Geological storage post-injection risk and liability

May 2026

DNV

OIL AND GAS CLIMATE INITIATIVE

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Abbreviations, acronyms, and initialisms

The table below provides a complete list of abbreviations, acronyms, and initialisms used within this report.

TABLE 1. List of abbreviations, acronyms, and initialisms in this report.

Abbreviation, acronym, or initialism	Definition
ACG	Australian Centre for Geomechanics
ALARP	As Low As Reasonably Practicable
CA	Competent Authority
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilisation and Storage
CO_2	Carbon Dioxide
EGS	Enhanced Geothermal System
EPA	Environmental Protection Agency
EU	European Union
EUA	Emission Unit Allowance
ETS	European Trading Directive
FC	Financial Contribution
FEP	Feature, Events and Processes
HSE	Health, Safety and Environmental
MMV	Measurement, Monitoring and Verification
NSTA	North Sea Transition Authority
O&G	Oil and Gas
OGCI	The Oil and Gas Climate Initiative
OPRED	The Offshore Petroleum Regulator for Environment and Decommissioning
QRA	Quantitative Risk Assessment
UIC	Underground Injection Control
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
US	United States
USDWs	Underground sources of drinking water

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Executive summary

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1. Executive summary

The Oil and Gas Climate Initiative (OGCI) aims to lead the oil and gas industry's response to climate change and accelerate action towards a net-zero emissions future consistent with the timeframe of the Paris Agreement. Since 2017, the OGCI member companies have collectively reduced upstream operated methane emissions and routine flaring by more than 60%, invested more than $125 billion in low-carbon technologies and shared best practices across the industry and other sectors to accelerate emissions reductions. OGCI's members are Aramco, bp, Chevron, CNPC, Eni, Equinor, ExxonMobil, Occidental, Petrobras, Repsol, Shell, and TotalEnergies.

Given their focus on carbon capture, utilisation and storage (CCUS), OGCI sought to develop a report, in collaboration with key stakeholders, to further the understanding around potential post-injection risks associated with subsurface geological carbon dioxide (CO_2) storage sites and corresponding strategies for mitigating any remaining risks. Although no large-scale commercial CCS projects are near the post-injection phase, the appropriate management of risks in the post-injection phase starts with appropriate CO_2 storage site selection and characterisation during the pre-injection phase and its success is further dependent on cautious CO_2 injection management as well as risk-based Measurement, Monitoring, and Verification (MMV) operations during the injection phase. Data acquisition through the project lifecycle is crucial to build confidence and enable the effective closure of CO_2 storage projects.

DNV and OGCI have developed this report anticipating that it will be a useful tool for developers, regulators and other stakeholders in identifying potential post-injection subsurface risks and how those risks may be effectively addressed through the screening, selecting, developing, operating, closing, and transferring of CO_2 storage projects.

As a result of this work, the primary messages and themes were identified and are summarised below.

Key elements to a effective CO_2 storage project
Typically, for a storage site development operators conduct a detailed characterisation of the subsurface encompassing five main elements. If a proposed storage site development lacks any of these elements, it may prevent the project from being feasibly matured:

- **Capacity:** Will the site have sufficient capacity to store the desired amount of CO_2?[1]
- **Injectivity:** Is there sufficient injectivity to be able to deliver the CO_2 into the reservoir at the required economic rate?
- **Containment:** Is the site able to demonstrate that injected CO_2 will be retained in the subsurface storage complex?
- **Monitorability:** Can the site be adequately monitored to confirm CO_2 behaviour in the subsurface?
- **Non-technical:** Does the project have stakeholder support? Stakeholder risk and non-technical risks must be evaluated to avoid project derailment e.g. regulatory acceptance and commercial viability.

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[1] Often this is referred to as having sufficient Storage Resource in line with definitions outlined in the SPE CO_2 Storage Resources Management System, where a CO_2 storage resource is defined as the quantity (mass or volume) of CO_2 that can be stored in a geologic formation.

Strong regulatory frameworks are influential but vary

Regulatory frameworks such as those in Europe and the US are in place to ensure the safe deployment of CO_2 storage projects in their respective regions. Other countries with ambitions to deploy CCS projects may have relatively immature regulatory frameworks, or lack them altogether. There are learnings to take from more mature regulatory frameworks such as the EU CCS Directive and US EPA Class VI. Ultimately, to obtain a permit or approval for storage activities, operators must demonstrate to regulators that they satisfy the regulatory requirements and critically that the risks of the proposed project are reduced to an acceptable level. Here, site selection, characterisation and development are key to managing, mitigating and eliminating risk prior to the award of a storage permit. In particular, an operator will screen out potential storage location if the risks cannot be mitigated adequately.

Risk assessment and MMV are critical to the safe development and operation of CO_2 storage projects

Following site selection, detailed risk assessments, tied directly to the result of comprehensive site characterisation efforts, provide storage operators with site-specific insights into the likelihood and consequence of the various risks associated with a given CO_2 storage project. In turn, this enables informed decision making throughout the project lifecycle, as well as the efficient allocation of any necessary project resources. Good practice for risk assessment and management related to CO_2 storage projects is well-documented in various guidance documents, recommended practises, and industry standards. Operators conduct site-specific risk assessments for each individual project, leveraging multi-disciplinary teams, to understand the overall risks for each storage location. These risk assessments can be considered live documents and may require updates throughout the project lifecycle, utilising input from operational and monitoring data. These initial risk assessments are used to inform the development of MMV plans.

Site-specific, risk-based approaches are imperative to the development of MMV plans

MMV plans are established considering the unique risks of each storage location identified during the risk assessment process. There are many monitoring solutions that can be employed in an MMV plan, the most appropriate solution is selected based on each risk. Risk based approaches are key to MMV development, particularly moving into the post-injection phase, to ensure that cost effective plans are developed. This includes the development of corrective measures and actions in the case that a risk materialises during the lifecycle of the project. Like risk assessments, data collected during the injection phase is used to refine and optimise monitoring plans throughout the project lifecycle. It is important to note that associated monitoring solutions themselves do not prevent risk, they are in place to monitor risks and signal any potential need to trigger corrective actions or mitigative measures (i.e., risk management and controls).

Trapping mechanisms vary and the fate of stored CO_2 should be understood

The influence of each trapping mechanism varies with time - an idealised depiction of this is shown in Figure 1 (A) . When considering the long-term fate of stored CO_2, particularly post-injection, it is important to highlight that the influence of each trapping mechanism is dependent on subsurface characteristics and storage setting that vary on a site-specific basis. An example of this is shown in Figure 1 (B), and other modelling studies have investigated the influence of each trapping mechanism over a number of scenarios.[2]

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[2] Snippe & Tucker, CO_2 fate comparison for depleted gas field and dipping saline aquifer. 2014, GHGT-12

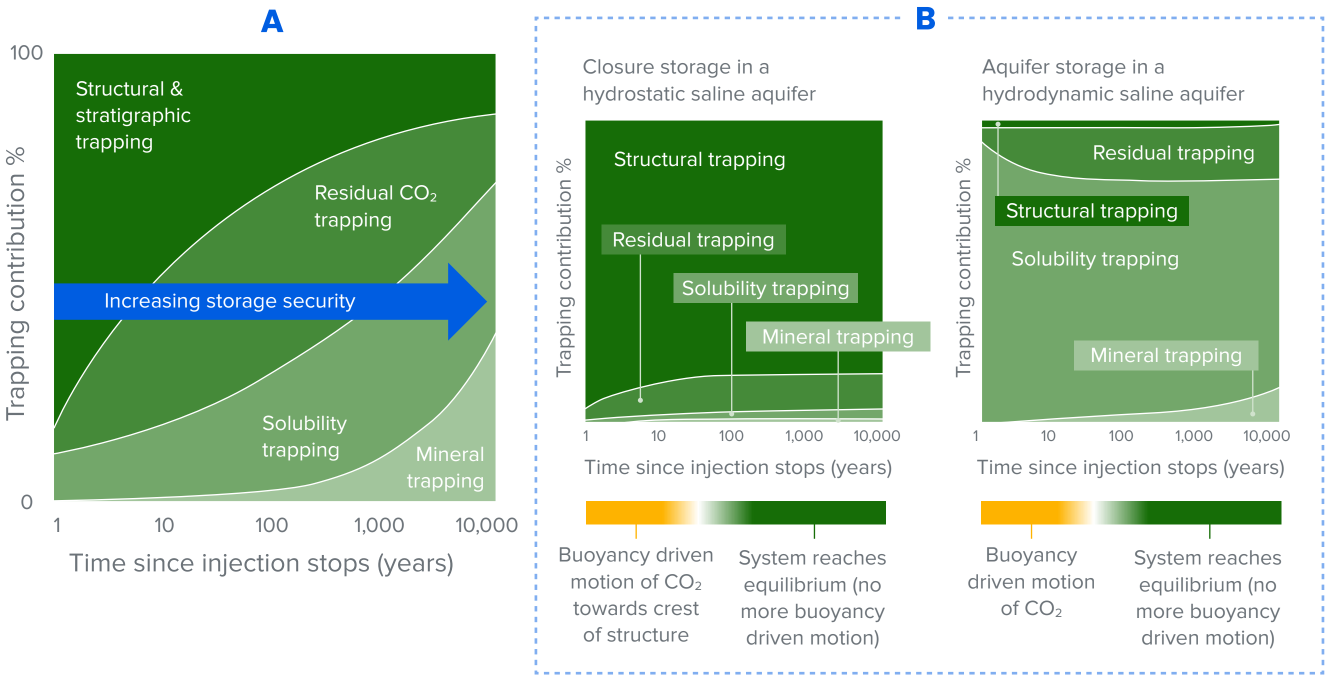

FIGURE 1. (A) Representation of storage security based on various expected trapping mechanisms (after IPCC 2005).[3] (B) An adaptation of the 2005 IPCC figure, based on two storage scenarios (modified after Shoulders & Hodgkinson, 2024).[4] Note that structural and stratigraphic trapping are combined in (A) and (B), despite the label only including structural trapping in (B).

Effective risk controls and safeguards during the injection phase reduces post-injection containment risk

It is important for the operator to consider risk controls and safeguards when assessing risk and the overall feasibility of a storage location. Risk controls can be either preventive or corrective. Where preventive, controls aim to avoid incidents from happening in the first place or minimising the impacts. Corrective controls are measures put in place to manage consequences after an incident has already occurred.

For CO_2 storage, a number of different safeguards can be considered:

- **Natural safeguards:** Based on the geology, e.g., a laterally extensive, undisturbed, and composed of high-quality seal lithology
- **Engineered safeguards:** Human-designed technical solutions, e.g., appropriate well design and later plugging and abandonment
- **Reactive safeguards:** Specific operational procedures, e.g., reduction in injection rate

Early risk assessments identifying inherent risks associated with a storage location, and development of potential risk controls to understand residual risk, are key elements to demonstrate to the regulator that risk associated with a storage location can be brought to an acceptable level. In particular, during the post-injection phase the information gained during operations through monitoring programs is critical to build an understanding of the behaviour of injected CO_2. Monitoring data helps to reduce uncertainty and optimise storage management to reduce risks into the post-injection phase.

Appropriate risk management is needed in the post-injection phase

This report's main focus is on the post-injection phase (including post-termination or -closure) and the approaches for managing any potential risks to a CO_2 storage project that may remain following the cessation of injection. Plausible subsurface-related CO_2

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3 IPCC, Special Report on Carbon Dioxide Capture and Storage, 2005

4 A process-led approach to framing uncertainty and risk in CO_2 storage in the subsurface, Shoulders & Hodgkinson, 2024

storage risks which could materialise over the course of the post-injection phase of the project and beyond are considered in relation to the keys to storage. Once injection has ceased, previous risks related to CO_2 capacity and injectivity are no longer relevant, meaning that containment- and monitorability-related risks are the only technical ones remaining from a subsurface perspective. Whilst not strictly grouped with containment and monitorability, risks related to seismicity and pressure communication from other subsurface activities may also be relevant during this phase.

Each project has its own unique risk profile

One well regarded and oft cited lifecycle risk profile for a CO_2 storage project, is illustrated in Figure 18. This profile depicts an increase in the risk profile during a project's operational period as CO_2 is injected, reservoir pressure evolves, the CO_2 plume increases in size and makes contact with a greater portion of the sealing formation and legacy wells.[5]

However, at all times during the project lifecycle, the risk profile for a well characterized, designed and managed project is expected to remain below the acceptable risk set by regulatory authorities and the design risk established by the project. After injection ceases at the end of the operational period, the project risk profile is expected to asymptotically and rapidly decrease as the (see Figure 2) pressure dissipates, the plume stabilises, and secondary trapping mechanisms further reduce the probability of leakage.

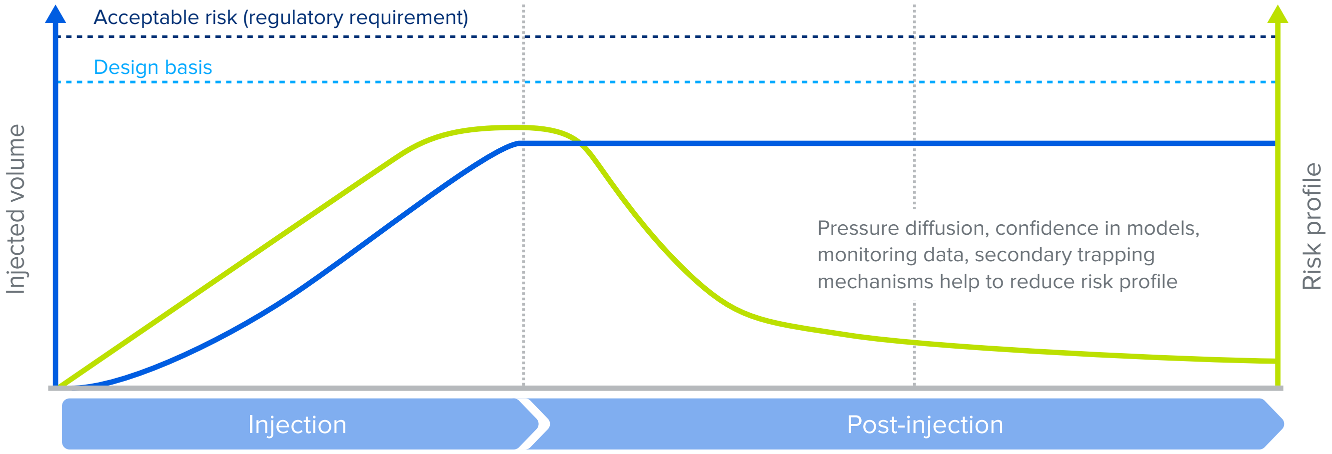

FIGURE 2. Risk profile with increase in CO_2 inventory (adapted after de Coninck and Benson 2014).[6]

The overall risk profile of a CO_2 storage project is expected to be site specific and dependent on the presence or absence of certain features. Each individual risk component of the lifecycle risk profile will contribute a different likelihood, consequence and timing. For example, legacy well leakage risks only have a likelihood of materialising where legacy wells are present and if it is possible (e.g., physically) that the CO_2 plume could migrate towards such wells. Typically, operators visualise risk throughout the life cycle through risk assessment matrixes, rather than plots like the above (as described in Section 3.1.1).

Lifecycle risk profiles are an effective communication tool in discussions with project stakeholders. Building on the lifecycle risk profile shown in Figure 2, CO_2 storage project developers have developed an alternate view of the risk profile across an idealised project taking into account detailed risk assessments, monitoring plans and corrective measures plans. This lifecycle risk profile changes as project safeguards are "tested," and CO_2 storage project operational and monitoring data are obtained, evaluated and incorporated. The lifecycle risk profile includes the types of risks that CO_2 storage project operators consider most relevant to the post-injection phases of a CO_2 storage project (Figure 3).

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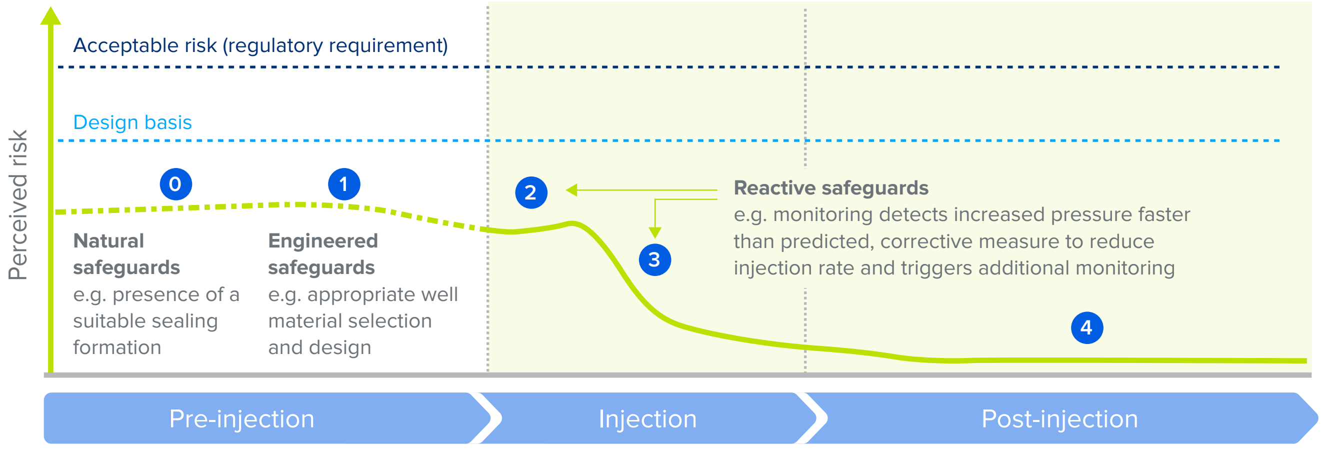
[5] Shoulders & Hodgkinson, A process-led approach to framing uncertainty and risk in CO_2 storage in the subsurface, 2024

[6] Carbon Dioxide Capture and Storage: Issues and Prospects, de Coninck & Benson, 2014



0 Project lifecycle risk is assessed during site selection and activities are defined to characterise and reduce identified risk pre-injection

1 Additional subsurface characterisation and refinement of development plans to reduce risk pre-injection

2 During operation identified risks do not materialise, risk decreases. Or a risk materialises, remediation is triggered and risk decreases

3 Monitoring data during operation help to reduce site uncertainty and optimize site management to reduce risks. Monitoring data confirms identified risks do not materialise, risk decreases. Or monitoring data confirms a risk materialised, remediation and corrective measure are triggered and risk decreases

4 Pressure diffusion, confidence in models, monitoring data, secondary trapping mechanisms help to reduce risk profile

FIGURE 3. Lifecycle risk profile for an idealised CO_2 storage project showcasing risk management through implementation of safeguards, monitoring and corrective measures. The green line represents the risk profile. Pre-injection is dashed as the risks have been characterised and assessed but are not active until injection commences.

Risk quantification remains relatively limited industry-wide compared to semi-quantitative approaches
Quantification of risk is a well understood process that has been conducted on a site-specific basis, with efforts made to quantify the potential risk of leakage from storage sites. Typically, Quantitative Risk Assessment (QRA) is applied using wide failure datasets for specific components, e.g., a valve. For CO_2 storage there is little failure data available to conduct true QRA and this approach often relies on expert opinion. Even with increased availability of data from CO_2 storage projects in the future, true QRA will remain challenging due to the inherent subsurface uncertainty and site-specific nature of each project. While absolute quantification of risks for CO_2 storage is limited industry-wide, semi quantitative approaches are successfully utilised. Results from the literature suggest a high-level of confidence that the long-term containment of CO_2 in the subsurface can be maintained. It is important to note that, in the event of a leakage, it is highly unlikely that the entire injected CO_2 volume would be at risk. Comprehensive, site-specific risk assessments conducted prior to injection, and updated during operations, will identify and characterize potential leakage scenarios. These assessments form the basis for developing robust MMV programs, which are specifically designed to detect anomalies at an early stage and enable timely implementation of corrective measures, thereby preventing significant volumes from escaping.

