Locked away – geological carbon storage

POLICY BRIEFING

THE ROYAL SOCIETY

Policy briefing

Politics and science frequently move on vastly different timescales. A policymaker seeking evidence on a new policy will often need the answer in weeks or months, while it takes years to design and undertake the research to rigorously address a new policy question. The value of an extended investigation into a topic cannot be understated, but when this is not possible good evidence is better than none.

The Royal Society's series of policy briefings is a new mechanism aiming to bridge that divide. Drawing on the expertise of Fellows of the Royal Society and the wider scientific community, these policy briefings provide rapid and authoritative syntheses of current evidence. These briefings lay out the current state of knowledge and the questions that remain to be answered around a policy question often defined alongside a partner.

Locked away – Geological carbon storage policy briefing
Issued: September 2022 DES7897
ISBN: 978-1-78252-616-2

This report can be viewed online at:
royalsociety.org/geological-carbon-storage

Cover image © LucynaKoch

Contents

Executive summary

This briefing explores the options for geological carbon dioxide (CO_2) storage, with the aim of permanently removing CO_2 from the atmosphere, and an emphasis on injecting CO_2 offshore into either deep saline aquifers or depleted oil and gas fields.

Global greenhouse gas emissions have increased by 12% in the last decade, amounting to the highest increase in decadal average emissions on record. To limit warming to 1.5°C or less, future projections suggest that global greenhouse gas emissions must peak between 2020 – 2025, fall by 45% by 2030 and reach net zero by 2050.

To achieve these reductions and transition to a net zero energy system, there will need to be a significant decrease in overall fossil fuel use. However, there will be some end uses, mainly those from industrial processes, agriculture, and heavy-duty transport, that will struggle to decarbonise by 2050 targets. The deployment of carbon capture and storage (CCS) will be vital to both capture emissions from residual point sources and for CO_2 removal from the atmosphere.

There are examples of successful CO_2 geological storage, including the Sleipner Field in Norway which has stored over 25 $MtCO_2$ over the past 25 years. Existing large-scale projects have demonstrated the ability to monitor the CO_2 plume using time-lapse seismic techniques and shown that, in high permeability formations, the buoyancy of the CO_2 controls the spreading of the plume. These projects have also identified the challenges of: sand production in pressure relief wells, the complexity of the flow in lower permeability formations and the need to control pipe corrosion.

As the CO_2 storage industry develops, there will continue to be significant new technical challenges associated with different geological systems, including structural integrity, flow assurance and geochemical and mineralogical processes.

There will also be new challenges for monitoring, assurance and optimisation of the storage process.

A typical site selected for subsurface CO_2 storage will have permeable rocks, such as sandstone (predominantly quartz) or carbonate (calcite or dolomite) rock, that lie 1.0 – 2.5 km below the surface and may have a porosity of around 10 – 20% of the volume of the formation. Typically, the target reservoir may be tens to hundreds of metres thick and extend laterally for tens of square kilometres.

There have also been some new approaches to geological CO_2 storage in very different rock formations, including basaltic systems, in which CO_2 reacts directly with the rock surface to form minerals.

Global rates of CCS deployment are significantly below those anticipated to be needed to limit global warming to 1.5°C or 2°C, with the present global storage infrastructure only accommodating 40 $MtCO_2$/yr. It has been estimated that there is likely to be a need for 7 – 8 $GtCO_2$/yr of storage by 2050, and a cumulative storage of approximately 350 – 1200 $GtCO_2$ by 2100, to keep temperatures below the 1.5°C rise threshold. With typical CO_2 injection wells having injectivity of about 1 – 2 $MtCO_2$/year, this will require the global development of many thousands of CO_2 injection wells by 2050. This would be an enormous undertaking, given the multi-year time scale required to plan, develop and commission such wells and the associated reservoirs and transport infrastructure. The technical building blocks are available to build up this industry, but this will need to be underpinned by fundamental research and development to optimise and improve transport, storage efficiency, monitoring and assurance technologies, the systems that link these elements and to identify high quality, secure storage resource. There is also a need for sustainable business models for carbon capture and storage.

Introduction

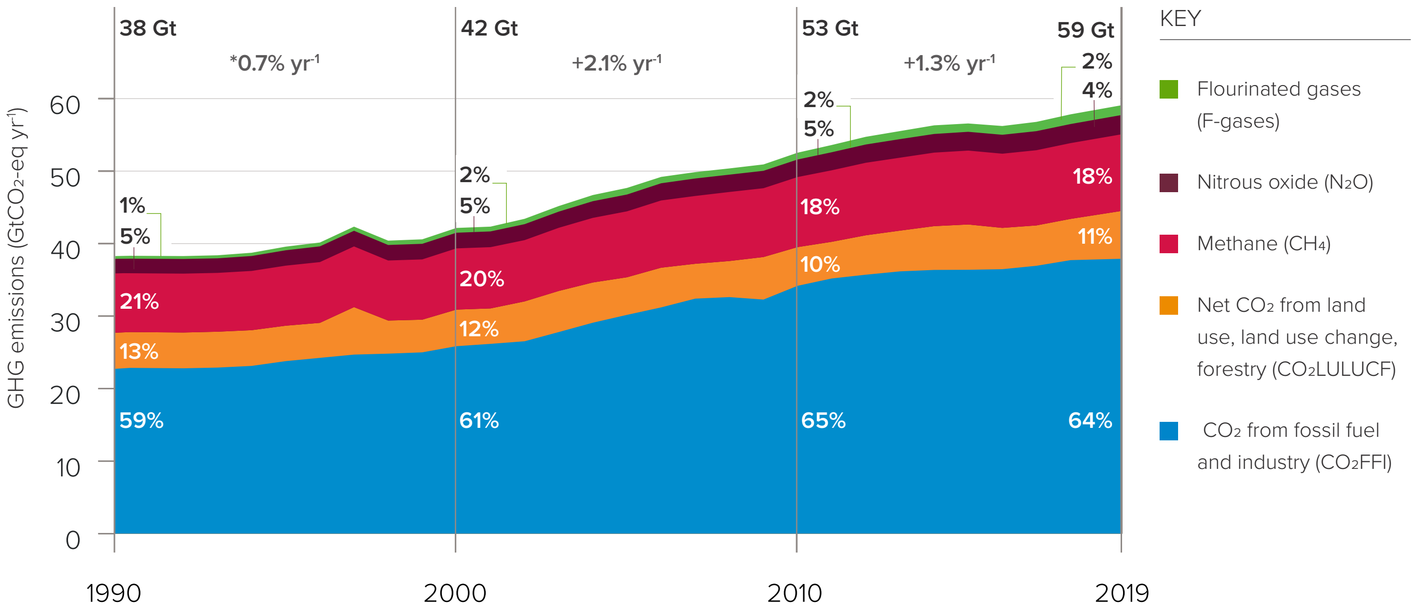
The need for carbon storage

To limit warming by 1.5°C or less, projections suggest that global greenhouse gas emissions must peak between 2020 – 2025, fall by 45% by 2030 and reach net zero by 2050. To achieve these reductions and transition to a net zero energy system, there will need to be a significant decrease in overall fossil fuel use alongside a major shift in the infrastructure for energy transport and use. Figure 1 illustrates how anthropogenic greenhouse gas emissions have been steadily increasing over the past 30 years.

While it is possible for many aspects of the energy system to transition, some industrial processes are hard to decarbonise, such as cement manufacture and iron and steel production. The deployment of carbon dioxide (CO_2) capture and storage (CCS) will therefore be vital to abate these residual emissions[1]. In addition, significant time will be required to re-engineer the infrastructure of the energy system; the use of CCS in power production will reduce future fossil fuel emissions until there is sufficient alternative energy supply to replace the present demand for fossil fuels.

FIGURE 1

Global net anthropogenic greenhouse gas emissions[1].



1 IPCC. 2022. Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. See https://www.ipcc.ch/report/sixth-assessment-report-working-group-3/ (accessed 10 April 2022).

Where CO_2 has migrated, most of the pathways were focused along geological faults in tectonically active regions, highlighting a possible risk to storage security.

CO_2 storage can source CO_2 from large, point sources, for example the exhaust gases from industrial plants or power stations, as well as CO_2 captured from the air through biological solutions, such as forestation, or engineered methods[2]. Once captured, the CO_2 can be transported and geologically stored.

This report explores the options for geological CO_2 storage, with emphasis on the offshore injection of CO_2 into either deep saline aquifers or depleted oil and gas fields. The subsurface injection and storage of CO_2 has been well-studied and there are several commercial-scale systems in operation, including the Sleipner field in the North Sea which has been operating since 1996 (see section 2.1). There is now a collection of new CO_2 storage projects planned, many centred on industrial clusters, and as they are developed and deployed there will likely be new technical challenges and opportunities to improve and optimise their performance (Box 2).

Naturally occurring CO_2 stores

CO_2 is produced through several natural Earth processes, some associated with the Earth's carbon cycle, that lead to CO_2 accumulation in subsurface reservoirs where it may remain trapped over geologic timescales[3]. For example, CO_2 has been trapped for tens of millions of years in hydrocarbon fields and deep aquifers in the central and southern North Sea, the Irish Sea, and for hundreds of thousands to millions of years in southern France, Germany and Italy.

In the USA, natural CO_2 reservoirs are accessible from the land surface or from shallow drilling and have been extensively studied. This has improved the understanding of long-duration subsurface CO_2 storage, which is difficult to reproduce in laboratory studies[4].

These reservoirs contain at least 310 $GtCO_2$, typically at concentrations of 85 – 99% CO_2 (by volume), with the majority having retained CO_2 for an excess of a million years[5, 6, 7]. The geological processes are equally applicable to storage sites deep below the land surface, or deep below the seabed.

These sites can provide:

- long-duration evidence of the interaction of CO_2 with the reservoir and the overlying caprock;
- geological evidence of ancient or current migration of CO_2 out of the primary reservoir, and sometimes to the surface;
- insights into the geological and mechanical mechanisms by which engineered sites may fail and thus inform the selection, management and monitoring of secure CO_2 storage sites;
- evidence of the rates and pathways of CO_2 leakage through geological time, and the health and environmental impacts of CO_2 leakage to the surface.

2 The Royal Society and Royal Academy of Engineering. 2018. Greenhouse Gas Removal. See royalsociety.org/topics-policy/projects/greenhouse-gas-removal (accessed 07 February 2022).

3 Wycherley H, Fleet A, Shaw H. 1999 Some observations on the origins of large volumes of carbon dioxide accumulations in sedimentary basins. *Marine and Petroleum Geology*, 16, 489 – 494. (doi:10.1016/S0264-8172(99)00047-1).

4 Baines SJ, Worden RH. 2004 The long-term fate of CO_2 in the subsurface: natural analogues for CO_2 storage. Geological Society, London, *Special Publications*, 233, 59 – 85. (doi: 10.1144/GSL.SP.2004.233.01.06).

5 Sathaye KJ *et al*. 2014 Constraints on the magnitude and rate of CO_2 dissolution at Bravo Dome natural gas field. *PNAS*, 111, 15332 – 15337. (doi: 10.1073/pnas.1406076111).

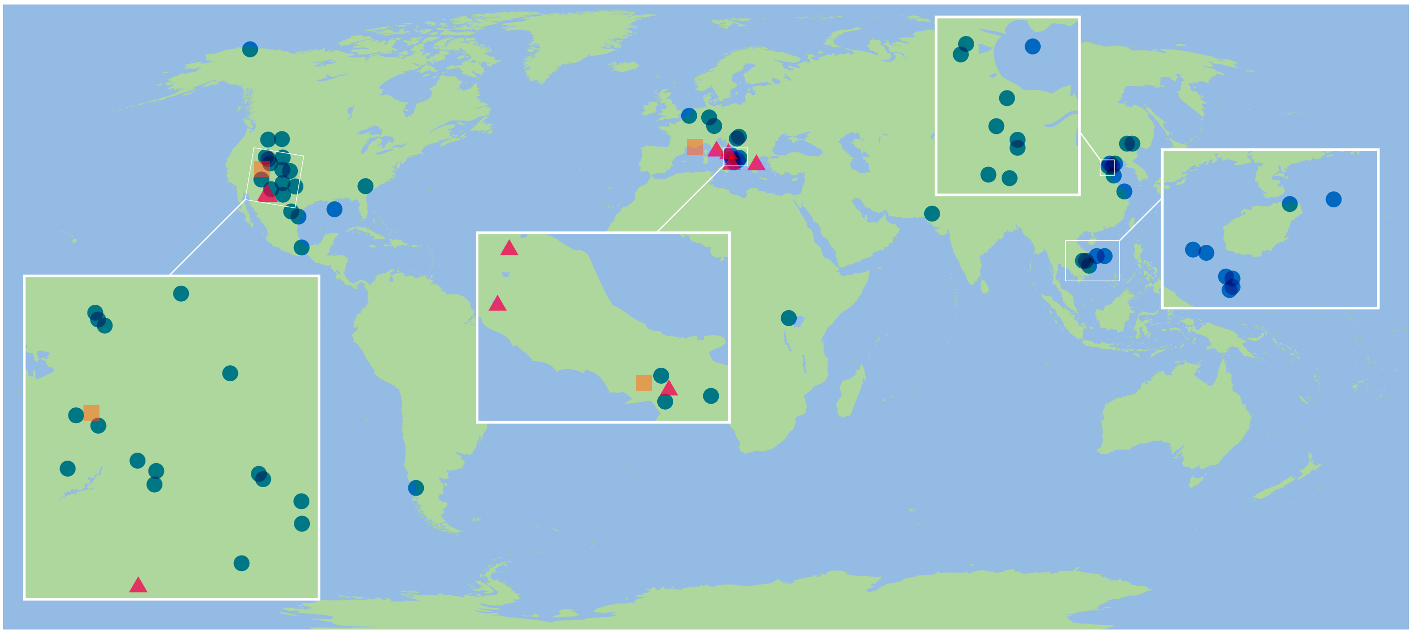
6 NETL, 2014 Subsurface Sources of CO_2 in the Contiguous United States - Vol I: Discovered Reservoirs. National Energy Technology Laboratory.

7 Gilfillan SMV *et al*. 2008 The noble gas geochemistry of natural CO_2 gas reservoirs from the Colorado Plateau and Rocky Mountain provinces, USA. *Geochimica et Cosmochimica Acta*, 72, 1174 – 1198. (doi: 10.1016/j.gca.2007.10.009).

FIGURE 2

Map showing most of the largest naturally occurring CO_2 reservoirs[8].

Most of the insecure reservoirs are found in tectonically active regions, such as the Apennine thrust belt in Italy or the Florina Basin in Greece.



KEY

Reservoir

- Inconclusive
- Secure
- Insecure

From the study of 76 naturally occurring CO_2 stores, there was no evidence of measurable CO_2 migration at 66 sites and analysis showed that successful CO_2 retention is controlled by thick and multiple caprocks and reservoir depths of more than 1200m (see figure 2)[8].

Laboratory studies have validated similar findings showing that the dense phase (fluid) CO_2 will not flow through natural caprock fractures, even though those same fractures can readily accept gas flow[9].

Where CO_2 has migrated, most of the pathways were focused along geological faults in tectonically active regions, highlighting a possible risk to storage security. A fault or related damage zone needs to be carefully assessed for CO_2 permeability during the appraisal process to fully quantify the risk of leakage (see section 1.4).

8 Miocic JM *et al*. 2016 Controls on CO_2 storage security in natural reservoirs and implications for CO_2 storage site selection. *International Journal of Greenhouse Gas Control*, 51, 118 – 125. (doi: 10.1016/j.ijggc.2016.05.019).

9 Edlmann K., Haszeldine S, McDermott CI. 2013 Experimental investigation into the sealing capability of naturally fractured shale caprocks to supercritical carbon dioxide flow. *Environmental Earth Sciences*, 70, 3393 – 3409. (doi:10.1007/s12665-013-2407-y).

The geological storage system

There are many potential sedimentary reservoirs for CO_2 storage.

1.1. Storage site design

The design and development of a CO_2 storage reservoir in layers of permeable rock below the ground surface involves a number of scientific and technological inputs. These include:

1 the assessment of the size, shape and mineralogy of the geological reservoir, and of the way fluid flows through the rock at both the pore scale and the reservoir scale;

2 the assessment of the mechanical response of the reservoir to pressurisation associated with the injection;

3 the design and drilling of CO_2 injection and pressure relief wells, which pass through the overlying rock and into the target geological formation.

These issues all present challenges for the successful development of CO_2 storage reservoirs, owing to the difficulty of characterising the flow and mechanical properties of rock below the surface in sufficient detail. These complexities include large variations in permeability coupled with the buoyancy and low viscosity of the CO_2 which may cause highly variable flow.

Further challenges include limitations on injection pressure to maintain seal integrity: the pressure imposed at an injection well may lead to elevated pressures at significant distances, owing to the low compressibility of the formation water, especially in closed systems. In conjunction with the above complexities, the injected CO_2 may therefore only access a small fraction of the available pore space, perhaps of the order of a few percent.

A typical site selected for subsurface CO_2 storage will have permeable rocks that lie 1.0 – 2.5 km below the surface where the pressure is sufficient that the CO_2 is a dense and supercritical fluid, increasing the mass stored per unit volume of rock. Such rocks typically have a porosity of around 10 – 20% of the volume of the formation.

The target reservoir may be tens to hundreds of metres thick and extend laterally for tens of square kilometres. There are many potential sedimentary reservoirs for CO_2 storage, including deep saline aquifers, which are composed of permeable sandstone (predominantly quartz) or carbonate (calcite or dolomite) rock.

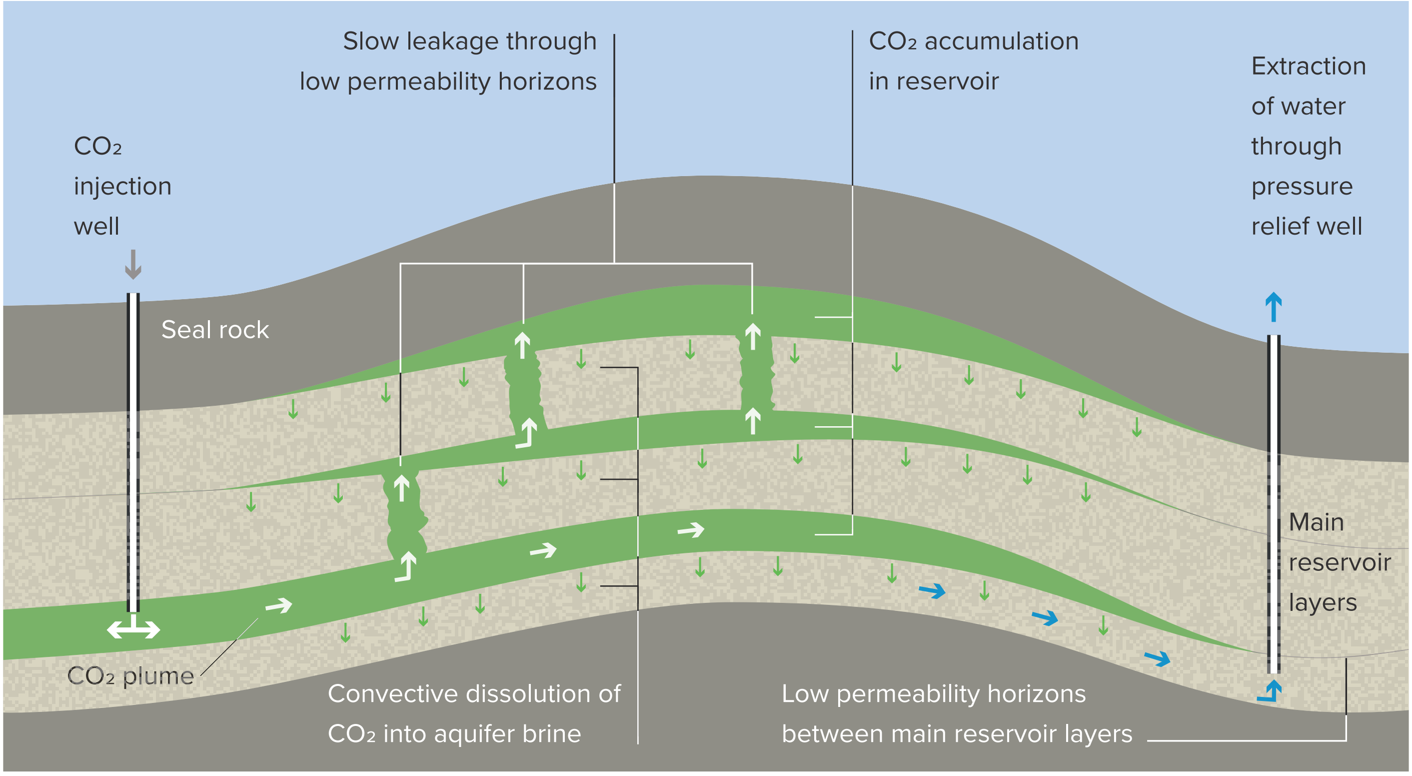
The storage system also requires overlying and underlying seal layers of sufficiently low permeability and high entry pressure to prevent the CO_2 escaping from the target reservoir.

