

Carbon dioxide storage

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Executive summary

CARBON CAPTURE AND STORAGE (CCS) REFERS TO THE SET OF technologies developed to capture carbon dioxide (CO₂) gas from the exhausts of power stations and from other industrial sources, the infrastructure for handling and transporting CO₂ and those for injection and storage in deep geological formations. All the individual elements operate today in the oil and gas and chemical processing sectors. However, their integration for CO₂ capture from power plants and heavy emitting industry is a challenge and the storage of huge quantities of CO₂ underground raises new issues of liability and risk. The focus of this Briefing Paper is on the storage of carbon deep underground; a companion Briefing Paper addresses the capture element of CCS, discussing the set of technologies developed to capture carbon dioxide (CO₂) gas from the exhausts of power stations and from other industrial sources.

Why are we interested in CCS?

CCS is a potentially critical transitional technology, offering a near-term way to mitigate climate change consistent with continued extensive fossil fuel use while progress is made towards establishing a truly sustainable low-carbon energy system in the medium to longer term. Indeed, the costs of mitigation are expected to be considerably higher if CCS is not included in future low-carbon energy technology portfolios. The deployment of CCS in countries with very large indigenous fossil fuel reserves could also reinforce energy security while achieving climate mitigation goals. Equally, decoupling the use of coal from CO₂ emissions is attractive in terms of allowing a more diverse range of energy sources for countries heavily reliant on imported fuels.

The current state of CCS storage

There are over a hundred sites worldwide where CO₂ is injected underground as part of normal oilfield operations, either as part of an enhanced oil recovery (EOR) scheme or to prevent toxic acid gases being released to

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Carbon Capture and Storage

- CO₂
- Electricity
- Gas
- Coal and Biomass

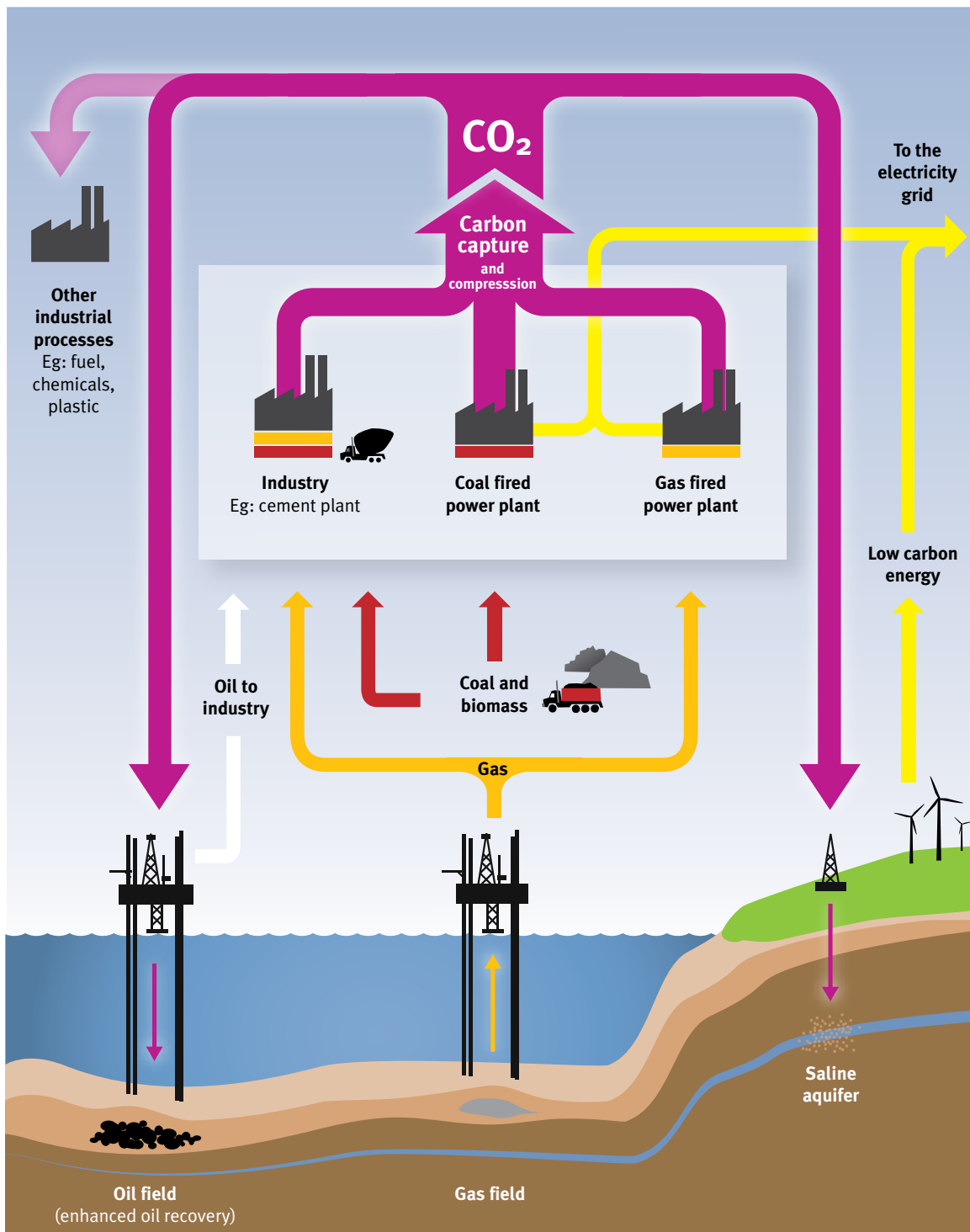


Figure 1. Schematic of carbon capture and storage. This Briefing Note will focus on the challenges associated with large-scale storage in saline aquifers and depleted oil and gas fields.

the atmosphere (CO₂ is injected mixed with hydrogen sulphide - H₂S)¹. There are also several current and planned storage projects, specifically designed to reduce atmospheric emissions of CO₂ which store around 1 Mt (one million tonnes) of CO₂ per year². The challenge is how to design storage such that the CO₂

remains underground for thousands of years and how to handle the huge volumes necessary to make an impact on global CO₂ emissions—we will need to store several thousand times more CO₂ than is captured by current projects if CCS is to have a significant impact.

Non-technical challenges

Credible policy and regulatory frameworks are needed to manage the economic, health and environmental risks associated with the full-scale demonstration phase and deployment if CCS is to gain public acceptance across the globe. Public perceptions will likely be formed based on the performance of the demonstration projects; early failures may have serious implications for the credibility and estimated cost of CCS as a major mitigation option. Cost reduction is the major challenge for carbon capture technology because more fuel must be burnt (about 20–30%) to produce the same amount of electricity, and thus, there are significant implications for fuel security and energy efficiency, which must be considered alongside emission mitigation strategies. The risks associated with carbon storage are generally considered more important than those associated with capture. However, as we discuss, with careful injection design it should be possible to ensure long-term safe storage. Initial demonstration projects need to be chosen carefully and it is likely that most of the first storage sites will be offshore; the real challenge though is establishing an infrastructure capable of handling the large volumes of CO₂ necessary.

