the PWR technology, with two standard design variants – the 900 MW class (34 reactors) and the 1300 MW class (20 reactors) (Anon, 2016). These reactors amounted to 56.6 GW of capacity.

The background to the UK’s original nuclear programme was security of supply concerns in the context of a rapidly growing domestic electricity demand, as well as geopolitical factors such as the Suez crisis. The programme may also have fitted an emerging narrative around a ‘new industrial revolution’, and a ‘new Elizabethan age’ (referring to the recent accession to the throne of Elizabeth II) (Hannah, 1982). Although the nationalized electricity industry was planned and operated by a centralized board – the British Electricity Authority (BEA), soon to be reorganized as the Central Electricity Authority (CEA) – the government established a separate working party to investigate the prospects for nuclear power, which led to the formation of the Atomic Energy Authority (AEA) (Hannah, 1982).

Hannah suggests that there was a strong impetus to commit to an immediate nuclear programme, and to base it on British expertise and technology. Within such constraints, there would only have been one technological option. The Magnox reactor had been employed for the British military programme, and though the newly completed Calder Hall reactor began to produce power in 1956, it was optimised for the production of weapons grade plutonium, with the electricity essentially a by-product (Hannah, 1982).

In 1957 a programme to build 6000 MW by 1965 was announced. As a result of this projected increase in generation capacity, the CEA was now projecting a coal surplus. As a result of consistent lobbying by the CEA and the later Central Electricity Generating Board (CEGB), the programme was scaled back so that in fact by 1965 only 2425 MW of nuclear power were shared between six stations (Hannah, 1982).

By 1971 nine Magnox stations had been constructed, however the thermal efficiency of the units was low – initially around 22%, rising to 28% in later units. In 1964, the government proposed a Second Nuclear Power Programme. Again there was disagreement between the AEA and centralized board of the electricity system – now the CEGB – with the CEGB favouring the US water-cooled design, and the AEA favouring its own advanced gas-cooled reactor (AGR) design. The AGR design was eventually adopted. Although the AGRs greatly improved thermal efficiency to 40%, there was little standardization between stations, and significant operational problems were experienced (World Nuclear Association, 2016).

In 1975 a third nuclear programme was launched. The CEGB again pushed for the PWR design, but this time a steam-generating heavy water reactor (SGHWR) design was favoured, and two stations ordered. However, due to rising costs the SGHWR design was abandoned in 1978, with the planned stations reverting to AGR design. In 1983, following a public enquiry, a PWR station was eventually ordered, which began operation in 1994 (World Nuclear Association, 2016).

A comparison of the British and French nuclear programmes should guard against too liberal an application of the benefit of hindsight. The French programme may have been seen to be taking something of a risk in its wholesale commitment to the Westinghouse PWR design from 1974 onwards. However, it had had some experimentation in the previous decade with a gas-cooled design, which it subsequently felt able to abandon. And it certainly seems evident that whether or not the French planners had a high level of certainty that the PWR was at that time the optimal design, the act of committing to it so comprehensively enabled standardization and economies of scale without which the extremely rapid rollout of plants over the next fifteen years would not have been possible.

By contrast, the early UK commitment to the Magnox design – even allowing and mitigating for the benefit of hindsight – could be considered questionable, for the reason that it was a design optimized for the production of weapons-grade plutonium, not for power production. The low thermal efficiencies achieved in the resulting units could be connected to its design origin. After the UK changed its preferred design to AGR, a better optimized technical design, nonetheless the programme did not manage to reap rewards of standardization and economies of scale, because of design differences between each of the stations.

As a coda to both the British and French nuclear stories, it should be recalled that the European Pressurised Reactor (EPR) design, which has evolved from PWR, is currently experiencing problems with delays and cost overruns in each of the three projects in which it is currently being employed. Despite the factory-line like rolling out of PWRs achieved by France in the 1970s and 1980s, its descendant, the EPR,

seems caught back in the trap of one-of-a-kind projects, with minimal standardization or economies of scale.

Rai et al suggest that technology selection and standardization was also significant in the development and roll out of SO₂ scrubbers in the US. The 1971 New Source Performance Standards (NSPS) promoted experimentation with technologies for SO₂ removal, however a 1979 revision of the standards effectively mandated flue-gas desulphurisation (FGD). 'Although a number of SO₂-control technologies besides FGD systems were in active development and commercial use before, the stringency of the 1979 NSPS was a verdict in favour of FGD systems'. It was only after this point that 'both capital and operating and maintenance (O&M) costs of FGD systems declined most significantly' (Rai et al., 2010).

Security and safety concerns can also be significant for large scale projects, and can make a contribution to increasing costs. Rai et al (2010) suggest that while the LNG market was dominated by Japan in the mid-1960s to the mid-1990s, 'Japan was inordinately concerned with the safety and security of LNG supply. This resulted in generous capacity and safety factors for the liquefaction plants, which further added to the costs'. Rai et al also suggest that belated attention to health and safety on the part of the regulatory agencies in the US nuclear industry, meant that in the late 1960s regulators were asking project developers to enhance safety features, in some cases after construction had already begun (Rai et al., 2010). Attention to safety is of course a major concern for large scale projects, and it might be expected that in first of a kind projects, or in the early stages of roll out, the costs of ensuring adequate safety could be high; nonetheless, amongst the hoped-for effects of standardization and replication ought to be an optimization of the costs of safety features, without compromising on required safety standards.

2.6.2 *Infrastructure requirements*

CCS projects will come with infrastructure requirements. Those projects in power applications will of course require connection to the electricity transmission and distribution infrastructures – though in most countries these are established networks, along with processes to enable new generators to connect, and the negotiating of these will be common to other power generation entrants. The more distinctive infrastructure requirement of CCS is that of the CO₂ transportation network.

Infrastructures that support energy networks are fundamentally shared assets – if they are not shared amongst a reasonable number of users the infrastructure becomes prohibitively complicated, inefficient and expensive.

Nonetheless, several historical examples of energy infrastructures show that their early development happened initially in a piecemeal fashion, built for and alongside the early entrepreneurial project developers that required them. In urban electricity systems in the early 20th century, it was not uncommon for single power stations to be set up to feed single demand sources, via single power lines, resulting in networks that were almost entirely 'unmeshed'.

As more users join, the missed opportunities of coordinated and meshed networks become increasingly clear. Nonetheless, resolving this issue is not always straightforward, and depends greatly on the kind of social and institutional frameworks – and indeed ‘actor networks’ – that prevail at the time.

The original town gas networks in Britain grew up at a time when the Municipality was a strong institution that took over responsibility for provision of public services. It therefore had both the kind of powers required to coordinate the physical laying down of networks, and the geographical extent consistent with a reasonably sized network for the gas supply and demand quantities of the time.

By the early 20th century when electricity innovations were growing in prominence, there was in fact some tension between the Municipalities and the entrepreneurs whose activities were driving much of the innovation in electricity supply systems and end use technologies, and who therefore resisted handing over control and future profits to the Municipalities. The tension persisted, even while the early electricity system grew at a strong pace, ever more unmeshed and uncoordinated. Eventually the problem was referred up to the national level, for the start of a centralizing coordinating process that reached its peak in the nationalisations of several industries, which took place in the second half of the 1940s (Hannah, 1979).

In Germany, by contrast, the regions retained a stronger position in the 20th century than that of the declining Municipalities in Britain. As a result the electricity grid was able to grow up in a highly regionalized way – unlike in Britain where from the 1920s on, the concept of a high voltage interconnecting ‘national grid’ has underpinned electricity system planning and operation.

An interesting side-story within the British case is that of the North East Supply Company (NESCO), an electricity supply company set up by a coalition of industrialists in the Newcastle area. Aware of the efficiencies that could be gained if their various power demands were linked up into a network supplied by large-scale generating stations, the members of the company built a grid that supplied the industrial users across the Newcastle coal field. Assisted by good personal relations and family ties between some of the main protagonists, the NESCO was able to achieve system efficiencies markedly greater than those achieved in other areas, where different actors considered each other as competitors and were unable to collaborate on the question of mutually beneficial shared infrastructure. The NESCO stands as an interesting example of how significantly actor-networks can affect the development of physical networks (Hannah, 1979).

The period in Britain between 1945 and the mid-1980s represents in retrospect the high water mark of centralization and state ownership of major industries, including the energy industries. Thus it was that when the potential for LNG arose in the mid-1960s, the Gas Council was well placed to order the construction of a high capacity transmission pipeline along the backbone of England, which later facilitated the broader conversion from town gas to natural gas. This process too was facilitated by the nationalized nature of the industry, which with relative rapidity, was able to roll out the required infrastructure changes on a region by region, and street by street basis (Watson et al., 2014).

2.6.3 *Legal and regulatory issues, investors and whole chain business risks*

Liability for nuclear waste and accidents in the UK ‘is strict and channelled to the operator. Liability insurance or financial security is mandatory and the overall liability of operators is capped’ (Watson et al., 2014). This means that any liabilities beyond this cap are ultimately the responsibility of governments – and, by implication, current and future taxpayers. Watson et al suggest that this is an appropriate basis for CCS liability, as open-ended liability is likely to deter investment. However, setting the liability cap too low would expose tax payers to too much risk (Watson et al., 2014).

Government actions to reduce risk for commercial actors have proved important to the development of large scale technologies, particularly in the early stages of development. According to Rai et al (2010), the Japanese state ‘essentially underwrote the entire risk in big LNG projects... Much of the funds for the development and expansion of these projects (\$3.6 billion in 2005 dollars for the Arun plant in 1973-1974) were either directly provided by the Japanese, or had their significant underwriting. At home, Japanese utilities were permitted to pass on the LNG costs to the customers, so price of LNG was not a big concern... the willingness of Japan to almost unilaterally absorb the risks proved critical to the expansion of LNG’.

Rai et al also find that government actions to reduce risk were similarly critical in the early development of the nuclear power industry. In the US, for example, the Price-Anderson Act in 1957 limited private liability to \$60 million, and the government assured another \$550 million for additional claims. The Government’s plutonium repurchasing program effectively took over responsibility for nuclear waste, and the cost of the first generation of US civil reactors was essentially underwritten by the Atomic Energy Commission (AEC) (Rai et al., 2010). Rai et al further comment that similar support was provided in other OECD countries, for example in France and Germany, where low-interest loans were made available to the industry (Rai et al., 2010).

Drawing parallels to CCS, Rai et al suggest that ‘somebody has to underwrite the massive financial risks associated with today’s CCS industry – for nuclear power and LNG that “somebody” was the government’ (Rai et al., 2010).

CCS projects also often rely on multiple actors, attempting to discover new methods of working together. The ease, or difficulty, of these business relationships may be strongly affected by policy. A recent National Audit Office report on the cancelled UK CCS demonstration programme concluded that the government’s standard approach to risk allocation was not necessarily the right approach for this particular technology (NAO, 2017). Other emerging legal and regulatory issues concerning CCS are discussed in more detail in Section 3.3.

2.6.4 *Public deliberation and debate*

Watson et al (2014) consider the ongoing process of identifying and selecting sites for long-term geological storage of radioactive waste in the UK. They observe that

two previous attempts at site selection had failed. These approaches 'were almost exclusively based on expert judgement of the technical feasibility with little public input and transparency and they faced substantial public opposition'. A third approach, ongoing at the time of Watson et al's study, was 'suggested by the Committee on Radioactive Waste Management where local communities volunteer to host the repository, and continued public engagement is seen as key in building trust in the selection process' (Watson et al., 2014).

Drawing parallels with CCS, Watson et al suggest that 'site selection needs to be a transparent and open process with stakeholder input in order to boost public trust'. They further comment that public engagement 'through an organisation which is independent of the CCS industry and government could reap benefits in terms of increasing public acceptance', and ensuring that '“procedural justice” is followed – i.e. that there is confidence in decision making processes about carbon storage in general'. They also note that experience suggests 'location specific engagement processes may also be required' (Watson et al., 2014).

Clearly CO₂ and radioactive wastes are very different substances that should not be conflated. However, the suitability of the analogy between the two at least on some dimensions is suggested by the experience of the public debate around both in Germany. As will be discussed in more detail in Chapter 3, public debate on potential CO₂ storage sites in Germany was strongly framed within the context of CO₂ as a waste product, which linked it to preceding narratives about the disposal of other wastes, including radioactive waste. This debate was also strongly affected by perceptions of spatial justice, with residents and politicians of the regions selected for CO₂ storage protesting that their region should not be the disposal unit for wastes generated by other regions. These protestations invoked a principle drawn from an analogy with other waste disposal issues – that waste should be disposed of within the boundary of the region responsible for creating it.

Issues of locality and geography, and their relation to interpretations of whether or not a just outcome has been reached, are often involved in debates around large infrastructures. A number of researchers uncovered such issues in exploring the public debates around a UK infrastructure project, HS2, a new high speed rail line. According to Rozema (2015), local actors perceived that issues of environmental protection and local concerns were structurally under-represented within the institutions that were taking the decisions in relation to the project. As a result, the 'respatialisation' of the issue as a contrast to the 'national interest' narrative can become a key part of the protest strategy of local actors (Rozema et al., 2015).

In another study of public engagement in the debate around HS2, Crompton (2015) discovered strong dissatisfaction with the government's consultation process. The process was criticised for the lack of information provided, and the restrictive and formal nature of the consultation, which was perceived to be dominated by leading questions designed to elicit the desired answers, whilst not including questions which would raise more critical answers. This gave rise to the perception that critical voices were being ignored, a perception that was strengthened by the claim that consultation responses of several critical organisations had been 'lost' by the government. The overall perception of biased and disingenuous consultation process

fed strongly into motivations for the mobilization of organised opposition. One of Crompton's interviewees commented, "when government introduced the concept of a consultation, I think they must have been thinking in nineteenth-century terms of a dumb population which would believe everything that their masters would say... we simply had to speak up and make our voices heard!" (Crompton, 2015).

HS2 provides an example where a perception that the government had already made a decision, and that the consultation was a sham, seems to have stoked whatever concerns there may already have been about the project. Similarly, the UK government's early, enthusiastic and almost unequivocal support for the development of hydraulic fracturing ("fracking") for natural gas in the UK, may well have meant that any decision to proceed with projects would never be seen as unbiased by local opponents.

Other examples show that technologies which are considered controversial in some locations, can find support in others, where local interests and national interests are more aligned. For example, in conducting public citizens panels about hydrogen energy in England and Wales, Flynn et al (2013) find that peoples' views about 'the desirability and feasibility of hydrogen are partly affected by the industrial history and economic and employment situation of the area, as well as its environmental characteristics'. Support for nuclear energy is often greater in regions containing existing nuclear power plants, from which employment benefits are significant. This of course is in contrast with the situation for long-term nuclear waste storage, from which the employment benefits would not be significant.

Public attitudes to technologies can also be nuanced by how the technology is contextualised, including, for energy technologies, by developments within the wider energy system. Flynn et al (2013) found that citizen panel participants attitudes were 'dependent upon obtaining impartial information from disinterested experts', and thus were examples of 'social trust' or 'critical trust'. They conclude that 'public perceptions are contingent on many different factors and will also reflect the complexity of different, alternative, future energy scenarios'. This last conclusion is also reflected by Parkhill et al (2013), who find that support for or objections to technologies can be affected by what else is perceived to be going on in the energy system, with support for some technologies contingent upon the development of others.

Watson et al (2014) also consider the development of natural gas infrastructure in the UK from 2000-2011. They find that a major concern was the possible safety risk associated with the development of the new infrastructure, such that 'a place that was previously felt to be safe could come to be seen as inherently unsafe' (Watson et al., 2014). Concerns were sufficient to raise protests, and a series of projects in the same region could stimulate a sustained opposition. Watson et al conclude that 'it would be unwise to ignore early reactions from small opposition groups', and that 'a wide range of local, national, and international factors will shape public reactions – so each site needs to be considered on a case by case basis' (Watson et al., 2014).

2.7. Conclusions

When seeking to understand the role of government policy in supporting the development and deployment of low carbon technologies, an innovation systems approach is required. Successful examples of support for innovation, cost reduction and increasing deployment often stem from a combination of different policy actions and instruments over a significant period of time.

Traditional neoclassical economic analysis often concludes that governments need to correct for two market failures, in order for a shift to low carbon technologies to occur: underinvestment in R&D by the private sector, and a lack of a price on carbon that reflects the social costs of damage. However, innovation systems approaches suggest that these policy prescriptions are necessary but not sufficient to support emerging low carbon technologies to commercialisation.

Technologies such as solar and wind have benefitted from public policy intervention in innovation systems that provide: medium to long term price support for the technology to create new markets; R&D support; and coordination through the innovation “valley of death” including financial support and in terms of supply chain and actor coordination. The result of this support, which has been consistently provided in several countries since the 1970s, has been increasing deployment and significant cost reductions.

However, CCS technologies have critical differences to technologies such as wind and solar PV. The large scale nature of CCS projects means that they are expensive and project specific, rather than being mass producible modules like solar PV. This means capital costs are high and at risk of being inflated by numerous project specific factors. Negative learning rates are not uncommon in the early years of such capital intensive technologies. Indeed, there is evidence that offshore wind has exhibited such negative learning in its very early stages – though that is now starting to give way to cost reductions driven by learning-by-doing and economies of scale.

A key challenge with large scale technologies is how and when to select a technology and focus on replication and standardisation, as opposed to maintaining diversity and experimentation – especially when at such large scales experimentation is expensive. However, the costs of focussing too early on the wrong design, for the wrong reasons, are also high. Market power of large commercial technology providers is also a risk. Linked to this, there is an important question about how much of CCS systems can be standardised, and how much of each project is site specific.

Costs can also be inflated if full chain project management – including health and safety standards – are not adequately addressed in the first instance, as belated action can impose delays. As noted in a recent National Audit Office report on the failure of the second UK demonstration programme, projects can also fail if risks are not allocated appropriately between consortium partners – and between the government and private sector (NAO, 2017).

Given the potential liabilities associated with the storage of CO₂ are large, strict, channelled and capped liability is likely to be the appropriate legal framework for projects of this kind. However, the setting of the liability cap at an appropriate level is important, as too low a cap would expose tax payers to too much risk, and potentially

erode public and political support. The role of government in underwriting the financial risk inherent in emerging technologies with multi-actor supply chains such as CCS, is critical, and there are precedents for this kind of support.

CCS projects also need to be seen not only as individual projects, but ultimately, if not immediately, as part of a fleet that will share the CO₂ transportation infrastructure. Without this shared and appropriately sized infrastructure, the infrastructure costs for each project could be prohibitive. The planning of shared infrastructure for projects that will emerge gradually, requires some kind of coordination by a body that can act above and on behalf of the various commercial owners of individual plants.

Public engagement in the process of developing large scale technological systems like CCS, and the role they could play in the overall transition to sustainable energy systems, is critical. Engagement must be transparent and supportable by demonstrably independent expert testimony. Governments must avoid being seen to pre-judge an answer, to attempt influence or bias debate, or suppress inconvenient views. Genuine consultation should begin early, and conflicts not dismissed. The importance of regional differences should be acknowledged, and opportunities for the alignment of regional interests with national interests sought. Engagement needs to take place on a case by case basis, but within the context of an overall national or regional debate about the future direction of the energy system.

3. The role of policy in CCS deployment to date

Key points

- CCS projects are in operation in various parts of the world, but such projects are typically cases where the addition of CCS is a relatively small incremental investment due to the nature of the existing process, or where captured CO₂ has a commercial value.
- For these kinds of projects, the economics are such that relatively modest policy incentives have provided sufficient additional incentive for companies to carry out geological sequestration of CO₂. However, policy drivers are not yet strong enough to bring about large-scale projects explicitly concerned with dedicated storage of CO₂ for climate mitigation purposes, where there is no other commercial value derived from the CO₂.
- Legal and regulatory frameworks for CCS are emerging in various jurisdictions, some adapting existing frameworks, others developing new frameworks. The design of a CCS legal and regulatory regime needs to incorporate effective review procedures and adaptation mechanisms in order to learn from developing scientific knowledge and technical experience.

3.1. Introduction

A number of CCS projects are underway in different countries. These include applications in various sectors, and are encouraged by a range of different economic, institutional and policy conditions. This chapter presents case studies of the CCS activities of selected countries. Section 3.2 considers activities in various countries which are considered influential in relation to the promotion – successful or otherwise – of technological demonstration projects, or early commercial plants. Section 3.3 then focuses on the parallel development of legal and regulatory frameworks.

3.2. Technology Case studies

3.2.1 *Canada*

Climate policy and resource protection is driving decarbonisation across Federal Canada. CCS incentives are located mainly in the resource-rich provinces of Alberta and Saskatchewan. Interest in CCS derives partly from being able to protect the continued exploitation of indigenous and export-grade oil and coal.

The federal government provides some incentive for CCS through an emissions standard of 1,100 lbs/MWh for new and existing coal fired power plants. Existing coal plants must be retired at 50 years operation. A floor price for carbon will be

implemented by 2018, differently in each province. Federal and provincial subsidies also exist for CCS projects (Banks and Boersma, 2015).

The Alberta government imposes a carbon tax on industrial facilities that emit more than 100,000 tonnes of CO₂ per year (GCCSI, 2015b). Alberta contains large and accessible oil reserves. However most of these are located in oil sands of partly biodegraded hydrocarbon, which requires double or treble the energy to extract it compared to low viscosity onshore oil. This oil is therefore subject to emerging fuel standards regulations led by California, which account for embedded hydrocarbon. CCS can partially capture the emissions incurred in oil sands production, which would enable oil from Alberta to be sold into the California markets. However, oil sand extraction and processing from Alberta has recently reduced because the price of liquid oil has fallen, especially in the USA due to lower cost shale oil being produced. Consequently the higher production costs of Alberta oil sands, and especially the processing costs to convert to export grade, and in future the anticipated CCS costs, make this source of oil less price competitive than rival sources to satisfy demand in the USA. This may reduce the extent to which this form of hydrocarbon extraction offers an opportunity for CCS.

Alberta also has significant coal resources that are impacted by both federal and provincial policy. Alberta's provincial climate change policy requires all coal-fired power plants to be emissions-free by 2030 or be shut down. Six plants in the province would have been able to continue operating past 2030 if the government had not introduced this deadline. Alberta's industrial emissions already play an important role in considering the viability of CCS and that has the potential to increase in the future.

Overall, CCS has the potential to contribute to the development of Canada's fossil fuel resources with improved efficiency, and revenues from CO₂-EOR provide a clear economic driver.

3.2.1.1 *Boundary Dam*

SaskPower's Boundary Dam 3 (BD3) plant in Saskatchewan is considered a significant milestone as the world's first operational large-scale CCS project in the power sector (GCCSI, 2015b, Banks and Boersma, 2015). The key policy driver for this project was the enforced closure of the BD3 power unit, having reached its federally defined operating timespan under new performance standards which came into effect in 2015. The standards required plants to achieve a CO₂ emissions intensity of 420 tonnes / GWh, approximately equivalent to current high efficiency combined cycle gas plants (SaskPower, 2016). Under such regulations, CCS is required if SaskPower are to continue burning coal, and thereby to protect resource value from the adjacent abundant lignite fuel. BD3 is a post-combustion retrofit, with a base load capacity of 120 MW, and is designed to capture CO₂ at a rate of 1 Mtpa. Attracted by the proximity of several large mid-life oilfields, the captured CO₂ is being used mainly for EOR, with resulting revenues estimated at \$CAN400-500 million over a 20-year period. It also captures fly ash, for use in concrete making, and sulphur dioxide, for use in the production of sulphuric acid (Banks and Boersma, 2015). The total cost of BD3 was \$CAN1.5 billion (SaskPower, 2016). About half of this

represents the investment made on boiler and steam turbine re-powering and emission controls, with the other half spent on the additional CCS components. \$CAN240 million of this total was provided by the Canadian government in subsidies (Banks and Boersma, 2015, IEAGHG, 2015).

The project was project-managed by SaskPower which is a Crown electricity company that has a near monopoly position in Saskatchewan, using hydrocarbon industry staff experienced in billion dollar projects. Learning from the construction, commissioning and operation of BD3 has encouraged SaskPower to suggest that future plants at Boundary Dam can be built at 30 percent lower cost. The company chose Shell-Cansolv as an established provider of amine capture equipment, and is also testing new amine technologies at its Shand Power Station to reduce parasitic losses of heat used in solvent regeneration. Operation of the BD3 capture plant has been successful. Although it commenced at just 50% of full design level for the first year and was slightly under target for the second year, it has in late 2016 reached design capacity. The shortfall of CO₂ supply during these early operational stages caused penalty clauses to be invoked and forced SaskPower to refund some payments for the purchase of CO₂. There have been problems with particulate carbon entering the wrong part of amine scrubbing system. An upgraded repair was provided by the vendor.

Storage of CO₂ from the project is in a deep saline aquifer 2km distant and at 3.4km deep (Banks and Boersma, 2015). However most of the CO₂ captured is contracted for commercial use in CO₂-EOR by 66km pipeline transport to the nearby Weyburn field where CO₂-EOR is has enabled improved oil recovery and extended field life.

The Canadian government's emissions standard, which required replacement of coal fuelled boilers after a defined number of operating hours had been reached, had a significant impact on the investment decision in BD3, in combination with the geographical conditions. Though the company could have complied with the emissions standard by opening a gas-fired plant, the area is still rich in coal reserves and had limited access to natural gas supplies. Saskatchewan has an estimated economically recoverable 300-year supply of (lignite) coal. Lignite coal is an important part of the province's energy supply and accounts for just under 47 per cent of provincial electricity production. Further, there were nearby opportunities for CO₂-EOR (Banks and Boersma, 2015).

3.2.1.2 Quest

The Quest project is in northern Alberta, developed and operated by Shell. The project involves upgrading bitumen so that it is more easily processed and converted into fuels. The upgrading process involves a reduction in the ratio of carbon to hydrogen in the product. It captures CO₂ after manufacturing hydrogen from an established steam methane reformer process, for the production of synthetic crude oil from bitumen. It is capturing approximately 1 Mtpa of CO₂ (GCCSI, 2017b). CO₂ is transported 60km to a dedicated storage site in a deep regional saline aquifer. The project cost was \$US1.35 billion, with \$CAN745 million from federal and provincial governments. Operational payments are linked to continued net storage of CO₂, and project revenue less or equal to project costs (Alberta, 2016). Interestingly, the

project is not expected to be profitable – Shell proceeded with the FID on a zero net present value basis. It began operations in 2015 (Reiner, 2016).

3.2.1.3 Alberta Carbon Trunk Line

The Alberta Carbon Trunk Line (ACTL) is a planned 240km pipeline which is intended for the transportation of CO₂ from sources in Alberta's industrial heartland to the Central Alberta oil fields for EOR (GCCSI, 2015b). The expected cost of the pipeline is \$600 million, and, it will have the capacity to gather and transport up to 14.6 million tonnes of CO₂ per year. Reports suggest that construction work may commence in 2017, with CO₂ injection planned to begin in 2018 (GCCSI, 2017a).

3.2.2 US

The US government has supported CCS since 1997. The drivers include safeguarding fossil fuel use, developing global technology leadership, and climate change. US support for CCS has included basic research support, part funding of both commercial and pilot scale projects, partnerships with industry, instigating regional centres of expertise, mapping storage resources and taking part in the international Carbon Sequestration Leadership Forum ministerial network (DOE, 2017a). Between FY2008 and FY2014, Congress appropriated \$6.4 billion for CCS research, development and demonstration (Banks and Boersma, 2015).

The bulk of the US Government's interventions to promote CCS are within the Department of Energy's (DOE) Carbon Capture Program; funding for large scale projects out of the Clean Coal Power Initiative (CCPI); and specific funding to the FutureGen project.

The DOE's Carbon Capture Program currently promotes the demonstration and commercial deployment of "1st generation", "2nd generation" and "transformational" technologies, with a cost of less than \$40/tonne of carbon captured being a key target for 2nd generation technologies (DOE, 2017b). The development has proceeded across power generation, industrial emissions capture, transport and demonstration of storage. A recent technology readiness review of the NETL states that there are 58 CCS R&D projects across the US ranging from laboratory scale to pilot stages (Banks and Boersma, 2015).

CCPI and FutureGen are facilitated out of the Government's Major Demonstrations program and are separate from the R&D program. The CCPI was designed to promote advanced, clean coal-fired power projects at commercial scale, with cost sharing between the DOE and the private sector. In three rounds between 2003 and 2009, a total of 18 power sector projects were awarded funding. Of those 18, seven projects selected in rounds two and three involved CCS. As of today, four of these CCS projects, Kemper County, Petra Nova, Hydrogen Energy California and Summit Texas, are still under development or in operation (NETL, 2017a).

The FutureGen project was developed in 2003 as a 10-year proposal. The objective was to aid through federal funding the "first of a kind" construction of a full chain CCS project using coal as a fuel, specifically using known capture technology which had not been proven at commercial scale. Strategically, it could be that this federal

funding would potentially reduce costs and increase efficiency of CCS on coal power, enabling the coal states of the US to continue employment in low cost fuel production. The US has about 200 years of coal resources, giving domestic security. FutureGen comprised a non-profit company made up of coal and utility companies, partnering with the DOE which was to cover 74 percent of the costs of an IGCC coal gasification new build power plant. In 2008 the DOE discontinued funding due to increasing costs. In 2010 FutureGen 2.0 was announced as a retrofit oxycombustion project on a 200 MW obsolete coal power plant in Illinois. However rising costs and legal challenges led to it being cancelled in February 2015 (Banks and Boersma, 2015). It is also apparent that the low price of shale hydrocarbons, utility scale solar PV, and utility onshore wind, are undercutting coal fuel costs, making commercial investment policy a greater risk – unless established coal assets are being protected as with Boundary Dam.

