Geological storage of CO_2

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Summary and key Drax take-aways undertaken by:
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Summary

Drax commissioned CSIC to provide a review of the current status of the geological storage of CO_2. The report begins by outlining the fundamental options, storage site suitability, trapping mechanisms and stages of CO_2 storage projects. It then looks in detail at the injectivity, leakage risks, permanence and security, monitoring, measurement and verification and non-technical risks such as public concerns, competition with other users (surface and subsurface) and transboundary issues. The report also provides two case studies outlining the subsurface monitoring approaches at Sleipner in Norway and Weyburn in Canada.

Key Drax take-aways

1. Geological storage of CO_2 is well demonstrated as a viable and secure option for climate change mitigation.
    - Industrial experience of injecting CO_2 into geological formations extends back to the 1970s for enhanced oil recovery.
    - The technical maturity of injecting CO_2 into saline aquifers is high (TRL 9), has been occurring commercially for climate mitigation reasons for nearly 30 years and has proven that CO_2 can be stored permanently.
    - Multiple trapping mechanisms immobilise and retain the CO_2 in the reservoir preventing its escape or leakage to the surface. They increase with time and hence storage security increases over time.
    - Geological storage is secure and can provide long-term durability. Various estimates provide storage security as likely to exceed 99% over 100-1000 years.
2. Critical factors for success include the injectivity of CO_2 and managing risks of leakage.
    - Injectivity refers to the rate and efficiency of CO_2 injection into the reservoir. Managing injection of fluids (including CO_2) into geological reservoirs is a standard oil and gas industry practice that has been demonstrated for decades. Risks can be mitigated through appropriate site selection and characterisation as well as through remediation actions.
    - As above, the risk of leakage is low and reduces over time, however understanding and managing such risks are crucial. Mitigations to the key risks include effective site characterisation and selection, monitoring, administrative controls and remediation plans.
    - Effective monitoring is crucial to ensure that both injectivity and leakage risks are appropriately mitigated. The report outlines the extensive range of monitoring options for geological CO_2 storage.

3. Non-technical risks also need to be managed

    - Other project risks include public concerns related to CO_2 storage and competition with other subsurface users.
    - These risks can be mitigated by transparent and responsive engagement with local communities and by integrated management plans and coordination between different stakeholders.

4. There are suitable rock formations globally to meet geological storage needs but the distribution varies, meaning some regions are better suited for geological storage than others.

    - The presence and distribution of suitable storage reservoirs are influenced by the geological history of the region, dictating where porous rock formations are located and their characteristics.
    - Saline aquifers and depleted oil and gas fields can be used for storage, but each have different benefits and risks. For example, historic production data from hydrocarbon fields means there is typically more data available to characterise the storage potential. However, legacy wellbores can introduce possible leakage pathways which are not present in saline aquifers.
    - The global storage potential in saline aquifers and depleted oil and gas fields is in excess of 1000 Gt.
    - The deveslopment of storage sites is currently focussed on regions with well understood sedimentary basins and long-established industry experience from the oil and gas sector such as the Gulf Coast region of the US and the North Sea basin in NW Europe.
    - Transport infrastructure will be important for enabling access to storage from regions lacking suitable geology.

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Study undertaken on behalf of:

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Disclaimer

Drax commissioned GEO3BCN-CSIC to provide a review regarding the feasibility of transportation, injection and underground storage of CO2 in geological reservoirs. Whilst GEO3BCN-CSIC had editorial control over the contents of this report, this report was written for and supported by Drax.

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Glossary of abbreviations and units

Abbreviation	Meaning
€	euros
º C	degrees Celsius
% v/v	per cent on volume basis
BECCS	biomass with carbon capture and storage
BHP	Bottom-hole pressure
CAPEX	capital expenditure
CCS	carbon capture and storage
CO_2	carbon dioxide
CO_2-EOR	carbon dioxide enhanced oil recovery
CSEM	controlled source electromagnetic
EOR	enhanced oil recovery
ERT	electrical resistivity tomography
JT	Joule-Thompson effect
km	kilometres
kPa/m	kilopascals per meter
kt	kilotons
kt/yr	kilotons per year
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m	metres
mD	millidarcies

MEG	Methyl Ethyl Glycol
MMcf	million cubic feet
MMVM	measuring, monitoring, verification, and mitigation
MPa	megapascal
Mt	megatons
Mt/yr	megatons per year
O&G	oil and gas
OPEX	operational expenditure
PFCs	perfluorocarbons
pH	acidity or basicity
ppm	parts per million
ppm w/w	parts per million on weight basis
ppmv	parts per million on volume basis
$scCO_2$	supercritical CO_2
t	tones
TRL	Technological Readiness Level
THP	Tubing-head pressure
USD	United States dollars
VCM	Voluntary carbon market
yr	year
wt.%	weight percent

1. Introduction

CO_2 storage process overview

The final part of the CCS chain is the geological storage (also termed *sequestration*) of captured and transported CO_2. In the natural (slow) carbon cycle, CO_2 originating from biological or geological processes eventually, over 100s of millions of years, accumulates in the subsurface as carbonate minerals or carbon rich sediments, where it can remain stored for millions of years (IPCC, 2005). The engineered geological storage process aims to emulate and speed up this process, and involves the injection of CO_2 in subsurface geological formations to permanently store this CO_2.

Initially, the CO_2 incoming from the transportation is processed to suit the specific conditions (temperature and pressure) of the reservoir. Following this, it is injected, in liquid, gaseous or supercritical form, into the selected geological formation through one or more injection wells. The storage complex typically consists of two components: a porous and permeable reservoir, and an impermeable caprock (Figure 1). There are two primary types of CO_2 storage reservoir rock types: sedimentary formations with porous media, and igneous formations used for mineral carbonation. This work will focus on CO_2 storage within sedimentary porous media reservoirs.

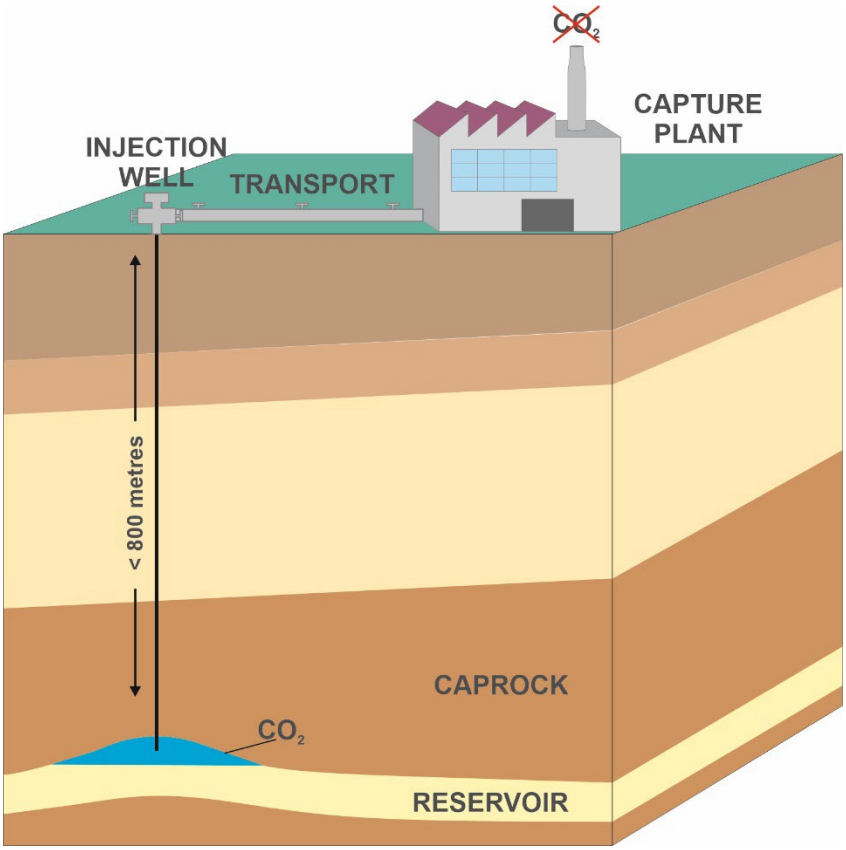

Figure 1: Sketch of a CO_2 storage complex. The CO_2 is captured at the emission point and it is transported to the storage site, where it is injected into the geological reservoir via an injection well. The impermeable caprock prevents the CO_2 from escaping back to the surface.

The minimum suitable depth for CO_2 storage is achieved at around 800 m depth, where the CO_2 can reach its supercritical phase, combining the diffusive properties of gas with the density of a liquid, significantly improving the efficiency of geological storage (Figure 2). Since the injected CO_2 is more buoyant than the fluids inside the reservoir (i.e. it 'floats' above these fluids), a sealing rock formation (caprock) overlying the reservoir is required to prevent the CO_2 from migrating upwards out of the reservoir. The proportion of the pore space within a reservoir rock that is occupied by CO_2, as opposed to other fluids like water or hydrocarbons, is called CO_2 saturation. It's a measure of how much of the reservoir's available pore volume is taken up by CO_2 after injection, influencing the efficiency and capacity of the storage site. Over time, various physical and chemical processes in the reservoir work to immobilize and securely retain this CO_2, progressively enhancing its containment until the CO_2 is permanently stored (IPCC, 2005). These "trapping"

processes and their impact on the storage are discussed in detail in Section 4 below (Permanence and security of geological storage).

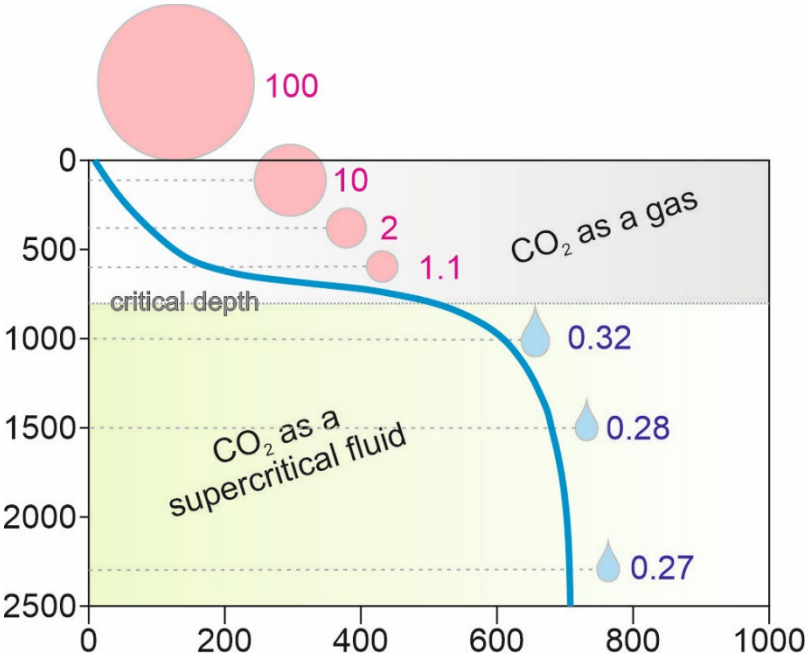

Figure 2: variation of density of CO_2 with depth, assuming typical geothermal and geobaric gradients. The size of the spheres represents the volume of the same amount of CO_2 at different depths in the gas (pink) or supercritical fluid (blue) phase. Modified from: CO2CRC (https://co2crc.com.au/).

The first practical demonstration of geological storage of CO_2 was through enhanced oil recovery with CO_2 (CO_2-EOR), dating back to the 1970s. In CO_2-EOR, CO_2 is injected into oil reservoirs to increase the pressure and reduce the viscosity of the oil, making it easier to extract. This process improves oil recovery rates while also results in some of the CO_2 being stored underground as a significant portion of the injected CO_2 remains trapped in the reservoir (Golzapour et al., 2005). The first dedicated CO_2 geological storage project (i.e., not for EOR purposes) was the Sleipner CCS project, which began in 1996 and has injected over 20 Mt CO_2 in more than 20 years of operation (Furre et al., 2017; Ma et al., 2022). Currently, there are 50 commercial projects in operation worldwide storing more than 50 Mt of CO_2 annually (GCCSI, 2024), with most storage capacity dedicated to EOR (Zhang et al., 2022a). Of these, 15 plants are intended for dedicated geological storage, with annual capture and storage rates of 11.4 Mt of CO_2/yr. Storage rates have increased steadily in the last decade, and estimations suggest that more than 300 Mt of CO_2 have been stored underground worldwide so far, mostly for EOR (Loira and Bright, 2021).

Stages of a CO_2 storage project

CO_2 storage projects are typically divided into distinct stages based on the operational activities carried out, the regulatory activities authorized, and the shifting liability throughout the project lifecycle (Figure 3). This staged approach not only ensures systematic progression and management of the project but also aligns with regulatory compliance requirements and facilitates effective stakeholder engagement. Each stage of the project—from initial exploration and CO_2 injection to post-injection monitoring and site abandonment—has specific objectives that contribute to the overall safety, efficiency, and environmental integrity of the storage (NETL, 2017). Regarding the operational framework, the storage project lifecycle is commonly structured in four stages:

1. **Pre-Injection (exploration period)**: Also referred to as the exploration period, this preliminary stage involves comprehensive geological surveys and modelling to identify and assess potential storage sites for their capacity, integrity, and suitability. This assessment includes understanding the geology and hydrogeology, modelling CO_2 plume migration and creating a development and construction plan. This phase also needs to assess potential environmental impacts, requiring operators to conduct risk analyses and develop mitigation strategies. The main aims of this stage are to prove the capacity and

injectivity of the site, assess associated risks, and establish appropriate monitoring and mitigation plans.

2. **Injection (operation period)**: At this stage, CO_2 is injected into the chosen geological formations. This process requires precise control and monitoring to manage the flow rates and pressures ensuring efficient distribution of CO_2 within the reservoir and preventing leakage or seismic events. Operators are liable for maintaining operational safety standards and adhering to regulatory requirements. Real-time monitoring systems are typically employed to track the injection process and respond quickly to any irregularities. The objectives in this phase are to safely store CO_2, prove containment, and maintain injectivity throughout the operational phase.

3. **Post-Injection (closure period)**: This phase involves continuous monitoring of the storage site to detect any potential leakage and to track the behaviour and migration of the injected CO_2. This monitoring is critical for ensuring the long-term stability and safety of the storage site. The main goals during this stage are to demonstrate conformance with initial modelling, ensure plume stabilisation, and confirm that all measures are functioning as expected.

4. **Abandonment (post-closure period)**: The final stage is the closure of the storage site. Even after the injection wells are sealed, monitoring may continue for an extended period to guarantee the continued containment and stability of the stored CO_2. The aim of this stage is to prepare for the transfer of liability to the relevant authority, ensuring that the site remains secure and stable long-term.

The operator is responsible of the monitoring and verification of the storage security until the storage facility is transferred to the relevant authority (e.g. the state), that takes full responsibility from that point.

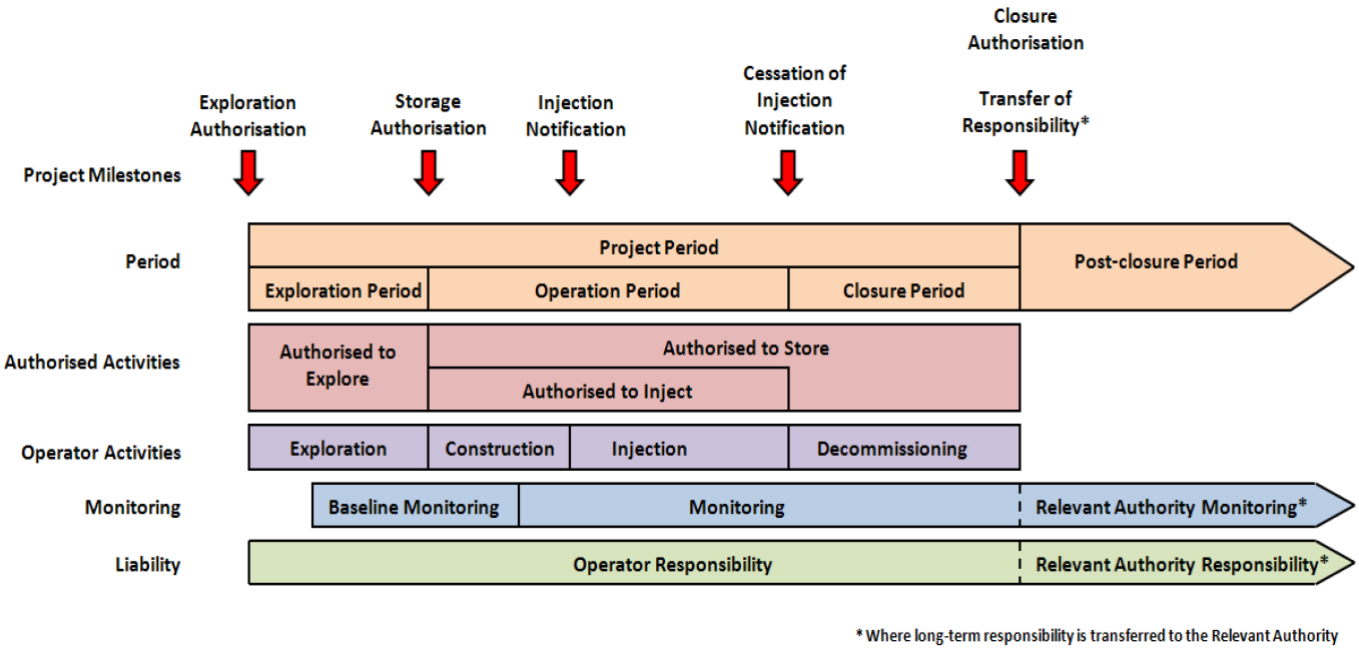

Figure 3: The stages of a CO_2 storage project from different perspectives. Source: IEA, 2010.

2. Fundamentals of CO_2 storage

CO_2 storage options

There are two main types of sedimentary formations that can be used for geological storage of CO_2: deep saline aquifers and depleted oil and gas (O&G) fields (Figure 4). Each of these formations offers unique characteristics and challenges for CO_2 storage. Other potential CO_2 storage options, including storage in unmineable coal seams and mineral carbonation, less technologically mature than the previous two, are discussed in a separate subsection below (Other storage options).