Sandstones are composed of sand grains which, over geological time, have been cemented together by growth of new materials and compressed by the overlying rocks. The fluid-accessible pore spaces or holes between the sand grains are microscopic (typically 10 – 100 microns). The pore space is typically filled with brine, or oil and gas in a depleted hydrocarbon field. The seal layer may be composed of salt or very fine clay (mudstone), which stops the motion of the CO_2. Limestone rocks may also be used for CO_2 storage. These typically have a much larger range of permeabilities for a given porosity, and more complex pore structure, adding to the complexity of characterising the flow through the system.

FIGURE 3

Illustration showing what happens to CO_2 when injected underground.

A typical 'anticline' reservoir for CO_2 with multiple layers of porous rock separated by thin layers of mudstone.



To store the CO_2, it is compressed at the surface and then pumped through a pipeline into a well which penetrates through the ground into the storage reservoir. At reservoir pressure and temperature, the CO_2 is in a supercritical state, for which there is no distinction between the liquid and gaseous form. Once in a formation, the CO_2 typically spreads out as a plume, initially being driven by the pressure of the injection, and displaces the reservoir fluid. There is a hierarchy of trapping processes with different timescales (see figure 3 and sections 1.1.1 – 1.1.4).

To limit the pressure build up from the injection of CO_2 and prevent fracture of the seal rock, pressure relief wells may be drilled, although they add to the cost of the system.

They are ideally located in the water-filled zone of the system below the CO_2. Extraction of water through pressure relief wells could affect the pressure gradient near the extraction wells and may lead to preferential flow paths which draw the low viscosity CO_2 from the injection wells.

Ultimately the pressure gradients associated with the injection wells and the pressure relief extraction wells will combine with the buoyancy forces to determine the flow paths through the reservoir during injection; a well-distributed series of injection wells and careful management of injection rate are required to ensure the CO_2 sweeps through as much pore space as possible rather than short-circuiting to the relief wells and limiting the storage potential of the system.

Also, the injection rate may need to be limited to avoid the pressure at the injection well becoming too large, and fracturing rocks near injection wells or activating pre-existing faults within or possibly below the storage zone.

1.1.1. Structural trapping

During the initial injection phase, which may last decades, the CO_2 tends to follow the path of least resistance through the permeable rock. The host fluid present is pushed out, which requires an applied local pressure to overcome both the capillary forces and the viscous resistance of the fluids to movement.

This capillary pressure develops because the CO_2 does not mix with the host fluid and is forced to move through pore spaces, between the sand grains in the porous rock.

As the size of the grains decreases, the force required to move the CO_2 increases to the point where the CO_2 cannot enter. These fine-grained layers act as a seal or caprock. The resistance of CO_2 to motion depends on the size of the grains, and the velocity of migration is characterised in terms of the permeability.

Given the CO_2 injected is less dense and viscous than the host fluid at typical reservoir pressure and temperature, it will gradually rise under buoyancy forces to the top of the formation. The overlying seal rock stops the ascent and causes the CO_2 to spread laterally and fill structural highs in the formation. The overlying geological strata should be effectively impermeable to CO_2 to prevent it rising through the subsurface and either flowing into potable aquifers or returning to the surface. This is called structural trapping.

For the typical pressures involved in CO_2 storage, and for rocks typical of those below the North Sea, the flow speed may be of the order of a few metres per year[10].

1.1.2. Capillary trapping

Once injection has ceased, CO_2 rises to the top of the formation and will be displaced by the reservoir fluid which fills the pore space left by the CO_2. Capillary forces will tend to isolate bubbles of CO_2 in the pore space which are surrounded by the reservoir fluid: this is called capillary trapping.

This will lead to a zone of residual saturation (see figure 4). Estimates of this saturation, based on laboratory experiments, suggest that CO_2 may occupy 10 – 20% of the entered pore space[8]. The rising plume of CO_2 gradually depletes in mass, with the trailing edge of the plume rising more quickly than the leading edge[11, 12, 13, 14].

Eventually the trailing edge of this plume either catches the leading edge or reaches the pool of CO_2 held under the caprock, at which point all the CO_2 is trapped either by the structure or by capillary forces.

10 Woods AW and Espie, T, 2012 Controls on the dissolution of CO_2 plumes in structural traps in deep saline aquifers, *Geophysical Research Letters*, (doi:10.1029/2012GL051005).

11 Song J, Zhang D. 2013 Comprehensive Review of Caprock-Sealing Mechanisms for Geologic Carbon Sequestration. *Environmental Science & Technology*, 47, 9–22. (doi: 10.1021/es301610p).

12 Pentland CH *et al*. 2011 Measurements of the capillary trapping of supercritical carbon dioxide in Berea Sandstone. *Geophysical Research Letters*, 38, L06401. (doi:10.1029/2011GL046683).

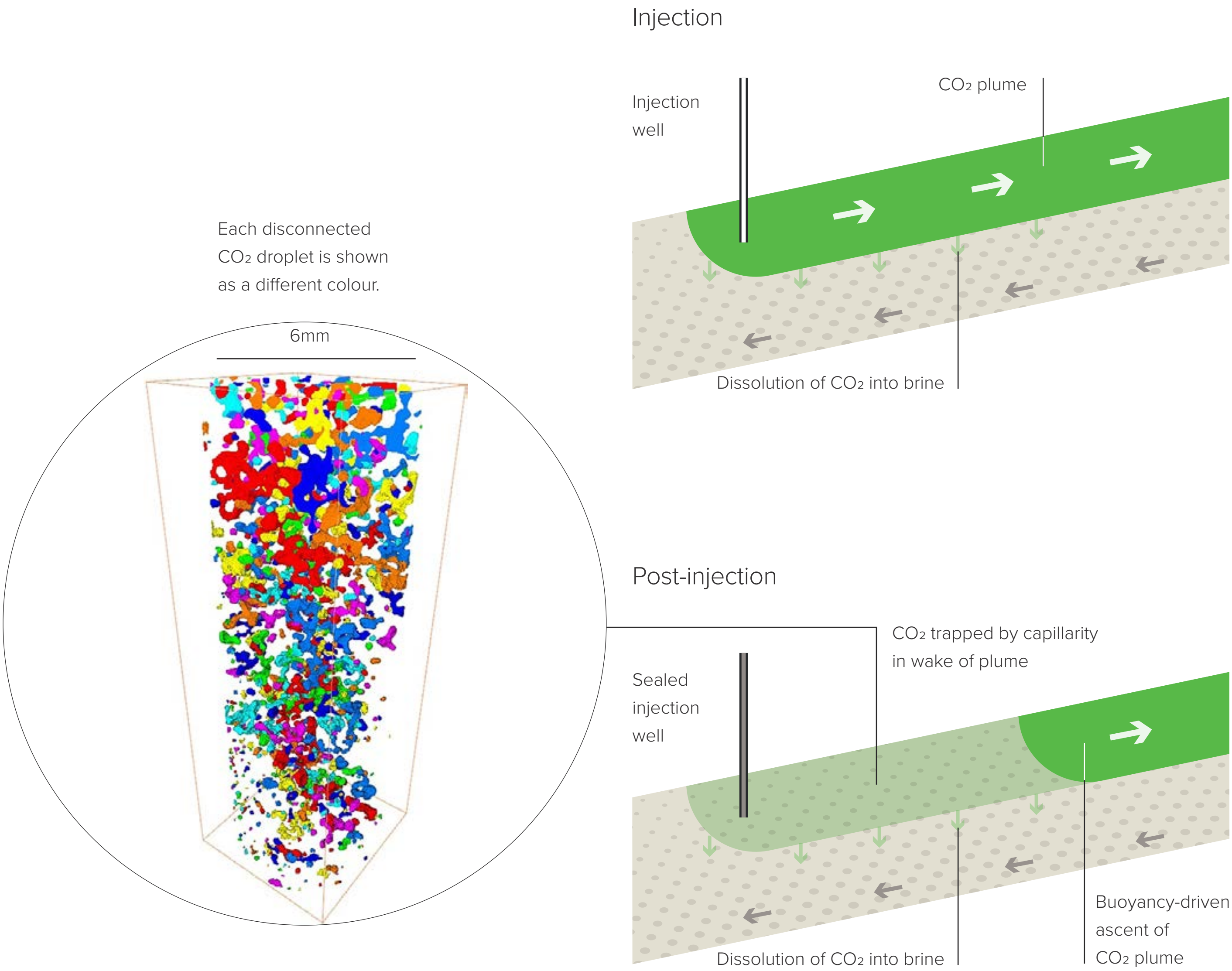
13 Krevor S *et al*. 2015 Capillary trapping for geologic carbon dioxide storage – From pore scale physics to field scale implications. *International Journal of Greenhouse Gas Control*, 40, 221 – 237. (doi: 10.1016/j.ijggc.2015.04.006).

14 Hinton, E, Woods, AW, 2021, Capillary trapping in a vertically heterogeneous permeable layer, *Journal of Fluid Mechanics*, 910. (doi:10.1017/jfm.2020.972).

FIGURE 4

Illustration showing the formation of a plume during injection and the formation of a capillary trapped zone post-injection.

Below left is an X-ray image showing capillary-trapped CO_2 in the pore space of a sandstone, typical of rock beneath the North Sea[15].



15 Andrew M, Bijeljic B, Blunt MJ. 2013 Pore-scale imaging of geological carbon storage under in situ conditions. *Geophysical Research Letters*, 40, 3915 – 3918. (doi: 10.1002/grl.50771).

Some of the CO_2 may react with the rock in the formation.

1.1.3. Solubility trapping

Since the CO_2 is weakly soluble in water, some of the CO_2 from the initial pure CO_2 plume will dissolve in the reservoir brine. CO_2 typically has a solubility of 2 – 3% by mass in the reservoir fluid. Since the CO_2-saturated brine is denser than unsaturated brine, it will sink into the underlying brine generating a convective flow. Once the fluid below the CO_2 interface becomes saturated in CO_2, the subsequent dissolution rate depends on the rate of replacement with fluid unsaturated in CO_2 from further away in the permeable strata, as occurs for example if there is a background hydro-geological flow; this may occur over time scales of thousands to hundreds of thousands of years[10, 16, 17, 18, 19].

1.1.4. Mineral trapping

Some of the CO_2 may react with the rock in the formation, leading to precipitation of carbonate or other carbon bearing solids. With time, provided the reservoir geochemistry is suitably reactive, the CO_2 becomes entombed underground as a solid. The timescales for this process are highly variable, dependent on the chemistry of the storage rock.

For relatively unreactive quartz (sandstone) and calcite (carbonate) rocks, this process may take many thousands of years or may not happen at all[20].

However, in more reactive formations, the reaction can be engineered to occur over a few years (see section 5).

1.2. Predicting CO_2 flow

Quantitative models to describe the flow at the pore scale have been developed by detailed laboratory experiments on small rock samples. There has been significant effort to scale up these models to describe the flow in the complex heterogenous rock over length scales of several kilometres. The large-scale flow of CO_2 through a porous reservoir is strongly controlled by the geometry and degree of heterogeneity of the reservoir, the positioning of the injection and pressure relief wells, as well as the pore-scale flow-properties of the formation[21, 22].

16 Sathaye, K. Hesse, M, Cassidy, M. Stockli, D, 2014. Constraints on the magnitude and rate of CO_2 dissolution at the Bravo Dome natural gas field, *PNAS*., 15332 – 15337 (doi:10.1073/pnas.1406076111)

17 Neufeld J *et al*. 2010 Convective dissolution of CO_2 in saline aquifers. *Geophysical Research Letters*, 37, L22404. (doi: 10.1029/2010GL044728).

18 Unwin HJT, Wells GN, Woods AW. 2016 CO_2 dissolution in a background hydrological flow. *Journal of Fluid Mechanics*, 789, 768 – 784. (doi: 10.1017/jfm.2015.752).

19 Leslie R *et al*. 2021 Quantification of solubility trapping in natural and engineered CO_2 reservoirs. *Petroleum Geoscience*, 27, petgeo2020-120. (doi: 10.1144/petgeo2020-120).

20 Gilfillan SMV *et al*. 2009 Solubility trapping in formation water as dominant CO_2 sink in natural gas fields. *Nature*, 458, 614 – 618. (doi: 10.1038/nature07852).

21 Riaz A *et al.* 2006 Onset of convection in a gravitationally unstable diffusive boundary layer in porous media. *Journal of Fluid Mechanics*, 548, 87-11. (doi: 10.1017/S0022112005007494).

22 Blunt M. 2017 Multiphase flow in permeable media: a pore-scale perspective. Cambridge University Press. (ISBN:9781316145098).

Heterogeneities take the form of layering, where rocks with different flow properties are interleaved in the geological strata, and also faults and fractures. Simplified models do provide useful insight into some of the controls on the flow pattern of the CO_2 but owing to the lack of detailed data on the subsurface architecture for specific fields, there are inherent uncertainties in the predictions and the effects of the heterogeneities. Heterogeneities of the system will tend to exaggerate the flow localisation and hence the fraction of the pore space accessed by the CO_2[23, 24, 25].

With more experience of real injection systems, and careful monitoring of the injection fronts, strategies can be developed to help mitigate some of these effects which tend to limit the potential storage capacity of a reservoir.

There is considerable uncertainty in the potential performance of the system owing to uncertainties in the properties of the formation, and their variations in space. Wells drilled in the system are often kilometres apart and so it is difficult to gather the detail of the flow properties of the rock and the sealing properties of layer-to-layer interfaces away from the wells; these properties can have a significant impact on the flow patterns. It is therefore important to explore a range of flow regimes in the planning for a CO_2 sequestration project, and to optimise the design accounting for this uncertainty.

1.3. Geological resource and capacity

The storage capacity is an estimate of the amount of CO_2 that can be safely and permanently stored. The theoretical storage capacity is calculated by estimating the overall volume of the rock strata, the total volume of pore space within the strata and the proportion of that pore space that can be reasonably expected to be utilised for CO_2 storage. The mass of CO_2 is calculated by estimating the density of the CO_2 at the temperatures and pressures of the subsurface.

To predict storage capacity, the characterisation of the pore scale and well-to-well scale structure of the permeable reservoirs is vital. A range of models can be built up through a combination of seismic imaging (see section 4), measurements in well-bores using geophysical tools, and analysis of the rock samples extracted from the formation when wells are drilled into the formation. These techniques have been developed from oil and gas recovery.

Estimates of the accessible pore space are uncertain and vary depending on the complexity of the geological formation being investigated. They are often much smaller than the total pore space, reflecting the limited amount of connected pore space available and the tendency for the flow to channel through the higher permeability parts of the formation. Often a range of values are used, together with a probability for each of these values, leading to a range of possible model outcomes.

23 Hesse MA, Woods AW. 2010 Buoyant dispersal of CO_2 during geological storage. *Geophysical Research Letters*, 37, L01403. (doi: 10.1029/2009GL041128).

24 Hinton EM, Woods AW. 2018 Buoyancy-driven flow in a confined aquifer with a vertical gradient of permeability. *Journal of Fluid Mechanics*, 848, 411 – 429. (doi: 10.1017/jfm.2018.375).

25 Bissel RC *et al*. 2011 A full field simulation of the in Salah gas production and CO_2 storage project using a coupled geo-mechanical and thermal fluid flow simulator. *Energy Procedia*, 4, 3290 – 3297. (doi: 10.1016/j.egypro.2011.02.249).

The integrity of the seal and the associated risk of leakage is an important element of storage.

In the UK, the total theoretical storage capacity has been estimated to be at least 78 $GtCO_2$ in over 50% of model predictions carried out to explore the impact of uncertainties in rock properties[26] (see figure 5). Of this total theoretical storage capacity, around 60 $GtCO_2$ occurs in saline aquifers, 8 $GtCO_2$ in chalk aquifers and a further 8 $GtCO_2$ in depleted oil and gas fields. A further 2 $GtCO_2$ is contained in small units of less than 20 $MtCO_2$ each.

As a CO_2 storage project develops, an estimate of the dynamic storage capacity can be made using a three-dimensional digital model of the reservoir, constructed from observed and analytical data to simulate the injection of CO_2 over time. The dynamic storage capacity is a more detailed assessment as it includes the injection rates, the maximum injection pressure, the design of injection wells and pressure relief wells, and the impacts of geological heterogeneity, on the rates of CO_2 trapping and migration.

The dynamic storage capacity finds limits on the rate at which CO_2 can be injected to avoid over-pressurising the formation, potentially inducing fracturing and creating leakage pathways. Often this leads to estimates of dynamic storage capacity being less than 1 – 2% of the total pore space [27].

For depleted oil and gas fields, in which the hydrocarbons have been produced, it is possible to estimate the CO_2 storage capacity by matching the volumes of oil and/or gas produced and adjusting for density differences between the hydrocarbons and CO_2.

Some gas fields can be considered as isolated volumes, that have low enough pressure when the natural gas has been produced, for there to be an initial period when the CO_2 is injected in the gas phase rather than as a dense supercritical phase.

1.4. Seal Integrity

The assessment of the integrity of the seal and the associated risk of leakage is an important element of storage. Natural CO_2 stores provide evidence of long-term storage (see Introduction), but ultimately, this risk should be quantified through a combination of geological characterisation of the reservoir and seal rocks, field scale tests and modelling.

The upper limit of reservoir pressure can be estimated from laboratory testing, in-well formation testing or knowledge from previous operations in the same or neighbouring fields. Some uncertainty remains associated with heterogeneities in mechanical properties across scales, and alteration of the reservoir or seal through geochemical reactions.

For CO_2 to flow through undamaged caprock, the pressure should exceed the capillary entry pressure of the rock, which can be very high (around 1 – 10 MPa). Fractured caprock will have a much lower capillary entry pressure. Geophysical investigations before and during CO_2 injection are used to screen for existing fractures and faults and to optimise the operational strategy to minimise any risk of leakage from the target formation[28].

26 British Geological Survey. UK CO_2 Storage Evaluation Database. See www.CO2Stored.co.uk (accessed 13 January 2022).

27 Bentham M *et al*. 2014 CO_2 Storage Evaluation Database (CO_2 Stored). The UK's online storage atlas. *Energy Procedia*, 63, 5103 – 5113. (doi: 10.1016/j.egypro.2014.11.540).

28 Dean M *et al*. 2020 Insights and guidance for offshore CO_2 storage monitoring based on the QICS, ETI MMV, and STEMM-CCS projects. *International Journal of Greenhouse Gas Control*, 100, 103120. (doi: 10.1016/j.ijggc.2020.103120).

FIGURE 5

Theoretical CO_2 storage capacity in the UK[27].