As well as RD&D funding, Congress has also authorised \$8 billion worth of loan guarantees for CCS projects, designed to support the funding of projects with high perceived levels of risk (Banks and Boersma, 2015). The first loan guarantee offer was made to Lake Charles Methanol for the construction of a methanol production facility with carbon capture at the end of 2016.(DOE, 2016a).

The US government also provides tax credits to encourage private sector investment in activities such as novel coal combustion, coal gasification and proven CO₂ sequestration (Folger and Sherlock, 2014). Banks and Boersma (2015) estimate that tax credits issued between 2009-2013 amounted to \$2.3 billion, with a further \$700 million to be issued from 2014-2018. The US DOE is also involved in joint funding and collaboration projects in China and Norway, as discussed in Section 3.2.4 and 3.2.6.

Some states provide support for CCS. Colorado offers cost recovery for IGCC plants that capture and store carbon dioxide, with costs spread across the rates of retail customers. Florida, Indiana, Mississippi, New Mexico and Virginia also provide some form of cost recovery. Some states have implemented portfolio standards. West Virginia, Pennsylvania, Michigan, Massachusetts and Ohio have “alternative energy” portfolio standards, for which CCS qualifies. Illinois has a specific clean coal portfolio standard, under which 25 percent of electricity sold in the state must be from “clean coal facilities” by 2025 (Banks and Boersma, 2015).

More generally the US EPA’s “Clean Power Plan” has introduced emission performance standards for “new, modified, and reconstructed power plants” (GCCSI, 2015b). An important clause in the Clean Air Act means that if the technology becomes established on new power plant, then a mandatory retrofit onto older plant can be enforced as a separate action. A critical legal distinction in the US is that excess CO₂ is defined as a substance which damages the health of citizens. That is unlike in Europe, where excess CO₂ is scrupulously avoided from being defined as a pollutant, to avoid being subject to charges on disposal under the EU Waste Directive. In 2015 the EPA also issued regulatory guidance stating that the CO₂ injected for EOR can also be classed as stored CO₂ (GCCSI, 2015b).

The Illinois Industrial CCS project began operating in April 2017. It will continue to develop and increase storage from the DOE Phase I funded Decatur project on the same site. That is the world's first large-scale bio-CCS project, capturing CO₂ from a corn to ethanol production facility, injecting into a deep saline formation at a rate of 1 Mtpa (GCCSI, 2015b). This is one of the very few North America CCS projects not to use CO₂ for EOR. This shows how low cost or zero cost capture from some types of industrial facilities can act as accessible entry points into the CCS system.

The Kemper County Energy Facility in Mississippi will be the largest CCS power project in the world, capturing 3 Mtpa, used for EOR (GCCSI, 2015b). It will also be the first power CCS project to use IGCC (Reiner, 2016). The project's electricity generation capacity is 582 MW, and would capture 65 percent of its CO₂ emissions. While the plant's CO₂ capture technology, Selexol, is over 40 years old, the facility uses a new type of coal gasification technology known as TRIG™, to burn lignite from an adjacent mine. However it has experienced long delays and severely rising costs (Banks and Boersma, 2015).

Petra Nova Carbon Capture Project in Texas captures more than 90% of the CO₂ from a 240 MW flue gas slipstream. The CO₂ goes to EOR for use and ultimate sequestration of 1.6 million tons annually. Petra Nova came online in 2017. Capture is a "conventional" post-combustion amine project. The project cost around \$1 billion, with the DOE contributing \$167 million from the CCPI (Banks and Boersma, 2015). The developer claims that a second project could be built at a reduced capital cost, however the economics of a second plant are detrimentally affected by the currently lower oil price – which reduces the value of EOR – compared to the price of oil at the time the original plant was in development (Helman, 2017).

The Texas Clean Energy Project (TCEP) is a new IGCC producing electricity, fertiliser and CO₂ for EOR, proposed to begin operation in 2021 (GCCSI, 2017c). This project is developed by Summit Power, a Seattle based developer of low carbon electricity. The finance was based on the project being able to attract a Federal loan guarantee and grant. However, the loan guarantee has been withdrawn, which has had subsequent knock-on effects on project costs. TCEP as originally envisaged is not proceeding as of late 2016. This illustrates the risk and impact that policy uncertainty can entail for early CCS developers.

The Air Products steam methane reformer project is located at the Valero Energy oil refinery in Port Arthur Texas and has been in operation since 2012. The project is associated with hydrogen production with CO₂ transported by pipeline for EOR (GCCSI, 2016a). This is a pressure swing separation process. Because of the higher CO₂ concentration in the gas stream, the equipment is much smaller in size, has much lower costs and less complicated construction with fewer parts than the amine scrubbing often chosen for power plant. The project involved retrofits of two reformers, the first of which began capturing CO₂ in December 2012 and the second in March 2013. Both plants have a combined capture capacity of 1 Mtpa CO₂/yr. The project received a total funding of US\$284 million from the DOE. The project's economics reflect the relatively low costs of separation to obtain pure H₂, used for upgrading in refineries, and in the sale of pure CO₂ for EOR which attracts tax credits

in the USA. This illustrates that an industrial CCS project can have lower costs of separation than a power plant, and that project economics depend on different incentives across oil and gas, industrial separation and improved oil security.

The Great Plains synfuel plant uses 14 Lurgi gasifiers on lignite to produce hydrocarbon products, including syngas pipelined for domestic use. The project driver was originally a security response to the global oil availability crisis (Dakota Gasification Company, 2017). Siting in North Dakota was determined by a predicted gas shortage in the Michigan-Illinois-Wisconsin region, as well as by the availability of local lignite for gasification and a large local water supply. Construction began in 1981, taking 3 years, costing \$2 billion (NETL, 2017b). The captured CO₂ is pipelined 205 miles to be injected for CO₂-EOR in the Weyburn-Midale Project – in operation since 2000 (GCCSI, 2017e).

In addition, CO₂ separation has taken place in a number of industrial projects across the US, in some cases stretching back decades. The Enid Fertilizer plant uses CO₂ for EOR, and has been in operation since 1982. Val Verde, Shute Creek, Century and Lost Cabin are natural gas processing plants, where CO₂ separated from natural gas production can be used for commercial EOR, and have been in operation since 1972, 1986, 2010 and 2013 respectively (GCCSI, 2017f). These various projects indicate that CCS can already be commercially attractive given certain conditions. In certain industrial processes capture of CO₂ is already integral; in others it may be a relatively small addition with a correspondingly small additional cost. If such low-cost capture processes also have a nearby commercial buyer of the captured CO₂, for example in EOR operations, then the value of the CO₂ can also justify the construction of transport and storage infrastructure.

3.2.3 Mexico

CCS in Mexico is driven by the wish to reduce emissions for climate mitigation purposes. Mexico is currently among the most active countries in international climate change discussions, and has an ambitious domestic strategy to manage its own significant emissions. Mexico is ranked about 14th in global CO₂ emissions and is aiming to progressively reduce its emissions by 30% below business as usual by 2020, and by 50% below 2000 levels by 2050. In April 2012, the Mexican Senate unanimously passed the *General Climate Change Law* which legislates these targets. The law also creates mandatory emissions reporting for the largest sources of GHG emissions. Mexico has gradually gained experience and built capacity in CCS. Funding has been supplied by World Bank funding established by the UK and Norway in 2009 (Mourits, 2015).

The Special Program on Climate Change is Mexico's key climate change policy document, and it outlines the country's adaptation and mitigation strategies. CCUS (carbon capture use and storage) was recognised as important in the first 2009-12 Special Program on Climate Change, but has been included more actively in the 2014-18 policy as a part of the mitigation pathway, through the implementation of pilot projects by the country's major power utility (Federal Electricity Commission) and national oil and gas company Petroleos Mexicanos (PEMEX) (SEMARNAT,

2014). The implementation of the pilot projects identified in the Special Program on Climate Change, and supporting actions, are outlined in a CCUS specific policy document – the CCUS Technology Roadmap in Mexico. The Roadmap identifies the following key stages: 1) Incubation; 2) Public Policy; 3) Planning; 4) Pilot and demonstration scale projects, including pilot projects in the oil industry and power generation sector, and a demonstration scale project; 5) Commercial scale project (SENER, 2014).

In July 2014 the Energy Reform laws were passed by Mexico's Congress, which provide the legal framework that opens up the energy sector to private investment, technology advancement and competition. This reform is expected to help develop technical knowledge and expertise in the energy sector – also applicable to CCS development. Another important aspect for CCUS within the Energy Reform is that CCUS has been clearly defined as a clean energy technology. This is the first time CCUS has been given equal status with renewables as a 'clean energy technology' in Mexico. The energy system in Mexico is much more reliant on fossil fuels (88%, with only 7% renewables) than other countries of comparable size; and that is supported by an historically large onshore and offshore domestic oil industry.

Mexico's need for CCS is two-fold. Firstly, electricity supply is forecast to increase significantly, with capacity rising from 60 GW in 2009 towards 113 GW in 2028. There is an ambition for 50% of Mexico's electricity to be from renewable sources by 2050, but gas-fired generation is also likely to remain a key source. Secondly, Mexico's offshore oil industry is expected to be rejuvenated by exploring for new fields in deeper water, and by obtaining enhanced production from existing fields by the use of CO₂-EOR. A pilot project is being planned by PEMEX at the Cinco Presidentes field. A second pilot project to be undertaken by the Federal Electricity Commission involves post combustion capture on a gas-fuelled power plant. Other supporting actions are outlined in the CCUS technology roadmap (SENER, 2014), which includes the establishment of a research and development centre. The initial focus of this centre is anticipated to be construction and operation of post-combustion amine capture on 160MW of a gas fuelled power plant in Poza Rica; and the search for, and evaluation of, storage sites in coastal regions of the oil rich Tampico province of south east Mexico – the region of Mexico's first oil well in 1901.

3.2.4 China

After a prolonged period of rapid, carbon- and energy-intensive growth, Chinese policy has in recent years made significant shifts towards curbing the environmental impacts of its economic growth and related energy consumption. These shifts have been prompted by the domestic agenda of local air pollution, by increased engagement in international climate change negotiations and by the possibility of becoming a significant manufacturer in low carbon energy technology. In November 2014, in a joint US-China announcement, China committed that its CO₂ emissions would peak by 2030. Its intended nationally determined contribution (INDC), submitted for the 2015 Paris COP, included a target to reduce its CO₂ emissions intensity (emissions per unit of GDP) by 60-65 percent from 2005 levels by 2030 (Khanna et al., 2016). China is currently highly dependent on coal. More than 80% of

China's CO₂ emissions arise from fossil fuel combustion, and coal accounts for 75% of these fossil fuels. China's coal demand accounts for half of the world's coal consumption (ADB, 2015). Given its large coal reserves and its current levels of coal consumption, its decarbonisation commitments provide highly relevant context to the potential future development of CCS in the country.

China signalled its intention to continue supporting CCS R&D through policy documents issued during the 12th five-year plan period (2011-2015) (Khanna et al., 2016). The Fossil Energy Protocol between the US and China, signed in 2000, is exposing Chinese companies and research organisations to US technologies, including CCS. Through the protocol's US-China Strategic Economic Dialogue in 2009, the Clean Energy Research Center (CERC) was established to create joint research activities including on clean coal and CCS. Funding for the CERC was extended to 2020 with the aim of delivering a CCS demonstration project in China (Banks and Boersma, 2015).

The US-China Joint Announcement on Climate Change of November 2014 provided funding for CCS research, and undertook to 'construct a large-scale CCS project in China involving enhanced water recovery' (GCCSI, 2015b). In August 2015 a further memorandum of understanding was announced to develop six carbon capture utilisation and storage (CCUS) pilot projects in China (GCCSI, 2015b).

In April 2016 China released policy documents dealing with technology innovation. Amongst these was an Energy Technology Revolution Key Innovation Action Roadmap, in which specific innovation targets for CCUS were set out, including goals to construct one large-scale full chain demonstration project by 2020, IGCC-based demonstrations by 2030, and by 2050 mature commercial development of CCUS across a range of industrial and power applications (GCCSI, 2016b). China also has seven pilot regional emissions trading schemes (ETSs). A national trading scheme is planned for launch in 2017 (GCCSI, 2015b).

The Guangdong CCUS Centre is jointly funded by the UK and China, and aims to support a large demonstration project, and to develop joint innovation and collaboration (Liang et al., 2014).

By 2014, nine pilot projects had been implemented, mainly in the power and coal-chemical sectors (ADB, 2015). The Shenhua Group, China Huaneng Group, PetroChina and other companies are engaged in research collaborations and pushing forward technology demonstrations, primarily in EOR. In August 2014, "key stakeholders including the China Huaneng Group and PetroChina jointly founded a CCS Alliance" (ADB, 2015).

Coal-chemical production is a significant industrial sector in China, using gasification to produce ammonia, methanol, olefins and synthetic natural gas. Because CO₂ is already separated as part of such processes, the addition of carbon capture is much less costly than for example on power plants, as the CO₂ requires only minor purification, increasing capital cost by only 1-3%. Coal-chemical plants are therefore considered a high-potential low cost early opportunity for CCS. An example of activity in this sector is the Yanchang Integrated Carbon Capture and Storage

Demonstration in Shaanxi province, where Yanchang Petroleum is developing with associate companies sources of CO₂ from the coal to chemicals sector, for use in EOR. One of the coal gasification facilities has a capture capacity of 0.05 Mtpa, and CO₂ from this source has been injected for EOR since 2012. At another gasification facility a larger capture plant with a capacity of 0.36 Mtpa is under construction, and expected to be in operation in 2018. The captured CO₂ will also be used for EOR (GCCSI, 2017d). EOR is potentially an important driver for CCS in China. The Ordos Basin region is considered to have high potential as an early stage demonstration area, as it has a high concentration of coal-chemical plants, as well as nearby oil and gas fields with the potential for CO₂-EOR (ADB, 2015).

As a large consumer of energy and particularly coal, if China made decisive moves in favour of deploying CCS it could bring about a very large scale deployment. However, in the context of rapidly growing electricity demand, it is not yet clear how much of a priority CCS is for Chinese policy makers, in comparison to other technologies that can be more rapidly deployed in the near term. Though there is clearly interest in R&D collaborations, and policy announcements envisage the construction of full scale projects, there has been little in the way of implementation of full scale projects so far – although the Yangchang demonstration is a significant step in this direction. Many planned and existing projects are tied to EOR, with historically low oil prices affecting their commercial viability, and funds to pay for CCS may also rely on the creation of internal emissions trading markets on a province by province basis. Chinese provincial ETS schemes are being based partly on the EU ETS. One of the key learning aspects from the earlier scheme will be the importance of controlling the number of allowances.

3.2.5 EU Countries – Germany, Netherlands and UK

The EU has adopted a broadly positive stance towards CCS; however, as with many other actions on energy in Europe, most details of how the technology is incentivised and supported through co-funding to match EU central grants are left to member states (MSs) through subsidiarity, where action can be most effective. A European Commission communiqué from 2008 envisaged that by 2020, 'or soon after', CCS could 'stand on its own feet in an Emission Trading Scheme (ETS) –driven system' (EC, 2008). In support of this aim, the communiqué reported that 'the European Council endorsed in March 2007 the Commission's intention to stimulate the construction and operation by 2015 of up to 12 demonstration plants of sustainable fossil fuel technologies in commercial power generation' (EC, 2008). According to Reiner (2016) this ambition was later amended to 10-12 projects by 2020. None have been delivered, partly due to the low price of permits in the EU ETS, and partly due to the complexity of co-funding required. It is also relevant that EU mandatory targets have tended to focus on renewables, not low carbon sources generally – hence CCS would not be a technology that could enable a MS to meet such targets.

The EU Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP) was founded in 2005. This is a coalition of 'European utilities, petroleum companies, equipment suppliers, scientists, academics and environmental NGOs' that acts as an advisory body to the Commission on research, development and deployment of CCS

(ZEP, 2016). In 2007 ZEP proposed a vision of a 'Flagship Programme' for CCS (EC, 2008). With recognition that many basic challenges facing CCS in Europe are financial, the ZEP (2015) designed and issued an "Executable Plan" which provides business and liability separation along the CCS chain. Reiner (2016) describes this in more detail. It included the aim to develop a spread of geographically and technologically diverse demonstration projects, spanning different storage options, capture technologies, fuels, CO₂ transportation modes, and including both new-builds and retrofits. It also included the intention of building at least one project in an emerging economy, and at least one non-power project (Reiner, 2016).

In 2009, the EU made €1.05 billion of support available for six projects under the European Energy Programme for Recovery (EPR) stimulus package (EC, 2016a, Reiner, 2016). Further support was to be made available from the auctioning of ETS emissions allowances under the New Entrant Reserve (NER). At the time, emissions allowances were trading at around €15 per tonne CO₂, which would have raised €5 billion from the New Entrant Reserve auction – the NER300 programme – most of which would be available for CCS (Reiner, 2016). However, the global financial crisis of 2009 reduced the EU's emissions, which had the effect of halving the price of emissions allowances, which in turn halved the funds raised by the NER300. Furthermore, the programme scope was expanded to admit a range of innovative renewable technologies, and in the end the first round did not fund any CCS projects. The second round included €300 million for the UK's White Rose project, one of the two selected projects in the UK's CCS commercialisation programme (discussed further below) (Reiner, 2016). A design modification of the EU-ETS was agreed in ENVI committee on 16 Dec 2016, to increase the fund from 400 million to 600 million EU-ETS saleable allowances. The fund will be provisionally divided between sectors, with scope for re-allocation (NER 400, 2017). In February 2017, the European Parliament voted on these changes, to be enacted from 2020 as the Innovation Fund (aka NER 400). The EU-ETS will reduce the number of allowances in the system, intending a sustained drive of the price up between €20-40, and will keep power support, whilst also creating much larger CCS support for industrial sites.

Meanwhile, progress was made on the legal frameworks for CCS. The EU Directive 2009/31/EC on the geological storage of carbon dioxide seeks to provide a legal framework for safe geological storage of CO₂. It sets out requirements for selection of sites for CO₂ storage, for the security of the transport network and storage sites, including the requirement for monitoring and corrective measures if required. It relies on existing legal frameworks on issues of liability, including for local damage to the environment, and for damage to health and property (EC, 2016b). The directive was required to be transposed into member state law by June 2011 (Krämer, 2011). It effectively means that member states (MSs) must have the legal frameworks in place to cover geological CO₂ storage, should this become a reality. It does not, however, compel any MS to deploy any amount of CCS – under the principle of subsidiarity, MSs have freedom to meet emissions targets set under other directives and international agreements, through their own choice of technologies (Krämer, 2011). The EU legislative approach is discussed further in Section 3.3. The CCS Directive was reviewed in 2015 and no changes were recommended – being a balance between some acknowledged deficiencies, versus the legislative risk of re-opening

protracted political discussions (EC, 2017). The remainder of this section discusses CCS developments in three EU countries: Germany, the Netherlands and the UK.

Germany has ambitious targets in relation to climate change. The Federal Government's 'Energy Strategy' set out in 2010, includes greenhouse gas reduction targets for 2020 and 2050 that exceed EU targets. The nuclear accident at Fukushima, Japan, in 2011, appears to have contributed to a decision to abandon nuclear energy, which has had considerable impact on the direction of the Energy Strategy. The 2010 Energy Strategy also indicated an interest in exploring the potential for CCS, and that two new demonstration projects would be built by 2020. Government climate planning is discussing a 20% reduction of industry emissions by 2030, driven by a policy wish to show global leadership heading for 95% reductions by 2050 (Oltermann, 2016). However storage legislation remains extremely complex and public opposition has been strong in some regions, as will be discussed further below.

An oxycombustion pilot capture plant was constructed by Vattenfall at Schwarze Pumpe in the Brandenburg region, and operated at 30 MW from 2008, before being closed in 2014. For part of this time, the CO₂ was transported by road trucks to a storage site at Ketzin, near Berlin, around 400km away. This onshore CO₂ injection and storage site was operational from 2008 to 2013, during which time the subsurface was monitored. It is also one of a very few projects to go through a research phase of decommissioning and shutdown (MIT, 2016b). The project was funded by German federal research, by German industry and research institutes, and Norway CLIMIT.

In 2009 RWE received a permit for a CCS lignite power plant near Cologne, the CO₂ from which would be transported by a 600km pipeline to an underground storage site in the Schleswig-Holstein region. When the pipeline and storage plans became known, they were the subject of considerable public objections and protests, with the government of Schleswig-Holstein also being persuaded to oppose the plans. Thus, later in 2009, RWE suspended the project, citing the lack of legislative framework, and the lack of public acceptance of transportation and storage of CO₂.

Krämer (2011) lists the following as the main concerns in Schleswig-Holstein in relation to the RWE project: potential for CO₂ leakage and its effects on health and safety, the environment and contamination of ground water; the land-take of the pipeline; the image of Schleswig-Holstein as a tourist region; the idea that pursuing CCS results in a lack of investment in renewables; and the perception of being a waste-depository for the activities of coal power plants being built elsewhere in Germany.

Indeed there are high levels of criticism and objection to CCS within German society. It has been found that objections seem to be stronger in the areas which are potential candidates for underground storage (Braun, 2016) - Schleswig-Holstein and Niedersachsen. The regional governments of both of these 'Länder', faced with considerable local opposition, have made representations to the federal government, which appear to have resulted in the insertion of a 'Länder clause' in the German

CCS bill, giving Länder the ability to authorise or prohibit CO₂ storage on their territory. Krämer (2011) writes that ‘their main argument was that they refused to be the ‘CO₂-WC’ for those German Länder, where coal-fired (lignite-fired) power plants were to be constructed or retrofitted... there seems to be a general tendency in German public opinion to require that storage facilities – such as for CO₂ or for nuclear waste – should best take place close to the location of the power plant’. Krämer further suggests that ‘generally, political parties, be it at the regional or the national level, which favour nuclear or CCS technologies – and these two technologies are often put on the same level in public discussions – run a strong risk of losing votes or even elections’ (Krämer, 2011).

In the Netherlands the main CCS activity concerns the proposed Rotterdam Opslag en Afvang Demonstratieproject (or ROAD project). This is a planned post-combustion retrofit onto a new coal fuelled power station near Rotterdam, the CO₂ to be transported to an offshore depleted gas reservoir. The project received €180 million from the EU’s EEPR, and a further €150 million for 2010-2020, from the Dutch government (MIT, 2016c). A full storage permit was granted for a depleted gas field 20km offshore. Reiner (2016) comments that the project ‘remains the most advanced CCS project in Europe’, but that it has been ‘stalled because of a funding shortfall’. As of early 2017 there is a possibility that a revised ROAD project will be launched. The project storage and lifetime have been re-specified to a single coastal gas well Q16-Maas and a different subsurface operator (eliminating offshore transport costs), with a 3 year project lifetime influenced by the small storage site (reducing total OPEX from its original 10 year programme). About 1.1 Mtpa will be sent to storage, while 0.4 Mtpa CO₂ is planned to be pipelined for sale to local greenhouse horticulture – the Netherlands’ current CCUS opportunity (GCCSI, 2016d, ROAD, 2017). Discussions with the European Commission are amending the federal grant, and allowing multi-national funding partners from Europe, including Norway. Operational capture and storage is planned for 2020.

Until the end of 2015 the UK was seen as having a world-leading policy framework for the promotion and deployment of CCS. In its 2015 international comparison of policy support for CCS, the GCCSI placed the UK in the upper tier of its constituent policy index, stating that “the United Kingdom continues to provide the strongest policy leadership in encouraging CCS” (GCCSI, 2015a). Also in 2015, in its CCS roadmap for China, the Asian Development Bank picked out the UK’s CCS policy framework in a case study as a “good practice example” (ADB, 2015). However, in late-2015, the UK government unexpectedly announced the withdrawal of the major pillar of its CCS policy, the UK CCS commercialisation programme.

Before discussing the UK’s CCS programme specifically, it is important to mention the UK’s broader decarbonisation policy framework, which would also have relevance to CCS. The overarching framework is the 2008 Climate Act which sets a target of an 80% reduction in UK GHGs below 1990 levels by 2050, and a system of intervening five-year carbon budgets leading towards that goal. A very important policy institution is the ongoing public scrutiny and monitoring of the GHG trajectory. These GHG budgets are publicly researched, recommended and progress publicly reported by the Committee on Climate Change, which is notably independent of, and

sometimes in conflict with, the UK Government. The Energy Act 2013 introduced an emissions performance standard which effectively prevented the construction of new unabated coal plants (though not of new gas plants), and a system of price incentives via “contracts for difference” (CfDs) for generators of low carbon electricity. In separate legislation, a “Carbon Price Support” is an available lever as a tax on carbon from electricity generators. This combination of policies has been reasonably successful in depressing construction of unabated fossil fuel power plant – especially coal. Price support for renewables has fostered a steady growth in renewable generation capacity, and the new nuclear project at Hinkley Point C has also been granted a CfD and government approval.

Progress on CCS however has been slow. The first government engagement with CCS started in 2005, when BP-SSE proposed a post combustion retrofit of the Peterhead gas fuelled power plant, with CO₂ storage offshore via an existing pipeline to the defunct Miller oilfield. The Government was not able to decide rapidly on multi-year price support for gas-fuelled CCS, partly because internal work had focused only on CCS for coal power, and sought reasons to defer and delay which caused BP to publicly withdraw its project proposal. After some 18 months of evaluation, the UK government in 2007 decided to commit up to £1bn capital investment for CCS through a CCS procurement competition, aiming to deliver a CCS project at a power station by 2014. Negotiations with the last remaining bidder were ended by the government in 2011, as a result of concerns that the project could not be funded within the £1 billion limit. The competition was re-launched in 2012 as the CCS Commercialisation Programme, and contracts were awarded to two preferred bidders: Capture Power (led by Alstom), for its White Rose project in Yorkshire, and Shell and SSE for the Peterhead project in Aberdeenshire. £1 billion was still available in capital funding, and further support for increased operational expenditure would be made available through the creation of a CCS CfD (ECCC, 2015).

However, on 25th November 2015, the government unexpectedly announced that the funding for the Commercialisation Programme would no longer be available. The House of Commons Energy and Climate Change Committee (ECCC), having written to the Department for Energy and Climate Change (DECC) to ask for the reasons for the decision, received the reply that the decision was part of ‘a full review of capital spending plans to identify the areas of spending that will achieve the best economic returns while delivering on the commitments to invest £100 billion in infrastructure by the end of the Parliament’ (ECCC, 2015). Thus it appears that both the termination of negotiations on the original competition in 2011, and the sudden cancellation of the commercialisation programme in 2015, were the result of spending constraints and the need to make budget savings in the near-term. The UK National Audit Office (NAO, 2017) inspection stated that £100M of public money had been spent, but that a fundamental flaw was the lack of agreement by Treasury to support any CCS project.

Some commentators have since raised issues regarding the design of the programme including that technology choices were made too early, and there was insufficient government appraisal of commercial risks. The scheme aimed to develop

full-scale operation immediately, rather than take an incremental learning pathway. It has been suggested that the competition's costing structures, with cross party risks, inflated costs up to a factor of four (Oxburgh, 2016).

As a result of the decision to cancel the commercialisation programme neither the White Rose, nor the Peterhead project will go ahead. White Rose will return €300M of NER300 restructuring funds to the EU. The Don Valley project will also return more than €150M of EEPF funding to the EU. Stakeholders are concerned that the announcement, as well as the manner and timing of it, has caused loss of international investment including from the EU, and has greatly undermined relationships and progress within the industry. The ECCC has urged the government to set out a clear strategy on CCS (ECCC, 2015). A residual benefit of the programme is that the detailed front-end engineering design (FEED) studies, for which the UK government paid £100 million, will be available to future developers (Reiner, 2016). The UK is also involved in joint funding and collaboration with China, as discussed in Section 3.2.4.

Some other projects are being proposed or evaluated in the UK. The Caledonia Clean Energy Project is proposed by Summit Power, the developer of TCEP in the USA. This project would build a clone of the TCEP project on a brownfield site in the Grangemouth industrial and petrochemical complex in Scotland. The plant would deliver dispatchable power into the regionally isolated Scottish market, and could, if policy is clear enough, be configured for 30% of its output to be hydrogen for heating. CO₂ from both value streams would total about 4Mt/yr and could be removed via a vacant onshore pipeline – as was evaluated previously for the UK CCS competition. The pipeline passes offshore at St Fergus in north-east Scotland, where numerous scalable options connecting to offshore storage are located due to legacy hydrocarbon infrastructure. Peterhead and nearby St Fergus are proposed to be joined by pipe to form a shipping import terminal for CO₂ supplied from Europe to abundant UK offshore storage sites. The project research is assisted by £5.4M from the Scottish Government and the UK Department for Energy and Climate Change (DECC), the latter now reorganised as the Department for Business, Energy and Industrial Strategy (BEIS).

The Don Valley Power project was originally proposed as a coal fuelled project, using locally mined UK coal. That gained great favour from EU evaluations and was awarded €300M from the EEPF, most of which remains un-spent due to lack of UK or investor support. With the demise of the first UK competition, this project faltered, and was sold to SarGas of Norway, who plan to re-configure the project as gas fuelled CCS, with potential to build a coal gasification unit to supply syngas at a later date. In 2016, after failure of the CCS Commercialisation programme the project remains dormant, now operated by SarGas.