Post-injection risks should be considered in the context of site closure and potential liability transfer
Establishing inherent risks and understanding residual risks of the CO_2 storage project as it progresses through the post-injection phase is critically important, particularly in the context of some regulatory regimes that have mechanisms enabling the transfer of long-term liability to the state. Liability transfer mechanisms do not exist in all regimes, however, they are of importance for developers of CO_2 storage sites. Assuming long-term liability for a project can deter developers from investing in the deployment of CO_2 storage projects. Regulatory frameworks that address liability can provide additional certainty for an operator's concerns and remove barriers to widescale deployment of CCS.

It is important to consider what enables the transition from the post-injection phase to the post-closure phase for CO_2 storage projects (Figure 3). Typically, at this transition there is a milestone for a “regulatory closure” where an operator is required to prove with confidence both containment and conformance. The timeframe for this milestone differs by jurisdiction, for example in Europe under the EU CCS Directive, the post-injection period is set as no shorter than 20 years. Should the competent authority be satisfied that certain criteria have been met, this period may be shortened.

The readiness of a project for closure could consider its site-specific characteristics and performance criteria rather than being dictated by an arbitrary time period. These decisions should consider the residual risks post-injection and the ability to demonstrate plume stability, containment and conformance. Linked to this, the subsequent post-injection monitoring efforts and associated liabilities should consider the site-specific residual risks following cessation of injection.

An important aspect of demonstrating confidence to the regulator that a project is ready for closure is the effective monitoring during the injection and post-injection phases to build confidence in an operator’s understanding of the behaviour of the injected CO_2. Independent assurance of operations considering best practice and international standards is another means to provide a regulator confidence in the development, operation and closure of the storage location.

Long term liability mechanisms are regional and evolving

Within existing regulatory frameworks there are methods for assessing liability, namely assigning a cost to cover a specific liability. These costs are typically associated with the remaining need for monitoring activities, or any remediation or corrective actions that may be required. Examples include financial security and contribution requirements for projects under the EU CCS Directive, and the post-closure stewardship fund in place in Alberta, Canada. Key to both of these examples is the use of probability and risk-based approaches. As above, the site-specific characteristics of each project should be taken into account.

In many US states, even those that do not have transfer of liability provisions, regulatory frameworks require operators to contribute to state-wide funds that are used to manage the potential long-term liabilities related to storage locations. It is not clear what defines the per-tonne contribution for many of these funds. Care should be taken to appropriately value the financial contribution necessary to manage the potential long-term liability.

There are emerging considerations related to the post-injection phase

There remain some emerging considerations related to the post-injection phase of CO_2 storage projects. The first issue of interest to CO_2 storage operators and regulators is the impact of pressure communication. There is an acknowledgement that neighbouring projects in the same hydraulic unit may have an impact on each other’s operations. Pressure build-up can affect the overall capacity, injectivity, containment, and conformance of each proximate site. A related issue is the potential for neighbouring activities to impact existing monitoring plans and potentially even corrective measures. At this stage it is somewhat unclear on the attribution of responsibility in such situations across regulatory regimes, particularly in a potential leakage scenario. Pressure communication issues on a regional basis will require collaboration between operators and regulators. For consideration is the need to develop regional networks to monitor this risk long-term.

02

Introduction

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2. Introduction

The Oil and Gas Climate Initiative (OGCI), aims to lead the oil and gas industry's response to climate change and accelerate action towards a net-zero emissions future consistent with the timeframe of the Paris Agreement. Since 2017, the OGCI member companies have collectively reduced upstream operated methane emissions and routine flaring by more than 60%, invested more than $125 billion in low-carbon technologies and shared best practices across the industry and other sectors to accelerate emissions reductions. OGCI's members are Aramco, bp, Chevron, CNPC, Eni, Equinor, ExxonMobil, Occidental, Petrobras, Repsol, Shell and TotalEnergies.

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DNV and OGCI have developed this report anticipating that it will be a useful tool for developers, regulators and other stakeholders in identifying potential post-injection subsurface risks and how those risks may be effectively addressed through the screening, selecting, developing, operating, closing and transferring of CO_2 storage projects.

03

CO$_2$ storage background

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3. CO_2 storage background

This report's main focus is around the post-injection phase and the approaches for managing any potential risks to a CO_2 storage project that may remain following the cessation of injection. Establishing inherent risks and an understanding of residual risks for a CO_2 storage project as it progresses through the post-injection phase is critically important, particularly in the context of some regulatory regimes that have mechanisms enabling the transfer of long-term liability to the state. Whilst some risks may be unique to the post-injection phase, the nature, level and management of remaining risks post injection are also the culmination of a journey that starts at the early stages when selecting a location to develop, as well as the operations period and closure.

The following sections will outline key background and context to frame the remaining discussion within this report.

3.1 Development and lifecycle of CO_2 storage projects

Individual CO_2 storage project lifecycles can be divided into pre-injection, injection, and post-injection phases (Figure 4), which take place over years or decades. Within each phase, project development advances over separate periods characterised by various activities and milestones. The specific timing, terminology, and meaning of these activities and periods vary greatly depending on the perspective (e.g., organisation, jurisdiction, industry, etc.). For reference, petroleum exploration and production (E&P) segment of the oil and gas (O&G) industry, European Union (EU), and International Organization for Standardization (ISO) terminologies are provided to highlight both their differences and similarities. Alongside the project phases and periods, generic CO_2 storage related activities (e.g., site characterisation), milestones (e.g., storage permit, SP) are also shown in Figure 4 to provide additional context for topics discussed in this report.

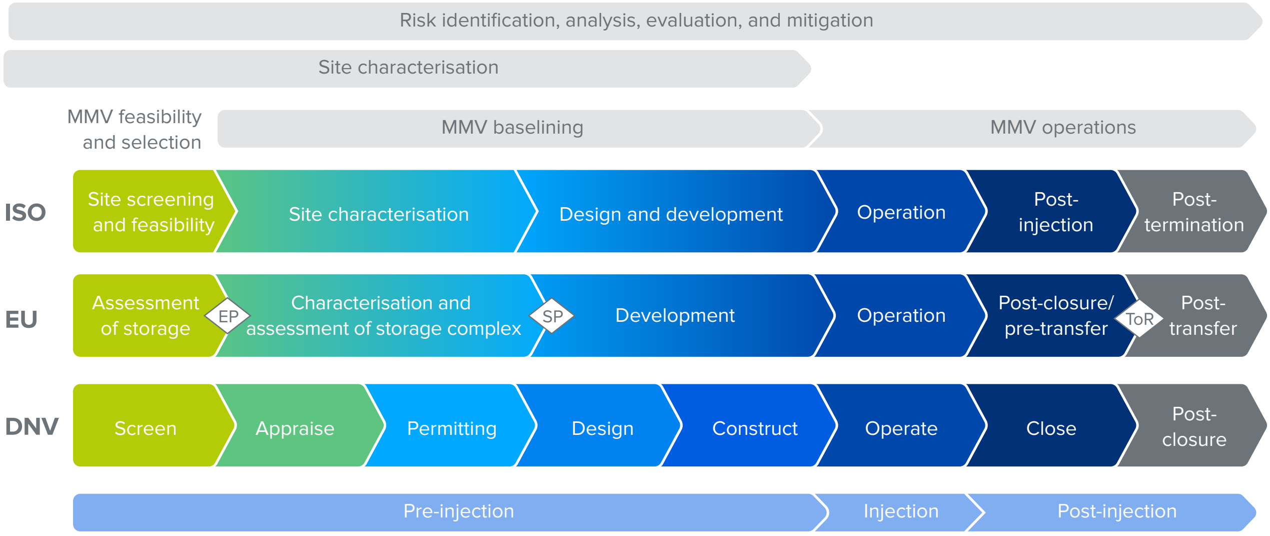

FIGURE 4. The pre-injection, injection, and post-injection phases of a CO_2 storage project lifecycle. Generic lifecycle period terminologies corresponding to these three phases based on ISO 27914:2026 (top; 2026), as well as CCS projects according to the EU CCS Directive Guidance Document 1 (middle; 2024) and DNV-RP-J203 (bottom; 2019) are shown for additional context. EP = exploration permit, SP = storage permit, ToR = transfer of responsibility.

Ultimately, the goal of a CO_2 storage project is to safely dispose of CO_2 in the subsurface for permanent storage. Key to ensuring this is both the proper characterisation, development, operation, and closure of a storage site. Regulatory frameworks that allow the storage of CO_2 are predicated on the need to ensure that storage activities are conducted in an environmentally protective manner. It is important that emerging regions develop strong regulatory frameworks, there are learnings to take from regions with mature regulatory frameworks such as Europe and the US. International standards also exist that provide operators and regulators with a recognised framework for development of CO_2 storage for the lifecycle of a project, notably *ISO 27914:2026 - Carbon dioxide capture, transportation and geological storage — Geological storage.*

In general, regulatory frameworks and standards guide in operators in conducting detailed characterisation of the subsurface encompassing five main elements. If a proposed storage site development lacks any of these elements, it may prevent the project from being feasibly matured:

- **Capacity:** Will the site have sufficient capacity to store the desired amount of CO_2?[7]
- **Injectivity:** Is there sufficient injectivity to be able to deliver the CO_2 into the reservoir at the required economic rate?
- **Containment:** Is the site able to demonstrate that injected CO_2 will be retained in the subsurface?
- **Monitorability:** Can the site be adequately monitored to confirm CO_2 behaviour in the subsurface?
- **Non-technical:** Does the project have stakeholder support? Stakeholder risk and other non-technical risks must be evaluated to avoid project derailment (e.g., regulatory acceptance and commercial viability).

As stated previously, the focus of this report is mainly around the post-injection phase and its periods, where it is important to understand which risks are still relevant as operators look to ensure the long-term and safe containment and provide assurance to regulators that CO_2 is behaving as expected within the subsurface. The understanding of identified risks evolves throughout the project lifecycle, meaning that some risks that may once have been considered material in terms of likelihood and consequence may no longer pose a material threat towards the later stages of a project's lifecycle as a result of continued data acquisition during CO_2 injection and monitoring activities.

3.1.1 CO_2 storage risk assessment and management

Subsurface geological storage of CO_2 has been safely conducted at a variety of locations around the world for several decades. The identification and characterisation of potential storage risks are prioritized and executed early in projects, using well-established methods stemming mostly from the hydrocarbon industry, but also from lessons learnt as a result of other storage projects. The methodologies for assessing these storage risks are also common across operators, and are effective for considering and understanding the inherent risk and uncertainties, as well as facilitating the establishment of a robust and adaptive set of risk management measures and strategies which bring the inherent risk to an understanding of residual (i.e., mitigated) risk before maturing to the injection phase of a project. However, this approach is continued during the injection and post-injection phases, as it is important to consider the evolution of risks over the project lifecycle.

Pre-injection (i.e., baseline) and injection-phase monitoring of risks and the effective deployment of risk management strategies will help position a CO_2 storage project well for successful navigation of the post-injection phase, in particular an increased understanding of storage reservoir behaviour to reduce

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[7] Often this is referred to as having sufficient Storage Resource in line with definitions outlined in the SPE CO_2 Storage Resources Management System, where a CO_2 storage resource is defined as the quantity (mass or volume) of CO_2 that can be stored in a geologic formation.

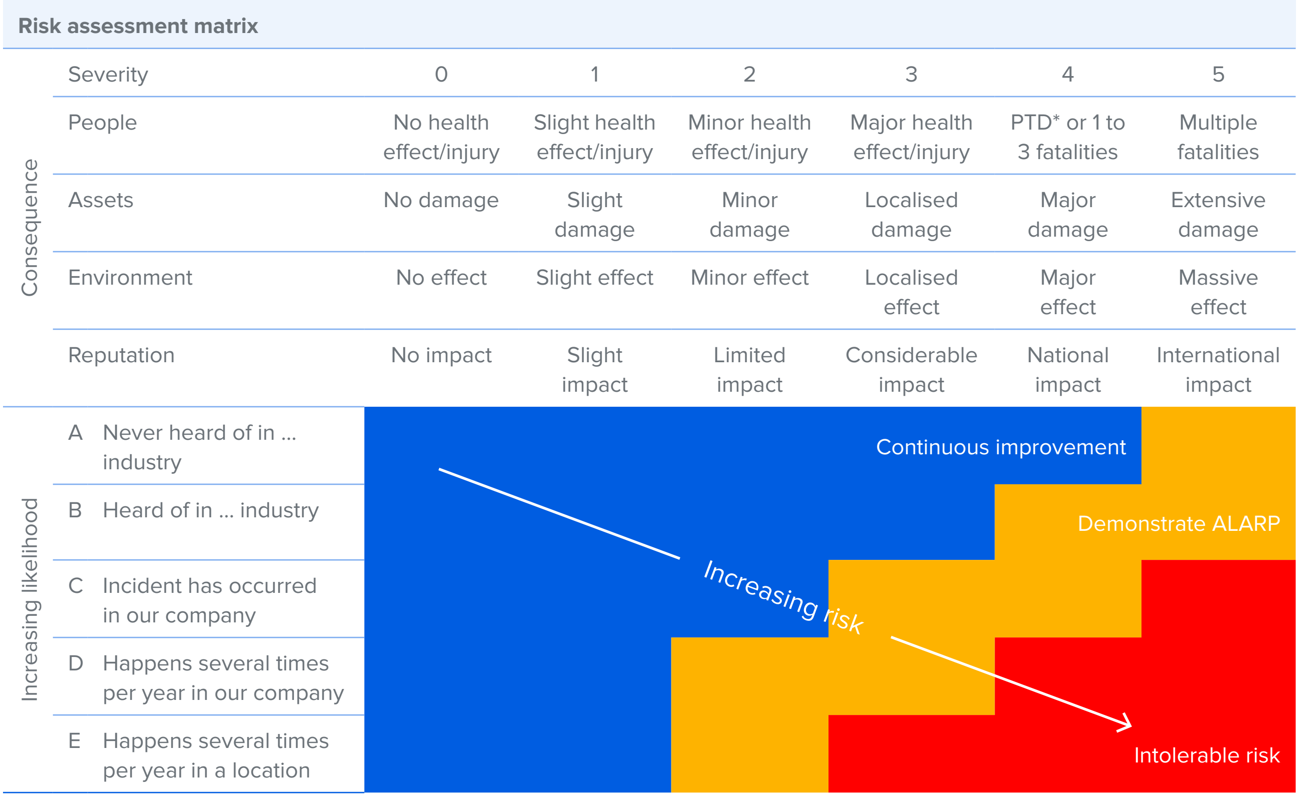
uncertainty and better characterise risks. Additionally, regulatory standards and project objectives may impose for the reduction of project risks to the point which the risk is deemed acceptable to the regulator.

Detailed risk assessments, which are tied directly to the result of comprehensive storage-location characterisation efforts, provide operators with project-specific insights into the likelihood and consequence of the various risks identified. In turn, this enables informed decision making at the beginning and throughout the project lifecycle, as well as effective allocation of project resources. Risk assessment for CO_2 storage projects is well-documented in industry standards, governmental reports, and technical papers (e.g. ISO 27914, DNV-RP-J203,[8] and EU CCS Directive Guidance Document 1,[9] respectively).

During the risk assessment process at any stage of the project, an operator will identify potential risk scenarios, the likelihood of each risk scenario, the severity of the potential consequences, sources of uncertainty, risk safeguards and controls, data requirements, and the aggregate likelihood that a significant impact on each element of concern could follows from a combination of risk scenarios.

Two common risk assessment tools applied by industry are summarised below, for more detail refer to other guidance such as *IOGP 670 – Overview of Risk and Uncertainty Assessment*.[10]

A typical approach is the use of risk assessment matrices and risk registers coupled with bowtie analysis. A risk assessment matrix is used to plot identified risks across a matrix of increasing likelihood and consequence to communicate the risks that have the potential impact on a project. A generic risk assessment matrix is shown in Figure 5, where consequence and likelihood categories will differ based on a developer's internal risk appetite and the regulatory jurisdiction it operates within.



Risk assessment matrix

	Severity	0	1	2	3	4	5
Consequence	People	No health effect/injury	Slight health effect/injury	Minor health effect/injury	Major health effect/injury	PTD* or 1 to 3 fatalities	Multiple fatalities
	Assets	No damage	Slight damage	Minor damage	Localised damage	Major damage	Extensive damage
	Environment	No effect	Slight effect	Minor effect	Localised effect	Major effect	Massive effect
	Reputation	No impact	Slight impact	Limited impact	Considerable impact	National impact	International impact
Increasing likelihood	A Never heard of in ... industry	🟦	🟦	🟦	🟦	🟦	🟧
	B Heard of in ... industry	🟦	🟦	🟦	🟦	🟧	🟧
	C Incident has occurred in our company	🟦	🟦	🟦	🟧	🟧	🟥
	D Happens several times per year in our company	🟦	🟦	🟧	🟧	🟥	🟥
	E Happens several times per year in a location	🟦	🟦	🟧	🟥	🟥	🟥

FIGURE 5. Generic HSE risk assessment matrix (adapted from Shell 2016).[11]

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[8] DNV, DNV-RP-J203 Geological storage of carbon dioxide, 2019

[9] European Commission, Guidance document 1, CO_2 storage life cycle and risk management framework. 2024

[10] IOGP 670, Overview of Risk and Uncertainty Assessment, 2023

[11] Shell, Peterhead CCS Project, Risk Management Plan & Risk Register, PCCS-00-PT-AA-5768-000001, 2016,

The bowtie method involves the evaluation of risks by linking to the specific threats that may cause the risk, as well as the effects or consequence of a specific event. Threats are displayed on the left-hand side of the bowtie and consequences are displayed on the right-hand side. Preventative safeguards and barriers are identified within the diagram that are in place to reduce the likelihood of a threat materialising (left-hand side of the bowtie), with corrective safeguards or controls identified to reduce the severity or prevent the end consequence from occurring (right-hand side of the bowtie). An example bowtie for containment risk is presented in Figure 6.

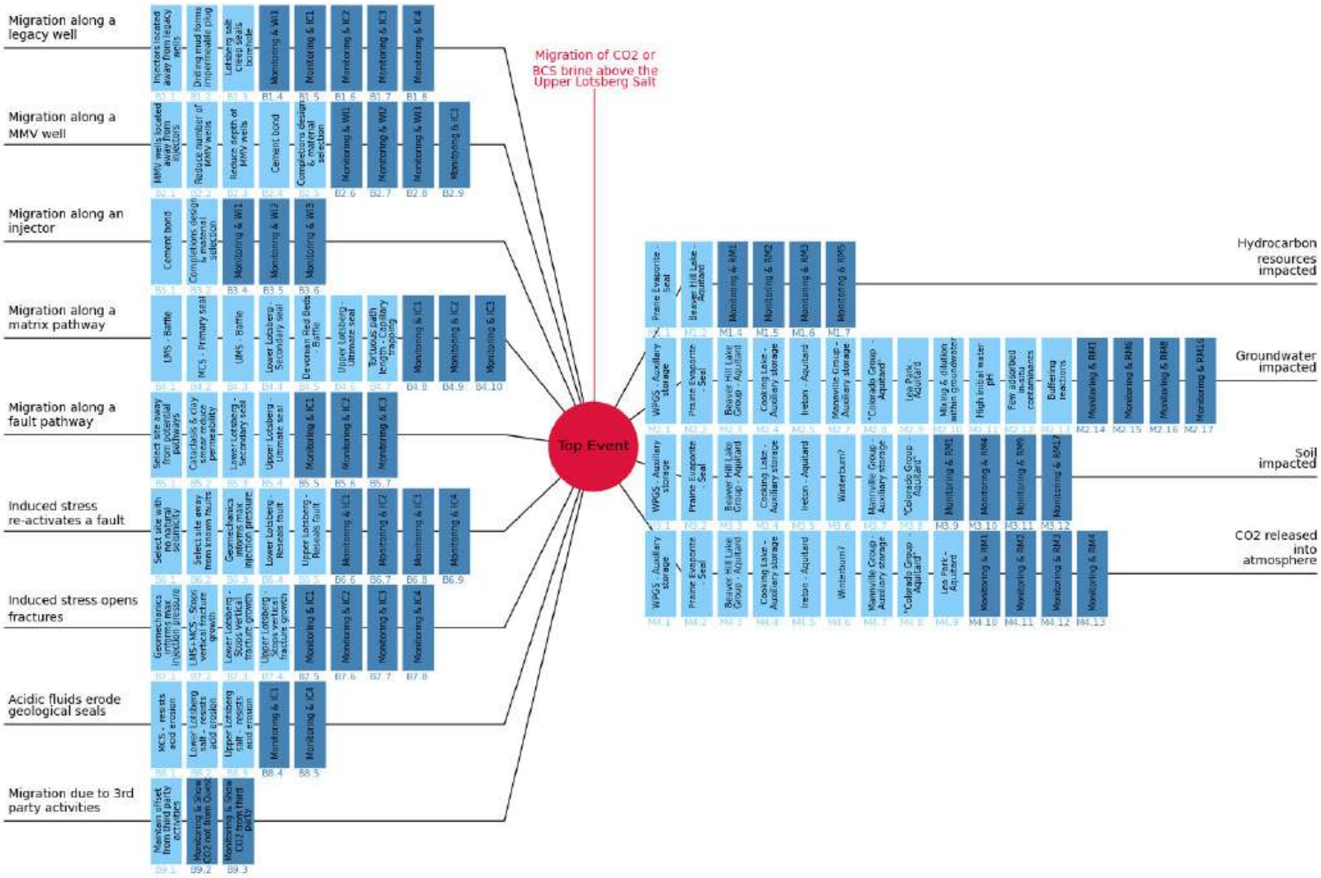

FIGURE 6. Containment Bowtie risk assessment diagram for the Quest CCS project, adapted from de Groot (2011).[12]

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[12] De Groot, Quest CCS Project, Containment Risk and Uncertainty Review, 07-3-AA-6619-004, 2011

ITERATIVE RISK ASSESSMENTS

Risk assessment should be considered a continuous exercise that starts during the scoping of a long-term geological CO_2 storage project and should be updated periodically (in line with industry best practices and applicable regulatory requirements), particularly at any major project milestone or decision gate.