Introduction

This Briefing Paper discusses the injection and underground storage of carbon dioxide. This is one component of carbon capture and storage (CCS), where CO₂ is collected from large industrial sources, such as power stations, refineries or cement works, transported and then injected deep below the sur-

face, as shown schematically in Figure 1. This is a companion to the Briefing Paper that focuses on carbon capture.

The paper explains what happens to CO₂ when it is injected into porous rock – either aquifers containing salty water or depleted oil and gas reservoirs – and describes the fate of CO₂ over tens to thousands of years, based on experimental evidence, numerical modelling and field trials. It also provides an analysis of how rapidly the CO₂ can be injected and the possibility of leakage, borrowing from extensive experience in the oil industry. We conclude that with proper design, CO₂ can be stored safely in large volumes; over time the CO₂ becomes less likely to escape and so extensive monitoring may only be required during the injection phase. In particular, CCS is a technology where the UK could take a lead, since ample offshore storage below the North Sea is available close to power stations near the East coast.

The need for carbon capture and storage

Carbon Capture and Storage (CCS), the collection of CO₂ from industrial sources and its injection underground, could contribute significantly to reductions in atmospheric emissions of this greenhouse gas³. Table 1 lists the three types of CCS, from collecting CO₂ already produced in routine oil-field operations to carbon-negative schemes where the CO₂ generated from burning biomass is stored⁴. In terms of mitigating huge levels of energy-related CO₂ emissions from coal power stations—estimated at some 12 Gt (1 Gt is 1 billion, 10⁹, tonnes or 10¹² kg) of CO₂ per year⁵—Type 2 Near Carbon Neutral CCS will be the most

Class of CSS

	Definition and impact on CO ₂ emissions	Typical Example
Carbon-positive	The capture and storage of CO ₂ from industrial operations that produce a carbon-containing fuel. CO ₂ is generated in significant quantities when this fuel is burnt, but the extra CO ₂ generated in its synthesis is collected	Coal-to-liquids plants producing synthetic fuels. Stripping natural CO ₂ from oil or gas production
Near carbon-neutral	Projects that produce carbon-free or low-carbon energy (normally electricity, hydrogen and/or heat). These projects should lead to significant CO ₂ emissions reductions since the majority of CO ₂ in the fossil fuel used can be captured. It is likely that there will still be some net CO ₂ emission to atmosphere from the project though (unless it burns biomass as well, see below), particularly when analysis is carried out on a lifecycle basis. Estimated close to 100% of CO ₂ can be captured	Power plant producing electricity using fossil fuels
Potentially carbon-negative	Class 3A: Direct capture of CO ₂ from the air. Class 3B: As class 2, but with fossil fuel replaced, partially or wholly, by biomass. If the CO ₂ emitted when the biomass is burnt or gasified is captured, the net CO ₂ emission for the biomass lifecycle can be negative, depending on how the biomass is grown and transported. This can offset the emissions associated with a Class 2 project and may allow for the whole project to remove CO ₂ from the atmosphere on a lifecycle basis	3B: Co-firing biomass in a power plant fitted with CO ₂ capture

Table 1. Classes of CCS⁴.

important application. Also important, to limit likely global average temperature increases to 2°C, is the implementation of CCS in power stations that burn both fossil fuels and biomass, allowing carbon negative electricity generation (Type 3). Possible sites for injection of the captured CO₂ include coalbeds, deep saline aquifers, and depleted oil and gas reservoirs.

Injecting CO₂ into depleted oil and gas reservoirs for enhanced oil recovery (EOR), which results in additional hydrocarbon recovery, generates revenue to off-set the costs of capture and storage⁶. CO₂ flooding is an effective and well-established oil recovery mechanism that can use existing injection infrastructure and the experience of the oil industry to extend the lifetime of many reservoirs. While suitable formations are easily located, they are inequitably distributed geographically⁷. Compared with oil and gas reservoirs, deep saline aquifers are widely distributed throughout the globe, although they often have poorly characterized geology. These systems could therefore be used for the disposal of anthropogenic CO₂ in locations where there are no suitable oil or gas reservoir alternatives. In the US and offshore UK, both areas which are blessed with many oil and gas fields, storage in depleted hydrocarbon reservoirs is an attractive option. In contrast, India and China have significant coal-fired power generation but do not have such widespread oil and gas resources, and so saline aquifer storage may be the only solution for large-scale storage in these countries.

To date, estimates of potential storage capacity have been approximate with wide error margins. In general, the volume of sedimentary rocks has been estimated and then multiplied by a small factor, representing the fraction that could, potentially, be occupied by CO₂. For oil and gas reserves, the estimates are rather more reliable, since we already have an assessment of how much hydrocarbon was originally stored in them. Later, we will discuss further the basis of these estimates and mention re-

cent research that is attempting to quantify UK storage capacity offshore. With these caveats, the best estimates imply that there is plenty of storage capacity in saline aquifers with significant capacity in oil and gas reservoirs. According to the International Energy Agency (IEA) Greenhouse R&D Program⁸, oil and gas reservoirs have an estimated CO₂ storage capacity of about 920 Gt – with a considerable margin of uncertainty. For comparison, the estimated total global emissions of CO₂ from fossil fuel use are around 30 Gt per year, while deep saline aquifers could store between 400 to 10,000 Gt in total⁹.

CCS is proposed as one component of a strategy to reduce CO₂ emissions into the atmosphere. CCS recognises that fossil fuels will continue to be used in the short to medium term, and removes most of the CO₂ emissions associated with fossil fuel use in power stations and some industrial plants. The IPCC report on CCS, published in 2005³, suggests that CCS could store up to 10 Gt of CO₂ per year when applied globally by 2050 (the IEA proposes a similar possible implementation⁸). This is still less than current emissions from coal alone (around 12 Gt/year) and so is only effective in combination with a move to greater energy efficiency combined with the development of other low-carbon power sources. While 10 Gt is a significant fraction of total emissions (30 Gt/year); it is not the whole story. CCS is potentially an important component, but not the only one, of serious efforts to reduce emissions.