KEY

- CO_2 sources (top 50)
- Saline aquifer (confined trap)
- Saline aquifer (open)
- Hydrocarbon fields

Capacity (P50)/Emissions (megatonnes):

- <10
- 11 – 100
- 101 – 1000
- <4000

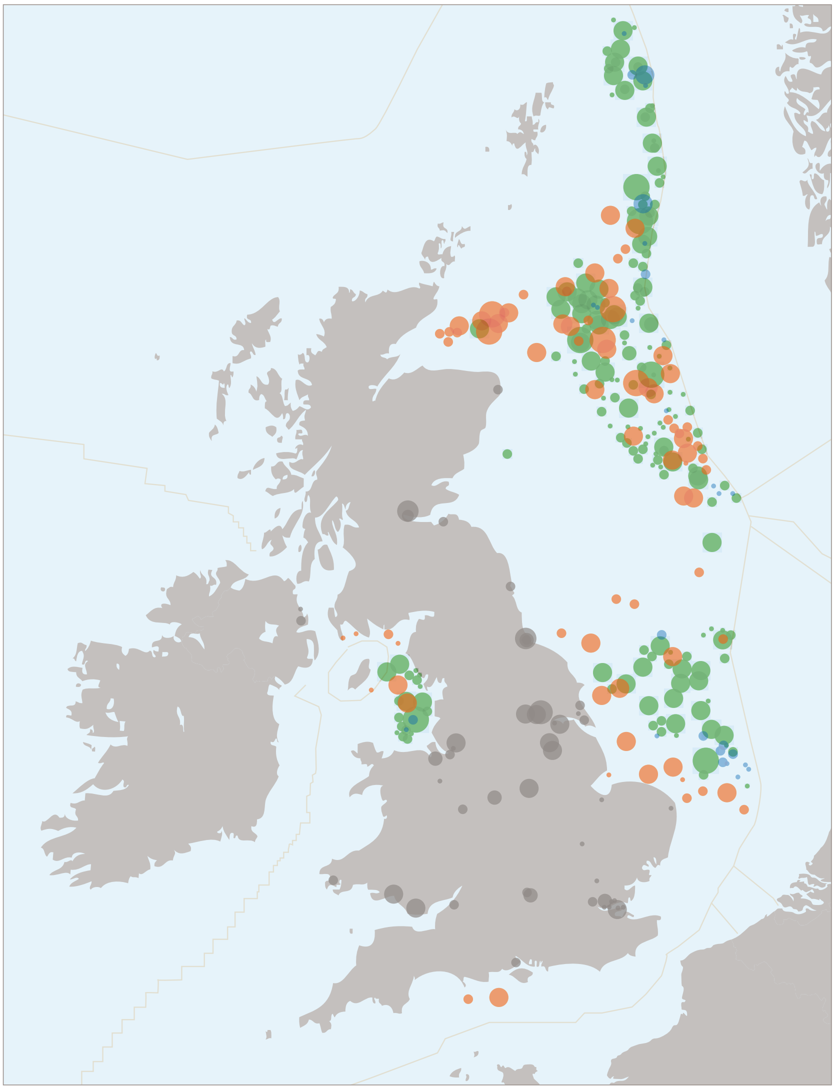
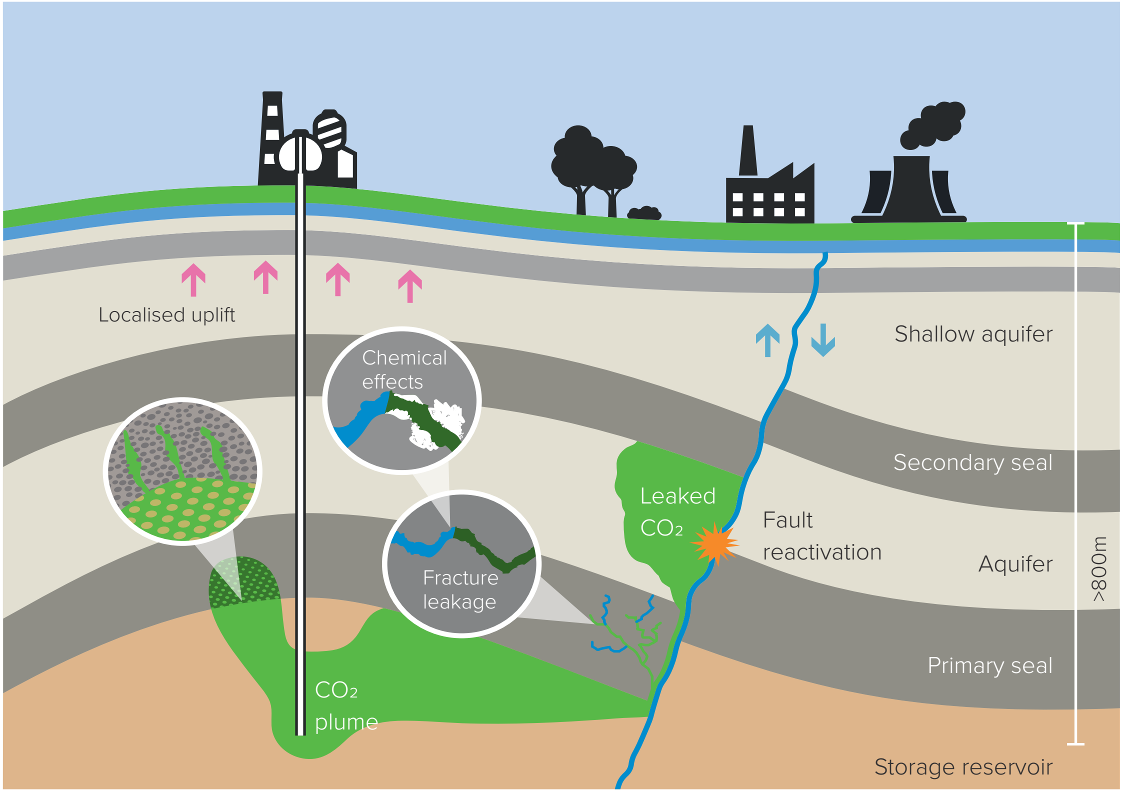


FIGURE 6

CO_2 leakage mechanisms and induced seismicity in subsurface CO_2 storage reservoirs.



Source: Adapted from a graphic created by Tomos Phillips and Erik Boersheim, Heriot-Watt University.

Faults can act as conduits for fluids both along and/or across the plane of the fault, and when (re)activating a fault system through pressurisation there are several associated risks. If the fault system connects vertically across the caprock, fluid leakage into the hydrosphere, atmosphere or biosphere might occur depending on how far the fault extends towards the Earth's surface (see figure 6).

This migrating CO_2 could react with the overlying rock, leading to channel formation or clogging of the fracture. These processes are less well studied.

Fracture permeability strongly depends on confining stresses and the relative orientation of fractures to the principal stress directions. In general, the permeability tends to increase towards the surface because of a reduction in confining stress. The flow also depends on the connectivity of the fractures across seals, the fracture density, aperture sizes and the capillary pressures[29].

29 Phillips T *et al*. 2020 Controls on the intrinsic flow properties of mudrock fractures: A review of their importance in subsurface storage. *Earth-Science Reviews* 211, 103390. (doi: 10.1016/j.earscirev.2020.103390).

Limited experimental data is available on these properties. It is likely that much of the CO_2 migrating upwards will be trapped in shallower salt water-bearing formations and that if CO_2 migrates to the surface, it will occur over a very large area rather than as a point source. When building models of the potential leakage pathways from analogue geological data, it is important to distinguish between leakage over geological timescales (hundreds of thousands to millions of years) and leakage on time scales relevant for CO_2 storage (hundreds to thousands of years)[30].

In practice, there will be a storage complex which envelops the actual permeable reservoir, and movement of CO_2 within the complex will be permissible, while any CO_2 passing through the boundary of the storage complex will be described as a leak.

Recent work has estimated that with realistically well-regulated storage in regions with moderate well densities there is a 50% probability that leakage remains below 0.0008% per year, with over 98% of the injected CO_2 being retained in the subsurface over 10,000 years[31].

With an unrealistic scenario, where CO_2 storage is inadequately regulated, the model estimated that more than 78% will be retained over 10,000 years, suggesting that geological storage of CO_2 can be a secure option, provided that appropriate storage sites are used, and it is well-regulated.

30 Busch A, Kampman N. 2018 Migration and leakage of CO_2 from deep geological storage sites. Geological Carbon Storage: Subsurface Seals and Caprock Integrity, 14. (ISBN: 9781119118657).

31 Alcade J *et al*. 2018 Estimating geological CO_2 storage security to deliver on climate mitigation. *Nature Communications*, 9, 2201. (doi:10.1038/s41467-018-04423-1).

BOX 1

Enhanced storage

Enhanced CO_2 storage research aims to discover methods to increase the fraction of the pore space that is accessible, and also to reduce the permeability of seal rock. The research is not well developed; however, some possible approaches can be adopted from those used during enhanced oil recovery (EOR). Some examples of enhanced CO_2 storage include:

- In EOR, the viscosity of the injected water is sometimes increased through addition of polymers, or a surfactant is added to the water to lower the interfacial tension with the oil, enabling more oil to migrate through the pore spaces ahead of the displacement front. Similar methods are being developed with CO_2: there are some polymers which can be used to increase the viscosity of supercritical CO_2 and may improve the degree of uniformity of the flow of the advancing CO_2 front, although the benefits of this need to be weighed up against the lower injection rates for more viscous fluid, and the reduction in water available for dissolution of the CO_2. Further research and investigation of the costs is needed.
- A finite pulse of higher viscosity fluid, such as polymer laden water, may be injected prior to the CO_2; this water may enter the higher permeability zones, impeding any short-circuiting of CO_2 which may subsequently be injected, and thereby accessing more of the pore space[32].
- Similar to EOR approaches, a dispersion of micro-bubbles of CO_2 in suspension in water could be injected to block off the more permeable zones of the formation. The subsequent injection of a CO_2 stream would be diverted to the lower permeability zones[33].
- Foams and CO_2 activated gels/cements have been investigated to reduce the permeability of fractures or other pathways through the seal rock, and hence delay the buoyant ascent of CO_2 through a layered reservoir[34, 35].

32 Cummings, S, Xing, D, Enick, R, Rogers, S, Heenan, R, m Grillow, J., Eastoe, J, 2012 Design principles for supercritical CO_2 viscosifiers, *Soft Matter*, 26 (doi:10.1039/C2SM25735A).

33 Lei, H, Yang, S, Zu, L, Wang, Z., Li, Ying, 2016 Oil recovery performance and CO_2 storage potential of CO_2 water alternating gas injection after continuous injection of CO in a multilayer formation, *Energy Fuels* 30, 11, 8922 – 8931. (doi:10.1021/acs.energyfuels.6b01307)

33 Nguyen Hai Le N, Sugai Y, Sasaki K, 2020 Investigation of Stability of CO_2 Microbubbles—Colloidal Gas Aphrons for Enhanced Oil Recovery Using Definitive Screening Design. *Colloids and Interfaces*; 4(2):26. (doi:10.3390/colloids402002)

34 Batôt G, Fleury M, Nabzar L. 2017 Reducing CO_2 Flow using Foams. *Energy Procedia*, 114, 4129 – 4139. (doi:10.1016/j.egypro.2017.03.1553).

35 Tongwa P *et al*. 2013 Evaluation of Potential Fracture-Sealing Materials for Remediating CO_2 Leakage Pathways during CO_2 Sequestration. *International Journal of Greenhouse Gas Control*, 18, 128 – 138. (doi:10.1016/j.ijggc.2013.06.017).

Existing carbon storage projects and experience

The injection of CO_2 for permanent geological storage is safe and viable at the Mt/yr scale.

In the 1970s, the injection of CO_2 into oilfields to enhance oil recovery (EOR) emerged. During EOR, injected CO_2 is cycled through a reservoir a number of times before being permanently trapped in the subsurface. Around 20 $MtCO_2$/yr is permanently trapped in the subsurface via EOR operations.

For the direct purpose of mitigating climate change, the injection and long-term storage of CO_2 started with the development of the Sleipner project (see section 2.1). The deployment of CCS projects is now rapidly accelerating. The Global CCS Institute's 2021 survey lists 27 CCS projects as being operational capturing 36.6 $MtCO_2$/yr, with a further 62 projects listed as being either in construction (n=4) or in advanced development (n=58)[36]. If these are all successfully deployed, the combined capture potential would be 86.4 $MtCO_2$/yr. A further 44 projects (60.9 $MtCO_2$/yr) are listed as being in an early stage of development. Details of some of the operational projects are given below.

2.1. Sleipner

The Sleipner CCS project in the Norwegian sector of the North Sea is the first industrial-scale project with the direct purpose of reducing CO_2 emissions[37]. CO_2 injection started in 1996 and around 1 $MtCO_2$/yr is captured from an offshore gas treatment facility and injected into a saline formation at around 1 km depth.

On a specialist offshore platform, CO_2 is separated from the natural gas that is extracted from the Sleipner West gas field and then reinjected via a single horizontal well into the lower levels of the Utsira saline formation. The CO_2 migrates vertically under buoyancy, with some CO_2 accumulating below each of a series of internal mudstone layers, until it reaches the impermeable top seal or caprock. The CO_2 then migrates laterally following the local topology of the top seal which has around a 0.5° slope (figure 7).

Seismic imaging has been extensively used at Sleipner and a dataset from repeated seismic surveys at intervals of 2 – 3 years has been developed[38]. This data has been a major resource for understanding how a large CO_2 plume spreads and for testing models of CO_2 migration under buoyancy. Fundamental questions still remain about the process by which the flow occurs across each of the mudstone interfaces between the layers, especially given the non-uniform distribution of CO_2 between the layers[39].

36 Global CCS Institute. Global Status of CCS 2021: CCS Accelerating to Net Zero. See https://www.globalccsinstitute.com/resources/global-status-report/ (accessed 14 January 2022).

37 Equinor. Sleipner area. See https://www.equinor.com/en/what-we-do/norwegian-continental-shelf-platforms/sleipner.html (accessed 15 January 2022).

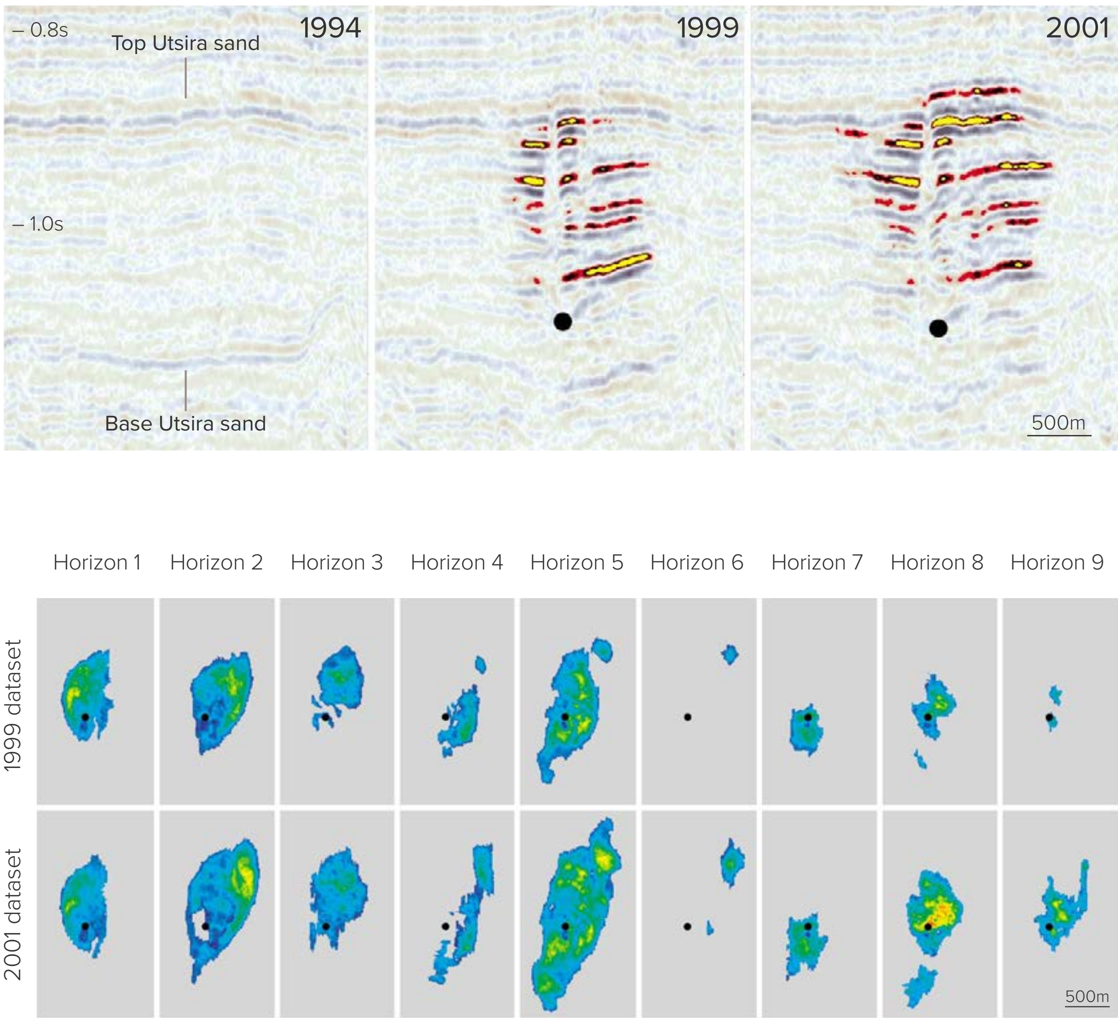
38 Equinor. Sleipner 4D Seismic Dataset. See https://co2datashare.org/dataset/sleipner-4d-seismic-dataset (accessed 14 January 2022).

39 Cavanagh AJ, Haszeldine RS. 2014 The Sleipner storage site: Capillary flow modelling of a layered CO_2 plume requires fractured shale barriers within the Utsira Formation. *International Journal of Greenhouse Gas Control*, 21, 101 – 112. (doi: 10.1016/j.ijggc.2013.11.017).

FIGURE 7

Seismic images showing the movement of CO_2 within the saline formation at Sleipner[40].

A side view of the spreading plume; and a top view of the plume in the nine parallel sub-layers which make up the Utsira saline formation. These are shown from two different surveys in 1999 and 2001.



40 Chadwick RA, Arts R, Eiken O. 2005 4D seismic quantification of a growing CO_2 plume at Sleipner, North Sea. 6th Petroleum Geology Conference, Geological Society London, 6, 1385 – 1399. (doi: 10.1144/0061385).

The Sleipner project has demonstrated several important factors, including:

- the injection of CO_2 for permanent geological storage is safe and viable at the Mt/yr scale and is potentially scalable to larger injection rates for reservoirs with such high permeability, provided the injection pressure does not reach the fracture pressure;
- several monitoring technologies have been successful in tracking the growth of a CO_2 plume;
- for high permeability formations, the plume dynamics are consistent with models of buoyancy driven flow but the process of flow between adjacent sedimentary layers, separated by mudstone layers, remains unclear.

2.2. In Salah

In 2004, the In Salah CCS project in central Algeria started capturing and separating the CO_2 which was produced along with natural gas from the In Salah Gas field[41]. The CO_2 was injected underground at a depth of 1.9 km via three horizontal wells into the aquifer zone of the reservoirs where the gas had been extracted.

The storage wells at In Salah had relatively low rock permeability so, unlike in Sleipner, this affected the injection interval and provides a good example of a lower threshold of viability for commercial CCS operations.

Injection was suspended in 2011 due to concerns regarding the integrity of the seal. During the project lifetime, 3.8 $MtCO_2$ was stored. The total cost of the project is estimated at £2 billion[42].

There were several key lessons from In Salah, including:

- plume development was far from homogeneous and required high resolution data for reservoir characterisation and modelling[43]. Due to the lower permeability, the dynamics of plume growth were more influenced by the injection pressure driving the flow through the formation. Most screening workflows now tend to set a higher minimum permeability to avoid this.
- storage performance was monitored with several geophysical and geochemical methods including a satellite technique, known as InSAR, which was used to measure very small (millimetre vertical) movements of the ground surface in response to injection and extraction of fluids. Other methods included time-lapse seismic surveys, CO_2 gas tracers in wellhead samples, and groundwater aquifer monitoring.

41 University of Edinburgh. In Salah: project details. See https://www.geos.ed.ac.uk/sccs/project-info/22 (accessed 20 January 2022).

42 Massachusetts Institute of Technology. 2016 In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project. See https://sequestration.mit.edu/tools/projects/in_salah.html#:~:text=Total%20project%20is%20estimated%20to%20cost%20US%242.7%20billion. (accessed 20 January 2022).

43 Ringrose PS *et al*. 2013 The In Salah CO_2 Storage Project: Lessons Learnt and Knowledge Transfer. *Energy Procedia*, 37, 6226 – 6236. (doi: 10.1016/j.egypro.2013.06.551).

2.3. Gorgon

The Gorgon project captures CO_2 from a liquified natural gas (LNG) facility off the coast of Western Australia. It was designed to inject 3.3 – 4 $MtCO_2$/yr into a massive sedimentary rock (known as the Dupuy Formation) at a depth of 2.5 km[44]. The seal rock for the site is provided by the Barrow marine shale. As the CO_2 is injected, the original brine in the formation is extracted to create space and prevent the reservoir pressure becoming too large.

The CCS operation started in 2019 and gradually ramped up injection to finally reach 4 $MtCO_2$/yr. At this rate, it was observed that sand was being produced in the brine disposal wells and impaired the performance by blocking pipes. Consequently, the plant is currently operating at a reduced rate while a solution to the sanding issue is being developed.

Originally, the developers promised that at least 80% of the separated CO_2 would be stored, however due to the reduced rate of injection only around 30% is being stored and the rest vented. Thus far, the CCS fraction of the Gorgon project is estimated to have cost £1.7 billion with 5 $MtCO_2$ injected in total. The target for this timepoint was 15 $MtCO_2$ in total.

Despite remaining challenges, specific lessons from the Gorgon project include:

- the performance of the CO_2 injectors and plume development have been consistent with previous experience and the monitoring technologies deployed have enabled tracking of the CO_2 plume;
- brine extraction for pressure management has been partially successful but management of sand production is needed to sustain higher rates.
- recognition of the importance of preventing or limiting the rate of pipe corrosion.

44 Chevron Australia. Gorgon Carbon Capture and Storage. See https://australia.chevron.com/our-businesses/gorgon-project/carbon-capture-and-storage (accessed 20 January 2022).

Surface infrastructure for storage

CO_2 is routinely transported by road, rail, ship and pipeline.

The design of the transport, wells and injection infrastructure is a major part of the post-CO_2 separation system which supplies the storage reservoir. The history of CO_2 transport for EOR has shown that it is technically feasible, but there are some specific challenges for CO_2 storage projects.

3.1. Transportation methods

CO_2 is routinely transported by road, rail, ship and pipeline. So far, road, rail and ship-based transport has generally been limited to relatively small volumes for the food and chemical industries or for small scale oil field operations. For large-scale UK CCS applications, it is anticipated that there will be flow rates from industries providing 5 – 50 $MtCO_2$/yr. At these tonnages, pipeline and ship methods of transportation become the most viable options[45].