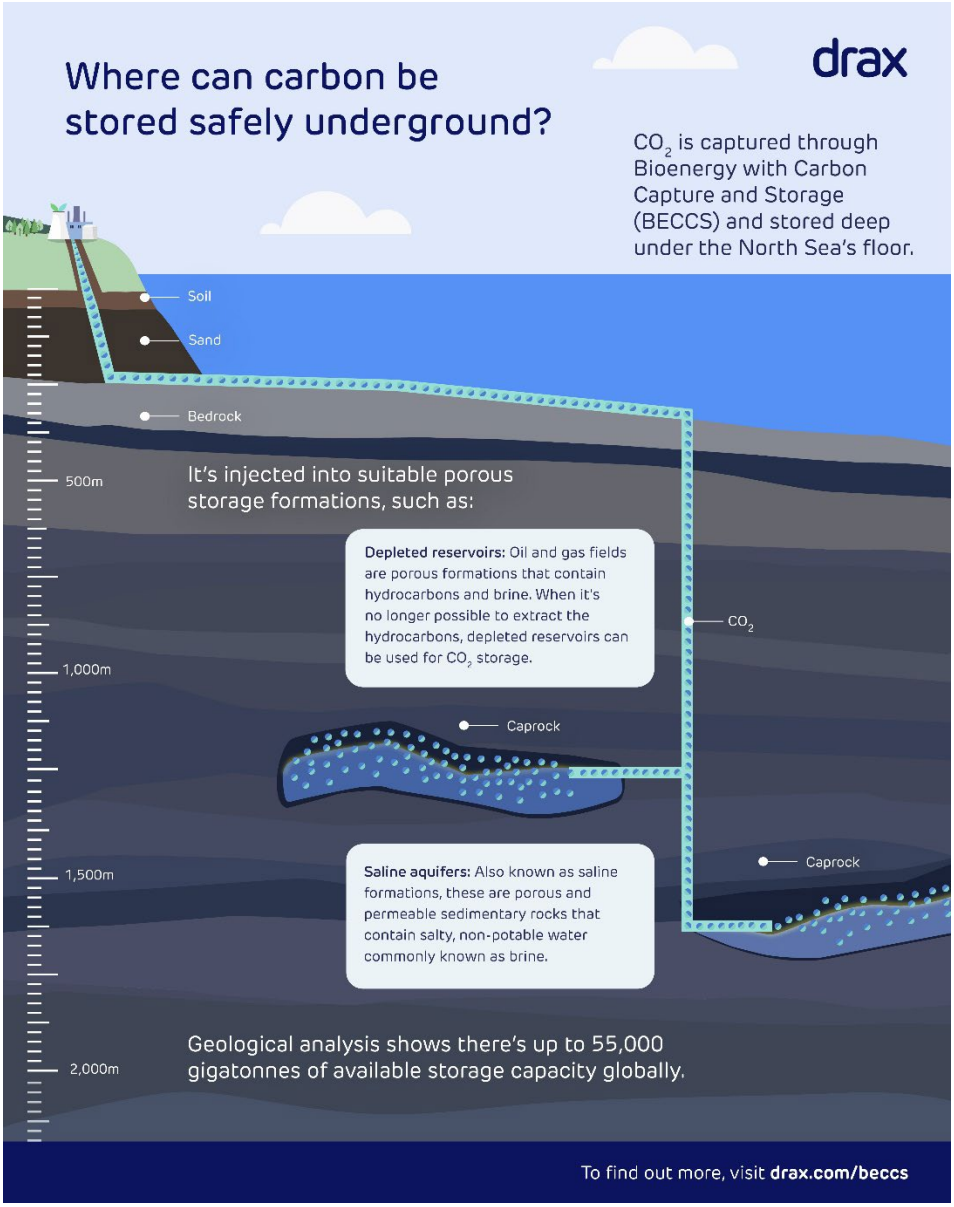

Figure 4: CO_2 storage options. Source: Drax Group (drax.com/beccs).

Deep saline aquifers

Deep saline aquifers are underground reservoirs that contain highly saline water due to the geological history of fluid migration in the region. They are distinguished from oil fields primarily based on the type of fluid they contain—saline water versus hydrocarbons—which reflects the geological processes and conditions that have occurred over time. The presence and distribution of these aquifers and oil fields are influenced by the geological history of the region, dictating where suitable rock formations are located and their characteristics. Typically screened at depths exceeding 800 meters, deep saline aquifers offer immense potential for CO_2 storage owing to their large storage capacities (in the Gt-scale, Ringrose and Meckel, 2019), making them a promising option for geological CO_2 storage. These aquifers are widespread (Figure 5), but their exact distribution and capacity can vary significantly. Apart from their vast capacities, saline aquifers offer several advantages over depleted oil and gas fields, which make them attractive for CO_2 storage. These benefits include the absence of legacy wells from the oil and gas industry, simplifying the sealing process and reducing the risk of leakage (Celia et al., 2015). Additionally, saline aquifers, typically close to their original hydrostatic pressures, offer favourable pressure conditions that simplify the management of pressure dynamics during CO_2 injection and storage. This stability means that less intervention is required to control pressure build-up (compared to depleted oil and gas fields), avoiding complexities related to under-pressure, expansion, or Joule-Thomson effects. However, fault reactivation or fracturing can be more of a concern in saline aquifers because their pre-injection pressure is closer to the fracture pressure (Worden, 2024), often needing other pressure management operations (e.g. brine production) to mitigate these risks. The fluid chemistry in these aquifers is also generally simpler because of the lack of hydrocarbons, reducing the likelihood of undesirable chemical reactions during storage. On the other hand, one of the key challenges with deep saline aquifers is

the limited knowledge about their geological characteristics. Unlike depleted O&G fields, which have been extensively studied and documented due to their commercial exploitation, the geological properties of deep saline aquifers are less understood. This lack of detailed geological data can lead to increased uncertainties in storage projects, particularly in terms of injectivity information (Lane et al., 2021), subsequently increasing the costs associated with reducing this uncertainty (e.g., by drilling wells). This affects not only the initial exploration phase, where more extensive geophysical surveys and drilling of exploratory wells may be required, but also impacts the long-term monitoring and verification processes.

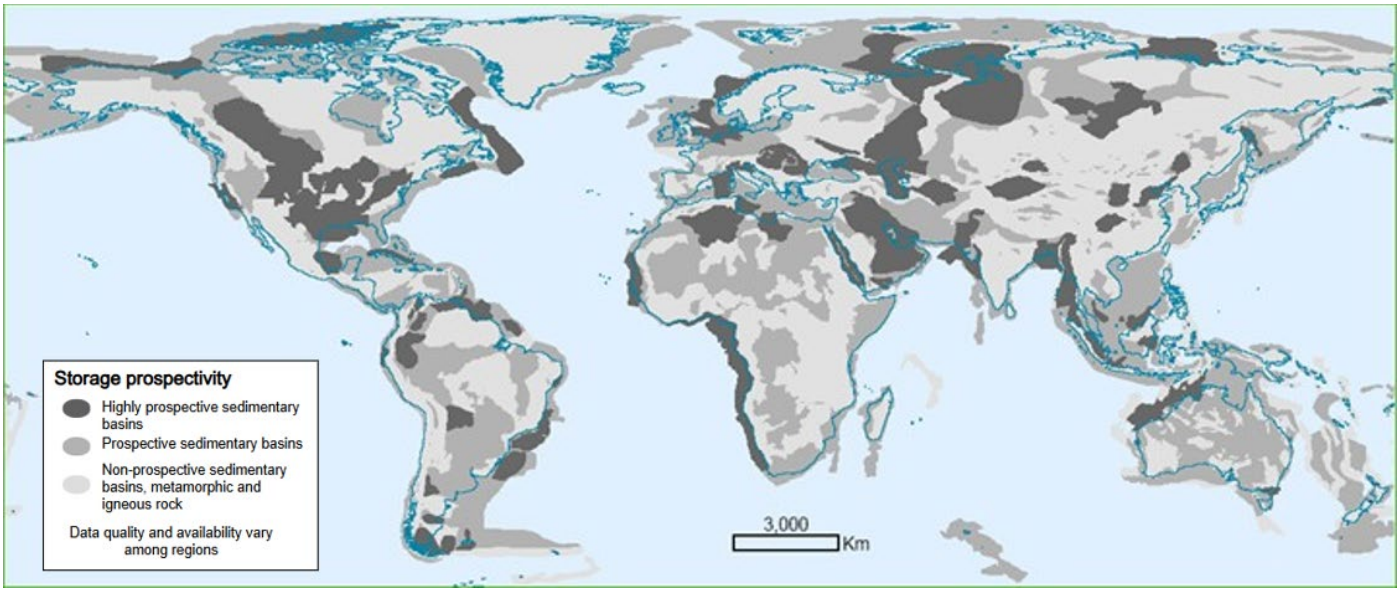

Figure 5: Prospective areas in sedimentary basins where suitable storage sites may be found. From IPCC, 2005.

As noted above, storage in deep saline aquifers began in the North Sea in 1996 at the Sleipner project, and several other projects are currently in operation or advanced stages of construction. The TRL in deep saline aquifers is considered the maximum (nine) thanks to these experiences that prove that: (1) the CO_2 can be injected at a significant rate (Mt-scale), (2) the CO_2 plume can be monitored within the reservoir, and (3) that the CO_2 can be stored permanently (Kearns et al., 2021).

Case study 1: the Sleipner CCS project – the first commercial CO2 storage project

The Sleipner CCS project was the first commercial project for dedicated CO_2 storage developed in the world. Located in the Norwegian North Sea, the project captures CO_2 from the Sleipner West field, a field in production since 1993 which contains 9% CO_2. To meet market specifications for natural gas and to avoid CO_2 emissions subject to Norway's carbon tax, the CO_2 is separated from the natural gas (Furre et al., 2017). Since its launch, over 20 Mt of CO_2 have been injected in the Utsira formation, demonstrating the feasibility of safely storing CO_2 in saline aquifers.

The project's extensive monitoring program employs repeated 3D seismic surveys that have detected thin shale layers with extensive lateral continuity, influencing CO_2 distribution significantly (Torp and Gale, 2004). These layers, up to 9 in number and 1-1.5m thick, have caused the CO_2 to migrate laterally across several hundred meters instead of rising directly to the top of the formation, enhancing CO_2 dissolution and effectively increasing the reservoir's storage capacity (Hermanrud et al., 2009).

The efficacy of 4D seismic techniques at Sleipner has been pivotal for monitoring the CO_2 plume (Arts et al., 2004), proving exceptional in identifying small CO_2 saturations and potential migration within the reservoir (Furre et al., 2017). Additionally, high-precision gravity monitoring provides an independent measure of density and saturation changes, contributing to both containment and conformance monitoring (Alnes et al., 2011). The monitoring strategy at Sleipner is designed to be flexible, incorporating both planned and triggered repeats, and evolves with technological advancements, reflecting over two decades of operational experience (Furre et al., 2017).

As a pioneer in the CCS field, the Sleipner project has demonstrated through its exhaustive monitoring program that CO_2 can indeed be stored safely and effectively in saline aquifers, setting a precedent for future CCS initiatives globally.

Depleted oil and gas fields

Depleted oil and gas fields offer a very suitable option to host CO_2. These fields have proven their capability to contain fluids over geological time scales, and have large pore space availability after the hydrocarbon production (Hamza et al., 2021). Furthermore, depleted oil and gas fields have a wealth of operational data and extensive information about how fluids migrate through the reservoir from the production period. The accumulation of well logs, core samples, seismic data, and other subsurface information over multiple years of production builds a robust evidence base for the storage potential of these fields. For example, this abundance of historical data allows for the application of "history matching," a standard process in the oil and gas sector where historical production data is used to refine and calibrate reservoir models (Ennis-King et al., 2011; Shi et al., 2013). This abundance of historical data means that the models for CO_2 storage can be developed with more real inputs compared to models for saline aquifers. Building similarly robust models in underexplored areas, such as saline aquifers, can be very costly due to the cost of characterisation (Eccles et al., 2012).

Depleted fields also have more available pore volume than saline aquifers because the extraction of hydrocarbons vacates the space within the existing porous structure of the rock (or pore-space). This vacated pore-space effectively increases the total volume available for CO_2 storage, unlike in saline aquifers, that require the displacement of existing fluids by the injected CO_2 (Bachu et al., 2007). However, dealing with the very low pressure derived from the reservoir depletion can also be a technical challenge in storage projects in depleted reservoirs, often requiring the use of compression or heating techniques that increase the complexity and cost of the operation (Hughes, 2009).

The existing infrastructure in depleted fields can sometimes be repurposed for CCS, which like in the case of transport, can help to reduce the overall cost of the project (Alcalde et al., 2019; 2021). However, dealing with existing infrastructure can be challenging (Hannis et al., 2017). For example, existing oil and gas wells can be repurposed to CO_2 injection, but significant intervention will be required for their reconditioning (Williams et al., 2022). This involves a thorough investigation of the status of the well, and subsequently can comprise re-entering the well (i.e. re-drilling) and replacement completion components, with substantial costs associated.

The storage capacity in depleted oil and gas fields (globally estimated at 675-900 Gt of CO_2), however, is generally lower compared to deep saline aquifers (1,000-10,000 Gt of CO_2) (IPCC, 2005; Jafari et al., 2017); in fact, oil and gas fields are often contained within larger deep saline aquifers. Although deep saline aquifers can store Mt of CO_2, depleted O&G fields have not yet been scaled to this level. While CO_2 storage in depleted oil and gas fields is a relatively mature technology (with TRL 5-8, Kearns et al., 2021), it has only been applied in demonstration CO_2 storage projects (Bui et al., 2018), in contrast with storage in saline aquifers which are already operating at full commercial scale. However, a number of storage projects in depleted oil and gas fields are in the pipeline and expected to reach operation by the 2030s (GCCSI, 2023). Depleted gas reservoirs are generally more favourable for CCS compared to depleted oil reservoirs due to the higher ultimate recovery and compressibility of gas, which allows for a larger storage capacity per pore volume (Cao et al., 2021). While the majority of the completed and currently operational facilities are dedicated to CO_2-EOR purposes, dedicated CO_2 storage sites dominate the facilities that are in development (GCCSI, 2023;). Deep saline aquifers also dominate over depleted oil and gas fields for future developments, thanks to their Mt-scale injection rates and their availability in early-development regions, such as in the US and the North Sea.

Worden (2024) analyses the main differences between CO_2 storage in saline aquifers and depleted oil and gas fields. An important aspect highlighted in their work is that depleted gas fields often start below the normal (hydrostatic) pressure as a result of the reservoir depletion because of the hydrocarbon production (Figure 6). This condition can significantly influence the initial injection strategy and the behaviour of CO_2 once injected, as these fields may require the injection of gas-phase CO_2 rather than the dense-phase CO_2 typically used in saline aquifers. This difference also leads to a different stress path related to CO_2 injection, influenced

by the geomechanical properties of the reservoir (Figure 6, right). In saline aquifers, CO_2 trapping is primarily governed by buoyancy, with residual and dissolved CO_2 developing over time. However, in depleted gas fields, the denser CO_2 phase sinks forming a cushion beneath the lighter residual methane.

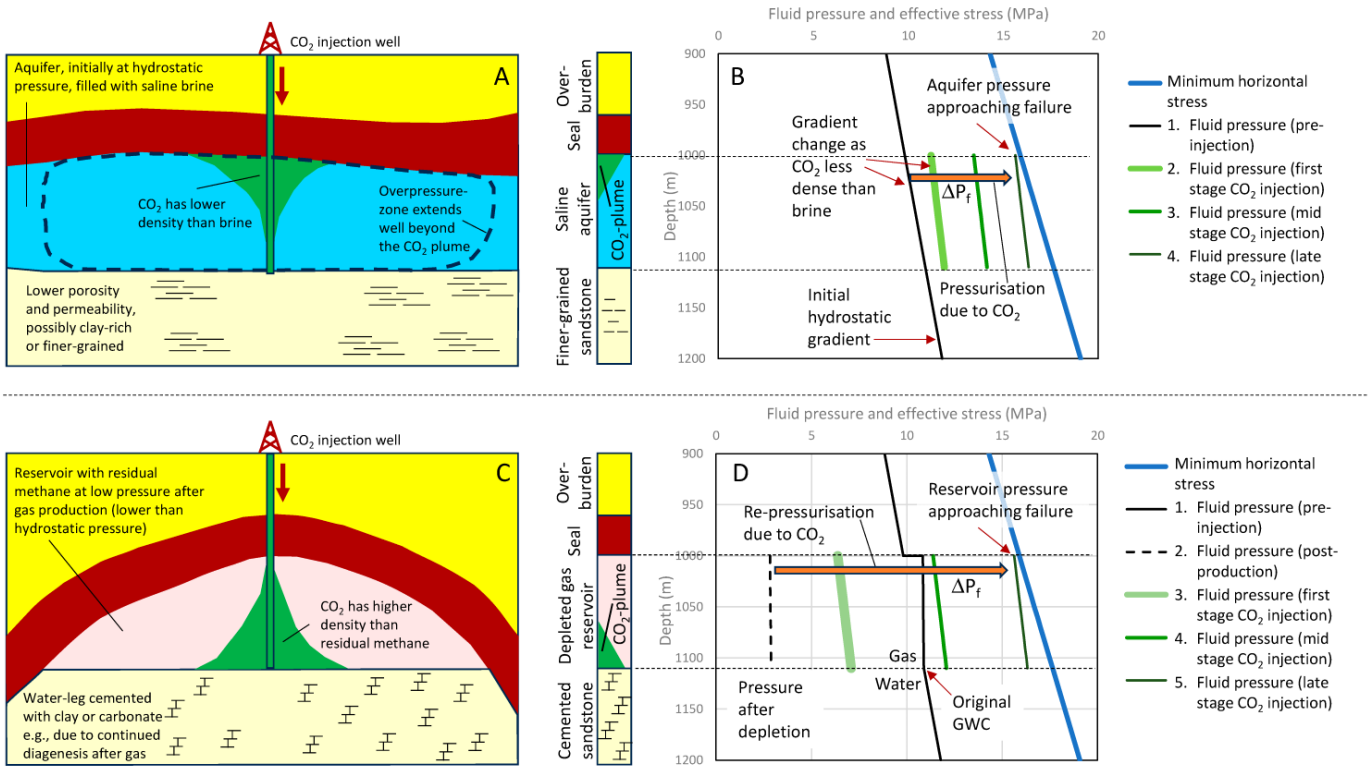

Figure 6: diagram illustrating a saline aquifer (above) and a depleted gas field (below) used for CO_2 injection and storage, depicting variations in pressure before and after CO_2 injection, alongside the minimum horizontal stress (fracture pressure). From Worden (2024).