The world has huge reserves of fossil fuels, particularly coal, that provide over 80% of the world's energy and yet analysis suggests that we will need to make radical reductions in CO₂ emissions over the next 50 years to limit the pace and scale of climate change and its associated impacts¹⁰. Figure 2 shows my own analysis of future production of oil, gas and coal and the consequences for CO₂ concentrations. Unlike many other scenarios, this is a resource-based estimate of production, based

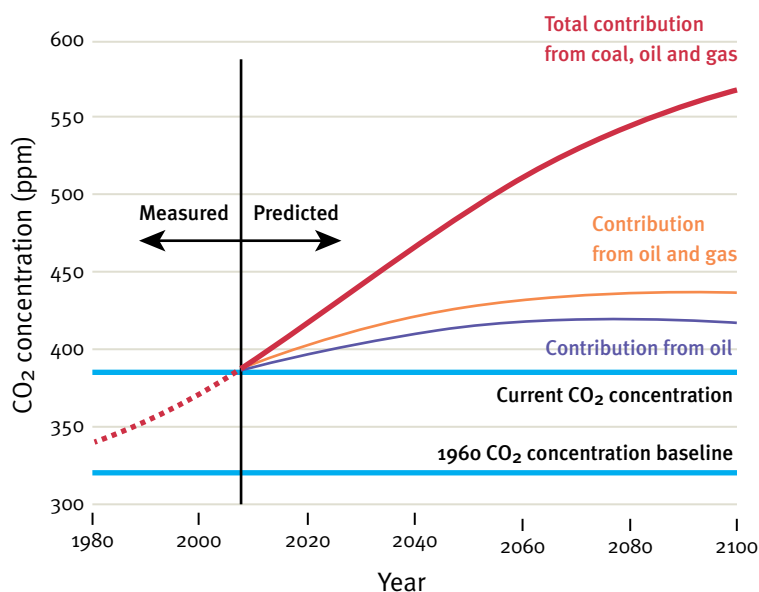


Figure 2. Predicted and measured atmospheric carbon dioxide concentrations. The dashed line from 1980 to 2008 is the concentration measured in Hawaii¹¹. The solid line is a prediction based on past and possible future use of fossil fuels. The coloured lines indicate the contributions of oil, gas and coal. The data is taken from the BP Statistical Review of Energy¹² and matched trends in the production of oil, gas and coal to a logistic equation (a Hubbert fit) and then extrapolated to the future. This assumes that half the CO₂ generated when the fuel is burnt remains in the atmosphere—the other half dissolves in the sea or is absorbed by the land surface and terrestrial biosphere. Until 2008, the estimated total contribution of fossil fuel matches the measured rise in concentration. 2008 is taken as a baseline and predictions of future concentrations are based on current trends in production.

on current trends—the data sources and approximations are described briefly in the figure caption. The curve demonstrates that according to current projections we are heading towards a CO₂ concentration close to 600ppm by the end of this century—this is at the higher end of IPCC demand-based estimates.

How do we deal with this trend in emissions? Low-carbon technologies will take several decades to deploy at sufficient scale to replace current consumption of fossil fuels and may not do so at the pace needed in countries such as India, China and the US, which have enormous reserves of coal that provide cheap energy to fuel economic growth. CCS provides a way to deal with emissions from fossil-fuel power stations, allowing us time to develop low-carbon forms of energy without massively disrupting global economic systems. Without CCS, it is likely that these cheap, abundant fossil fuels will be burnt unabated for many years to come, with significant consequences for the world's climate.

Carbon storage in geological formations

Key to appreciating the challenges associated with storage is an understanding of the rock into which the CO₂ is injected. The CO₂ will be injected deep underground at depths of around 1,000m or more. This is to ensure that it cannot escape, as well as being at sufficient pressure to liquefy the gas, making it much denser and more efficient to store, since a given mass of CO₂ occupies less volume under these conditions. The CO₂ will be injected into sedimentary rock. This is rock composed of particles—sand, crushed sea shells or precipitated calcium carbonate, for instance. They are deposited over millions of years in river estuaries, deltas and in shallow seas, and have been crushed and cemented together as more sediment has piled on. Their key feature is that they contain holes which connect, allowing fluids to flow through them. These rocks are permeable with somewhere between 10% and 30% of the total volume of the rock comprising pore space. Sandstone and limestone used in building, and chalk cliffs are all examples of sedimentary rock.

Box 1. Permeability—Darcy's law and fluid flow

The measure of permeability (denoted here by K) is the darcy, named after Henry Darcy, the French Civil Engineer who first expressed the linear relationship between flow rate and pressure gradient for flow in porous media:

$$q = -\frac{K}{\mu} \nabla P$$

where q is the flow rate (the volume of fluid flowing per unit area per unit time – it has the units of speed), μ is the viscosity of the fluid and ∇P is the pressure gradient caused by pumping at wells or gravity.

The void space of the rock deep underground is full of water, unless it also contains oil and gas (see below). At high pressure, salts dissolve in the water and so we have highly saline brines, often saltier than sea water, that cannot be used for drinking or agriculture. It is proposed to store the CO₂ in these saline aquifers.

Much research has been conducted on such rock formations as they occasionally contain oil or gas. These valuable hydrocarbons are the product of the partial decay of living organisms after burial at high temperatures and pressures. The higher the pressures and temperatures, the more the complex molecules are broken down, so shallow environments lead to heavy, viscous oils, while deep reservoirs contain natural gas (methane). Hydrocarbons are formed in source rocks and then migrate upwards under gravity (oil is less dense than water) until they reach rock through which they cannot flow, called cap rock.

Consider the iconic images of the Grand Canyon, where the Colorado River has cut through hundreds of metres of sedimentary rock; this shows that the subsurface can, and often does, contain many packages of porous sandstone and carbonate that are many hundreds of metres in thickness, and extremely widespread – often extending for hundreds of kilometers. Hydrocarbon basins such as the Illinois Basin¹³, Texas Gulf¹⁴ or the North Sea¹⁵ are also endowed with multiple layers of sandstone and each layer may be hundreds of metres in thickness. Figure 3 shows a schematic cross-section through rock below the North Sea, indicating oil and gas fields. This indicates that there are huge volumes of potential storage space around the world.

Current storage projects

The separation of CO₂ from other gases and its injection underground is old-fashioned, standard technology in the oil industry, with well over 100 places worldwide where CO₂ is injected as part of routine oil-field operations¹. There are two principal reasons for this, neither of them associated with concerns over climate change. The first is that natural gas in underground reservoirs, in the type of porous rock described above, often

A permeability of 1 darcy means that water flowing under gravity will have a flow rate of approximately 10⁻⁵ m/s. Imagine that a slab of rock is saturated with water. When excess water is poured onto the slab; water flows through the rock and drips off the underside. A rock of permeability 1 darcy would allow a pool of water 1 mm deep to drain every 100 seconds or nearly 1 metre every day. This represents a permeable rock with pore spaces (between grains) that are typically some 10 – 100 μm across. Most storage sites will have permeabilities from around 1 darcy to 10 millidarcies (10 thousandths of a darcy).