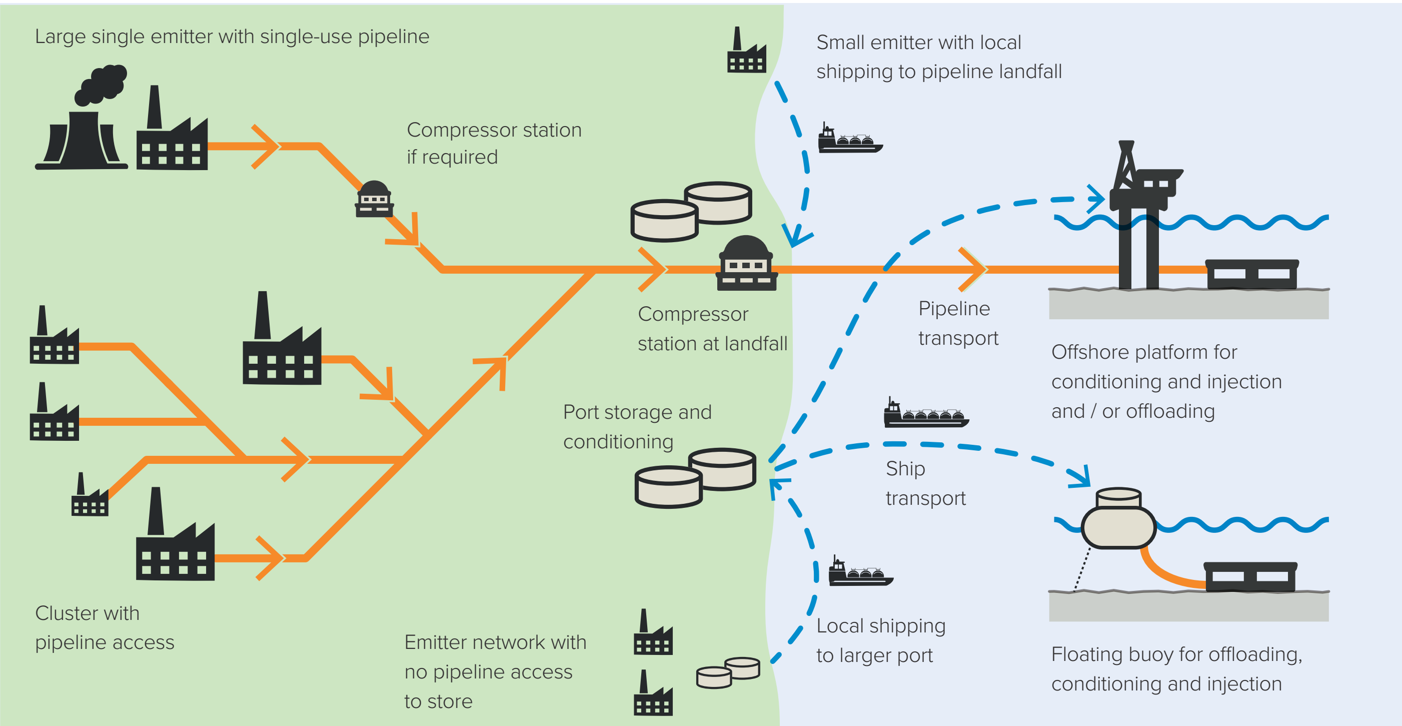
There are different transportation scenarios that can be envisaged in the UK context, some of which are illustrated in figure 8, which also indicates the infrastructure requirements for these scenarios.

For CCS applications, the transportation method for the CO_2 from the capture site to the storage site (if they are not co-located) is dictated by the mass of CO_2 to be transported, the distance of transportation, the terrain (for example onshore or offshore), and the phase or state that the CO_2 is in during transportation.

The CO_2 can exist as either a vapour (gas), a liquid or a solid depending on the temperature or pressure (see figure 9). There is also a 'critical point' (7.4 MPa (73.8 bar), 31°C), above which the CO_2 exists as a supercritical or dense phase (depending on temperature).

FIGURE 8

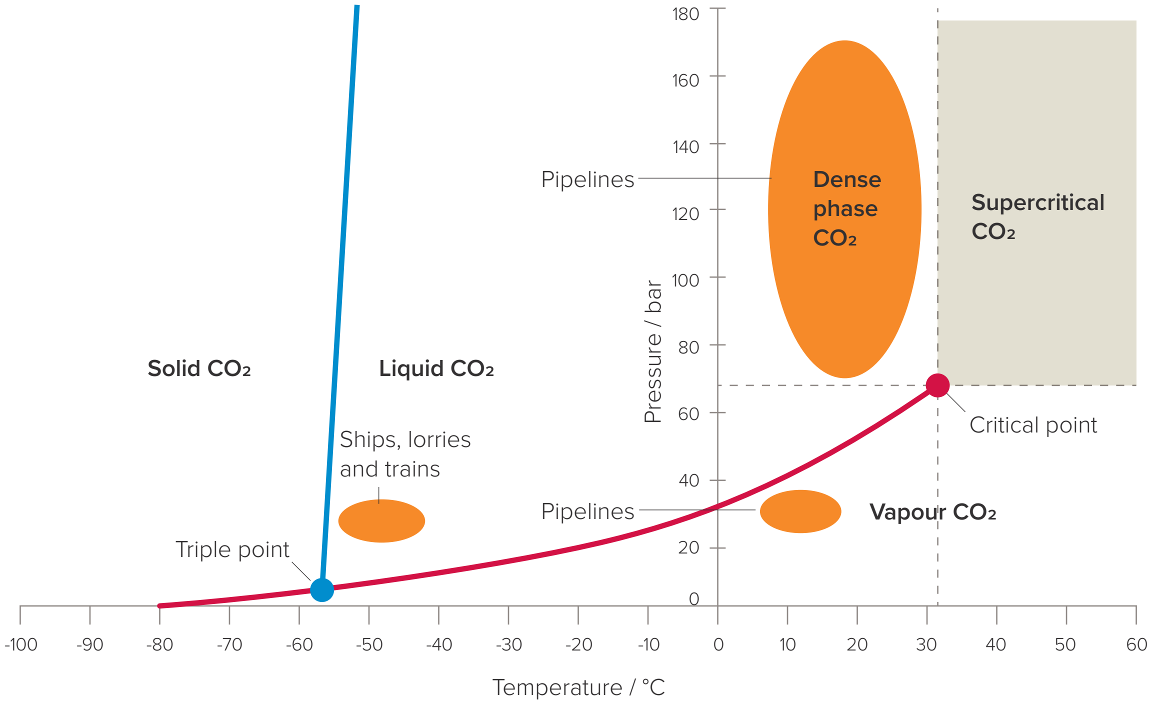
Potential transportation scenarios for transport of CO_2 to offshore storage in the UK.



45 Global CCS Institute. 2018 Transporting CO_2: Fact Sheet. See https://www.globalccsinstitute.com/wp-content/uploads/2018/12/Global-CCS-Institute-Fact-Sheet_Transporting-CO_2-1.pdf (accessed 20 January 2022).

FIGURE 9

Phase diagram for pure CO_2 showing the phase state for different modes of transportation[46].



3.1.1. Pipeline transportation

Globally there are around 8,000 km of pipelines transporting over 40 $MtCO_2$/yr, predominantly in the United States for EOR[47]. This infrastructure is mainly onshore with currently only one operational offshore pipeline at Snøhvit in the Barents Sea.

The dense phase is the most efficient for the pipeline transport of CO_2 as it has the density of a liquid, but the viscosity and compressibility of a gas. For dense phase transportation, it is important that the pressure is kept well above the critical pressure to avoid changes in density of the CO_2 within the pipeline.

Consequently, compressors (booster stations) may need to be installed along the pipeline length to repressurise the CO_2. The CO_2 can also be transported in the gaseous phase at lower pressures and larger volumes.

46 Pershad H *et al*. 2010 Development of a Global CO_2 Pipeline Infrastructure: Report 2010/13 (Adapted). International Energy Agency Greenhouse Gas R&D Programme. See https://ieaghg.org/docs/General_Docs/Reports/2010-13.pdf (accessed 35 January 2022).

47 Peletiri SP, Rahmanian N, Mujtaba IM. 2018 CO_2 Pipeline design: A review. *Energies*, 11, 2184. (doi: 10.3390/en11092184).

Pipelines must be routed such that there is a safe distance between the pipeline and human population in case of leakage.

There are several special design aspects that must be carefully considered, which are the subject of ongoing research, including:

1 Composition of the CO_2: impurities can affect the critical pressure of the gas and hence the required operating pressure of the pipeline, the corrosion behaviour, the mode of failure in the unlikely event that the pipeline fails, and the impact of a release of CO_2 from the pipeline[48]. The composition of the CO_2 from different emitters and processes will vary and therefore the compositional mix in a pipeline network, in which CO_2 is being transported from a number of different emitters, needs to be tightly specified[49].

2 Material properties of the pipeline infrastructure: low-carbon steel is the most economical material from which to construct long distance CO_2 pipelines. However, it is vulnerable to corrosion if water is present with the CO_2, therefore it is critical that water is removed prior to transportation. The toughness of the steel needs to be tightly specified to ensure fracture control during decompression of the CO_2.

3 Safety and risk criteria: high concentrations of CO_2 can lead to asphyxiation. Therefore pipelines must be routed such that there is a safe distance between the pipeline and human population in case of leakage.

In the UK, the network of onshore natural gas pipelines could be converted to transport CO_2 in the gaseous phase and the feasibility has been considered in demonstration and commercial projects, for example, the use of the National Grid Feeder 10 natural gas pipeline from St. Fergus[50]. However, with new build pipelines, higher pressures may be deployed.

Indeed, for offshore pipelines, the design pressures are higher and dense phase transportation is possible. The construction materials, the condition of the pipeline given its previous service history, the route of the pipeline and the suitability in terms of safety and risk need to be assessed. In particular, the CO_2 needs to be very dry to limit corrosion in the pipes or injection wells. Many projects have also included the reuse of offshore infrastructure, such as the Goldeneye and Miller pipelines[51].

3.1.2. Ship transportation and associated infrastructure

Ship transportation offers flexibility, potentially allowing collection of CO_2 from isolated sources with delivery either to a port hub for onward transportation to a storage site or directly to an offshore storage site without the need to install multiple arrays of pipelines. However, as well as the cost of ships, this requires infrastructure at port to cool, liquefy and pressurise the CO_2, and then store the CO_2 prior to loading onto the ship. Several studies suggest that CO_2 should be transported under pressures of 0.6 and 1.5 MPa and between -50 to -25°C.

48 Wetenhall B, Race JM, Downie MJ. 2014 The effect of CO_2 purity on the development of pipeline networks for carbon capture and storage schemes. *International Journal of Greenhouse Gas Control*, 30, 197-211. (doi: 10.1016/j.ijggc.2014.09.016).

49 International Organization for Standardization. 2016 ISO Standard 27910:2016 Carbon dioxide capture, transportation and geological storage – Pipeline transportation systems. See https://www.iso.org/standard/64235.html (accessed 25 January 2022).

50 Brownsort PA, Scott V, Haszeldine RS. 2016 Reducing costs of carbon capture and storage by shared reuse of existing pipeline – Case study of a CO_2 capture cluster for industry and power in Scotland. *International Journal of Greenhouse Gas Control*, 52, 130 – 138. (doi: 10.1016/j.ijggc.2016.06.004).

51 Alcalde J *et al*. 2021 A criteria-driven approach to the CO_2 storage site selection of East Mey for the acorn project in the North Sea. *Marine and Petroleum Geology*, 133, 105309. (doi: 10.1016/j.marpetgeo.2021.105309).

Typical injection conditions may require pressures of 5 to 40 MPa with the CO_2 reheated to temperatures of -15 to 20°C, and this requires infrastructure on the ship or the offshore platform or well-head system. While technically feasible, development of pilot examples will be key for establishing the viability of the end-to-end CO_2 ship-transport system.

Large scale ship transportation of cryogenic liquids is feasible and routinely used for Liquefied Natural Gas (LNG) and Liquefied Petroleum Gas (LPG). LNG and LPG ships can carry cargos of 120,000 – 270,000m^3 (60 – 135 kt) and can inform the design safety and development of CO_2 ships, although the operating pressure of the CO_2 vessels on board would be higher.

Transport of CO_2 by ships is already undertaken on a small scale and there are a number of future plans. For example, in the UK, the South Wales Industrial Cluster is exploring CO_2 shipping from ports in South Wales to offshore carbon storage reservoirs[52]. The Norwegian Northern Lights project is considering the shipping of liquid CO_2 from multiple industrial cluster sites along the Norwegian west coast to an onshore port; the CO_2 would then be transported via pipeline to an offshore storage location[53].

Shipping could be a more economical solution for transportation over long distances or to short term or smaller stores[54]. As the transport distances increase, the cost of ship transport relative to pipeline becomes attractive, with some estimates suggesting economic benefits over distances in excess of 500 – 1,000 km[55].

In addition, in regions with natural hazards, including earthquakes and tsunamis, the safety of subsea pipelines can be challenging, leaving shipping as a safer alternative.

More work is required to assess:

- the behaviour of CO_2 in the low temperature liquid phase relevant for shipping, especially in the presence of impurities, and on the role of dissolved water in the CO_2 which will affect density-pressure relations and could lead to corrosion and hydrate formation.
- understanding the vapour-liquid equilibrium of CO_2 would be very valuable in terms of the safety of CO_2 being transported in pressurised cooled vessels.
- the fate of the CO_2 in the event of large-scale discharge of the cargo are important considerations from a safety perspective. CO_2 is dense, and tends to collect in low lying zones, possibly leading to danger.
- meeting specific constraints of existing ports (such as the ship length and storage space).
- the theoretical possibility of multi-purposing ships, for example the ability to carry LPG in one direction and captured CO_2 in another.

The cost of CO_2 transportation by ship shows a significant range of estimates from US$10/t$CO_2$ (£7.6/tCO_2) to US$167/t$CO_2$ (£127/tCO_2) [54]. The range depends on the distance travelled, the geological storage location and discharge amount. Economies of scale are expected to decrease the costs, however it has been noted that the cost of shipping has increased since this analysis.

Shipping could be a more economical solution for transportation over long distances or to smaller stores.

52 Costain. 2021 Next phase of project to decarbonise industry in South Wales receives funding. See https://www.costain.com/news/news-releases/next-phase-of-project-to-decarbonise-industry-in-south-wales-receives-funding/ (accessed 25 January 2022).

53 Equinor. Northern Lights. See https://www.equinor.com/en/what-we-do/northern-lights.html (accessed 25 January 2022).

54 Al Baroudi H *et al*. 2021 A review of large-scale CO_2 shipping and marine emissions management for carbon capture, utilisation and storage. *Applied Energy*, 287, 116510. (doi: 10.1016/j.apenergy.2021.116510).

55 Element Energy. 2018 Shipping CO_2 -UK Cost Estimation Study. See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/761762/BEIS_Shipping_CO2.pdf (accessed 25 January 2022).

Wellbore integrity might degrade with time.

3.2. Well design

Injection rates in wells may vary from 0.5 to up to 5 $MtCO_2$ / yr, depending on a range of factors. Factors include the geometry and distribution of perforations of each well, and the permeability of the rock. In relatively high permeability formations, the injection wells can be vertical provided that the surface area of the well in contact with the reservoir is sufficient to achieve the required injection rate without over-pressuring the formation. In low permeability formations, the injection wells may be drilled deviated to the vertical or even horizontal. This provides a greater surface area for the fluid to enter the formation, and hence reduces the injection pressure for a given flow rate. For example, at the In Salah formation the wells extended up to 1.9 km horizontally within the reservoir section to enable sufficient injection of CO_2 without the pressure fracturing the overlying seal rock (see section 2.2).

Any impairment of the rock permeability caused during the drilling process can reduce the injectivity. Heterogeneity of the reservoir can lead to the rock formation being separated into a series of smaller reservoir elements, or compartments, which may reduce the volume of rock that is accessible to the well.

There are some specific requirements for ensuring high wellbore integrity, including the composition of cement which stabilises the well against subsurface stresses and potentially reactive fluids. Wellbore integrity might degrade with time, possibly leading to steel or cement corrosion or the formation of small gaps between cement and casing or cement and host rock[56]. Such degradation needs to be monitored carefully as they might represent leakage paths. Legacy wells, formerly used for petroleum production, may not be suitable for a CO_2 storage reservoir and might require replacement.

As CO_2 flows from an injection well into a depleted permeable reservoir, the decrease in pressure can be accompanied by cooling (the Joule-Thompson effect). Such cooling could lead to formation of precipitate, which may impede the flow of CO_2 into the system. Research and development are ongoing to determine potential means to manage or prevent the effects occurring, especially specific to the complexity of individual reservoirs.

Following the injection of CO_2, wells are plugged and abandoned, typically by putting multiple thick cement plugs in place to separate the storage formation from more shallow geological layers or the sea bottom, aiming for safe storage of over 10,000 years.

56 Gasda SE, Bachu S, Celia MA. 2004 Spatial characterization of the location of potentially leaky wells penetrating a deep saline aquifer in a mature sedimentary basin. *Environmental Geology*, 46, 707-720. (doi: 10.1007/s00254-004-1073-5).

Monitoring and assurance

Successful implementation of CO_2 storage will require monitoring the CO_2 migration in the subsurface, understanding the processes controlling the subsurface distribution of the CO_2, and to provide assurance that the CO_2 is safe and not leaking upwards through the geological strata. Such assurance is vital to assess the risk of leakage of CO_2 from the reservoir, and to help establish a process for the potential long-term transfer of liability from the operator responsible for injection of the CO_2 to national governments.

Owing to the remoteness of CO_2 in a storage reservoir, many of these techniques can help address specific questions about the lateral extent of the plume, the solubility of the plume in the water originally in the storage reservoir, and the interaction of the plume with the formation. However, the resolution of the monitoring may be limited in time for repeat seismic surveys, or in space, with monitoring at injection, pressure relief or observation wells. The monitoring data are often combined with parameterised models of the various flow processes to restrict the range of possible scenarios consistent with the data, but significant uncertainties remain.

4.1. Seismic monitoring

Seismic methods are the most common tools for monitoring and verifying CO_2 storage in geologic reservoirs. When the sound wave enters a different layer of rock, some of the wave is reflected, and interpretation of these reflected signals help to describe the structure of the reservoirs and to monitor the CO_2 as it is injected and stored. There are two ways that seismic methods can monitor CO_2 storage, either actively or passively.

4.1.1. Active-seismic monitoring: time-lapse seismic reflection surveying

Seismic surveys are acquired to capture a snapshot of the subsurface structure. The sources and the receivers that record the seismic waves can be deployed on the surface, seabed or in boreholes. The most common approach is to use seismic energy that travels from the source back to the surface as reflections from deep interfaces in the rock (seismic reflection surveys: see figure 10). Other approaches include cross-borehole surveys, where sources are in one well and receivers in another, or vertical seismic profiling, where receivers are deployed in a borehole and sources on the surface.

Fluids in reservoirs change reservoir properties and this can impact the strength of seismic reflections; changes in seismic wave-speeds and density affect how much seismic energy is reflected back to the receivers, or the strength of the seismic reflections. Repeated seismic snapshots of the sub-surface can be used to track the movement of fluids.

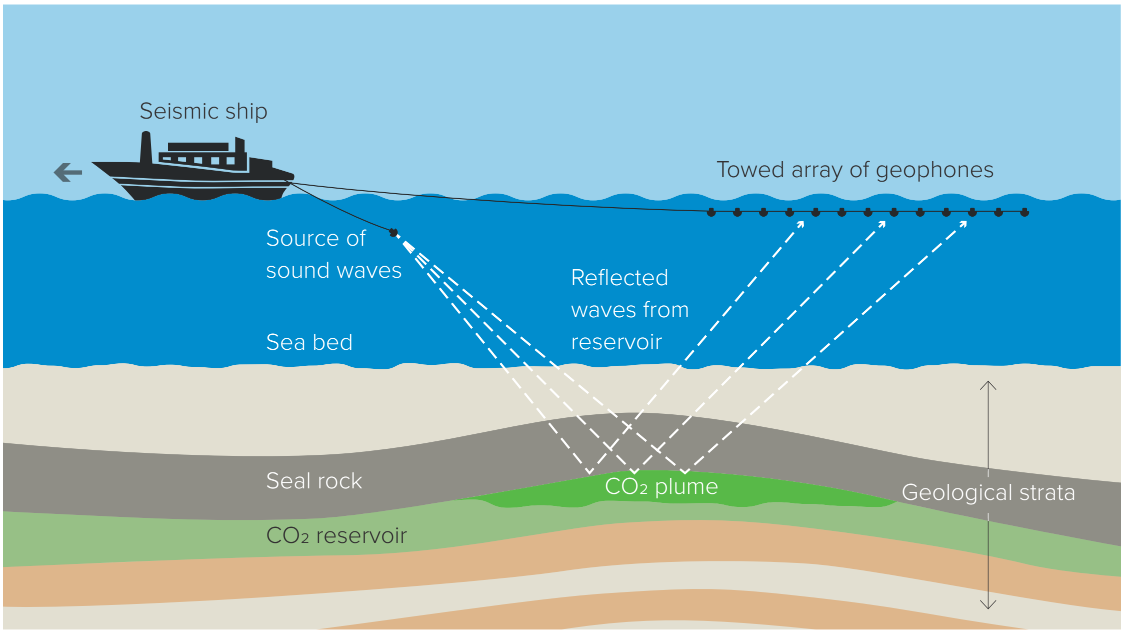
Seismic data from multiple sources and multiple receivers are regularly spaced along a line (2D surveys) or across a grid (3D surveys). The signals from multiple sources and multiple receivers are rearranged and summed together to accentuate the reflected energy and suppress the unwanted energy (noise). This technique is the main tool used in the exploration for oil and gas, but it is equally useful in imaging where CO_2 migrates after injection. Data acquisition can be on land or in marine settings, with differences in the nature of the seismic source and the receiver.

Fluids in reservoirs change reservoir properties and this can impact the strength of seismic reflections.

FIGURE 10

Schematic of seismic reflection surveying.

Seismic waves are emitted from the ship and travel through the water and rock. They are reflected/refracted at the boundaries between different density materials. These reflections are picked up by the towed array of geophones and analysed to determine the subsurface structure.