The Teesside collective project involves the UK's largest industrial complex, containing most of the UK's chemical industries, fertiliser plants, and a small CO₂ import-export shipping facility. A grouping of 7 of the larger companies have formed a co-operative endeavour to propose a CO₂ gathering and separation system, similar to that of Rotterdam. Although this is a potentially large project with good scalable

follow on, the entry costs of defining storage and building a pipe require confidence from investors.

In summary, UK CCS suffers from stop-go policy indecision, with an unusual arrangement where private investors are expected to take the lead as innovators and developers. The unwillingness of the State to underwrite significant risk or financial exposure has resulted in projects where developers add in additional margins and extra equipment – resulting in a higher price. The Oxburgh Report (2016) as suggested that the cost per MWh of electricity could drop from £160/MWh for first projects envisaged under the cancelled commercialisation programme, to £85 / MWh for first projects if the State created a company to act as lead developer, enact co-ordination and hold more risk.

3.2.6 Norway

Norway is the country that has done much more than any other in Europe on CCS. The policy driver is to reduce GHG emissions from processes and the economy, as mitigation of climate change. There is, and has been, good cross-party consensus in the Norwegian Parliament to provide stable, long duration support and funding both for R&D and for practical development nationally and internationally. Two projects are operating with gas sweetening offshore (Sleipner and Snøhvit), an international capture test facility operates at Mongstad, and there is a pilot plant for cement capture at Brevik. There is an ambition to develop a full scale industrial CCS project to be operational by 2022 (Gassnova, 2016), and an increasing momentum to be the leading developer of North Sea storage of CO₂.

The Sleipner CO₂ storage project captures CO₂ from natural gas processing offshore. The source of the CO₂ is natural gas extracted from the Sleipner West field in the North Sea, and the CO₂ is stored in a formation above the Sleipner East field. The project has been capturing CO₂ since 1996, at the rate of approximately 0.9 Mtpa. The gas extracted from the Sleipner West field naturally contains CO₂ in concentrations of 4-9 percent. This is above market specifications and hence must be stripped out to before the gas can be sold to consumers. In addition to this requirement, from 1991 a policy of the Norwegian government introduced a tax on CO₂ emissions applying to a number of sectors, including the offshore hydrocarbon industry. This made it more cost-effective for the company to re-inject the stripped out CO₂ into a natural storage reservoir, than to release it and be subject to the tax. The reservoir in question is a sandstone reservoir in the Utsira Formation, with a seal provided by a gas tight caprock (GCCSI, 2015c).

CO₂ capture and injection also takes place at the Snøhvit gas field, operational since 2008, at the rate of approximately 0.7 Mtpa. Here, the natural gas contains 5-8 percent CO₂ which must be removed before the gas is processed into LNG. As with Sleipner, the CO₂ tax creates an incentive to reinject the CO₂, rather than simply release it. However, in this case additionally the Norwegian state mandated CCS as a condition of granting the original license to operate (GCCSI, 2015d).

In 2007 the Norwegian Government licensed the construction of a gas power plant at the Mongstad refinery, and entered into an agreement for the construction of a CCS

project there (Bugge and Ueland, 2011). The CCS project was intended to have two phases. The first was a test centre for different capture technologies. This joint venture between the Norwegian Government, Statoil, Shell and Sasol, is known as the European CO₂ Test Centre Mongstad (TCM), and began operating in 2012. The second phase was to be a scale-up to a full CCS operation, retro-fitted onto the gas plant (MIT, 2016d). However, in 2013 the Norwegian Oil and Energy Ministry announced it was cancelling the full CCS plant due to rising costs (MIT, 2016d, Holter, 2013). The government said however that it would continue to invest in capture testing (Holter, 2013), and has maintained a CCS strategy under which it is exploring the potential for realising a large-scale CCS demonstration facility by 2022 (Ministry of Petroleum and Energy, 2016). Under the framework of a Memorandum of Understanding between the Norwegian Ministry of Oil and Energy and the US DOE, a jointly funded research programme into a second-generation CO₂ capture solvent technology at the Mongstad centre, has recently been announced (NETL, 2016).

Bugge and Ueland (2011) suggest that public opinion in Norway is generally supportive of CCS, as a 'necessary environmental measure'. They suggest that this general support is due to the fact that CO₂ storage is currently taking place some distance offshore, not nearby anyone's 'backyard', combined with the fact that the petroleum industry has been operating offshore with few serious accidents, since the 1970s.

In 2016 the Norwegian Government let a contract to evaluate 3 storage sites for CCS. A successful bid was received from Statoil in mid-2016, and the project is to go to full FEED design. The planned project would gather CO₂ from the Oslo region in three medium industrial sources and transport by shipping tanker, to direct injection or to a dedicated pipe terminal. The three sources are Oslo city waste to heat incinerator, the Norcem cement plant at Brevik, and the Yara fertiliser plant. The project cost would be \$500-\$900 million, and if it goes ahead it is hoped that it could be in operation by 2022 (Reuters, 2016b).

3.2.7 *Australia*

The main funding source for CCS in Australia is the federal government's CCS Flagships program. The Program was launched in 2009 with \$1.9 billion earmarked over 9 years, to support 2-4 commercial scale CCS projects (MIT, 2015). The original funding available for the Flagships program has however been cut more than once by successive governments, culminating in a cut of \$459 million over three years, announced in November 2015 (Taylor, 2014).

To date the program has provided funding for two demonstration projects. The first, the Western Australian South West Hub was selected in 2011, with an initial focus on demonstrating suitable geological storage. Following a review in 2015, the scope of the project was reduced. The findings of the analysis of the geological data will be made available to future industrial users. In 2012, a second project, CarbonNet, was selected for funding through the feasibility stage, for which up to \$100 million is being made available. The feasibility stage work will predominantly be focussed on

modelling and testing of CO₂ storage sites (Department of Industry Innovation and Science, 2015).

The Global CCS Institute was launched in April 2009, with the government initially committing \$100 million per year for a four-year period. In 2010 GCCSI announced that 6 projects around the world would receive funding support from the GCCSI, totalling \$18 million (MIT, 2015). The funding and mission of the GCCSI has since changed considerably into a membership-driven and funded organisation, rather than one associated with project delivery.

Australia also has one of the world's most active CCS R&D programmes both on capture and especially storage. The Otway site, operated by the CO₂CRC, has produced fundamental insights on injection tracing, migration and saturation of CO₂.

The Australian Government also has a \$AUD 25 million CCS RD&D fund for industry and research organisations (DIIS, 2017). BHP Billiton, a global minerals and fuels company listed in Melbourne is an industry leader in CCS action – in 2016 allocating \$20 million to collaboration with University of Regina, and \$7 million to collaboration with Peking University (Reuters, 2016a).

Outside of government sponsored demonstration projects, the Gorgon project is a major gas sweetening project being constructed by Chevron on behalf of a consortium comprising Chevron, Shell, ExxonMobil, Osaka Gas, Tokyo Gas and Chubu Electric Power. Gorgon will be a natural gas extraction and processing facility located on Barrow Island, Western Australia. Gas from the Gorgon field contains on average around 14% CO₂. This percentage exceeds sales quality, so normal practices of gas sweetening will remove CO₂, which in this case will be re-injected, for climate mitigation purposes, into a deep saline formation more than two kilometres below the surface of Barrow Island. It is anticipated that injection and storage will take place at a rate of 3.4 – 4 Mtpa CO₂ (GCCSI, 2015b, GCCSI, 2016c). The policy driver is very similar to that of gas processing projects in Norway: to future-proof operating costs of the project against an anticipated carbon tax. The Australian government assisted by accepting liability, and by committing \$60 million to the project through the Low Emissions Technology Demonstration Fund (LETDF) (MIT, 2016a).

3.2.8 Japan

Japan gained experience in CO₂ underground injection during the 1990s through EOR test projects. The Research Institute of Innovative Technology for the Earth (RITE, a public interest incorporated foundation), subsidised by the Ministry of Economy, Trade and Industry (METI), began investigating CO₂ storage from 2000. Trials of its technology were undertaken by the Teikoku Oil company at its Nagaoka saline aquifer in the Niigata Prefecture. During 18 months, from 2003 to 2005, around 10,000 tonnes of CO₂ were stored in an aquifer 1.1 km below ground (Healy, 2016, Tanaka et al., 2014). Additional small pilot projects have included the Mikawa power plant project, Osaki CoolGen, Nagaoka and COURSE 50.

The current policy driver for CCS in Japan is the option of creating a high technology clean hydrogen society, by gasification of lignite, with CCS. This is part of a wider move to low carbon climate targets. In 2008, METI commissioned Japan CCS Co. Ltd (JCCS), a consortium of 35 Japanese companies from the power, oil, engineering, steel and chemical sectors, to investigate the potential for a large-scale CCS demonstration project in Japan (Healy, 2016, Tanaka et al., 2014). The selected site for this first full-chain CCS capture-to-storage project in Japan is Tomakomai port on Hokkaido Island. The source of CO₂ is the off-gas from a hydrogen production facility, which is part of an oil refinery, near Tomakomai. The off-gas had previously been used as a fuel for the reformer furnace. The CO₂ is purified using amine scrubbing, and sent for injection into two offshore reservoirs. The CCS demonstration will take about 60% of the off-gas, capturing at a rate of approximately 100,000 tonnes CO₂ per year (Tanaka et al., 2014). Injection began in April 2016 (JCCS, 2016), and is expected to continue for 3 years, and to be monitored for five years (Tanaka et al., 2014). The aims of the project included the demonstration of the technologies and systems involved, as well as conducting monitoring for leakage and seismic activity (Tanaka et al., 2014).

Japan's 4th Strategic Energy Plan, approved in 2014, contains an intention to promote next generation coal technologies and CCS, and to invest in R&D. METI and the Ministry of Environment (MOE) are also undertaking surveys of geological reservoirs for potential future large-scale CCS projects (Tanaka et al., 2014).

3.2.9 Algeria

Algeria has not historically had a climate or a CCS policy. The location of an international CCS pilot project was suggested by commercial partners in production from a gas-field, due to being a convenient and low-cost demonstration site. The In Salah natural gas processing project began operation in 2004, stripping CO₂ from produced gas. The CO₂ was re-injected into the same reservoir, which is a thin rock body with unusually low permeability, falling below international guidelines for CCS. The project was operated by BP on behalf of Sonatrach, the Algerian state owner, and Statoil. Injection was about 0.7Mtpa CO₂ from 2004 to 2011, over which time subsurface and surface monitoring using adapted hydrocarbon technology was engaged. The monitoring showed some small surface uplift of tens of millimetres. After 2011, monitoring suggested that the CO₂ was adversely affecting the seal and may have left the reservoir. Injection was stopped because of this early warning by monitoring and the injection project is now closed. No adverse effects have been detected above the deep top seal, and none at all at the surface (Ringrose et al., 2013).

3.3. Legal and regulatory issues

Alongside technological demonstrations and early commercial projects, the legal and regulatory frameworks relating to CCS are also in development. The following section explores issues that have arisen in these areas.

3.3.1 Overview of emerging challenges in relation to CCS legislation

A number of different models of CCS legislation have developed over the last decade in different parts of the world. This analysis is not intended to provide a comprehensive summary of existing legislation which would duplicate material already existing² but considers some of the core models chosen, and the lessons they may provide for future development, or for new jurisdictions considering the need for CCS law. To some extent, any legislation will reflect national regulatory styles and traditions, and distinctive political and commercial considerations that prevail in any particular jurisdiction. The concept of a single, 'perfect' model is therefore unrealistic, though, publications such as the International Energy Agency's 2010 Model Regulatory Framework (IEA, 2010) have provided a valuable summary of the core regulatory issues that should be addressed in regulatory developments.

Perhaps the fundamental governmental challenge when faced with a new technology³, or a technology being used in a new context, is determining the appropriate time for regulatory intervention.⁴ Too early, when the real nature of the risks involved are still unknown, can stifle the development of technology; while the opportunity to influence industry practice and standards may be missed if intervention is left too late. Incorporating 'flexibility instruments' into the structure of the legislation (the power to make delegated regulations, the language of discretionary judgment to decision-making, use of guidance documents, etc.) are classic methods for dealing with the need for legal adaptation and learning, but have to be balanced against the attractions of regulatory certainty for both industry and investors, and the wider public. Existing CCS legislation to date provides examples of completely different approaches in this context, and a number of key themes can be seen to emerge:

- (i) The extent to which CCS legislation can be based on existing models of regulation, particularly in the oil and gas industry
- (ii) Whether CCS should be treated as a new technology, requiring special treatment in legislation, and whether legislation is best confined initially to demonstration plants
- (iii) Division of state and federal responsibilities in a non-unified state

² See, for example, Global Carbon Capture and Storage Institute Legal and Regulatory Indicator 2015, which provides a valuable summary and scorecard of the state of legislation across the world, though does not go into the details of specific laws. It confirms that the most developed legislation is to be found in Australia, both Commonwealth and States; the EU and Member States; some Canadian provinces, with Alberta the most developed; and the US, with a combination of some Federal laws, and state legislation in Montana, Texas, North Dakota, Illinois and Wyoming. GCCSI conclude however that despite these developments in the US "CCS is not dealt with in a fully-integrated, comprehensive manner at either the federal or state level"

³ Many would argue that the components of CCS are not 'new' in the ordinary sense, hence the second part of the sentence.

⁴ See for example, Moses L (2011) "Agents of Change: how the law 'copes' with technological change' 20 Griffith Law Review 4 , 763-796

- (iv) The issue of public engagement, and whether existing models of public participation in policy or project proposals are appropriate to CCS
- (v) Long-term liability issues, including the possibility of transfer of closed storage sites to the State, and the conditions of such transfer.

Developing these issues a little further,⁵ core issues that need to be considered in developing a regulatory regime include:

- Ownership and property issues including rights of access
- Compliance with relevant international law relating to offshore storage
- Competition with existing and future holders of petroleum rights
- Composition of CO₂ streams to be stored
- Third party access to transportation networks and storage sites
- Regulation of capture and transportation
- Regulation of site exploration and project authorization including public participation
- Inspection and monitoring requirements
- Regulatory enforcement tools and identification of regulatory authorities
- Post closure authorization, including monitoring obligations and financial contributions after cessation of operations
- Liability during operations and post closure, including provisions of financial bonds or equivalent and the issue of channelling liability on specific operators⁶
- Liability transfer post cessation
- Linkages with emissions trading regime or other economic incentives
- Linkages with enhanced oil recovery regimes

3.3.2 Five models of CCS regulatory framework

Five main models can be identified in the regulatory frameworks that have emerged to date, and examples will be given of each. The legislative option chosen often reflects particular natural political and policy assessments at the time of promotion. For government departments developing CCS legislation, securing legislative slots is

⁵ The IEA Framework IEA 2010. Carbon Capture and Storage Model Regulatory Framework. Paris: International Energy Agency. has identified 29 issues that need to be addressed. These are not repeated here, and the list here is a little different

⁶ Where liability for the escape of CO₂ under regulatory law is, for example, channelled onto the storage operator or owner of transportation networks, it is then left to the parties involved to share risks with other interests involved under commercial arrangements which will reflect the relative strength of bargaining positions.

often a very real and sometimes overlooked constraint, and political opportunism may sometimes influence the choice of model. The five models may be summarised as follows:

1. **Stand-alone legislation dealing with CCS as a technology requiring a distinctive regulatory regime but of general application.** In reality, such legislation will almost inevitably contain some linkages with other existing laws to a greater or lesser extent. The 2009 EU Directive (considered further below) is an example of a stand-alone law with a large focus on storage provisions,⁷ but deliberately amending existing regulatory regimes to handle capture and transportation, as well as environmental assessment and public engagement. Other examples would include the Greenhouse Gas Geological Sequestration Act 2008, Victoria, Australia dealing with on-shore CCS; and the Greenhouse Gas Storage Act 2009, Queensland, Australia. A 2013 report for the New Zealand Government advocated stand-alone legislation.⁸
2. **Stand-alone legislation confined to specific projects, research or demonstration sites.** For example, the Barrow Island Act 2003, Western Australia, is confined to one site; Gesetz zur Demonstration der dauerhaften Speicherung von Kohlendioxid, BGBl. 2012, Germany, was confined to demonstration projects.
3. **Adaptation or amendment of petroleum and gas regimes to incorporate the storage of CCS,** with examples including the Off-shore Petroleum Act 2006 as amended by the Offshore Petroleum Amendment (Greenhouse Gas Storage) Act 2008, Australia (off-shore, non-territorial waters); and the South Australia Petroleum and Geothermal Act 2000.⁹
4. **Mixed regimes involving effectively a stand-alone regime coupled with significant adaptation of provisions in existing legislation.** An example would be Alberta's Mines and Minerals Act amended in 2010 to include a new Part 9 dealing with CCS, dealing especially with tenure and transfer issues, together with amendments to the Oil and Gas Conservation Act providing additional regulatory powers relating to CCS.
5. **Using adaptations of existing environmental laws as a substitute for a dedicated CCS regime.** A good example would be the US EPA's development of a new class of wells, Class VI, under the authority of the Safe Drinking Water Act's Underground Injection Control (UIC) Program. This

⁷ As an EU Directive, the legislation contains minimum standards and obligations which must be transposed into national law. National law will flesh out procedural requirements, institutional arrangements, and enforcement tools, and will differ from country to country.

⁸ Barton et al (2013) Carbon Capture and Storage – Designing the Legal Framework for New Zealand. But for a counter-view that it is preferable to use existing well established resource management regulatory regimes see Severinsen (2014) 'Constructing a Legal Framework for Carbon Capture and Storage in New Zealand : Approaches to Legislative Design' Energy Procedia 63 6629-6661

⁹ This has been the practice to date, though Severinsen (supra) advocates adapting well-established resource management legislation in New Zealand rather than petroleum and gas regimes.

development and its particular focus reflects the division of Federal and State competences in the United States. Some State laws have been developed to clarify particular aspects of CCS.

Examples of each of these five legislative model types will now be presented and discussed in some more detail.¹⁰

3.3.2.1 Stand-alone legislation, requiring a distinctive regulatory regime but of general application – EU Directive 2009/31/EC

EU Directive 2009/31/EC was perhaps the first dedicated CCS legislation in the world, and was agreed within a reasonably short time-scale without undue political controversy. As a Directive its provisions were required under EU law to be transposed into the national law of EU Member States by 2011. The Directive does not oblige EU Member States to provide storage sites, and initially there was a legal dispute as to whether the storage provisions in the Directive still had to be transposed into national law even where a Member State was not intending to provide storage sites. It was eventually agreed by the European Commission that Member States were not obliged to transpose all the provisions, and could, for example, initially confine transposition to research or demonstration plants. By the time it came to transposition public concern in some countries had given rise to real issues of acceptability, while at the same time the costs involved, including the low price of emission credits under the EU emissions trading regime, had stalled any further development of demonstration plants within the EU. Only one permit has been awarded under the Directive (the Dutch ROAD project) but the project has not been implemented to date due to the economics (as discussed in Section 3.2.5).

The Directive covers the capture, transportation and the storage of CO₂, with core provisions focussed on the regulation of storage. A review of the Directive by the European Commission in 2015 (COM (2015) 576 final) concluded that the Directive was fit for purpose at the present time though the lack of practical experience precluded any robust judgment on its effectiveness. It was considered that reopening the Directive at this stage would only create greater uncertainty in a market that already lacked confidence in the technology.

It is possible, though, to criticise a number of features of the Directive which may not have assisted its subsequent implementation. It is arguable that it might have been preferable to confine the legislation to demonstration plants initially, learning from the experience before embarking on regulation of more general application.¹¹ Although a dedicated piece of legislation with distinct provisions relating to storage, it nevertheless in many areas builds upon existing EU legislation by adapting their provisions – capture provisions, and transportation are largely governed by amendments of existing laws. Public participation is included by amendments to

¹⁰ As is the usual practice in legal regimes, many of the details of the provisions in the primary legislation have been fleshed out in regulations. To preserve focus, we have not included reference to the regulations in this report.

¹¹ In relation to storage plants, this in effect is what has happened in some countries such as Germany where the transposition has initially been confined to demonstration plants.

existing laws on environmental assessment relating to more conventional projects, while it could be argued that in respect of what would appear to many to be a new technology something more imaginative was required rather than relying on existing models.

The EU legislation had the intention of providing both the regulation of risks and addressing commercial barriers, the latter being achieved by linking CCS to the EU emissions trading regime. The price of emission trading units had in fact collapsed by the time the directive came to be implemented, but by linking CCS to the system it also created enormous uncertainties for future liabilities in respect of leakages, in that the provisions had to account not just for the environmental consequences of a leakage but for liability in respect of emissions already credited, and estimated at a future unknown price, creating challenges for insurability.

Other potential problem areas have emerged, which again reflect the sensitivities in ensuring the legislation was passed without undue controversy. The conditions relating to the purity of the CO₂ stream are strict, and make combining EOR with CCS especially challenging. The conditions for eventual transfer of a closed CCS storage site to the State are also written in very tight language introducing a requirement to satisfy a level of scientific certainty of containment which on a strict reading would be very difficult to achieve.

It is worth mentioning that post Brexit, and assuming that the UK fully leaves the EU¹², the UK as a country still broadly supportive of CCS with offshore storage, would have the opportunity of reformulating its transposing regulations to create an improved legal regime.¹³

3.3.2.2 Stand-alone legislation confined to specific projects, research or demonstration sites – Barrow Island Act 2003

The Barrow Island Act 2003 (Western Australia) and amended by the Barrow Island Amendment Act 2015 is distinctive in that the law is confined to a single site, and essentially ratifies and authorises a joint venture project agreement between the State and four industries concerning gas processing and storage of carbon dioxide – the Gorgon Gas Processing and Infrastructure Project Agreement – which is contained in Schedule 1 of the Act. The Act provides for Ministerial authorisation of carbon injection, and amends provisions of the State’s legislation relating to the pipeline transportation of petroleum to accommodate the transportation of carbon dioxide. Post-closure provisions are included, but did not initially provide for liability transfer. These were provided by amendments introduced in 2015 which introduce an indemnity provision by the State to the joint venture in respect of common law liabilities in respect of acts or omissions carried out under the approval authority.

¹² The precise model remains uncertain. If the UK remained part of the European Economic Area (the ‘Norway model’) it would still be obliged to transpose the Directive

¹³ Examples would include introducing more flexibility into the liability transfer conditions, post-monitoring obligations, financial security and liability for emissions trading obligations. In addition the UK would no longer be bound by EU state aid requirements, giving more freedom to provide government finance.

The development of the site specific Barrow Island legislation - the first in Australia relating to carbon capture and storage - could be seen as a model of a law dealing with a new technology but essentially confined to a demonstration phase, thereby providing lessons in experience which could be valuable in the development of future, more general legislation on the subject. This could be its effect, but in reality the use of a joint venture agreement between commercial interests and the State, and subsequently ratified in legislation, is a familiar practice in Australian energy projects,¹⁴ and reflects the distinctive legal mechanisms for handling joint venture agreements in Australia between the state and private companies. Ratification by law removes any uncertainty about state powers to enter such agreements, and can also deal with issues requiring statutory authority such as the modification and acquisition of property interests, and the modification of existing legislation necessary for the venture.

3.3.2.3 *Adaptation or amendment of petroleum and gas regimes to incorporate the storage of CCS – Australian Offshore Petroleum and Greenhouse Gas Storage Act 2008*

The Australian Offshore Petroleum and Greenhouse Gas Storage Act 2008 dealing with offshore storage outside state territorial waters was developed by the Commonwealth government following consultation between government and industry. In its discussion paper the government considered various models including the development of stand-alone legislation as opposed to amendments to existing petroleum and gas law. There were concerns that stand-alone legislation could be cumbersome and inefficient, while at the same time it was considered that the operators in the petroleum and gas industry were most likely to be involved in CCS activities, and using a familiar regime with which there was considerable experience would be attractive. As the Explanatory Memorandum noted, "*Petroleum and greenhouse gas operations will in many respects be similar and the resources of the seabed and subsoil that the two categories of title-holders will seek to exploit have much in common*".¹⁵ Another attraction was that offshore petroleum law had recently been codified and modernized under the Offshore Petroleum Act 2006, legislation based on the Petroleum (Submerged Lands) Act 1967 but designed to be a "*more user-friendly enactment that will reduce compliance costs for the upstream petroleum industry and for the governments that are charged with administering it*".¹⁶ With such recently agreed legislation, there were clear attractions of amending it to include provisions concerning CCS and renaming the Act as the Offshore Petroleum and Greenhouse Gas Storage Act 2006.

Despite these clear attractions, there are potential disadvantages in adopting this method in that the petroleum industry may be seen to have too great an influence

¹⁴ For a comprehensive review and discussion of the rationale for such legal mechanisms see Hillman R 'The Future Role for State Agreements in Western Australia' (2006) 25 Australian Resources and Energy Law Journal 293-329;

¹⁵ Para 1 Explanatory Memorandum, Offshore Petroleum Amendment (Greenhouse Gas Storage Act) Bill 2008 C2008B00177

¹⁶ Para 2, General Outline, Explanatory Memorandum Offshore Petroleum Bill 2005

over legislation whose primary goal is concerned with greenhouse gas abatement. In this context, there was considerable controversy as to whether the Bill in its original form gave too much weight to the interests of existing petroleum license holders at the possible expense of CCS development. Complex amendments were introduced in an attempt to balance the interests involved, with holders of pre-existing titles to petroleum extraction receiving preferential treatment, where carbon storage operations may pose a significant risk of adverse effect, and effectively giving existing holders a veto over new storage operations. For non-existing titles granted after the legislation came into force, the legislation provides for a fairer balance, with greater power to the Minister to apply a public interest test in balancing the interests involved.

The other key issue that emerged was the question of long term liability. Originally the Bill made no provision for transfer of liabilities and/or indemnity post cessation of injection activity, on the grounds that the CCS industry should receive no special treatment different from other similar activities including oil and gas exploration. The Government, however, was persuaded to introduce amendments on the grounds that this in effect was a new type of technology involving potentially unknown risks, and that it would inhibit the development of a viable industry unless some special treatment concerning liability was introduced. In essence, the law provides that the Government will indemnify the operator for liabilities occurring after the end of the closure assurance period, and attributed to acts or omissions authorized by the relevant regulatory authority. If the operator has ceased to exist, the government assumes liability. Legislation in a number of Australian states has not provided a similar model of indemnity.¹⁷ The issue, epitomized in the debates on the Commonwealth legislation, raises important questions concerning the function of liability regimes, and the extent to which they provide an inducement to good regulatory practice, or whether the distinctive nature of CCS requires special treatment.

3.3.2.4 *Mixed regimes – a stand-alone regime coupled with significant adaptation of provisions in existing legislation – Alberta, Canada*

As with Australia, the divisions of powers between the Federal and State governments is an important factor in the design of CCS legislation in Canada. With the exception of trans-provincial pipelines, and some emissions reductions¹⁸, the development of regulations for capture, transportation and storage is a matter for

¹⁷ But the state legislation has provided that on surrender of a relevant licence, the stored greenhouse gas becomes the property of the state, appearing to imply legal responsibilities on the State for liability from that date. For a recent comprehensive comparative analysis of legal liability provisions with a focus on the EU Directive and UK transposition provisions, Alberta, and on Victoria, Australia see Havercroft I and Macrory R 'Legal Liability and Carbon Capture and Storage – A Comparative Perspective' Global Carbon Capture Storage Institute, July 2014.

¹⁸ For Federal performance standards concerning coal fired generation stations, see Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations 2012, made under the Canadian Environmental Protection Act 1999, and which came into force in 2015. The regulations include provisions relating to exemptions for plant involving carbon capture.

provincial competence. Without going into the details of the regulatory regimes the Alberta experience to date has a number of distinct features.

The legal technique was essentially a mixed approach in the adaptation of legislation involving two main laws. In 2010, significant changes to the Mines and Minerals Act and Oil and Gas Conservation Act were made to accommodate CCS. The amendments of the Mines and Mineral Act were largely concerned with issues of tenure, ownership of CO₂, and liability transfer provisions, while amendments to the Oil and Gas Conservation Act (OGCA) focused on regulatory controls. Amendments to the OGCA was chosen in preference to developing a new stand-alone regime because the regulator under OGCA already had extensive experience in regulating the disposal and injection of acid gas, and the injection and storage of CO₂ was considered to be a similar technology. Nevertheless, this apparent clear division between property and regulation could not be wholly sustained, and because of the liability transfer provisions, the Mines and Minerals Act contained provisions about monitoring and verification, while OGCA includes provisions on liability to ensure consistency with the Mines and Mineral Act. Different bodies enforce the provisions under the two Acts, containing the potential for overlap or conflict. In respect of petroleum interests, the legislation does not contain a balancing test as seen in the Australian Commonwealth legislation in respect of non-existing rights, but requires that approval may not be given unless the applicant “satisfies the Board that the project will not interfere with hydrocarbon production and storage interests.”¹⁹

The second distinctive feature in Alberta was the decision of the government to initiate in 2011 a wide ranging review of existing policies and regulatory structures to determine whether the regulatory structure was fit to handle full scale commercialization of CCS. The review, known as The Regulatory Framework Assessment, lasting over two years, was an ambitious multi-stakeholder process involving over 100 national and international experts, and four working groups (monitoring and verification, regulatory, geological, environmental), and is an exercise which has not yet been undertaken in any other jurisdiction. The review came up with 71 recommendations aimed at clarifying and improving regulatory structures.