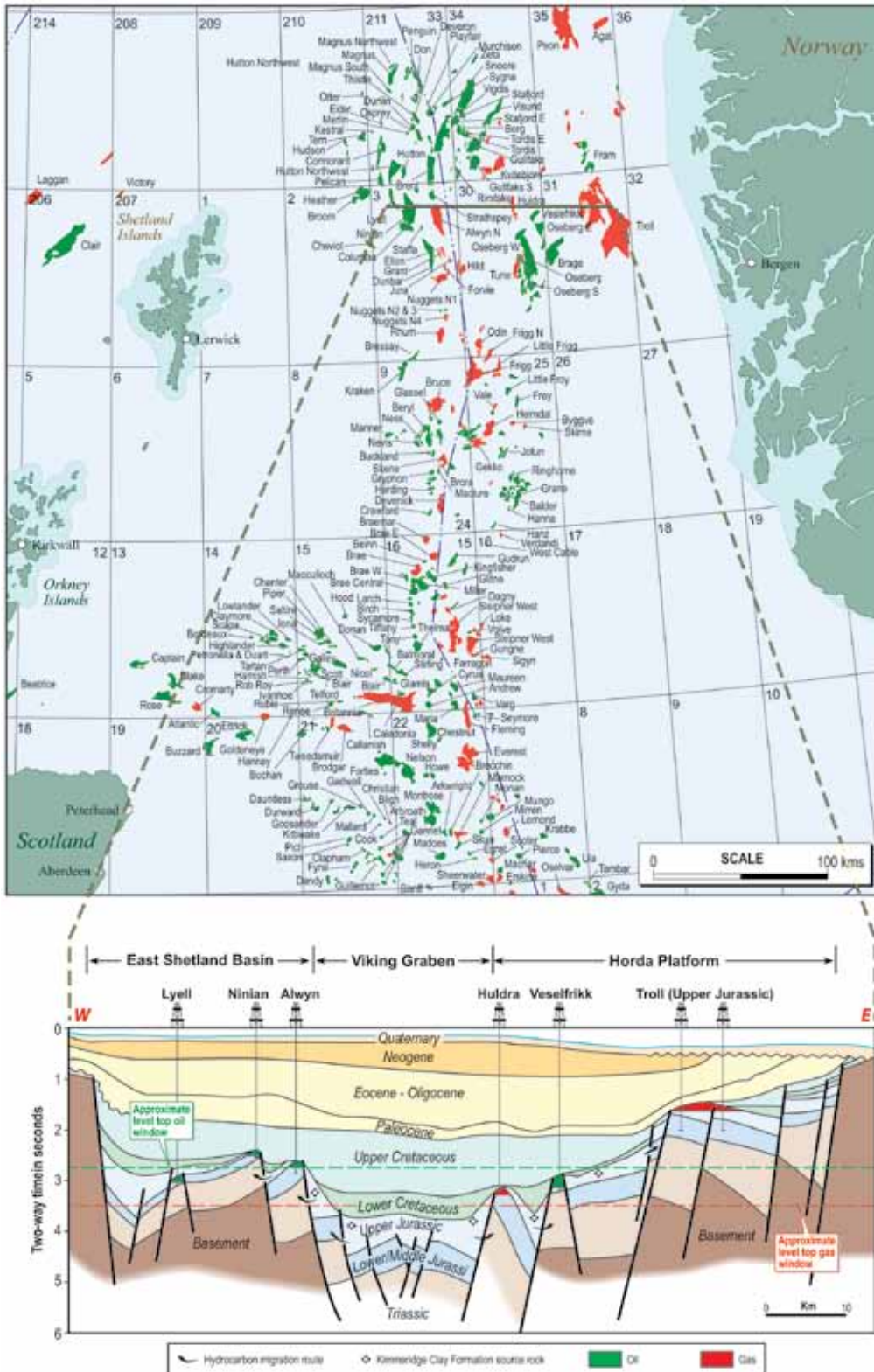


Figure 3. The upper map shows oil and gas fields in the Northern North Sea; these are potential storage locations for carbon dioxide. Oil fields are shown in green and gas fields in red. The lower figure shows a vertical cross-section through the rock below the sea bed along the solid bold line indicated on the top map. The pale coloured regions represent sedimentary rock, saturated with brine. There are several thousand metres of porous rock in which carbon dioxide could be stored—the oil and gas fields represent just a small fraction of the total volume. The structure is imaged using seismic surveys—sending sound waves through the rock. The vertical axis is the travel time for a sound wave to travel through rock and reflect back to the surface, measured in seconds—a 1 second travel time represents, approximately, a true depth of 1 km. Figure adapted from^{16,17}.

contains CO₂. To sell the natural gas, the CO₂ needs to be removed. Usually the CO₂ is simply vented to the atmosphere, but often H₂S, a much more toxic gas, is also present. The H₂S-CO₂ mixture is injected underground to obey local air pollution laws. The second major application of CO₂ injection is for enhanced oil recovery (EOR). CO₂ at high temperatures and pressures will dissolve in oil. This helps remove oil from the rock and boosts recovery. There are approximately 70 CO₂ injection projects

worldwide devoted to EOR, most situated in West Texas where over 1,000 km of pipelines have delivered CO₂ to many oilfields in the region for over 30 years. Here, principally, natural sources of CO₂—again from underground reservoirs—are used.

With all this experience, it seems surprising that CCS is presented as a new and even speculative technology. There are several reasons for this. The principal one is scale: CO₂-EOR projects

typically inject a few million metric tonnes (Mt) of CO₂ per year at most, and much of this CO₂ flows through the reservoir and is produced with the additional oil. This is good for oil production, but not useful for permanent storage. Projects associated with CO₂ separation from natural gas are of the same size or smaller. In contrast, a large coal-fired power station producing 1 GW of power will produce 4-5 Mt of CO₂ per year—several times the size of current projects: for instance, the Cottam coal-fired power station, which is the 4th largest individual source of CO₂ in the UK, emits approximately 9 Mt of CO₂ per year and generates around 2 GW of power¹⁸. Furthermore, to make a significant difference, up to 1,000 of these schemes are required across the world—not just a few small-scale pilot plants. Secondly, the current methods used to separate CO₂ from a stream of gas—natural gas, or the exhaust of a power station—are energy intensive and expensive. The companion Briefing Paper on capture discusses new methods that are potentially cheaper and more efficient. Thirdly, while each component of CCS has been demonstrated individually—capture, transport and injection—they have not all been assembled together on a full-size power plant.

In addition to the experience mentioned above, there are projects where CO₂ storage specifically attempts to reduce greenhouse gas emissions. Since 1996, approximately 1 Mt per year of CO₂ has been injected as part of the Sleipner project, in the Norwegian sector of the North Sea. CO₂ is separated out of a natural gas stream and injected into a saline aquifer to avoid Norway's carbon tax^{19,20}. In-Salah in Algeria also stores CO₂ from a natural gas field, while the Weyburn field in Canada uses CO₂ collected from a gas-to-liquids plant for EOR. All three of these projects may be characterized as Class 1 (Table 1)—storage of CO₂ produced from routine industrial activities. A recent review of some twenty CO₂ injection projects, of which nine are at, or are intended to be at, an industrial scale, storing 1-to-130 Mt CO₂ during the project lifetime, has concluded that large quantities of CO₂ can be injected and stored in porous rock successfully². The Scottish Centre for Carbon Storage, University of Edinburgh²¹ provides a map showing current and planned CCS projects worldwide. To make a significant impact on emissions, we would have to handle and store volumes of CO₂ similar to

the amount of oil and gas currently handled by the hydrocarbon industry—a huge, but not insurmountable challenge (see Box 2).