The risk assessment should be based on best available knowledge and data to determine the probability and consequences for each identified risk scenario, whereby any additional data gathered throughout the project lifecycle can be used to revisit (and subsequently iterate) the risk assessment even in the post-injection phase, as applied in the Quest CCS project (Bourne et al., 2014).[15]

Uncertainty characterisation is a key element of risk assessment, where identified uncertainties can underpin future risk assessment and management during the early stages of the project. Uncertainty will be dependent on a number of project-specific characteristics. For example, the initial characterisation of a first-of-its-kind CO_2 storage location in a saline aquifer, i.e., a greenfield site, will be expected to have greater uncertainties up front than a project developed from a depleted oil and gas field. Uncertainties, however, can be effectively reduced in either case through data collection via stratigraphic appraisal wells, seismic surveys, and other activities (e.g., monitoring) throughout a CO_2 storage project's operational period. At site closure, after injection has ceased, storage operators may be expected to demonstrate that all material uncertainties have been resolved to satisfy regulatory or other requirements.

As mentioned earlier, the identified project risks and corresponding risk profile evolve during the project lifecycle, this and post-injection period specific considerations are discussed further throughout Section 4 of this report.

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13 Bourne, S., Crouch, S., & Smith, M. (2014). A risk-based framework for measurement, monitoring and verification of the Quest CCS Project, Alberta, Canada. International Journal of Greenhouse Gas Control, 26, 109-126.

RISK CONTROLS AND SAFEGUARDS

Prior to a regulatory body issuing a permit for CO_2 storage, an operator is required to demonstrate that the selected storage site has an acceptable level of risk. This varies by regulatory regime, e.g., the EU CCS Directive guidance suggests an ALARP (as low as reasonably practicable) approach is suitable, whereas in the UK the regulator deems it necessary to evidence that there is "no significant risk of leakage or harm to human health or the environment."

Hence it is important for the operator to consider risk controls and safeguards when assessing risk and the overall feasibility of a storage site. Risk controls can be either preventive or corrective. Where preventive controls aim to avoid incidents from happening in the first place or minimising the impacts. Corrective controls are measures put in place to manage consequences after an incident has already occurred.

For CO_2 storage, a number of different safeguards can be considered:

- Natural safeguards: Based on the geology, e.g., a laterally extensive seal
- Engineered safeguards: Human-designed technical solutions, e.g., appropriate well design
- Reactive safeguards: Specific operational procedures, e.g., reduction in injection rate

Early risk assessments identifying inherent risks associated with a storage site and development of potential risk controls to understand residual risk is a key element to demonstrate to the regulator that risk associated with a storage site can be brought to an acceptable level.

3.1.2 Risk-based approached to measurement, monitoring, and verification (MMV)

MMV activities should be a core component of risk management, allowing for the assessment of storage project performance and ensuring that CO_2 emission reductions are effective. It's essential to recognize that site- and project-specific conditions must be understood within a risk assessment framework to tailor MMV for maximum effectiveness.

Risk assessment is crucial for prioritizing monitoring efforts by pinpointing the areas and activities that pose the greatest risks. This allows organizations to focus their monitoring actions on effectively mitigating and managing those risks. A MMV program should be tailored to each site to address the specific risks associated with CO_2 storage sites. To develop a reliable and cost-effective monitoring plan, it is essential to identify the highest risks, determine how they can be monitored, and establish the necessary measurements to meet monitoring objectives.

As risk assessment is a continuous process, data collected and new insights from the monitoring program continuously inform and update the assessment and ranking of site risks. By closely integrating risk assessment with MMV, operators can better anticipate and prevent potential issues before they escalate. Establishing a clear baseline for measurements is a valuable tool for benchmarking irregular measurements or leakage events and understanding their relative magnitude. The interaction of risk assessment and MMV also leads to changes to the MMV program throughout the lifecycle of the project, an example of this is the Quest project in Canada (Figure 7), where over time the monitoring plan has been updated by the operator reflecting the most current understanding of site risks.

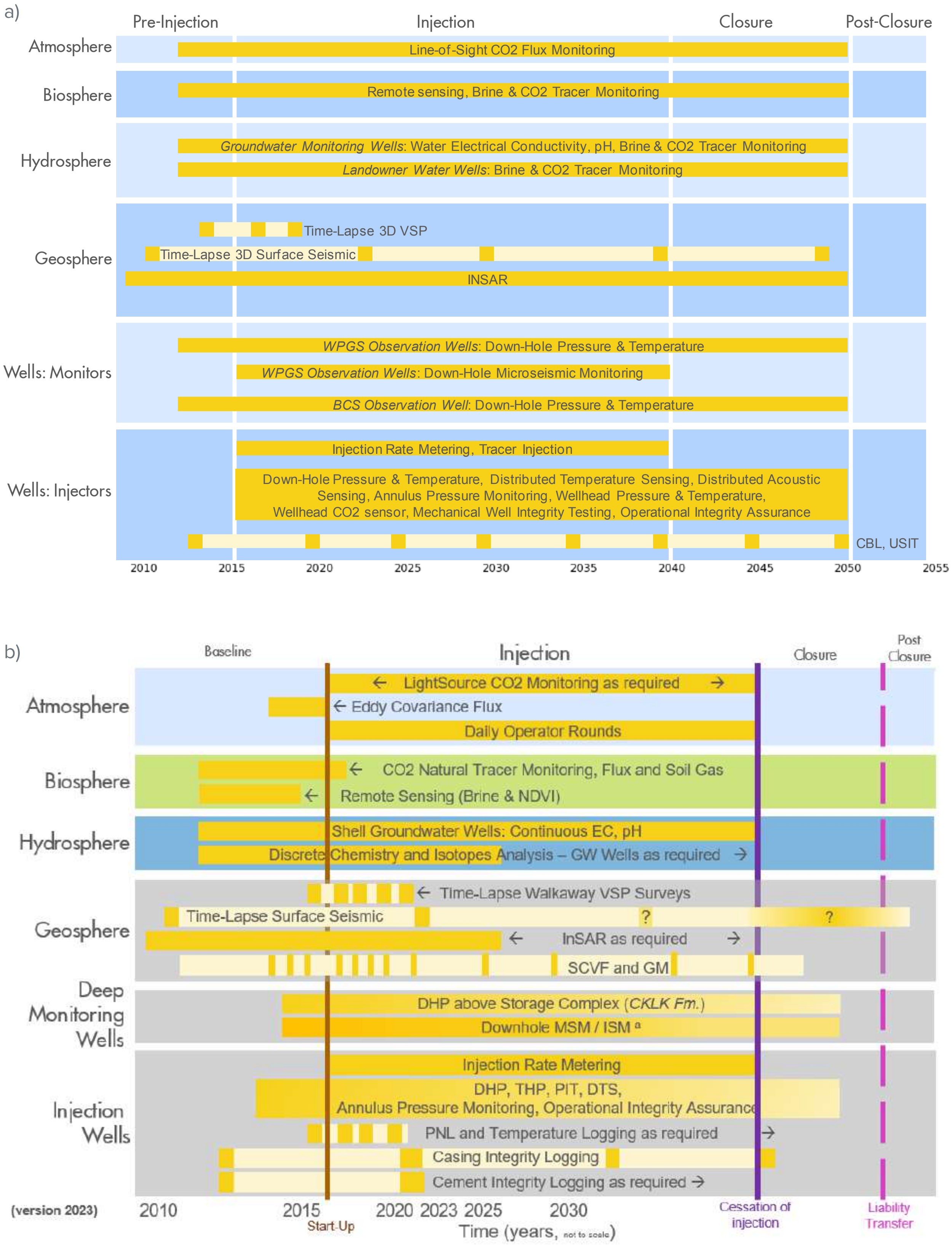

FIGURE 7. a) the initial MMV plan for the Quest CCS project[14] b) the updated MMV plan as of 2023[15]

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[14] https://open.alberta.ca/dataset/46ddba1a-7b86-4d7c-b8b6-8fe33a60fada/resource/00910deb-ff9a-4b11-8282-bce28bc2e2f2/download/measurementmonitoringandverificationplan.pdf

[15] https://static.aer.ca/prd/documents/by-topic/ccus/2023-ShellQuest-MMV-Plan.pdf

3.1.3 Storage environments, settings and concepts

The risks of a CO_2 storage project will vary on a site-specific basis and are impacted by a number of different factors. Of note is the storage environment, which can either be onshore or offshore. Additionally, storage can take place in various subsurface settings, including those that are the focus of this report, saline aquifers or depleted oil and gas fields. The storage environment and setting will ultimately have some influence over capacity, injectivity, containment and monitorability aspects of a project, which feed into the project's overall storage concept. The geological characteristics of the reservoir, caprock, faults and overburden will also impact the risk level of a project.

A variety of storage concepts can be employed to ensure successful CO_2 storage. For instance, projects may rely on the presence of a geological closure to provide structural containment, in which CO_2 will accumulate in a fluid column at the crest of the closure. These are often seen in depleted field settings but are also encountered in saline aquifers settings. Other concepts involve saline aquifer storage in an open system, where CO_2 can be immobilised without the need for confining structural or stratigraphic features (i.e., migration assisted storage).

While many of the same considerations apply or are inherent across the development a wide array of storage concepts, many risks are unique to each individual site and need to be evaluated and mitigated appropriately on a case-by-case basis. In particular for the post-injection phase, the influence of different storage concepts, environments, settings and pressure conditions (Figure 8) may impact the associated remaining risk post-injection, this is discussed throughout Section 4 of this report.

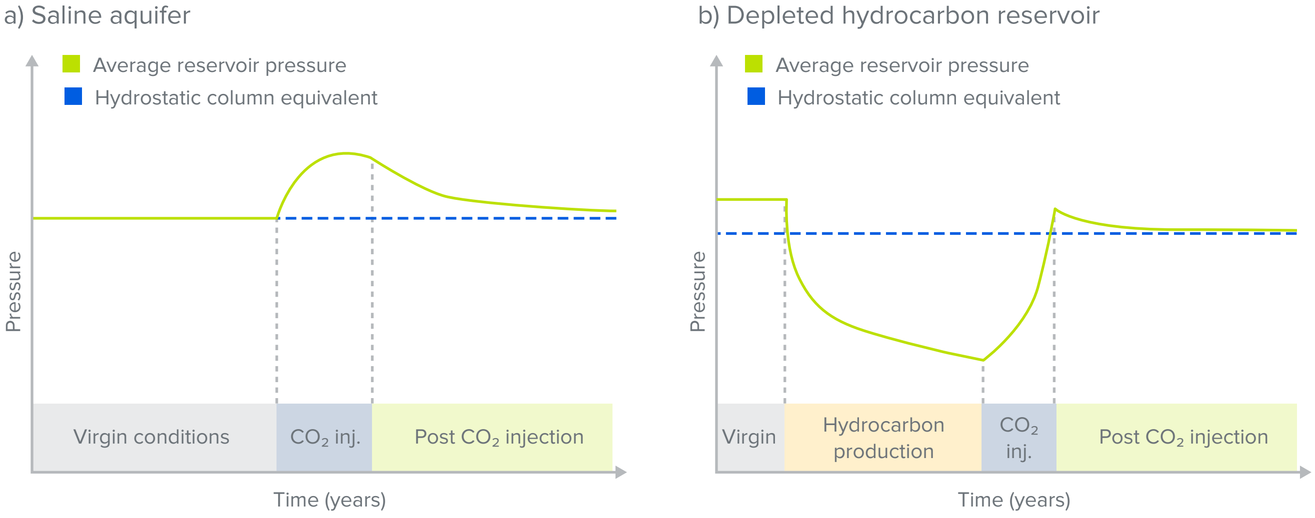

FIGURE 8. Conceptual diagrams showcasing dynamics of reservoir pressures for a typical (a) saline aquifer and (b) depleted reservoir (adapted from Torsæter et al., 2024).[16]

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[16] Torsæter, Malin and Bello-Palacios, Alejandro and Borgerud, Line Kristin and Nygård, Ole-Kristian and Frost, Tone Karin and Hofstad, Karina Heitnes and Andrews, Jamie Stuart, Evaluating Legacy Well Leakage Risk in Co2 Storage (December 18, 2024). Proceedings of the 17th Greenhouse Gas Control Technologies Conference (GHGT-17) 20-24 October 2024, Available at SSRN: https://ssrn.com/abstract=5062896 or http://dx.doi.org/10.2139/ssrn.5062896

3.1.4 Long-term storage of CO_2 and the post-injection phase

The ultimate objective of CCS is to inject CO_2 within the subsurface for long-term storage for emissions reduction or removal. However, it must be noted that there are different interpretations of “long-term” within the literature, for the purposes of ensuring effective climate change mitigation estimates range from the order of 1,000 (Brunner, et al., 2024[17]) to 10,000 years (i.e., Lindeberg, 2003;[18] Miocic, et al., 2016;[19] Alcalde, et al., 2018[20]).

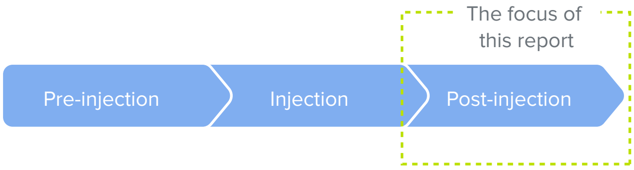

FIGURE 9. Project lifecycle stages highlighting this report’s focus on the post-injection phase, which includes regulatory jurisdiction specific milestones such as Transfer of Responsibility under the EU CCS Directive (see Figure 4).

The post-injection phase can generally be divided into two periods: an initial phase leading up to regulatory site closure, followed by a postclosure phase that begins once regulatory approval has been granted (Figure 9). The timeline for regulatory closure varies by jurisdiction ranging from 20 years and up to 50 years, in some jurisdictions following this closure there is the potential to transfer liability back to the state (see Section 6). When considering the risks related to CO_2 storage, these are typically greatest during the operational lifetime, i.e., during the injection phase. Some risks are expected to reduce in likelihood when moving into the post-injection phase (see Section 4.5), the post injection phase is significantly longer than the injection phase (i.e., the operational period) of projects.

To date, there are few projects that are actively within the post-injection phase, as such best practise for it is difficult to define. The CO_2CARE project,[21] which concluded in 2014, aimed to put forward a set of pragmatic and workable generic procedures and best practises for future closure and long-term post closure safety of sites in Europe. The project focused on three CO_2 storage sites in Europe, namely Sleipner (offshore Norway), K-12B (offshore Netherlands) and Ketzin (onshore Germany) for the development of these guidelines. Ketzin is an example of a pilot project that is currently in the post-injection phase of its lifecycle.

3.1.5 Fate of stored CO_2

When considering how effective long-term storage of CO_2 in the subsurface is, it is important to understand the different mechanisms that ensure containment. Within the targeted storage formation, CO_2 may be trapped vertically and laterally through five different mechanisms:

1. **Structural trapping:** CO_2 is physically trapped by formations that have been naturally deformed and arranged over geologic time into a structural feature which forms a closure, such as a dome or fault block
2. **Stratigraphic trapping:** CO_2 is physically trapped by low-permeability formations (i.e., confining units) that are arranged over geologic time into a stratigraphic feature which forms a closure, such as a channel complex
3. **Residual trapping:** CO_2 is physically trapped within formation pore space along the migration path

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[17] Brunner, C., Hausfather, Z. & Knutti, R. Durability of carbon dioxide removal is critical for Paris climate goals. Commun Earth Environ 5, 645 (2024). https://doi.org/10.1038/s43247-024-01808-7

[18] Lindeberg, E. (2003) The Quality of a CO_2 Repository: What Is the Sufficient Retention Time of CO_2 Stored Underground. Proceedings of Greenhouse Gas Control Technologies 6th International Conference (GHGT-6), Elsevier Science Ltd., Amsterdam, 255-260.

[19] Johannes M. Miocic, Stuart M.V. Gilfillan, Jennifer J. Roberts, Katriona Edlmann, Christopher I. McDermott, R. Stuart Haszeldine, Controls on CO_2 storage security in natural reservoirs and implications for CO_2 storage site selection, International Journal of Greenhouse Gas Control, Volume 51, 2016,

[20] Alcalde, J., Flude, S., Wilkinson, M. et al. Estimating geological CO_2 storage security to deliver on climate mitigation. Nat Commun 9, 2201 (2018). https://doi.org/10.1038/s41467-018-04423-1

[21] CO_2CARE, 2013, D5.4 Best Practice Guidelines

4. **Solubility trapping:** CO_2 is chemically trapped as it dissolves into formation water, reducing the amount of free-phase CO_2 remaining in the subsurface

5. **Mineral trapping:** CO_2 is chemically trapped as it reacts with both the formation and formation water to form minerals in the subsurface

The influence of each trapping mechanism varies with time, a traditional idealised depiction of this is shown in Figure 10 (A). When considering the long-term fate of stored CO_2, particularly post-injection, it is important to highlight that the influence of each trapping mechanism is dependent on subsurface characteristics and storage setting that vary on a site-specific basis. An example of this is shown in Figure 10 (B), and other modelling studies have investigated the influence of each trapping mechanism over a number of scenarios.[22] Overall, it is likely that for a given project, the amount of free-phase CO_2 trapped reduced over time, which influences the level of post-injection risk.