The Quest project (discussed in Section 3.2.1.2) provided the first experience of a major CCS project going through the regulatory process. A public hearing in 2012 to deal with a number of unresolved issues involved five landowners, though interestingly no environmental organizations participated. The Energy Resources Conservation Board granted final approval under the Oil and Gas Conservation Act in September 2012. Full evaluation of the process and lessons to be learnt has yet to be undertaken, though it has been commented that the authorization says little

¹⁹ There is ambiguity as to whether this means only existing interests at the time of the application or can encompass future potential interests

about liability and financial assurance²⁰ – perhaps not surprisingly since this remains largely the province of distinct decision making under the Mines and Minerals Act.

3.3.2.5 *Using adaptations of existing environmental laws as a substitute for a dedicated CCS regime – the US Federal Underground Injection Control Program*

The division of federal and state competences in the US has meant that the development of CCS legislation at federal level has been fragmented. In respect of storage, in 2010 the US Environmental Protection Agency developed minimum requirements concerning underground injection of CO₂ under the authority of the Safe Drinking Water Act, with its underlying purpose to protect underground sources of drinking water.²¹ The rules²² build upon an existing framework of regulation concerning injection by adding a new Class VI well, handling CO₂ injection and storage, and covers permitting, siting, construction and operational activities, monitoring and testing, closure and financial responsibility. Although the storage of CO₂ is clearly presented by the Environmental Protection Agency in the context of greenhouse gas abatement policies, the distinctive legal focus on the protection of drinking water, dictated by legislative competence, has rather distorted the policy concern and many in industry have criticized the structure of the standard as being unwarranted.

EOR using carbon dioxide is a well-established industry in the US (as discussed in Section 3.2.2), and particularly complex issues have arisen concerning the overlap of Class II wells (storage of CO₂ associated with enhanced oil recovery) where there was already extensive experience, and the new Class VI standards. Uncertainties in the application and scope of the new legal requirements led to a lack of confidence by the existing EOR industry, until in 2015 the EPA issued new guidance²³ indicating when Class II wells did not require to transition into Class VI wells. This distinctive model for minimum storage standards, essentially determined by the US division between federal and state competences, is not one that has particular attractions, and despite the development of CCS laws in some States, has not helped the development of integrated CCS regulation with a focus on greenhouse gas abatement.

3.3.3 *Key Legal Issues for future consideration*

National legislation almost always reflects the distinctive legal, political and economic considerations that prevail in any particular jurisdiction, and CCS is no exception. As such there is unlikely to be a single perfect legal model, and existing CCS regimes that have been developed to date have adopted quite different approaches.

²⁰ Bankes N (2012) 'Quest. The Energy Resources Conservation Board Approves the First Commercial Scale Carbon Capture and Storage Project in Alberta' posted August 3 2012 University of Calgary ABLawg.CA

²¹ The EPA also developed mandatory reporting of greenhouse gas for specified industries together with certain performance standards under the Clean Air Act.

²² Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells

²³ Memorandum, EPA Director Office of Ground Water and Drinking Water 23 April 2015

Nevertheless there are a number of core issues that need to be addressed in the design of an effective CCS legal and regulatory regime:

- For those jurisdictions developing new CCS legal and regulatory regimes, it may be preferable to initially confine a new regime to specific projects, research or demonstration plants in order to learn from experience before designing legislation of general application.
- Where a jurisdiction already has a well-developed oil and gas regulatory regime, consideration should be given to adapting this regime to handle CCS rather than design stand-alone CCS legislation.
- CCS legal and regimes must address the issue of potential conflicts between CCS storage and petroleum interests, both existing and in the future. Careful balancing will be required to avoid undue constraint on the development of CCS technology
- In Federal regimes, the design of CCS legal and regulatory regimes may involve complex boundary between federal and state/provincial competences. Where devolved jurisdictions within a single Federal state develop CCS regulatory regimes, it is generally preferable to ensure as consistent an approach as possible, and appropriate mechanisms should be established to improve harmonization.
- In developing new CCS legal and regulatory regimes, it may be preferable to separate legislation dealing with environmental and safety requirements from provisions dealing with fiscal incentives for the technology.
- Where a CCS regime is linked to incentives under an emissions trading regime or similar market mechanism, careful consideration needs to be given to the construction of liability provisions should leakage occur, and the amount of any prior financial security provided. Given the long time scales involved, the low probability of significant leakage where there is an effective regime for site selection, and the difficulties of predicting future emission prices, unduly strict liability provisions may all too easily present an unacceptable fiscal disincentive.
- Existing legal and regulatory regimes for EOR have not generally been designed in the light of climate change mitigation. In the future, closer integration of EOR and CCS regimes could prove of value.
- The long time scales involved in CCS indicate that legal and regulatory regimes should provide for the transfer of responsibility of storage sites to the State at some point post-cessation of injection activities. The precise legal conditions for transfer and the extent of liabilities that are transferred in existing CCS regimes shows considerable variation, and their design requires particular attention.
- Evaluative and review procedures should be established to test the application of CCS legal and regulatory regimes, identify problem areas, and learn from experience.

Further, there is a challenge in providing sufficient legal certainty in order to attract commercial and public confidence, while maintaining sufficient flexibility to handle inevitable uncertainties and the long time scales involved. The timing and degree of regulatory intervention requires careful judgment to avoid stifling an emerging technology.

In summary, the design of a CCS legal and regulatory regime should not be seen as a static exercise, and needs to incorporate effective review procedures and adaptation mechanisms in order to learn from developing scientific knowledge and technical experience.

3.4. Discussion

CCS is currently operating in a number of large-scale projects in several different countries. For the most part, however, these are projects in which the commercial viability of the technology is helped by the fact that there is a value to the captured CO₂. The most obvious example is CO₂ used for EOR. In Boundary Dam 3 in Canada, as well as most of the planned projects in the US and China, EOR is a key part of the commercial viability of the project.

In several other applications, CCS can be seen to be under development or in operation because the incremental costs of it are relatively low, in comparison to the existing process to which it is being applied. This is particularly the case in gas processing. In Sleipner and Snøhvit in Norway, as well as the Gorgon project in Australia, the natural gas that is being extracted has a high CO₂ content, which has to be stripped out before the product can be sold. Thus a large part of the capture process is already undertaken in the existing commercial process, and the incremental costs of purifying the CO₂ stream, transporting and storing it are low because of the location and pre-existing infrastructure of the projects. Thus, only a relatively modest carbon price, or other relatively modest policy inducement, is required to persuade operators to inject and store the CO₂, rather than simply release it to the atmosphere.

Similar observations can be made about the hydrogen production industry, as in Tomakomai, Japan, Valero Texas, or Great Plains Dakota, and the coal-chemicals sector, which has been highlighted as a potential low-cost CCS sector in China. Both of these processes already involve the separation of CO₂, and so the addition of a complete CCS system for transport for EOR or for dedicated storage is a relatively small investment.

It is much more challenging, however, to deliver a large-scale CCS project in the power sector, especially in situations where no price-supported market exists for the premium electricity or no market is proposed for sale or utilisation of the captured CO₂. In recent years several such projects have stalled or been cancelled. Mongstad in Norway, White Rose and Peterhead in the UK, FutureGen in US have all been cancelled due to policy decisions to withdraw funding. ROAD in Netherlands was stalled for several years due to cash-flow problems. RWE withdrew its Cologne project citing lack of legal framework and lack of public acceptance.

Reiner (2016) notes that the period from approximately 2005 to 2009 was one of optimistic activity in the realm of CCS, with several countries launching relatively ambitious programmes of demonstration projects. However, the financial crisis of 2009 seems to have affected these CCS demonstration projects in a number of ways. Clearly, a major issue is the contraction in government budgets which have forced governments to look again at their spending priorities – the UK government in particular acknowledging that the cancellation of the CCS commercialisation programme was related to general expenditure saving. Reiner (2016) notes that ‘as each CCS ‘demonstration’ costs on the order of \$1 billion, during a time of fiscal austerity it has proved difficult to justify public support’. Although in certain cases – the EU and the US – additional funding has been found for CCS since 2009, as a result of the financial crisis, through recovery stimulus packages, in general the net effect seems to be less money available for CCS. A further possible effect, noted by Reiner, is that the economic slowdown resulting from the financial crisis reduced emissions, allowing countries more easily to meet such near term emissions targets as they had, and thereby reducing the perceived need for CCS. In the EU a further implication of the emissions plateauing as a result of economic slowdown was the halving of the price of EUAs, directly resulting in a halving of the money available in the NER300 fund.

In some cases, particularly Norway, cancellation of funding was related specifically to spiralling of costs in the project budget. This might suggest that mistakes had been made in the planning of the project, that the cost control during construction of the project was poor, that there were too many unknown factors at play in the circumstances of the project, or that the technologies had been too soon transferred from R&D to demonstration stage.

The question of when to scale up from R&D to demonstration is key. Reiner (2016) observes that ‘research and development on CCS is seen as having one of the highest median returns, which begs the question of why and when to demonstrate CCS options relative to continued R&D’.

On the other hand it could be argued that some overrun of budget is a necessary risk for any demonstration project, and that funders should be more tolerant of such an eventuality if and when it occurs. Some failure is inevitable, which needs to be acknowledged. In any case, the IEA estimate that by 2015, total cumulative global public and private investment in CCS projects in operation or under construction totalled around USD12 billion since 2005 (IEA, 2015c). This is much less than the subsidies received by some other low carbon technologies and, of course, fossil fuels. Reiner comments: ‘Much like basic R&D, demonstration requires tolerance of failure. At the scales discussed (~300 MW or 1 MtCO₂ stored), the stakes are high and costly early failures may reduce support for the technology... but the nature of demonstration implies the need to assume some risk by identifying innovative technologies that might have a higher potential for learning’ (Reiner, 2016). This can be difficult when both countries and rival trans-national corporations are essentially acting as individual entities, and the failure of a technology means wasted investment and losing out to competitors.

Technological innovation and cost reduction requires both learning from diversity – pursuing a range of technological options to allow the best ones to emerge; and learning from replication – producing more and more of the same technology to drive costs down through experience. ‘There are important trade-offs and complementarities between the two. Replication assumes a degree of clarity regarding where to place resources in the hope of driving down costs, whereas investments in diversity implies a spreading of bets in the hopes of resolving uncertainties’ (Reiner, 2016). Thus the two types of learning do to a certain extent pull in different directions. However it is clear that both types are needed, and the question is of balancing the benefits of further diversification against the benefits of picking a technology and moving towards replication. Once again, due to the sheer scale of CCS demonstrations, it is very difficult for countries acting in isolation to achieve much in terms either of diversity or replication. In relation to the current wave of demonstrations, Reiner observes ‘in the absence of widespread deployment of CCS, the projects that have endured do not form a coherent programme aimed at learning... There is a need for greater clarity over what time frame, at what scale, at what cost and to what end CCS demonstration is being pursued’.

Some have called for greater international collaboration and coordination on CCS, including transparency, knowledge transfer and cost sharing, along the model of ‘big science’ projects such as ITER and CERN (de Coninck et al., 2009, Georghiou, 1998, Victor, 2006). A key issue at stake here however is that several countries and jurisdictions, including for example the EU (EC, 2008), are internally promoting CCS with the argument of achieving competitive advantage for their own industries in a technology that will they suggest, in a future low-carbon world, be greatly in demand. It is not clear how easily such promises would sit with a highly internationally collaborative model, and they may indeed be a stumbling block towards it. However, whether CCS will be more effectively pursued through a competitive model, or through an internationally collaborative model for the ‘greater good’, is perhaps a question that deserves some consideration.

Reiner (2016) hints at a possible middle way – ‘rather than imagining some centrally conceived portfolio, there is a need for more negotiation across jurisdictions and accounting for what is going on elsewhere and learning from every stage of these other projects, both foreign and domestic’. For example, he continues, ‘if China were to aim to build a large-scale CCS project, should it choose a post-combustion coal project similar to Boundary Dam (learning by replication) or a gas-fired post-combustion or oxy-fuel coal plant (learning from diversity, assuming the UK is not going ahead with its projects)? How might China best reflect on what is needed globally and explicitly take into account projects in Canada, USA, Australia, Saudi Arabia and elsewhere (thereby strengthening international coordination)? Should greater emphasis be placed on learning about plant flexibility to improve understanding about operations and help de-risk the technology? Should it seek to demonstrate bioenergy plus CCS or an industrial CCS hub (further broadening learning by diversity)?’

Reiner (2016) also acknowledges that ‘unlocking private financing remains elusive and depends on developing necessary legal, institutional and commercial

frameworks...'. The EU's CCS Directive is an important step for level playing field harmonisation in this direction, dealing with issues such as site selection, monitoring and liability. Even with that, the experience from ROAD in Netherlands shows that arranging funded collaboration internationally is very difficult indeed, and is still restricted to the nations who are already active in CCS.

3.5. Conclusions

CCS technologies are available, viable and in several cases in commercial operation. Different manifestations of "CCS" are more or less successful. Policy reasons for CCS include: technological dominance, maintaining fossil fuel asset value, domestic energy security and, hardest of all, compliance with GHG goals for 2030 or 2050 as part of climate protection. The viability of current projects is particularly strong for low-cost industrial separation processes such as natural gas processing, or high purity CO₂ from hydrogen production. If there is commercial value for captured CO₂, such as in EOR, or sale for chemicals, food or agriculture use, this also provides helpful secure revenue.

Progress in fitting dedicated CCS to low-carbon power sector applications is much more elusive, and is favoured where local conditions are suitable, such as a restricted power market, or protection of a long-lasting low cost fuel source. Much clearer policy support is likely to be needed to move power demonstrations forward. There is also minimal progress in heavy industry applications such as steel and cement production, where again much clearer policy support will be required due to the increased costs that would be incurred by industries that applied CCS in such applications. In addition to direct price support, one of the key challenges is to reduce commercial risk, which is a major factor behind inflating the costs of projects.

Legal frameworks are also very important to support CCS, and clarity on these issues is also important for investor confidence. Alberta and Western Australia have successfully developed frameworks on a case-by-case basis for specific demonstration projects, and learned progressively from the requirements of these – rather than trying to develop from scratch a comprehensive legal framework to apply to all future projects, or trying to adapt existing legislation from other sectors, which may not always be suitable.

4. The role of CCS as part of a low carbon future

Key points

- Analysis of future climate mitigation scenarios – including comparisons of scenarios produced for this report with scenarios produced in other modeling exercises – provides robust evidence that if CCS were to become available on a large scale it could play an important role in meeting climate policy targets.
- The non-availability of CCS appears to make climate mitigation scenarios at best much higher cost, and at worst infeasible. In scenarios where CCS is not available, energy and material efficiency can help to reduce costs, and as such appears to be a key “no-regrets” option.
- In scenarios where it is available, CCS plays a significant but not dominant role in power sector decarbonisation – however its role appears much more critical in ‘hard-to-decarbonise’ sectors for which alternative mitigation options are very expensive or not available, such as heavy industry and manufacture of synthetic transport fuels for non-electrifiable transport modes.
- Bioenergy used in conjunction with CCS (BECCS) features significantly in a number of low carbon scenarios as a means of balancing carbon budgets with so-called ‘negative emissions’. Separate from the operation of CCS itself, the risks and uncertainties around the availability of large quantities of sustainable biomass is another key concern arising from this analysis.

This chapter considers the potential role that CCS could play in a future low carbon world, by analysing the outputs of modelling studies, including an original analysis produced for this report. Modelling of emissions pathways decades into the future does of course feature considerable uncertainties, especially around the availability and cost of technologies in future years. As such particular outputs of individual scenarios should in no way be considered firm ‘predictions’ of future outcomes. Nonetheless, by analysing the dynamics across scenarios, within and between different modeling platforms, robust insights into the nature and challenges of future emissions pathways can be found.

The chapter first reviews a range of previous modelling exercises that have presented global scenarios consistent with meeting long-term emissions reduction objectives, and considers the extent to which CCS features in these. We then present and analyse the results of new scenarios produced for this report using the TIAM-UCL global energy systems model. Within the analysis we consider the implications of these scenarios for the development and roll-out of CCS technology. In the final Chapter 5, we draw these modelling insights together with those from

previous chapters, to consider what policy conditions might need to exist, if technological pathways similar to those described in the scenarios were to be realised.

4.1. Review of existing scenario and modelling work

Modelling of future global emissions scenarios, for the purpose of analysing the potential impact of technology, policy and demand drivers on greenhouse gas emissions, is a well-established activity, now informed by decades of literature and experience, for example dating back to the IPCC's First Assessment Report in 1990. In this section we briefly review some recent modelling studies, and consider how CCS is placed within these, in order to provide some context to our own modelling results that follow in subsequent sections.

WBGU (2011) provides a meta analysis of scenarios produced by global modelling studies. In the table reproduced as Table 4.1, below, the cumulative emissions to 2050 of the various scenarios reviewed by WBGU are shown. The authors also calculate the probability of such scenarios exceeding 2°C, with and without the contribution of CCS, where the comparison is available. 9 out of the 14 scenarios reviewed include a role for CCS. Of the 9 scenarios that feature CCS, the smallest amount of CO₂ captured cumulatively between 2000 and 2050 is 59 Gt, the largest 310 Gt.

Table 4.1: Comparison of cumulative CO₂ emissions, contribution of CCS and probability of exceeding 2°C, in selected mitigation scenarios reviewed by WBGU. Carbon prices in US\$ per t CO₂-eq Source: WBGU (2011), based on original sources.

No.	Model, scenario name	Cumulative CO ₂ emissions from fossil sources 2000–2049 [Gt CO ₂]	Probability of exceeding 2°C without CCS [%]	CCS by 2050 [Gt CO ₂]	of which bio-CCS [Gt CO ₂]	Probability of exceeding 2°C with CCS [%]	Average growth rate of renewable energies 2010–2050 [%/year]	CO ₂ prices	
								2030	2050
(1)	MESSAGE, GEA Efficiency	1,496	56	192	4,6	40	3	23	60 [§]
(2)	MESSAGE, GEA Mix	1,391	47	92	4,6	40	3.5	67	177 [§]
(3)	MESSAGE, GEA Supply	1,444	52	259	4,6	34	3.5	53	140 [§]
(4)	IMAGE, RCP 3 PD	1,434	51	164	102	33	3	86	165
(5)	REMIND, RECIPE	1,455	51	77	35	43	4.4	22	92
(6)	REMIND, Adam	1,229	36	172	92	24	4.5	49	75
(7)	MERGE, ETL Adam	1,345	43	83	33	36	2,1	14	45
(8)	MARKAL, ETP Blue	?	?	59			3.6		
(9)	POLES, Adam	1,144	42	310	32	16	3.2	35	135
(10)	MESSAGE, WEC C1	1,138*	53				2		
(11)	MESAP, Energy [R]evolution 2008	?	?				3.7	30	50
(12)	MESAP, Energy [R]evolution 2010	1,107*	50				3.5	30	50
(13)	MESAP, Advanced Energy [R]evolution 2010	970*	38				4.1	30	50
(14)	WBGU	1,017*	41				4.8		

*Note on table: The authors clarify that “the scenarios marked with an * do not include all anthropogenic CO₂ emissions. Non- CO₂ greenhouse gases and land-use related emissions were not taken into account in these scenarios. Emissions from international air and maritime traffic, fugitive emissions, and process-related emissions from the industrial sector are also not included in some of the marked scenarios. To include the shares that were not taken into account (which is necessary in order to determine the probability of exceeding 2°C), corrective factors were used, based on the relative contributions of these activities in 2005. The probabilities of exceeding 2°C were calculated with the aid of the ‘2°C-Check’ tool from the supplementary material accompanying the publication of Meinshausen et al (2009)” (WBGU, 2011).*

5 of the 14 scenarios reviewed by WBGU (scenarios 10-14) avoid the use of CCS. Figure 4.1, below, compares the primary energy consumption of the scenarios by energy carrier, which offers some insight into how the non-CCS scenarios achieve their emissions reductions. The 5 non-CCS scenarios are those represented by the columns furthest to the right. These scenarios have substantially lower energy use in 2050 than most of the others – indeed they imply a stabilisation or reduction in primary energy demand compared 2010 levels. This would suggest very high levels

of energy efficiency given anticipated global population growth and increasing affluence. They also show considerably greater rates of growth in renewable generation, and reduced oil consumption – suggestive of greater electrification in the transport sector.

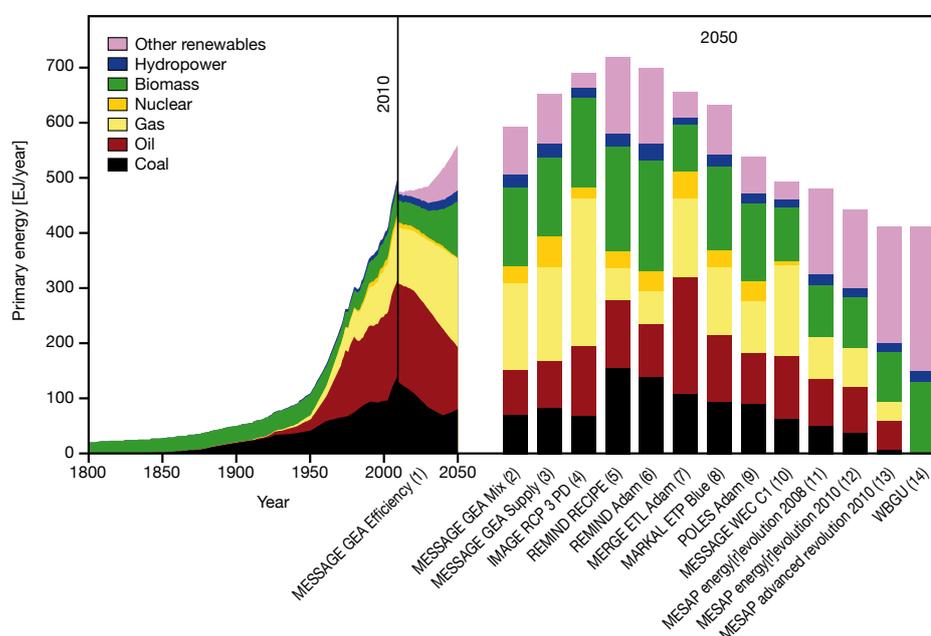


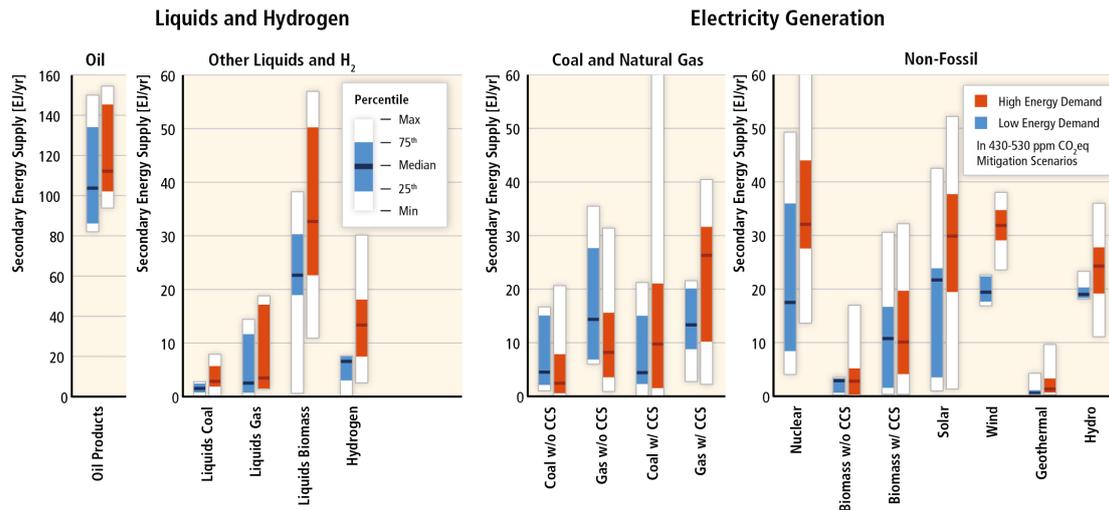
Figure 4.1: Global primary energy demand in selected scenarios reviewed by WBGU (2011), by energy carrier. Source: WBGU (2011) based on original sources.

Note on Figure: Appears as Figure 4.2-4 in WBGU (2011). The period 1800 to 2008 shows historical energy demand. The area graph from 2010 to 2050 shows the results of the MESSAGE GEA Efficiency scenario. The remaining columns show the 2050 snapshots of the remaining scenarios reviewed.

However, it is important to put these results in context; carbon budget stringency under the AR5 is typically more stringent than those budgets stated here (Rogelj et al., 2016). In addition, these types of budgets imply significant levels of negative emissions in the 2050-2100 periods, given that budgets to 2100 tend to be smaller than those to 2050 due to the incorporation of negative emission technologies (and accounting) in integrated assessment models (Rogelj et al., 2015).

A more recent meta analysis is summarised in Figure 4.2 and Figure 4.3, which present results from the IPCC’s review of global modelling results in the Fifth Assessment Report. Figure 4.2 shows activity levels of different technologies, including CCS, across scenarios that reach about 450-500 (430-530) ppm CO₂-eq concentrations by 2100. CO₂-eq concentrations of 450 ppm in 2100 would be considered “likely” (with a probability greater than 66 percent) to keep temperature rise below 2°C relative to the period 1850-1900. CO₂-eq concentrations of 500 ppm in 2100 would be considered “more likely than not” (probability greater than 50 percent) or “about as likely as not” (probability of 33-66 percent) to stay below a 2°C rise, depending on whether or not CO₂-eq concentration levels temporarily exceed 530 ppm before 2100 (see IPCC (2014), Section 3.4 and Table 3.1).

Comparing the median values and ranges of annual electricity supplied in 2050 suggests that across the models, CCS tends to have a significant, though not necessarily dominant role in the power sector, in comparison to other major low carbon electricity generation types such as nuclear, solar, wind and hydro. Across all technologies, high-demand scenarios tend to require greater and faster roll-out than low-demand scenarios, emphasising the importance of demand-side assumptions in scenarios. Biomass with CCS also features fairly consistently, with median values of electricity production in 2050 of about 10 EJ for both high and low energy demand scenarios.



1	2	3	4
High energy demand scenarios show higher levels of oil supply.	In high energy demand scenarios, alternative liquid and hydrogen technologies are scaled up more rapidly.	High energy demand scenarios show a more rapid up-scaling of CCS technologies but a more rapid phase-out of unabated fossil fuel conversion technologies.	In high energy demand scenarios non-fossil electricity generation technologies are scaled up more rapidly.

Figure 4.2: Activity levels of selected energy supply technologies, in terms of secondary energy supplied (EJ/yr) in 2050, for mitigation scenarios reaching about 450-530 (430-530) ppm CO₂e concentrations by 2100. Blue bars indicate 'low energy demand' scenarios (<20% increase in final energy demand in 2050 from 2010), red bars indicate 'high energy demand' scenarios (>20% increase in final energy demand in 2050 from 2010). Each technology bar shows median, interquartile and full deployment range. Source: Edenhofer et al (2014)

However, electricity generation is not the only sector in which CCS can be applied – its role in reducing emissions from industry and in achieving negative emissions in combination with biomass may also be critical. Thus an assessment of the importance of CCS to decarbonisation is likely to require looking beyond the electricity sector to the whole system. The degree of importance a particular technology has within a future low carbon system can also be considered in terms of the effect on the system of its lack of availability. Figure 4.3 depicts the effects on mitigation scenarios of limiting or excluding different technology types, showing the percentage increase in mitigation costs relative to the default technology assumptions in each scenario. Particularly high cost increases are found in scenarios when CCS is excluded, as well as when bioenergy is limited, with still higher costs when these conditions are combined with more stringent mitigation scenarios. When CCS is excluded, the median percentage increase in mitigation cost for 550 ppm scenarios is 39, with a range of 18-78; for 450 ppm scenarios the median is 138 with

a range of 29-297²⁴. The total number of no-CCS 450 ppm scenarios on which this latter range and median is based, is only 4 – reflecting the fact that many of the models were not able to produce a scenario under these constraints. In another meta analysis of the IAM scenarios that were produced for the IPCC’s 5th Assessment report, Peters et al (2017) comment that ‘without large scale CCS, most models cannot produce pathways consistent with the 2°C goal’.

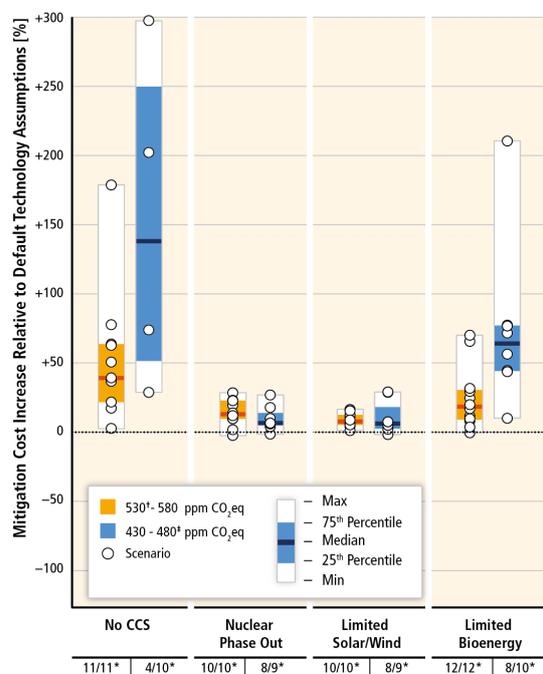


Figure 4.3: Percentage increases in net present value mitigation costs (2015-2100) as a result of various technology constraints, in comparison to the default technology assumptions. Source: Edenhofer et al (2014)

Dessens et al (2016) review a wide range of modelling studies and inter-modelling comparisons, including those presented in the IPCC AR5. They find that renewable technologies typically account for the largest share of electricity generation by 2050, with the share of electricity generation from CCS ranging from 8 to 32 percent. These shares are influenced by assumptions on the year in which CCS becomes available, and deployment rates of renewables. However the role of CCS often becomes more important in the second half of the century, especially in scenarios with stringent targets or overshoots, which may require BECCS to achieve negative emissions (Dessens et al., 2016).