CO_2-Enhanced Oil Recovery

CO_2-Enhanced Oil Recovery (CO_2-EOR), where CO_2 is used to boost oil extraction, is a key technology for geological storage, because much of the knowledge generated in the half a century experience of CO_2-EOR has been incorporated to the dedicated CO_2 storage (Allinson et al., 2017). In EOR, the CO_2 can be injected in the reservoir to increase the pressure in the reservoir and to increase oil mobility by reducing oil viscosity, hence improving oil mobility and enhancing oil extraction efficiency. CO_2-EOR can offer an economic incentive for CCS that can help its early development (Mendelevitch, 2014; Ringrose et al., 2021a), and its use offers lower emissions than conventional oil (net life emission factor of 438 kg CO_2e/bbl vs. ~500 kg CO_2e/bbl of conventional oil) (Azzolina et al., 2016). It is estimated that over 300 Gt of CO_2 could be stored globally while producing over 1000 billion barrels of oil (Kolster et al., 2017). However, some stakeholders perceive that CO_2-EOR helps to perpetuate the dependence on fossil fuels (Mabon and Littlecott, 2016), and thus its role in climate mitigation is under debate (Dooley et al., 2010; Cooney et al., 2015; Núñez-López and Moskal, 2019;). However, while part of the CO_2 employed is trapped in the reservoir, CO_2-EOR is predominantly considered a carbon capture and utilisation (CCU) technology (e.g. Kuuskraa et al., 2013; Shiyi et al., 2022), and hence it will not be explored further in this chapter, except to highlight the differences and intersections with dedicated CO_2 storage operations (Table 1).

Table 1: comparative assessment between CO_2 storage in depleted fields, in saline aquifers and in CO_2-EOR sites, based on the analysis of nine real case sites. Modified from Hannis et al. (2017).

	Depleted oil and gas field	**Saline aquifer**	**CO_2-EOR**
Overarching motivator	Climate change abatement. Containment required by storage-specific regulations (environmental protection and emission abatement)	As depleted oil and gas fields	Hydrocarbon production. Containment required by storage-specific regulations (environmental protection and emission abatement)

Regulation maturity	Purpose-designed, relatively recent (EU: 2009, USA: 2011) & not tested in either EU or USA yet	Purpose-designed, relatively recent (EU: 2009, USA: 2011) & not tested in EU yet	Very mature, but somewhat fragmented and comparably complex in USA
Characterization effort required	Low: Well(s) with production history, tested containment of CH4	High: Few or no wells, no production history, untested trap. Well tests likely needed to reduce uncertainty prior to permitting/injection	Low: Many wells with production and injection history. High effort may be required to assimilate vast historic datasets
Modelling requirements	To predict behaviour & demonstrate site capacity & containment. Initial predictions submitted to obtain permit. Thereafter, history matched (and long-term stability predictions updated) EU: reported annually, USA: no reporting schedule specified.	As depleted oil and gas fields	Typically focused on improving understanding of sweep efficiency and compositional phase behaviour for operator internal use only.
Modelling capabilities	May be complex because of residual hydrocarbon saturations, but can be matched to production data to reduce uncertainty. Geomechanical modelling to include site history to ensure wellbore/caprock rock integrity after pressure cycling	Less complex because no residual hydrocarbon saturations (2 phases only), but no production data to match to, to reduce uncertainty.	May be complex because of residual hydrocarbon saturations. (Potential data 'overload' to match to full field history. E.g. Pressure cycling may be complex)
Monitoring requirements	Report to regulator typically annually (EU): risk-based monitoring focusing on how results demonstrate containment & conformance with models. Monitoring requirements in the Voluntary Carbon Market (VCM) are under development and may require additional information	As depleted oil and gas fields	Report to regulator typically monthly (USA): well production and injection volumes, wellhead pressures. Other risk-based monitoring data may be collected but not reported
Monitoring capabilities	Wells may allow opportunities for well-based monitoring. May be difficult to distinguish CO_2 from residual hydrocarbons using geophysical techniques	Less opportunities for well-based monitoring from pre-existing wells so monitoring must be designed for the injection wells and potentially also dedicated monitoring wells. CO_2 likely to be much more readily distinguishable from brine using geophysical techniques thanks to the lack of residual hydrocarbons	Wells almost certainly allow opportunities for well-based monitoring. May be difficult to distinguish CO_2 from residual hydrocarbons using geophysical techniques
Injection-related issues	Reservoir depletion and changes in geomechanical properties due to previous hydrocarbon extraction may induce a rapid expansion of the injected gas, associated with a rapid temperature drop (Joule-Thompson effect), affecting the integrity of the well and/or surrounding rocks	No/reduced Joule-Thompson, but potential issues related to brine displacement that may require brine production to avoid overpressure	Complex, related to the production history. Pressure management available via production wells
Irregularity detection and contingency potential	Likely to have continuous well-based monitoring for early warning irregularities, although less spatial coverage than at CO_2-EOR sites (but also	Less opportunities for continuous well-based monitoring from pre-existing wells, but could represent a lower risk of wellbore leakage. High spatial coverage monitoring (e.g. seismic) likely to	Many wells - lots of well-based continuous monitoring, potential for early catching of irregularities (but also many more possible leakage paths). Potential for "plume steering" using multiple

	consequent reduced wellbore leakage risks)	be periodic (i.e. less opportunity for early detection of irregularities)	active wells as a way for contingency containment.
Site closure requirements	In EU operator needs to demonstrate long term stability of the site, potentially monitor for up to 30 years.	In EU operator needs to demonstrate long term stability of the site, potentially monitor for up to 30 years.	No specific requirements for CO_2-EOR compared to other EOR operations.
Potential global storage resource	675-900 Gt of CO_2	1,000-10,000 Gt of CO_2	> 300 Gt of CO_2
Costs & economics	May be savings in reusing infrastructure such as wells, but may also have additional costs to re-complete/re-case wells unsuitable for CO_2 or to plug wells that have not been suitably plugged and abandoned.	Likely to be additional costs for characterization and infrastructure installation. Long-term costs for abandonment might be less (fewer wells)	Economic benefit from sale of produced hydrocarbon. Additional costs of equipment and higher operating costs for EOR. May be cost savings by reusing existing wells.

Other storage options

CO_2 storage in unmineable coal seams involves injecting carbon dioxide into coal beds that are too deep, thin, or uneconomical to be mined. Storage in unmineable coal seams involves a process known as adsorption, where CO_2 molecules physically adhere to the surface of the coal. This CO_2 exists in a more stable form inside the coal mass, which greatly reduces the risk of CO_2 leakage into the atmosphere, enhancing the safety and effectiveness of this carbon storage method (Perera and Ranjith, 2012). Furthermore, coal beds often contain methane in their structure as a result of natural geological processes, and it is commercially being exploited throughout the world (Moore, 2012). With CO_2 injection, this methane can be released and extracted (a process known as Enhanced Coalbed Methane, ECBM) as CO_2 displaces it due to its preferential adsorption onto the coal surface. This process not only helps to store CO_2, but also facilitates the extraction of methane, a valuable energy source, thus providing an additional economic benefit to the carbon storage operation (Shi and Duruncan, 2005). As with the CO_2-EOR case, this practice has conflicting impacts on climate change mitigation; while it promotes CO_2 storage in the process, the extraction and subsequent use of methane contributes additional greenhouse gases to the atmosphere, offsetting some of the climate benefits of carbon storage. Despite significant theoretical interest in this technology, particularly in countries with large coal reserves like China or the U.S. (e.g. Sun et al., 2018; Rasool et al., 2023), only four pilot ECBM operations have been completed in these countries and no commercial projects specifically targeting these fields implemented to date worldwide (TRL of 2-3, Kearns et al., 2021).

An alternative option for CO_2 injection and permanent storage, is mineral carbonation. This option involves the injection of CO_2 into certain reactive basic rocks, such as mafic (e.g. basalts) or ultramafic lithologies (e.g. peridotites) (Snæbjörnsdóttir et al., 2020). This process chemically binds the CO_2 into stable, solid minerals such as magnesium carbonate or calcium carbonate. These minerals, formed as a result of the reaction between CO_2 and the silicate minerals in the rock, effectively lock away the CO_2 in a solid, inert form. The resultant carbonate minerals are stable over geological timescales, thereby ensuring that the carbon dioxide does not re-enter the atmosphere. While promising, this technology is currently at a lower TRL (2-6) than injection in sedimentary formations (Kearns et al., 2021), with only two pilot projects targeting basalts. Since this technology is not currently commercially mature, this chapter focuses on the CO_2 storage options in sedimentary basins.

Storage site suitability

CO_2 storage sites must be carefully analysed to ensure that they are suitable for storing CO_2 (Ramírez et al., 2010; Raza et al., 2016; Alcalde et al., 2021) (Table 2). A suitable reservoir features high porosity and permeability, which determine the capacity and injectivity of the reservoir formation. Porosity refers to the fraction of the rock that consist of microscopic pores rather than rock grains, which can then be occupied by CO_2. Sedimentary rocks, the primary targets for CO_2 storage and the focus of this work, exhibit varying degrees of porosity, typically ranging from low values in caprocks or poor reservoirs (e.g. 0-10%) to higher values in fair and good reservoirs (>10-20%). In nature, this pore space is filled with formation fluids, like saline water (brines) and, sometimes, hydrocarbons (oil and natural gas), and the injected CO_2 will displace

part of these formation fluids to occupy a portion of the pores. Permeability, on the other hand, is the ability of the rock to allow fluids to pass through it. This controls how easily CO_2 can be injected (injectivity) and spread within the reservoir formation, ultimately dictating how much of the reservoir volume can be reached by the CO_2 plume (Hajiabadi et al., 2021). While high permeabilities in the reservoir (e.g. greater than 100 millidarcies, mD) are sought, too high permeabilities can also lead to operational and storage challenges. The rapid CO_2 migration in such conditions can lead to an uneven spread of the CO_2 plume, resulting in inefficient storage, especially in low injection rate scenarios, where gravity causes CO_2 to form stable pathways through high-permeability areas and primarily occupy large pores, reducing trapping effectiveness (Juanes et al., 2006). Furthermore, managing injection pressures in highly permeable reservoirs is challenging, with the risk of creating high-pressure zones that could induce seismicity or compromise caprock integrity (see Section 3. CO2 Injection in the reservoir).

Table 2: Factors that determine a suitable storage site.

	Property	Desired characteristic	Rationale
Reservoir	Porosity	High (e.g. > 10 %)	Allows for a larger volume of CO_2 to be stored
	Permeability	High (e.g. > 100 mD)	Enables efficient CO_2 injection and dispersal within the reservoir
	Capacity	High relative to the storage needs of the project (e.g. on the 10s of Mt of CO_2)	Enough to host the CO_2 volumes required by the project
	Salinity	Above potable levels (e.g. > 100 g/l) but lower preferred	Water not suitable for other uses while maintaining CO_2 solubility
	Stratigraphy	Well characterised	Reduces the complexity and unpredictability of CO_2 injection and storage
	Faulting & fracturing	None/low or sealed	Minimize leakage pathways for CO_2
	Thickness	> 50m	Provides sufficient volume for CO_2 storage while facilitating injectivity (in combination with the permeability)
	Pressure	Low relative to the fracturing pressure	Minimizes the risk of induced seismicity and allows for a greater total injection volume
	Depth	800 - 2400 m	Ensures the CO_2 remains in a supercritical state
Caprock	Permeability	Very low (< 0.1 mD)	Effective seal to prevent CO_2 escape
	Stratigraphy	Uniform	Ensure caprock's integrity and predictability as a seal
	Faulting & fracturing	None/low or sealed	Minimize leakage pathways for CO_2
	Thickness	> 10m	Ensure presence of a reliable seal for containment
Storage complex	Tectonic activity	Low	Prevent disruption of the storage site and ensure long-term containment

Overlaying the porous reservoir is the impermeable caprock, or multiple caprocks, which work as a seal preventing the upward migration of the buoyant CO_2 outside of the reservoir. The integrity of this caprock is critical, as any failure could allow the CO_2 to migrate outside of the reservoir, undermining the effectiveness and safety of the storage site. For the caprock, characteristics are equally critical for secure storage; low permeability under 1 millidarcy and uniform stratigraphy are vital for its role as an impermeable seal. Hence, a suitable caprock must have a certain thickness (generally > 10 m) to avoid capillary leakage (Busch et al., 2010) and structural weaknesses, and also must be free of fluid escape conduits, such as open faults or fractures, to minimize the risk of CO_2 escape and guarantee a robust containment barrier (Hawkes et al., 2005).

A key suitability parameter is the storage capacity, or storage resource. Capacity can be calculated using two types of methods, static and dynamic (Table 3). The static storage capacity (also called “volumetric storage resource”) provides a first order calculation of the storage resource. Static capacity calculations are independent of time and include volumetric estimates and calculations based on pressure build-up (Pickup,

2013). There are different ways to calculate this volume, but the formulas usually combine the pore volume of the reservoir, the density of the CO_2 at the reservoir conditions and an "Efficiency factor" (*E*), which provides a measure of how effectively a given reservoir volume can store CO_2. The storage efficiency is calculated as the ratio of the volume of reservoir accessible or occupied by the CO_2 to the total pore volume of the medium (Bachu, 2015). This parameter is important because not all the pore volume of the reservoir can be accessed by the CO_2, and the volume that is accessed will not be fully saturated with CO_2. The storage efficiency is influenced by various factors, making it a complex aspect to quantify precisely. Bachu (2015) provide a comprehensive analysis of these factors. Firstly, the characteristics of the storage site play a crucial role. In situ conditions such as pressure, temperature, and salinity directly impact the density and viscosity of CO_2 and aquifer water, affecting CO_2 buoyancy and fluid mobility. The displacement characteristics of the CO_2/brine system, including saturations and relative permeabilities, and CO_2 capillary entry pressure, are also significant. The internal features of the aquifer, like depositional environment, lithology, porosity, permeability, and their distributions, as well as external features like areal extent, thickness, and topography, further influence the storage efficiency. Additionally, the operational characteristics of the CO_2 storage, including the injection rate, duration, number and orientation of injection wells, and injection strategy, also determine how efficiently the CO_2 is stored. Bachu (2015) and Leng et al., (2024) provide comprehensive overviews and comparisons amongst the different methods for calculating this storage efficiency factor. Goodman et al. (2013) statistically compared static capacity estimation methods and determined that realistic storage efficiency factors range from 0.3% to 7.2%, with storage efficiency being lower in saline aquifers than in depleted oil and gas fields (Worden, 2024).

Table 3: Summary of methods for assessing CO_2 storage capacity. From Pickup (2013).

Category	Method	Summary
Static	**Volumetric**	• Calculate reservoir formation pore volume • Assume a storage efficiency • Simple approach
	Pressure build-up	• Assume a closed system • Estimate the maximum allowable pressure build-up • Calculate CO2 volume from total compressibility and pressure increase
Dynamic	**Semi-closed**	• Similar to the pressure build-up method, but allows water to leak through the seals
	Pressure build-up at wells	• Assumes pressure at injection well is the limiting factor • Uses an analytical formula to estimate the injection pressure
	Material balance	• Similar to the pressure build-up method, but updates calculations with time
	Decline curve analysis	• Monitor pressure build-up in a CO2 injection site • Opposite of decline curve analysis in hydrocarbon reservoir
	Reservoir simulation	• Construct a detailed geological model • Perform fluid flow simulations • Requires most data and is the most time-consuming method • This method is required under permit requirements in the US, EU and UK (i.e. any store under permitting and development will use reservoir simulation, but during the exploration phase the other methods would be used)

A more robust, but also more complex capacity assessment is the dynamic capacity. Dynamic capacity calculations incorporate the time dimension and involve analytical approaches and numerical simulations. Dynamic capacity modelling is based on site-specific factors such as the rate, pattern, and timing of injection, as well as pressure interference between injection locations (Goreki et al., 2015). This approach allows for a more sophisticated evaluation of capacity and enables the testing of various injection strategies to optimize storage efficiency and safety (Ghanbari et al., 2020).

Another fundamental aspect for storage is the depth of injection. As you go deeper into the Earth's subsurface, temperature and pressure generally increase following geothermal (the rate of temperature increase per unit depth) and geobaric (the rate of pressure increase per unit depth) gradients. CO_2, like any gas, will compress under higher pressure and expand with higher temperature (Figure 7). At approximately

800 m depth (31 ºC and 7.37 MPa at typical geothermal and geobaric gradients), the CO_2 transitions from gas to a dense supercritical phase (van der Meer et al., 2009). In this state, supercritical CO_2 ($scCO_2$) has a higher density than in its gaseous form, which allows for a larger quantity to be stored in a given portion of the reservoir (Figure 2). Below this depth, the increasing pressure ensures that CO_2 remains in this compact form, while keeping a reduced mobility compared to gaseous CO_2, reducing the risk of leakage (Chadwick et al., 2008). The ideal range for CO_2 storage lies approximately between 800 m and 2400 m, depending on the geothermal and geobaric conditions. The shallower boundary is defined by the supercritical state of CO_2, which optimizes storage density and injectivity, while the deeper boundary is influenced by changes in rock wettability; at high pressures, CO_2 can alter the rock's wettability to CO_2-wet conditions, leading to diminished structural trapping and increasing the risk of CO_2 migration beyond intended storage zones (Iglauer, 2018).