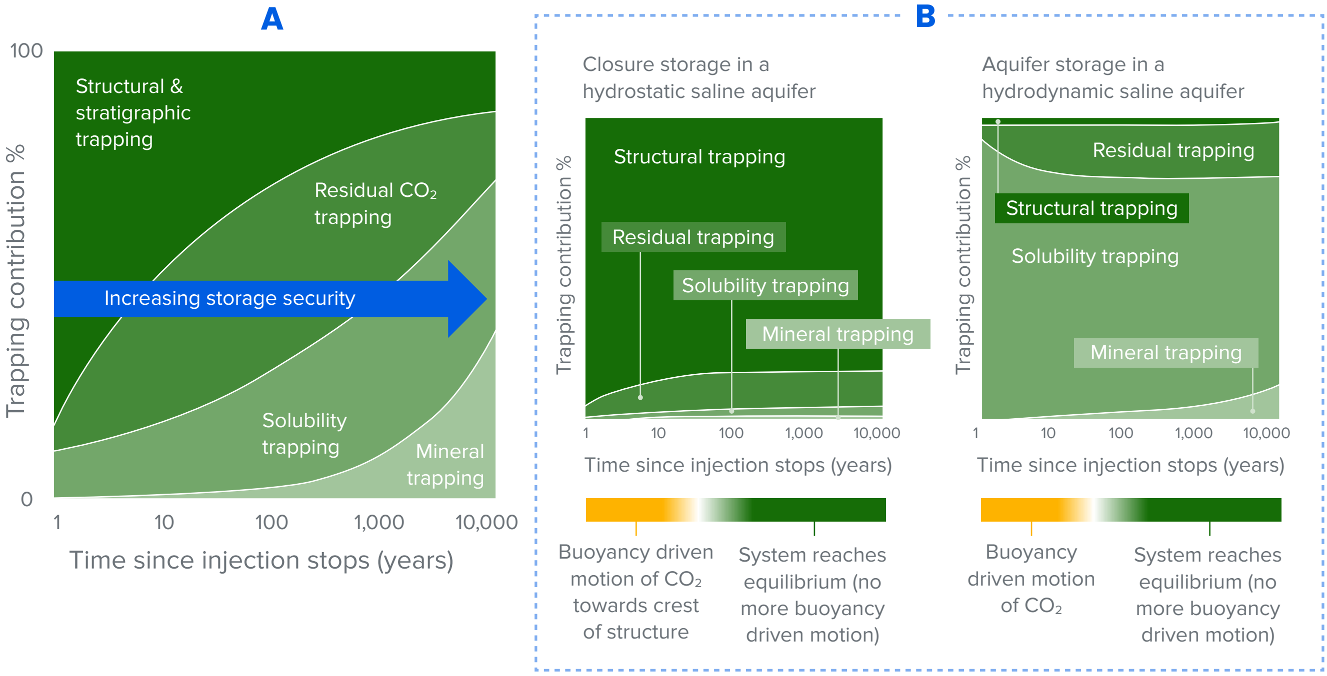

FIGURE 10. (A) Representation of storage security based on various expected trapping mechanisms (after IPCC, 2005).[23] (B) An adaptation of the 2005 IPCC figure, based on two storage scenarios (after Shoulders & Hodgkinson, 2024).[24] Note that structural and stratigraphic trapping are combined in (A) and (B), despite the label only including structural trapping in (B).

3.1.6 Quantification of risk and event probabilities

The nature of large projects encourages the precise calculation of risk – whether that is through “measurable uncertainty” or explicitly as “uncertainty associated with an event that can be quantified on the basis of empirical observations of causal knowledge.”

One potential advantage of quantifying risks (i.e., via QRA) might be the greater precision that it offers.

Qualitative expressions of risk are typically rather vague and subjective, whereas quantitative risks appear to be precise and objective. In reality, and contrary to the impression sometimes given by authors of QRA studies, quantified risks are often highly uncertain and sensitive to many choices that are rooted in the judgement of the analyst, their industry and the expected consumer. This is highlighted further when considering QRA specifically for CO_2 leakage risks, given there are little to no recorded incidents

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[22] Snippe & Tucker, CO_2 fate comparison for depleted gas field and dipping saline aquifer. 2014, GHGT-12

[23] IPCC, Special Report on Carbon Dioxide Capture and Storage, 2005

[24] A process-led approach to framing uncertainty and risk in CO_2 storage in the subsurface, Shoulders & Hodgkinson, 2024

of leakage from CO_2 storage making the absolute quantification of any risk difficult.

Typically, for a CO_2 storage project, there is a semi-quantification applied to risk to understand the likelihood of occurrence, as well as understanding the magnitude of the consequence (e.g., the volume of CO_2 at risk from a specific CO_2 leakage threat). There are several studies in recent years that have attempted to better quantify the likelihood and severity leakage from CO_2 storage projects on a long-term basis. The following section outlines the most recent studies and understanding in this area, as well as discussing analogues from the underground natural gas storage industry.

3.1.6.1 Deep geological storage of CO_2 on the UK Continental Shelf

Published in February 2023, the Crondall Energy report,[25] is a view of the UK Continental Shelf and the potential quantification of risks associated with the storage of CO_2. The report was commissioned by the UK Government and as such can be viewed as being moderately independent. External verification of the work additionally leads some credence to their findings.

In summary, the report established the following:

- While the risk of leaks from both wells and geological pathways is low, depleted field storage sites are more likely to have well containment issues than geological ones. Saline aquifers might have higher geological risks because of limited knowledge. However, the corollary is that fewer wells at a storage site means the risk of well leaks is lower. Legacy wells decommissioned prior to planning for future CCS projects have a higher risk of leakage.

- Most leaks, whether from geological or well pathways, are likely to be small. The authors believed that major leaks from geological features at UK storage sites are unlikely for both depleted fields and saline aquifers. The significant loss of containment events from wells are unlikely, especially if the injection wells are designed and constructed to modern standards.

The breakdown of these risks for depleted and saline aquifers are shown in Table 2 and Table 3 considering a 25 year injection period at a rate of 5 Mt/yr of CO_2.

TABLE 2. Probability of leakage for depleted fields, reproduced from Crondall Energy (2023).

Overall depleted oil or gas field storage site results	Leak category (and pathway sub-mechanism)	Probability of occurrence		Context of probability estimate	Leak rate (tonne/day)	
		Max.	Min.		Max.	Min.
Active wells (including monitoring wells)	Seep	1.00E-01	1.00E-03	Per well	1	0.1
	Minor	1.00E-03	1.00E-05	Per well per annum	50	1
	Moderate	1.00E-04	1.00E-05	Per well per annum	1000	50
	Major	1.00E-05	1.00E-06	Per well per annum	5000	1000
Inactive wells	Seep	1.00E-01	1.00E-03	Per well	1	0.1
	Minor	1.00E-03	1.00E-04	Per well per annum	50	1
	Moderate	1.00E-04	1.00E-05	Per well per annum	1000	50
	Major	1.00E-05	1.00E-06	Per well per annum	5000	1000

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[25] Deep geological storage of carbon dioxide (CO_2), offshore UK: containment certainty - GOV.UK

Overall depleted oil or gas field storage site results	**Leak category (and pathway sub-mechanism)**		**Probability of occurrence**		**Context of probability estimate**	**Leak rate (tonne/day)**	
			Max.	**Min.**		**Max.**	**Min.**
Through caprock	Diffusion		Negligible for UKCS		10x10 m area after 1,000,000 years	2.74E-06	2.74E-08
	Capillary flow through intact caprock		Negligible for UKCS		For 10x10 m area after 1,000 years	2.74E-05	2.74E-09
	Lateral variability in caprock lithology		Negligible for DOGF in UKCS		For 1x1 km area, after 100 years	43	4.3
Faults (and fractures)	Major tectonically/ volcanically active fault zone		Negligible for UKCS		Per fault zone	5479	27.4
	Large block-bounding fault zone	Minor	1.00E-04	1.00E-05	Per fault zone	2.7	2.7
	Map-scale faults	Seep	1.00E-03	2.74E-04	Per fault zone	1	0.27
		Minor	2.74E-04	1.00E-04		2.7	1
	Sub-seismic scale faults & fracture network	Seep	2.50E-03	2.02E-04	Per site	1	0.027
		Minor	2.02E-04	1.00E-04		2.7	1
Induced faulting/ fracturing	Reactivation of pre-existing faults	Seep	1.00E-03	5.23E-04	Per site	1	0.27
		Minor	5.23E-04	1.00E-04		27.4	1
	Initiation of new faults/fractures	Seep	1.00E-03	5.23E-04	Per site	1	0.27
		Minor	5.23E-04	1.00E-04		27.4	1
Gas chimneys/ pipes	Seep		2.50E-03	2.66E-04	Per feature	1	0.1
	Minor		2.66E-04	1.00E-04		2.7	1
Lateral migration	Seep		2.67E-03	6.30E-04	Very site-specific averaged geological risks used to derive notional values	1	0.027
	Minor		6.30E-04	1.70E-04		27.4	1

TABLE 3. Probability of leakage for saline aquifers, reproduced from Crondall Energy (2023).

Overall confined saline aquifer storage site results	Leak category (and pathway mechanism)		Probability of occurrence		Context of probability estimate	Leak rate (tonne/day)		Duration (years/event)
			Max.	Min.		Max.	Min.	
Active wells (including monitoring wells)	Seep		1.00E-01	1.00E-03	Per well	1	0.1	25
	Minor		1.00E-03	1.00E-05	Per well per annum	50	1	0.5
	Moderate		1.00E-04	1.00E-05	Per well per annum	1000	50	0.33
	Major		1.00E-05	1.00E-06	Per well per annum	5000	1000	0.33
Inactive wells	Seep		1.00E-01	1.00E-03	Per well	1	0.1	125
	Minor		1.00E-03	1.00E-04	Per well per annum	50	1	0.5
	Moderate		1.00E-04	1.00E-05	Per well per annum	1000	50	0.33
	Major		1.00E-05	1.00E-06	Per well per annum	5000	1000	0.33
Through caprock	Diffusion		Negligible for UKCS		10x10 m area, after 1,000,000 years	2.74E-06	2.74E-08	0
	Capillary flow through intact caprock		Negligible for UKCS		For 10x10 m area after 1,000 years	2.74E-05	2.74E-09	0
	Lateral variability in caprock lithology		5.00E-03	5.00E-04	For 1x1 km area, after 100 years	43	4.3	10
Faults (and fractures)	Major tectonically/ volcanically active fault zone		Negligible for UKCS		Per fault zone	5479	27.4	0
	Large block-bounding fault zone	Minor	1.00E-03	5.00E-04	Per fault zone	1370	2.7	25
	Map-scale faults	Seep	1.00E-02	5.23E-03	Per fault zone	1	0.27	100
		Minor	5.23E-03	1.00E-03		27.4	1	100
	Sub-seismic scale faults & fracture network	Seep	1.25E-02	3.35E-03	Per site	1	0.027	100
		Minor	3.35E-03	1.00E-03		27.4	1	100
Induced faulting/ fracturing	Reactivation of pre-existing faults	Seep	1.00E-02	5.23E-03	Per site	1	0.27	100
		Minor	5.23E-03	1.00E-03		27.4	1	100
	Initiation of new faults/fractures	Seep	1.00E-02	5.23E-03	Per site	1	0.27	100
		Minor	5.23E-03	1.00E-03		27.4	1	100
Gas chimneys/ pipes	Seep		1.00E-02	3.00E-03	Per site	1	0.1	100
	Minor		3.00E-03	1.00E-03		8.2	1	100
Lateral migration	Seep		1.75E-02	5.40E-03	Very site-specific averaged geological risks used to derive notional values	1	0.027	100
	Minor		5.40E-03	1.83E-03		27.4	1	25

Although the report is extensive and utilises many different sources of information for the analysis, there are a number of considerations associated with it.

- Firstly, it considers the UKCS, which is a tectonically quiescent area of moderate water depth, correctly plugged legacy wells and generally within easy access of logistical hubs should the need arise – these feed into both the frequency of events and the magnitude of leaks.
- As well as this, given it considers only the UKCS, it is less applicable to other regions and onshore settings.
- Furthermore, the assumption that the caprock/ultimate sealing formation is at least 400 m thick and consistent across the entire storage site can be the only reason for the negligible probability associated with diffusion and capillary flow.
- The ultimate probabilities of risks, their impacts on the loss of CO_2 are not reproduced here due to their direct link to several criteria assumptions.

3.1.6.2 Storage security calculator

Alcalde et al.,[26] developed the Storage Security Calculator (SSC) in 2018, which is a numerical model designed to simulate CO_2 retention and leakage over a 10,000-year period. The model evaluates three scenarios: Offshore well-regulated, Onshore well-regulated, and Onshore poorly-regulated, with each representing varying levels of regulatory oversight and geological conditions. In well-regulated scenarios, the model predicts over 98% CO_2 retention with leakage rates below 0.0008% per year. Even under poorly regulated conditions, retention remains above 78%, although early leakage rates may exceed 0.5% annually. The study identifies abandoned wells as the most significant risk factor for leakage and uses Monte Carlo simulations to confirm the robustness of its predictions across a wide range of uncertainties. Importantly, even in worst-case scenarios, natural subsurface trapping mechanisms effectively limit long-term leakage.

The study concludes that geological CO_2 storage is a secure and resilient climate mitigation strategy, particularly under well-regulated conditions. However, it also highlights uncertainties in the long-term subsurface behaviour of CO_2, emphasising the need for continued monitoring and conservative risk assessment.

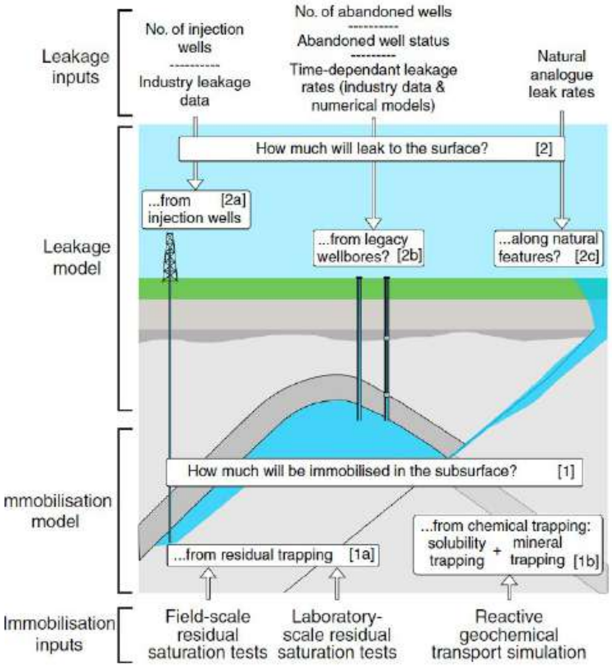

FIGURE 11. Schematic of the Storage Security Calculator (SSC) model (adapted from Alcalde et al., 2018).

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26 Alcalde, J., Flude, S., Wilkinson, M. et al. Estimating geological CO_2 storage security to deliver on climate mitigation. Nat Commun 9, 2201 (2018). https://doi.org/10.1038/s41467-018-04423-1

TABLE 4. Percentage of CO_2 that leaked in various scenario (reproduced from Alcalde et al., 2018).

Scenario	Time (year)	CO_2 leaked (%)[b]			
		Base case[c]	P95[c]	P50[c]	P05[c]
Offshore Well-Regulated	1	0.000755	0.000506	0.000779	0.00144
	100	0.0286	0.0249	0.0447	0.0888
	1000	0.0744	0.0709	0.213	0.646
	10,000	0.532	0.483	1.89	6.29
Onshore Well-Regulated	1	0.00201	0.00133	0.00217	0.00451
	100	0.0861	0.0737	0.156	0.358
	1000	0.269	0.246	0.888	2.96
	10,000	2.1	1.81	8.18	25.71
Onshore Poorly Regulated	1	0.215	0.0517	0.202	0.521
	100	6.71	1.7	6.41	16.5
	1000	7.12	2.39	8.05	20
	10,000	11.3	6.91	22	32.6

Notes:

The leakage values are expressed as a percentage of originally injected CO_2. Example times are presented at t = 1, 100, 1000 and 10,000 years

a Three scenarios are represented, to illustrate regional storage security decreasing from well-regulated to poorly-regulated

b The total leakage percentages are calculated by adding together all the yearly increments of leaked CO_2 calculated for each model run. Values reported to three significant figures

c Four probabilities of CO_2 leakage are chosen to be represented: a Base Case, where the model parameters are selected by expert judgement, and Monte Carlo results of sampling the whole probability range of each parameter in the Immobilisation and Leakage model datasets. P95 means that 95% of the calculated leakage values are greater than the percentage calculated (not a 90% probability of occurrence), P50 represents that 50% of values will be greater (the median), and P05 means that 5% of the calculated leakage values from the original total injected (not a 10% probability) are greater than the calculated percentage. Conventional reporting of statistics of subsurface hydrocarbon reserves and resources, or of the greatest possibility of an outcome, use P50 (the median) as the most probable outcome

3.1.6.3 Underground natural gas storage

For the US, underground natural gas storage is a crucial component for the country's energy system to provide security of supply in the event of supply disruption or excessive energy demand. The majority (79%) operate in depleted oil and gas reservoirs and 12% from saline aquifers – making their operation, risk events, probability and mitigations quite analogous to the CCUS industry.

Published in 2024, the Lackey et al. paper[27] details the results of federal investigations that only started in 2017 as a result of a well leakage incident for the Aliso Canyon underground storage facility in California. Before 2017, the evaluations of operations had been state-controlled, and the frequency and rigor varied across the country.

Key takeaways:

- Casing and wellhead failure were the most frequent cause of well leakage events, with human activity (or inactivity) being the primary cause through incorrect operation and corrosion control being the main causes.
- Corrosion of the production tubing resulted in the largest volume of gas being released, even though it accounts for only 1 of the 53 reported incidences.

Operators chose to isolate problem wells rather than report safety-related concerns.

- 450 incidences occurred which were below the threshold value for reporting during the same period.
- It is important to note that wells designed for natural gas storage are typically designed for cyclical operations, resulting in the well components being exposed to pressure and temperature cycling, which can have an adverse effect on well integrity. The operating conditions of CO_2 injection wells will differ.

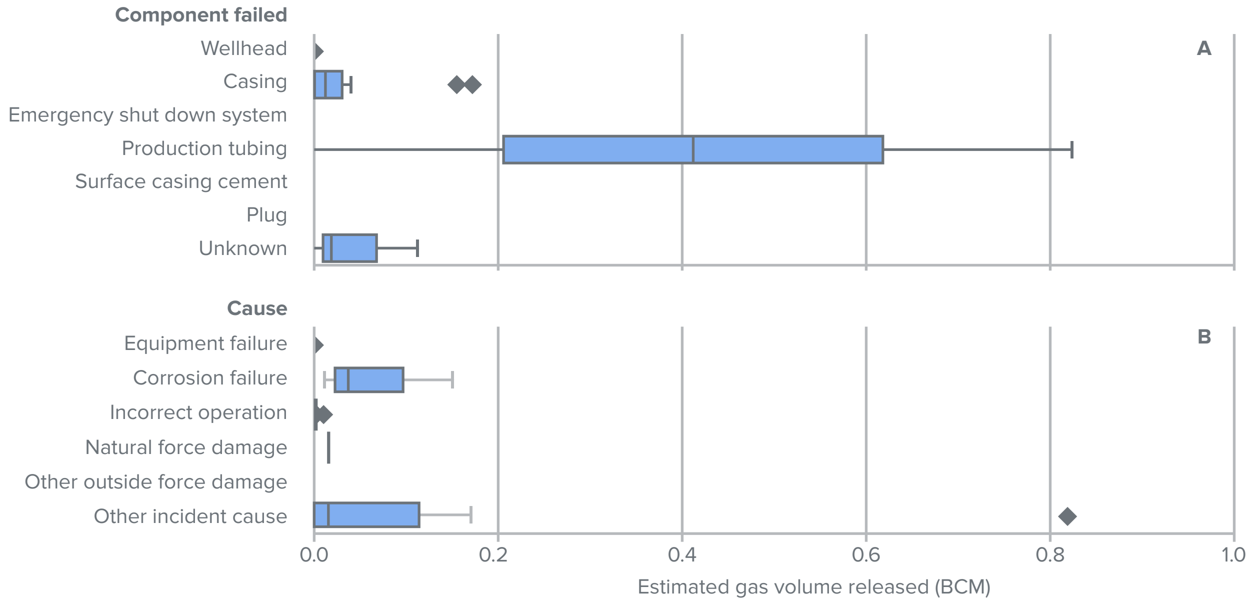

FIGURE 12. Cause and component failures of US gas storage wells.

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27 Lackey, G. et al., 2024. Underground natural gas storage facility operations and well leakage events in the United States

04

Post-injection CO_2 storage risks

Photo: Adobe Stock

4. Post-injection CO_2 storage risks

This report's main focus is around the post-injection phase and the approaches for managing any potential risks to a CO_2 storage project that may remain following the cessation of injection. Establishing inherent risks and understanding remaining risks of the CO_2 storage project as it progresses through the post-injection phase is critically important, particularly in the context of some regulatory regimes that have mechanisms enabling the transfer of long-term liability to the state.

Plausible subsurface-related CO_2 storage risks which could materialise over the course of the post-injection phase of the project are considered in relation to the keys to storage (i.e., capacity, containment, injectivity, monitorability and non-technical). This is because once injection has ceased, previous risks related to CO_2 capacity and injectivity are no longer relevant, meaning that containment and monitorability related risks are the only technical ones remaining from a subsurface perspective. Whilst not strictly grouped with containment and monitorability, risks related to seismicity and pressure communication from other subsurface activities are also discussed throughout this section.