Storage mechanisms

Super-critical CO₂: it weighs like a liquid and flows like a gas.

The CO₂ will generally be injected underground as a so-called super-critical fluid. The somewhat alarming term 'super-critical' simply means that the CO₂ has a liquid-like density and flows like a gas, and with a decrease in pressure will expand to form a gas without a phase transition (it will not boil). The CO₂ density will still be less than water. The viscosity—an inverse measure of how well the CO₂ flows—will be typically less than a tenth of the brine resident in the rock. CO₂ cannot burn or explode; the only reaction that it can undergo in the subsurface is the precipitation of solid, described below.

The injected CO₂ will migrate to the top of the rock layer because of buoyancy forces. As we are interested in the long term trapping of the CO₂ for hundreds to thousands of years, it is imperative that the CO₂ cannot escape. There are four principal ways in which the CO₂ is prevented from reaching the surface:

Cap rock. Structural or stratigraphic trapping refers to low-permeability layers of rock (cap rock) that prevent the upwards movement of CO₂. Similar traps have held oil and gas underground for millions of years. The traps are comprised of salt, shale or clays: they need not be completely impermeable, but have pore spaces that are so small that the CO₂ has insufficient pressure to enter. In well-characterised formations, this is a good way to ensure storage. For instance, in Sleipner, the use of periodic seismic surveys (using sound waves to image the subsurface) have shown that the injected CO₂ rises to the top of the aquifer and then spreads out underneath low permeability cap rock layers at the top. However, if CCS is to be applied on a global scale, some storage sites may not be as well characterised as major oil and gas producing basins such as the North Sea. In this case another approach is required in case the cap rock contains gaps or fractures or is absent.

Box 2. The scale of CCS needed to make an impact

Imagine that CCS, when implemented at a global scale, is injecting some 6 Gt of CO₂ per year: this is only half the current emissions from coal and 20% of total CO₂ fossil fuel emissions, so it is an important contribution to limiting emissions, but only one of a number of technologies necessary. Typical densities of the CO₂ when injected at high pressure deep underground are 500 – 700 kg/m³. Assuming 600 kg/m³, 6 Gt is equivalent to 10¹⁰ m³ of CO₂ per year or 2.7 x 10⁷ m³ per day. Compare this with global oil production, which is measured in barrels (1 barrel is 42 US gallons or approximately 0.169 m³) at around 80 million barrels, or 1.5 x 10⁷ m³ of oil per day; the

volume of CO₂ stored would be approximately twice global oil production. That the volumes of CO₂ injected in CCS and oil produced are of the same order of magnitude should make intuitive sense: oil contributes a significant fraction of fossil fuel use – when burnt it produces CO₂ and we are dealing with fluids of similar density. We also produce gas and use water to displace oil from reservoirs – it is estimated for every barrel of oil, three barrels of water are also treated and re-injected. So the scale of the problem is huge, but around the size of the current oil industry in terms of volume of fluid handled.

Dissolution. Over hundreds to thousands of years, the CO₂ will dissolve in the formation brine forming a denser phase that will sink. CO₂ at high pressure has a reasonably high solubility in water, although this solubility decreases as the brine becomes more saline. As an example, a 6% sodium chloride solution—almost twice as salty as sea water—will dissolve approximately 30–40 kg/m³ of CO₂ at temperatures of 80°C and pressures of 10 MPa²², representative of a reservoir at a depth of around 1,000 m where heat from the earth’s core makes it hotter than near the surface. While this is promising, the dissolution of CO₂ is a slow process, mediated by molecular diffusion and the flow of the denser CO₂-laden brine. Simulation studies indicate that it takes hundreds to thousands of years for a significant fraction of the CO₂ to dissolve in typical reservoir settings²³.

Reaction. The CO₂ dissolved in brine forms a weakly acidic solution that may react over thousands to millions of years with the host rock, forming solid carbonate. This is a complex geochemical process, but in essence, oxides in the rock dissolve and then re-precipitate as carbonate. The opposite can also occur, in that the acidic brine dissolves part of the rock, increasing the volume of the pore space and the permeability. The speed, extent and nature of these reactions depends principally on the mineralogy of the rock.

Dissolution and precipitation both render the CO₂ less mobile over time. The storage security increases over hundreds to thousands of years. The problem is that these are slow processes: in the worst case, by the time a significant fraction of the CO₂ has dissolved, much of the CO₂ may already have escaped to the surface^{23–25}.

Capillary trapping. The final process, which is more rapid, is capillary trapping. This occurs when water displaces CO₂ in the pore space. Figure 4 shows this process—coupled with dissolution—at the field scale, while Figure 5 illustrates CO₂ trapped at the pore scale. Water tends to wet the surface, leaving the CO₂ surrounded by water in pore-space bubbles that cannot escape (Figure 5). Simulation studies of CO₂ storage have emphasized the importance of this mechanism^{26–30}. This process is well established in the oil industry: water is used to displace oil from reservoirs, but typically only around half the oil is recovered since much remains trapped in the pore space. Further water injection simply leads to excessive recycling of water from injection to production wells with little or no further oil recovery—this is why three barrels of water are recovered for every barrel of oil on average. This is a process that is well understood in the laboratory: if you inject water, you cannot push all the oil, or CO₂ out, as it gets trapped in the pore space.

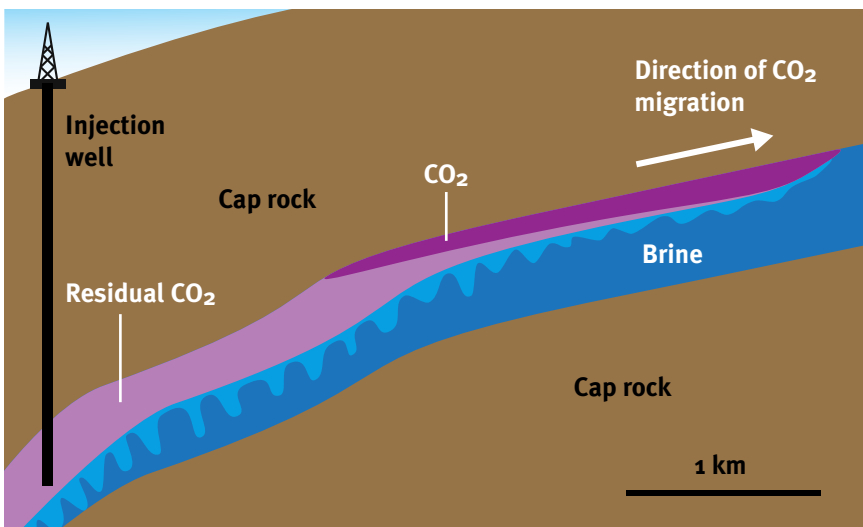


Figure 4. A schematic of CO₂ movement after injection. Since the CO₂ (purple) is less dense than brine, it moves upwards through the aquifer, under the cap rock. At the bottom of the injected CO₂ plume, brine displaces the CO₂. This leaves behind a trail of trapped CO₂ (pale purple) as bubbles in the pore space, illustrated in Figure 5. CO₂ also dissolves in the brine (shown in blue); this denser CO₂-laden brine (pale blue) sinks slowly through the aquifer²⁹.