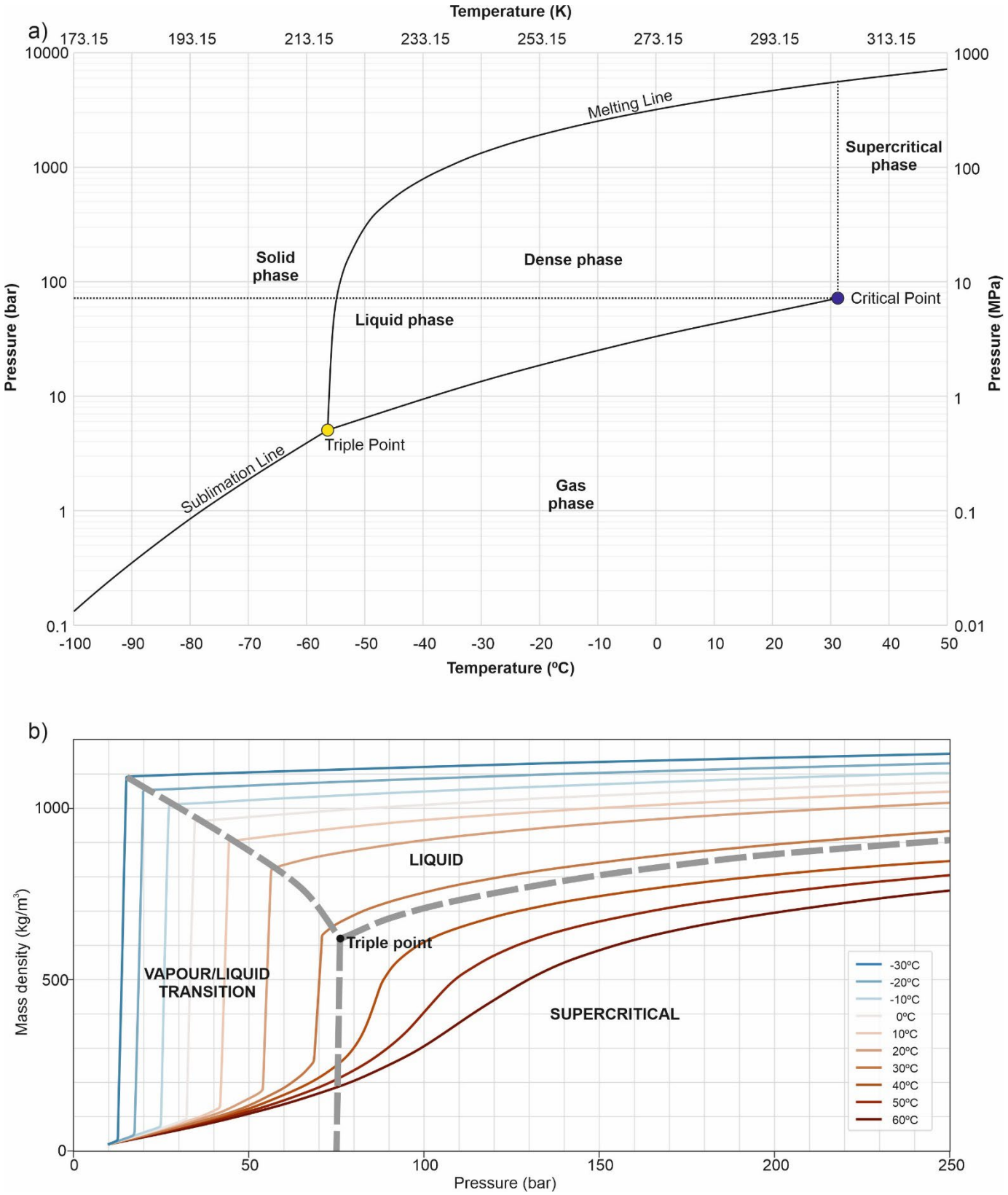

Figure 7: (a) Phase diagram for pure CO_2. Modified from DEA (2021). (b) Mass density of pure CO_2 as function of pressure based on Peng-Robinson equations of state. Modified from: DNV, 2010.

When selecting CO_2 storage sites, other factors beyond porosity and permeability are key to determine their suitability and long-term stability (Table 2). For example, salinity levels in the brine is recommended to be high (e.g. > 30 g/l) to ensure that the water is not suitable for other uses (drinking, irrigation), to avoid potential usage conflicts (Chadwick et al., 2008). Reservoir heterogeneity can impact injectivity and capacity either positively or negatively, influenced by variations in reservoir properties and their effect on fluid flow. Uniform stratigraphy in a reservoir simplifies CO_2 injection and storage processes, enhancing the predictability of the

CO_2 plume behaviour and the reliability of storage operations. However, heterogeneity can also be beneficial, as seen in the Sleipner project where shale baffles improved trapping efficiency by creating barriers that slowed the upward migration of CO_2, thereby enhancing its dissolution into the surrounding brine (Williams and Chadwick, 2021). It is thus crucial to thoroughly understand the reservoir's stratigraphy to accurately model its characteristics. Additionally, maintaining reservoir pressure well below the fracture pressure of the seal is essential to minimize the risk of geomechanical effects, such as induced seismicity or ground deformation, and to maximize the CO_2 storage capacity without risking the integrity of the storage site (Rutqvist, (2012).

Additional complexity is introduced if the storage complex is in a tectonically active area. For this reason many early storage projects have been selected in tectonically quiet areas. However, this is not always possible (e.g. Japan and Indonesia). In such cases, careful consideration of the geological conditions must be observed when addressing the characterisation and monitoring of these sites, including (Tsuji et al., 2014): (1) Heterogeneous geological formations in plate convergent margins are more complex than large reservoirs in the interior of plates, resulting in more complex geological models. (2) These are often regions with limited geophysical data, hence requiring innovative approaches to characterise the reservoirs from sparse data. (3) These are areas prone to natural earthquakes, requiring careful monitoring and control of pore pressure variations to differentiate natural and engineered events and to mitigate the risk of fault reactivation induced by CO_2 injection. And (4), given the necessity for long-term monitoring in CCS, which may span over a century, robust and continuous monitoring strategies are crucial, particularly in lithologies with heterogeneous features such as faults or fractures. With these particular aspects in mind, the Nagaoka CCS pilot (Chiyonobu et al., 2013) and the Tomakomai CCS demonstration projects (Tanaka et al., 2014) were developed to define and refine methods for reservoir characterization and monitoring of CO_2 injection in tectonically active regions.

Trapping mechanisms

After its injection into the reservoir, the CO_2 is subject to different processes that immobilise and retain the CO_2 in the reservoir, preventing its escape, or leakage, to the surface (IPCC, 2005). These so-called *trapping mechanisms* act at different rates through time, gradually decreasing the chances of the CO_2 to return to the surface, and hence increasing the security of the storage.

The trapping mechanisms for CO_2 can be broadly classified into chemical and physical entrapment, each playing a distinct role in ensuring the safe and long-term storage of CO_2 (Figure 8).

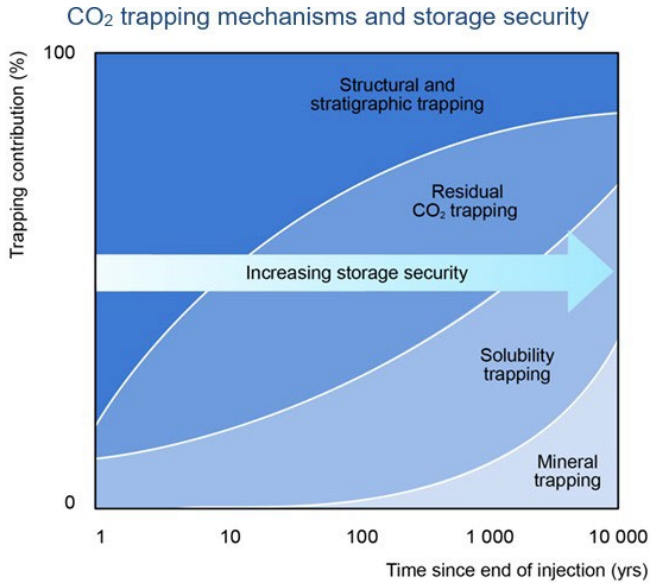

Figure 8: After the CO_2 injection in the reservoir, different trapping mechanisms work at different rates over time, gradually increasing the overall security of the storage. Source: IEA (2022).

Physical Trapping: involves retaining the injected CO_2 in its original physical state within the geological formation. After injection, the movement and spread of CO_2 are constrained by physical barriers, typically the

caprock or other impermeable geological features like faults. These natural barriers act like a seal effectively trapping the CO_2, preventing it from migrating upwards or out of the designated storage area. This form of entrapment dominates in the initial stages of CO_2 storage, providing immediate and effective containment.

1. **Structural and Stratigraphic Trapping**: This is the primary initial trapping mechanism and involves the physical trapping of large connected volumes of CO_2 beneath geological formations that act as barriers (Iglauer, 2018). Structural traps are formed by the geological features such as folds or faults in the rock layers, while stratigraphic traps result from variations in rock types and their properties. In both cases, the buoyant CO_2 is injected into a porous rock formation (reservoir), and the impermeable rock layer above it prevents the upward migration of CO_2. This type of trapping relies on the integrity of the caprock to ensure that CO_2 doesn't escape. This mechanism defines the geometry of the store where other permanent mechanisms occur but it does not directly immobilize the CO_2 itself (IPCC, 2005).

2. **Residual Trapping**: After CO_2 injection, some CO_2 becomes trapped as micro bubbles in the pore spaces of the reservoir rock due to capillary forces. While the CO_2 travels through the reservoir, a fraction of the CO_2 becomes disconnected and immobile. This process, known as residual trapping, occurs when CO_2 droplets are immobilized in the pore spaces, surrounded by the brine (Burnside & Naylor, 2014). The CO_2 is isolated as discrete, disconnected bubbles inside pores and separated by narrow pore throats filled with brine. The bubbles cannot easily move through the narrow pore throats so are effectively trapped. Over time, a significant portion of the injected CO_2 can be trapped by this mechanism, enhancing the storage security.

Chemical Trapping: This occurs through a series of geochemical interactions between the injected CO_2, the formation brine, and the surrounding rock. These interactions lead to changes in the physical and chemical properties of the CO_2, ultimately resulting in its transformation. In this process, CO_2 ceases to exist as a separate, identifiable phase – either mobile or immobile – as it gets chemically incorporated into the brine or the rock matrix. This transformation is a key factor in enhancing the storage capacity and is particularly significant for the long-term containment of CO_2. The chemical reactions often involve the conversion of CO_2 into stable mineral compounds within the geological formation, ensuring its permanent immobilization. The most significant chemical mechanisms are:

3. **Solubility Trapping**: Solubility trapping occurs when the injected CO_2 dissolves in the formation water (brine). This dissolution process is gradual and depends on the pressure, temperature, and salinity of the brine. As CO_2 dissolves, it forms a slightly acidic solution, which can react with minerals in the rock, leading to the fourth mechanism, mineral trapping. Solubility of CO_2 in saline water depends on the temperature, pressure, salinity of the formation water and the type/composition of the formation rock (De Silva et al., 2015). The solubility of CO_2 in the brine increases with increasing pressure and decreases with increasing temperature, and salinity level (Ennis-King and Paterson, 2001; Portier and Rochelle, 2005; Darwish and Hilal; 2010). CO_2 saturated brine is more dense than unsaturated brine so tends to sink to the bottom of the storage reservoir, reducing the likelihood of leakage to surface.

4. **Mineral Trapping**: This is the most permanent but slowest form of CO_2 trapping. It involves the chemical reaction between the dissolved CO_2 and the minerals in the rock to form stable carbonate minerals such as calcite (Liu and Maroto-Valer, 2011). This process effectively locks the CO_2 into solid form within the rock formation, ensuring long-term stability. The pH of the brine acts as a buffer, controlling the rate of these mineralisation reactions. However, mineral trapping is a relatively slow process and may take hundreds to thousands of years to significantly immobilize large quantities of CO_2. This is the dominant mechanism acting in CO_2 injection into basalts, where the rates are orders of magnitude greater (e.g. at the Carbfix project, more than 95% of the injected CO_2 was mineralised within the first two years of operation, Snaebjornsdottir et al., 2020, Holdsworth et al., 2024).

3. CO_2 Injection in the reservoir

The operation of a commercial CCS project involves the sustained injection of CO_2 in the reservoir, often at a Mt-scale. The injection process of CO_2 begins at the surface with the preparation of CO_2 to ensure it is in the optimal phase for injection, based on the specific characteristics of the geological storage site. CO_2 can be injected in supercritical, liquid, or gaseous forms, each selected based on factors such as the depth and

temperature of the reservoir. At depths greater than approximately 800 meters, where pressure and temperature exceed the critical points of CO_2 (7.38 MPa and 31.1°C), it is typically injected in a supercritical state (Figure 2). This state combines the density of a liquid, increasing the storage capacity, with the viscosity of a gas, allowing for higher mass transport efficiency and better distribution across the reservoir (Pruess and Garcia, 2002). If the reservoir conditions are shallower or cooler, liquid CO_2 might be used, requiring pressurization to maintain its liquid form against lower geological pressures (Vilarrasa et al., 2013). For gaseous injection, applicable in less common scenarios with specific geological conditions (e.g. in early stages of injection in depleted gas fields), the CO_2 needs minimal pressurization and is used when the injection pressures required to achieve supercritical or liquid states would risk fracturing the reservoir rock.

The storage operation needs to deal with the CO_2 rates transported from the capture plants, and it involves two main factors: a well system that enables the injection, and a reservoir with characteristics that accept the given injection rates. The injection strategy, well placement and well controls can have strong effects on the storage capacity and are therefore critical to ensure the efficiency and safety of the entire CCS operation (Thanh et al., 2020). Each well requires a tailored design based on reservoir conditions, injection rates, and stream characteristics *(*Acevedo and Chopra, 2017*).* Injection wells can be either vertical or horizontal, with the choice largely dictated by the geological structure of the storage site and the intended injection strategy. Vertical wells are generally less expensive and simpler to drill and are suitable for deep, uniform formations. In contrast, horizontal wells, although costlier and more complex, provide greater exposure to the reservoir, enhancing the injection process by distributing CO_2 more evenly and increasing the contact area with the reservoir rocks without exceeding the formation's maximum allowed pressure (Okwen et al., 2011; Firoozmand and Leonenko, 2024). All wells must adhere to stringent standards to maintain integrity, prevent leaks, and ensure long-term containment of CO_2. This involves the use of durable materials resistant to CO_2 corrosion and the application of advanced cementing techniques to secure the wellbore.

CO_2 injectivity

A critical factor in the success of the storage operation is the CO_2 injectivity. Injectivity refers to the rate and efficiency with which CO_2 can be introduced into a geological reservoir without fracturing the formation (Raza et al., 2015). Injectivity is primarily controlled by the reservoir's intrinsic properties such as permeability, which dictate the ease with which CO_2 can flow through the reservoir, reservoir and caprock's fracture pressures, which indicate the maximum stresses allowed, and injection rates. High permeability facilitates CO_2 migration and enhances overall storage capacity and thus high permeability is a major factor in screening potential storage reservoirs. Should low permeability be unexpectedly encountered in a reservoir, it can severely restrict CO_2 movement, potentially requiring interventions like hydraulic fracturing or acidizing to improve permeability and thus injectivity (Huerta et al., 2020; Hajiabadi et al., 2021). Additionally, formation permeability and thickness are primary variables impacting pressure build-up during CO_2 injection (Ambrose et al., 2008). Thick and highly permeable reservoirs are more suitable for CO_2 storage because they enhance the injectivity, allowing for higher CO_2 injection rates per well. This efficiency in injection rate minimizes the number of wells required to achieve commercial storage targets (Valluri et al., 2021).

During injection, different mechanisms related to the physical-chemical effects of the injection of CO_2 in the reservoir can generate injectivity impairment (Figure 9). Salt precipitation, in particular, is the most reported issue regarding injectivity loss (Table 4). Salt precipitation poses a significant risk to the injectivity as it happens rapidly near injection wellbores, driven by swift precipitation kinetics (Miri and Hellevang, 2016). As CO_2 injection continues, residual formation brines may become oversaturated due to water evaporation into the CO_2 stream; when salt concentration exceeds its solubility limit, salt will precipitate. This process can block pore throats and impair injectivity (Muller et al., 2009). This phenomenon is very well known in the oil and gas industry (Kleinitz et al., 2001; Golghanddashti et al., 2013) and has been observed in several field deployment projects, including the Ketzin project in Germany (Baumann et al., 2014), the Snøhvit project in Norway (Grude et al., 2014), and the Boundary Dam project in Canada (Talman et al., 2020). Additionally, numerous experimental and simulation studies have been conducted to elucidate the mechanisms of salt precipitation, its impact on CO_2 injectivity, and potential mitigation strategies (Miri and Hellevang, 2016; Cui et al., 2023) – remediation techniques including for salt precipitation are covered in section ***Monitoring and management of injection*** below.