Section 4 is structured to first provide a description of each risk and its occurrence, how the risk is likely assessed, managed and mitigated against during the pre-injection and injection phases (Section 4.1–Section 4.4), highlighting considerations for different storage settings. This is then followed by a description of how these risks may be expected to evolve through to the post-injection phase (Section 4.5, Figure 13). Finally, within Section 4.6 there is a discussion around the risk profile throughout the project lifecycle and how that may be expected to evolve, with considering preventative and corrective barriers and safeguards in place.

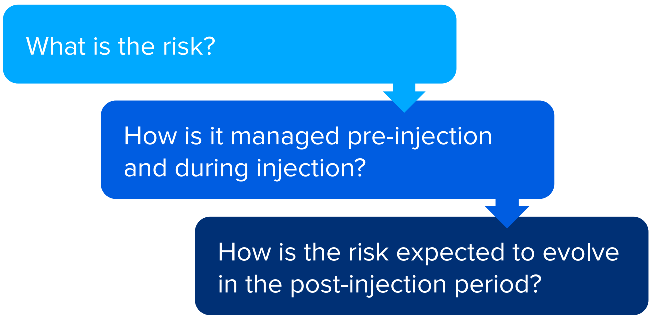

FIGURE 13. Conceptual structure of Section 4.

4.1 CO_2 containment

Ensuring subsurface containment of injected CO_2 is fundamental throughout the storage project lifecycle. This includes the post-injection phase because the CO_2 will continue to move, yield to trapping mechanisms, and equilibrate within the subsurface for many years after injection. Many definitions for CO_2 leakage from the subsurface are available within the CCUS industry and across different regulatory regimes. For the purposes of this report, leakage is defined as in ISO 27914, i.e., "an unintended release of CO_2 outside of a pre-defined *containment* (retention of CO_2 within a *storage complex*)." Thus, the storage complex is a pre-defined subsurface geological system, which extends vertically to include the storage unit(s), confining formation(s) or seals, and laterally to the defined limits of a storage location. Figure 14 depicts a conceptual diagram illustrating the nature of the storage complex, according to the EU, but the definition of leakage varies in different regions. For example, within the EU, movement of free-phase CO_2 (i.e., not dissolved in water) within the storage complex is defined as migration, and the movement of free-phase CO_2 outside the defined storage complex is classified as leakage. It is important to note that whilst the CO_2 may have leaked outside of a defined storage complex, this does not mean that the CO_2 will eventually leak into the atmosphere (i.e., emissions) or result in environmental consequences. Some only refer to leakage if it results in an environmental impact and would refer to movement of CO_2 outside of a storage complex as "out-of-zone migration" or "non-conformance" posing a regulatory compliance risk only.

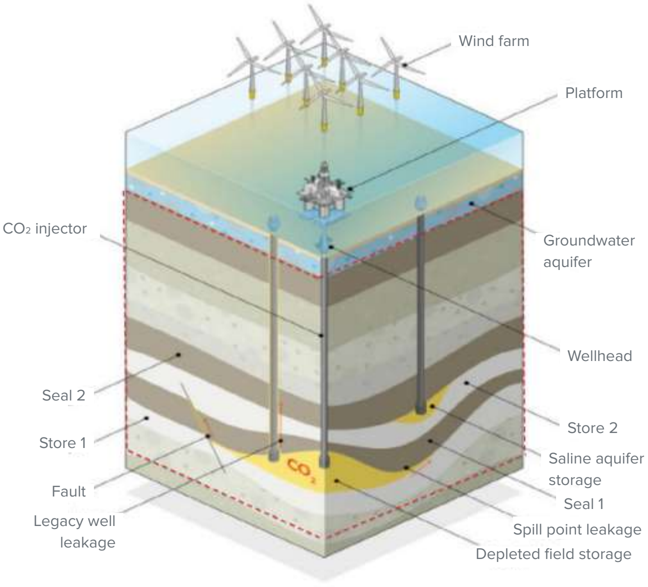

FIGURE 14. DNV illustration depicting the four main categories of leakage pathways from a storage complex. The red dashed line shows the boundary of the storage complex. The potential migration and leakage pathways are indicated by the red-coloured arrows (modified from EU CCS Directive Guidance Document 1, 2024).

Much like the boundaries and stratigraphic units of a given storage complex, potential CO$_2$ leakage pathways and their impact on containment must thoroughly be identified and characterized. The boundaries of the storage complex may even be designed in such a way that the injected CO$_2$ may remain separated from potential leakage pathways. These pathways can be divided into natural (i.e., geological) and artificial pathways, where leakage could be relevant under a variety of project- and site-specific scenarios and conditions, even once CO$_2$ injection operations have ceased. Below, each of these leakage pathways are described, also highlighting approaches to characterising, managing and mitigating against the potential post-injection risks.

4.1.1 Natural leakage pathways

In the post-injection phase of a storage project, potential natural pathways related to CO$_2$ storage projects include those which facilitate leakage:

- vertically through the sealing formations;[28]
- vertically along transmissive faults or fractures intersecting the storage complex;
- vertically through or along other geological features (e.g., igneous features); or
- via lateral migration out of the storage complex and/or leading to another leakage pathway.

4.1.1.1 Vertically through sealing formations

The potential for CO$_2$ leakage through sealing formations is a key containment risk that is thoroughly assessed and mitigated against prior to the selection and development of a storage location, where the understanding may be refined over the course of the project. A seal may be achieved by either a single geological formation or multiple formations overlying the injection zone, each of which have properties or characteristics that restrict the upward migration of CO$_2$. In some cases, a sealing formation will be far less permeable than the injection reservoir, relatively thick and laterally extensive. Whilst not always a requirement, storage operators may identify a primary sealing formation that is also overlain by additional permeable layers (e.g., another reservoir), followed by other sealing formations which can provide supplementary barriers to leakage (i.e., secondary sealing formations) before reaching the stratigraphic overburden or surface.

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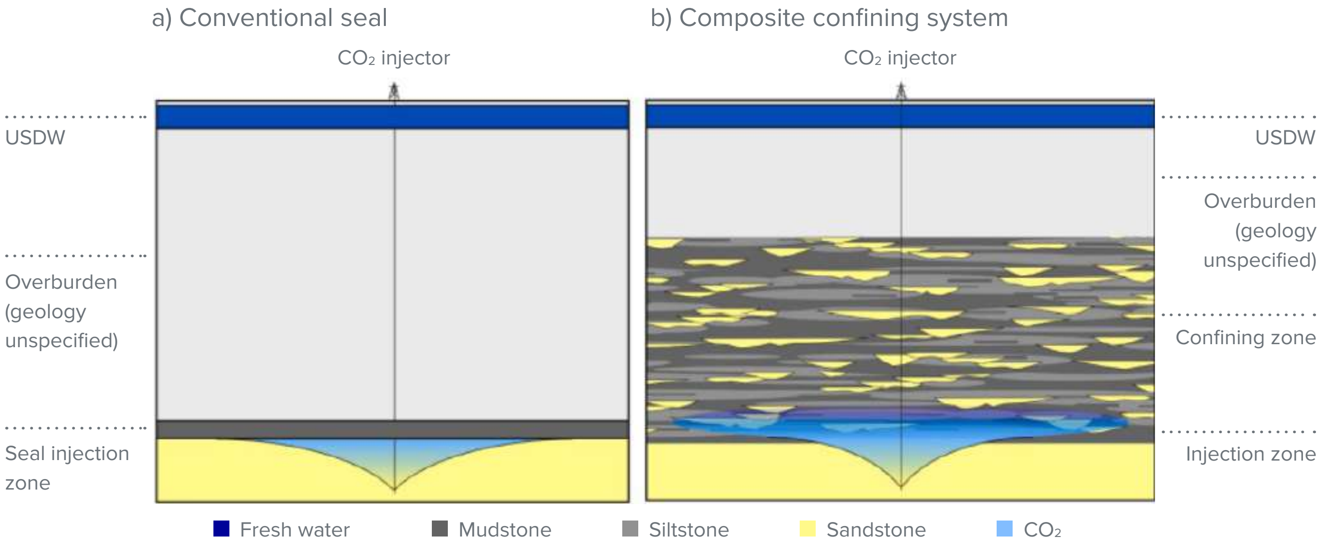
[28] Often times in the literature the term “caprock” is used interchangeably with a sealing formation. For this report, the definition of a sealing formation is found in Section 4.1.1.1



Seal characteristics	Composite confining zone characteristics
Discrete geologic unit	Composite zone of varying geologic units
Homogeneous	Heterogeneous
Laterally continuous	Individual units may be laterally discontinuous
High capillary entry pressure	No a priori capillary entry pressure requirement
No a priori thickness requirement	Aggregate thickness of 100s of meters
No invasion of CO_2 expected	Some invasion of CO_2 is expected

FIGURE 15. Conceptual diagram of a conventional "sealing formation" (A) and (B) a composite confining zone made up of collection of barriers, adapted after Bump et al., (2023).[29]

CO_2 leakage through sealing formations can result from a variety of potential causes, including but not limited to:

- poor or variable lithological properties or features within the undeformed sealing formation which may enable CO_2 leakage via diffusion or capillary effects;
- thermal interactions or geochemical reactions between the injected CO_2, formation fluids and sealing formation, reducing seal integrity; or
- existing deformational features (e.g., faults, connected networks of permeable natural fractures, or fractures due to;
- increased pressure or other deformation mechanisms; discussed in more detail in Section 4.1.1.2.

Assessment, management and mitigation

Proper subsurface characterisation plays a key role in assessing risk related to leakage through sealing formations. In many cases, such risks to seal integrity can be mitigated or avoided during the injection and post-injection phases if properly assessed early in the pre-injection phase (e.g., the Appraise period). Storage operators assess the nature of the sealing formation with respect to its presence on a regional to storage site scale, using the best available data. Subsurface data (e.g., geophysical, petrophysical, lithological, geochemical, geomechanical etc.) and geological assessments (e.g., depositional environments) may be used to characterise the sealing potential. This could stem from exploration/appraisal well drilling, 3D seismic mapping, as well as studies focused on the regional geology, among other sources. Additionally, more specialized studies, such as geochemical modelling, can help with assessing the quality of the

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[29] Alexander P. Bump, Sahar Bakhshian, Hailun Ni, Susan D. Hovorka, Marianna I. Olariu, Dallas Dunlap, Seyyed A. Hosseini, Timothy A. Meckel, Composite confining systems: Rethinking geologic seals for permanent CO_2 sequestration, International Journal of Greenhouse Gas Control, Volume 126, 2023,

sealing formation. In cases where depleted oil and gas reservoirs are being developed for CO_2 storage, uncertainty around the ability of the sealing formation to contain CO_2 is reduced due to the previous ability to contain hydrocarbons, provided there has not been significant deformation compromising the geomechanical integrity of the seal and the amount of CO_2 injected and pressure increases do not exceed the sealing capacity of the rock. Monitoring plans, fit-for-purpose injection programs, appropriate CO_2 specification, and corrective measures plans also help manage the risk of leakage in the post-injection phase. Possible remediations in a case of leakage through sealing formations may consist in decreasing injection pressures, targeting deeper storage formations, or ensuring that shallower seals will be efficient for CO_2 storage.

For a more detailed view on methods to characterise and evaluate seal integrity, refer to IEAGHG Technical Report 2024-06.[30]

4.1.1.2 Vertically through faults or fractures

Faults and fractures represent deformation features which may be present within otherwise undeformed geological units, including those comprising the storage complex (e.g., the sealing formation). As such, faults and fractures within the storage complex could represent CO_2 leakage pathways depending on their location, geometry, and other characteristics (e.g., Figure 16). The potential pathways include but are not limited to:

- faults which are permeable due to poor fault rock properties, mechanical reactivation by natural seismicity (e.g., tectonically), or mechanical reactivation by induced seismicity (e.g., from related or nearby industrial subsurface activities such as CO_2 injection);
- pre-existing fracture networks which are “open” (i.e., uncemented or stress dependent) and vertically extensive enough to allow for CO_2 leakage; or
- pre-existing fracture networks reopened or new fractures created as a result of storage operations or other causes, which are vertically extensive enough to allow for CO_2 leakage.

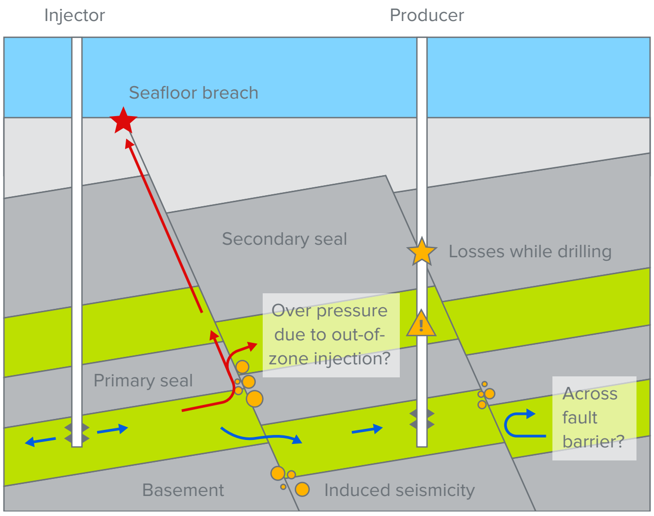

FIGURE 16. Schematic example showing potential CO_2 migration pathways across or along faults, adapted from Bisdom & Chan, 2024.[31]

Leakage along faults or fractures can occur due to existing, inherent conductivity or created conductivity due to opening, propagation, shear, or initiation. Faults or fractures may be inherently conductive via geological processes which negatively affect their sealing potential. In the case of created conductivity, it may be the result of CO_2 storage operations, or from prior hydrocarbon production if applicable. Dynamic aspects, such as geochemistry, thermal effects, and pressure changes are important considerations. It must also be noted that faults and fractures have been observed as conductivity baffles or barriers, highlighting that the level of leakage risk they represent will depend on site-specific conditions.

Assessment, management and mitigation

To address their threat to CO_2 leakage, the number, spacing, connectivity, geometry (e.g., vertical extent), tectonic history, as well as the vertical and/or lateral sealing potential of faults intersecting the storage complex or other potential significant faults are scrutinised in great detail. Similarly, the nature

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[30] 2024, IEAGHG, Geological Storage of CO_2: Seal Integrity Review

[31] Bisdom & Chan, 2024, De-risking fault leakage risk and containment integrity for subsurface storage applications, iScience, Volume 27, Issue 6, 2024

of fractures within the storage complex, if present, are characterised to address the risk of leakage. Geomechanical, thermal, and chemical assessments are also important steps of fault and fracture characterisation, requiring an adequate understanding of the local and regional subsurface conditions (e.g., the state of stress, geothermal gradient, formation fluid properties, etc.). All of this is considered in light of the evolving location and extent of the CO_2 plume and related properties (e.g., pressure, temperature, etc.).

Whilst much of this is carried out in the pre-injection phase assuming standard industry practices, as well as relevant environmental and regulatory controls in place, the results remain applicable for the post-injection phase. However, learnings from the injection phase of the project will continue to inform the level of leakage risk related to faults and fractures, and further refinement may take place during the post-injection phase. Monitoring plans and appropriate injection programs, safeguards, and corrective measures plans reduce the risk negatively influencing fault and/or fracture integrity. In addition to active seismic surveys, passive seismic arrays and fibre optic Distributed Acoustic Sensing (DAS) may be used to “listen” for very small seismic events that may indicate fracture reactivation or changes in fault stress during and after injection. Properly designed arrays (downhole geophones, seabed nodes, or DAS VSP in existing wells/cables) can achieve low magnitude of completeness thresholds sufficient to detect precursory activity. These observations provide early warning and help discriminate pressure driven behaviour from background tectonic noise.

Additionally, the composition/specification of CO_2 can be selected in order to minimise the risk of geochemical effects on the storage complex. Possible remediations in a case of leakage through faults or fractures may consist in decreasing injection pressures, injecting further away from leakage areas, or targeting deeper storage formations, not experiencing leakage.

4.1.1.3 Vertically through other geological features

Depending on the geological setting of a storage site, there may be a risk of vertical leakage of CO_2 through geological features located in and around the storage complex other than those mentioned above. Such features may include igneous bodies (e.g., volcanic intrusions), evaporite-related structures (e.g., salt domes), fluid-escape features (e.g., injectites), etc. Similar to faults and fractures, they may provide inherent or created conductivity, and are subject to detailed characterisation efforts. Features may be inherently conductive if their seal quality is less than that of the sealing formation(s) and cannot be considered a seal, or if they provide relatively high-permeability pathways (e.g., via open fracture networks). Again, created conductivity may result from the CO_2 storage project (e.g., geochemical degradation from CO_2 exposure) or from prior subsurface activities. Alternatively, evidence may confirm that such features within a given storage complex may not represent potential leakage paths, but could be considered as part of the sealing or storage formation(s) instead, depending on their characteristics and nature of the storage complex.

Assessment, management and mitigation

As with the potential leakage pathways described previously in Section 4.1.1.1 and Section 4.1.1.2, the risk related to these· other features is addressed in the pre-injection phase through detailed site characterisation studies, and is refined, through the life of the storage project. In some cases, this may include targeted data acquisition and dedicated studies, to reduce uncertainty. Where knowledge about such features has been gathered from previous subsurface activities, (e.g., hydrocarbon production), uncertainty may be reduced significantly. Once characterised, the learnings provide the necessary details to complete informed risk assessments, MMV plans, and corrective measures plans, and suitable CO_2 specifications.

4.1.1.4 Lateral migration pathways

There are potential leakage risks associated with unintended lateral migration of injected CO_2 outside of a pre-defined storage complex. This lateral migration may not always result in a loss of containment, however there may be potential scenarios where the CO_2 plume encounters another vertical leakage pathway, such as a legacy well, that may not provide sufficient barriers to shallower formations or the surface. Lateral migration outside of the storage complex, resulting in a breach of a storage permit's conditions in many jurisdictions, but such events may not present risks to human health or the environment because the CO_2 may remain trapped within the subsurface geology outside the storage complex boundary.

Assessment, management and mitigation

In the pre-injection phase, subsurface mapping and characterisation (e.g., using well or seismic data) defines the geometric arrangement, properties, and other aspects of the storage complex elements. Characterisation work will include geophysical and geological interpretation, and for storage concepts that rely on structural trapping, mapping of structural spill points, and any uncertainty associated with structural spill contours. Outputs of this, as well as dynamic modelling are then used extensively to support analysis of risk scenarios related to lateral migration outside of the storage complex. The development plan and well placement can help to manage any potential lateral migration risks.

During operation, the MMV plan supports the management of lateral migration risks. Monitoring data is collected and used to update dynamic modelling to confirm CO_2 is behaving as expected in the subsurface. If lateral migration is not adequately characterised, this movement could intersect with transmissive faults, legacy wells, or other permeable pathways, potentially resulting in unintended CO_2 migration into sensitive formations.

4.1.2 Artificial leakage pathways

Artificial CO_2 leakage pathways generally come in the form of penetrations, such as wells, caverns, shafts, etc. Wells are focused on herein, as they represent the most common potential leakage pathway of artificial origin during both the injection and post-injection phases.

The types of wells associated with CO_2 storage projects can broadly be subdivided into three well types:

- **Legacy wells:** Preexisting wells that may or may not penetrate the storage complex or be located within an elevated pressure zone.[32] These include fully decommissioned wells (potentially decommissioned under earlier regulatory requirements or decommissioned in accordance with standards which may not have considered later CO_2 storage), partially decommissioned and/or suspended wells, and wells that will be decommissioned prior to CO_2 injection.

- **Repurposed wells:** Legacy wells that are repurposed for a CO_2 storage project.

- **New wells:** Wells that are designed and drilled specifically for a CO_2 storage project. These include CO_2 injection wells, monitoring wells, and pressure-management wells, or other types (if required).

To understand how a given well may provide a pathway for leakage, the mechanisms by which a legacy or new well can lose integrity and become a containment risk must be identified. Figure 15 outlines potential well leakage mechanisms.