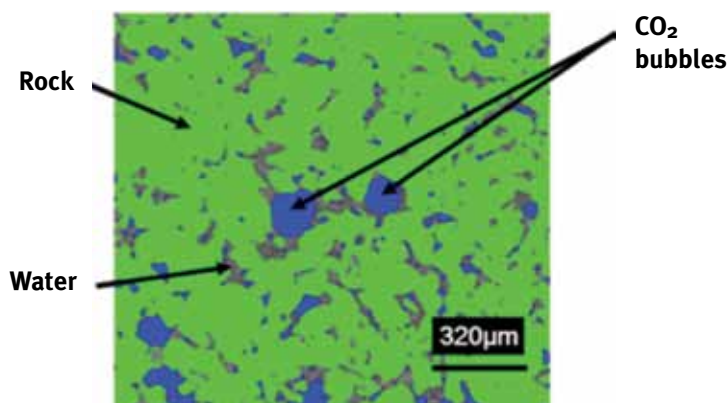


Figure 5. A two-dimensional cross-section of a three-dimensional image of a reservoir sandstone. The image has a resolution of approximately 10 µm using X-rays: the colouring is false and used to illustrate the contrast between rock grain (green), water or brine (grey) and capillary trapped non-wetting phase (blue)³¹.

The CO₂ would be trapped when it is displaced by water due to a regional movement of groundwater or when a buoyant CO₂ plume migrates upwards: at the trailing edge, water displaces—and potentially traps—the CO₂. Recent work has suggested that pumping out saline water (brine) from the aquifer and then re-injecting would enhance this natural process²⁹, leading to the proposal of an injection scheme where CO₂ and brine are injected together followed by chase brine³². This is discussed later in this paper: the idea is to design injection so that all the CO₂ is trapped during the injection phase, making significant leakage very unlikely.

Pressure response

In the oil industry there is a net removal of fluid from the subsurface. This does not create a vacuum in the pore space of the rock, of course. The pressure in the reservoir drops and the rock, water and hydrocarbon expand to fill the space vacated by hydrocarbon. In most reservoirs, the natural expansion of rock and water surrounding the reservoir is insufficiently fast to prevent a very rapid drop in pressure. When this happens, natural gas comes out solution in the oil (this is just the same as CO₂ liberated from a bottle of champagne—or, more prosaically, cola—when it is opened). This is bad news for recovery, as the gas is preferentially produced (it has a much lower viscosity than oil), leaving the valuable oil behind. To compensate for this, to maintain pressure and push the oil out, water is usually injected—hence the comments on water production in the preceding paragraph. In gas fields this is not necessary—simply allowing the pressure to decrease allows the gas to expand and be produced.

The obvious storage solution is to inject CO₂ to replace the oil and gas produced in old hydrocarbon fields in an EOR scheme. This has three advantages and one major drawback. First, the field must have a good cap rock to have contained the hydrocarbon for millions of years and so safe storage is possible. Second, the injection of CO₂ can enhance oil and gas production, giving some economic pay-back, as mentioned before. Third, there is a pipeline infrastructure in place for injection, although this may be ageing and not specifically suited for CO₂. The injected CO₂ will cause the reservoir pressure to rise again, replacing the volume of produced hydrocarbons. The main disadvantage is that the extra production causes more CO₂ to be burnt when extra oil and gas is produced—typically at least as much CO₂ as is stored. So this is not going to deliver the large-scale net storage of CO₂ required. Additionally, the capacity in oil and gas fields could be insufficient to deal with all the CO₂ required for CCS projects, while hydrocarbon fields are unevenly distributed and may not be close to the sources of CO₂.

CO₂ storage in aquifers is the opposite of hydrocarbon production—volume is added to the system and the pressure in the reservoir increases. The CO₂ displaces brine and the increased fluid pressure tends to expand the pore space, pushing the rock apart. If the fluid pressure is too high, this can fracture the rock,

creating cracks through which the CO₂ could escape.

This discussion hints at two potential problems with the injection of CO₂. First, to inject CO₂ sufficiently quickly may require such high pressures as to fracture the rock, or may simply prove beyond the limits of compressors at the surface. Second, the CO₂ needs to displace brine and rock, which are not very compressible. This squeezing of the subsurface also leads to regional pressure increases, which again could cause extensive fracturing, or the seepage of salty water to displace fresh water, contaminating drinking water supplies. Certainly, the experience that—in most oil reservoirs—the water cannot respond sufficiently fast to maintain the pressure during production indicates that in reverse, the water may not be able to escape with enough rapidity to avoid a huge build-up of pressure.

The likely pressure response of aquifers has sparked a heated debate in the literature^{33, 34}. Box 3 discusses some of the numbers: it is possible to inject and store the required volumes of CO₂, but this will cause regional fluid pressure increases that need to be carefully monitored to avoid intrusion of brine into drinking water supplies, or fracturing of the rock leading to leakage of the CO₂. The experience of Sleipner and other sites where large volumes of CO₂ have been injected without significant increases in pressure provides evidence that large aquifers do have substantial storage capacity³⁴—as Figure 3 indicates, there are huge volumes in which the pressure can be dissipated. Fracturing the rock, although it sounds alarming, is often done deliberately in oil and gas fields, to speed up production and to allow water to be injected more easily; it is only a concern if the overlying cap rock is fractured and even then only for relatively shallow aquifers where this provides an escape route for the CO₂.

Injection design

The preceding sections lead to considerations of injection design. CCS is not impossible or even problematic, but neither is it a simple matter of drilling a well and injecting. Successful storage requires careful appraisal, management and monitoring. The CCS literature is littered with estimates of storage capacity, or how much CO₂ can be securely stored in different subsurface formations. These estimates are normally simply some fraction of the estimated pore volume; in reality the amount of CO₂ that can be stored is a function of how the injection is engineered—how many wells are drilled, what sort of wells and whether or not brine is produced. The storage design depends on economics and the field properties, and so it is usually unrealistic to talk of a single capacity estimate. While we know there is potentially sufficient storage space to allow CCS to make a substantial contribution to global mitigation efforts, each project has to be considered carefully.