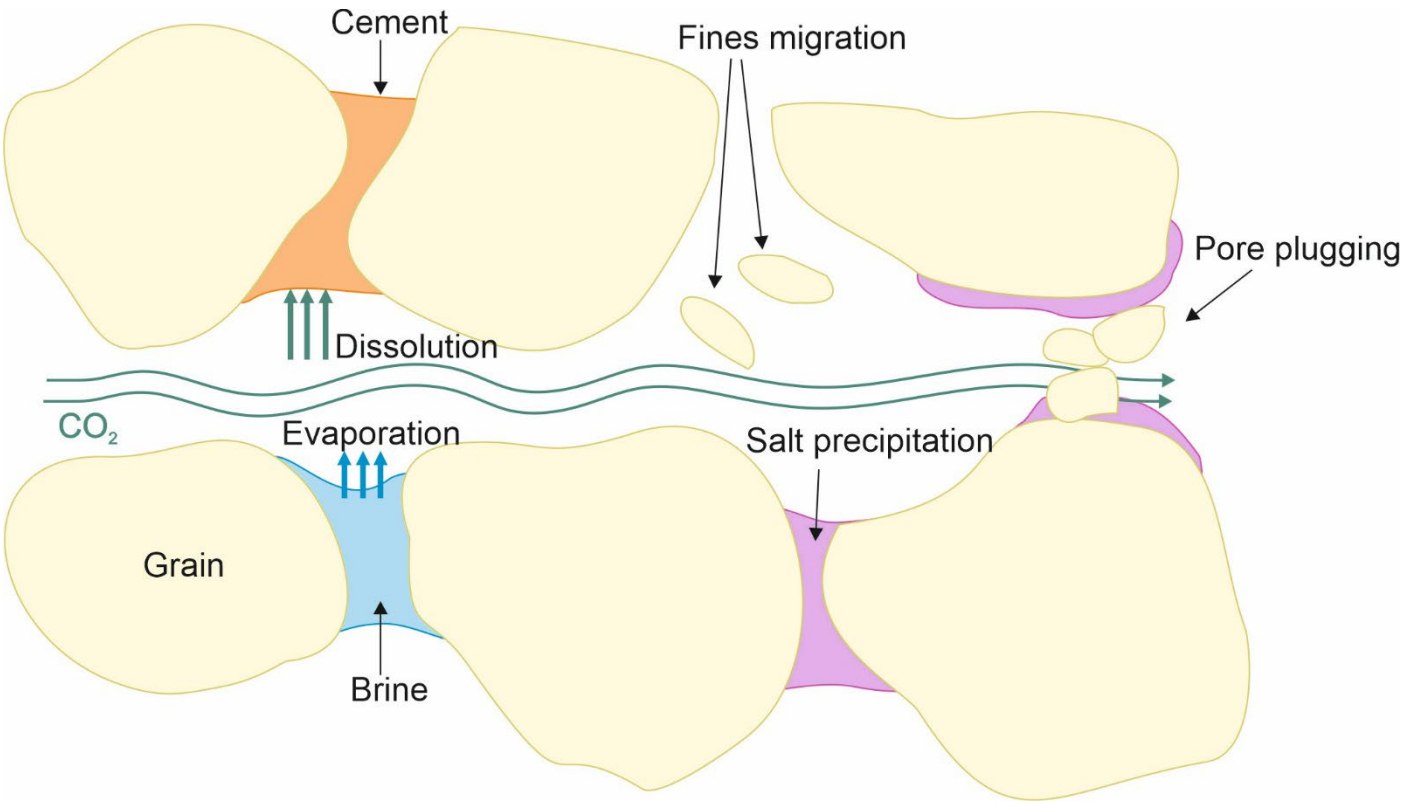

Figure 9: Illustration of the main physical-chemical mechanisms affecting injectivity in the reservoir: mineral dissolution, salt precipitation and fines migration. Modified from Ge et al., (2022).

Table 4: Reported Salt Precipitation Problems in CO_2 Storage Projects. Modified from Darkwah-Owusu et al., 2024.

Storage project	Causes of the injectivity loss	Remediation method	References
Quest CCS	Salt precipitation predominantly	Injection of a water-based fluid to dissolve the halite precipitate	Smith et al., 2022
Sleipner	Salt precipitation, fines	Fresh water stimulation	Kleinitz et al., 2003
Ketzin	Bacterial activity	Nitrogen hydraulic lift	Zettlitzer et al., 2010; Baumann et al., 2014; Köhler et al., 2013
Aquistore	Predominantly salt	Periodic injections of Water	Talman et al., 2020
AEP CCS Research Project	Hydrate-salt (Antarcticite)	Running a gauge ring to physically remove the material and flushing the well with a light brine solution	Sminchak et al. 2014

Torsaeter and Cerasi, (2018) describe several other factors that can create injectivity loss beyond salt precipitation. Fines migration, a phenomenon often observed in waterflooding but less so in CO_2 storage, involves the physical clogging of pore spaces by small particles displaced by the fluid flow. These fines can be present in the injected fluid, enter the stream through contamination from drilling mud or filter cake residues on the wellbore walls, or they may originate from within the rock formation itself, for example when clay coatings are dislodged from minerals. This process can drastically reduce permeability, particularly in unconsolidated sands, where it may also lead to further compaction of the formation (Torsaeter and Cerasi, 2018), but it can also enhance the residual trapping because the pores plugged by fines migration and mineral reactions trap CO_2 (Ge et al., 2022). Laboratory experiments have shown that as little as 0.5wt.% particle concentration in the pore fluid can reduce injectivity in up to 80% (Sokama-Neuyam et al., 2017). Other

chemical interactions, particularly CO_2 solubility in brine, also significantly impact injectivity by altering the rock's physical structure through processes like mineral dissolution and precipitation (Ge et al., 2022). These changes can either enhance or impair CO_2 mobility within the reservoir. For example, the dissolution of minerals, chiefly carbonates, can increase porosity and permeability, whereas precipitation from supersaturated solutions can clog pore spaces, reducing permeability. Ott et al. (2011) observed this effect in an experiment where the injection of $scCO_2$ in a sandstone core increased the effective CO_2 permeability five times, whereas the absolute permeability was reduced by a factor of four. However, other geochemical reactions involving CO_2 and the minerals forming the reservoir (e.g. siliciclastics or carbonates) occur at very slow rates (over 100s of years or even slower) and with relatively minor impact (Wilkinson et al., 2009; Ringrose et al., 2021b)

Brine salinity also impacts injectivity. High-salinity brines, while enhancing gravitational forces and convective mixing at the pore scale, can significantly diminish the dissolution trapping mechanism's efficiency by reducing CO_2 solubility in the brine (Hajiabadi et al., 2021). Othman et al., (2019) describe the impact of brine salinity in permeability as a competition between pore enlargement due to dissolution, dominant in low-salinity water media, and pore blockage due to precipitation and fines migration, where dissolution is greater but so is the number of dislodged fines, leading to permeability decrease. Additionally, bacterial activity can further reduce injectivity, as observed in the Ktzi 201 well of the Ketzin project in Germany (Zettlitzer et al., 2010). Favourable conditions for this bacterial growth included moderate temperatures around 35 °C, lowered salinity due to the use of fresh water during packer activation, and a rich supply of nutrients from organic polymers present in the drilling mud and viscous pills

Borehole deformation, another significant factor, particularly affects soft or weak geological formations (Khodaverdian et al., 2010). This deformation can result from the mechanical stresses induced by injection pressures, leading to wellbore collapse or sand production. Geomechanical and geochemical interactions can also play a critical role in injectivity variations. When clay minerals in shales within the reservoir interact with the injected CO_2 and water, their volume increase, a phenomenon called “clay swelling”, which leads to a reduction in pore space and thus injectivity (Busch et al., 2016). This effect is exacerbated in formations with substantial clay content, not only reducing the injectivity but significantly affecting the formation's mechanical strength (Papamichos et al., 2012), which can lead to shear failure of the caprock or of pre-existing faults (Busch et al. 2010). However, clay swelling can also lead to the closure of fractures or the reduction of fracture apertures, thereby improving seal integrity (Busch et al., 2020). Different clay-swelling inhibitors are commonly used in oil and gas operations (Suter et al., 2011), and could be adapted to CO_2 storage operations.

Hydro-physical effects, including changes in pressure and temperature associated with CO_2 injection, significantly influence the dynamics of subsurface formations and injectivity (Hoteit et al., 2019). When CO_2 in its liquid or supercritical state is injected under surface conditions where the pore pressure is below the bubble point, it is likely to vaporize either within the well tubing or near the wellbore. This phase change from dense to gas state significantly reduces CO_2 density, causing its volume to increase fivefold and its viscosity to halve, which in turn enhances the fluid's mobility and flow velocity. Such drastic changes in density can create backpressure, affecting tubing-head pressure (THP) and reservoir bottom-hole pressure (BHP). Additionally, the vaporization of CO_2 leads to localized cooling, known as the Joule-Thomson (JT) effect. Under these conditions, CO_2 temperature can rapidly drop to −78 °C, potentially leading to the formation of solid hydrate phases in the presence of water and gas (Boufflers et al., 2014). This can impair CO_2 injectivity and pose a risk to well integrity, and can lead to pressure build-up (Mathias et al., 2010). If this pressure exceeds the design limits of the injection infrastructure or the geological containment, it can result in a blowout—a violent release of fluids from the well (Jordan and Carey, 2016). Avoiding the Joule-Thomson (JT) effect poses a significant challenge in depleted oil and gas fields due to the low reservoir pressures that result from extensive hydrocarbon extraction (Mathias et al., 2010). It often involves injection of heated CO_2 or even in gas phase, which can be both expensive and emission intensive (Cerasi et al., 2022). However, not all thermal effects from CO_2 injection are detrimental. For instance, at the Quest CCS project, an injectivity enhancement of up to 10% was observed following the injection of colder CO_2 into a warmer reservoir, a phenomenon potentially attributable to thermally-induced micro-fracturing (Tawiah et al., 2020). Managing these hydro-physical effects is crucial as their impact can vary, and improper handling can lead to reduced injectivity, potentially compromising both the integrity and capacity of the storage site.

Finally, geological heterogeneities such as varying layer properties or composition, or the presence of faults, can lead to uneven CO_2 distribution and localized stress fields. These complications may lead to compartmentalization of the reservoir and varying permeability that can affect the distribution and ultimate storage capacity of the reservoir, thereby indirectly impacting injectivity. Such heterogeneities are often not detectable by standard seismic techniques and are typically identified through detailed core data analysis and history matching (e.g. Ennis-King et al., 2011; Sohal et al., 2021). A clear example of uneven plume distribution is observed in Sleipner, where the presence of thin, intra-reservoir mudstone layers (baffles) partially trapped the CO_2 vertically into multiple layers (Figure 10) (Williams and Chadwick, 2021). While these baffles did not cause injectivity loss, they vertically segmented the storage reservoir preventing fast upward migration of the CO_2, increasing storage security and stability by distributing the CO_2 across various isolated segments. However, this configuration can also lead to compartmentalization and varying permeability that can affect the distribution and ultimate storage capacity of the reservoir, thereby indirectly impacting injectivity. In the Snøhvit field, reservoir heterogeneity in the vicinity of the injection well F-2H did result in lower injectivity than expected (Hansen et al., 2013). The history matching modelling conducted by Ennis-King et al. (2011) on the CO2CRC Otway Project data demonstrated that reservoir heterogeneity, such as the presence of a major shale break, can significantly impact gas migration and storage dynamics during CO_2 injection.

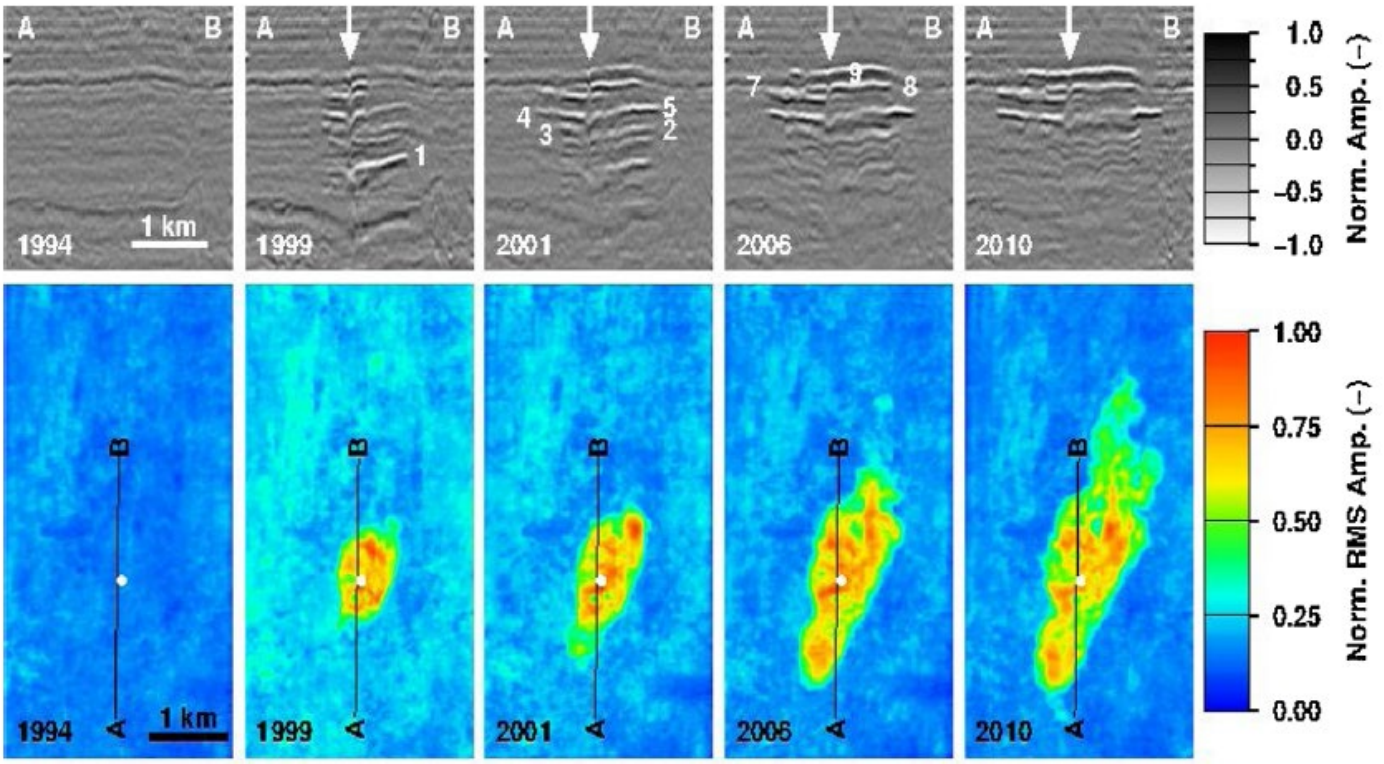

Figure 10: Time-lapse 3D seismic data from Sleipner, featuring the baseline dataset from 1994 alongside a series of subsequent surveys. Top: Seismic sections displaying pronounced reflections from CO_2 plumes, with annotations indicating specific CO_2 layers. Bottom: Reflectivity maps depicting the areal distribution of the CO_2 plume. Modified from Williams and Chadwick, 2021.

These heterogeneities were particularly noted in projects like the Snøhvit field, where they contributed to a heterogeneous CO_2 plume development and varying injectivity issues across different sections of the reservoir.

Monitoring and management of injection

Maintaining CO_2 injection at desirable rates throughout the project life time is important for ensuring the commercial viability of the project (Darkah-Owusu et al., 2024). Injectivity issues have resulted in the abandonment of a number of CCS projects in the past. Huerta et al., (2020) reported the consequences of insufficient injectivity in three different projects: (1) the Midwest Regional Carbon Sequestration Partnership (MRCSP) Phase 2 project was abandoned in 2010 after unsuccessful attempts to stimulate injectivity using hydrochloric acid. (2) the FutureGen 2.0 Project required a costly and complicated CO_2 injection design to overcome the unexpectedly thinner reservoir and low permeabilities (Gilmore et al., 2016). And (3) the low

permeability found at the Wallula storage site casted doubts about the commerciality of the formation for commercial CO_2 storage, although this was a basaltic reservoir (MCGrail et al., 2014). Constraints on injectivity could be a major limiting factor to the global development of CCS, because achieving robust injectivity information (either before committing to develop a store, or even during the operation) can be very expensive (Lane et al., 2021).

The loss of injectivity in the near well can cause not only economic loss, but safety issues, due to the build-up of pressure in the vicinity of the well. This effect was observed in the In Salah project (Algeria), where Interferometric Synthetic Aperture Radar (InSAR) data revealed significant ground uplift (up to 2 cm) and subsequent subsidence around the injection wells, a direct consequence of pressure build-up (Ringrose et al., 2009; Durucan et al., 2011). This build-up caused the tensile opening of pre-existing fractures creating high-permeability channels that resulted in the inhomogeneous spread of the CO_2 plume (Shi et al., 2012; Boholi et al., 2018).

Effective monitoring of injectivity, as evidenced at In Salah, is crucial to ensure the success and safety of CO_2 injection (Hajiabadi et al., 2021). Injection monitoring techniques include tracking pressure build-ups in the well to evaluate the effects of CO_2 on reservoir properties (Sun et al., 2024). In addition to monitoring data, injection management employs various models to determine the maximum sustainable injection pressure and effectively manage pressure build-up. These models analyse hydro-physical, chemical, and geomechanical interactions caused by CO_2 injection to optimize injection processes and maintain the geological integrity of the storage site (Hajiabadi et al., 2021). Different tests comparing pressure rates with other factors such as time, flow rates or injected volumes provide useful information to update and refine these models, and help to identify positive or negative changes in the injectivity. Additionally, monitoring techniques such as seismic tomography, pressure sensors, and tracer tests are utilized during and after CO_2 injection to monitor CO_2 dispersion within the reservoir and detect any potential migration or leakage, providing critical real-time data on the behaviour of injected CO_2, thereby ensuring the success and safety of CO_2 injection for CCS. For example, in the Tomakomai CCS demonstration project (Japan), continuous monitoring of temperature and pressure in two injection and three monitoring wells was complemented with seismic monitoring (Tanaka et al., 2014), and was used to detect the movement of the CO_2 plume and judge the stability of stored CO_2 based on comparisons with the numerical simulation results (Sun et al., 2024).

When injectivity loss is detected, different actions such as re-drilling, hydraulic fracturing, acidizing, or CO_2 injection into reservoir sections with better qualities are commonly used to enhance injectivity (Hajiabadi et al., 2021). For example, at Sleipner, injectivity loss was detected in the injection well 15/9-A-16 immediately after the start of CO_2 injection started in September 1996, attributed to sand influx (Hansen et al., 2005; Ahmadinia and Shariatipour, 2020). To mitigate this issue, the well was re-drilled and equipped with sand screens and gravel packs to achieve stable injection rates, which have kept stable since then (Singh et al., 2010). In Snøhvit, salt precipitation near the wellbore led to reduced injectivity within the first year of operation (Hansen et al., 2013). To remedy this, Methyl Ethyl Glycol (MEG) was injected weekly, which eventually resolved the issue of low injectivity. At the Quest CCS facility (Canada), halite precipitation caused plugging of the perforation tunnel and pores in the near wellbore area, but the injection of a water-based fluid (fresh water, glutaraldehyde and ammonium bisulfite) resulted in an injectivity enhancement of 263% (Smith et al., 2022).