Time-lapse or 4D seismic reflection data refers to repeated 3D surveys used to image fluid flow across a region (see figure 11). They provide better coverage than borehole monitoring and help to calibrate numerical simulations of fluid flow in the reservoir. Such data can be used to identify parts of the reservoir that are receiving CO_2 and those which are bypassed, including areas where there might be leakage from the reservoir[57].

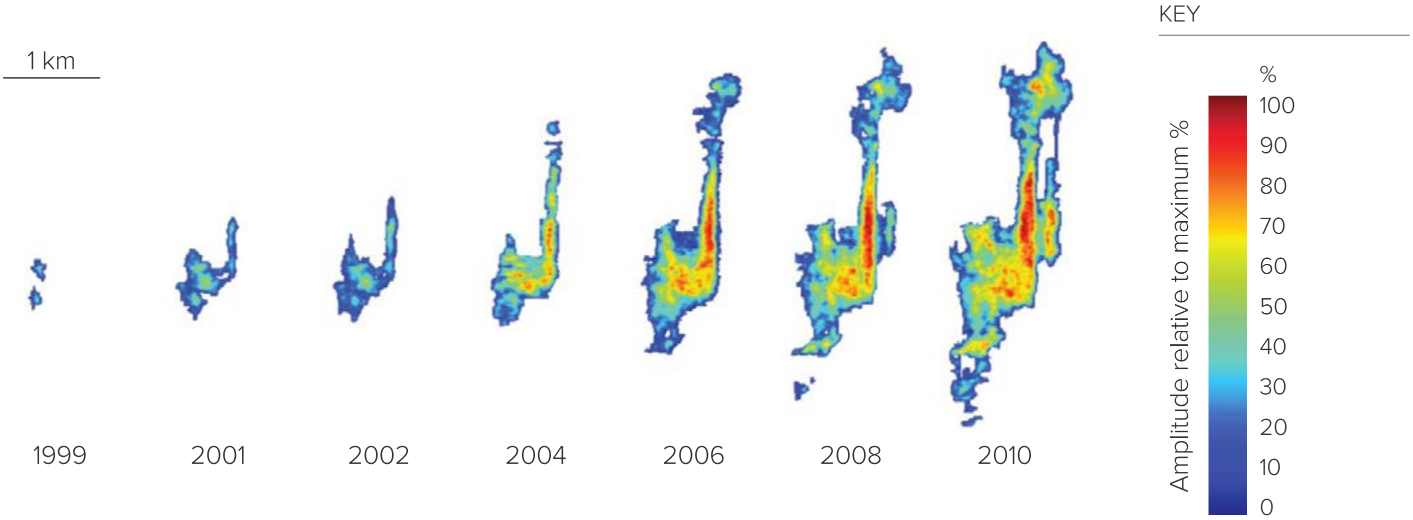
However, there are some limitations:

- Estimating the mass of CO_2 at each point in the reservoir is less precise owing to the non-linear relationship between the reflection amplitude and the gas content.
- The wavelengths of the seismic waves are typically greater than 10m, while the rock formations may be layered on a much smaller vertical scale, so the CO_2 may spread out as a series of thin plumes and the seismic signal involves some vertical averaging across the formation.
- It is difficult to accurately assess the fraction of CO_2 which is mobile compared to that which is structurally trapped, capillary trapped or dissolved into the host fluid. Nonetheless, the data can be used to test leading order predictions from models of the flow of CO_2 in the subsurface.
- Although seismic reflection produces very useful images of stored CO_2, it is regarded as expensive.

57 White D. 2009 Monitoring CO_2 storage during EOR at the Weyburn-Midale Field. *The Leading Edge*, 28, 838. (doi: 10.1190/1.3167786).

FIGURE 11

Seismic maps of CO_2 concentration at Sleipner and how they have changed from 2004 to 2010 (red indicates regions with higher concentration of CO_2).



Source: Kiær A, Eiken O, Landrø M. 2015 Calendar time interpolation of amplitude maps from 4D seismic data[58].

4.1.2. Passive-seismic monitoring

Passive-seismic methods are deployed on the surface or in boreholes, but the sources are not actively produced by the operator. The Earth constantly produces tiny earthquakes, or microseismicity, and this 'background hum' is used to monitor the reservoir, including fault reactivation into the overlying rock. Passive-seismic methods are particularly useful over decadal timescales and are cheaper and more continuous than active-source methods. A downside of this approach is that the location and timing of the microseismicity is unknown ahead of time.

Further, as fluids are injected or extracted from the subsurface, the forces acting on the reservoir, and around it, will change leading to microseismic earthquakes. These sources can be used to image properties of the reservoir, including the development of fracture networks and the migration of CO_2. The time and location of these events helps to track the migration of the CO_2 plume. They also indicate fault reactivation, which can be an early indication of failure in containing the CO_2 in the reservoir (see section 1.4). In very few cases, induced seismicity becomes felt at the surface[59], but most commonly events can only be detected with sensitive downhole instruments[60].

58 Conference Proceedings, Third EAGE Workshop on Permanent Reservoir Monitoring, 2015, 1-5. (doi: 10.3997/2214-4609.201411971)

59 Stork AL, Verdon JP, Kendall JM. 2015 The microseismic response at the In Salah Carbon Capture and Storage (CCS) site. *International Journal of Greenhouse Gas Control*, 32, 159 – 171. (doi: 10.1016/j.ijggc.2014.11.014).

60 Verdon JP. 2016 Using microseismic data recorded at the Weyburn CCS-EOR site to assess the likelihood of induced seismic activity. *International Journal of Greenhouse Gas Control*, 54, 421 – 428. (doi: 10.1016/j.ijggc.2016.03.018).

Many studies of induced seismicity[61, 62] indicate that with knowledge of the fault locations and appropriate monitoring, larger earthquakes can be avoided.

Another category of passive-seismic imaging involves the use of seismic noise. This noise can be associated with cultural activity (for example, traffic) or the faint signal from waves crashing on distant shorelines (this is called the microseism, not to be confused with microseismicity). Another example is wind turbines which may act as a passive source on offshore sites. The application of ambient noise imaging at CO_2 storage sites is still in its infancy but is expected to be a commonly used tool in the future and is likely to embrace techniques from machine learning.

4.2. Non-seismic monitoring

4.2.1. Gravity monitoring

The density of the injected CO_2 is dependent on temperature and pressure. In general, as CO_2 spreads into a rock formation after injection, it reduces the overall density of the fluid-filled rock. Gravimeters are very sensitive instruments that can measure incredibly small changes in the Earth's gravitational field; the strength of the field is slightly reduced when CO_2 enters the storage reservoir.

Gravity surveys at the Sleipner field have been used to estimate the density of CO_2 in the saline aquifer[63]. This was performed using gravimeters deployed by remotely operated vehicles on the seafloor. Interpreting the amount of CO_2 responsible for the gravity signal requires careful processing of the data.

4.2.2. Geoelectrical monitoring

Geoelectric surveys can be used to measure variations in the conductivity structure of the Earth. Conductivity refers to the ease at which electrical current can flow through a material. These are often referred to as resistivity surveys, where resistivity is the reciprocal of conductivity. CO_2 has a much lower electrical conductivity (higher resistivity) than the brine it is displacing, therefore, the resistivity of a rock saturated with brine and CO_2 depends on the relative amounts of each fluid.

Resistivity data are acquired using at least four current electrodes, where a battery is connected across two of the electrodes. This results in current flowing through the ground and the potential difference between the other two electrodes provides a measure of the resistivity of the ground between the electrodes. Varying the separation and geometry of the electrodes can be used to generate an image of the resistivity or conductivity structure across the region. In practice, many tens or hundreds of electrodes are deployed at the same time and the choice of current electrodes is varied systematically to best acquire an image of the subsurface conductivity.

61 Langenbruch C, Weingarten M, Zoback M. 2018 Physics-based forecasting of man-made earthquake hazards in Oklahoma and Kansas. *Nature Communications*, 9(3646), 1-10, (doi:10.1038/s41467-018-06167).

62 Williams-Stroud S, Bauer R, Leetaru H, Oye V, Stanke F, Greenberg S, Lenget N, Analysis of microseismicity and reactivated fault size to assess the potential for felt events by CO_2 injection in the Illinois basin. *Bulletin Seismological Soc. 110*, 2020

63 Nooner SL *et al*. 2007 Constraints on the *in situ* density of CO_2 within the Utsira formation from time-lapse seafloor gravity measurements. *International Journal of Greenhouse Gas Control*, 1, 198 – 214. (doi: 10.1016/S1750-5836(07)00018-7).

The application of resistivity methods is normally done using borehole measurements, but surface arrays can be used to detect shallow leaks of CO_2. Borehole experiments at Ketzin, a research scale CO_2 storage site in Germany, have shown how time-lapse resistivity measurements can be used to track the migration of the CO_2 plume[64]. Deploying instruments in multiple boreholes improves the 3D image of CO_2 movement and may contribute to early warning of leakage from the reservoir.

4.2.3. Electromagnetic monitoring

Another type of geophysical survey uses electromagnetic fields propagating in the Earth. A magnetic field varying in time generates an electrical current, and conversely an alternating electrical current generates a magnetic field. The field can be naturally occurring, for example currents associated with disturbances in the upper atmosphere or lightning strikes. In active methods, the electromagnetic field can be generated using coils placed near the surface.

Magnetotellurics is a passive method that uses the Earth's naturally varying electrical and magnetic fields. These fields propagate through the Earth: when they encounter a conductive region, they excite electrical currents, which in turn generate their own magnetic fields. Sensitive instruments on the surface can record differences between the original (primary) field and the induced (secondary) field. Such information can be used to map the conductivity of the subsurface.

Controlled source electromagnetic (CSEM) surveys have been used extensively in the mining and oil and gas industries and could be suited to imaging CO_2 plumes in reservoirs. They are normally conducted at sea, where a primary electromagnetic coil is placed on the sea bottom. A downside of the CSEM method in comparison to seismic methods is that they have lower resolution and some uncertainty in depth estimates.

Ideally, a number of geophysical methods can be combined to monitor CO_2 storage, providing a robust early warning system for leak detection. Each method has its own strengths and limitations. For example, combined time-lapse seismic reflection and CSEM surveying provides very high-resolution images, but are the most expensive techniques. Combining gravity and geoelectrical methods is a cheaper approach, but these techniques are less sensitive to changes in CO_2 content than seismic methods.

64 Kiessling D *et al*. 2010 Geoelectrical methods for monitoring geological CO_2 storage: First results from cross-hole and surface – downhole measurements from the CO_2SINK test site at Ketzin (Germany). *International Journal of Greenhouse Gas Control*, 4, 816 – 826. (doi: 10.1016/j.ijggc.2010.05.001).

4.3. Tracer transport, partitioning and dispersion

Effective application of chemical tracers with the injected CO_2 can provide valuable information about the migration and fate of CO_2 and can allow 'fingerprinting' of the injected CO_2[65, 66, 67, 68]. When using tracers, it is key to characterise the fluid environment before CO_2 injection to optimise tracer doping levels and estimate the sensitivity of tracers used in reservoir model calibration. This is particularly important if shallow fluid systems form part of the monitoring strategy for CO_2 leakage.

Tracers are measured at either observation wells if these are available, or injection wells, and while spatially limited provide an observational base to identify processes and quantify the models forming a picture of the flow and reactions across a storage reservoir which may extend several kilometres from the injection well. With frequent monitoring, the data may be of relatively high resolution and when coupled with a flow model, the data provides very useful constraints on the flow rates and on reactions of the CO_2.

There are three main types of gas tracer:

1 Artificial: those that are added to the injected CO_2 to allow it to be distinguished from that present naturally in the subsurface[66]. These can be impractical due to high costs, environmental concerns, and some could potentially contribute to global warming when injected in large quantities[66].

2 Inherent: those contained or directly associated with the CO_2 itself, for example, the stable isotopes of carbon and oxygen or the noble gases present in trace quantities within the injected CO_2[69, 70] or the changes in subsurface chemistry that result from the injection of CO_2, such as pH or changes in alkalinity[71].

3 Acquired: isotopic or chemical species from the fluid and solid environment that the injected CO_2 equilibrates or reacts with. These include dissolved gases that have accumulated within the groundwater/pore fluids such as nitrogen and methane.

Inherent and acquired tracers are considerably less expensive and logistically easier tools for fingerprinting the injected CO_2, but care must be taken to establish the baseline chemistry to ascertain the difference between the inherent tracer composition and those acquired from the natural environment[69, 70].

65 Gilfillan SMV *et al*. 2014 The application of noble gases and carbon stable isotopes in tracing the fate, migration and storage of CO_2. *Energy Procedia*, 63, 4123 – 4133. (doi: 10.1016/j.egypro.2014.11.443).

66 Myers M *et al*. 2013 Tracers – Past, present and future applications in CO_2 geosequestration. *Applied Geochemistry*, 30, 125 – 135. (doi: 10.1016/j.apgeochem.2012.06.001).

67 Roberts JJ *et al*. 2017 Geochemical tracers for monitoring offshore CO_2 stores. *International Journal of Greenhouse Gas Control*, 65, 218 – 234. (doi: 10.1016/j.ijggc.2017.07.021).

68 Ringrose PS *et al*. 2021 Storage of Carbon Dioxide in Saline Aquifers: Physicochemical Processes, Key Constraints, and Scale-Up Potential. *Annual Review of Chemical and Biomolecular Engineering*, 12, 471 – 494. (doi: 10.1146/annurev-chembioeng-093020-091447).

69 Flude S *et al*. 2017 The inherent tracer fingerprint of captured CO_2. *International Journal of Greenhouse Gas Control*, 65, 40 – 54. (doi: 10.1016/j.ijggc.2017.08.010).

70 Flude S *et al*. 2016 Inherent Tracers for Carbon Capture and Storage in Sedimentary Formations: Composition and Applications. Environmental Science & Technology, 50, 7939 – 7955. (doi:10.1021/acs.est.6b01548).

71 Kharaka YK *et al*. 2006 Gas-water-rock interactions in Frio Formation following CO_2 injection: Implications for the storage of greenhouse gases in sedimentary basins. *Geology*, 34, 577 – 580. (doi:10.1130/G22357.1).

Chemical tracing complements other monitoring technologies, such as geophysical measurement, and can provide information about:

1. Leakage detection: the minimum level of CO_2 leakage that can be quantified is governed by the analytical detection limit for the tracer, the pre-existing tracer concentration in the natural environment, the flux of tracer to the surface and surface dispersion mechanisms for the tracer[66, 72, 43].

2. Plume migration, reservoir heterogeneity and field compartmentalisation: injecting an artificial tracer into one well and assessing migration by monitoring for the species at other observation wells. Additional information about the heterogeneity of a reservoir can be obtained by using tracers which can be differentiated analytically or using a combination of inherent and acquired tracers and monitoring the change from baseline as the injected CO_2 arrives at observation wells.

3. Quantifying CO_2, water, and rock interactions, and assessing trapping mechanisms[73, 74, 75, 76, 77]: critical information on the fate of CO_2 in the storage site can be provided by the partitioning of tracers between water and supercritical CO_2, interaction of chemical tracers with the rock surface and differing reactivity of the CO_2 and tracers.

4. When multiple artificial tracers with different subsurface behaviours are injected into a formation at the same time (or very close together), fluid properties and trapping processes can be determined through a combination of laboratory experiments, field trials and computer modelling by comparing the tracer concentration as a function of time. This can be achieved using several wells in which the tracer travels from an injection well to the production wells or in a single well configuration in which the same well is first used for injection, then production.

72 Korre A *et al*. 2012 Quantification techniques for CO_2 leakage: Report 2012/02. International Energy Agency Greenhouse Gas R&D Programme. See https://ieaghg.org/docs/General_Docs/Reports/2012-02.pdf (accessed 27 January 2022).

73 Gilfillan SMV *et al*. 2009 Solubility trapping in formation water as dominant CO_2 sink in natural gas fields. *Nature*, 458, 614 – 618. (doi:10.1038/nature07852).

74 Zhou Z *et al*. 2012 Identifying and quantifying natural CO_2 sequestration processes over geological timescales: The Jackson Dome CO_2 Deposit, USA. *Geochimica et Cosmochimica Acta*, 86, 257 – 275. (doi:10.1016/j.gca.2012.02.028).

75 Györe D, Gilfillan S, Stuart F. 2017 Tracking the interaction between injected CO_2 and reservoir fluids using noble gas isotopes in an analogue of large-scale carbon capture and storage. *Applied Geochemistry.* 78, 116 – 128 (doi:10.1016/J.APGEOCHEM.2016.12.012).

76 Györe D, Stuart F.M, Gilfillan S.M, Waldron S. 2015 Tracing injected CO_2 in the Cranfield enhanced oil recovery field (MS, USA) using He, Ne and Ar isotopes. *International Journal of Greenhouse Gas Control.* 42, 554 – 561 (doi:10.1016/J.IJGGC.2015.09.009).

77 Serno S *et al.* 2016 Using oxygen isotopes to quantitatively assess residual CO_2 saturation during the CO_2CRC Otway Stage 2B Extension residual saturation test. *International Journal of Greenhouse Gas Control*. 52, 73 – 83 (doi:10.1016/J.IJGGC.2016.06.019).

Microbial activity has the potential to impact CO_2 storage by converting some of the CO_2 to methane.

4.4. Biological impact and geochemical monitoring in shallow subsurface

Many proposed geological CO_2 storage targets are deep enough to be at temperatures that do not support microbial life. At shallower levels, almost all rock environments contain microbes in the water filled pore spaces and fractures. In these systems, microbial activity has the potential to impact CO_2 storage by converting some of the CO_2 to methane (CH_4) (microbial methanogenesis: see figure 12). This is important when considering how to identify and understand the impact of CO_2 leakage from deep to shallower systems and for developing a monitoring strategy.

Methane is less compressible, less soluble, less reactive in the subsurface, and a stronger greenhouse gas than CO_2.

EOR has provided an opportunity to assess what happens to the geological ecosystem when it is perturbed on an engineering timescale by injecting CO_2. For example, CO_2 was injected about 35 years ago for EOR into Olla, an on-shore oil field in the Gulf of Mexico, at a depth of 850m, and the microbial methanogenesis of injected CO_2 was identified[78, 79, 80].

Further geochemistry and gene sequencing showed that at least 19% of the residual CO_2 has been converted to CH_4 by microbial methanogenesis[81].

Examples of microbial methanogenesis are, to date, in systems with hydrocarbons or labile organic sediments present, likely playing a role in sourcing the hydrogen[78, 79, 80, 81].

Potential CO_2 sites in depleted oilfields only form a small (10%) portion of currently identified subsurface storage potential, and only some of these will be in the environmental window for microbial methanogenesis[82]. It will be important to assess potential CO_2 sites that are close to or within the temperature (up to 110°C) and pH range (4 – 9.8) that could support stimulation of microbial methanogenesis over the lifetime of the planned CO_2 storage[83].

The further impact of CO_2 seepage on shallow microbial stimulation and geochemical detection has not been considered. For example, the escape of CO_2 to shallower fluid systems cannot rely on the detection of CO_2 alone, and either associated fugitive gases and/or signals of CH_4/CO_2 carbon addition to the shallower fluid systems should be included as sampling targets to help with early leak detection[84].

78 Shelton J.L, McIntosh I, Warwich P.D, Zhi Yi A.L. 2014 Fate of injected CO_2 in the Wilcox Group, Louisiana, Gulf Coast Basin: Chemical and isotopic tracers of microbial – brine – rock – CO_2 interactions. *Applied Geochemistry.* 51, 155 – 169 (doi:10.1016/J.APGEOCHEM.2014.09.015).

79 Shelton J. L, McIntosh J. C, Warwick P. D, McCray J. E. 2016 Impact of formation water geochemistry and crude oil biodegradation on microbial methanogenesis. *Organic Geochemistry* 98, 105 – 117 (doi:10.1016/J.ORGGEOCHEM.2016.05.008).