Figure 4.4 shows interquartile ranges of the carbon prices of the 450ppm scenarios reviewed by Dessens et al, in various scenario years. The right hand panel shows only “optimal” 450 ppm scenarios, with early adoption of mitigation policy and availability of all technologies, whereas the left hand panel includes all 450 ppm scenarios. The figure suggests that early adoption of mitigation policies and full technological availability are important for keeping costs down.

²⁴ The ranges quoted here encompass the 16th and 84th percentile of the scenario set. This is not the same range shown by the coloured bars in Figure 4.3, which is the inter-quartile range.

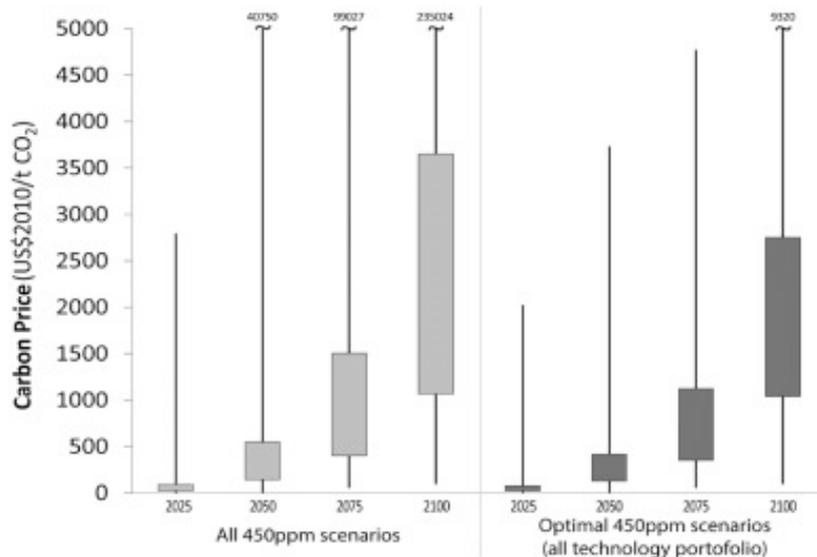


Figure 4.4: Carbon price for 450 ppm scenarios reviewed by Dessens et al (2016) for 2025, 2050, 2075 and 2100 in US\$2010/tCO₂. Left panel: all 450 ppm pathways; right panel: optimal full-technology 450 ppm scenarios only. Source: Dessens et al (2016).

More specifically, Figure 4.5 depicts the effect on costs and feasibility of placing certain technological restrictions upon 2°C scenarios. The figure shows the following groups of technological restriction: no CCS; EERE (low energy intensity, high renewable and neither CCS nor nuclear); Conv (conservative renewable availability); LowBIO (low biomass availability); LowSW (low solar and wind penetration); NoNuc (no nuclear); LowEI (low energy intensity). For each group, percentage changes in cost relative to the default scenario (inter-quartile range, median and full range) are shown. The position of each group along the x axis represents a measure of feasibility, calculated as the proportion of scenarios able to solve for 2°C targets from the total number in the group.

The median increase in total discounted costs from excluding CCS is 138 percent, and from limited access to bioenergy the median increase is 64 percent. By comparison the median increase in costs from phasing out of nuclear is 7 percent, and of limited access to solar and wind, 6 percent. The feasibility measure of no-CCS scenarios is also much lower than in other groups, with only just over 40 percent of scenarios with that constraint able to solve for 2°C targets.

Reductions in energy intensity and hence in energy demand can reduce total costs below the default level for some scenarios (Low EI). Demand reduction can also contribute considerably to reducing the costs associated with unavailability of CCS (EERE).

2°C scenarios: technology sensitivity

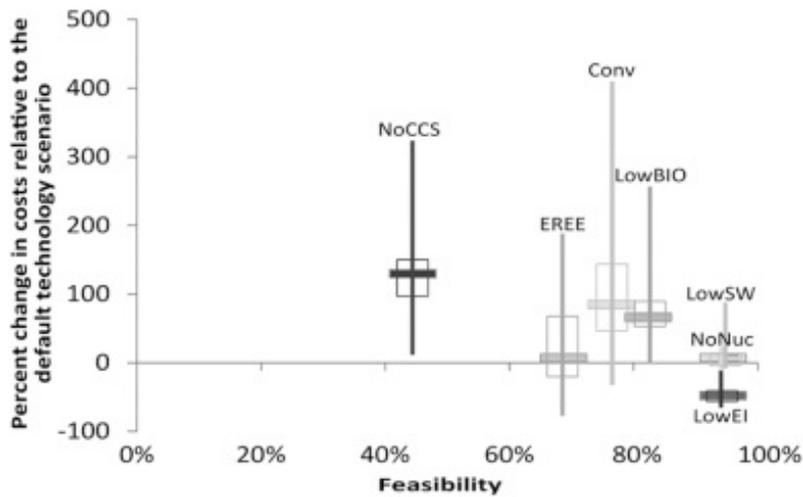


Figure 4.5: Sensitivity to technological restriction of total discounted cost (median, inter-quartile range, and full range) and feasibility of 2° scenarios extracted from the AR5 database

Akashi et al (2014) report in more detail on one modelling study, using the AIM/Impact [Policy] and AIM/Enduse [Global] models, to explore the effects of excluding nuclear and CCS from 2°C scenarios over a mid-term perspective (to 2050). Figure 4.6 summarises key results from their scenarios, showing 2005 values along with 2050 values for: a 'Baseline' scenario (no climate policy); a '50% default' scenario (reducing global GHG emissions to 50% by 2050 compared to 1990 levels – equivalent to a 2° C pathway); a '50% nonucccs' scenario (as the previous scenario but with no new nuclear and no CCS); and a '50% nonucccs&mef' scenario (as the previous scenario but with improvements in material efficiency). It is important to bear in mind that while these scenarios are consistent with a 2°C pathway as far as 2050, they do not explore the pathway for the remainder of the century, as is done by other scenarios reviewed by Edenhofer et al (2014) and Dessens et al (2016). Akashi et al (2014) find that a 2° C pathway to 2050 excluding both nuclear and CCS is technically feasible, but with increased cost (as shown in Panel f of Figure 4.6). The 'nonucccs' scenario requires substantially reduced overall energy consumption, and a greater contribution from power generation (as shown in Panels b and c of Figure 4.6).

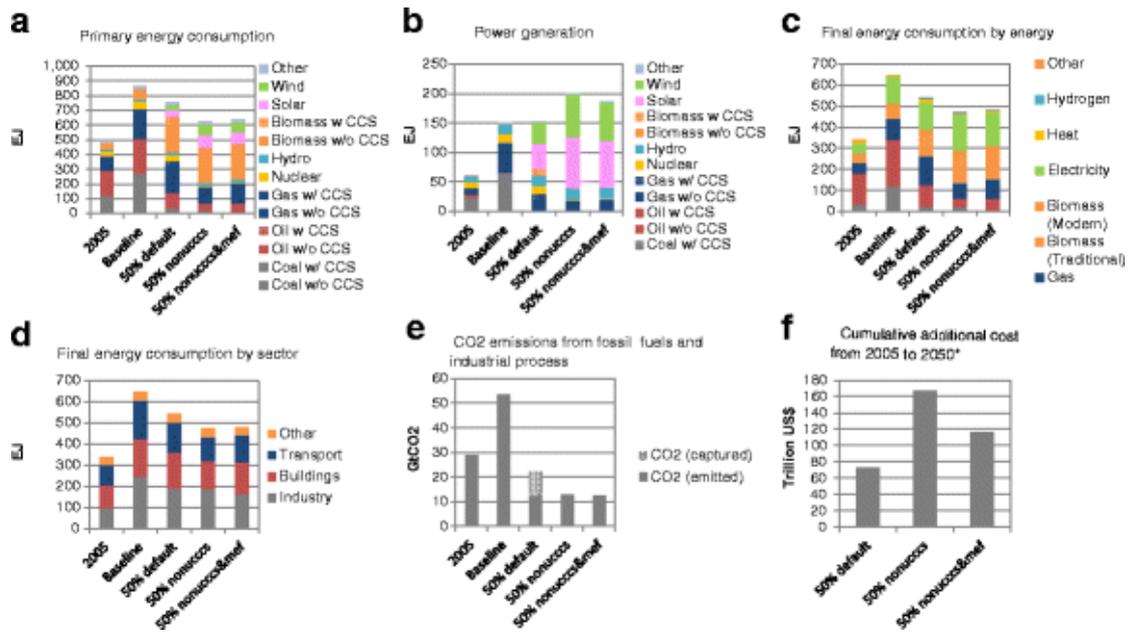


Figure 4.6: Summary of scenarios reported by Akashi et al (2014). Energy consumption and CO₂ emissions in 2005 and 2050 and cumulative cost from 2005 to 2050

Comparing sectoral emissions of the ‘50% default’ and ‘50% nonucccs’ scenarios shows that without nuclear and CCS, emissions are increased in power generation, steel and cement sectors (Figure 4.7). In the steel and cement sectors this reflects the lack of other options to replace CCS in reducing emissions from these processes. In power generation the effect of the lack of availability of negative emissions from BECCS is clearly seen. By comparison, the reduction in availability of nuclear power has a smaller impact, as it can be more readily replaced in the generation of low carbon electricity by other sources, such as renewables.

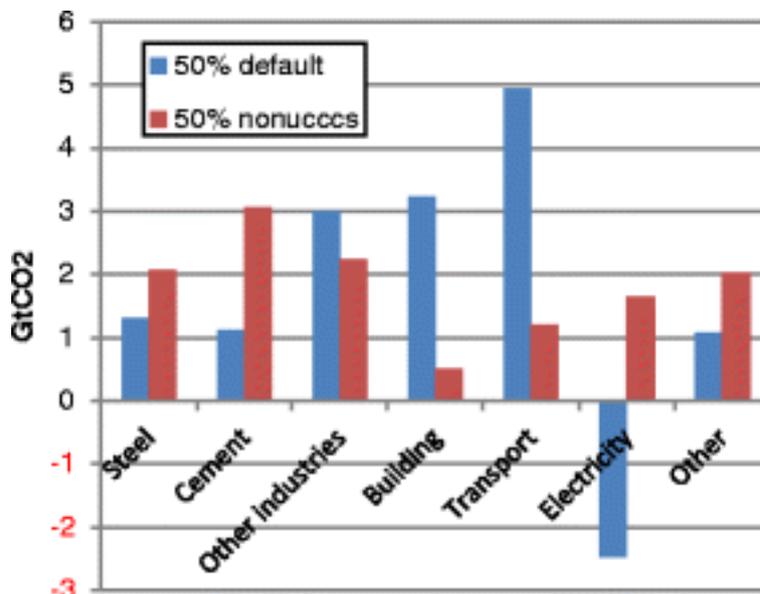


Figure 4.7: Sectoral breakdown of CO₂ emissions in ‘50% default’ and ‘50% nonucccs’ scenarios. Source: Akashi et al (2014)

The increased emissions in the power, steel and cement sectors are compensated for by even more stringent reductions in other sectors, particularly transport and

buildings (Figure 4.7), where the two key measures are increased electrification and increased energy efficiency (Figure 4.8). Increased stringency in these sectors is the main factor behind the increased cost of the 'nonucccs' scenario.

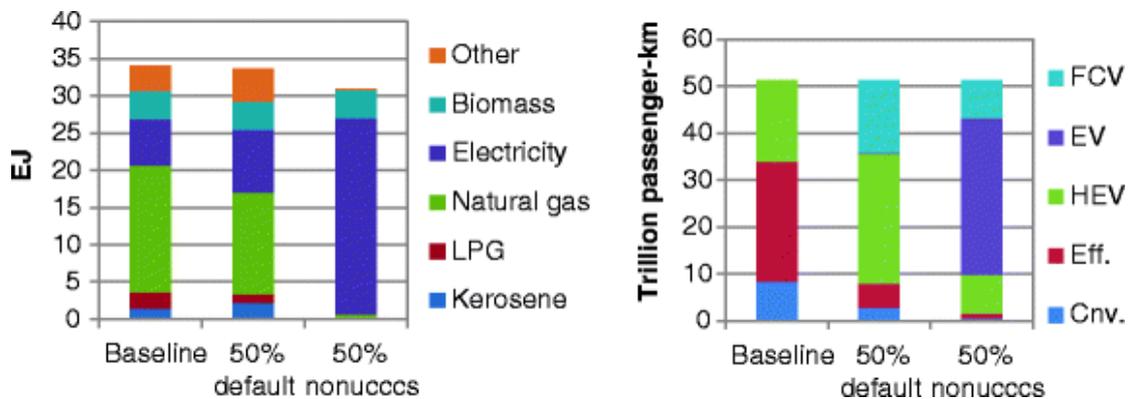
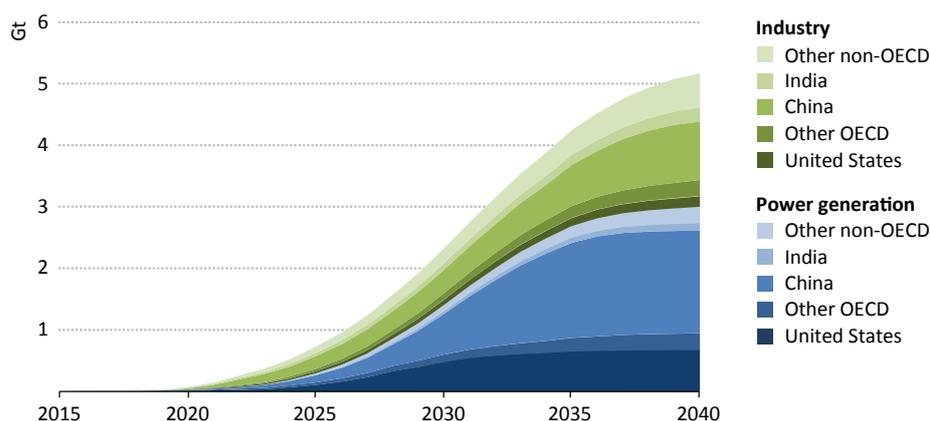


Figure 4.8: Energy demand by energy vector for space heating (left hand panel) and passenger vehicle-km demand by vehicle technology (right hand panel) for 'Baseline', '50% default' and '50% nonucccs' scenarios

Akashi et al (2014) also explore the effect of increased material efficiency on reducing material and energy demands in the cement and steel sectors. They find that these measures can reduce CO₂ emissions from steel and cement by 56 percent and 45 percent respectively, compared with the baseline scenario. When applied to the 'nonucccs' scenario, these measures curb the emissions of the steel and cement sectors in the absence of CCS, reducing need for other more expensive technological options in other sectors. As a result the total cost of the 'nonucccs&mef' scenario is US\$ 52 trillion less than the 'nonucccs' scenario (Figure 4.6, Panel f).

Other modelling studies also suggest that CCS has a critical role in emissions reduction due to its role in industry, and, in combination with bioenergy, in producing negative emissions (van Vliet et al., 2014, Kriegler et al., 2014, Krey et al., 2014). Without CCS and bioenergy in particular, achieving stringent emissions targets becomes more expensive, and in some cases infeasible. This contrasts to restrictions on the availability of low carbon power generation technologies such as nuclear, wind and solar, which have a relatively small impact due to the higher availability of alternative technologies to substitute for them (Krey et al., 2014).

In its Special Report on Energy and Climate Change (IEA, 2015a), the IEA presents a 450 Scenario, showing a global technology pathway to 2040 consistent with stabilisation of GHGs in the atmosphere at 450 ppm, itself giving a 50% chance of keeping temperature rise below 2°C. IEA notes that 'CCS technologies are vital to decarbonising the power supply and industry in the 450 Scenario, capturing 52 Gt CO₂ from 2015 to 2040, of which 5.1 Gt CO₂ is in 2040'. CCS is found to be 'an important part of mitigation action in China and the United States, and to a lesser extent in India and the Middle East', while several other countries in Asia-Pacific, Europe and Latin America may also need to rely on CCS to achieve required emission reductions (Figure 4.9).



Note: Industry includes the following sectors: steel, cement (energy- and process-related), chemicals and paper production; oil refining; coal-to-liquids, gas-to-liquids and natural gas processing.

Figure 4.9: CO₂ captured in the IEA 450 Scenario by sector and region. Source: IEA (2015a)

The scenario assumes cost reductions for CCS technology based on a learning rate of 11%. 60% of CCS investment in the scenario is in the power sector, the remainder in industry. The total capacity of power plants installed with CCS increases at a rate of around 20 GW per year through the 2020s, and at over 50 GW per year in the 2030s, reaching a global total of 740 GW in 2040, which constitutes 20% of fossil fuelled generation capacity at that point. United States and China account for 80% of power sector CCS installations in the scenario in 2040.

In industry, most CCS capacity is installed in non-OECD countries, 'led by China, India, Russia and the Middle East, with lesser amounts in OECD countries, led by the United States and Europe.' The scenario sees a capture rate in industry of 2 Gt CO₂ per year in 2040. This is led by the cement sector (1 Gt), followed by iron and steel (0.5 Gt) and chemicals (0.3 Gt). Around half of global cement and steel production is fitted with CCS in 2040, as well as a large share of chemicals production (IEA, 2015a).

4.2. Our modelling – the structure of the model, and the scenario inputs

The next two sections of this chapter discuss a modelling exercise carried out within the TIAM-UCL model, for this report.

4.2.1 The model – TIAM-UCL

TIAM-UCL is a global partial-equilibrium energy systems model which maximises total welfare to determine lowest cost pathways for the energy system over the coming century, under sets of imposed constraints, such as global or regional emissions reduction targets. The model is linked to a climate module which allows consideration of effects such as radiative forcing and temperature change that are associated with each energy pathway. It is an established international model that

has been used to explore many different decarbonisation pathways (for example, see Kesicki and Anandarajah (2011), McGlade and Ekins (2015), Pye et al. (2016)).

The model provides a technology-rich representation of the energy system, encompassing all the various energy processes from resource extraction to technology production and through to final energy demand. It models all of the main primary energy resources such as coal, oil, gas, biomass, nuclear, wind and solar as well as many other important technologies. Technological progress tends to be assumed in an exogenous manner as improved efficiency and new technologies come on line in later time periods, often at reducing cost. The model runs to 2100 across 16 world regions including China, USA and Europe, with regional and global energy supply and demand balancing. These regions are linked through trade in resources such as crude oil, pipeline gas, LNG and biomass.

The sectoral structure of the model includes upstream and electricity production, and 5 end use sectors - residential, commercial, agriculture, transport and industry. All reflect the current system in each region. The electricity sector includes all central electricity and heat production including combined heat and power (CHP), while the upstream sector includes fossil fuel resources and extraction processes, renewable potentials, and various fuel transformation processes including petroleum refineries.

Each of the energy end use sectors has its own set of final energy service demands e.g. heating and cooling in the residential sector. In total, each region has 42 final energy service demands to meet across these sectors.

CCS applications are available in the following sectors – electricity and heat production, hydrogen production, biofuel production (via Fischer Tropsch processes) and industry for combustion emissions from process heat production in iron and steel, non-metallic minerals and other industry sub-sectors. There is also a CCS technology that captures CO₂ process emissions from the use of petrochemical feedstocks. Biomass in TIAM-UCL, which can be used in combination with CCS to generate so-called ‘negative emissions’, is assumed to be carbon neutral, and while land-use is considered here, there is no competition with other uses such as food production – such an analysis would require a general equilibrium setting.

Energy demands are exogenous to TIAM-UCL and are affected by drivers such as GDP and population. Central growth assumptions are used to drive energy demand growth. Population reaches 9.5 billion people in 2050, and 10.8 billion in 2100, based on UN estimates. GDP is assumed to grow from \$50 trillion in 2010 to \$155 trillion in 2050 and \$350 trillion in 2100, putting GDP growth in the middle of the SSP range (Riahi et al., 2016). Further details on the general TIAM model structure and assumptions are available in Anandarajah et al. (2011).

4.2.2 *The scenarios*

In our analysis we implement six separate scenarios in the model, shown in Table 4.2. There are three scenarios which have different temperature/emissions targets with standard central CCS model assumptions – INDC, 2°C and 1.5°C. We also implement three scenarios, all for the central 2°C temperature target, and vary the

CCS assumptions. These include High CCS costs (high costs, increased growth constraints), Low CCS cost (low costs, decreased growth constraints) and No CCS.

Table 4.2: Scenario grid

	INDC	2°C	1.5°C
Standard CCS cost	✓	✓	✓
High CCS cost		✓	
Low CCS cost		✓	
No CCS		✓	

The INDC scenario assumes that all INDC (or NDC)²⁵ commitments from the Paris agreement are implemented in our model resulting in global GHG emissions of around 53 Gt CO₂e in 2030. Beyond 2030 the INDC scenario assumes there is no increased ambition and that each country (aggregated to TIAM-UCL regions) keeps their emissions per capita at 2030 levels. The other two temperature constrained scenarios apply global temperature constraints (using TIAM-UCL’s climate module) to achieve specific average increase in temperature limits of 2°C and 1.5°C in 2100 respectively. Note that such limits do allow for overshoot in the temperature limits prior to 2100.

These three emissions scenarios all assume the standard CCS costs for power and industry which are held in our model, as detailed by Anandarajah et al (2011). These are aligned with the central assumptions in Rubin et al. (2015) for power generation. Costs and other parameters for power sector CCS are shown in Table 4.3.

Table 4.3: Cost and efficiency penalty assumptions by power generation type. Costs differentials between plant with and without CCS were taken from Rubin et al. (2015), with biomass plant aligned to coal. A capture efficiency of 90% is assumed for all plants, and held constant over time.

Plant type	Investment cost (\$2005/kW)			Cost adjust. factor		Efficiency penalty	
	2020	2030	2050	High	Low	2010	2050
Coal IGCC	3756	3521	3286	118%	87%	8.5%	6.0%
Coal USC	4249	3983	3718	109%	87%	9.0%	7.0%
Gas CCGT	1773	1662	1551	127%	69%	8.5%	6.0%
Biomass	4216	3952	3689	109%	87%	9.0%	7.0%

We then run a High CCS cost scenario that assumes the highest cost in the range for investment and fixed O&M costs for power generation CCS. This is between 10-25% higher than the central cost assumptions depending on the power technology. For industry and fuel production sectors the high cost sensitivity assumptions are on average 20% higher than the central case, reflecting similar cost increase assumptions to those of the power sector. For the Low CCS cost case, power generation costs are between 15-25% lower than the central scenario, and 15% lower for non-power technologies. In addition, these scenarios were also given alternative growth rate constraints on the deployment of CCS, which are intended to

²⁵ INDCs are now NDCs for those countries that have ratified the Paris Agreement. At the beginning of 2017, this stood at 121 out of the 194 signatories (http://unfccc.int/paris_agreement/)

encompass other factors (implicitly) such as policy inertia, supply chain constraints and problems with social acceptance. As a rule of thumb, annual growth rates in deployment were increased (in the low cost) or reduced (in the high cost) by 50%. In this model growth rate constraints are not linked to cost assumptions as the model does not have endogenous technical learning. There is also a No CCS scenario which simulates a 2°C target case without CCS technology in any sector.

4.3. Modelling results and analysis

4.3.1 Total CO₂ capture across CCS scenarios

Figure 4.10 shows the impact of CCS in the three main scenarios in which it is deployed, in terms of Gt CO₂ captured annually, by CCS process sector. For this and other results that follow, the cost sensitivity cases can be found in Appendix A.1. The four sectors to which CCS is deployed include power and heat generation, hydrogen production, industry (iron and steel, non-metallic minerals and other industry) and biofuel production (Fischer Tropsch).

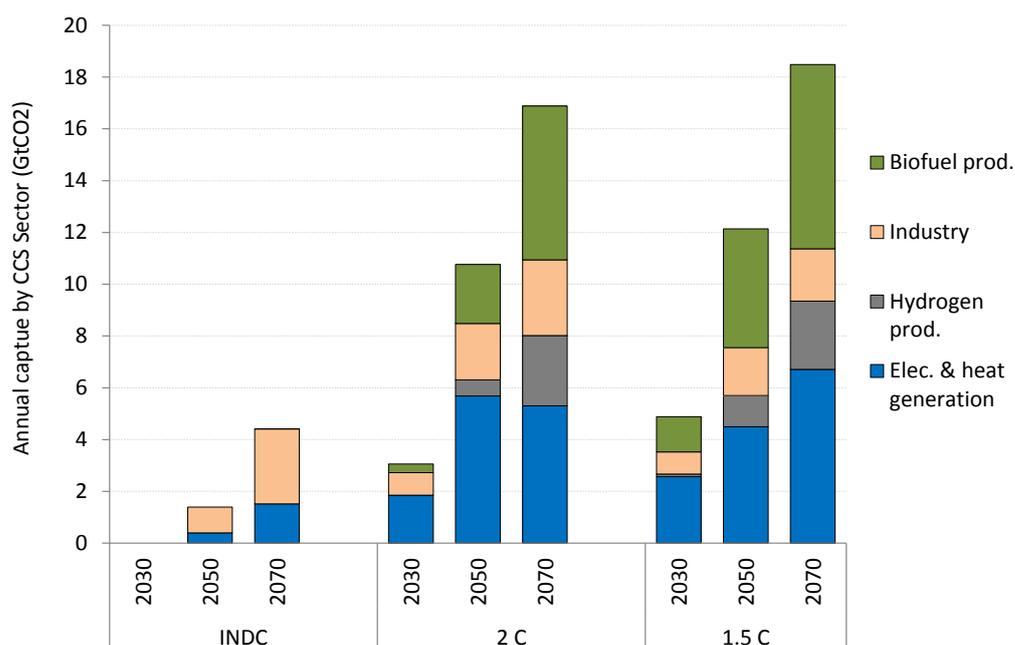


Figure 4.10: Annual capture by CCS sector (Gt CO₂) across selected scenarios in which CCS is deployed, in years 2030, 2050 and 2070

In the INDC scenario, CCS is deployed in both power and industry sectors, but only at relatively low levels, and much later than in higher ambition climate scenarios. Total annual CO₂ capture in the INDC scenario is 1.4 Gt in 2050 and 4.4 Gt in 2070. Whilst these levels of capture appear small relative to the higher ambition scenarios, as absolute numbers they are still considerable. The current projects reviewed in Chapter 3 are typically capturing in the range of 1-3 Mt of CO₂ per year per project – it would therefore require thousands of such similarly sized projects to reach the levels of capture in the INDC scenario.

The 1.5° C scenario reaches much higher levels of capture, and much earlier. Across all sectors, it already captures 4.9 Gt of CO₂ in 2030, rising to 12.1 Gt in 2050 and 18.5 Gt in 2070. The largest sectors are electricity and heat generation and biofuel production, though substantial capture is also made in industry and hydrogen production.

The 2° C scenarios follow a similar trajectory to the 1.5° C scenario, though with slightly lower overall capture. By 2070 in the standard 2° C scenario, total annual capture is 16.9 GtCO₂. The range of total capture across the three 2° C scenarios is 16.1 Gt (high CCS cost) to 17.3 Gt (low CCS cost) (see Appendix A.1, Figure 6.1). Alternative cost assumptions thus have only a small effect on the total amount of CCS deployed. This implies that to meet high ambition climate scenarios, a cost optimal pathway would choose CCS in similar quantities, whether its full-chain cost was near the high, or the low end of current projections. This relative lack of sensitivity to CCS cost assumptions reflects the fact that the model finds this variation in cost to be much less than the additional cost that is incurred from not having CCS at all.

It is interesting to note that whereas in the 2°C scenarios the level of capture in the industry sector increases steadily all the way out to 2070, in the 1.5°C scenario the level reaches a peak in 2050 and then remains broadly constant between 2050 and 2070. This is because the higher marginal costs are bringing other industrial options into play, such as electrification. This is one of the factors that causes overall levels of electricity demand to be higher in the 1.5° scenario (as shown in Figure 4.11). The electrification of energy supply in industry, including to some extent in the energy intensive sectors, means less CCS is required. For example, the level of electricity use in the iron and steel sector in 2070 is double relative to that observed for the same period in the 2°C case. CCS is still critical in the 1.5°C scenario – as noted the scenario has the highest levels of overall capture. However, as well as providing more electricity, the additional capture comes from the production of synthetic low carbon fuels, which are now particularly valuable for demands for which electrification options are not available, such as long distance and freight transport.