Dynamic capacity. The first consideration is injectivity, or dynamic storage capacity. This means, can the CO₂ be injected at the rate required (several Mt per year for a full-size power station)? Techniques common in the oil industry—seismic surveys and testing of wells that are drilled—can be employed to

Box 3. Compressibility and how to squeeze the CO₂ into porous rock

Compressibility is defined as the fractional change in volume for a unit increase in pressure. When CO₂ is injected at high pressure, it compresses the resident brine and pushes the rock apart, increasing the pore volume. The combination of rock and brine has a compressibility of around 10^{-9} Pa⁻¹. An aquifer at a depth of 1,000 metres will typically have a pressure of around 10 MPa (10^7 Pa). To avoid fracturing it is wise to limit the pressure increase to between 10% and 50% (detailed geomechanical calculations provide a more accurate estimate—the pressure in the fluid should not exceed the pressure in the solid rock itself). Hence the pressure should increase by no more than 1-5 MPa. This leads to a fractional change in volume of the order 1.5×10^{-3} or 0.1-0.5%.

A regionally extensive aquifer some 100 km long and 100 km wide with permeable layers of a total thickness of 1,000 m (1 km) has a total rock volume of the order of 10^4 km³ or 10^{13} m³. Using our typical density of 600 kg/m³, this allows the storage of 6-30 Gt of CO₂. If we wish to apply CCS at a global scale for several decades, we will need to store CO₂ in many large aquifer units around the world.

ensure that the wells are drilled through formations of adequate permeability. The use of additional wells, or horizontal wells through layers of high permeability come with an additional cost, but will allow CO₂ to be injected more rapidly. Other approaches include the removal of brine from the injection site to avoid pressure build-up; this brine can be treated and disposed at sea, re-injected into the same formation (see below) or injected into another aquifer. Current field experience indicates that a single well can readily inject up to 1 Mt of CO₂ per year; more than one injection well, albeit in the same formation, will therefore be required for large storage projects, especially if CO₂ is collected from several sources before injection.

Static capacity. Large, regionally-extensive aquifers almost certainly have sufficient storage capacity even under rather modest constraints on pressure increase. The second concern is the extent of the CO₂ itself, since this indicates the potential footprint for any escape. Simulation studies suggest that in highly heterogeneous systems, the lowest storage capacity is around 2% of the pore space. Since the pore space itself is around 25% of the rock volume, this represents around 0.5% of the total rock volume, which is similar to the capacity estimated using pressure constraints.

The storage capacity and storage security can be improved, through improved injection design. If it is known that there is a good cap rock (such as in hydrocarbon reservoirs), CO₂ can be allowed to accumulate under the cap rock, where it can occupy the majority of the pore space.

If the cap rock is of poor or unknown quality, we can consider the injection of both brine and CO₂. In the oil industry, it is standard practice to inject gas and water together or in alternating slugs – since the mobility of the combination of the two phases has a lower mobility than CO₂ alone, leading to a more stable displacement and a more efficient sweep of the reservoir⁶. In contrast, CO₂ alone has a very high mobility (low viscosity) and tends to rise to the top of the reservoir and channel along high permeability channels. We propose the same strategy here: brine and CO₂ are injected together to provide a more stable displacement, forcing the CO₂ into more of the formation. Brine is then injected on its own (chase brine) to trap the CO₂³².

Figure 6 illustrates this design. The results of a simulation study on a North Sea aquifer indicate that with only a short period of brine injection, the vast majority of the CO₂ can be capillary trapped, ensuring permanent storage.

Since we are dealing with injection in the subsurface, there is always uncertainty associated with the permeability and structure. It is never possible to guarantee that a cap rock will be impermeable to CO₂, or that the permeability will be sufficiently high to allow rapid injection. However, the oil industry is

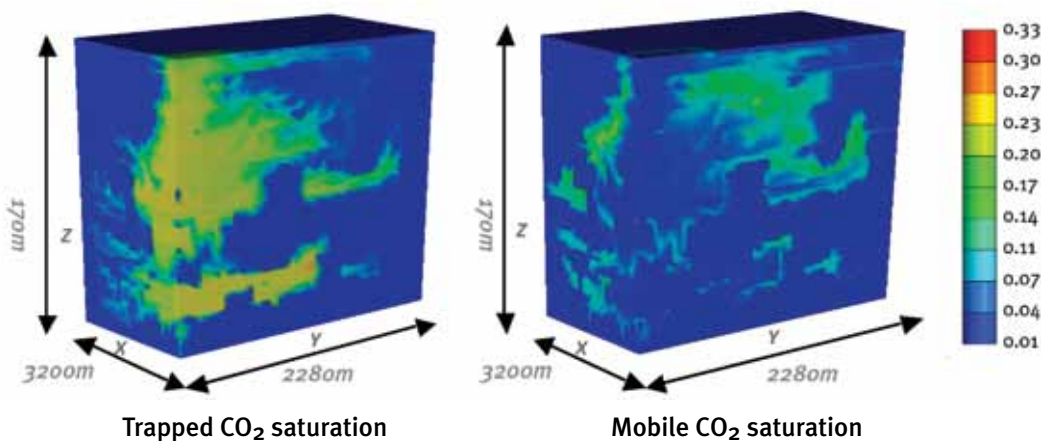


Figure 6. Saturation distributions near the injection well for a three-dimensional simulation for CO₂ injected with brine. Trapped CO₂ (left) and mobile CO₂ (right). 20 years of CO₂ and brine injection is followed by 2 years of chase brine injection³².

experienced at dealing with such difficulties, and a combination of different well placement and orientation, and injection design should allow storage projects to overcome these challenges.

Long-term security: it gets better with time. Over time, CO₂ storage gets safer. The high pressures near an injection well diffuse out over time. While it may take over hundreds of years or more for the pressure to equilibrate over hundreds of kilometres, the maximum pressure in the formation will decrease. Furthermore, the storage mechanisms: capillary trapping, dissolution and mineral precipitation all render the CO₂ less mobile over timescales of decades to hundreds of years. Careful design of injection, coupled with appropriate monitoring of well pressure and direct measurements of local CO₂ concentrations, should be sufficient to ensure that the vast majority of the injected CO₂ remains underground for thousands of years, and does not contribute to climate change. The typically low flow rates in porous media, combined with the absence of a strong force to drive the CO₂ through the rock prevents fast, dangerous releases of the CO₂, while pressure diffusion, dissolution, precipitation and capillary trapping all act to reduce the leakage risk.