80 Shelton J. L. *et al.* 2018 Microbial community composition of a hydrocarbon reservoir 40 years after a CO_2 enhanced oil recovery flood. *FEMS Microbiol Ecol* 94, 10. (doi:10.1093/FEMSEC/FIY153)

81 Tyne R, *et a*l. C. 2021 Rapid microbial methanogenesis during CO_2 storage in hydrocarbon reservoirs. *Nature*, 600 (7890),
670 – 674 (doi:10.1038/s41586-021-04153-3)

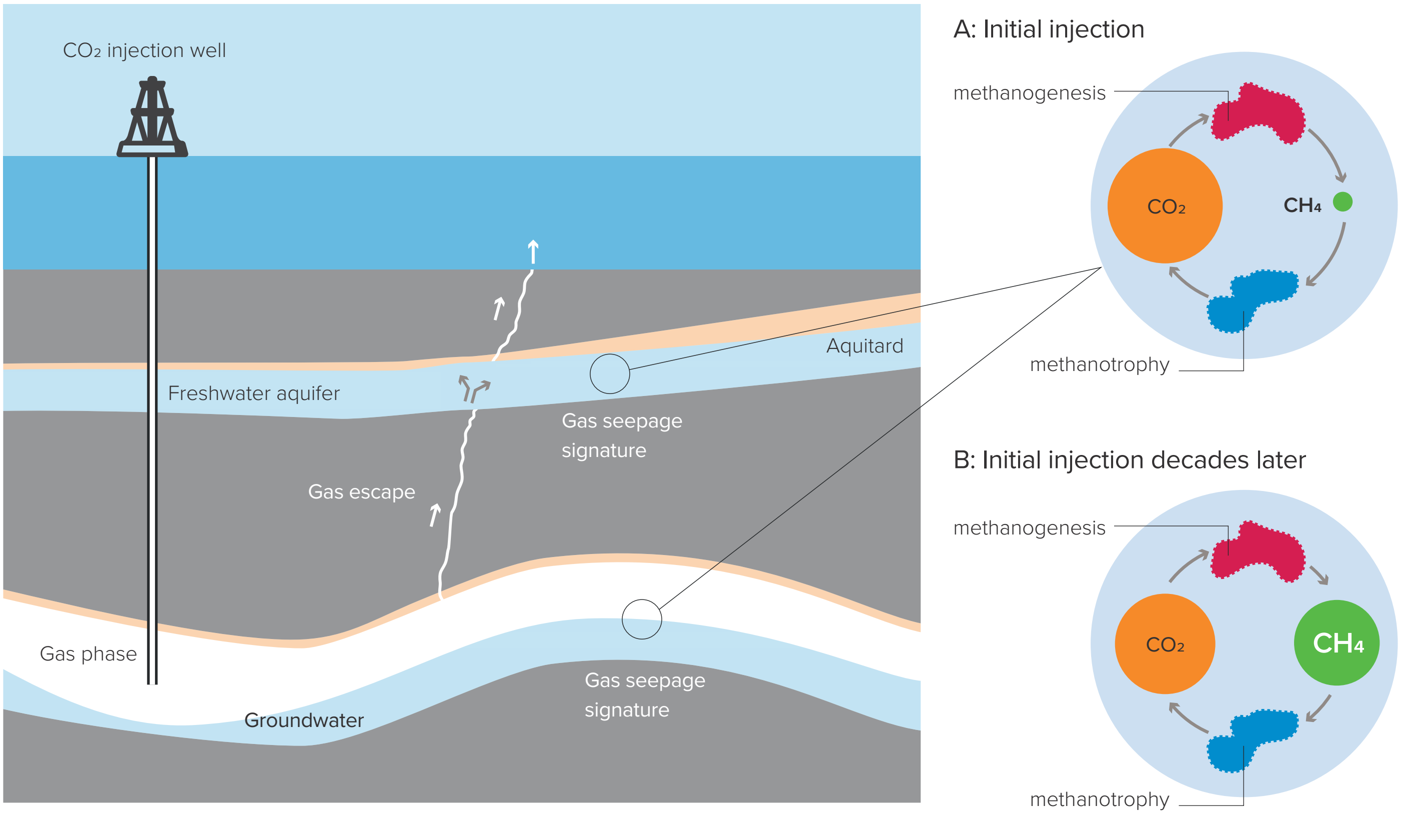
82 Leung, D. Y. C, Caramanna G, Maroto-Valer M.M. 2014 An overview of current status of carbon dioxide capture and storage technologies. *Renewable and Sustainable Energy Reviews.* 39, 426 – 443. (doi:10.1016/J.RSER.2014.07.093)

83 Angelidaki I, Karakashev D, Batstone D, Plugge C, Stams A. 2011 Biomethanation and its potential. *Methods in Enzymology* 494, 327 – 351. (doi:10.1016/B978-0-12-385112-3.00016-0)

84 Darah T.H, Vengosh A, Jackson R.B, Poreda R.J. 2014 Noble gases identify the mechanisms of fugitive gas contamination in drinking-water wells overlying the Marcellus and Barnett Shales. *PNAS* 111, 14076 – 14081. (doi:10.1073/PNAS.1322107111)

FIGURE 12

Initial dominance of CO_2 in the storage system (A) and how methanogenesis can change the geochemical character (B)[85].



4.5. Environmental assurance

Leakage is generally legally defined as CO_2 migrating across the boundary of a storage complex; this storage complex is defined as a region which envelopes the actual target rock formation into which the CO_2 is injected but may extend some distance from the target rock formation. Leakage from the storage complex may result in the CO_2 reaching the human environment, which for sub-sea storage is defined as into the water column and on land as either across the ground surface or into potable water.

Monitoring is primarily focused on delivering assurance of geological storage robustness via geophysical imaging of the deep sub-surface. However, monitoring at the sea floor or land surface can be much more sensitive (detecting fluxes measured in kg/day), and provide further assurance of both storage robustness and environmental well-being.

85 Tyne R, *et al*. 2021 Rapid microbial methanogenesis during CO_2 storage in hydrocarbon reservoirs. *Nature*, 600 (7890), 670 – 674 (doi:10.1038/s41586-021-04153-3)

Surface or near-surface monitoring is also necessary to assure against engineering leaks from pipelines and injection wells and may also be required to address disputes about leakage from one storage complex to a neighbouring storage complex, for example from third parties. Should a leak be confirmed, surface monitoring is also vital to quantify leakage with respect to carbon accreditation[86, 87].

There are many potential challenges. For the marine system these include accessing the remote sea floor, distinguishing natural phenomena from suspected leakage, monitoring over large areas and long-time frames and potentially, detangling suspected anomalies from highly variable biologically and physically imposed natural dynamics or distinguishing impacts caused by other environmental stressors. On land the problems are similar, and although access is generally easier, CO_2 in the atmosphere is inert, unlike in seawater where CO_2 ionises and dissolves in water. Over the last decade significant progress has been made and many technology-ready, or near-ready solutions exist.

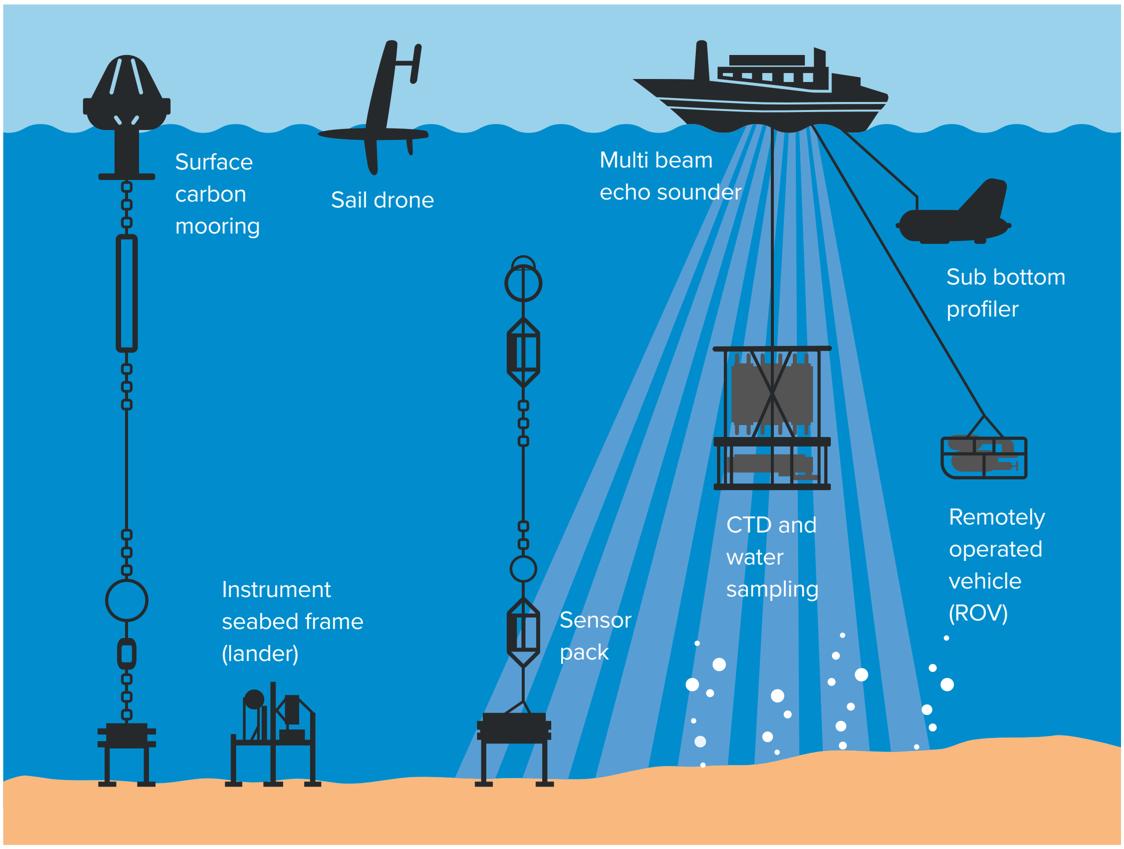
In marine settings, leaks may initially form bubble plumes and can thus be detected by acoustic methods[88]. Research has determined that sensitive, low error detection can be obtained by 'smart' anomaly criteria, for example, monitoring for deviations from natural ratios of CO_2 to O_2 or spotting unusually fast CO_2 changes[89, 90].

In seawater, CO_2 is highly reactive, causing chemical changes (for example to pH) which are measurable by routinely deployable sensors. Acoustic and chemical sensors are at high levels of technology readiness and can be deployed from terrestrial rigs, boats or on autonomous underwater vehicles or sea floor platforms (see figure 13)[91, 92]. A summary of optimal sensor and other methodologies relating to each part of the monitoring process has recently been completed[93].

86 Blackford J *et al*. 2015 Marine baseline and monitoring strategies for carbon dioxide capture and storage (CCS). *International Journal of Greenhouse Gas Control.* 38, 221 – 229. (doi:10.1016/J.IJGGC.2014.10.004)
87 Dixon T, Romanak K.D. 2015 Improving monitoring protocols for CO_2 geological storage with technical advances in CO_2 attribution monitoring *International Journal of Greenhouse Gas Control.* 41, 29 – 40. (doi:10.1016/J.IJGGC.2015.05.029)
88 Li J, White P.R, Bull J.M, Leighton T.G, Roche B, Davis J.W. 2021 Passive acoustic localisation of undersea gas seeps using beamforming. *International Journal of Greenhouse Gas Control.* 108, 103316. (doi:10.1016/J.IJGGC.2021.103316)
89 Omar A.M *et al.* 2021 Detection and quantification of CO_2 seepage in seawater using the stoichiometric Cseep method: Results from a recent subsea CO_2 release experiment in the North Sea. *International Journal of Greenhouse Gas Control.* 108, 103310. (doi:10.1016/J.IJGGC.2021.103310)
90 Blackford J, Artioli Y, Clark J, de Mora L. 2017 Monitoring of offshore geological carbon storage integrity: Implications of natural variability in the marine system and the assessment of anomaly detection criteria. *International Journal of Greenhouse Gas Control.* 64, 99 – 112. (doi:10.1016/J.IJGGC.2017.06.020)
91 Waage M, Singhroha S, Bünz S, Planke S, Waghorn K.A, Bellwald B. 2021 Feasibility of using the P-Cable high-resolution 3D seismic system in detecting and monitoring CO_2 leakage. *International Journal of Greenhouse Gas Control.* 106, 103240. (doi:10.1016/J.IJGGC.2020.103240)
92 Monk S.A *et al.* 2021 Detecting and mapping a CO_2 plume with novel autonomous pH sensors on an underwater vehicle. *International Journal of Greenhouse Gas Control*. 112, 103477 (doi:10.1016/J.IJGGC.2021.103477)
93 Lichtschlag A *et al.* 2021 Suitability analysis and revised strategies for marine environmental carbon capture and storage (CCS) monitoring. *International Journal of Greenhouse Gas Control*. 112, 103510 (doi:10.1016/J.IJGGC.2021.103510)

FIGURE 13

Subsea carbon dioxide leak detection[94].



On land, CO_2 plumes can be detected and measured by acoustic methods, such as eddy covariance, and detection and verification methods can be based on chemical changes in water-bearing soils.

The choice of smart anomaly criteria is important in ruling out natural phenomena and has been used to investigate leakage claims in a terrestrial setting[95].

94 Adapted from: CSIRO. Validating monitoring technologies for carbon storage. See https://www.csiro.au/en/research/natural-environment/oceans/validating-monitoring-technologies-for-carbon-storage (accessed 24 May 2022).

95 Romanak K.D *et al*. 2015 Process-based soil gas leakage assessment at the Kerr Farm: Comparison of results to leakage proxies at ZERT and Mt. Etna. *International Journal of Greenhouse Gas Control*. 34, 146 – 146. (doi:10.1016/J.IJGGC.2014.08.008)

A significant challenge is how to deploy sensors to maximise the chance of detection. Several algorithms have been developed to optimise sensor deployment using computer generated hypothetical leaks in realistic modelled environments and work is underway to develop a digital toolbox to aid operators and regulators to derive optimal monitoring strategies[96, 97, 98].

Attribution of a suspected leak to a specific storage reservoir or to an individual user of a reservoir is a major challenge. The use of inert tracers added to sequestered CO_2 has been proposed: this would provide a distinctive signature which could be associated with a given storage reservoir but would add cost to the capture-storage process (see section 4.3)[99, 100]. Sub-surface migration could be traced geophysically, and theoretically from reservoir to surface. However, small volume/flow leakage would be hard to visualise.

4.5.1. Action

If leakage is confirmed, the challenge is to quantify the level of leakage of relevance to carbon credits and impact assessment. Several methods can be used to estimate leakage including the direct capture of bubble streams, eddy-covariance and reverse engineering observed concentration distributions[101, 102, 103, 104]. It is important to account for emissions that tend to vary over time, and particularly in the marine system with tidal state due to changes in bottom pressure[105].

A baseline survey to understand the natural chemical, biological and ecological state of a site, to assist both detection and impact assessment, is necessary. However, the challenge is to comprehensively cover spatial, seasonal, and inter-annual variability. Baseline surveys are inherently timebound and over the multi-decadal operational span of a storage complex will rapidly become outdated. It has been proposed that a sufficient baseline understanding can be derived by using a combination of existent system models, Earth observation and survey effort, supplemented by small amounts of novel observations[106].

96 Alendal G. 2017 Cost efficient environmental survey paths for detecting continuous tracer discharges. *Journal of Geophysical Research: Oceans*. 122, 5458-5467. (doi:10.1002/2016JC012655)

97 Cazenave P.W *et al.* 2021 Optimising environmental monitoring for carbon dioxide sequestered offshore. *International Journal of Greenhouse Gas Control*. 110, 103397. (doi:10.1016/J.IJGGC.2021.103397)

98 Greenwood J, Craig P, Hardman-Mountford N. 2015 Coastal monitoring strategy for geochemical detection of fugitive CO_2 seeps from the seabed. *International Journal of Greenhouse Gas Control.* 39, 74 – 78. (doi:10.1016/J.IJGGC.2015.05.010)

99 Flohr A *et al.* 2021 Utility of natural and artificial geochemical tracers for leakage monitoring and quantification during an offshore controlled CO_2 release experiment. *International Journal of Greenhouse Gas Control*. 111, 103421 (doi:10.1016/J.IJGGC.2021.103421)

100 Roberts J.J, Gilfillan S.M.V, Stalker L, Naylor M. 2017 Geochemical tracers for monitoring offshore CO_2 stores. *International Journal of Greenhouse Gas Control.* 65, 218 – 234. (doi:10.1016/J.IJGGC.2017.07.021)

101 Taylor P *et al.* 2015 A novel sub-seabed CO_2 release experiment informing monitoring and impact assessment for geological carbon storage. *International Journal of Greenhouse Gas Control*. 38, 3 – 17. (doi:10.1016/J.IJGGC.2014.09.007)

102 Li J *et al.* 2021 Acoustic and optical determination of bubble size distributions – Quantification of seabed gas emissions. *International Journal of Greenhouse Gas Control*. 108, 103313.(doi:10.1016/J.IJGGC.2021.103313)

103 Koopmans D *et al.* 2021 Detection and quantification of a release of carbon dioxide gas at the seafloor using pH eddy covariance and measurements of plume advection. *International Journal of Greenhouse Gas Control*. 112, 103476. (doi:10.1016/J.IJGGC.2021.103476)

104 Mori C *et al.* 2015 Numerical study of the fate of CO_2 purposefully injected into the sediment and seeping from seafloor in Ardmucknish Bay. *International Journal of Greenhouse Gas Control.* 38, 153 – 161.

105 Blackford J *et al.* 2014 Detection and impacts of leakage from sub-seafloor deep geological carbon dioxide storage. *Nat Clim Change*. 4, 1011 – 1016. (doi:10.1038/nclimate2381)

106 Blackford J *et al.* 2021 Efficient marine environmental characterisation to support monitoring of geological CO_2 storage. *International Journal of Greenhouse Gas Control*. 109, 103388. (doi:10.1016/J.IJGGC.2021.103388)

4.5.2. Impact of leaks and mitigation

For the marine system, the impact footprint of a range of hypothetical leakages has been assessed using computation techniques, informed by a small number of experiments in which CO_2 was released at depth, below the sea surface[107]. From this analysis, leaks below the order of 1 t/day would have a minimal impact in terms of affected area. Larger leaks (for example, in excess of 10 t/day) would have the capacity to impact large areas if left unabated, but would be more detectable. Research has been mostly driven by concerns about ocean acidification and there have been release experiments designed to mimic CO_2 leakage[108, 109]. Many marine species are highly sensitive to increased CO_2, but the precise response is less known as it is dependent on many other factors such as general health and life stage of the organisms. Any ecosystem impact assessment required for a CO_2 storage operation should consider comparing a hypothetically impacted area with a nearby unimpacted area with similar environmental characteristics[110].

There are various techniques available to mitigate leakage, including isolating pipelines if breached, repairing wells by replacing a leaking completion string or adding additional cement into leaking annuli between casing and cement, or casing and wall rock[111, 112]. Wells can be plugged with cement and abandoned in case repair options are ineffective. Injecting sealants (for example, foams, gels, and polymers) is standard practice in oil and gas production to stabilise formations. More recently, biomineralisation sealing technologies have been proposed which lead to the precipitation of carbonate[113]. Furthermore, several methods allow for depressurisation of the reservoir, including (i) pressure release via new or existing wells, (ii) injection of solid reactants, nanoparticles or water to immobilise CO_2 either by dissolution of gaseous CO_2 or precipitation of carbonates and (iii) in more complex situations, reservoir pressure can be released by transferring fluids into neighbouring reservoirs.

Larger leaks (for example, in excess of 10 t/day) would have the capacity to impact large areas if left unabated.

107 Blackford J *et al*. 2020 Impact and detectability of hypothetical CCS offshore seep scenarios as an aid to storage assurance and risk assessment. *International Journal of Greenhouse Gas Control.* 95, 102949. (doi: 10.1016/J.IJGGC.2019.102949).

108 Kroeker K *et al*. 2013 Impacts of ocean acidification on marine organisms: quantifying sensitivities and interaction with warming. *Global Change Biology*.19, 1884 – 1896. (doi:10.1111/gcb.12179).

109 Blackford J *et al*. 2014 Detection and impacts of leakage from sub-seafloor deep geological carbon dioxide storage. *Nature Climate Change*. 4, 1011 – 1016. (doi: 10.1038/nclimate2381).

110 Blackford J *et al*. 2021 Efficient marine environmental characterisation to support monitoring of geological CO_2 storage. *International Journal of Greenhouse Gas Control*. 109, 103388. (doi: 10.1016/J.IJGGC.2021.103388).

111 EU MiReCOL project. Fighting global warming safely. See https://www.mirecol-CO_2.eu/. (accessed 25 May 2022).

112 Brunner I , Neele F. 2017 MiReCOL – A Handbook and Web Tool of Remediation and Corrective Actions for CO 2 Storage Sites. *Energy Procedia.* 114, 4203 – 4213. (doi: 10.1016/J.EGYPRO.2017.03.1561)

113 Phillips A *et al*. 2018 Enhancing wellbore cement integrity with microbially induced calcite precipitation (MICP): A field scale demonstration. *Journal of Petroleum Science and Engineering*. 171, 1141 – 1148. (doi: 10.1016/J.PETROL.2018.08.012)

New approaches: carbon storage through reaction with rocks

There have been some new approaches to geological CO_2 storage in very different rock formations, including basaltic systems, in which CO_2 reacts directly with the rock surface to form minerals.

Geological 'carbon mineralisation' is a reaction between CO_2-bearing fluids and calcium- or magnesium-rich rocks, such as basaltic lavas, to form solid carbonate minerals such as calcite ($CaCO_3$) and magnesite ($MgCO_3$). The carbonation reactions are spontaneous in most natural, near surface situations[114].

In natural conditions, this process is too slow to affect atmospheric CO_2 contents on a human time scale. Since 1990, a variety of methods have been proposed to accelerate the natural process to achieve rates fast enough to store megatons to gigatons of CO_2 per year in inert, stable carbonate minerals[115], for example:

- ex-situ carbon mineralisation: high temperature and pressure reactors where rock powder is reacted with purified CO_2.
- surficial carbon mineralisation: accelerated reaction of crushed rock-mine tailings and compositionally-similar industrial alkaline wastes in waste heaps, either with gas or water or with air.
- subsurface carbon mineralisation: injection of CO_2-rich fluids into reactive rocks or injection of surface waters into reactive rocks with return of carbon-depleted water to the surface to draw down CO_2 from air.
- oxide looping via ambient weathering: calcining of crushed rock (for example, $MgCO_3$ or $CaCO_3$) to produce Magnesium Oxide or Calcium Oxide + CO_2, with offsite storage or use of CO_2, followed by ambient weathering of Magnesium Oxide or Calcium Oxide to reproduce carbonate minerals ($MgCO_3$, $CaCO_3$), in a looping process.