Another commonly used mechanism to mitigate injectivity loss in the hydrocarbon industry is hydraulic fracturing, or fracking. Fracking has been commercially used since the 1950's and is currently used in many/most oil and gas prospects worldwide (Barati et al., 2014). Hydraulic fracturing involves the injection of a fracturing fluid (largely composed of water – 98-99% - sand and chemical additives) in a reservoir to increase the pressure in the reservoir beyond its fracture point, creating fractures that enhance the permeability (King, 2012). Although no CO_2 storage prospects to date have proposed to use fracking it has been mentioned repeatedly in the literature as a potential method to remediate injectivity losses. For example, hydraulic fracturing can be used to enhance near well injectivity and can help to connect two or more high permeability zones that are separated by an impermeable or low-permeability zones (Fu et al., 2017). Huerta et al., (2020) analysed various fracking scenarios involving different horizontal well lengths, number of fractures, fracture geometries, and fracture properties. They observed that these variables significantly enhance injectivity and can increase capacity by 13% to 71% compared to a base case scenario with an unfractured vertical well. However, numerical experiments, such as those conducted by Raziperchikolaee et al. (2013), indicate that fracking can decrease the long-term CO_2 trapping. This occurs because the CO_2

reaches the top seal earlier during injection, reducing its contact with the brine at the bottom of the saline aquifer in the post-injection phase, which leads to less effective long-term residual gas trapping. Mismanaged hydraulic fracturing can also lead to contamination of shallow water and soil resources, fluids escape back to the atmosphere or induced seismicity (Osborn et al., 2011; Holland et al., 2013; Birdsell et al., 2015; Jabbari et al., 2016; Schultz et al., 2020). These factors have contributed to a mostly negative perception of this technique (Thomas et al., 2017), which have even impacted the perception of CO_2 storage as a whole by association (Gough et al., 2017; Cox et al., 2021). Therefore, employing hydraulic fracturing in CO_2 storage is a sensitive issue.

When the pressure resulting from CO_2 injection increases too much (e.g. approaches or exceeds the fracture limit of the caprock), the efficiency of the storage operation is reduced and measures must be taken to mitigate this risk and maintain the structural integrity of the storage site. In such scenarios, a solution can be the production of water/brine from the reservoir formation to alleviate the excess pressure (Bergmo et al., 2011). This technique has been effectively employed in various projects, including the Gorgon project, to ensure that the induced pressures do not compromise the caprock's ability to function as a reliable seal (Chevron, 2022). By managing the pressure in this manner, the project can prevent fracturing and potential leakage, ensuring the long-term stability and safety of the CO_2 storage, and can even help to extend the life of ongoing storage projects (Zhang et al., 2022). The produced brine usually must be treated before its release because they often contain various concentrations of dissolved solids, suspended solids and other contaminants (Kaplan et al., 2017). The results from a modelling experiment described in IEAGHG (2018) suggest that brine production can increase the dynamic storage efficiency from 4.7% to 5.9% in the Minnelusa Formation (USA) and from 4.7% to 7.4% in the Bunter sandstone (North Sea). This is the equivalent of raising the total storage capacity from 202 to 302 Mt of CO_2 in the former example (34% increase) and from 1,770 to 2,806 Mt of CO_2 in the latter (37% increase). The brine production approach not only helps in maintaining the mechanical stability of the geological structures but also in controlling the migration paths of the injected CO_2 (Han et al., 2020).

4. Permanence and security of geological storage

The permanence of CO_2 in geological storage is a critical aspect in assessing the long-term effectiveness and viability of CCS as a climate change mitigation strategy (Alcalde et al., 2018). This concept refers to the ability of underground reservoirs to securely contain injected CO_2 over geological time scales without significant leakage to the atmosphere or biosphere (IPCC, 2005). Ensuring the permanence of CO_2 storage relies on the selection of appropriate geological formations that exhibit both favourable physical and geochemical properties to retain CO_2 (Alcalde et al., 2021). The selected storage sites conventionally have a combination of porous reservoir rock for CO_2 accommodation and impermeable cap rocks to prevent upward migration. Additionally, it is important to ensure well leakage potential is minimised at these sites to maintain the safety of the operations and ensure the secure containment of the stored CO_2 (Watson et al., 2009). The integrity of these elements is as important as the understanding of how CO_2 interacts with reservoir fluids, rock formations and storage infrastructure over time to delivering a permanent secure geological storage site (Gholami et al., 2021).

The following section 'Leakage Risks' addresses specific challenges and mechanisms that influence the security and stability of CO_2 storage over the short term, spanning decades. The subsequent section, 'Monitoring, Measuring, Verification, and Mitigation,' outlines essential measures and strategies for maintaining containment and ensuring the safety of the storage operation. Finally, 'Storage Security in the Long Term' discusses the fate of the injected CO_2 over geological timescales—hundreds to thousands of years—and explores the implications of potential leakage for the effectiveness of CO_2 storage in climate change mitigation.

Leakage risks

CO_2 storage is a key element of the CCS chain that, as with other parts of the value chain, involves a spectrum of potential environmental, economic, social and legal risks that require a range of tailored management approaches. The risk of leakage from a storage site is highest during initial injection activities, primarily due to geological complexities and insufficient data to fully understand the impacts of CO_2 injection (Figure 11),

but usually decreases over time as operational data is used to reduce uncertainties. Understanding and managing these risks is thus crucial to ensure the effectiveness, security and sustainability of the CO_2 storage operations (Gholami et al., 2021).

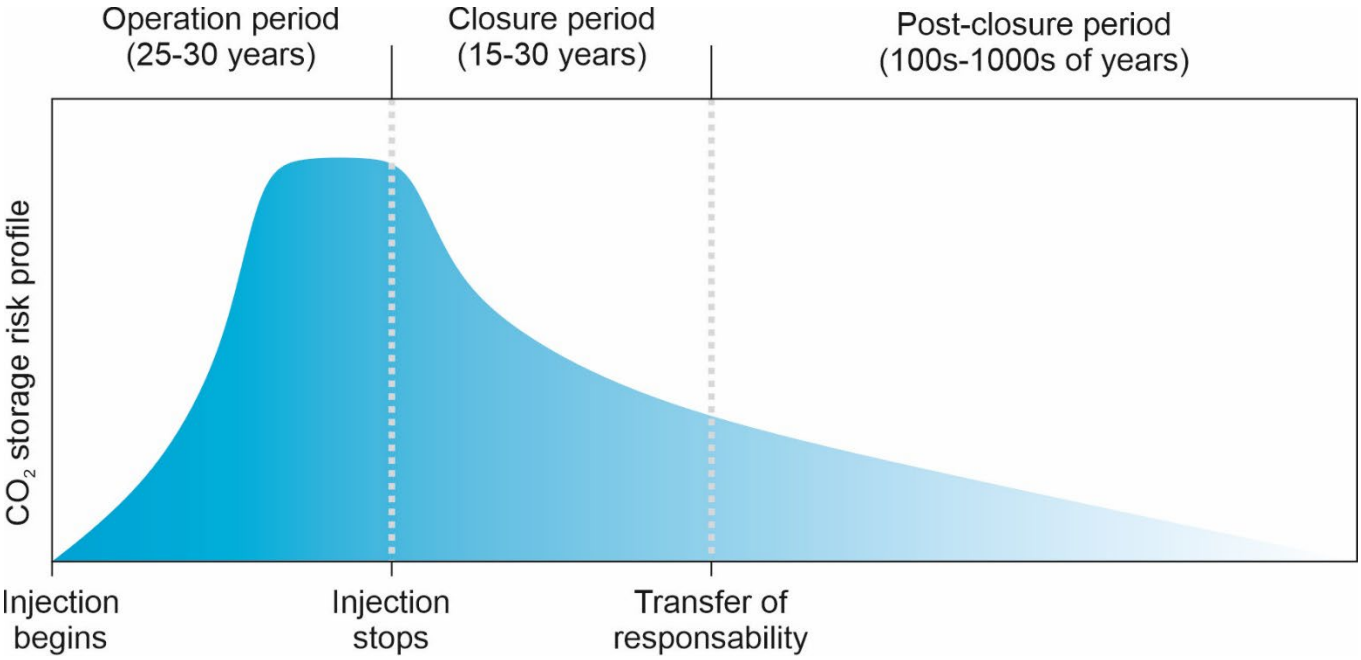

Figure 11: Conceptual risk profile of CO_2 storage in geological porous media. Modified from Benson (2007).

In addition to the risks related to the injection operations, described in Section 3, the leakage of CO2 back into the atmosphere is often regarded by stakeholders as the most significant risk, as it can cause environmental and health issues and, in the long term, negate the climate benefits of CCS (Table 5) (Gholami et al., 2021). This risk underscores the need for careful site selection, rigorous monitoring, and the development of strategies for remediating leakage pathways (Figure 3) (Pawar et al., 2015). Since CCS is not yet deployed at a large scale, learning from natural and engineered analogues (e.g. hydrocarbon or geothermal industries) provides valuable insights into the long-term behaviour of geological storage helping to model, predict and mitigate potential leakage scenarios effectively (Jeandel et al., 2010; Miocic et al., 2013; Alcalde et al., 2018). As noted by Koornneef et al. (2012), the severity of consequences from CCS failures varies with the flow rate of CO_2 escape. High flow rates, more typical of transport failures, can have immediate safety implications, whereas lower, diffuse emissions from storage operations might pose long-term health risks. At the same time, large emissions are more easily detected and thus can be more readily addressed, allowing for quicker implementation of corrective measures. This distinction illustrates that while leakage to the atmosphere is a concern, the likelihood and potential impacts differ substantially between transport and storage phases of CCS operations.

Table 5: Summary of key risks of storage and potential impacts from those risks. Modified from de Coninck and Benson (2014). In terms of management approaches, most risks can be mitigated with effective site selection and monitoring and remediation of the leakage pathways (if any). Additional mitigation strategies can include administrative controls, ecosystem clean-up, regulatory measures to prevent induced seismicity, well integrity assessments, and socio-economic measures such as stakeholder engagement and impact assessments. Integrated resource management and regulatory frameworks are also essential for addressing resource competition and cross-boundary issues.

Categories	Key Risk	Potential Impact
General risks	Leakage of CO_2 into the atmosphere	Ineffectiveness of CCS for climate change mitigation
	Accumulation of elevated CO_2 concentrations in ecosystems	Damage to CO_2-sensitive habitats
	Accumulation of elevated CO_2 concentrations where humans can be exposed	Chronic or acute health concerns from CO_2 exposure
	Leakage of CO_2 to groundwater	Acidification of groundwater and potential dissolution of toxic minerals

	Induced seismicity	Potentially felt ground motion and structural damage
	Subsidence or ground deformation	Potential damage to surface infrastructure
Site specific risks	Leakage of hydrocarbons to groundwater	Contamination of groundwater with organic compounds
	Displacement of saline brine into drinking water aquifers or surface water	Contamination of groundwater or surface water with dissolved salts
Socio-economic risks	Land use changes	Disruption of existing land uses, potential conflicts with agricultural or recreational areas
	Reduction of property values	Decrease in real estate values due to perceived risks or actual impacts of nearby CO_2 storage sites
	Public perception and acceptance	Negative public sentiment leading to opposition and potential project delays or cancellations
	Local economic shifts	Shifts in local economies that could result from changes in land use or property values; potential job losses in some sectors and gains in others
Geopolitical and legal risks	Resource competition	Interaction between the CO_2 storage facilities and other users of the subsurface
	Cross-boundary issues	International legal and diplomatic challenges

However, to fully understand the impact of potential leaks, the volume leaked alone is insufficient; the probability of occurrence and local conditions are crucial when assessing risk with quantitative indicators (Koornneef et al., 2012). A report by the Zero Emissions Platform (ZEP, 2019) evaluates ten potential CO_2 leakage scenarios at a storage site in the North Sea, detailing their likelihood, impact, duration, and financial costs (Table 6). The scenarios range from minor leaks to significant failures, with injections planned over 50 years at depths between 2000-3000 m, involving one operational and one abandoned well. The probabilities are calibrated to reflect the chance of occurrence within a 500-year timeframe post-injection. The authors of the report emphasise that, despite the detailed exploration of these scenarios, the overall probability of any such event occurring is considered extremely low: all the scenarios listed have a less than 1% chance of occurring over 500 years.

Table 6: Summary of ten theoretical leakage scenarios for a CO_2 storage site in the North Sea over a 500-year timeframe, detailing the probability of occurrence, peak leakage rates, duration, total and risked leaked mass, and associated remediation costs. The assumed case is a storage site injecting a total of 100 Mt tonnes at 2000-3000 m depth, over a period of 50 years. Modified from ZEP (2019).

Scenario	Probability over 500 years including lifetime of the project and post closure (%)	Peak leakage rate (t/d)	Duration of leak	Total mass leaked (tonnes)	Risked leaked mass (total mass leaked * probability of occurrence, in tonnes)	Percentage of the total amount injected (%)
Minor leakage; fault & fracture	0.2	100	50 years	1,825,000	3,800	0.000038
Moderate leakage; fault & fracture	0.05	700	12 years	3,066,000	1,550	0.000016

Severe leakage; fault & fracture	0.005	5,000	4 years	7,300,000	365	0.000004
Active well leakage	0.5	50	250 days	12,500	62.5	0.000001
Active well blowout	0.15	5,000	250 days	1,250,000	1,875	0.000019
Abandoned well blowout	0.1	3,000	1 year	1,095,000	1,100	0.000011
Seepage in abandoned well	0.5	7	100 years	255,500	1,250	0.000013
Severe well problem, no repair successful	0.005	6,000	2 years	4,380,000	215	0.000002
Leak from installation	0.25	100	5 days	500	1.25	0.000000
Undesired plume spread	0.03	0	N/A	N/A	N/A	0.000038
Total					**10,219**	**0.000102**

Natural features, such as faults and fractures in the caprock, can serve as potential conduits for CO_2 escape if not properly identified and managed. These geological discontinuities may become reactivated due to changes in pressure induced by CO_2 injection, potentially creating pathways for CO_2 to migrate upwards or into adjacent formations (Song and Zhang, 2013). Additionally, permeable or semi-permeable faults or fractures that were overlooked during the characterization phase can also become leakage pathways or may be reactivated, potentially causing damage to the caprock's integrity and increasing the risk of CO_2 leakage (Blanco-Martín et al., 2022). However, as noted by Miocic et al. (2016), the majority of naturally occurring CO_2 accumulations do not show evidence of CO_2 leakage to the surface, suggesting that the probability of natural open pathways being present and leading to leakage can be generally considered low. Capillary leakage through the caprock, where CO_2 overcomes the capillary entry pressure and migrates through pores or fractures, poses a risk, especially if the caprock's integrity is compromised or if it is inherently weak (Song and Zhang, 2013). However, diffusive leakage through an intact caprock is considered very unlikely because caprocks are typically water-wet, and the capillary entry pressure for CO_2 is considerably high (Postma et al., 2019).

An important aspect to monitor during the injection operations are the geochemical processes occurring in the reservoir, that can affect the mineralogical structure and thermodynamic equilibrium of the reservoir (Gaus, 2010). The injected CO_2 is soluble in the brine present in the reservoir, more so if it is in super critical state (Portier and Rochelle, 2005). When CO_2 dissolves in water, it forms carbonic acid (H_2CO_3), which dissociates in the brine, leading to a drop in pH and initiating reactions with the minerals in the host rock and cement. It is important to monitor this acid-induced reaction, as it can directly impact the well surrounding by altering rock porosity and permeability. Additionally, interactions with alumino-silicate minerals, such as clays and feldspars, play an important role in the permanent trapping of CO_2. These reactions, occurring over thousands of years at low temperatures (30-50°C), contribute to the long-term stability of CO_2 storage by forming secondary carbonates like calcite ($CaCO_3$), dolomite ($CaMg(CO_3)_2$), siderite ($FeCO_3$), and dawsonite ($NaAlCO_3(OH)_2$) (Xu et al., 2003). Each reaction, with its unique kinetics and environmental conditions, can positively or negatively affect the reservoir's physical properties and the efficacy of CO_2 storage. It is important to ensure that injected CO_2 does not interact with or contaminate ground or drinking water. Risks such as the acidification of groundwater or the unintended release of harmful minerals demand robust monitoring systems and strategies to minimise the potential for (and mitigate if needed) any adverse impacts on water quality.

This is particularly important to safeguard drinking water sources and maintain ecological balance (see section 5).

Any changes in reservoir pressure and temperature, even small ones, can induce stress-and-strain alterations in and around the injection zone (Figure 12). These alterations can in turn produce local permeability reduction (Rutqvist, 2012), induced seismicity (Vilarrasa et al., 2019; Cheng et al., 2023) or ground deformation (Murdoch et al., 2020). A major consideration during the injection phase is the potential pressure build-up, which could reduce the dynamic capacity of the reservoir (Anderson and Jahediesfanjani, 2019), potentially lead to the reactivation of faults (Cerasi et al., 2018), and/or promote acid-driven mineral dissolution which can weaken the caprock (Fitts and Peters, 2013). Extreme cases of these risks can cause ground motion and structural damage, which can have direct impacts on surface infrastructure and local communities. Managing these risks involves a combination of careful site selection, monitoring, and regulatory measures designed to limit pressure build-up and adjust injection rates as necessary.