It is also insightful to consider the cumulative CO₂ capture under these scenarios, provided in Table 4.4. Under the 2°C case, it is interesting to note that the amount of CO₂ captured is at a level equivalent to the entire CO₂ budget (at around 1100 GtCO₂), underlining the role of CCS in this modelling. For the 1.5°C case, the amount of CO₂ captured is almost double the budget, of 600 GtCO₂.²⁶ To 2050, the CCS numbers are broadly in the range of the scenarios shown in Table 4.1. The BECCS deployment values in this period are however more optimistic. The CO₂ capture values per year are considerably higher than the estimates by the IEA of around 5 Gt/year, despite their estimates only being to 2040. This is explained by the higher annual capture rate of 10Gt in 2050 in the TIAM-UCL analysis in the 2°C case (jumping from 3 Gt in 2030), compared to 5 Gt in 2040 under the IEA assessment.

²⁶ The CO₂ budgets (to 2100 and beyond) stated here are the result of the climate constraint used in the model. In other words, they were not introduced as an explicit constraint but are rather an output of the modelling.

Table 4.4: Cumulative emissions captured via CCS

Scenario	Cum. emissions by 2050 (GtCO ₂)	% BECCS (by 2050)	Cum. emissions by 2100 (GtCO ₂)	% BECCS (by 2100)
INDC	13	0%	339	15%
1.5 C	194	71%	1184	48%
2 C	153	67%	1098	46%
2 C HighCost	125	69%	1058	46%
2 C LowCost	158	67%	1148	45%

4.3.2 Sectoral dynamics and trade-offs

In this section, we explore the role of CCS in the power generation sector, as part of the sector’s low carbon generation mix, and the types of fuels used in CCS systems. We then consider the role of CCS beyond the power generation sector, identifying its role in the production of transport fuels, including synthetic biofuels and hydrogen. Finally, we consider its role as a mitigation option across industrial sectors.

Figure 4.11 shows total electricity generation in the base year, 2010, and the four core scenarios for the years 2030, 2050 and 2070.

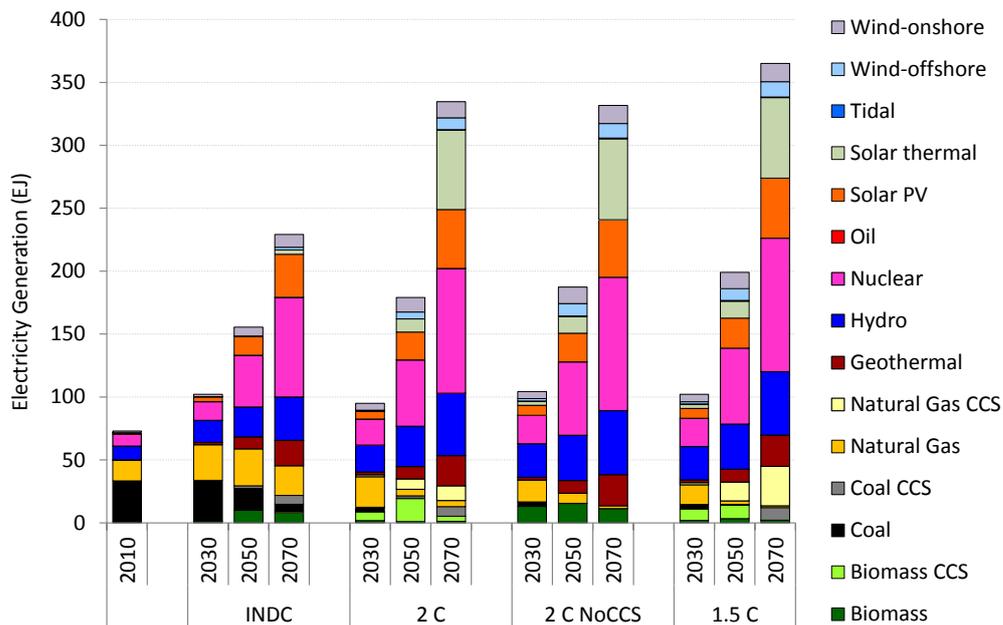


Figure 4.11: Total electricity generation (EJ) in the base year (2010) and in selected scenarios for the years 2030, 2050 and 2070 (Cost sensitivity scenarios can be found at Appendix A.1)

The growth in total electricity generation in all future scenario years compared to the 2010 base year partly reflects the projected overall increase in energy service demands, due to rising population and affluence, which are exogenous model inputs. However, decarbonisation is an additional driver, as shown by the notable increases

in electricity demand in the 1.5°C and 2°C scenarios compared to the INDC scenario. The relatively large range of low carbon options within the electricity generation sector results in increasing electrification as emissions constraints become tighter, with the use of low carbon electricity increasing across all sectors where it can be used as an alternative.

In all scenarios a wide-ranging portfolio of electricity generation technologies is deployed. In the INDC scenario the relatively less stringent emissions constraints allow some unabated gas and coal generation to remain on the system in 2070, and coal CCS makes a small contribution of around 3% of total electricity generated in 2070. In the 1.5°C and 2°C scenarios, unabated coal is almost entirely displaced from the system by 2050, though unabated natural gas continues to make a small contribution (providing electricity system flexibility). In all scenarios, the generation mix becomes dominated by low or zero-carbon generation technologies in addition to CCS, with wind, solar, nuclear, hydro and geothermal making substantial contributions. There are of course important regional differences, with solar making a particularly strong contribution in regions with higher solar radiation, and nuclear featuring more in those regions with higher acceptability. Some of the regional differences in generation mix are shown in Figure 4.12. CCS is an important contributor to this mix, without being dominant. It accounts for about 11% of electricity generated in 2070 in the 1.5°C scenario, and between 6 and 9% in the 2°C scenarios.

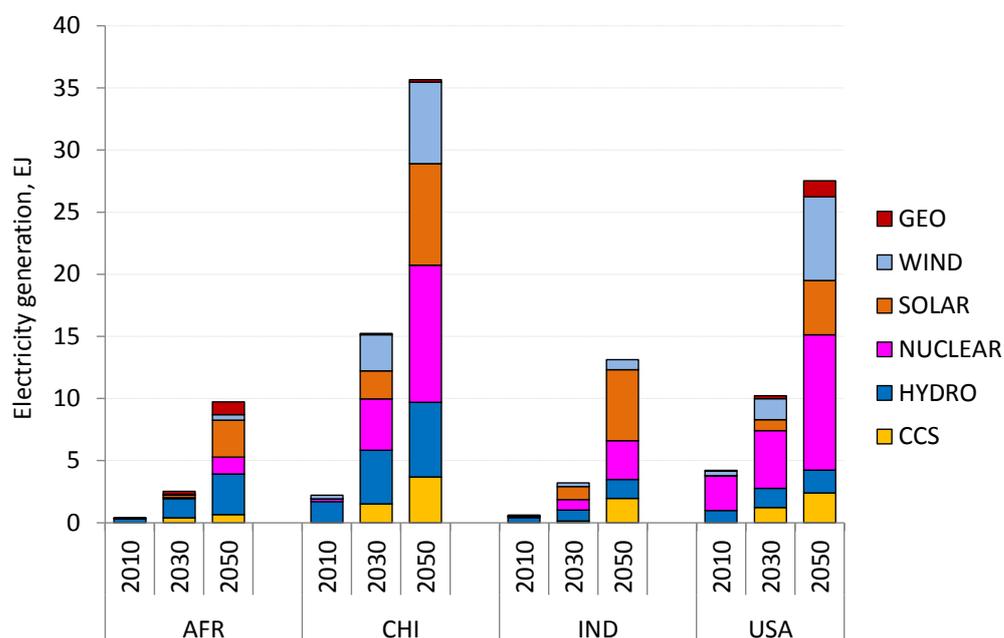


Figure 4.12: Electricity generation (EJ) from low carbon sources of electricity in the base year (2010) and for the years 2030 and 2050 in the 2°C case

In terms of generation capacity, to provide an idea of scale, global cumulative installed capacity in GW of CCS in the power sector in the 2°C standard costs scenario reaches over 300 GW by 2030, and peaks at around 1100 GW in 2050. For much of this period, this entails an annual installation rate of around 40 GW.

Figure 4.13 focusses in more detail on the electricity supplied from fossil and biomass sources, with and without CCS, across the main scenarios.

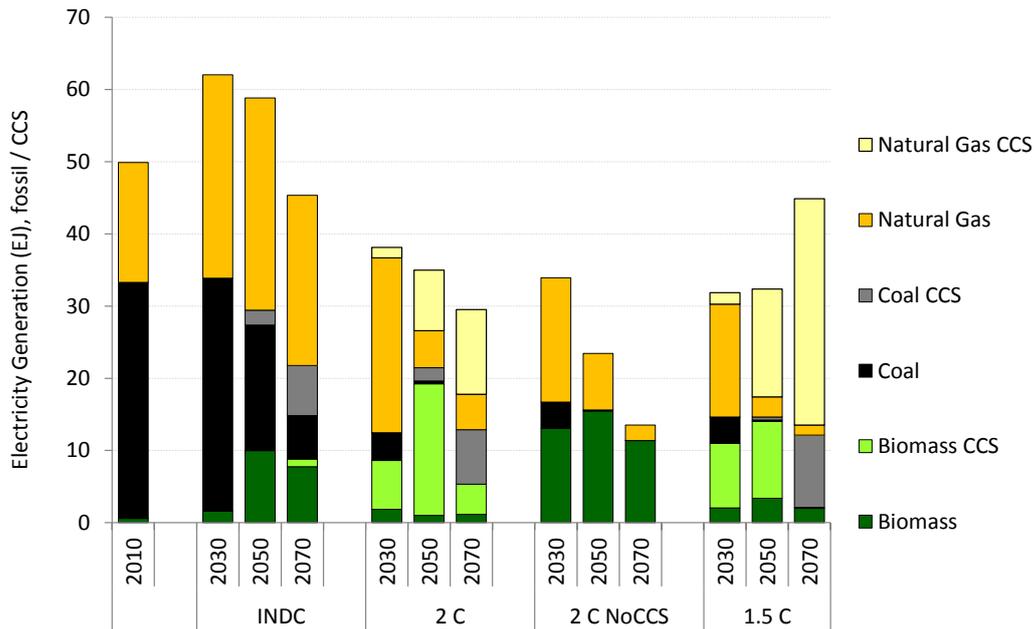


Figure 4.13: Electricity generation (EJ) from fossil fuels and biomass, with and without CCS, in the base year (2010) and selected scenarios for the years 2030, 2050 and 2070. Note that this does not include CCS used in centralised heat production, as shown in Figure 4.10

Figure 4.13 also shows that biomass CCS in power generation increases in both the 1.5°C and 2°C scenarios to 2050, but then is reduced by 2070 – most dramatically in the 1.5°C scenario. However, Figure 4.14 shows that capture from CCS using biomass (BECCS) continues to rise between 2050 and 2070 in the 1.5°C and 2°C scenarios. That is, rather than being deployed to produce power, BECCS is preferred for the production of synthetic biofuels and hydrogen for the transport sector. This again reflects the relative urgency and need of different sectors, as the stringency of the emissions constraint increases in later time periods. In the later part of the modelling horizon, power sector decarbonisation is comparatively straightforward, with a range of available options. However, at this stage, there is a need to decarbonise the transport sector, and it is here that BECCS is increasingly deployed. While electricity can also be increasingly used in the transport sector, this is primarily in the smaller vehicle fleet (LDVs) and less so in larger freight and aviation.

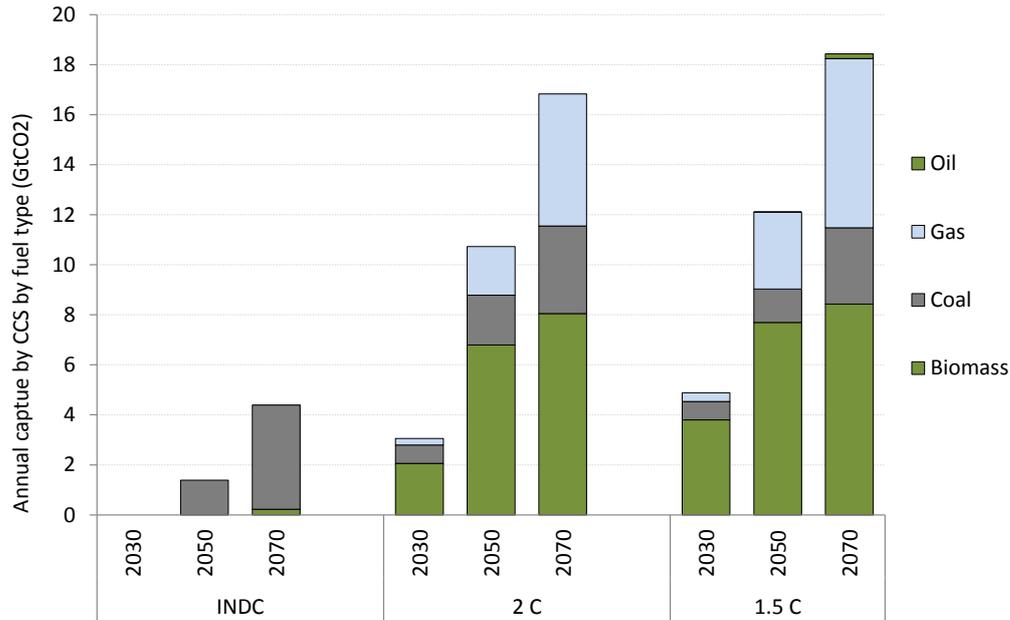


Figure 4.14: Annual CCS capture (Gt CO₂) by fuel supply in all sectors across selected scenarios in which CCS is deployed, in years 2030, 2050 and 2070

As shown in Figure 4.10 hydrogen production is also a significant user of CCS systems under the 1.5°C and 2°C scenarios. Hydrogen is produced by a range of sources, with CCS processes accounting for around 20% and 39% in 2050 and 2070 respectively, of hydrogen production in the standard cost 2°C scenario; in the 1.5° scenario, CCS accounts for 20% and 27% of hydrogen produced in 2050 and 2070, respectively. In all scenarios hydrogen is used almost exclusively for transport (Figure 4.15) – providing a low carbon vector to displace oil-derived transport fuels. The No-CCS scenario requires comparatively higher levels of hydrogen in transport – which also must be produced from bioenergy and electrolysis. The lack of CCS to provide mitigation especially in industry and through negative emissions, means that more mitigation must be done in other sectors, notably transport.

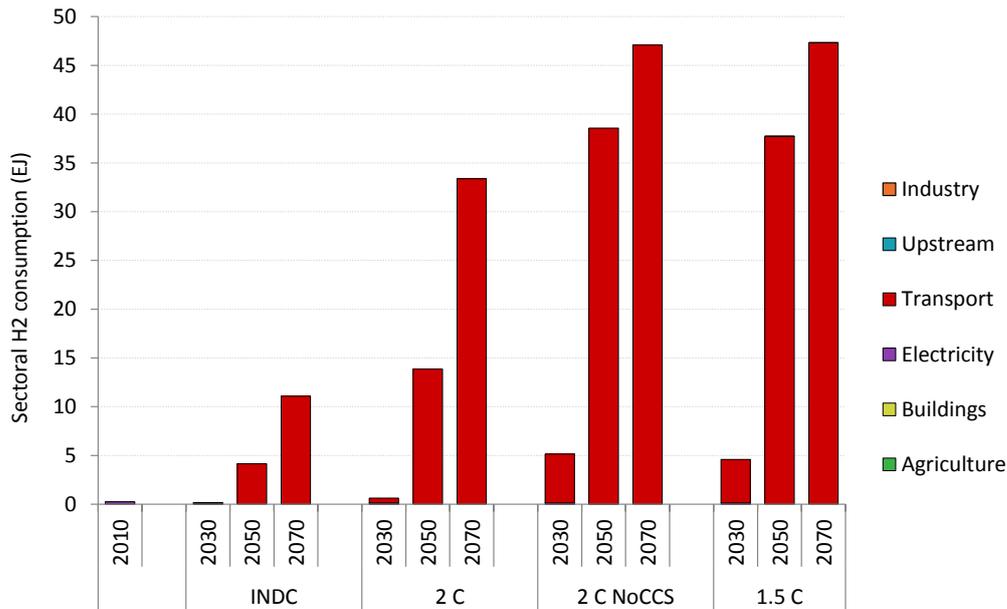


Figure 4.15: Sectoral hydrogen consumption (EJ) across selected scenarios for years 2030, 2050 and 2070

As shown in Figure 4.10, CCS plays an important role across the industrial sector. The split according to sector is shown in Figure 4.16, with heavy industry sectors accounting for a high share, but also CCS being deployed in the ‘other’ sector – unclassified industrial processes that require large process heat loads, and which therefore benefit from CCS. It is interesting to observe that CCS deployment in this sector in 2050 and beyond is higher in the 2°C than in the 1.5°C scenario. This reflects the relatively lower emissions total in the 1.5°C scenario (7.5 GtCO₂ in 2070) prior to sequestration, compared to over 10 GtCO₂ in the 2°C scenario.

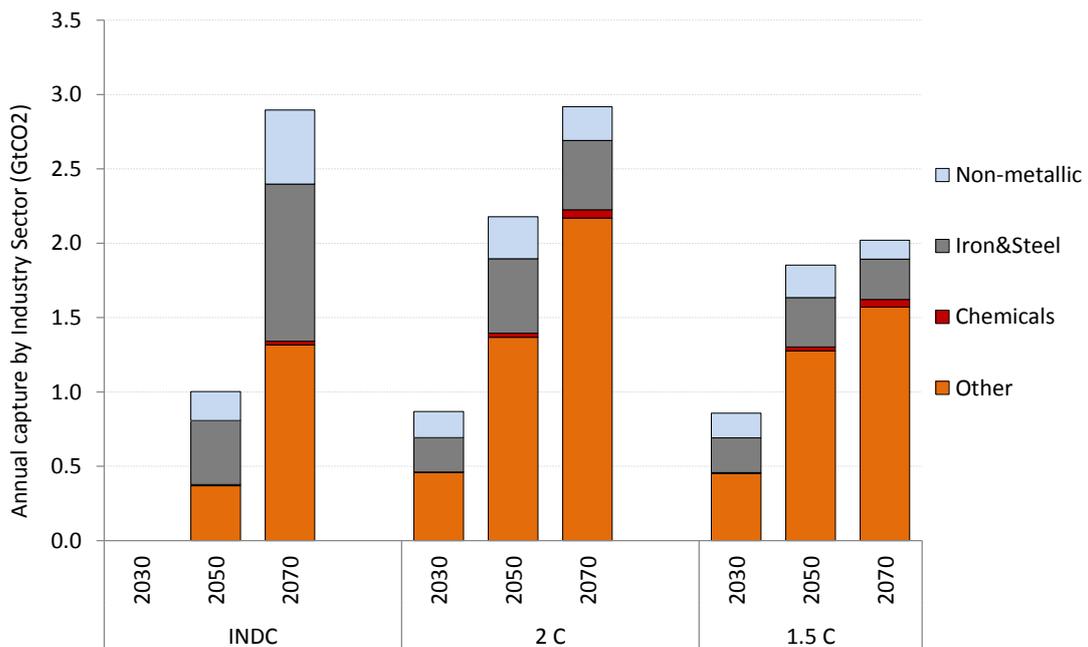


Figure 4.16: Annual CCS capture (Gt CO₂) by industry sector across selected scenarios in which CCS is deployed, in years 2030, 2050 and 2070

The scaling of CCS systems in selected regions of the world is shown in Figure 4.17. Of particular note is the relatively rapid scale up in China to mitigate emissions from the energy intensive sectors in that country.

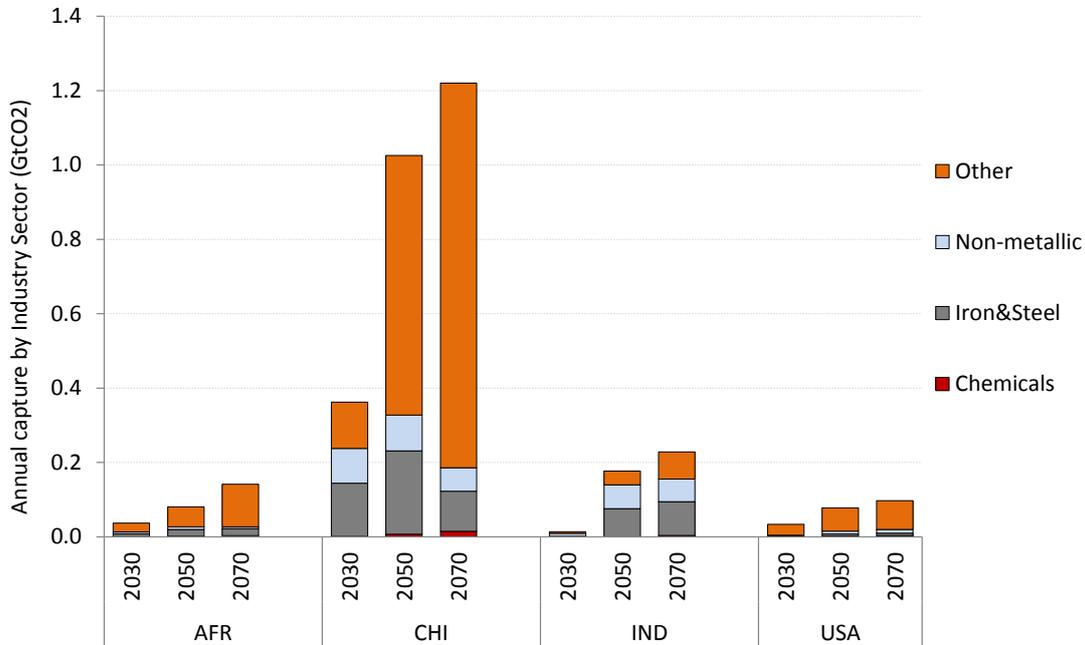


Figure 4.17: Annual CCS capture (Gt CO₂) by industry sector under the 2 C scenario in selected regions, in years 2030, 2050 and 2070

4.3.3 Emissions

Figure 4.18 shows CO₂ emissions across all sectors, including positive emissions above zero on the y axis, and negative emissions below zero. Scenarios which deploy CCS are clearly identifiable by bars extending below zero on the y axis, primarily composed of the categories of CO₂ capture from electricity and industry (which partially or wholly compensate for the positive emissions in the relevant categories), as well as the category ‘sequestration from biomass with CCS’ which shows where biomass has been used as a fuel in CCS, rather than fossil fuels, allowing an additional ‘negative emission’ credit. Black diamonds show the total emissions net of the effect of CCS on relevant sectors, but not including CO₂ sequestration with BECCS; red crosses show total emissions also including BECCS. It can be observed that the emissions totals (red crosses) never drop below zero, as seen in many other Integrated Assessment Model (IAM) scenarios (e.g. Figure 1 in Fuss et al (2014)). This is because no allowance is permitted for net negative emissions accounting; while negative emissions technologies, namely BECCS in this model, can be part of the solution in achieving a net-zero position, they cannot provide additional flexibility to the system by taking the accounting system into negative balance. This additional flexibility, allowed in other models and scenarios, has been to shown to allow the achievement of meeting more stringent targets, and

needs to be kept in mind when discussing the emissions and cost implications below. However, we decided not to adopt this approach, but rather to constrain the role of BECCS in permitting delayed action, particularly given the uncertainties in respect of its deployment.

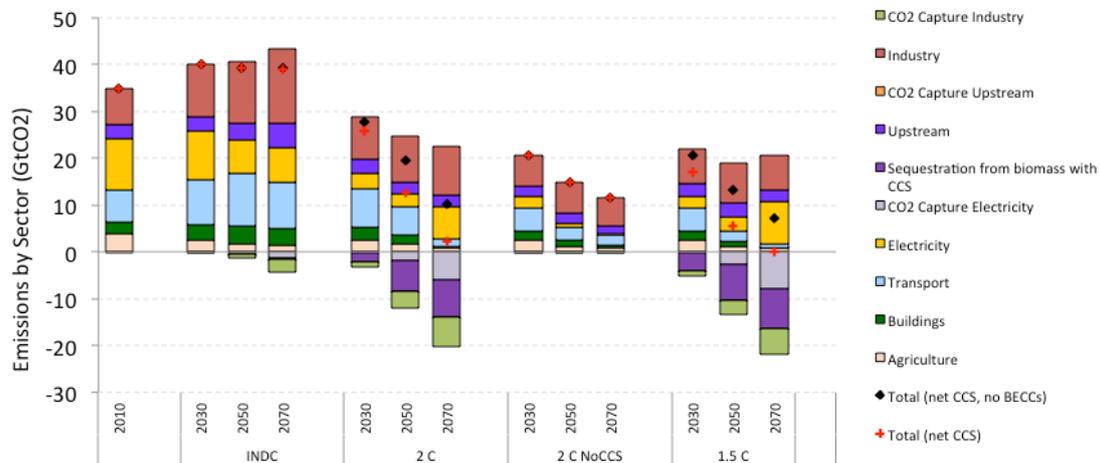


Figure 4.18: CO₂ Emissions by sector, and total net CO₂ emissions, across selected scenarios, in the years 2030, 2050 and 2070

As shown in Figure 6.6, Appendix A.1, the total emissions levels for the 2°C standard, low and high cost scenarios are very similar but not exactly the same. The variation is due to the fact that the constraint is not only on CO₂ but also on other GHGs, with scenarios targeting different levels of mitigation at the different GHGs. However, the total emissions for the 2°C No- CCS scenario in 2070, by contrast, are noticeably much higher than in the main 2° scenario (Figure 4.18). In this case, the emissions constraint is so difficult to meet that the model is relying on a ‘backstop’ technology in order to find a solution. This ‘dummy’ technology is only deployed as a last resort given its extremely high cost, and reflects the absence of any known alternative mitigation opportunity in the model. In the 2°C No- CCS scenario, the ‘backstop’ technology is used to mitigate some 10-15 GtCO₂ towards the very end of the time horizon, with industry accounting for up to 65% of these residual emissions, showing the difficulty in decarbonising this sector. This provides further evidence of the likely extreme difficulty of reaching the kind of energy system CO₂ emission-levels that are consistent with 2°C, without CCS.

4.3.4 Marginal costs

Figure 4.19 shows the marginal costs of CO₂ across the six scenarios, from 2010 to 2070. The marginal cost of CO₂ is the cost incurred to mitigate the last, and most expensive, tonne of CO₂. In any run it therefore represents the most expensive abatement option that had to be called upon – it is in this sense importantly different from other measures of cost which are spread across all abatement measures, such as an average or total cost of abatement. Whilst theoretically this marginal cost could be considered as indicative of the kind of carbon price that would be required to drive the last, or marginal, abatement measure, this interpretation should be treated with some caution. This is firstly because this interpretation implies that the only policy

lever available is carbon pricing – in reality a suite of incentives, penalties and innovation strategies are available to policy makers, as discussed in Chapter 2. In most scenarios with very high marginal costs, there will be a very large difference in cost between the marginal abatement measure and most of the other abatement measures, hence the marginal cost, if interpreted as a ‘carbon price’ would not necessarily be the one experienced across most of the economy, most of the time, even if some kind of ‘economy-wide carbon price’ was implemented. Finally, in the particular modelling exercise being reported in this section, it should also be noted that the ‘backstop technology’ is an extremely high marginal cost abatement option – however its cost is not directly equivalent to any particular existing technology, but rather set at a high level to be indicative of a highly constrained system.

The INDC scenario is associated with a marginal cost of CO₂ rising to only around \$40/tonne by 2070, however much higher marginal CO₂ costs are implied by more ambitious mitigation scenarios. The standard 2°C scenario and the 2°C CCS low-cost scenario both have similar marginal CO₂ costs in 2070, at around \$530/tonne. Although, as discussed in relation to Figure 4.10, the alternative cost assumptions for CCS do not have a major impact on the physical deployment of CCS within a 2°C constraint, it can be seen from Figure 4.19 that the higher cost CCS assumptions do noticeably increase the marginal cost of abating CO₂, by around \$100 to around \$630/tonne in 2070.

Figure 4.19 also clearly shows the significant additional difficulty and cost of moving from a 2°C to 1.5°C abatement pathway, as marginal CO₂ costs in the 1.5° scenario rise to just over \$3000/tonne in 2070. However, even higher than this is the marginal CO₂ cost of trying to limit temperature rise to 2°C without the option of CCS – in this scenario marginal CO₂ costs are just under \$3500/tonne in 2070, showing the importance that CCS, if deployed at scale, can play in reducing costs of mitigation. The particularly high marginal costs found in the 1.5°C and 2°C No-CCS scenarios are primarily driven by the introduction of a backstop technology, as described above, and reflect the limited options (as represented in TIAM-UCL) to meet such ambitious climate objectives, including in the absence of CCS, and as described earlier, the restriction on net negative accounting. As discussed above, these values should therefore be interpreted as a useful indicator of a highly constrained system, and not necessarily as the types of price incentives required to transition to a low carbon system.