Most of the methods described above have not been extensively tested at the field scale [114, 116, 117]. However, there have been two field-scale pilot experiments on carbon storage via CO_2 mineralisation in Ca- and Mg- rich, basaltic lavas:

114 Kelemen PB *et al*. 2020 Engineered carbon mineralization in ultramafic rocks for CO_2 removal from air. *Chemical Geology*. 550, 119628. (doi: 10.1016/J.CHEMGEO.2020.119628).
115 Seifritz W. 1990 CO_2 disposal by means of silicates. *Nature*. 345, 486. (doi: 10.1038/345486b0).
116 Kelemen PB *et al* 2019. An overview of the status and challenges of CO_2 storage in minerals and geological formations. *Frontiers in Climate*. 1, 9. (doi: 10.3389/FCLIM.2019.00009/BIBTEX).
117 National Academies of Sciences Engineering and Medicine *et al*. 2018 Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. *Washington (DC): National Academies Press (US). 495. See* https://doi.org/10.17226/25259. Washington DC: The National Academies Press.

5.1. The Wallula experiment

This experiment involved injection of supercritical CO_2 into a permeable layer beneath an impermeable caprock in the thick 'flood basalt' sequence known as the Columbia River basalts in the US Pacific Northwest. This site contains permeable layers, typically 'flow tops', beneath the base of massive, essentially impermeable overlying lava flows. In 2013, about 1 $MtCO_2$ were injected into these permeable zones, of which some remains as fluid in pore space[118, 119]. Newly formed carbonate minerals were sampled from the walls of the injection borehole, and a variety of seismic and hydrological observations have been modelled to show that approximately 60% of the CO_2 had reacted with the basalt to form solid carbonate minerals[120, 121].

5.2. The CarbFix experiment

CarbFix is an independent commercial company based in Iceland, and its ongoing experiments involve injection of CO_2-rich aqueous fluids into permeable basalt formations in southern Iceland[122]. The experiments have employed the novel technique of 'solution trapping', where CO_2 is dissolved in aqueous fluid by co-injecting water and CO_2: the CO_2 dissolves into the water on reaching a sufficient pressure in the injection well.

As a result, there is no free-phase of CO_2 and hence no need for an overlying caprock to prevent escape of low-density CO_2 fluid or gas.

Phase I of CarbFix injected about 175 tCO_2 into highly permeable basalts at 400 – 800m depth, via a 2 km borehole cased to 400m depth[123]. Prior to injection, pores in the basalt were filled with a slightly alkaline aqueous fluid. At the injection site, the water table was around 30m below the surface, and water spontaneously flowed down the cased borehole to the target depth. A total of around 5 kt of water was injected. A pipe carried the compressed CO_2 to a depth of 330 – 360m. A carefully calibrated 'sparger' was used to create tiny bubbles in the descending water. The CO_2 flow rate was regulated to ensure that the bubbles would completely dissolve in water before it reached the target depth, achieving 'solution trapping'[124]. If fluid pathways were to lead upward, CO_2 could separate from pore water, forming low density gas that might then escape to the surface. However due to the increase in the fluid density, up flow of the CO_2-bearing fluid is viewed as unlikely[123].

118 McGrail BP *et al*. 2017 Wallula Basalt Pilot Demonstration Project: Post-injection results and conclusions. *Energy Procedia*. 114, 5783-90. (doi: 10.1016/J.EGYPRO.2017.03.1716).

119 McGrail BP *et al* 2014. Injection and monitoring at the Wallula Basalt Pilot Project. *Energy Procedia.* 63, 2939-48. (doi: 10.1016/J.EGYPRO.2014.11.316).

120 Xiong W *et al*. 2018 CO_2 Mineral Sequestration in Naturally Porous Basalt. *Environmental Science Technology*. 5, 142-7. (doi: 10.1021/ACS.ESTLETT.8B00047/SUPPL_FILE/EZ8B00047_SI_003.AVI).

121 White SK *et al*. 2020 Quantification of CO_2 Mineralization at the Wallula Basalt Pilot Project. *Environmental Science Technology*. 54, 14,609-14,16. (doi: 10.1021/ACS.EST.0C05142/SUPPL_FILE/ES0C05142_SI_001.PDF).

122 Carbfix. We turn CO_2 into stone. See https://www.carbfix.com/. (Accessed 15 May 2022) .

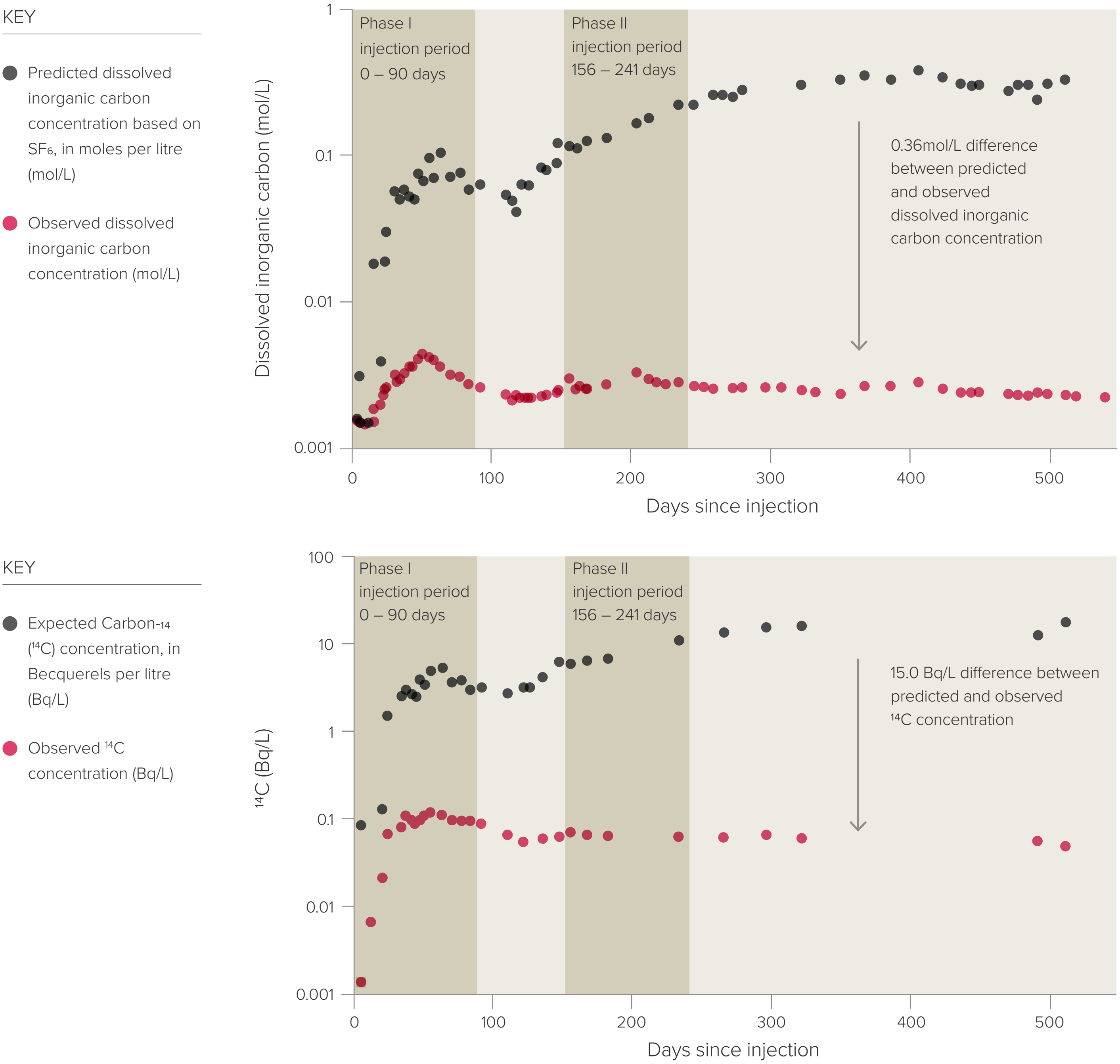
123 Sigfusson B *et al*. 2015 Solving the carbon dioxide buoyancy challenge: The design and field testing of a dissolved CO_2 injection system. *International Journal of Greenhouse Gas Control.* 37, 213-9. (doi: 10.1016/J.IJGGC.2015.02.022).

124 Snæbjörnsdóttir SÓ *et al*. 2018 Reaction path modelling of in-situ mineralisation of CO_2 at the CarbFix site at Hellisheidi, SW-Iceland. *Geochimica et Cosmochimica Acta.* 220, 348 – 366. (doi: 10.1016/J.GCA.2017.09.053).

FIGURE 14

Tracer results from CarbFix Phase I, indicating loss of 95% of injected carbon along a 500m flow path from the injection well to a production well[125].

Note the log scale on the vertical axes. The loss is determined by reference to the SF_6 tracer concentration when injected and later at the observation well. The larger fraction of SF_6 tracer recovered points to the loss of CO_2 through mineralisation.



A production well around 500m 'downstream' from the injection site was used to monitor fluid composition over time and tracers were used to determine the timing and mixing proportion of the injected fluid (see figure 14)[125]. The tracers suggest that 95% of the injected carbon was lost along the flow path, presumably via carbon mineralisation. However, any CO_2 loss via fluid decompression and degassing would not be detected using these tracer methods.

In more recent efforts, Phase 2 of CarbFix is exploring the process in deeper and more laterally extensive systems[126]. Here, tracer experiments indicate that about 50% of the injected CO_2 was lost along the 1.5 km flow path. Rocks in this aquifer have already undergone more extensive, natural hydrothermal alteration compared to the Phase I aquifer. The injection fluid in this phase has relatively low dissolved CO_2 concentrations and much more water was injected, per ton of CO_2, which could be a limiting factor in other regions.

In both phases, there was no appreciable reduction in permeability, despite precipitation of carbonate minerals and other alteration minerals in the pore space due to reaction with the injected fluid. This may be explained by the high initial porosity of the target aquifers, and the relatively dilute nature of injected fluid components[127].

Up to 2017, CarbFix had injected more than 20 ktCO_2. As the project is able to use existing wells and other infrastructure at the Hellisheidi power plant, cost estimates of mixed gas capture (CO_2 + Hydrogen sulfide) and storage at that site are US$25 – 27/t$CO_2$ (£19 – £20/tCO_2), and the cost if using a newly developed site is US$48/t$CO_2$ (£36/tCO_2), assuming a 30-year lifetime (based on an electricity cost of US$0.12/kWh (£0.09/kWh))[128].

125 Matter J, Stute M, Schlosser P, Broecker W. 2015 Radiocarbon as a Reactive Tracer for Tracking Permanent CO_2 Storage in Basaltic Rocks. *US Department of Energy Office of Scientific and Technical Information.* (doi:10.2172/1238341)

126 Ratouis TM *et al*. 2022 Carbfix 2: A transport model of long-term CO_2 and H2S injection into basaltic rocks at Hellisheidi, SW-Iceland. *International Journal of Greenhouse Gas Control. 114*, 103586. (doi: 10.1016/J.IJGGC.2022.103586).

127 Aradottir ESP *et al*. 2011 CarbFix: A CCS pilot project imitating and accelerating natural CO_2 sequestration. *Greenhouse Gases - Science and Technology*. 1, 105 – 18. (doi: 10.1002/GHG.18).

128 Gunnarsson I *et al*. 2018 The rapid and cost-effective capture and subsurface mineral storage of carbon and sulfur at the CarbFix site. *International Journal of Greenhouse Gas Control.* 79,117 – 126. (doi: 10.1016/J.IJGGC.2018.08.014).

The theoretical storage capacity is potentially 100s of trillions of tons of CO_2, particularly in 'flood basalt' terranes[115, 129]. Use of solution trapping could utilise huge volumes of rock that lack an overlying, impermeable caprock, but requires large volumes of water to operate at the scale of millions to billions of tons of CO_2 per year.

Other pilot projects are also being conducted, for example in Oman, to store CO_2 via carbon mineralisation in magnesium rich peridotite rather than basalt[130, 131]. Carbon mineralisation reactions in peridotite are likely to be faster than in basalt, and the storage capacity of CO_2 is about three times larger in fully carbonated peridotite compared to basalt[132, 133, 134, 135].

129 Snæbjörnsdóttir SÓ *et al*. 2020 Carbon dioxide storage through mineral carbonation. *Nature Reviews Earth & Env*. 1, 90 – 102. (doi: 10.1038/s43017-019-0011-8).

130 44.01. Turning CO_2 into Rock! See https://4401.earth/ (accessed 16 June 2022).

131 Mervine EM *et al*. 2014 Carbonation rates of peridotite in the Samail Ophiolite, Sultanate of Oman constrained through ^{14}C dating and stable isotopes. *Geochimica et Cosmochimica Acta.* 126, 371 – 397. (doi: 10.1016/J.GCA.2013.11.007).

132 Kelemen PB, Matter J. 2008 In situ mineral carbonation in peridotite for CO_2 storage. *Proc. National Acad. Sci. (US).* 105, 17295 – 17300. (doi: 10.1073/PNAS.0805794105/SUPPL_FILE/0805794105SI.PDF).

133 Kelemen PB *et al*. 2011 Rates and mechanisms of mineral carbonation in peridotite: Natural processes and recipes for enhanced, in situ CO_2 capture and storage. *Annual Review of Earth and Planetary Sciences*. 39, 545-76. (doi: 10.1146/annurev-earth-092010-152509)

134 Kelemen, P, Hirth G. 2012 Reaction-driven cracking during retrograde metamorphism: Olivine hydration and carbonation. *Earth and Planetary Science Letters*. 345 – 348, 81 – 89. (doi: 10.1016/J.EPSL.2012.06.018).

135 Kelemen, PB *et al*. 2022 Listvenite formation during mass transfer into the leading edge of the mantle wedge: Initial results from Oman Drilling Project Hole BT1B. *J. Geophys. Res*. 127. (doi:10.1029/2021JB022352)

Scaling up

The UK Climate Change Committee describes CCS as being on the 'critical path' to net zero[136]. On a global scale, it has been estimated that there is likely to be a need for 7 – 8 $GtCO_2$/yr of storage by 2050[137], and a cumulative storage of 350 – 1200 $GtCO_2$ by 2100, to keep temperatures below the 1.5°C rise threshold[138, 139]. This is a significant challenge and corresponds, for example, to around 7000 – 8000 Sleipner-type wells, each injecting 1 Mt/yr and in operation by 2050.

The technical building blocks are available to scale up this industry, but this will need to be underpinned by fundamental research and development to optimise and improve transport, storage efficiency, monitoring and assurance technologies and to identify high quality, secure storage resource.

At present, about 1 $MtCO_2$/yr can be injected through a typical well into a subsurface storage system. Based on this injection rate, as an example, a future global CO_2 storage industry would need 7,000 – 8,000 wells feeding large subsurface storage systems to reach the proposed targets. To build up this global industry by 2050, an average of 300 – 400 wells per year would require successful commissioning. Drilling rigs can drill into the subsurface at a typical rate of 10 – 100m/day, so depending on the rock type and depth, it may take around 1 – 2 months to drill a 1.0 – 2.5 km well. Development of 300 – 400 wells each year would thus require about 90 – 120 dedicated drilling rigs in continuous operation.

An ongoing challenge of such an industry is that each reservoir would be of finite capacity, and therefore a continuing source of new reservoirs or improvements in the storage technology would be required.

From a UK perspective, based on the (UK) Committee for Climate Change plan for decarbonisation, the Oil and Gas Authority (OGA) suggest the UK needs to be storing about 10 MtCO2/yr by 2030 and between 75 – 175 $MtCO_2$/yr by 2050[140] (see figure 15). With storage sites capable of accommodating 3 – 4 injection wells, this will require development of about one new storage site every year until 2050. Given that each such site will need 5 – 7 years to develop, and will need to establish partnerships with major emitters of CO_2, there will need to be a substantial upscaling of the industry.

The technology for the design and development of CO_2 storage systems can draw from the oil and gas industry, although there are some CO_2-specific scientific and engineering challenges. The timescale could be reduced in a well characterised depleted oil or gas field, but there may still be a need for new transport and well infrastructure.

136 Committee on Climate Change (CCC). 2019 Net Zero- the UK's contribution to stopping global warming. See https://www.theccc.org.uk/wp-content/uploads/2019/05/Net-Zero-The-UKs-contribution-to-stopping-global-warming.pdf (accessed 16 June 2022).

137 IEA. 2021 Net Zero by 2050: a roadmap for the global energy sector. See: https://www.iea.org/reports/net-zero-by-2050 (accessed 16 September 2022)

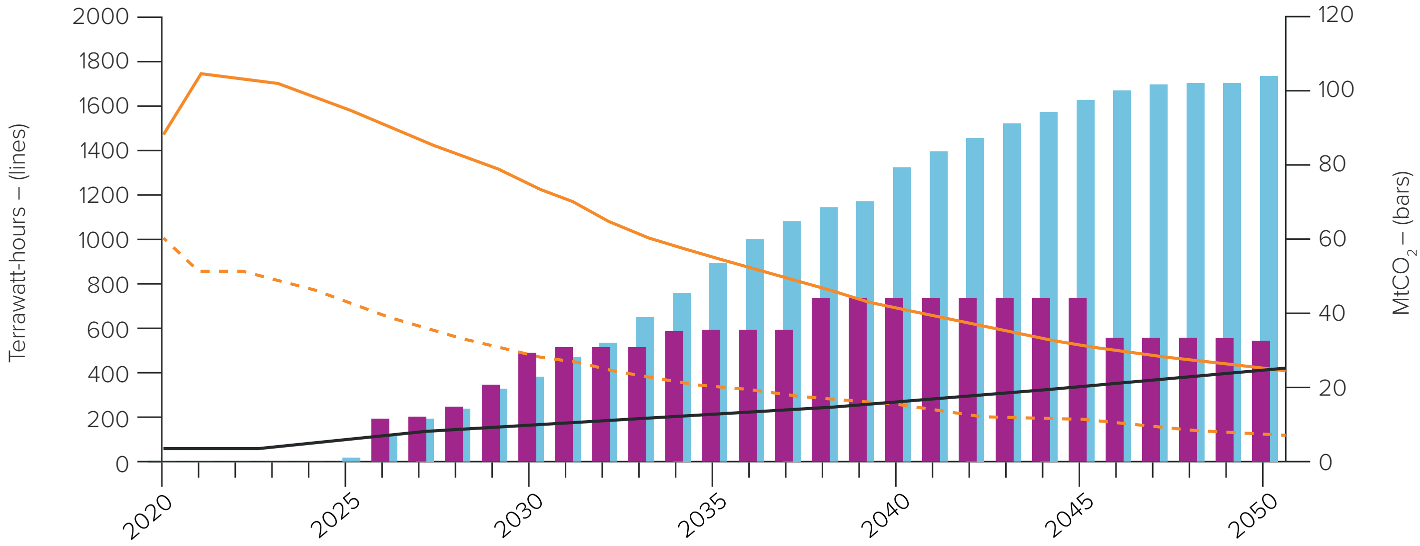
138 IPCC Special Report: Global Warming of 1.5°C. 2018 See https://www.ipcc.ch/sr15/. (accessed 16 June 2022)

139 IEA. Transforming Industry through CCUS. *Clean Technology Scenarios.* see https://www.iea.org/reports/transforming-industry-through-ccus (accessed 15 June 2022).

140 Oil and Gas Authority. 2020 UKCS Energy Integration: final report. See: https://www.nstauthority.co.uk/news-publications/publications/2020/ukcs-energy-integration-final-report/ (accessed 15 September 2022)

FIGURE 15

The UK projected storage rate from current unrisked licences and the CO_2 storage required to meet the UK net zero by 2050 target[141].



KEY

- Projected CO_2 injection rate from licenses/applications (un-risked, Q1 2022)
- CCS CO_2 injection rate required to meet Balanced Net Zero Pathway scenario
- Oil and gas demand
- Oil and net gas production
- Offshore wind electricity generation

The costs for a storage system, including the wells and infrastructure are highly variable depending on whether the system is onshore or offshore, the subsurface geology, and the CO_2 transport system. For example, the reinjection system for the Norwegian Sleipner field had costs of about £12.9 million for the well, £61 million for the compressor train, and about £5.3 million per annum to run the reinjection. The OGA suggest that to become competitive as an emission abatement technology, transport and storage costs could reach £12 – 30 per tonne CO_2[142].

A further challenge for scale up of CO_2 storage will be the co-location and adjacent co-existence of offshore users such as offshore windfarms and fishing. This will require a prioritisation strategy, active stakeholder collaboration and cross-disciplinary co-location design.

141 North Sea Transition Authority, 2022 Projected CO_2 injection rate from existing CCS licenses/applications (unrisked, in Q1 2022) vs CO_2 injection rate required to meet the Carbon Budget 6 Balanced Net Zero Pathway Target, compared with oil, gas and wind projections to 2050 [Presentation]

142 Oil and Gas Authority. 2020 UKCS Energy Integration: final report. See: https://www.nstauthority.co.uk/news-publications/publications/2020/ukcs-energy-integration-final-report/ (accessed 15 September 2022)

BOX 2

Operating challenges

Much of this report has focussed on the underpinning scientific challenges of CO_2 injection and migration through a geological storage system including techniques for monitoring the CO_2. However, as the number of CO_2 storage systems grow, there will likely be a series of new technical challenges which arise, especially given the uncertainties and variability in geological systems.