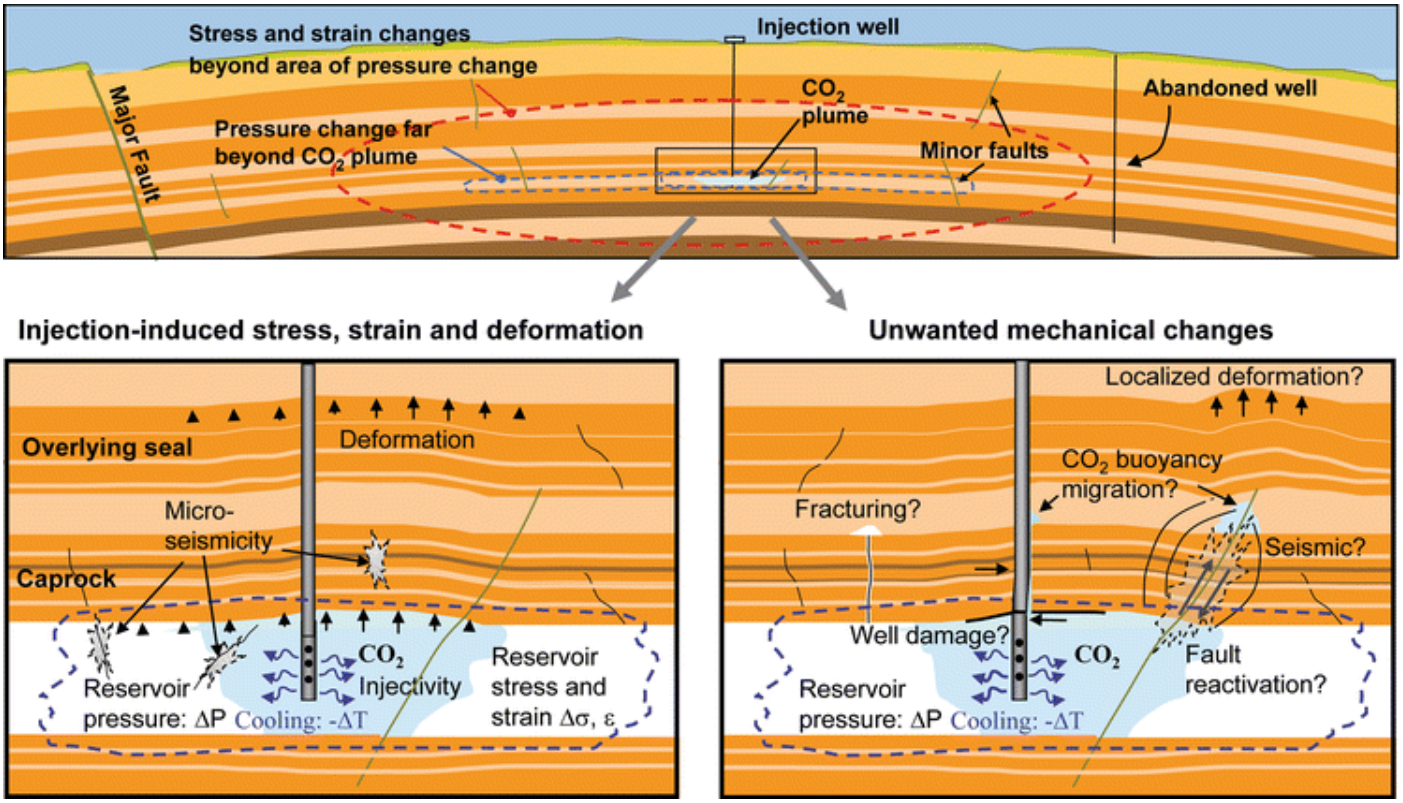

Figure 12: Geomechanical processes and technical issues derived from the injection of CO2 in a reservoir. From Rutqvist, (2012).

Well integrity is also critical to prevent the uncontrolled release of fluids, either rapidly (blowouts) or slowly but continuous (leakage or seepage) (Oldenburg & Lewicki, 2006; Jordan & Benson, 2009). Mitigating this risk requires a comprehensive assessment of injection well integrity and the use of blowout preventers, alongside adjustments in drilling and injection rates, which are standard practices in the oil and gas industry. Abandoned wells penetrating the storage reservoir can also be pathways to leakage, depending on their abandonment conditions and status. In such circumstances, leakage can occur along the interfaces between cement and steel casing, within the cement matrix due to its degradation, or through holes in the steel casing caused by corrosion (Gasda et al., 2004). Additionally, fractures in the cement, as well as the interfaces between cement and the surrounding rock, can also be potential sources of leakage. Assessing the integrity of legacy wells and planning any necessary remedial work is a crucial part of the exploration and construction phase for a storage site, and is required by regulation.

Regarding the potential impacts of leakage, while the risk of CO_2 or CO_2-enriched brine leaking from geological storage sites is low, any potential leakage could affect the quality of overlying fresh groundwater resources (Lions et al., 2014). The mixing of CO_2-brine with fresh groundwater is likely to result in a reduction of pH levels, leading to more acidic conditions (Trautz et al., 2013). This change in pH, coupled with alterations in redox potential, can disrupt microbial metabolism in the water (Noble et al., 2012; Schulz et al., 2012). Additionally, this interaction can trigger the mobilization of contaminants, such as Pb, As and U (Zheng

et al., 2021), thereby posing a risk to the safety and usability of these groundwater resources. Beyond the direct impact on groundwater, CO_2 migration into the vadose zone (the area between the ground surface and water table) can lead to its accumulation in soil gas (Gasparini et al., 2015), which may have negative effects in plant growth (Gupta & Yadav, 2020). This, in turn, can result in the release of CO_2 into the atmosphere or its accumulation in surface water, both of which are considered potential environmental hazards. Although there has been no known incident of CO_2 contaminating groundwater to-date, these risks highlight the need for careful monitoring and management of CO_2 geological storage sites to protect vital groundwater resources.

Although carbon dioxide (CO_2) is neither toxic nor flammable, the sudden release of CO_2 can create safety hazards. For example, exposure to high concentrations of CO_2 in the air (over 10% by volume) can pose physiological hazards, potentially leading to asphyxiation (Gale and Davison, 2004). Therefore, it is imperative that any CO_2 storage operation includes a robust Monitoring, Measurement, Verification, and Mitigation (MMVM) program to detect any signs of leakage and ensure containment integrity, which is described in detail in the following section.

Beyond the direct environmental impacts, CO_2 storage projects, like all major infrastructure developments, also intersect with socio-economic and geopolitical domains. Issues like land use changes, public perception, resource competition, and cross-boundary legal challenges highlight the need for a holistic approach to project planning and execution. This involves engaging with local stakeholders, conducting comprehensive impact assessments, and developing regulatory frameworks that balance diverse interests and uses of subsurface resources.

Monitoring, Measuring, Verification and Mitigation

The processes of monitoring, measuring, verification, and mitigation (MMVM) are crucial for ensuring the effectiveness, safety, and environmental compliance of the storage operations.

Monitoring is a continuous process that tracks the behaviour of injected CO_2, the integrity of the storage site, and any environmental impacts. Monitoring activities must be customized to address the risk and uncertainties of specific storage sites (NSTA, 2022). In terms of its spatial extent, monitoring can be classified in three categories: atmospheric, near-surface, and subsurface monitoring, each targeting different aspects of the environment and storage integrity (Brown et al., 2009).

Atmospheric monitoring tracks changes in the air directly above the storage site, often using satellite-based measurements or directly installed at the surface, to detect any CO_2 that might be escaping into the atmosphere (Jenkins et al., 2008; Zhang et al., 2021). Satellite-based surface deformation analysis allows for the precise detection of subtle changes in the Earth's surface that can indicate the movement or migration of subsurface fluids, either as uplift or subsidence, that could signify leakage or unexpected distribution of injected CO_2 (Ringrose et al., 2009).

Near-surface monitoring involves the analysis of soil and water near the storage site. This includes the measurement of soil gas compositions and water quality to detect any signs of leakage or migration of CO_2 towards the surface (Romanak and Bomse, 2020). May and Waldmann (2014) describe the methods that can be used to monitor shallow environments; these include: (1) groundwater monitoring uses sensor-based technologies to provide continuous online observations in monitoring wells, assessing groundwater quality near potential leakage pathways. (2) Areal groundwater resistivity mapping employs airborne or ship-towed electromagnetic mapping to detect changes in resistivity. (3) Gas emissions detection involves planes or helicopters performing multispectral scanning to rapidly identify vegetation stress and changes, with land-based mobile infrared systems specifically targeting CO_2 anomalies. (4) Sonar equipment for underwater monitoring to identify bubble streams.

Subsurface monitoring delves deeper, focusing on the reservoir and caprock, and including faults, wells, and seals (Ajayi et al., 2019). Subsurface monitoring can be done using direct methods (i.e. measurements taken directly in the reservoir, such as sensors placed in wells) or indirectly (i.e. measurements taken from the surface, geophysical methods).

Often, storage sites include monitoring wells drilled specifically for direct monitoring purposes. Different measurements are commonly done in these wells using wireline logging systems, including conductivity, pressure, temperature, acoustic velocity, nuclear magnetic resonance (NMR), electrical and electromagnetic responses, borehole images, and formation fluid composition (Harbert et al., 2016). Geochemical monitoring methods involve the analysis of water and gas samples taken from the reservoir to detect changes in composition that could indicate CO_2 leakage or interaction with the reservoir rock. For example, changes in the concentration of certain ions or gases can signal interactions or leaks. Added tracer compounds to the CO_2 stream can help to detect the arrival of the CO_2 plume to the monitoring wells (Boreham et al., 2011). Emberley et al (2004) describe how measured changes in inherent fluid compositions (rather than added tracers) such as pH, concentrations of HCO_3, Ca, Mg, and $\delta^{13}CO_2(g)$, allowed them to identify areas in which injected CO_2 dissolution and reservoir carbonate mineral dissolution occurred after just 6 months after the injection begun at the Weyburn project.

The injection of CO_2 can also alter the temperature and pressure within the reservoir, potentially leading to changes in the stress regime. Temperature and pressure sensors placed in the injection well or at certain distances in these monitoring wells, can also provide dynamic information about the CO_2 behaviour in the subsurface (Bielinski et al., 2008; Nogues et al., 2011; Zheng et al., 2022). For example, temperature anomalies along the wellbore could suggest the migration of the CO_2 along the wellbore (Mawalkar et al., 2019). Monitoring the strain field in CO_2 storage is also helpful for identifying and mitigating geomechanical risks such as fault slips and CO_2 leakage, thereby ensuring safe and effective storage (Murdoch et al., 2020). These temperature and stress changes often propagate at a different rate than the CO_2 plume itself, adding another layer of complexity to monitoring efforts.

Indirect methods include a variety of geophysical techniques that assess changes from the surface or near-surface. When CO_2 is injected into a reservoir, displacing the brines in the pores, it alters the physical properties of the reservoir due to its distinct characteristics compared to brine. By comparing the reservoir's properties before injection ("baseline") with those after injection, effective monitoring can assess the behaviour and extent of the CO_2 plume. For instance, seismic monitoring techniques are sensitive to changes in the propagation velocity and density, together defining the “seismic impedance”, of the reservoir materials caused by the introduction of CO_2 (Lüth and Liebscher, 2017). Controlled-source seismic methods (also called “active seismics”) employ energy sources (e.g. vibrator trucks, explosives or air guns) to generate seismic waves that propagate through the geological media and that are recorded in sensors. The way in which these waves propagate is defined by the properties of the energy source, of the sensors and, most importantly, of the subsurface. Seismic methods are particularly well suited for CO_2 storage monitoring in saline aquifers because of the large impedance contrast between brine and free phase CO_2, but not so much in depleted oil and gas fields because of the small contrast between the initial reservoir conditions and those after starting CO_2 injection (Lüth and Liebscher, 2017). This seismic monitoring is usually carried out in 3D and repeated in time to track changes in the plume, hence called 4D seismic monitoring (Lumley, 2010) (Figure 10). 4D seismic is considered one of the most important monitoring methods because it can visually track the spatial and temporal migration of CO_2 within the reservoir. It has been used in several storage sites around the world, such as Sleipner (Arts et al., 2010), Weyburn (White et al., 2011), Decatur (Kaven et al., 2014) and Quest (Harvey et al., 2022).

The injection of CO_2 produces an alteration in pore pressure and effective stresses within and around a reservoir, potentially reactivating pre-existing faults and fractures or creating new fracture networks. These geological changes can emit seismic energy, often in very small magnitudes (micro-earthquakes), but detectable by geophones installed in nearby boreholes or the surface (Ugalde et al., 2013). Through monitoring, variations in microearthquake frequency can be linked to fluctuations in fluid-injection rates and pressure disturbances (Bonhoff et al., 2010). Passive seismic monitoring, which records continuously and allows for near real-time analysis, is limited to imaging areas between active micro-seismic events and the locations of receivers. While 4D controlled-source seismic methods are suitable for detecting changes in fluid saturation and stresses, passive seismic excels at identifying geomechanical deformations induced by injection (Verdon et al., 2010). This monitoring is vital for detecting active or newly formed fractures in the caprock, which are critical for maintaining CCS integrity, as these fractures could provide pathways for CO_2 leakage if they propagate extensively into the overburden.

Additionally, gravity surveying detects variations in subsurface density, which change as the less dense CO_2 displaces the brine, providing vital data on the extent of the plume and even the rate of dissolution of the

CO_2. For example, Alnes et al. (2011) conducted gravity measurements above the Sleipner field and used them to estimate the CO_2 density at the reservoir, which indicated that the CO_2 had not yet dissolved at the time of the measurements. Furthermore, the resistivity of the reservoir rock significantly increases when the highly resistive CO_2 displaces the highly conductive brine in the reservoir (Bergmann et al., 2012). This can be observed using electromagnetic, such as electrical resistivity tomography (ERT) or controlled source electromagnetic (CSEM), which track changes in resistivity as CO_2 saturation increases using electrodes installed in wells (Carrigan et al., 2013; Vilamajó et al., 2013). Other electromagnetic methods, such as magnetotellurics, track resistivity changes using electrodes installed on the surface (Ogaya et al., 2013). In general, electromagnetic methods offer an advantage over seismic methods due to the relatively consistent change in electrical resistivity with changes in CO_2 saturation, whereas seismic P-wave velocity shows a more nonlinear response, making electrical methods especially well-suited for estimating CO_2 saturation in a reservoir (Breen et al., 2012).

Measuring involves quantifying the amount of CO_2 injected and its distribution within the storage site. This is accomplished through various techniques such as mass flow meters at injection wells, downhole pressure and temperature sensors, and seismic imaging to visualize CO_2 distribution underground (Chadwick et al., 2019).

Verification, often a regulatory requirement, ensures that the storage project adheres to stated goals and safety standards. Oldenburgh (2018) defines two terms relevant to this process: *concordance*, which refers to the agreement between models and data, and *performance*, which relates to the agreement with permit requirements (Jenkins et al. 2017 employ the term *conformance* instead of *concordance*). Verification (concordance+performance) involves the independent assessment of data collected through measuring and monitoring activities, confirming that CO_2 is being stored securely and effectively (Barros et al., 2021). For example, Shi et al. (2019) employed history matching methods that combined reservoir simulation, injection pressure analysis, and microseismic monitoring data to enhance understanding of the injection processes at the In Salah storage site. These concepts are important in verifying the accuracy of the predictive models and ensuring compliance with regulatory frameworks. Chadwick and Noy (2015) consider the following conformance indicators: plume footprint area, maximum lateral migration distance of CO_2 from the injection point, area of CO_2 accumulation trapped at top reservoir, volume of CO_2 accumulation trapped at top reservoir, area of all CO_2 layers summed, and spreading co-efficient.

Mass balance verifications, which track the volumes of injected CO_2, are also useful to confirm that they are confined to the designated storage zones and align with the emission limits established prior to the start of these projects (Gasperikova and Hoversten, 2008). Bulk changes of mass can be calculated from monitoring of gravity changes (Kim et al., 2015). These verifications help demonstrate both concordance and performance by ensuring that the actual behaviour of the stored CO_2 matches the predictions and adheres to the stipulated safety and environmental standards. Mass balance and geochemical monitoring, particularly through stable isotope mass balance, can play a crucial role in distinguishing the origin of CO_2 in shared subsurface environments, such as those involving both CCS and CO_2-EOR projects. By analysing carbon isotope ratios, it becomes possible to trace the fate of injected CO_2 and confirm its source, because CO_2 from different sources exhibits distinct isotopic signatures. For example, Mayer et al. (2013) analysed carbon isotopes from over a decade of sampling in the IEA GHG Weyburn-Midale CO_2 Monitoring and Storage Project in Canada. They successfully distinguished the carbon isotope ratios of the injected from these of background CO_2 and HCO_3^- in the reservoir, allowing them to infer the fate of the injected CO_2, including its movement, dissolution and trapping.

Another potential method in this area is the use of geochemical tracers, which are detectable at low concentrations within the CO_2 due to their minimal background levels in the atmosphere or storage complex (Flude et al., 2016). By comparing the composition of the injected CO_2 with that of the sampled atmosphere or reservoir gases, detailed insights into the migration and fate of the CO_2 can be obtained (Stalker et al., 2009). It is thus imperative to have comprehensive baseline conditions to be able to effectively observe changes produced by potentially leaked CO_2. The addition of geochemical tracers for environmental monitoring and interpretation of reservoir dynamics is a long-standing practice in the hydrocarbon industry, but its cost and environmental impact makes them potentially less suitable for CO_2 storage monitoring (Flude et al., 2016). Instead, using the isotopic and trace element geochemistry of the injected CO_2 itself as a tracer offers an innovative approach to in-reservoir tracing and leakage monitoring (Mayer et al, 2015). Roberts et al. (2017) identify inherent tracers, such as noble gas isotopes or radiogenic carbon, as the best option for

monitoring, with helium and xenon isotopes (particularly $^{124,129}Xe$), and artificial tracers such as perfluorocarbons (PFCs) and deuterated methane are the most suitable added tracers.

Mitigation refers to the strategies and actions taken in response to any issues identified during monitoring and verification. This could involve adjusting injection practices (e.g. slowing or interrupting the injection) or implementing remediation measures in case of leakage. Koornneef et al. (2012) reviewed the literature to identify the possible containment issues and their remedial actions for CO_2 storage. These include monitoring and controlling injection pressures to prevent caprock fracturing, enhancing well integrity through advanced drilling and completion techniques, and using seismic and remote sensing technologies for early detection of leaks and structural changes. Additionally, they recommend strategic management of reservoir pressures, such as brine production, to mitigate risks associated with overpressure. For a complete overview of these options, see Table 7.

Table 7: Containment issues and their mitigation/remediation measures. From Koornneef et al. (2012).