Transport

The focus of this Paper has been storage, but a vital component of CCS is the transport of CO₂ from power stations or other industrial plants to the storage site³⁵. Small quantities, for demonstration projects, could be transported offshore by ship, but any serious plans involve transport via a dedicated pipeline. The construction of gas pipelines is a mature technology; the UK, for instance, has an extensive infrastructure for natural gas (primarily methane), while in the US over-ground pipes carry CO₂ to oilfields for EOR operations, as mentioned before. CO₂ is generally transported in a super-critical phase; it is pumped at high pressure, with booster stations to maintain the pressure. To avoid corrosion, the CO₂ has to be of high purity: in particular H₂S and water need to be removed from the gas stream. In Europe, with high population densities, the pipes would be buried underground. It is likely that the first projects to collect CO₂ from power stations will be as close as possible to the coast, to minimize the length of onshore pipeline, and to use existing routes for natural gas pipelines, or indeed use these pipes where possible, to avoid creating new routes.

There are risks associated with CO₂ transport; were the gas to leak, since it is denser than air, it can collect in low ground with a risk of asphyxia at high concentrations. This can be mitigated with appropriate design and monitoring and careful siting.

Unlike natural gas, there is no chance of explosion should the pipeline leak or rupture.

Policy and international context

In the UK, the Department of Energy and Climate Change (DECC) has announced a competition to support one full-scale (up to 300 MW) CCS project, with the results announced in 2011 and implementation sometime after 2014: this is a class 2 project (Table 1). The UK Government is committed to support a further three class 2 CCS projects, coupled with European funding. While this is exciting, the relaxed pace of the DECC competition and the refusal of the UK Government to fund the Miller-Peterhead project (an innovative scheme proposed by BP to pioneer pre-combustion capture in a gas-powered plant combined with CO₂ for EOR in the mature Miller Field), which would have been operational in 2009 generating significant revenue from increased oil recovery, reveals a disappointing lack of urgency associated with CCS projects.

A similar pattern emerges worldwide with only four Class 1 projects injecting significant amounts of CO₂ (1 Mt/year or more) and with some plans on hold or abandoned²¹. This contrasts with the stated support of the G8 countries in 2008 to launch 20 large-scale CCS projects by 2010 with widespread implementation by 2020³⁶. The barriers to rapid implementation include cost, creating a market mechanism to determine who pays and who benefits, lack of infrastructure, absence of a clear regulatory regime for managing CCS projects, and public reluctance to accept onshore storage and transport. Detailed roadmaps to large-scale implementation are available, but, frustratingly, there seems little will to follow them⁸.

This paper suggests that large-scale storage is feasible and safe, but there are many hurdles to be overcome before CCS can play a significant role in efforts to mitigate climate change. To address some of the potential problems, the UK Department of Energy and Climate Change (DECC) recently concluded a consultation exercise to determine options for further demonstration projects, possible funding mechanisms and planned projects³⁷. The focus of proposals in the UK is to collect CO₂ from power stations located near the East coast with offshore storage in depleted gas fields in the Southern North Sea or permeable, extensive saline aquifers, with the CO₂ being delivered by sub-surface pipeline, with as little transport onshore as possible.

Another issue is the development of an appropriate transport and storage infrastructure. A single demonstration may use

Large-scale storage is feasible and safe, but there are many hurdles to be overcome before CCS can play a significant role in efforts to mitigate climate change

a small, dedicated pipeline to one specific storage site; if, however, CCS is to be deployed at scale, it makes sense to create hubs where CO₂ is collected from all power stations in a relatively small area, collected in a single pipeline network and then stored in different locations. For example, Humberside represents one possible hub, where several nearby existing power stations emit currently 60 Mt/year of CO₂: creating the necessary transport infrastructure to handle collection of all these emissions and storage under the southern North Sea will save costs later, rather than relying on a piecemeal one-demonstration-at-a-time approach.

Coupled with this is a lack of a regulatory and financial framework to allow CCS to happen spontaneously within a free market economy. The carbon price under the European Emissions Trading system is currently far too low to allow investment in CCS without significant Government subsidy and, as yet, no clear long-term funding mechanism that significantly rewards the storage of CO₂ and/or penalizes atmospheric emissions has been established, in contrast to some other mitigation technologies. On the regulatory side, CO₂ can be injected under the North Sea for normal oilfield operations, while progress is being made on updating international treaties to allow CO₂ injection primarily for long-term storage.

The final issue concerns public acceptance of CCS. Public surveys (see, for instance,³⁸) have revealed a widespread lack of knowledge of CCS coupled with a concern that it could deflect attention away from the deployment of renewable power technologies. It is not known how acceptable CCS will be perceived to be when large-scale projects are implemented and how CCS projects will fare in comparison with the construction of large wind farms or nuclear power stations.

Discussion and conclusions

This Briefing Paper has discussed the challenges associated with the injection of CO₂ in the subsurface. We have described the rock in which the CO₂ will be stored and the physical and chemical processes that occur over decades to millions of years. The principal points to note are:

- It is during the injection of CO₂ that the fluid pressures are greatest and the CO₂ is most mobile and hence potentially able to escape. Over time, the CO₂ will dissolve, precipitate or become trapped and the pressure dissipates. This implies that proper monitoring and injection design is needed for the duration of the project, but not necessarily long afterwards.
- Ensuring sufficient injectivity and avoiding large pressure increases at the well and in the underground formation is necessary to allow large-scale storage without fracturing the rock or causing encroachment into drinking water. Careful injection design, targeting extensive permeable formations should ensure successful large-scale storage.
- There is a huge amount of field experience from the oil industry of injection of CO₂ deep underground. CO₂ storage is quite well understood with over one hundred sites worldwide where CO₂ has been injected.
- With relevant oil industry experience, abundant offshore capacity and major sources of CO₂ on the East coast, the UK is in an ideally placed to take a lead in an exciting, challenging technology that could play a major role in reducing emissions of CO₂.

About the author

Martin Blunt is head of the Department of Earth Science and Engineering at Imperial College London. He joined Imperial in June 1999 as a Professor of Petroleum Engineering. Previous to this he was Associate Professor of Petroleum Engineering at Stanford University in California. Before joining Stanford in 1992, he was a research reservoir engineer with BP in Sunbury-on-Thames. He holds MA and PhD (1988) degrees in theoretical physics from Cambridge University.

Professor Blunt's research interests are in multiphase flow in porous media with applications to oil and gas recovery, contaminant transport and clean-up in polluted aquifers and geological carbon storage. He performs experimental, theoretical and numerical research into many aspects of flow and transport in porous systems, including pore-scale modelling of displacement processes, and large-scale simulation using streamline-based methods.

He has written over 200 scientific papers and is on the editorial boards of three international journals. He serves on the CCS Technical Review Board for National Grid. Prof. Blunt works on several major research programmes and collaborations with other institutions, including the Shell Grand Challenge on Clean Fossil Fuels to study the fundamentals of CO₂-brine-rock interactions and the Qatar Carbonates and Carbon Storage Research Centre, funded by Qatar Petroleum, Shell and the Qatar Science and Technology Park, which combines studies of CO₂ in the subsurface with reservoir simulation and design attached to a demonstration of storage in the Middle East.

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