Some of the technical challenges of scaling up might include:

i. the performance of the injection wells may decline owing to build up of scale or fines, reducing the injectivity,

ii. the pipeline infrastructure may be impacted by corrosion,

iii. the pressure relief wells may be subject to scale build up or sanding, as in the Gorgon reservoir,

iv. pressurisation of the permeable system may lead to partial failure of some seal layers, or growth of some small-scale fractures which then require management and monitoring during subsequent injection of CO_2,

v. continued assessment of the reactions between minerals in both the seal and reservoir rock with the CO_2-saline water mixtures may be key.

Each of these will require intervention to continue operation, with developments in chemical or physical treatment processes needing innovation, combined with changes in the operating protocols.

There will be challenges associated with the interpretation of data, including seismic reflection data, tracer studies and well log data, and trying to assess changes in the performance of the system and patterns of migration of fluids or tracer through the system. Further scientific modelling and measurement will likely be significantly beneficial in resolving and understanding such issues.

As discussions develop around the long-term integrity of the storage systems, and the transfer of liability from operator to national government, specific technical challenges may arise which require new data, monitoring or modelling to establish details of the likely long-term distribution and possible evolution of the CO_2 within the reservoir.

Continuous feedback between industry and research will be important for the development of the industry so that it continues to be underpinned by the best scientific understanding of the fundamental issues.

Policy

The CO_2 storage projects carried out to date have largely focused on natural gas extraction and treatment facilities, and have been one-off projects rather than reflecting a wider systemic approach.

Previous longer-term roadmaps have laid out ambitious plans for rolling out CCS. For example, in 2008, the European Council called for 'up to 12' large-scale projects to be operating in the EU by 2015 and in 2013 the International Energy Agency (IEA) highlighted the need for 30 large projects globally by 2020[143, 144]. In 2007 and 2012, the UK initiated £1billion competitions for commercial-scale CCS projects, which both reached advanced stages before being cancelled[145]. Globally, the number of commercial-scale (>1MtCO_2) projects have lagged stated ambitions and deployment roadmaps[146]. The large upfront capital costs, lack of sufficient and predictable incentives to support operating costs, and concerns over social license to operate in many jurisdictions have contributed to the deployment delay. Scaling up will require demonstration projects, robust policy frameworks, and the evolution of a business model which will put in place the necessary infrastructure, reduce subsurface uncertainties and address legal and regulatory issues, all of which enable cost reductions[147].

Nevertheless, the importance of CCS in meeting ambitious climate goals is widely agreed and could, for example, provide a cost-effective pathway to scale up low-carbon hydrogen production rapidly, and allow for CO_2 removal from the atmosphere through bioenergy with carbon capture and storage (BECCS) and direct air carbon capture and storage (DACCS)[148].

Apart from gas processing projects, there have been a small handful of large-scale projects based on different applications including coal-fired power (Boundary Dam in Saskatchewan and Petra Nova in Texas), steel (Emirates Steel in Abu Dhabi), ethanol (Decatur, Illinois), hydrogen (Quest in Alberta), and fertilisers (Alberta Carbon Trunk Line Nutrien plant).

Public opinion and communication are also vital to implementation and scale up[149]. A number of past projects have failed because of their inability to take account of local considerations[150, 151].

143 Poulsen N, van Gessel S, 2015 Towards CCS EuroGeo Surveys. See https://www.eurogeosurveys.org/wp-content/uploads/2015/11/Towards-CCS-Horizon-2020-Projects-Portal.pdf. (Accessed 15 June 2022).
144 IEA Technology Roadmap - Carbon Capture and Storage 2013 https://www.iea.org/reports/technology-roadmap-carbon-capture-and-storage-2013. (Accessed 15 June 2022).
145 National Audit Office. Carbon capture and storage: the second competition for government support. See https://www.nao.org.uk/report/carbon-capture-and-storage-the-second-competition-for-government-support/#:~:text=for%20government%20support-,Carbon%20Capture%20and%20Storage%3A%20the%20second%20competition%20for%20government%20support,support%20for%20carbon%20capture%20storage. (Accessed 16 June 2022)
146 Reiner D. 2016 Learning through a portfolio of carbon capture and storage demonstration projects. *Nature Energy.* 1, 15011. (DOI: 10.1038/nenergy.2015.11)
147 Herzog H. 2011 Scaling up carbon dioxide capture and storage: From megatons to gigatons. *Energy Economics*, *33* (4), 597 – 604. (doi:10.1016/j.eneco.2010.11.004).
148 IEA. (Net Zero by 2050: A roadmap for the Global Energy Sector) See https://www.iea.org/reports/net-zero-by-2050. (Accessed 16 June 2022)
149 Ashworth P, Wade S, Reiner D, Liang X. 2015 Developments in public communications on CCS. *International Journal of Greenhouse Gas Control*. *40*, 449 – 458. (doi: 10.1016/J.IJGGC.2015.06.002).
150 Von Rothkirch J, Ejderyan O. 2021 Anticipating the social fit of CCS projects by looking at place factors. *International Journal of Greenhouse Gas Control*. *110***,** 103399. (doi: 10.1016/J.IJGGC.2021.103399).
151 Ostfeld R, Reiner D. 2020 Public views of Scotland's path to decarbonization: Evidence from citizens' juries and focus groups. *Energy Policy***.** *140*, 111332. (doi: 10.1016/J.ENPOL.2020.111332).

UK

The UK Climate Assembly found significant opposition to electricity generation using fossil fuels with CCS, although BECCS and DACCS were viewed somewhat more favourably[152]. Public dialogue events at locations closer to proposed UK industrial clusters where CCS could be deployed showed a more positive perspective[153]. Policy support around the world for CCS has followed similar patterns but reflect the national circumstances in terms of energy and industrial mix as well as the typical policy instruments used in different countries.

The UK has been developing a suite of policies following the 2018 *Delivering Clean Growth: CCUS Cost Challenge Taskforce* report[154]. The current policy focuses on regional decarbonisation and industrial clusters. Around half of UK industrial emissions (37.6 $MtCO_2e$ in 2018) are in clustered sites[155]. These sites provide an opportunity to share decarbonisation solutions, activities and systemic efficiencies, but will require stakeholder engagement and research. Proposed policies include a regulated asset base model to support pipelines and operating expenditure, contracts for difference to pay for electricity, and capital co-funding for construction.

UK Research and Innovation (UKRI) has committed over £200m in funding to support six different industrial clusters across the UK to decarbonise at scale and nine projects (three offshore and six onshore infrastructure projects)[156]. The UK Government has set a target to deliver CCS in four clusters (two by the mid-2020s and two by 2030) which will capture and store around 20 – 30 $MtCO_2$/yr[157] . The two Phase 1 clusters are the East Coast Cluster (Teesside plus Humber) and HyNet in the Northwest, with the Scottish Cluster selected as a 'reserve cluster'. A second group of projects is due to compete in 2022, for awards in early 2023 (Phase 2). The UK still holds a carbon price support tax on power station fuel of £18/tCO_2 and in 2021 introduced a UK Emissions Trading Scheme for permits to emit CO_2, which exceeded £70/tCO_2 in Q4 2021.

US

The US first used a tax credit in the 1980s to jumpstart enhanced oil recovery (EOR). In 2018, a federal production tax credit (Section 45Q tax credit) was put in place and will have a value of US$50/metric ton of CO_2 by 2026 for secure geological storage and US$35/$tCO_2$ for EOR[158]. This has led to many new project proposals such as linking biorefineries in the Midwest to CO_2 storage sites in the South or West of the United States[159].

152 Climate Assembly UK. The Path to Net Zero: Climate Assembly UK Full Report. See https://www.climateassembly.uk/report/read/final-report.pdf. (Accessed 16 June 2022).
153 GOV.UK Carbon Capture Usage and Storage: Public Dialogue. See https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-ccus-public-dialogue. (Accessed 16 June 2022).
154 GOV.UK Delivering Clean Growth: CCUS Cost Challenge Taskforce report. See https://www.gov.uk/government/publications/delivering-clean-growth-ccus-cost-challenge-taskforce-report. (Accessed 16 June 2022).
155 GOV.UK Industrial Decarbonisation Strategy. See https://www.gov.uk/government/publications/industrial-decarbonisation-strategy. (Accessed 16 June 2022).
156 UKRI Industrial decarbonisation challenge. See https://www.ukri.org/what-we-offer/our-main-funds/industrial-strategy-challenge-fund/clean-growth/industrial-decarbonisation-challenge/. (Accessed 16 June 2022).
157 HM Government. 2021 Net Zero Strategy: Build Back Greener. See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1033990/net-zero-strategy-beis.pdf (Accessed 16 June 2022).
158 Edwards R, Celia M. 2018 Infrastructure to enable deployment of carbon capture, utilization, and storage in the United States. *Proceedings of the National Academy of Sciences*. 115(38), E8815 – E8824. (doi: 10.1073/PNAS.1806504115/SUPPL_FILE/PNAS.1806504115.SD07.XLSX).
159 Sanchez D, Johnson N, McCoy S, Turner P, Mach K. 2018 Near-term deployment of carbon capture and sequestration from biorefineries in the United States. *Proceedings of the National Academy of Sciences*, 115, 4875 – 4880. (doi: 10.1073/PNAS.1719695115/SUPPL_FILE/PNAS.201719695SI.PDF).

California has implemented a Low Carbon Fuel Standard that creates over US$100/t$CO_2$ payment for CCUS-enabled fuel products[160]. This has been adopted in Washington and Oregon and is being considered in over a dozen other states; this can be layered on top of the 45Q support. The US Department of Energy has also launched a Carbon Negative Shot, which aims to bring the costs of CO_2 removal such as BECCS or DACCS to below US$100/t$CO_2$ (£75/tCO_2) within a decade[161].

Norway

Norway is investing in a large-scale full chain CCUS, known as Longship[162]. This supports both capture from industrial facilities (cement and waste-to-energy) and the collective transport and storage infrastructure of coastal shipping and CO_2 pipeline to storage (known as Northern Lights). Phase one, with a capacity of 1.5 MtCO_2/yr, is expected to start in mid-2024 with an eventual goal of reaching 5 MtCO_2/yr subject to market demand.

The Netherlands

The Netherlands also has industrial cluster plans. In 2021, the Government approved subsidies of €2.1 billion to emitters as part of the Porthos initiative in the Port of Rotterdam to bridge the gap between the EU Emissions Trading System price and the cost of capture. Porthos will use a small, depleted gas field under the North Sea for storage, and intends to inject from late 2024, and is expected to reach 2.5 MtCO_2/yr[163].

Canada

Canada has established various CCUS policies including the federal Strategic Innovation Fund and Clean Fuel Standards, alongside provincial efforts including Alberta's Technology Innovation and Emissions Reduction regulation. This is a tax and rebate system, where individual consumers can be protected from cost increases. Canada's carbon tax schemes plan to be C$50/t$CO_2$ in 2022 and rising by C$15/yr until it reaches C$170/tCO_2 in 2030.

Australia

Australia identified CCS as a priority low emissions technology as part of its Technology Investment Roadmap. In 2020, the remits of the Clean Energy Finance Corporation (AU$10billion fund) were expanded to include CCUS and in 2021 AU$300million over ten years was committed. This is made up of a AU$50million CCUS Development Fund for pilot or pre-commercial projects aimed at reducing emissions and a AU$250million CCUS Hubs and Technologies program[164].

160 Romanak K, Dixon T. 2022 CO_2 storage guidelines and the science of monitoring: Achieving project success under the California Low Carbon Fuel Standard CCS Protocol and other global regulations. *International Journal of Greenhouse Gas Control*. 113, 103523. (doi: 10.1016/J.IJGGC.2021.103523).

161 US Department of Energy. 2021 Carbon Negative Shot. See https://www.energy.gov/fecm/carbon-negative-shot (Accessed 16 June 2022).

162 Northern Lights. About the Longship Project. See https://northernlightsccs.com/about-the-longship-project/. (Accessed 16 June 2022).

163 Akerboom S, *et al*. 2021 Different This Time? The Prospects of CCS in the Netherlands in the 2020s. *Frontiers in Energy Research*. 9, 193. (doi: 10.3389/FENRG.2021.644796/BIBTEX).

164 Department of Industry, Science, Energy and Resources. Reducing emissions through carbon capture, use and storage. See https://www.industry.gov.au/policies-and-initiatives/australias-climate-change-strategies/reducing-emissions-through-carbon-capture-use-and-storage. (Accessed 16 June 2022).

China

China has undertaken around 35 small-scale demonstration CCS projects. There is one large-scale project operating at Jilin oilfield, and (as of late 2021) five under construction or about to begin operations (0.1 – 0.5 $MtCO_2$ scale) and another 10 planned for 2025 – 2030 (0.5 – 3.0 $MtCO_2$)[165]. These projects are on coal power, chemical plants, and natural gas processing. CCS was included for the first time in the twelfth Five Year Plan (2012 – 17), and clean industry goals established in the fourteenth Plan (2021 – 25). China has an Emissions Trading System (modelled on the EU-ETS) active in several provinces, but to introduce CCS will require initial price support similar in amount to that introduced for onshore wind. There has been particular interest in utilising CO_2 for EOR and for Coal Bed Methane to increase known oil production by 20% and methane production by 30%. Starting with 20 $MtCO_2$/yr in 2030, total injection could reach 2.7 $GtCO_2$/yr by 2050.

Germany

In Germany**,** hydrogen policy is exclusively focused on green hydrogen (i.e. produced by electrolysis via renewables as opposed to 'blue hydrogen' produced by steam methane reformation, which would involve CCS) and some states even ban CO_2 storage. Nevertheless, in 2021, the German government announced funding aimed at commercialising CO_2 capture technologies and began to scope out CO_2 transport infrastructure. German CO_2 emitters have expressed interest in purchasing storage services from North Sea providers[166].

165 Oil and Gas Climate Initiative (OGCI). 2021 *CCUS in China: The Values and Opportunities for Deployment*. See https://www.ogci.com/wp-content/uploads/2021/09/China_CCUS_paper_September_2021.pdf. (Accessed 16 June 2022).

166 Clean Energy Wire. 2021 German industry urges new debate on carbon capture, storage and utilisation. See https://www.cleanenergywire.org/news/german-industry-urges-new-debate-carbon-capture-storage-and-utilisation. (Accessed 16 June 2022).

Conclusion

Carbon dioxide storage is widely agreed to play a significant role in the global push for decarbonisation. There are some examples of full-scale successful CO_2 storage, including the Sleipner Field in Norway which has stored over 25 $MtCO_2$ in the past 25 years, and there is a growing global interest as decarbonisation and transitioning from the present energy mix comes into sharper focus.

Many of the technical challenges related to CO_2 storage have been addressed through adoption of historic oil and gas technology, but there are still specific challenges associated with CO_2 storage. Despite substantial scientific and technical literature which has addressed some of these challenges, there remain significant questions, many arising from the details of specific rock formations and their flow properties, the development and refinement of monitoring techniques, and the ongoing need to optimise storage systems. For these, scientific priorities include:

i. improving predictions of plume migration and storage capacity of specific fields in detail, which requires a combination of geological, geophysical, and geochemical data collection and flow modelling to test and calibrate the models, coupled with quantification of the considerable uncertainties about subsurface formations;

ii. assessing storage safety and the critical pressures for failure of the seal rocks, the potential ensuing leakage pathways, and developing assurance of the long-term safety of the system;

iii. testing and combining monitoring strategies for subsurface CO_2 detection, including the use of seismic surveys, tracer tests and potentially other geophysical techniques;

iv. developing approaches to enhance the storage capacity of a given system, through the use of novel additives or modifications to well-arrays and injection strategies.

Further, the establishment of an appropriate policy environment, for example through security of payment for storage and transfer of liability to national government, will be key to ensure the acceleration of CO_2 storage schemes. As the CO_2 storage industry develops, there will continue to be significant new technical challenges associated with different geological systems, including structural integrity, flow assurance, geochemical reactions and mineralogical processes, as well as challenges for monitoring and assurance.

To drive this nascent industry forward to the levels of CO_2 storage required in many of the net zero pathways, an enormous and continued investment each year to 2050 is required to build the injection wells, transport networks, monitoring technologies, and a skilled workforce, to install hundreds of new wells each year. In addition, there is a need to enhance communication about the critical role for carbon storage to the wider public.

Annex A: Definitions and abbreviations

Anticline: upward, curved fold in layers of rock in the Earth's surface, visible as an arch-like shape.

Aquifer: underground porous layer of rock that contains water or allows water to flow through.

Basalt: fine-grained igneous (volcanic) rock.

Buoyancy force: upward force when submerged in a fluid of greater density.

Capillary action/force: movement of a liquid through a narrow space or porous material controlled by adhesive (interfacial) forces between the rock and the liquid.

Caprock or seal rock: rock of very low permeability that acts as an upper seal to prevent flow out of reservoir.

Dense phase: a highly compressible fluid that demonstrates properties of both liquid and gas i.e. has the density of a liquid, but the viscosity and compressibility of a gas.

Dynamic storage capacity: storage capacity generated by numerical simulation of CO_2 injection into a reservoir model. Includes the injection rates, the maximum injection pressure, the design of injection wells and pressure relief wells, and the impacts of geological heterogeneity,on the rates of CO_2 trapping and migration.

Eddy covariance: atmospheric measurement technique to quantify the changes in gas measurements between soil, vegetation, and the atmosphere.

Enhanced oil recovery: extraction of oil using processes to increase the ability of oil to flow to a well by injecting water, chemicals, or gases into the reservoir or by changing the physical properties of the oil.

Fault: a surface at which strata are no longer continuous, but displaced.

Fracture: any break in the rock along which no significant movement has occurred.

Geological carbon storage: involves the injection of CO_2 into rock formations deep underground, (for example, deep saline aquifers or depleted oil and gas fields), and permanently removing it from the atmosphere.

Joule-Thompson effect: the change in temperature that occurs when a gas is forced through a small hole or porous material and then expands.

Microbial methanogenesis: anaerobic respiration by microbes (methanogens) that generates methane as the final product of metabolism.

Microseism: the seismic signal associated with the Earth's dominant background noise.

Microseismicity: small-scale seismic tremors.

Supercritical CO_2: fluid state of CO_2 where it is held at or above its critical temperature and pressure.

Theoretical storage capacity: calculated by estimating the overall volume of the rock strata, the total volume of pore space within the strata and the proportion of that pore space that can be reasonably expected to be utilised for CO_2 storage.

Tracer: a chemical compound or isotope added in small quantities to trace flow patterns.

List of abbreviations

BECCS: Bioenergy with carbon capture and storage

CCS: Carbon dioxide Capture and Storage

CCUS: Carbon dioxide Capture, Use and Storage

DACCS: Direct air carbon capture and storage

EOR: Enhanced Oil Recovery

LNG: Liquefied Natural Gas

LPG: Liquefied Petroleum Gas

Currency conversions

£1= US$1.319, AU$ 1.822, € 1.194.

Annex B: Acknowledgements

Working Group members

The members of the Working Group involved in producing this report are listed below. The Working Group members acted in an individual and not organisational capacity. No conflict of interest was declared for this report. Members contributed on the basis of their own expertise and good judgement.

Working Group Chair	
Professor Andy Woods FRS	University of Cambridge
Working Group members	
Professor Chris Ballentine	University of Oxford
Jerry Blackford	Plymouth Marine Laboratory
Professor Martin Blunt FREng	Imperial College London
Professor Andreas Busch	Heriot Watt University
Tony Espie	BP
Dr Stuart Gilfillan	University of Edinburgh
Professor Stuart Haszeldine	University of Edinburgh
Professor Peter Kelemen	Columbia University
Professor Mike Kendall FRS	University of Oxford
Jonathan Pearce	British Geological Society
Dr Julia Race	University of Strathclyde
Dr David Reiner	University of Cambridge

Contributors	
Eva Halland	Norwegian Petroleum Directorate
Professor Franklin Orr	Stanford University
Professor Hywel Thomas FREng FRS	Cardiff University

Royal Society staff

Many staff at the Royal Society contributed to the production of this report. The project team are listed below.

Royal Society staff	
Frances Bird	Policy Adviser
Paul Davies	Senior Policy Adviser
Leonardo Marioni	Policy Adviser
Elizabeth Surkovic	Head of Policy, Resilient Futures

The Royal Society is a self-governing Fellowship of many of the world's most distinguished scientists drawn from all areas of science, engineering, and medicine. The Society's fundamental purpose, as it has been since its foundation in 1660, is to recognise, promote, and support excellence in science and to encourage the development and use of science for the benefit of humanity.

The Society's strategic priorities emphasise its commitment to the highest quality science, to curiosity-driven research, and to the development and use of science for the benefit of society. These priorities are:

- The Fellowship, Foreign Membership and beyond
- Influencing
- Research system and culture
- Science and society
- Corporate and governance

For further information
The Royal Society
6 – 9 Carlton House Terrace
London SW1Y 5AG

T +44 20 7451 2500
W royalsociety.org

Registered Charity No 207043

9 781782 526162

ISBN: 978-1-78252-616-2
Issued: October 2022 DES7897