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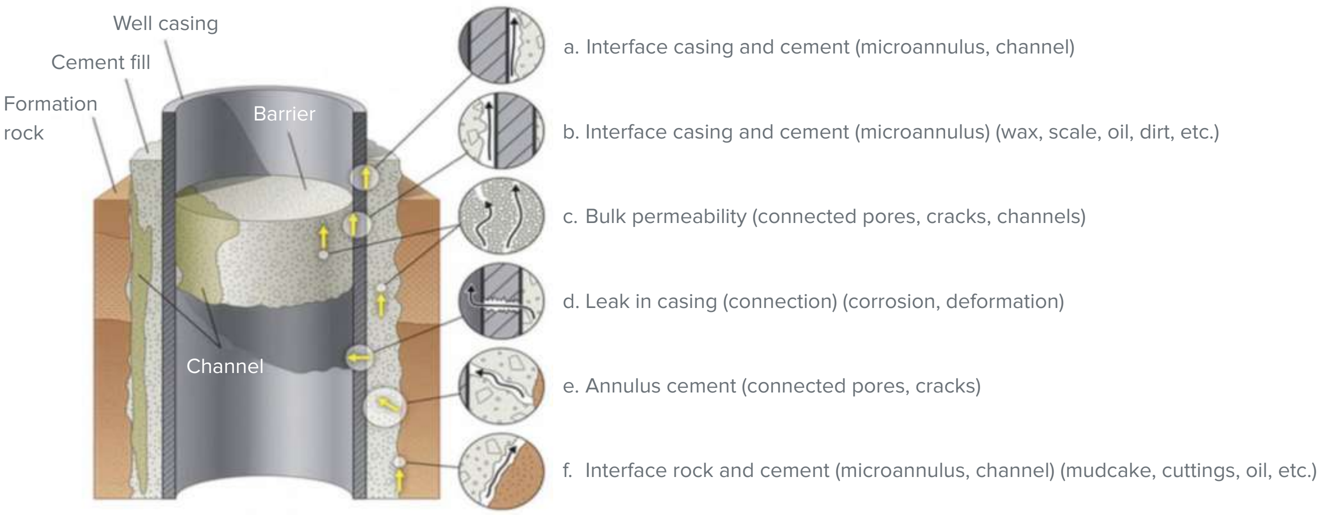
[32] In ISO 27914:2017, the elevated pressure zone is defined as zone within a storage complex where there is sufficient pressure to cause flow of formation fluids through a pathway from the storage unit(s) to outside the storage complex into economic resources, protected groundwater, or the biosphere.



Shrinkage of cement
can create micro annuli pathways:
- Cement and casing (casing cement annulus)
- Cement and formation (cement formation annulus)
- Internal cement plug and casing

Bad cement job
- Poor placement of plug, due to cement pumping issues
- Gas intrusion into the cement slurry before the cement sets, creating channels in the cement
- Damage to primary cement due to unsuitable pressure testing

Casing and cement failure
- Mechanical failures (connection leaks or corrosions) creating a pathway from the formation into the wellbore
- HC depletion can result in compaction in the subsurface and induce additional stress and strain on wellbore.
- Increased casing loading especially on repurposed wells during injection of CO_2 – temperature cycling on repurposed wells could cause casing cement annulus to fail

FIGURE 17. An example well schematic for a modern legacy well showing (left) CO_2 entry points into a well system from multiple potential CO_2 storage zones, and (right) seven fluid migration pathways and various formation mechanisms, from Lackey et al. 2026.[33]

Assessment, management and mitigation

The integrity of legacy, repurposed, and new wells is often among the top-ranked containment risk for many CO_2 storage projects. In the pre-injection, phase well containment risks require early identification, detailed evaluation, analysis, and subsequently, long-term management into the post-injection phase.

Knowledge about the number, location, and status of legacy wells is required for a much wider area than conventionally considered for oil and gas development projects to assess potential legacy well leakage over the full project lifecycle. Each well must be reviewed for integrity, and the mechanical barriers built into wells, perforations, open-hole intervals, etc. must be verified. However, wells penetrating the storage complex generally represent greatest leakage risk, and special consideration should be placed on those that intersect the storage formation or reservoir. If integrity cannot be confirmed, well intervention may be required to establish or confirm well integrity, or CO_2 contact with the well should be avoided (e.g., with considered injection-well placement). Well remediation techniques and equipment have advanced in recent years, however, these techniques still dependent on the well status and accessibility of the borehole. Some legacy wells may no longer be accessible, introducing potentially complex well re-entry operations.[34] Well integrity risks will be integrated into the MMV plan. Dynamic modelling and reservoir simulation is used to refine the development plan and placement of injection wells to minimise any risks associated with problematic legacy wells.

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[33] Celia M.A., S. Bachu, Nordbotten J.M., Gasda S.e., Dahle H.K. (2004): Quantitative estimation of CO_2 leakage from geological storage: analytical models, numerical models and data needs », In Proceedings of 7th International Conference on Greenhouse Gas Control Technologies. Volume 1: Peer-Reviewed Papers and Plenary Presentations (E.S. Rubin, D.W. Keith and C.F. Gilboy, ed.), IEA Greenhouse Gas Programme, Cheltenham, UK.

[34] Greg Lackey, Timotheus K.T. Wolterbeek, Aaron Cahill, Andrew Cavanagh, Al Moghadam, Jaisree Iyer, Preston Jordan, Rajesh Pawar, A decade of progress in understanding and managing legacy well integrity for geologic carbon storage, International Journal of Greenhouse Gas Control, Volume 151, 2026, 104604, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2026.104604.

Each well that is proposed to be repurposed for injection or monitoring during the project should also undergo an integrity assessment. Studies should be carried out to ensure suitability for CO_2 service. For new wells, well and perforation design should also accommodate CO_2 service with appropriate material selection and qualification of the suitability for any new technologies. A well integrity plan covering scenarios like tubing leaks, bad packers seals, valve failures, and seal other breaches should be developed.

4.2 Seismicity

The risk of seismicity (i.e., earthquakes) occurring and affecting the project or its surroundings is a key consideration, particularly during the injection and post-injection phases, depending on the geological setting. Seismicity has potential to damage surface infrastructure, but also create leakage pathways through the reactivation or perturbance of nearby faults, damage to wells, or opening of fracture networks in the storage complex. Seismic events can be broken down into natural and induced forms, which are discussed in more detail in Section 4.2.1 and Section 4.2.2. While regulatory frameworks and controls often place emphasis on the limitation of induced seismicity, it is worth noting that it is important to understand potential risks related to both forms of seismicity. In either case, however, an understanding local and regional seismic hazards, formation pressure, background and historical seismic magnitudes and frequency, ground stability, and local infrastructure are just a few aspects which are considered when assessing risks related CO_2 storage projects. The spatial distribution, magnitude, frequency, effect, etc. of seismic events are rather site specific, and depend largely on a wide range of factors which go beyond the scope of this report.

4.2.1 Natural seismicity

Seismicity can occur natural (i.e., without influence from anthropogenic activities, etc.) and is an important risk consideration for subsurface geological CO_2 storage projects. Historical seismic activity and relevant geological features (e.g., faults, volcanoes, etc.) and potential risks within a given region should be reviewed accounted for appropriately.

Assessment, management, and mitigation

Similar to leakage through sealing formations, early subsurface characterisation plays a key role in assessing risk related to natural seismicity. In many cases, when screening suitable storage sites, an operator will conduct an assessment of the historical natural seismicity of the region. Projects may be screened out if they are deemed to have sufficiently high risk associated with natural seismicity, hence for most projects to date the risks related to natural seismicity are often considered low likelihood due to their geographical and geological location. Additionally, baseline seismicity surveys conducted in the pre-injection phase can help establish project location conditions which can be used for site screening or comparison during the injection and post-injection phases. Monitoring of existing or site-specific networks can also help mitigate natural seismicity risks.

4.2.2 Induced seismicity

Induced seismicity is defined as seismic events caused by anthropogenic activities, directly caused by humans or humans causing a change in the natural surroundings resulting in more frequent and/or significant events. Induced seismicity poses both a technical and stakeholder risk to subsurface projects, in particular when considering the development of storage projects onshore.

The injection of CO_2 in the subsurface has the potential to induce seismicity through the modification of natural stresses on pre-existing faults promoting slip. The most common mechanisms that promote fault destabilisation as a result of fluid injection include pore-pressure increases and poro-elastic deformation, but thermal perturbations and geochemical alterations may also play a role.[35] Stress changes can bring critically stressed faults close to failure. Failure of faults that intersect sealing formations or artificial pathways may provide a pathway for CO_2 to leak.

MAGNITUDE, FELT SEISMICITY AND GROUND MOTION

It is important when discussing natural and induced seismicity to understand the difference between magnitude, felt seismicity and ground motion. Magnitude is an objective, numerical measurement of the energy released by an earthquake. It's calculated using seismograph readings and is typically expressed using scales like:

- Richter scale
- Moment magnitude scale (MMS)
- Local magnitude scale (ML)

Felt seismicity, on the other hand, is the human perception and experience of an earthquake. It's subjective and is typically measured using the Modified Mercalli Intensity (MMI) scale, which ranges from I (not felt) to XII (total destruction). Felt seismicity depends on factors like:

- Distance from the earthquake epicenter
- Local geology and soil conditions
- Building type and construction
- Time of day (people are more likely to feel earthquakes when stationary)
- Floor level (higher floors may feel more movement)

Ground motion is the physical movement and shaking of the Earth's surface during an earthquake. Ground motion is recorded through a measurement of how the ground moves at a specific location typically recorded by seismometers. The strength of ground shaking is characterized by several key parameters, such as: the velocity of ground movement, the acceleration of ground movement, the frequency content of the seismic waves, and the duration of shaking. Geological aspects, such soil or bedrock type, properties, and distribution, are also considered important.

Assessment, management, and mitigation
Risks associated with induced seismicity are assessed early in the development of a CO_2 storage project. Through site selection and detailed characterisation an operator will assess the number, spacing, vertical extent, tectonic history, and vertical or lateral seal potential of faults intersecting the storage complex or other potential significant faults.[36] Additionally, the local and regional stress state before industrial subsurface activities began will be assessed and throughout the full lifecycle. Stakeholder engagement is also key, in terms of understanding potential interactions with other users of the subsurface (interaction with other users of the subsurface is discussed further in Section 4.4). As well as engagement with regulators and the public, where transparency is important. Transparency with regulators and the public population near proposed subsurface projects is important. Previous subsurface projects that have invested in stakeholder engagement have seen that public populations may be tolerant of small felt induced seismicity if they are well informed by the project developers.[37]

Traffic light systems developed based on site specific risks and impacts are widely used to set operational thresholds as a measure to react to detection of

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[35] IOGP, 2025, Assessing and managing induced seismicity risks associated with geologic storage of carbon dioxide

[36] Bisdom & Chan, 2024, De-risking fault leakage risk and containment integrity for subsurface storage applications, iScience, Volume 27, Issue 6, 2024,

[37] Institute, S.e., 2019. Why communicate about Enhanced Geothermal Systems? A comparison of St Gallen and Basel in Switzerland, United Downs Deep Geothermal Power project: Hot Topic.

induced seismicity. These systems alone are not always effective tools, particularly where arbitrary thresholds are set as opposed to being guided by thorough risk and hazard assessments specific to a project. Whilst not direct analogues for CO_2 storage, learnings from geothermal developments where traffic light thresholds were determined based on other projects suggest the importance of a site-specific assessment when it comes to developing traffic light systems.[38] Guidance developed by the US Department of Energy on managing induced seismicity for Enhanced Geothermal Systems (EGS), may provide a useful guide to addressing this risk for other subsurface projects (Guidance on induced seismicity risk from Enhanced Geothermal Systems projects in the US.).

TABLE 5. Guidance on induced seismicity risk from Enhanced Geothermal Systems projects in the US.[39]

Perform a preliminary screening evaluation	Recommendations: a. Review relevant laws and regulations b. Determine radius of influence within which there could be negative impact due to induced seismicity c. Identify potential impacts, including physical damages, social disturbances, nuisance, economic disruption, and environmental impacts d. Establish an approximate lower and upper bound on potential damages e. Classify overall risk based on a very Low-Low-Medium-High criteria
Implement an outreach and communication program	Recommendations: a. Evaluate outreach needs b. Develop plans to approach community, stakeholders, regulators and public safety officials c. Develop a public relations plan to generate interest in the project from local media d. Hold an initial public meeting and site visit that covers both technical and non-technical issues. e. Additional meetings throughout the project development (e.g., during drilling, first stimulation), including site visits if feasible
Review and select criteria for ground vibration and noise	Selected recommendations: a. Assess existing conditions b. Assess human exposure to vibration c. Assess interface with industrial and institutional land uses d. Assess ground-borne noise

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[38] Bachmann, C.e., Wiemer, S., Woessner, J., Hainzl, S., 2011. Statistical analysis of the induced Basel 2006 earthquake sequence: introducing a probability-based monitoring approach for Enhanced Geothermal Systems. Geophysical Journal International 186, 793-807

[39] https://www.energy.gov/eere/geothermal/articles/protocol-addressing-induced-seismicity-associated-enhanced-geothermal

Establish seismic monitoring	Selected recommendations: a. Monitoring program should try to collect data that is not biased in time or space b. Minimum data processing should provide location, magnitude and source mechanisms c. Monitoring should be maintained through injection activity to validate engineering design in terms of fluid movement directions, and to guide the operators on optimal injection volumes and rates
Quantify the hazard from natural and induced seismic events	Selected recommendations: a. Estimate the baseline hazard from natural seismicity b. Estimate the hazard from induced seismicity
Characterise the risk of induced seismic events	Selected recommendations: a. Characterise ground motion at each location within the area potentially impacted b. Identify assets that could be adversely affected and contribute to overall risk c. Characterise the damage potential from risk contributors d. Estimate the risk
Develop risk-based mitigation plan	Selected recommendations: a. Direct mitigations (e.g., traffic light systems) b. Indirect mitigations (e.g., seismic monitoring, increased outreach, compensation, community support) c. Liability and Insurance

Once in the injection phase of a project, seismic monitoring is conducted in order to detect and assess both natural and induced seismicity. Moreover, injection temperature, pressure, rate, and fluids controlled in order to avoid inducing a seismic event, with environmental and societal consequences, above the safe threshold defined by the regulator. A combination of (baseline) seismic monitoring and site-specific geomechanical modelling helps to build an understanding of relations between induced and natural seismicity, as well as potential refinement to thresholds set in traffic light systems.

For a detailed review of assessment and management of induced seismicity risks associated with geologic storage of CO_2, refer to IOGP 680 (2025).[40]

4.3 Formation water and/or brine displacement

In many regulatory jurisdictions, there is an emphasis on the need to protect underground sources of drinking water. During CO_2 injection, the resulting pressure front that is created, can displace the resident formation water or brine, into areas that could cause damage to these underground sources of drinking water, as well as potentially inducing seismicity as discussed in the previous section. Similarly to lateral migration concerns raised in Section 4.1.1.4, an environmental impact associated with the displacement of formation water or brine will be dependent on the presence of any other pathways that may lead to a source of drinking water or to the surface.

The displacement of brine is primarily driven by the residual pressure gradient established during injection. In confined systems, this pressure dissipates gradually, but in more permeable or hydraulically

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[40] IOGP, 2025, Assessing and managing induced seismicity risks associated with geologic storage of carbon dioxide

connected formations, displaced fluids may migrate laterally or vertically. If not adequately characterised, this movement could intersect with transmissive faults, legacy wells, or other permeable pathways, potentially resulting in unintended fluid migration into sensitive formations.

This risk is particularly relevant in onshore settings where regulatory frameworks, such as the US EPA Class VI or the EU CCS Directive, mandate the protection of potable groundwater resources. In offshore environments, while the risk to drinking water is reduced, the displacement of brine into adjacent formations may still affect pressure regimes and operational planning for nearby subsurface activities (discussed in Section 4.4).

Assessment, management, and mitigation

A robust site characterisation process is essential to identify the extent and connectivity of aquifers, faults, and other potential conduits. Dynamic reservoir modelling, calibrated with injection-phase monitoring data, can be used to simulate the extent of brine displacement and predict its evolution throughout the lifecycle of the project.

Mitigation measures may include:

- Selecting storage sites with natural hydraulic barriers or a low-permeability overburden
- Implementing pressure management strategies, such as brine extraction wells
- Designing MMV plans that include groundwater sampling and pressure monitoring in overlying formations

PRESSURE MANAGEMENT

One mitigation measure for limiting pressure increases in the storage reservoir, and reducing the risk of brine displacement, is the implementation of a pressure management strategy. Such a strategy may include adjusting CO_2 injection rates at existing wells or installing dedicated water production wells to enable controlled brine extraction.

Although brine extraction is often described as a straightforward mitigation option, its planning and execution are frequently underestimated. In practice, brine extraction systems can be complex, and numerous operational challenges may emerge. Regulatory requirements for brine management vary significantly between countries, and extracted brine may need to be reinjected into a separate formation, an option that requires suitable geology and available injection capacity. Offshore settings also introduce additional constraints, such as limited platform space and restricted access for handling produced water.

4.4 Formation pressure communication

Subsurface pressure conditions are perturbed as a result of storage operations. Generally speaking, CO_2 injection may increase the pore pressure within the storage formation and affects stress conditions in and around the storage complex area. Where two or more storage projects are located in close proximity to one another (e.g., kilometres from one another), the pressure perturbations stemming from one project may affect pressure conditions in another (and vice versa), potentially impacting storage potential and other aspects of each project.[41,42] Hence, it is critical that the site-specific risk of potential pressure communication between storage projects or other subsurface activities (e.g., hydrocarbon production) is well-understood throughout the project lifecycle.

Pressure communication can influence several critical aspects of a CO_2 storage project:

- **Capacity:** In closed or semi-closed systems, residual pressure from neighbouring operations may reduce the available pore space or limit the pressure envelope, thereby constraining future injection volumes.
- **Injectivity:** Elevated background pressures can increase the bottomhole pressure required to maintain injection rates, potentially breaching geomechanical thresholds or requiring the drilling of additional wells to maintain injection targets.
- **Containment:** Pressure-induced stress changes may compromise caprock integrity or activate faults, increasing the risk of vertical migration. Lateral migration can also be impacted, with the CO_2 plume migrating outside of the storage complex, or in a different direction than initially modelled
- **Monitorability:** Pressure interference may obscure or distort monitoring signals, complicating the interpretation of plume behaviour and conformance assessments.

Assessment, management, and mitigation

The evolution of the subsurface pressure conditions will vary from location to location. In cases where subsurface industrial activities have taken place prior to CO_2 storage interest, the initial (i.e., "virgin") conditions must be established in addition to evaluating how pressure conditions have evolved as a result of relevant subsurface industrial activities through data analysis, modelling, and history-matching. Once the current or anticipated pressure conditions are determined, dynamic modelling and data assessment will provide the basis for understanding how the pressure conditions will continue to evolve due to CO_2 injection considering all the available subsurface data and plan for storage injection and development. Injection phase and post-injection phase monitoring will enable updates to pressure conditions until deemed unnecessary. Dynamic reservoir modelling, informed by injection-phase monitoring data, should be used to simulate pressure evolution and assess the likelihood of inter-site communication.

This generalised workflow, however, does not take into consideration the risks and complexities due to pressure communication between multiple storage projects.

A comprehensive understanding of the regional pressure regime is essential. This includes establishing baseline (or "virgin") pressure conditions, characterising hydraulic connectivity, and identifying potential transmissive features such as faults or legacy wells.

Mitigation strategies may include:

- Coordinated regional planning and permitting to manage cumulative pressure impacts
- Pressure management techniques, such as brine extraction or staggered injection schedules
- Regulatory requirements for pressure monitoring in adjacent formations or shared aquifers
- Development of shared data platforms to facilitate transparency between operators

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[41] Ougier-Simonin, Audrey, Owain Tucker, Alex Bump, Sarah Gasda, Elise Otterlei, Adriana Lemgruber-Traby, Eric Mackay, Ludovic Ricard, Felix J. Herrmann, and Matthias Imhof. "The pressure balancing act in geological storage: sharing the subsurface for the common good." Available at SSRN 5783514.

[42] Alexander P. Bump, Susan D. Hovorka, Pressure space: The key subsurface commodity for CCS, International Journal of Greenhouse Gas Control, Volume 136, 2024, 104174, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2024.104174.

4.5 CO_2 storage risks and their evolution in the post-injection period

As discussed in Section 4, when considering the post-injection period subsurface CO_2 storage risks related to capacity and injectivity are not relevant. However, containment and monitorability risks continue their relevance into the post-injection period. As well as this, risks related to seismicity and pressure communication also remain relevant. Post-injection considerations for each of these risks are discussed in greater detail within this section.