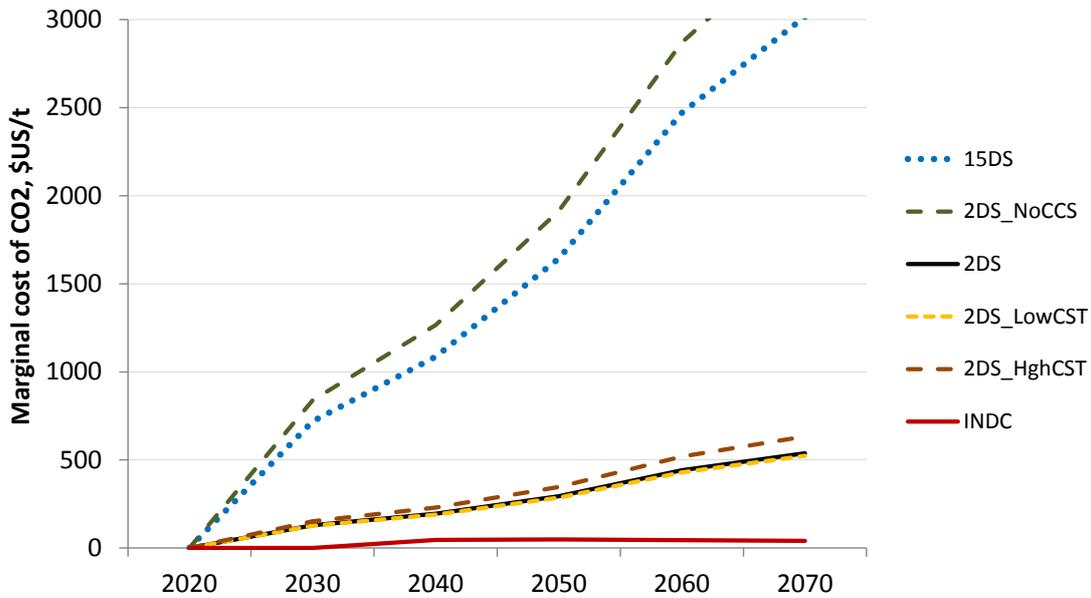


Figure 4.19: Marginal cost of CO₂ (US\$/tonne), across all scenarios, 2010-2070

These marginal costs can be compared to the ‘carbon prices’ found by the review of Dessens et al (2016), shown in Figure 4.4. From the scenarios reviewed, Figure 4.4 indicates that in the year 2075 the interquartile range of carbon prices is US\$500 – 1500 / tCO₂. A comparison with Figure 4.19, above, indicates that the 2°C scenarios which include CCS are within this range, and towards the lower end of it. Reviewers such as Dessens et al (2016) and Edenhofer et al (2014) report substantial increase in total costs from excluding CCS from 2°C pathways, with median values representing more than a doubling of total costs. This is consistent with the very sharp increase in marginal costs in the 2°C No-CCS scenario, compared to the other 2°C scenarios, shown in Figure 4.19.

4.3.5 The impact of CCS on the use of fossil fuels

Figure 4.20, Figure 4.21 and Figure 4.22 show the consumption of fossil fuels across the six different scenarios, as well as for a 4°C scenario – effectively a scenario with no climate policy at all. From Figure 4.20 it can be seen that compared to the 2°C No-CCS scenario, the mitigation scenarios in which CCS is available are able to make use of substantially more natural gas, indeed at levels not too different from those in the INDC and 4°C scenarios. This is due to the direct capture of CO₂ from the natural gas that is used in the power and electricity sectors, and because the use of biomass in CCS to achieve negative emissions buys more flexibility for the use of unabated fossil fuels in other sectors. Hence the generally increased usage of natural gas in transport in the mitigation scenarios which have access to CCS, compared to that under the No-CCS scenario.

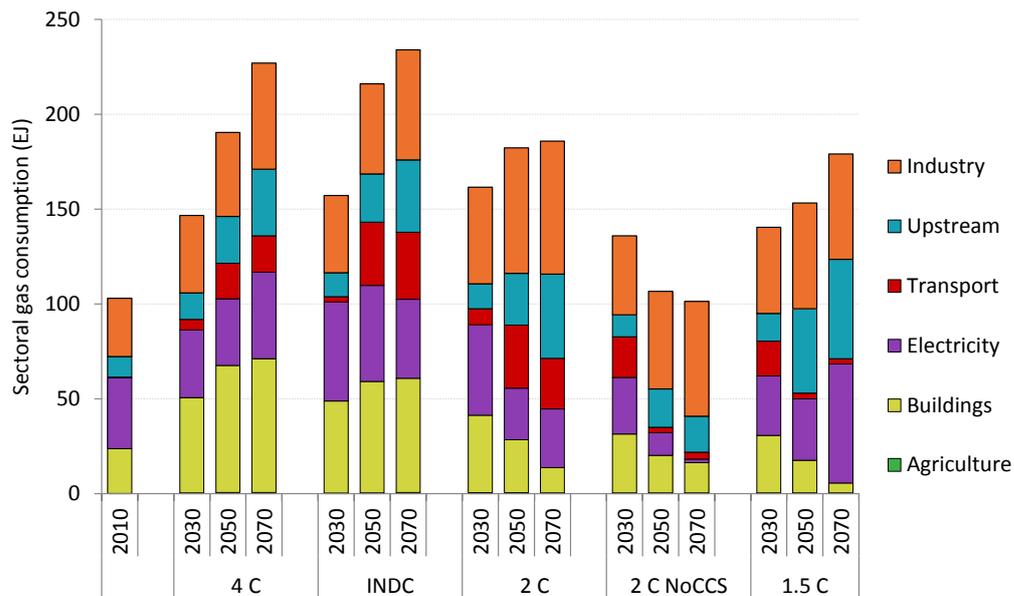


Figure 4.20: Sectoral gas consumption (EJ) across selected scenarios, (including a 4° scenario), for the years 2030, 2050 and 2070

A similar effect can be observed in Figure 4.21, which shows more flexibility to use oil in the transport sector in the CCS mitigation scenarios compared to No-CCS, particularly in the earlier years of the time period. The low carbon scenarios suggest that there could still be a significant role for oil in the energy system in the second half of the 21st century, even within emissions trajectories consistent with 2°C or 1.5°C warming. However the amount of oil used in the energy system in low carbon scenarios is ultimately significantly less than the quantities currently used, and very significantly less than the future quantities projected to be used in high carbon scenarios. As shown in Figure 4.21, in the scenarios produced for this report, the base year of 2010 uses 155 EJ of oil. In a 4°C scenario the oil use increases to 283 EJ by 2070. However, under the 2°C scenario oil use falls to 136 EJ by 2070, and under 1.5°C it falls to 112 EJ by 2070. An even greater restriction on oil consumption is required in the 2°C scenario that excludes dedicated CCS – here oil use is restricted to 111 EJ by 2070. This reflects the fact that the absence of negative emissions from biomass-CCS (BECCS) requires even more stringent reduction of remaining emissions in hard-to-decarbonise sectors, such as transport.

The role of oil in these scenarios has important implications for the compatibility of CO₂-EOR with low carbon trajectories. As discussed in Section 1.2.2, the extent to which CO₂-EOR can play a role in CO₂ mitigation in a low carbon energy system depends on the amount of conventional oil that would otherwise still be present in that system. The production of CO₂-EOR oil that displaces conventional oil which would in any case still be used in the low carbon system, is consistent with emissions reduction in the sector from which the CO₂ has been captured, without increasing emissions from the use of oil, and possibly slightly decreasing them, if the oil it displaced had higher life-cycle emissions. However, if CO₂-EOR produced quantities of oil greater than that which could be used in a low carbon system, and this oil was

used, then it would effectively be displacing lower carbon fuels and causing overall emissions to rise.

As discussed, and shown in Figure 4.21, oil is still consumed in our low carbon pathways. In our 2°C scenario, cumulative oil consumed to 2050 is around 6,600 EJ, or 1,160 Bbbl. According to the IEA (2015b), the technical potential for oil produced from CO₂-EOR 'over the next 50 years' would be 431 Bbbl. Evidently, this estimated 50-year technical potential does not exceed the quantities of oil cumulatively demanded by the 2°C scenario until 2050. On the basis of this assessment, it is therefore possible that EOR-produced oil would only displace other kinds of oil, rather than displacing low carbon fuels, and therefore that CO₂-EOR would not necessarily be inconsistent with a low carbon trajectory.

In terms of CO₂ stored, the IEA (2015b) estimates the technical potential for Advanced EOR as 240 Gt CO₂, while the technical potential if EOR techniques are designed to maximise storage rises to 360 Gt CO₂. For comparison, our 2°C scenario requires a cumulative storage of CO₂ of 153 Gt by 2050, rising to 1098 Gt cumulatively by 2100. This suggests that, again based on the IEA's assessment, while the CO₂ storage reservoirs provided by CO₂-EOR projects alone could be compatible with low carbon trajectories to mid-century, considering the longer term transition as a whole, the development of dedicated CCS, without CO₂-EOR, will also be crucial.

Thus, comparing IEA's assessment of technical potential for CO₂-EOR with the oil consumption of the low carbon scenarios produced for this report, suggests that the technical potential of EOR might not exceed the maximum allowable quantities of oil production in low carbon trajectories, hence EOR could be consistent with such trajectories.

Because CO₂-EOR is already a relatively attractive commercial proposition, it offers a potentially viable way of developing CCS, and given the quantities of oil which will continue to be used in the energy system for some years, even within a low carbon trajectory, it has the potential to offer genuine emissions reductions through the application of CCS to power plants, as long as the oil it produces is of a lower CO₂ intensity than the oil it displaces. However it will not be sufficient on its own for most low carbon trajectories, which will also need significant amounts of dedicated CCS, beyond the storage capacities provided by CO₂-EOR alone.

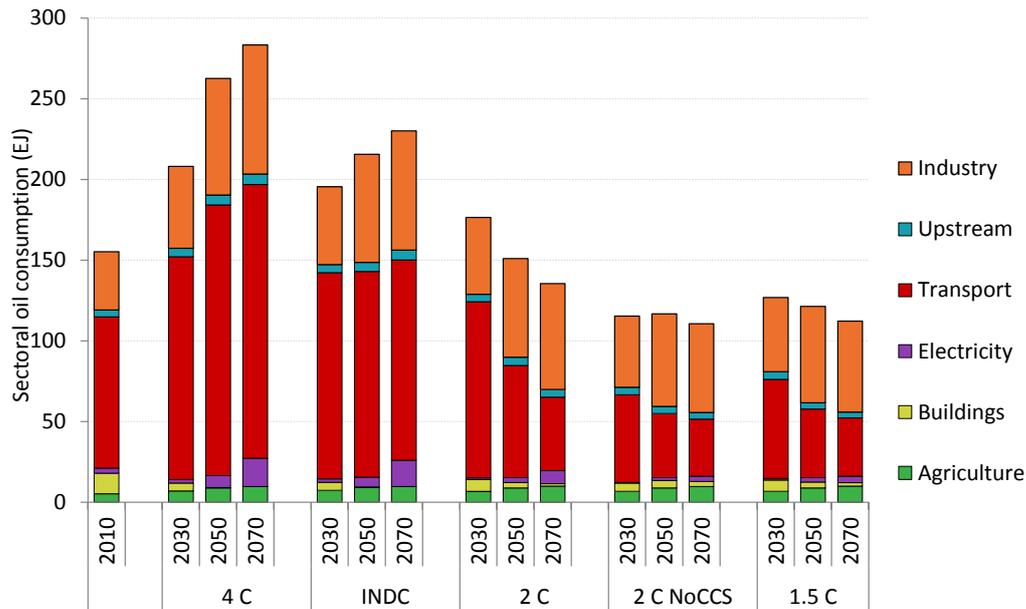


Figure 4.21: Sectoral oil consumption (EJ) across selected scenarios, (including a 4° scenario), for the years 2030, 2050 and 2070

Figure 4.22 also shows that the CCS mitigation scenarios allow a greater use of coal than the No-CCS scenario, which is used in power and industry sectors with CCS directly applied. However, Figure 4.22 also draws attention to the fact that the amount of coal that is consumed in a 2°C or 1.5°C scenario is vastly less than the amount which would otherwise be consumed in a weak- or no-climate policy scenario, and this is the case even in a mitigation scenario in which CCS is available. Successful development of CCS would not provide a simple pass to unlock much of the world’s coal reserves while remaining within 2°C, primarily due to the residual emissions from coal CCS. Even in a high CCS scenario, the amount of coal that would need to remain unused in order to remain within 2°C limits would be substantial.

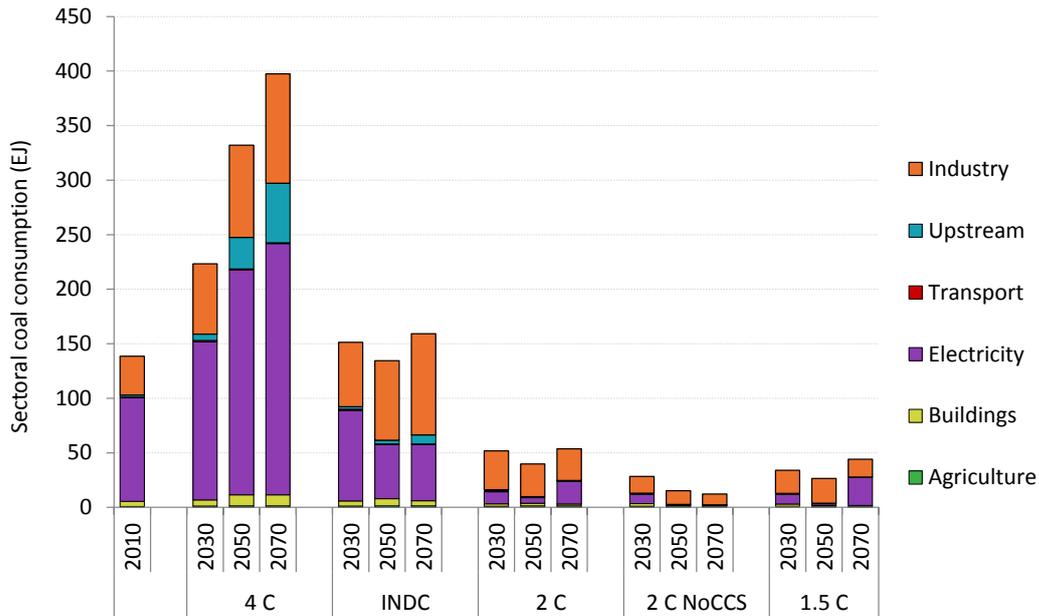


Figure 4.22: Sectoral coal consumption (EJ) across selected scenarios (including a 5°C scenario), for the years 2030, 2050 and 2070

4.4. Conclusions

Modelling of emissions scenarios fifty or more years into the future is of course subject to considerable uncertainties, not least in relation to the possible costs and availability of technologies in future years. As such, particular numbers and cost figures from any particular scenario must not be treated as firm predictions of the future. Rather, a careful analysis of the technological choices and inter-sectoral dynamics within and between scenarios, and across different modelling platforms, can yield robust insights about key requirements for low carbon pathways, and the challenges associated with them.

The original modelling analysis presented in this chapter provides a set of scenarios that show different outlooks for CCS in different sectors and for different fuels, based on the assumption of effective commercialisation in the late 2020s. This latter point is critical in the interpretation of the results, with large uncertainties around the timing of commercialisation and subsequent scaling of CCS systems.

The scenarios indicate the importance of CCS as an emission reduction solution, which increases in line with the level of ambition. The importance is further illustrated by limited sensitivity of the model to cost increases in CCS systems; higher costs have limited impact on the deployment of CCS, as such cost increases are small compared to the costs that would be incurred if CCS were not available.

Without CCS, as represented by the 2°C NoCCS case, the ability of the system to reduce emissions to a level commensurate with a 2°C objective appears at best extremely challenging and costly, and at worst, not possible (as indicated by the

deployment of a 'backstop' technology). This is because the system has to get to net zero emissions; however, there are sectors that cannot fully decarbonise and therefore rely on negative emissions from CCS to offset their emissions. It is worth noting that other negative emission technologies (NETs) apart from BECCS are not considered. This finding from our modelling is also reflected in reviews of other modelling studies of 2°C pathways, which find median increases in total system cost of over 100 percent, as well as high proportions of models unable to find a solution for 2°C, without CCS.

In the current study we also report on a 1.5°C scenario. In this case, the challenge is one of scaling technologies such as CCS more rapidly, due to the need to get current emissions down rapidly. In this modelling, this cannot be done rapidly enough – as again is shown by the deployment of the backstop technology in this run. It is important however to emphasise that in this modelling we have not allowed for net negative accounting, which would in theory provide additional flexibility in the long term to return temperature increases to the average warming level of 1.5°C.

Another important finding is that CCS is not just a system that is applied to the power sector, but plays an equally or more significant role in decarbonizing industry, and in efforts to produce hydrogen and synthetic low carbon transport fuels. These latter applications prove increasingly important in the much longer term, when it becomes more important to fully decarbonise transport systems, and when decarbonisation of the power sector and increasing electrification has already taken place. This finding reflects those of other modelling studies that the criticality of CCS arises from its ability to provide abatement in, or offsets for, sectors where few if any other low carbon options are available. Our modelling aligns with insights from these other studies, to the effect that the power sector is an important, but not as critical sector for CCS, due to the availability of other low carbon power options. A related finding is that the increased cost or reduced feasibility arising from not having CCS is typically much greater than for low carbon technologies that only in operate in the power sector, as these can be more easily substituted for by alternative power sector technologies.

Further, the importance of bioenergy in combination with CCS (BECCS) arises strongly from our modelling – a finding that is again reflected in reviews of other modelling studies. Our 2°C scenario uses BECCS as a key measure to avoid the most expensive abatement measures in hard to decarbonise sectors, and, as already noted, without this option our 2°C No-CCS scenario appears very expensive or potentially infeasible. Our 1.5°C scenario requires the backstop technology even with CCS. However as noted our modelling does not allow net negative accounting – if it did, this would in theory provide additional flexibility to limit temperature rise to 1.5°C at lower cost than in our current scenario. Such a pathway would of course be likely to further increase the need for negative emissions technologies such as BECCS.

It is worth highlighting a couple of caveats about the modelling, which are critical in the interpretation of the results. Firstly, the model assumes commercialisation and allows for rates of CCS deployment that are relatively optimistic compared to the IEA assessments. In part, the nature of the 'optimization' model also means fewer barriers to deployment are envisaged, and therefore deployment should be viewed

as being at the optimistic end of the range. Secondly, the strong deployment of CCS (including BECCS) can result in very different systems to those where CCS deployment is limited. For example, the future role of fossil fuels looks more promising, and other sectors where CCS is not deployed have to undertake less mitigation action, relying on being given headroom by CCS.

The rate of roll-out of CCS technologies and infrastructure described by the scenarios looks extremely challenging, particularly when considering the challenges faced by CCS. In the final chapter, we draw on insights from the preceding chapters to make suggestions as to how policies might support and enable the kinds of CCS technology pathways described in these scenarios, to take place.

5. Conclusions and policy recommendations

Key points

- On the basis of available evidence, we judge that the risks of CCS not being available as part of a portfolio of mitigation options to address climate policy targets are greater than the risks associated with attempting to develop it.
- In particular CCS should be considered a critically important part of any strategy for limiting temperature rise to 2°C, and even more so for limiting temperature rise to 1.5°C.
- Pursuing CCS requires a whole-chain, innovation systems approach, including coordination of actors and infrastructure.
- There is an important active role for governments in such an approach.
- Legislative and regulatory frameworks are crucial, but CCS systems are still emerging – hence review and adaptation is important.
- The process of policy development and CCS implementation should be supported by robust and transparent risk management practices, reflecting and building on those employed to date, and by genuine public engagement. Critical issues include transparently verifying that CO₂ can be safely stored in any given project, and demonstrating the full life cycle sustainability of biomass used in BECCS applications, including with appropriate certification processes.
- CCS should be seen as an important component of a portfolio of mitigation strategies. Other low-carbon supply side technologies will also make critical contributions, and increasing energy and material efficiency is likely to be a key “no-regrets” option.

This report has considered the role of CCS in meeting climate policy objectives. We now present our conclusions.

5.1. What is the current status of CCS?

CCS is not a single technology, but a number of technologies operating within a system. Each of the component parts of this system can be seen to be operating in different parts of the world at present, in a variety of applications including commercial projects. However, a major roll out of CCS power and industry projects for the dedicated sequestering of CO₂, on a scale consistent with significant greenhouse gas mitigation, remains elusive. This is not primarily due to technological constraints, however, but due to the lack of sufficiently strong policy or market drivers for such systems.

The CCS systems that are in existence have been developed because the policy or market drivers in that particular instance are in combination sufficient, in comparison to the added cost of applying CCS, to make the project a viable proposition. In many cases this is assisted by the fact that the captured CO₂ has its own value, for example for enhanced oil recovery, or as an input for another chemical process. In other cases, the capture of CO₂ already occurs as part of a pre-existing process, such as in natural gas processing, so that the sequestration of the CO₂ is a relatively small additional step. In many of these cases a relatively low carbon price, or equivalent policy incentive, provides the incremental push required to bring about a CCS project.

However, such relatively modest policy-driven price incentives have not yet been sufficient to bring about the kind of major roll out of CCS power and industry projects with dedicated sequestration of CO₂, that would be required if CCS were to make a significant contribution to greenhouse gas mitigation. In many situations the added costs of applying CCS to fossil fuel processes are much greater than in the kinds of applications mentioned above, especially for first of a kind projects. Several attempted projects of this nature have been supported, at least initially, by fairly substantial government grants. However concerns over increasing costs have meant that such projects have not been seen through to completion. There are clearly barriers to the large scale roll out of CCS on the scale required for significant greenhouse gas mitigation. Such barriers, and ways to overcome them, will be discussed in Section 5.3.

Nonetheless, the CCS projects that have been developed give a reasonable outlook on the prospects and challenges associated with CCS systems. The separation of CO₂ directly from fossil fuels or from related gaseous streams can be achieved by a number of techniques which have been demonstrated at commercial scale. The transportation of gases through pipelines is also a well-established practice in a number of industries. The area with the most significant enduring uncertainties is that of deep geological storage. It is inevitable that there will always be some uncertainty in predicting the behaviour of gas injected into geological formations or deep sea aquifers. However, monitoring of CO₂ injected thus far gives reasonable evidence that CO₂ can be successfully contained; and that if unexpected behaviour did arise that the monitoring capability would be such that injections could be halted or amended to avoid a major leakage.

CCS is controversial, in the sense that there are contrasting opinions as to whether CCS systems should play a role within future energy systems. Strong criticisms have been voiced against CCS. These propose that CCS is not cost effective; that there is an unacceptable risk of leakage; or that it is not a genuinely low-carbon technology but a smoke-screen for the continuation of carbon intensive activities. In assessing these criticisms in view of the evidence of this report, we find that we can partially agree that these areas present important and relevant challenges to CCS that should not be dismissed lightly. The cost-effectiveness of CCS as a major low-carbon technology has yet to be proven; there remain, and will always remain, elements of uncertainty around leakage, and a major failure in this area could pose health risks as well as negating the low-carbon credentials of CCS; it is clear that CCS systems that do not achieve substantial net-carbon benefits are possible, and that therefore if

there are not effective policy guidelines around the use of CCS, its impact on decarbonisation could be marginal. These are all risks that would threaten to undermine the case for CCS. We do not propose that risks associated with deploying CCS can be entirely eliminated. However, we suggest that for any action it is reasonable to compare the risks of acting against the risks of not acting, and that CCS should be no different in this regard. Therefore in this report we have examined the role that CCS might play in a future low carbon world, and the impacts that could be felt on climate policy targets were it not available. We summarise the key conclusions of this analysis in the following section.

5.2. How important is CCS to a future low-carbon world?

Evidence from a range of energy system modelling exercises suggests that the contribution of CCS is likely to be of substantial importance to achieving stringent emissions reductions scenarios. In emissions scenarios, produced by integrated assessment models (IAMs), that are consistent with keeping average global temperature rise below 2°C, CCS is consistently selected where available. It is deployed in the power sector as a means of producing low-carbon electricity, and to reduce emissions from industrial processes. Such scenarios frequently combine CCS in these applications with biomass fuel, in order to achieve “negative emissions”, as a significant contributing factor to achieving stringent emissions reductions.

Some IAM scenarios have been run with CCS excluded as a technological option, in order to see what the impacts would be on stringent emissions targets of CCS not being available. A robust finding across a range of modelling frameworks is that non-availability of CCS tends to significantly increase costs for any given emissions target. This is not so much to do with direct implications for the power sector – a range of low carbon electricity generation technologies, including nuclear and renewables, are available to replace CCS in this sector. The increased costs tend more to be a result of the relative lack of alternatives to CCS in industrial processes, where increased electrification is a more costly alternative; and due to the lack of ability to create negative emissions through BECCS, which also means that more stringent and more expensive emissions reductions measures are required in other sectors. It is also a notable observation that many IAMs are unable to solve at all under a 2°C constraint if CCS is not available.

The scenarios run in the TIAM-UCL model for this report align with wider IAM literature on the question of the increased difficulty of achieving stringent emissions abatement in the absence of CCS. In the modelling undertaken for this report, the absence of CCS from a 2°C scenario substantially increases its costs. This is due to more expensive measures in various sectors, particularly industry, as well as the requirement to use the “backstop” technology to meet the constraint. This is a very expensive emissions reduction option available to the model if other options are exhausted, but for which there is no direct real world equivalent. The model’s use of the backstop technology can be taken as a very clear signal that, from the perspective of this model, limiting temperature rise to 2°C without CCS appears to be extremely difficult.

In our 1.5°C scenario the costs are extremely high, even with CCS. Interestingly however the costs are slightly lower than the 2°C scenario when CCS is excluded, emphasising again the very high costs of this latter scenario. Although we didn't run a 1.5°C scenario without CCS, the clear implication is that attempting 1.5°C without CCS would be even more challenging.

Variants of the 2°C scenario were run to test the sensitivity of the outcome to alternative assumptions of CCS technology costs, both higher and lower than in the standard 2°C scenario. It was found that the deployment of CCS was relatively insensitive to varying its cost, due to the fact that such costs variations were substantially less than the costs incurred from not using CCS at all.

In our 1.5°C and 2°C scenarios, CCS was found to be an important, but not dominant contributor in the power sector. Its absence in the No-CCS 2°C scenario is compensated for by relatively incremental expansions across the portfolio of other low carbon power generation technologies. Much more critical however is the role of CCS in 'hard-to-decarbonise' sectors, especially industrial sectors such as steel, cement and sectors with high temperature process heat demands. It also becomes crucial – particularly in the 1.5°C scenario – in producing synthetic transport fuels for transport modes for which electrification options are not available.

The use of biomass in combination with CCS (BECCS) is also a major part of the story of both 1.5°C and 2°C scenarios. Around 48% of cumulative captured CO₂ emissions by 2100 in the 1.5°C scenario are achieved through BECCS, and 45-46% in the 2°C scenarios. Without negative emissions, the 2°C scenario appears at best very high cost and at worst infeasible. It is also important to recall that our scenarios are prevented from using BECCS to make the overall emissions accounting go negative at any point. If this constraint were relaxed, it might reduce the costs, and increase the feasibility of the 1.5°C scenario. However, this would also entail greater use of biomass for BECCS.

The extensive use of BECCS in the scenarios raises critical questions about whether such usage would be sustainable in terms of land use change and other environmental impacts. It is beyond the scope of the current study to investigate those potential impacts in detail, however the critically important role of biomass in combination with CCS in stringent emissions scenarios, makes further investigation of such impacts a major priority.

In summary, we consider that the contribution of CCS could be extremely important to successfully achieving high levels of decarbonisation at the global level. A consistent finding across scenarios produced by IAMs is that at the very least achieving 2°C without CCS is likely to be significantly higher cost than a scenario in which CCS is available. Further, many IAMs are actually unable to solve for 2°C in the absence of CCS, and in our own modelling, the 2°C scenario without CCS relied on the "backstop" technology. There are fewer available examples of 1.5°C scenarios. However, our own 1.5°C scenario uses CCS even more extensively, across all sectors, and makes more use of BECCS, than our 2°C scenario. As such, although our own modelling did not include a 1.5°C scenario without CCS, it can be expected that such a scenario would entail an even greater increase in costs and

more extensive use of the backstop technology, than occurred as a result of the exclusion of CCS from the 2°C scenario. All of these findings provide strong evidence for the contention that, without CCS, limiting warming to below 2°C at a reasonable probability becomes very difficult. Of course, it is in theory possible that options not covered by our modelling may become available which would allow stringent emissions scenarios to be achieved at reasonable cost without CCS. As discussed in our review of modelling literature in Section 4.1, a few IAM scenarios are reported that can find solutions to meeting stringent emissions constraints in the absence of CCS. Such scenarios require for example very substantial changes from the business-as-usual projections of energy demand, much greater efforts in material and energy efficiency, and very high levels of low-carbon electrification in buildings and transport sectors, to compensate for the lack of CCS options especially in industry. Significant breakthroughs in other technologies, particularly in ‘hard to decarbonise’ sectors, could also theoretically reduce pressure on the need for CCS. However, we suggest whilst these outcomes are not impossible, that it would be a risky strategy to rely on them with no other option available. In our judgement the risks of CCS not being available as part of a portfolio of mitigation options to address climate policy targets are greater than the risks associated with attempting to develop it. Hence we conclude that CCS should be considered a critically important part of any strategy for limiting temperature rise to 2°C, and even more so for limiting temperature rise to 1.5°C.

5.3. What could be done to enable CCS to play a role in a future low-carbon world?

As discussed, scenarios across a number of modelling platforms suggest that CCS may be critical to limiting temperature rise to 2°C – and even more so for 1.5°C – because of its role not only in power sector decarbonisation, but also in industry, production of synthetic transport fuels, and in achieving negative emissions through BECCS.

However, at present, although CCS component technologies, processes and infrastructures are being deployed at commercial scale in a variety of applications, the development of full-scale CCS projects that are unequivocally devoted to decarbonising energy supply is making slow progress. Several ambitious low-carbon CCS programmes or projects have recently stalled or been withdrawn.