Environmental Concerns Regarding CO_2 Storage	Mitigation/Remediation
Leakage and seepage through/alongside Caprock: • Catastrophic failure and quick release • Gradual failure and slow release	• Injection/reservoir pressures lower than initial pressure • Injection pressures up to 85 % of fracture gradient • Control composition of CO_2 • Avoid fracturing conditions • Stop injection, remove CO_2 from reservoir • Detecting leakage (mass balance, seismic monitoring, monitoring impact zone)
Leakage along wells including shallow accumulation: • Upward leakage through existing deep oil and gas wells	**Monitoring:** • Pressure in annulus of the well • Analysis for gas in well annulus **Mitigation:** • Use state of the art drilling and completion techniques • (Re-)completion of unused wells • Reworking deep wells • Appropriate plugging of wells • Early abandonment if well integrity is doubtful • Common O&G industry mitigation techniques for leaking wells
Release through induced faults resulting from increased pressure (local over-pressure)	• Determine induced/activated fractures through seismic monitoring • Detect micro-seismicity • Alter injection strategy • Reduce injection pressure • Venting CO_2 from reservoir • Move to another injection well • Water production from reservoir
Leakage into non-target aquifers due to unknown structural or stratigraphic connections and due to lateral migration beyond spill point	• Stop injection • Remove CO_2 accumulation
Upward leakage through undocumented, abandoned, or poorly constructed wells	• Survey field for existing wells • Remote sensing (through satellites), atmospheric monitoring, surface and near surface monitoring and subsurface monitoring.
Induced fracturing (as consequence of injection/production cycle)	• Monitor and control of temperature and pressure of CO_2 • Minimal distance injection well and fault: −200 m
Effects of pressure development due to injection/production Earth subsidence or uplift Seismicity	**Monitoring:** • Seismographic • Water levelling **Mitigation:** • Production of reservoir fluids
Leakage to near-surface environmental compartments	• Sanitize groundwater • Sealing well zone • Building modification

When a breach in containment occurs, it is imperative to promptly create barriers to prevent further leakage and stabilise the affected area. Castaneda-Herrera et al., (2018) classify mitigation technologies into two main categories based on the type of barrier they form: high- and low-viscosity fluid barrier formation. High-viscosity fluid-based technologies, including cements, geopolymers, gels, and nanoparticles, are effective for sealing engineered pathways such as wellbores, offering robust and durable barriers due to their thicker consistency. Cement is traditionally used for sealing leaky wells in the oil and gas industry, but the presence of CO_2 in the system can produce chemical degradation of these cements (Carey, 2013). On the other hand, low-viscosity fluid-based technologies, like biomineralization, hydraulic barrier formation, and chemical reactive barrier formation, are especially suited for leakage through natural pathways, such as faults or fractures. These methods use fluid-like materials that can permeate small spaces and react with the environment to create barriers. The selection between these technologies depends on the leakage nature, geological site characteristics, and specific project constraints, with high-viscosity options ideal for controlled settings and low-viscosity choices offering adaptability to various conditions (Castaneda-Herrera et al., 2018).

The importance of MMVM in CO_2 storage cannot be overstated, as it not only guarantees the operational success and compliance with environmental regulations but also plays a key role in maintaining public trust and the credibility of CCS as a viable climate change mitigation technology (Feitz et al., 2014).

Case study 2: the Weyburn-Midale project – a leakage event debunked

Since September 2000, CO_2 has been transported from the Dakota Gasification Plant in North Dakota through a 320-km pipeline and injected into the Weyburn oilfield in Saskatchewan, Canada, via a 320-km pipeline. CO_2 injection commenced in October 2000 at the adjacent Midale oilfield, with daily rates between 3000 and 5000 tons, contributing towards ¼ of the total oil production of the field through EOR (White et al., 2004). By 2015, operating cost was about US$20/t of CO_2 (Aminu et al., 2017).

In January 2011, the owners of the Kerr farm, situated in the southwest portion of the Weyburn-Midale Unit, claimed that CO_2 from the Weyburn-Midale Project was leaking onto their property (Romanak et al., 2014). Subsequent investigations by the farm's owners led to two reports. The first concluded that "CO_2 and light hydrocarbons have not only penetrated the anhydrite cap rock but have also surfaced in large amounts through fast-flow conduits such as faults and fractures" (p.25, Lafleur, 2010), while the second report stated, "the high concentrations of CO_2 in the soils of the Kerr property are clearly from the anthropogenic CO_2 injected into the Weyburn reservoir" (Lafleur, 2011).

To investigate these claims, extensive soil gas and CO_2 flux measurements were conducted above and around the Weyburn oil field to monitor for potential surface leaks (Beaubien et al., 2013; Romanak et al., 2014). The studies aimed to determine if gases from the deep subsurface had migrated to near-surface environments, indicating potential pathways for gas transport from the reservoir, and to identify major in situ processes active shallow subsurface to accurately assess the origins of the soil gases. The sampling methods utilized included discrete sampling of soil gas CO_2, O_2 + Ar, N_2, δ13C-CO_2, He, Rn, and CH_4, continuous monitoring of soil gas CO_2 and Rn, and discrete sampling of CO_2 flux. The results indicated no signs of leakage from the injected CO_2, including at the alleged leakage site. Near-surface gas geochemistry techniques determined that the observed anomalies in soil gas CO_2 and CO_2 flux were of biogenic origin, rather than resulting from leakage associated with the CO_2 storage reservoir.

The Weyburn case was the first public report of an alleged leak receiving relatively extensive media coverage. However, when independent scientific assessment reports were released almost a year later, media coverage was minimal, limiting public access to the outcomes through mainstream channels (Boyd et al., 2013). This incident illustrates the significant role local community stakeholders can play, not only during the development of potential projects but also throughout the operational phase. It underscores the need for developing effective science-for-community communication strategies and maintaining continuous engagement with local groups.

Storage security in the long term

The long-term security of the CO_2 storage operation is critical for the effectiveness of CCS. The fate of the injected CO_2 is governed by a combination of a variety of mechanisms that retain or allow the CO_2 to return to the surface, and their effect can determine the success or failure of CO_2 storage. Leakage rates of 0.01% of the injected CO_2 per year (or retention of 99% of the injected CO_2 in 100 years) are generally accepted

within the scientific community as adequate for effective CO_2 storage, ensuring negligible impact on temperature rise (Hepple et al., 2005; Chadwick et a., 2008; Lenzen, 2011), while other experts propose even stricter criteria, (e.g. 0.001% per year, Shaffer, 2010).

Estimating the potential leakage risk in CO_2 storage operations involves assessing the frequency of occurrence and the consequences of a leak. This estimation is very challenging due to the number of variables that need to be considered, including specific operational characteristics, such as injection volume, number and status of wells, presence of geological features like faults or fractures, and intensity and duration of the leakage events. To delve into these aspects, the work by Alcalde et al. (2018) built the Storage Security Calculator, a numerical program designed to estimate the security of CO_2 storage and its potential leakage to the atmosphere over geological timescales. The tool aims to quantify the immobilization of CO_2 injected into the subsurface for geological storage and the total CO_2 leaked to the atmosphere over a 10,000-year period.

The Storage Security Calculator combines two core elements: a CO_2 immobilization model and a CO_2 leakage model (Figure 13). The immobilization model calculates the quantities and rates of processes that lead to the permanent trapping of CO_2 in the subsurface, including residual trapping, which occurs instantaneously on geological timescales and can be measured in laboratory and field tests, and chemical trapping, which combines solubility and mineral trapping over longer timescales. Structural/stratigraphic trapping is not including in the modelling, as the CO_2 remains in free phase and thus it does not imply permanent trapping.

The leakage model, on the other hand, assesses the potential quantity of CO_2 leaked from active and abandoned hydrocarbon industry wells, as well as leakage through natural geological features, such as faults. Active wells, used for the injection of CO_2, can become potential leakage points if not properly designed, constructed, and maintained. Abandoned wells, often remnants of the hydrocarbon industry, represent another significant leakage pathway. If the CO_2 plume extends to these legacy wells and they are not properly sealed, they can become conduits for the CO_2 to escape to the surface. The study notes that the density and condition of these abandoned wells in a given area can greatly impact the overall security of CO_2 storage. Regions with a higher density of poorly maintained abandoned wells are more susceptible to leakage. Leakage through active and abandoned wells can occur in small, continuous form or in discrete, large events, such as blowouts. Natural pathways pose a more uncontrollable risk, depending on geological conditions. In contrast, active and abandoned wells offer more manageable risks, as their integrity can be directly influenced by human intervention through proper construction, maintenance, and sealing practices. The modelling considers a range of factors such as migration pathways, reservoir pressure, and CO_2 column height, to estimate potential leakage.

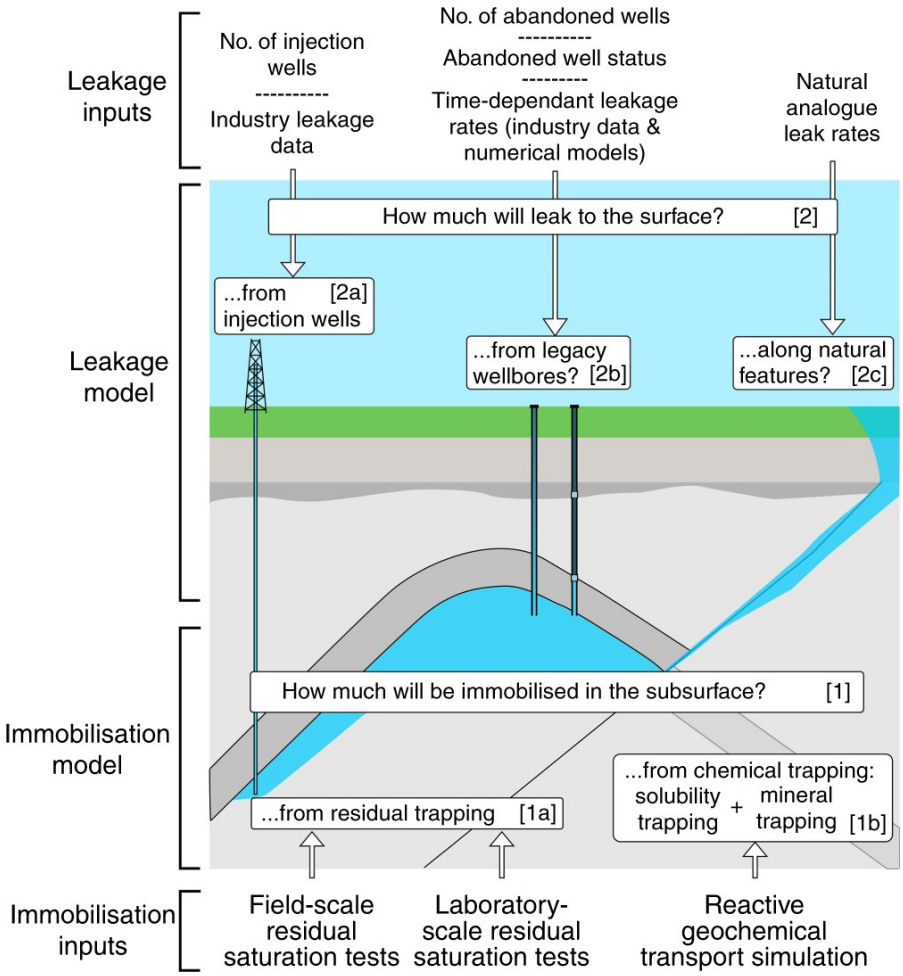

Figure 13: The Storage Security Calculator concept. The fate of the injected CO2 is ultimately dictated by how much of it will be immobilised by the trapping mechanisms and how much it will travel back to the surface via the leakage mechanisms. Source: Alcalde et al., (2018).

The study's main findings indicate that CO_2 storage in well-regulated regions has a high probability of being secure. Specifically, there's a 50% chance that leakage will remain below 0.0008% per year, with over 98% of the injected CO_2 retained in the subsurface over 10,000 years. These results are well aligned with the leakage rates and probabilities reported by the IPCC (retention very likely to exceed 99% over 100 years and likely to exceed 99% over 1000 years, IPCC, 2005) and the Zero Emissions Platform (99.99% over 500 years for a typical storage site in the North Sea, ZEP, 2019). More recently, the UK's Department for Energy Security and Net Zero (DESNZ) (previously Department for Business, Energy & Industrial Strategy (BEIS)) have also released a report concluding that the estimated minimum containment for both typical saline aquifer and depleted field storage sites exceeds 99.9% of the injected CO_2 (Daniels et al., 2023).

The results of these analyses demonstrate that geological storage of CO_2 can be a viable and secure option for climate change mitigation in geological timescales. However, they also highlight that the long-term behaviour of CO_2 in the subsurface is a significant uncertainty that needs to be addressed, via monitoring, measuring, verification and mitigation methods.

5. Non-technical risks

Public concerns

A recent review by Tcvetkov et al. (2019) delves into various public concerns related to CO_2 storage, all of which shape public attitudes towards this aspect of the CCS chain. These include apprehensions about potential risks such as leakage, induced seismicity, and impacts to groundwater. The review cites examples of local incidents that negatively impacted public perception of CCS. For example, after the Fukushima nuclear power plant accident in Japan in 2011, public perception shifted more negatively towards the

prospects of both on-shore and off-shore CO_2 storage due to potential leakage caused by earthquakes (Itaoka et al., 2014).

The 'Not In My Backyard' (NIMBY) effect reflects a reluctance to have CO_2 storage facilities nearby. Raising public awareness and improving the image of the technology, along with providing economic incentives, may sometimes lead to suspicion that stakeholders are hiding information about the real risks of the project. In a survey done in China, Chen et al., (2015) report that, in spite of a high approval of CCS (90%), 48.4 % of the respondents would prefer if the storage facility was located more than 100 km away from their home. A similar case of “NIMBYsm” was observed by Krause et al., (2013) in Indiana (U.S.), where 80% of the respondents to a survey were supportive of CCS, but one fifth of these reacted negatively when it was suggested a CCS facility be sited close to their communities. The authors hypothesise that despite the initial NIMBY reaction, the respondent’s opinions may soften when provided with detailed information about the economic benefits of project implementation nearby, such as job creation, fiscal benefits, and other economic incentives, in line with other similar types of activities (Jenkins-Smith and Kunreuther, 2001). Communication to the public can thus have a strong impact on the perception of a CCS development. Additionally, public awareness and understanding of CO_2 storage technologies can impact perceptions, with misconceptions and information gaps often leading to negative views. As previously mentioned, this includes the impact on public perception when CO_2 storage is erroneously associated with unrelated practices such as hydraulic fracturing (Gough et al., 2017; Cox et al., 2021).

Competition with other users

The co-existence of dedicated CO_2 storage projects with existing sub-surface uses, such as oil and gas production or geothermal energy production, can lead to complex challenges and impacts. For instance, the injection of CO_2 into geological formations already used for oil extraction (CO_2-EOR) could alter the pressure and dynamics of the reservoir, potentially hindering oil recovery or causing subsurface disturbances. In areas where geothermal energy production is prevalent, the introduction of CO_2 storage projects could impact the thermal properties of the geothermal systems, potentially reducing their efficiency. This interaction could also raise concerns about induced seismicity, as the alteration of subsurface pressures and temperatures might trigger seismic events (Beresten & de Pater, 2020). Also, the processes of mineral dissolution and precipitation associated with CO_2 mineralization and storage, can adversely impact the efficiency of heat extraction in CO_2-enhanced geothermal systems (EGS) (Wu & Li, 2020). If the resultant mineral precipitation clogs the fractures within the reservoir, it would decrease the reservoir's permeability and subsequently diminish the productivity of hot CO_2. Moreover, the legal and regulatory implications of navigating shared subsurface rights could become intricate, with potential disputes over resource management and environmental impacts. For example, in regions where both oil extraction and CO_2 storage are operational, delineating responsibility for any leakage or environmental damage becomes a significant concern.

As the CCS industry scales up to meet global decarbonization targets, it will catalyse the emergence of a new "green" industry, which could significantly aid in the just transition of traditional subsurface industries. However, this development introduces complexities, as CO_2 storage must be seamlessly integrated with other subsurface uses that also contribute to the green economy, such as geothermal energy and the storage of renewable energy. These competing demands necessitate a well-balanced approach to subsurface management, ensuring that the deployment of CO_2 storage technologies does not obstruct other sustainable initiatives. Thus, strategic planning and regulatory frameworks must prioritize the integrated management of subsurface resources, accommodating the diverse needs of a transitioning energy sector to ensure a holistic approach to sustainability.

Marine settings present additional complexities. The co-existence of CO_2 storage facilities with other marine activities, such as fisheries, offshore wind farms, and other marine industries, presents a complex set of challenges and considerations. One issue is the potential for restricted access, particularly for essential tasks like monitoring and remediation of the CO_2 storage sites (NTSA, 2022). For instance, conducting seismic surveys, which are crucial for monitoring the integrity and distribution of stored CO_2, can be significantly hampered within wind farm areas due to spatial constraints and operational interference. Additionally, the presence of multiple marine industries in close proximity can lead to conflicts over resource use and raise concerns about environmental impacts. This necessitates a careful balance between the various interests and activities, ensuring that CO_2 storage operations do not adversely affect other marine uses and vice versa. Coordinating between different stakeholders, implementing integrated management strategies, and

developing clear guidelines for co-location are essential for the successful integration of CO_2 storage facilities within the broader spectrum of marine activities.

Transboundary issues

Transboundary issues related to the transportation and storage of CO2, such as unintended migration or leakage across jurisdictional borders and the use of storage complexes spanning multiple jurisdictions, can present significant challenges (IEA, 2010). Such situations can lead to legal disputes over liability, coordination difficulties between varying regulatory frameworks, and complexities in managing shared resources. Addressing these challenges effectively requires international collaboration and agreements to manage cross-border CO_2 migration and storage effectively. Furthermore, secondary effects from storage activities, such as the migration of the pressure front through the subsurface or the displacement of subsurface fluids, can have transboundary implications, especially when these effects cross jurisdictional borders. In these cases, transboundary regulation will be necessary to clarify rights, obligations and liabilities of the stakeholders involved.

6. Conclusion and recommendations

This report has detailed the fundamentals of geological CO_2 storage as a decarbonization technology within the CCS chain, emphasizing its significance in combating climate change. The focus has been primarily on storage in porous media, such as saline aquifers and depleted oil and gas fields, which represent the most advanced and viable options for carbon abatement. Other storage options and purposes, such as EOR, have not been considered in this analysis.

Throughout the analysis, the processes involved in CO_2 storage were thoroughly reviewed, including the identification of the most suitable sites for storage, the mechanisms governing the fate of CO_2 in both the short and long term, and the safety considerations crucial for deployment. Although the technology is mature—bolstered by decades of experience in the oil and gas sector—and fundamentally regarded as safe, the report underscores the necessity of fully understanding safety implications to ensure the effectiveness and overall success of CO_2 storage projects. This understanding is key, especially as models affirm the long-term safety (spanning thousands of years) of this approach. The selection of suitable sites and the implementation of comprehensive monitoring, measuring, verification, and mitigation programs are pivotal to the success of CO_2 storage projects. Addressing public concerns proactively is important as these have historically posed barriers to the advancement of CCS projects. Engaging communities and stakeholders transparently and responsively will play a fundamental role in mitigating scepticism and enhancing the public acceptability of storage projects.

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