4.5.1 Natural leakage risks

During the post-injection period the risks associated with natural leakage pathways may be minimal in comparison to potential risks posed by artificial pathways. Across all these potential pathways, risks can generally be expected to decrease after injection ceases, provided the site behaved as expected during the operational phase. Declining pressures, immobilisation of the CO_2 plume, and the increasing impact of secondary trapping mechanisms collectively contribute to long-term containment. The combination of detailed site characterisation, robust measurement, monitoring and reporting programs, and adaptable risk management plans ensures that any remaining uncertainties can be effectively managed throughout the post-injection period. During the post-injection phase the information gained during operations through monitoring programs is critical to build an understanding of the behaviour of injected CO_2. Monitoring data helps to reduce uncertainty and optimise storage management to reduce risks into the post-injection phase.

Sealing formations

The long-term containment capability of the sealing formation is important moving into the post-injection phase of projects. The operational phase when CO_2 is being injected is where the highest level of sealing formation related risks may be expected. This is due to exposure to increased pressure, (with particular focus around injection wells), temperature and geomechanical changes on the sealing formation or caprock.[43] During injection, monitoring data collected will provide additional information on the effectiveness of the sealing formation. Entering the post-injection phase without a breach of the caprock or sealing formation, suggests that there is a very small likelihood that any future failure may occur. This is due to pressure dissipating over time within the storage formation as well as other trapping mechanisms coming into play, such as CO_2 dissolution into water.

Mechanisms such as CO_2 diffusion through the sealing formation are expected to operate on longer timescales (on the order of 100,000 years for <1m of diffusion)[44] and is not considered to be a significant concern as a leakage pathway.[45] For the UK North Sea, a recent government study suggested that the potential leakage rate across the sealing formation would be negligible.[46] The same conclusion was made, in an earlier study,[47] that diffusive losses through the sealing formation would be negligible on relevant CO_2 storage time scales.

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[43] Microsoft Word - 2007 June 5 liability workshop summary final.doc

[44] Kampman, N., Busch, A., Bertier, P., Snippe, J., Hangx, S., Pipich, V., Di, Z., Rother, G., Harrington, J.F., Evans, J.P. and Maskell, A., 2016. Observational evidence confirms modelling of the long-term integrity of CO_2-reservoir caprocks. Nature Communications, 7(1), p.12268.

[45] Busch, A., Amann, A., Bertier, P., Waschbusch, M., and B. M. Krooss. "The Significance of Caprock Sealing Integrity for CO_2 Storage." Paper presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, New Orleans, Louisiana, USA, November 2010. doi: https://doi.org/10.2118/139588-MS

[46] Deep geological storage of carbon dioxide (CO_2), offshore UK: containment certainty - GOV.UK

[47] Alcalde, J., Flude, S., Wilkinson, M. et al. Estimating geological CO_2 storage security to deliver on climate mitigation. *Nat Commun* 9, 2201 (2018). https://doi.org/10.1038/s41467-018-04423-1

Faults and fractures

Assuming the risk of CO_2 leakage via faults or fractures has been assessed and managed appropriately during the pre-injection and injection phases, the risk of leakage may very well decrease into the post-injection phase. This is mainly because geochemical reactions between the CO_2 and formation fluids are very slow and often minute, storage formation pressure is unlikely to increase, and subsurface temperature will begin to re-equilibrate.

Other geological features

Like other potential pathways described herein, the potential for CO_2 leakage through faults or fractures will be thoroughly evaluated and effectively mitigated during both the pre-injection and injection stages. As a result, likelihood of leakage will likely diminish in the post-injection phase, assuming the above is true and that the risk remains a consideration after injection.

Lateral migration

The storage concept also plays a role, in the overall evaluation of the risks to natural leakage pathways. For example, for lateral migration where the CO_2 is stored in an open saline aquifer system, with a greater reliance on CO_2 dissolution as the dominant trapping mechanism. Towards the end of the injection phase, the lateral extent of the mobile CO_2 plume is likely at its greatest. As the system transitions into the post-injection phase, the pressure gradient will gradually decline, reducing the driving force for further fluid displacement. Monitoring may likely continue until pressure stabilisation is confirmed. The duration in which the CO_2 plume will be mobile will vary depending on site-specific conditions, the type of storage concept and the relative contributions of different trapping mechanisms.

KEY TAKEAWAY

Assuming the various natural leakage pathways have been thoroughly assessed and effectively managed during the pre injection and injection phases, the overall risk of CO_2 leakage from these pathways typically declines once injection ceases. Early risk mitigation, combined with data gathered before and during injection, forms the foundation for reducing long term storage uncertainties. Robust site characterisation and risk assessment, informed and refined through high quality monitoring data acquired throughout the pre-injection and injection period are used to update dynamic modelling. These activities all serve to build confidence in an operator's understanding of the behaviour of injected CO_2 within the subsurface.

4.5.2 Artificial leakage risks

Assuming the risk of CO_2 leakage via wells has been assessed and managed appropriately during the pre-injection and injection phases, the risk of leakage associated with wells may decrease into the early post-injection phase as pressure within the reservoir equilibrates.

However, it is important to consider the position of various wells within the storage complex, during the injection and post injection phases, different wells will be exposed to the evolving CO_2 plume at different times. For example, a legacy well in close proximity to an injection well may be exposed to elevated pressures during the entire injection period, whereas a legacy well on the outskirts of the storage complex may only be exposed to an elevated pressure front towards the end of the injection phase.

In the early post-injection phase, there is an additional consideration related to the relevant point at which to plug and abandon new wells. Typically, these wells are equipped with monitoring technologies and in some cases may be dedicated monitoring wells and as such the data collected is valuable, but at the same time provide a potential leakage pathway prior to their abandonment. In the near term, well decommissioning guidance is available for new wells for their eventual plugging and abandonment at regulatory closure.

However, on longer timescales there may be a risk that well integrity degrades over time potentially allowing for a leakage pathway. Practical examples of wells that have been exposed to CO_2 and potential corrosion for longer timescales are limited. This will likely be an area of focus for both operators and regulators in the future. In particular given a recent incident in the US, where a monitoring well associated with a CCS project experienced corrosion of tubing constructed from Cr13 Steel. This corrosion created holes sufficient to allow movement of CO_2 that was ultimately detected in a formation above the sealing formation, in violation of the operator's permit.[48] The incident was detected by the monitoring program and the regulator's review of the information provided indicated that no currently utilised sources of drinking water are impacted.[49] However, this incident highlights the importance of selecting construction materials suitable for exposure to CO_2. As well as this, the benefits of the value brought through critical data and information gained from monitoring wells is challenged by the placement of these wells. Where monitoring wells penetrate sealing formations, they also introduce another potential leakage pathway.

Another consideration for longer timescales, is research into the concept of natural sealing or "self healing" associated with wells. These mechanisms can provide additional barriers to leakage in wells, for additional confidence in long term containment. Salt, a typical sealing formation in CO_2 storage projects, can exhibit viscoplastic/viscoelastic behaviour referred to as salt creep. The results in salt formations slowly flowing and closing around wellbores, providing an additional barrier to leakage. However, this phenomenon is not a substitute for proper well abandonment and should not be relied upon as a primary barrier, it may function as a secondary, passive safeguard. As well as this, there are uncertainties associated with the timeframe for salt creep, with recent modelling studies suggesting that this may occur on long timescales (>100 years).[50]

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[48] https://yosemite.epa.gov/OA/RHC/EPAAdmin.nsf/Filings/4E356273C357CA2A85258B9E000235DE/$File/SDWA-05-2025-0001_ProposedOrder_ArcherDanielsMidlandCompany_DecaturIllinois_25PGS.pdf

[49] https://yosemite.epa.gov/OA/RHC/EPAAdmin.nsf/Filings/4E74F043FD01955A85258CE5004E38BC/$File/ADM_Class%20VI%20UIC%20Order_Responsiveness%20Summary.pdf

[50] Nicholas, J. et al. "The Influence of Trapped Brine on the Sealing of Boreholes by Natural Salt Creep." Sixth EAGE Global Energy Transition Conference & Exhibition (GET 2025) (2025): n. pag.

KEY TAKEAWAY

Assuming the risk of CO_2 leakage via wells has been assessed and managed appropriately during the pre-injection and injection phases, the risk of leakage associated with wells may decrease into the early post-injection phase as pressure within the reservoir equilibrates.

Overall, whilst wells may still pose a leakage risk in the post-injection period, albeit reduced in likelihood, provided sufficient monitoring and corrective measures are in place, remediation of any detected issues is achievable.

For legacy wells, detailed assessments highlighting wells that present elevated risks, and the mitigations developed pre-injection (e.g. adjustments to overall capacity or alteration of injection strategies), coupled with monitoring data during operation help to provide confidence that these legacy well risks are not materialising. However, there are still some uncertainties with respect to the long-term exposure to CO_2 environments and corrosion risk. A strong focus on long term legacy well integrity will be required from operators and regulators, given recent well corrosion incidents observed in the US.

For newly constructed wells, material selection and their appropriate plugging and abandonment is important in ensuring containment, particularly for long term exposure to CO_2.

4.5.3 Seismological risks

The risk of natural seismicity is unlikely to differ throughout the lifecycle of a storage project, as mentioned above early site screening will look to avoid the development of sites in areas of high background natural seismicity. Ultimately, there is a risk that some natural seismicity may occur in the post-injection period, but this is out of control of the operator.

Whilst the risk of natural seismic activity affecting the storage project will likely remain the same throughout the project life-cycle, the risk of induced seismicity may decline once reaching the post-injection phase, as pressure within the storage formation dissipates and the CO_2 plume disperses and evolves. With increasing time, this risk is expected to become almost negligible in the post injection period. The timing of this risk is also dependent on the risk receptor on which it is acting on. For example, the risk near an injection well will likely decrease with time as the pressure plume spreads out. However, as the pressure front moves outward it may intersect with a distal fault and trigger seismicity.

In other industries where subsurface fluid injection takes place there have been situations where potential induced seismicity events have occurred "post-injection." Most notably, in Prague, Oklahoma an earthquake occurred attributed to wastewater injection 18 years after injection of fluid had ceased.[51] This phenomenon of post-injection induced seismicity has also been reported in Enhanced Geothermal Systems (EGS).[52] There is however a difference in the operation of enhanced geothermal systems compared

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[51] He, L., Wu, Q., Chen, X., Sun, X., Guo, Z., & Chen, Y. J. (2021). Detailed 3D seismic velocity structure of the Prague, Oklahoma fault zone and the implications for induced seismicity. Geophysical Research Letters, 48, e2021GL096137. https://doi.org/10.1029/2021GL096137

[52] Auregan Boyet, Silvia De Simone, Frédéric Cappa, Víctor Vilarrasa, (2025). Understanding post-injection seismicity: Causes and mechanisms of trailing earthquakes in Enhanced Geothermal Systems,Renewable and Sustainable Energy Reviews, https://doi.org/10.1016/j.rser.2025.116055.

to CO_2 storage projects. EGS typically involves an initial hydraulic fracturing of a reservoir and cyclical injections of fluid in comparison to a relatively constant CO_2 injection rate. With CO_2 storage, there is an associated pressure increase and pressure front that spreads out within the reservoir. However, further research on potential “post-injection” seismicity related to EGS is being investigated and the learnings may be applicable to CO_2 storage.

There are few CO_2 storage projects in the post-injection period, however, the Tomakomai demonstration project in Japan is an example. Japan is a seismically active area and as such has many seismic monitoring networks in place allowing for a detailed monitoring of the impact of CO_2 injection with respect to any potential induced seismicity post-injection. Within the monitoring area, a total of fifteen events were recorded (nine pre-injection, three during injection and a further three post-injection). These events were recorded in the basement rocks beneath the storage reservoirs, suggesting that no post-injection seismicity can be attributed to CO_2 storage activities.[53] However, it is important to note that commercial scale projects will involve injection of far greater volumes of CO_2.

Another consideration for the post-injection period relates to the other subsurface activities within the same basin as a CO_2 storage project. With multiple active CO_2 storage projects at different stages of the project lifecycle, there may be a need for the regulator to determine the ‘origin of induced events, in particular where they may have triggered a corrective measure for projects actively in the post-injection period. Here, coordinated monitoring and stakeholder engagement on the basin scale may become of increasing importance in the future, to mitigate against this risk. This is also discussed in Section 4.5.5.

4.5.4 Formation water and/or brine displacement risks

Following the cessation of CO_2 injection, the pressure front generated during operations may continue to propagate through the formation, displacing resident fluids such as brine or formation water. This displacement can extend beyond the immediate storage complex and, in some cases, may pose a risk to overlying aquifers, particularly those designated as underground sources of drinking water (USDWs).

As the system transitions into the post-injection phase, the pressure gradient will gradually decline, reducing the driving force for further fluid displacement. However, monitoring will likely continue until pressure stabilisation is confirmed. The duration of this phase will vary depending on site-specific conditions, the type of storage concept and the relative contributions of different trapping mechanisms.

4.5.5 Formation pressure communication risks

In discussion with stakeholders, this is an area that is known to operators and regulators but it requires further discussion with respect to any potential risks or liabilities that may arise.

Following the cessation of CO_2 injection, the pressure perturbations induced during the operational phase may persist within the storage formation and surrounding strata. These residual pressure effects can propagate beyond the immediate storage complex, potentially interacting with adjacent geological formations, legacy wells, or other subsurface activities. In the post-injection phase, although the injection has ceased, the pressure front may continue to migrate, especially in formations with high permeability or limited natural dissipation mechanisms. In the post-injection phase, pressure dissipation is expected to occur gradually, depending on the permeability and boundary conditions of the storage formation. However, the risk of pressure communication does

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[53] Tanase, D., Niiro, R., Kato, H., Machida, H., Nakagawa, K., & Tanaka, J. (2022) "The post-injection phase of the Tomakomai CCS Demonstration Project"

not immediately vanish. In fact, it may become more complex as new projects commence operations nearby. A recent publication[54], highlights the potential challenges associated with multi-user activity and associated pressure impacts, suggesting that managing pressure on a basin-scale is essential for safe and efficient deployment.

The risk is not solely confined to the originating project. In multi-user basins, pressure interference from one site may compromise the containment or monitoring strategies of another. For example, a later project initiating injection in proximity to an existing post-injection site may inadvertently elevate pressures in the latter's storage complex, potentially reactivating faults or altering plume behaviour.

Regulators and operators must therefore remain vigilant. Ongoing monitoring of pressure trends, particularly in formations adjacent to the storage complex, is essential. Where pressure interference is detected, adaptive management strategies should be employed, including updates to MMV plans and risk assessments.

Furthermore, regulatory frameworks should clearly define the responsibilities of new entrants in managing potential impacts on existing sites in the post-injection phase. This includes the obligation to assess and mitigate pressure communication risks and, where necessary, to contribute to additional monitoring or remediation efforts.

Mitigation strategies may include:

- Coordinated regional planning and permitting to manage cumulative pressure impacts
- Pressure management techniques, such as brine extraction or staggered injection schedules
- Regulatory requirements for pressure monitoring in adjacent formations or shared aquifers
- Development of shared data platforms to facilitate transparency between operators

4.6 Risk profiles across the project lifecycle

As noted previously in Section 3, the risk profile for a storage site will vary across the project lifecycle, where both the level of risk and timing of exposure to risk will be unique to each storage site based on the storage environment, setting, and concept, as well as each site's own subsurface characteristics.

One well regarded and often cited lifecycle risk profile for a CO_2 storage project, is illustrated in Figure 18. This profile depicts an increase in the risk profile during a project's operational period as CO_2 is injected, reservoir pressure evolves, the CO_2 plume increases in size and makes contact with a greater portion of the sealing formation.[55] However, at all times during the project lifecycle, the risk profile for a well characterized, designed and managed project is expected to remain below the acceptable risk set by regulatory authorities and the design risk established by the project. After injection ceases at the end of the operational period, the project risk profile is expected to asymptotically and rapidly decrease as the (see Figure 18) pressure dissipates, the plume stabilises, and secondary trapping mechanisms further reduce the probability of leakage.

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[54] Ougier-Simonin, Audrey and Tucker, Owain and Bump, Alexander and Gasda, Sarah and Otterlei, Rannveig Elise and Lemgruber-Traby, Adriana and Mackay, Eric and Ricard, Ludovic and Herrmann, Felix J. and Imhof, Matthias, The Pressure Balancing Act in Geological Storage: Sharing the Subsurface for the Common Good. Available at SSRN: https://ssrn.com/abstract=5783514 or http://dx.doi.org/10.2139/ssrn.5783514

[55] Shoulders & Hodgkinson, A process-led approach to framing uncertainty and risk in CO_2 storage in the subsurface, 2024

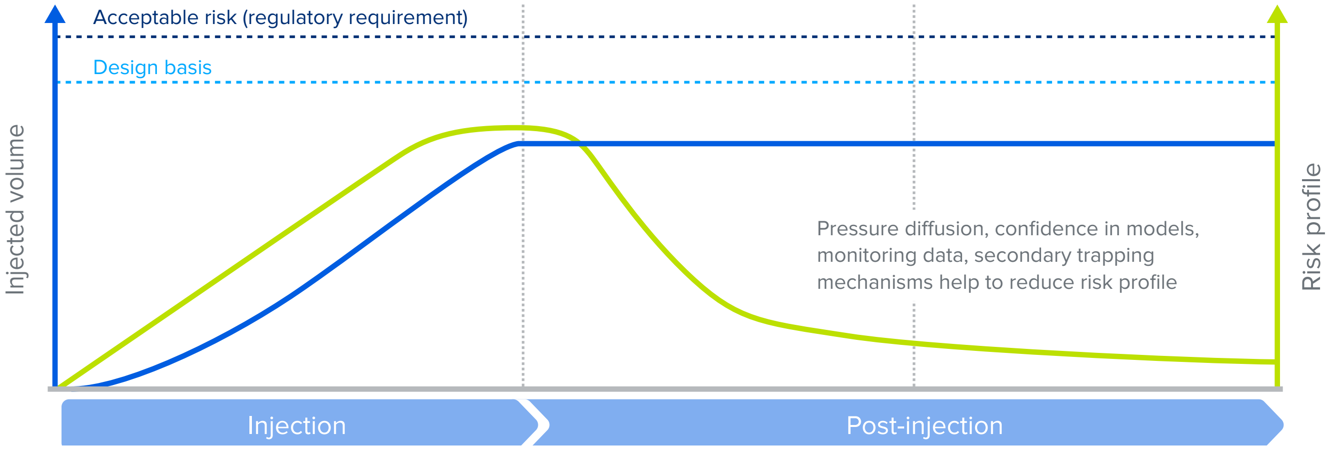

FIGURE 18. Risk profile with increase in CO_2 inventory (adapted after de Coninck & Benson 2014).[56]

The overall risk profile of a CO_2 storage project is expected to be site specific and dependent on the presence or absence of certain other features. Each individual risk component of the lifecycle risk profile will contribute a different likelihood, consequence and timing. For example, legacy well leakage risks only have a likelihood of materialising where legacy wells are present and if it is possible (e.g., physically) that the CO_2 plume could migrate towards such wells. Typically, operators visualise risk throughout the life cycle through risk assessment matrixes, rather than plots like the above (as described in Section 3.1.1).

Lifecycle risk profiles are an effective communication tool in discussions with project stakeholders. Building on the risk profile shown in Figure 18, CO_2 storage project developers have developed an alternate view of the risk profile across an idealised project taking into account detailed risk assessments, monitoring plans and corrective measures plans. This lifecycle risk profile changes as project safeguards are “tested,” and CO_2 storage project operational and monitoring data are obtained, evaluated and incorporated. The lifecycle risk profile includes the types of risks that CO_2 storage project operators consider most relevant to the post-injection phases of a CO_2 storage project. This is presented below in Figure 19, along with a more detailed discussion of activities that an operator would conduct throughout the project lifecycle, with examples from an active CO_2 storage project on the role of monitoring and corrective measures to manage risk.