If the case for the long-term importance of CCS in achieving stringent emissions reductions scenarios is accepted, clearly further action is required to bring CCS technologies forward. This section discusses the main barriers to CCS, and key measures that respond to them.

5.3.1 *Innovation systems for supporting and enabling CCS*

CCS technologies are already widely applied. However, ongoing research, development and early stage demonstration will remain valuable. Increasing capture efficiencies will evidently benefit CCS projects, and other characteristics such as increased flexibility of operation would have particular benefit in low carbon power

systems. Governments should consider examples of other successful industrial R&D centres and innovation systems, and the long-term dividends these have paid. Given the likely criticality of CCS to future low carbon pathways, governments expecting these pathways to come about should correspondingly expect considerable activity in CCS, and as a result considerable benefits to countries whose industrial actors position themselves at the forefront of this industry. Establishing national test-centres, and coordinating networks of actors to stimulate innovation and cost reduction, have been shown to yield benefits in other industries, such as on- and offshore wind. There may also be potential for international collaboration in specific early stage demonstration projects. Such collaborations should aim to maximise the value of RD&D by identifying projects and technical challenges in most need of investigation, and with greatest potential learning value.

However, as noted, CCS technologies are by no means immature, and hence lack of R&D is clearly not the only factor inhibiting their wider uptake and deployment.

A first problem is that CCS systems are inevitably more expensive than the fossil-fuel equivalent. In countries where energy industries are privatised, private actors will not invest in such technologies unless they have a clear incentive to do so – they would require clear long-term certainty in the existence of policy frameworks that support and reward low carbon technologies, enabling them to make a return on their investment.

An important way of contributing to increased certainty for investors is to establish an overarching long-term goal, legal standard, or target, such as has been adopted in the UK and Germany. Such long-term frameworks can help to instil confidence in investors that governments have a serious and long-term commitment to decarbonisation.

However, while such overall frameworks are extremely important, experience also shows that, especially for relatively novel technologies, more specific incentives are also required to enable the balance sheets of private investors to look positive over the investment time horizon. Such incentives would aim to reduce the cost-disadvantage faced by the technology that policy makers wish to promote, and could include carbon taxes or carbon price floors (which ‘internalise’ the carbon ‘externality’, increasing the ability of low carbon options to compete); or by feed-in-tariffs, long term price contracts or other price support mechanisms (which increase the revenue that can be achieved from a certain desirable technology). In the case of CCS, power projects could be incentivised by technology specific price contracts for electricity generated, industry projects by payments for units of CO₂ stored; or projects in either sector could be directly incentivised with a sufficiently high carbon price. Experience in the renewable energy sector shows that measures can be found to ensure that such long term price support remains cost-effective for governments or other counter-parties, for example by issuing contracts on an auction basis. However for any such measure, an essential aspect will be for policy makers to generate confidence in its long-term stability, clarity and predictability. Without such confidence, investors will simply not invest in capital intensive low carbon projects such as CCS.

However in addition to “technology push” approaches such as R&D coordination, and “market pull” measures such as carbon taxes or price supports, an ‘innovation systems’ approach is also required, that acknowledges the feedback effects between different stages along the innovation chain, and the importance of actors, networks and institutions in coordinating the process. Such a systemic view of innovation has been shown to be important for technologies including wind and solar PV, however it is even more crucial for CCS, which is not a single technology but a technological system, characterised by multi-actor supply chains, long-term liabilities and large shared technological infrastructures. Previous examples of technological systems with these kinds of characteristics have benefitted from whole-system supply chain and actor coordination, and it is unlikely that CCS systems will make a substantial contribution to decarbonisation without similar support.

Exactly what such an innovation chain would consist of may vary among different countries – however it is very likely to imply an important role for governments. That is, as well as providing policies which set out a clear overall low carbon trajectory, and policies that provide specific incentives to low carbon generation or disincentives to carbon intensive generation, the implication is that governments will need to take a clear position on CCS as a national industrial strategy. This is likely to include, identifying the major CO₂ sources, identifying the major CO₂ sequestration sites, planning and optimising an infrastructure to connect them, and commissioning actors and consortia to deliver particular elements of this at the required points.

Different countries will have different ways of interpreting this. One example in the UK context is sketched out by Oxburgh (2016). This proposes the establishment of a CCS delivery agency, which takes overall responsibility for specific projects and thus for overall risk. The delivery agency would commission the various particular components of the CCS system on a competitive tender basis. Oxburgh (2016) suggests that this approach would significantly reduce costs compared to a purely private-actor consortium. Reflecting the UK context, Oxburgh (2016) notes that the delivery agency could eventually be privatised once it had done its job. Such an outcome would in fact mirror the history of the development of the UK’s other major networks – including for gas and electricity – much of which were developed and expanded in a centrally planned manner, before being privatised and run as a regulated monopoly. However this latter point is clearly a UK nuance. Other countries would develop their own versions of this process of actor, supply chain and infrastructure management or coordination, depending on the institutional arrangements they have for managing their large, shared technological infrastructure systems.

5.3.2 *Legal and regulatory issues*

CCS projects will require CO₂ to be stored in perpetuity. However, because of the relatively limited experience in storing CO₂ on a large scale, and the absence of evidence of CO₂ storage over very long time frames, the liability of such storage, if passed entirely to private actors in perpetuity, would constitute a major barrier to investment. If CCS is to be developed at all by private sector actors, the long time scales involved indicate that legal and regulatory regimes should provide for the

transfer of responsibility of storage sites to the State at some point post-cessation of injection activities. This may be considered a controversial issue. However, as discussed in Section 2.6.3 there are several other historical examples of major infrastructure projects for which the state underwrote risk or assumed some long-term liability, acknowledging that no private actor was in a position to do so.

National legislation almost always reflects the distinctive legal, political and economic considerations that prevail in any particular jurisdiction, and CCS is no exception. As such there is unlikely to be a single perfect legal model, and existing CCS regimes that have been developed to date have adopted quite different approaches.

A key challenge is to provide sufficient legal certainty in order to attract commercial and public confidence, while maintaining sufficient flexibility to handle inevitable uncertainties and the long time scales involved. The timing and degree of regulatory intervention requires careful judgment to avoid stifling an emerging technology.

The design of a CCS legal and regulatory regime should not be seen as a static exercise, and needs to incorporate effective review procedures and adaptation mechanisms in order to learn from developing scientific knowledge and technical experience.

5.3.3 *Public deliberation and the long term sustainability of CCS*

Societal perception of CCS, and whether it is initially welcomed, tolerated or opposed, will vary in different national and regional contexts. Even though CCS is still largely at a nascent stage, examples have been seen both of tolerant and oppositional stances towards it in different countries.

The extent to which public deliberation is a part of energy system development is itself a contextual factor. However, for many countries, excluding public opinions from energy system choices is no longer a desirable – or indeed possible – approach. In such contexts, early, transparent and genuine engagement with issues of concern and uncertainty will be essential.

It will be important to make it clear that the development of the kind of CCS roll out programme described in high-level terms in Section 5.3.1, would be linked to and conditional upon ongoing scientific assessment of the safety, effectiveness and sustainability of the system. One relevant issue is the ability of the system to securely store CO₂ without leaks. Attempting to insist pre-emptively that the system is one hundred percent secure, and that any concern is without foundation, may simply arouse suspicion that a decision has already been taken and that any consultation is simply a sham. Such initial situations can develop into long running and intractable stand-offs in which trust and communication become in short supply. A more constructive approach may be to engage openly with the concept of risk from the outset, being clear about the reasons for the programme as well as its potential uncertainties, but to emphasise that high-quality scientific monitoring would be engaged from the outset, and that any emerging concerns would trigger a pause and reassessment.

Another very significant issue emerging from modelling studies is the substantial use of biomass within CCS systems as a means of achieving negative emissions. The quantities of biomass entailed in these scenarios would be likely to raise significant – and legitimate – concerns about sustainability. Given the importance of the connection between biomass and CCS across numerous modelling studies, national CCS development programmes should also engage openly and early on in questions of biomass supply. Once again, the establishment of ongoing scientific assessment of options for sustainable supply of biomass is crucial, to ensure that if BECCS is pursued, the process does in fact achieve net negative emissions over the full life cycle, and that impacts arising from land use change from producing the biomass, are tolerable. Internationally recognised sustainable biomass certification systems may make an important contribution.

Other aspects of CCS may have more positive weight in public deliberations. For some countries there could be economic and employment benefits from the continuation of hydrocarbon industries within a low carbon economy, and opportunities for redeployment of relevant skills from fossil fuel energy sectors. Public deliberation around CCS might also be helped by locating it within the context of an overall low carbon transition, rather than presenting it as an isolated endeavour. In particular, some models suggest that demand reduction through major increases in energy efficiency could substantially reduce the cost of climate action, including in those scenarios with very high very high costs due to the unavailability of CCS. As such energy efficiency is a no-regrets measure, and further, may be crucial to the feasibility of climate policy targets if, for any reason CCS cannot be realised to the extent envisaged in the scenarios discussed in this report.

5.4. Summary of recommendations

1. CCS is not without risks and uncertainties. However, it is our judgement that at the present time, the risks of not having CCS available – in terms of the impact that would have on the achievability of climate targets – appear to be greater than the risks that may be associated with attempting to develop it.
2. The development of CCS requires an innovation system perspective. This includes: long-term clarity through a high-level long-term carbon commitment, such as a legislated target; targeted research development and demonstration activities, including national test centres and cross-national research collaborations; long-term price incentives, or equivalent carbon disincentives; and a whole chain coordination approach, due to multi-actor supply chains, liabilities and shared infrastructures.
3. Legal and regulatory issues are also crucial, but CCS is an emerging area. As such the development of legislation and regulation should not be seen as a static exercise, but incorporate effective review procedures and adaptation mechanisms. Project specific regulation during periods where it is too early to commit to enduring regulatory frameworks, may be appropriate.
4. Transparent and ongoing scientific assessment of risks and uncertainties will be a crucial part of the long term sustainability and acceptability of CCS. Critical issues include transparently verifying that CO₂ can be safely stored in any given project, and

demonstrating the full life cycle sustainability of biomass used in BECCS applications, including with appropriate certification processes. Broader risks of CCS not delivering to the extent envisaged in the scenarios discussed in this report may also be mitigated through strong increases in energy and material efficiency, which should be pursued as a no-regrets option.

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A.I Additional modelling results

This appendix presents additional results from cost sensitivity analyses that were not presented in Chapter 4 due to lack of space.

Each graph shows metrics already reported in Chapter 4 for the central scenarios. Here we compare results of these metrics for the 2°C standard CCS cost scenario (already reported in Chapter 4), with the 2°C high-CCS-cost scenario and 2°C low-CCS-cost scenario.

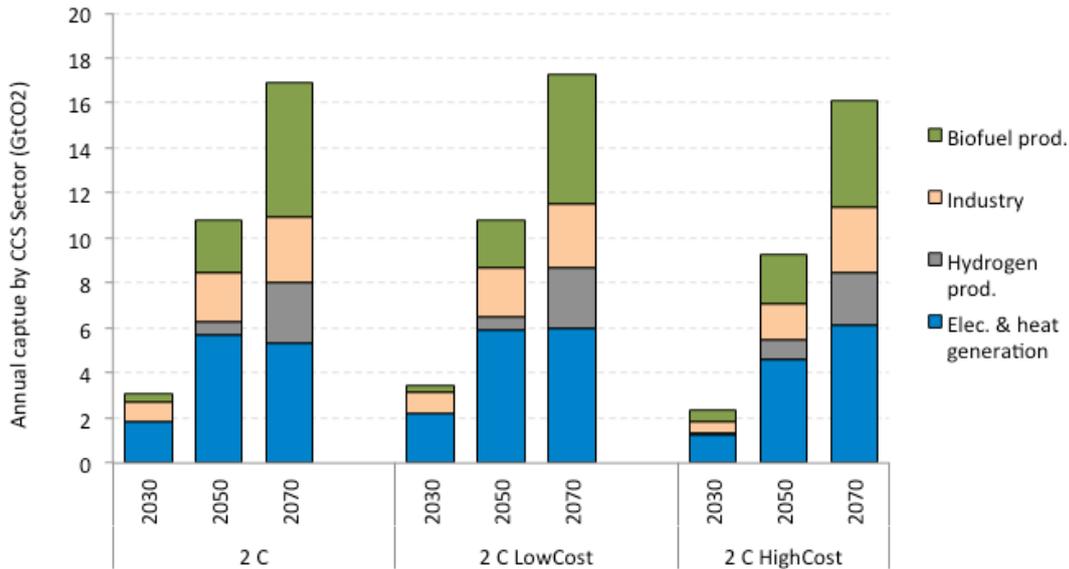


Figure 6.1: Annual capture by CCS sector (GtCO₂), for 2°C standard CCS cost scenario, 2°C low-CCS-cost scenario and 2°C high-CCS-cost scenario, for 2030, 2050 and 2070

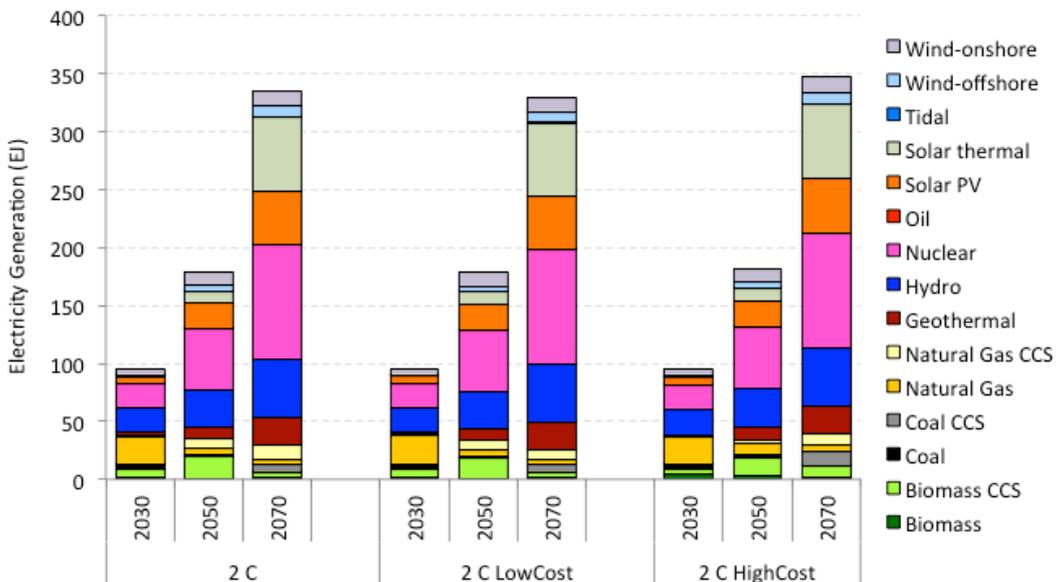


Figure 6.2: Annual electricity generation (EJ) for 2°C standard CCS cost scenario, 2°C low-CCS-cost scenario and 2°C high-CCS-cost scenario, for 2030, 2050 and 2070

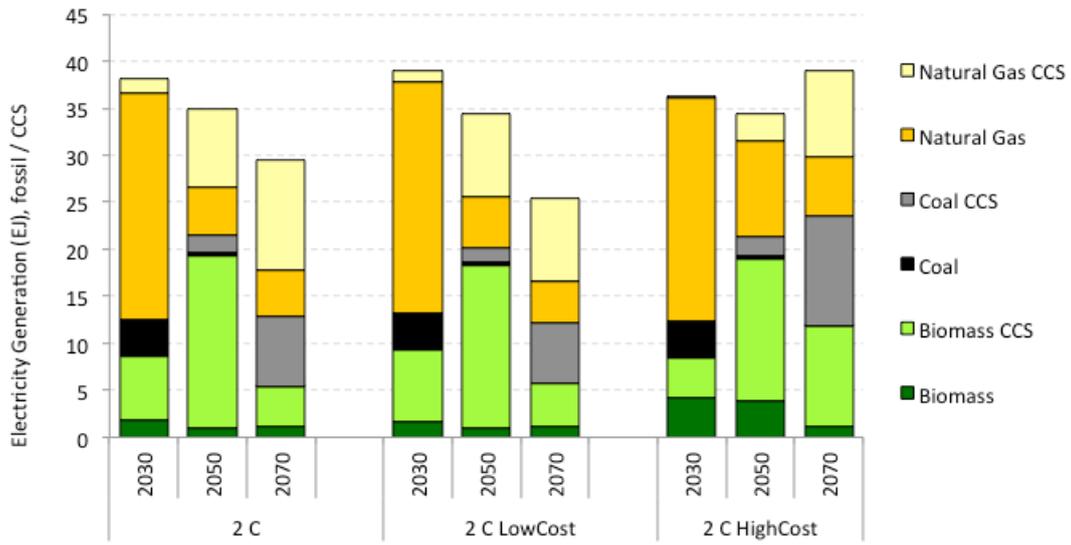


Figure 6.3: Annual electricity generation from fossil fuel sources for 2°C standard CCS cost scenario, 2°C low-CCS-cost scenario and 2°C high-CCS-cost scenario, for 2030, 2050 and 2070

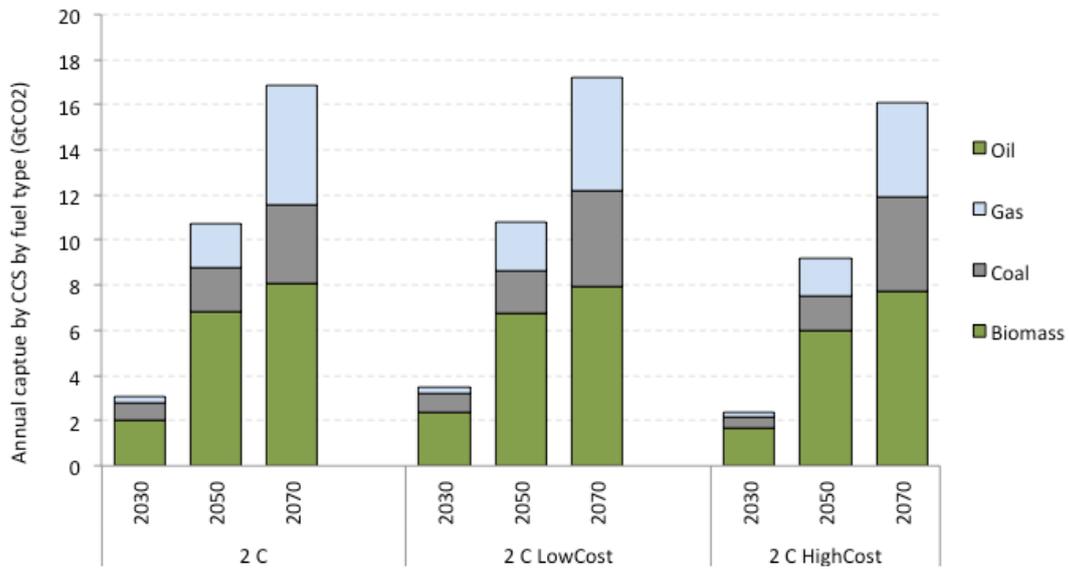


Figure 6.4: Annual capture by CCS (Gt CO₂) by fuel type for 2°C standard CCS cost scenario, 2°C low-CCS-cost scenario and 2°C high-CCS-cost scenario, for 2030, 2050 and 2070

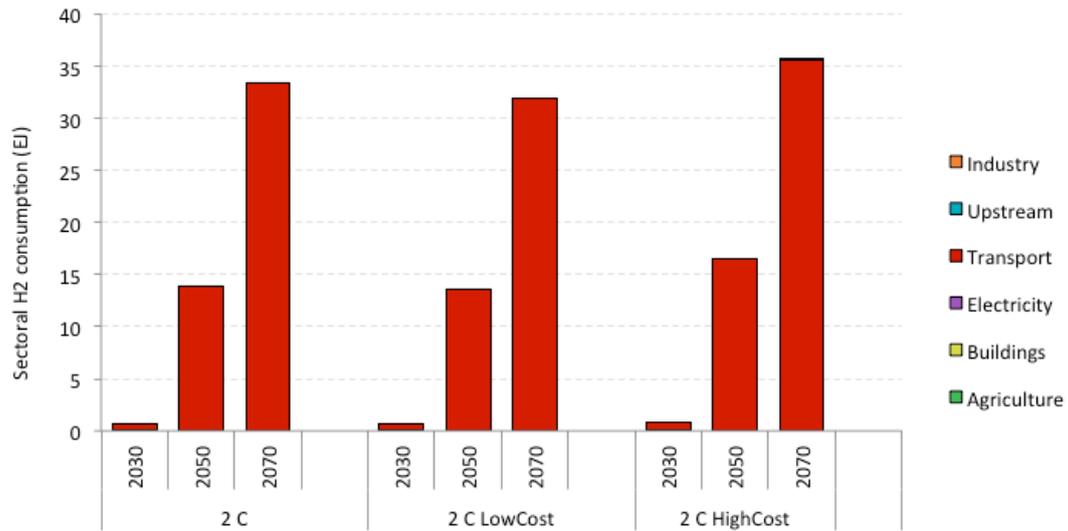


Figure 6.5: Sectoral hydrogen consumption (EJ) for 2°C standard CCS cost scenario, 2°C low-CCS-cost scenario and 2°C high-CCS-cost scenario, for 2030, 2050 and 2070

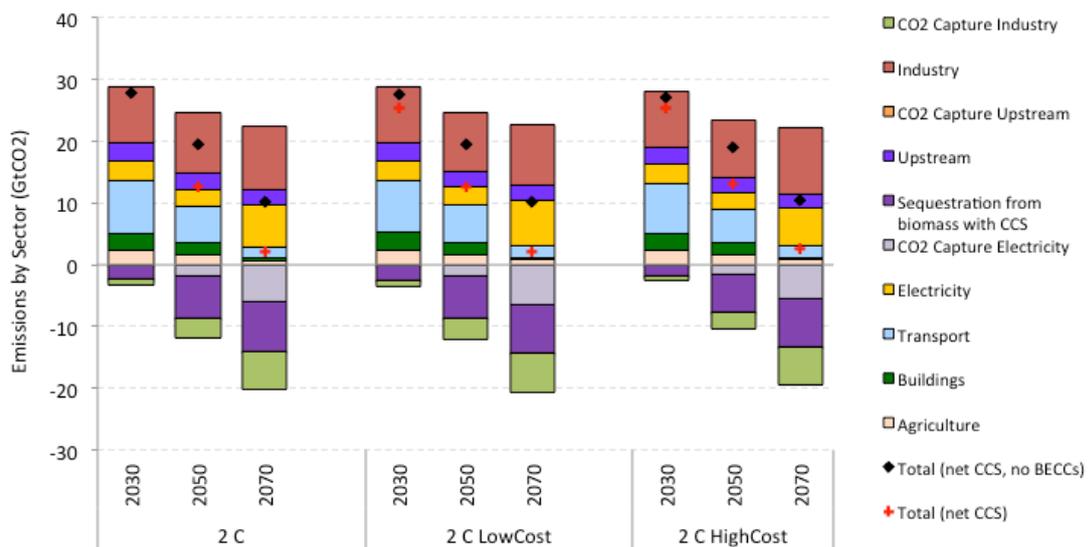


Figure 6.6: Emissions by sector (GtCO₂) for 2°C standard CCS cost scenario, 2°C low-CCS-cost scenario and 2°C high-CCS-cost scenario, for 2030, 2050 and 2070

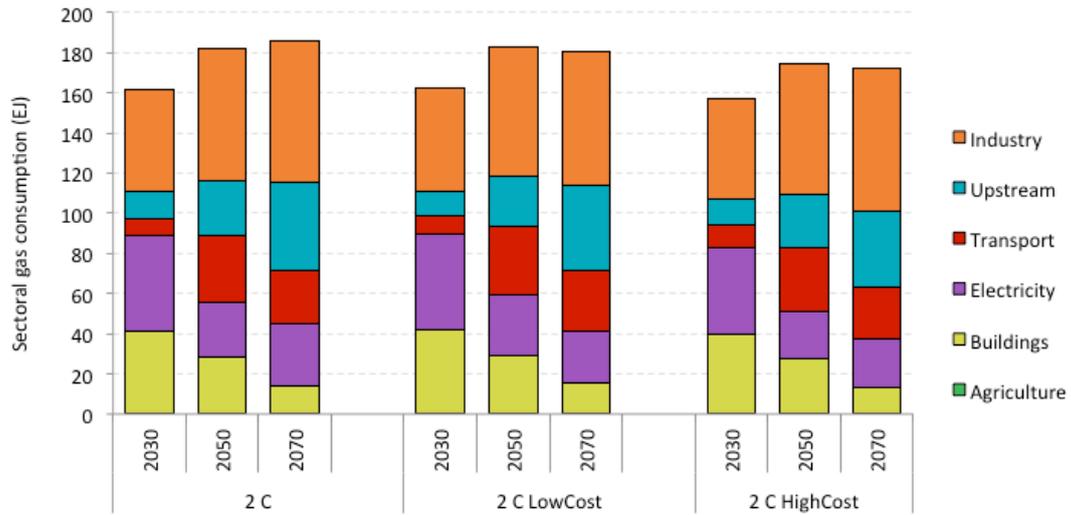


Figure 6.7: Sectoral gas consumption (EJ) for 2°C standard CCS cost scenario, 2°C low-CCS-cost scenario and 2°C high-CCS-cost scenario, for 2030, 2050 and 2070

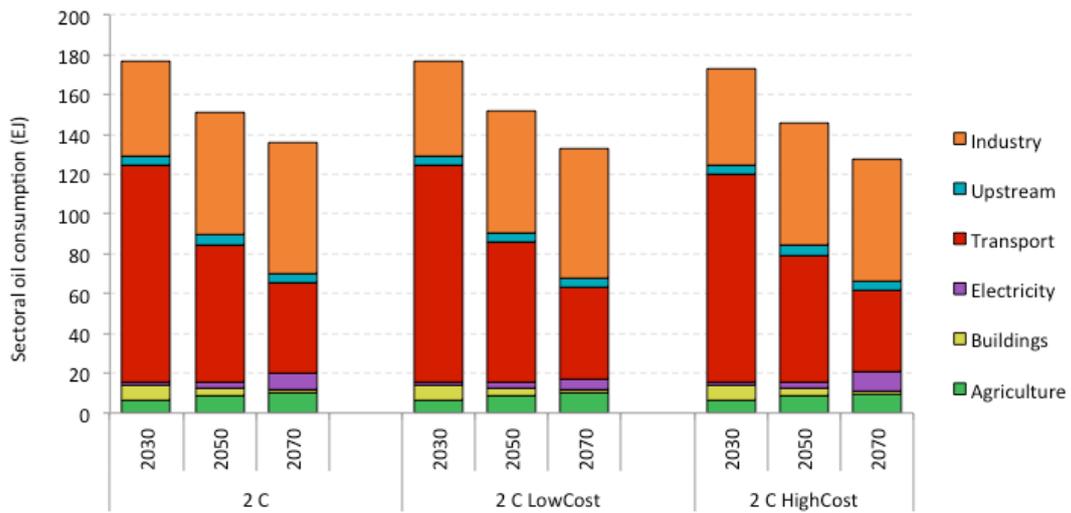


Figure 6.8: Sectoral oil consumption (EJ) for 2°C standard CCS cost scenario, 2°C low-CCS-cost scenario and 2°C high-CCS-cost scenario, for 2030, 2050 and 2070

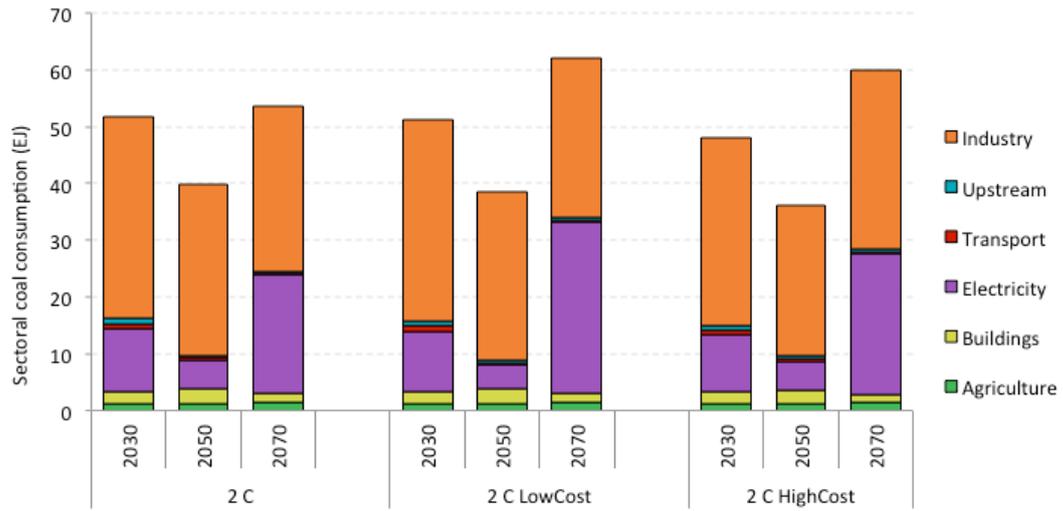


Figure 6.9: Sectoral coal consumption (EJ) for 2°C standard CCS cost scenario, 2°C low-CCS-cost scenario and 2°C high-CCS-cost scenario, for 2030, 2050 and 2070