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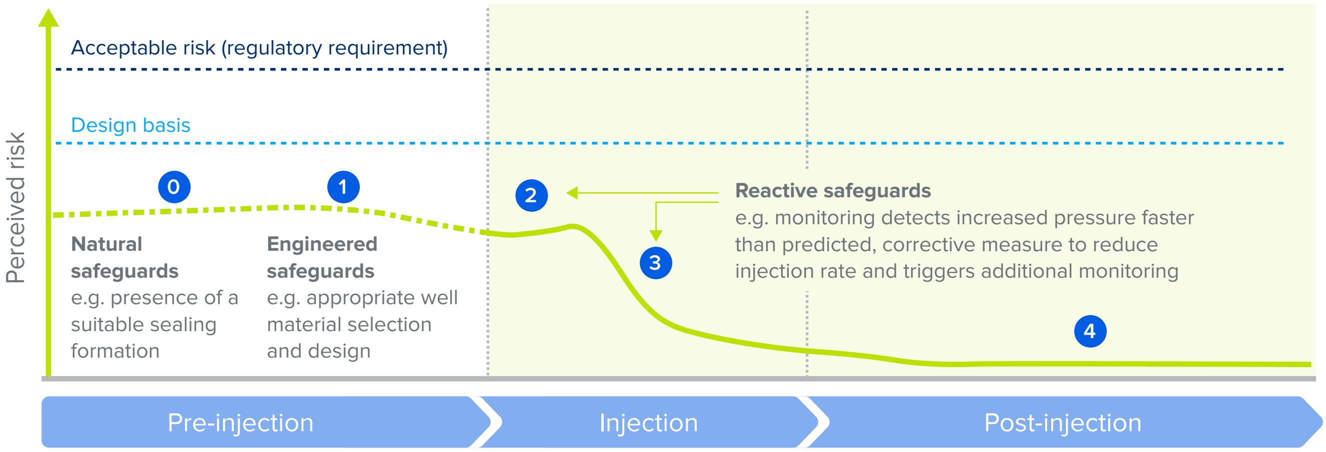
[56] Carbon Dioxide Capture and Storage: Issues and Prospects, de Coninck & Benson, 2014



⓪ Project lifecycle risk is assessed during site selection and activities are defined to characterise and reduce identified risk pre-injection

① Additional subsurface characterisation and refinement of development plans to reduce risk pre-injection

② During operation identified risks do not materialise, risk decreases. Or a risk materialises, remediation is triggered and risk decreases

③ Monitoring data during operation help to reduce site uncertainty and optimize site management to reduce risks. Monitoring data confirms identified risks do not materialise, risk decreases. Or monitoring data confirms a risk materialised, remediation and corrective measure are triggered and risk decreases

④ Pressure diffusion, confidence in models, monitoring data, secondary trapping mechanisms help to reduce risk profile

FIGURE 19. Lifecycle risk profile for an idealised CO_2 storage project showcasing risk management through implementation of safeguards, monitoring and corrective measures. The green line represents the risk profile. Pre-injection is dashed as the risks have been characterised and assessed but are not active until injection commences.

Pre-injection

During the pre-injection phases of a project, the operator will carry out site screening, site characterisation and design and development activities. During this phase the operator will undertake the initial risk identification and assessment process, identifying actions that may be required to reduce uncertainty and better characterise risks (e.g., further data collection requirements).

Prior to the commencement of injection each project will have a base level of identified risk, which can be better understood as the project begins operation and further data is available to better constrain the uncertainty associated with risks.

Injection

As the With increasing volume of CO_2 injected CO_2 increases, so does during the injection phase, the risk profile of the project. The key hazards and risks, pre-identified pre-injection, associated with injectivity, capacity, containment and monitorability of the storage site risks may or may not materialise, potentially activating mitigating measures as part of the pre-defined risk management plan. As CO_2 is injected, pressure and plume monitoring data is used to recalibrate models and refine operational thresholds such as injection rate to reduce the likelihood of risks materialising. The reduction of subsurface and operational uncertainties combined with optimal operational settings, reservoir and site management can help to reduce the risk during the injection phase. For example, within a depleted field setting relying on a structural closure to provide containment, as CO_2 is injected and accumulates at the crest of the structure, greater pressure will be exerted on the sealing formation above, increasing the risk that the sealing formation(s) may fail. This risk will depend on sealing formation characteristics such as thickness, capillary entry pressure, heterogeneity, etc. As well as the amount of CO_2 injected and the amount and rate of deformation the sealing formation(s) experience due to pressure increases. Mitigations that might be deployed to reduce the risk of seal failure may include reduction in injection rates or reducing pressure through water production adequately manage risks in the injection phase.

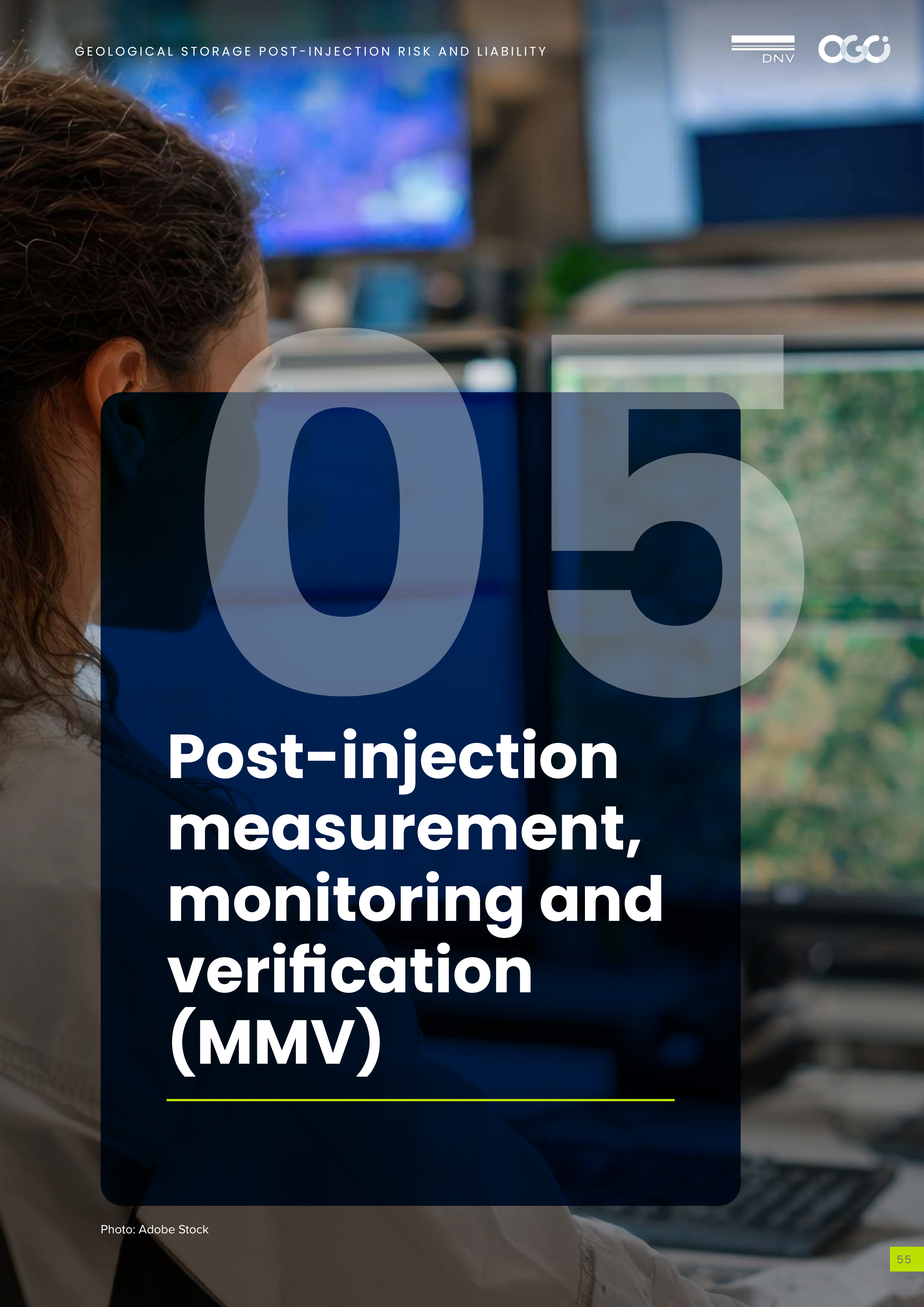
During this phase, the identified natural, engineered and reactive safeguards are “tested.” Should monitoring data spot an irregularity, corrective measures (reactive safeguard) can be employed to address a risk. An example of this is the Snøhvit storage site in Norway. CO_2 from the onshore liquefied natural gas processing plant was captured and stored offshore in the Tubåen Formation. Injection began in 2008, with approximately 5 Mt of CO_2 injected by 2017. During the initial 3 years of injection, a gradual pressure rise was observed suggested that there was a risk to overall containment and storage capacity. The significant compartmentalisation in the Tubåen Formation limited access to available pore space for CO_2. The mitigation and remediation measure taken by the operator, was to reperforate the well in a shallower formation to avoid pressurising the store. Following this, the operator decided to drill a second injector to replace the initial injector. As well as an adjustment to the injection plan to allow for injection into the above Stø formation.

Snøhvit illustrates the importance of an effective risk-based MMV plan to provide key monitoring data to understand the evolution of risks and detect any unexpected behaviour.

Post-injection

As CO_2 injection has ceased the main operational risks around CO_2 injectivity and capacity are no longer relevant. At this stage the emphasis is around the containment and monitorability of the storage site. The pressure within the system will begin to dissipate as the system approaches stability. Some of the key risks related to pressure may decrease in likelihood as this pressure dissipates. The monitoring plan is in place to ensure containment and conformance and build confidence to plug and abandon site correctly in line with regulatory requirements. Data from the monitoring plan is used to update the risk assessment for the remaining relevant risks at this stage. The post-injection monitoring timeframe will vary dependent on the regulatory jurisdiction, where some projects may be able to demonstrate with confidence to the regulator that the timeframe where the operator is responsible for monitoring can be reduced due a low likelihood of any remaining risks materialising.

Within the post-injection phase, there are milestones associated with the regulatory closure of the storage project. In some cases, the responsibility for monitoring can be transferred back to a state entity, where the regulator may conduct a level of assurance monitoring to confirm the CO_2 is behaving as expected as part of a long-term stewardship program. On a longer-term basis, pressure dissipation, and the influence of various trapping mechanisms will bring the risk level down. Again, the key risks are focused on the containment of the storage site.



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Post-injection measurement, monitoring and verification (MMV)

Photo: Adobe Stock

5. Post-injection measurement, monitoring and verification (MMV)

Underpinned by sufficient risk assessment and management, MMV is a key component of CCS projects that involves the use of various techniques and technologies to track the quantity, location and behaviour of CO_2 that has been injected into geological formations for permanent storage. MMV is a critical tool when entering the injection and post-injection phase and provides a means to demonstrate to stakeholder that CO_2 behaviour within the subsurface is understood and long-term containment can be maintained.

5.1 Purpose of MMV

The main purpose of MMV activities is to manage the project health, safety, and environmental (HSE) risks whilst also assessing the effectiveness of storage activities. Key HSE risks (i.e., potential impacts) should be directly connected to chosen MMV technologies and deployment strategies where MMV activities should:

- Spot early indicators of HSE impacts and stay on top of all identified risks.
- Ensure the injected CO_2 is contained, assess the effects of increased pressure, spot early signs of leaks, and initiate corrective or recovery actions as required.
- Verify and validate dynamic earth models, such as CO_2 plume migration, geomechanical, and geochemical models, to regularly update forecasts for storage capacity, injectivity, and containment risks. Model conformance should demonstrate long-term security of the storage facility and support the transfer of responsibility.

Other reasons for conducting MMV activities may be driven by specific requirements unique to each site, such as:

- Commercially supporting CO_2 volume accounting, such as for financial transactions with third-party entities (like CO_2 emitters or replacing emission credits). Reducing project risk by optimizing CO_2 plume migration to maximize capacity and injectivity at the lowest possible cost (by maintaining technical integrity and minimizing equipment downtime), along with achieving the lowest possible injection and reservoir pressure.
- Conform and comply with local regulations.
- Demonstrate MMV technology readiness (i.e., research and development).
- Address stakeholder expectations and concerns.

MMV also supports the accounting of emissions reduction achieved by a storage project with essential data, which then serves as the basis for allocating storage credits but is not necessarily relevant once injection operations have ceased.

MMV plans are typically developed and matured during the “appraise” and “permitting” phases of a project and then fine-tuned as part of the storage permit application process. Further refinement of the MMV plan can take place during the injection phase as operational data is collected.

MMV relies heavily on data acquisition, and its relevance to monitoring activities varies by project phase:

- **Pre-injection phase:** Data acquisition supports site characterisation (and site selection) and forms monitoring baselines for future repeated data acquisition. The goal is to reduce uncertainties, mitigate risks during the design phase, and select monitoring options to address residual risks during later project phases. Baselines establish pre-injection conditions for comparison with future monitoring data. Ultimately, pre-injection data collection aids in MMV plan development prior to injection.

- **Injection phase:** Data collection focuses on maintaining safe injection operations, mitigating leakage risks, and ensuring conformance monitoring to align forecasted storage behaviour with measured outcomes. Additionally, data acquisition during the injection phase supports MMV plan updates. MMV during the injection phase also provides important subsurface information to reduce uncertainty and optimise injection strategies and reduce risks.
- **Post-injection phase:** Data acquisition demonstrates whether conditions for the closure of the project are met (and potential transfer if the regulatory jurisdiction allows for it), meaning the CO_2 behaviour within the storage site is understood and will remain safely stored. Following the achievement of closure, the regulator may continue to conduct a level of monitoring to provide continued assurance that no leakage is occurring.

5.2 Effectiveness

As previously discussed, MMV plans should be (1) developed through site-specific, risk-based approaches and (2) may be continuously updated throughout the lifecycle of the storage project. As a result, it is important to understand the considerations that go into selecting monitoring solutions.

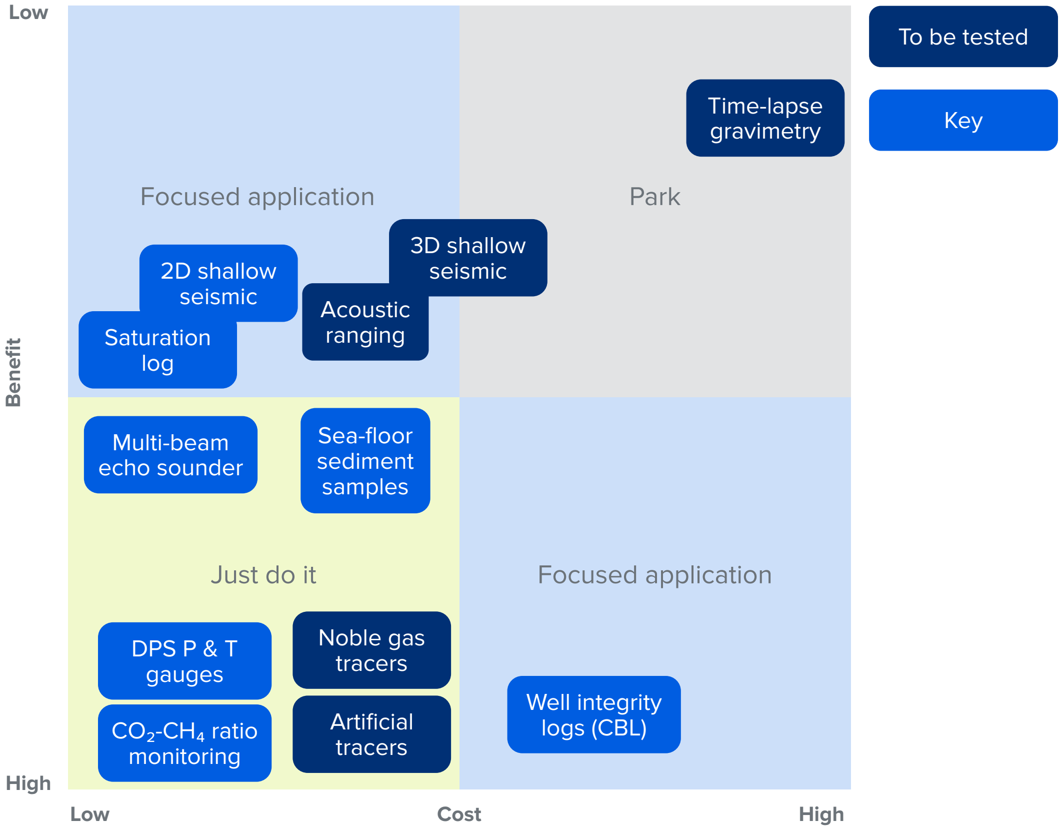

FIGURE 20. Example of a cost benefit analysis of potential monitoring solutions, after EZK (2024).[57]

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[57] EZK, 2024, MONITORING REQUIREMENTS FOR CO_2 STORAGE SITES ON THE DUTCH CONTINENTAL SHELF

During MMV plan development, potential monitoring solutions will be identified from the risk assessment process, e.g., from bowtie analysis. MMV plans are typically subdivided into base plans, identifying issues, and contingent monitoring plans, to collect further data where an issue materializes and the response to be taken. At a later stage, Boston plots can be implemented to map the cost-benefit screened MMV solutions into basic categories which can aid the selection process. While some MMV solutions may outweigh others, an MMV plan should be based on a combination of techniques to meet monitoring objectives.

Given the site-specific nature of each storage project, it is important to understand that regulatory regimes should avoid being prescriptive with regards to monitoring technology requirements. Fit for purpose technology should be selected based on the specific risk that is being monitored.

5.3 Post-injection MMV implications

MMV activities in the post-injection phase are essential for demonstrating the long-term integrity and safety of a CO_2 storage site. These activities provide the evidence base for regulatory closure and, where applicable, the transfer of long-term liability to the state. The scope, duration, and intensity of post-injection MMV must be tailored to the remaining risks specific to each project and aligned with the expectations of the relevant regulatory framework.

It is important to distinguish between the post-injection and post-project termination periods within the post-injection phase, as they represent different stages of regulatory oversight and operational responsibility:

- **Post-injection period:** This begins immediately after the cessation of CO_2injection. The operator remains responsible for monitoring and reporting. MMV activities during this phase focus on confirming plume stabilisation, pressure dissipation, and conformance with predictive models. The goal is to demonstrate that the site is progressing towards a stable state suitable for closure.

  Where applicable, the transfer of long-term liability to the competent authority may be possible. Monitoring during this phase is typically limited to low-frequency assurance activities and is often conducted by the regulator. The scope and duration of post-termination monitoring are determined by the final risk assessment and the conditions of the closure permit.

Different jurisdictions have adopted varying approaches to post-injection MMV, reflecting their regulatory maturity and risk tolerance:

- **European Union (EU):** Under the EU CCS Directive, post-injection monitoring must continue for a minimum of 20 years unless the operator can demonstrate earlier that the site has reached long-term stability. Monitoring must confirm containment and conformance, and the operator must provide financial contributions to cover post-transfer obligations.

- **United States (US):** The EPA's Class VI regulations require a minimum of 50 years of post-injection site care unless the operator can demonstrate that the site no longer poses a risk to underground sources of drinking water. The operator must submit a post-injection site care and site closure plan, and monitoring must include pressure, plume behaviour, and groundwater quality.

- **Canada:** In Alberta, operators may transfer liability after 10 years if they can demonstrate containment, plume stability, and declining risk. The Alberta province maintains a Post-Closure Stewardship Fund to cover ongoing monitoring and remediation. Other provinces, such as British Columbia and Saskatchewan, have less developed frameworks and may require operators to retain liability indefinitely.

- **Australia:** Under the Offshore Petroleum and

Greenhouse Gas Storage Act, operators must conduct post-injection monitoring for at least 15 years before liability can be transferred. The Commonwealth and state-level frameworks vary, with some states not providing for liability transfer at all.

A key objective of the post-injection MMV activities is to provide evidence that the site is ready for closure. This includes:

- Confirming that the CO_2 plume has stabilised and is no longer migrating
- Demonstrating that reservoir pressure has returned to safe levels
- Ensuring that no leakage has occurred and that all monitoring data align with predictive models

These findings are typically compiled into a closure report submitted to the regulator. Independent assurance, such as third-party verification or adherence to international standards (e.g. ISO 27914), may further support the case for closure.

Once the site has been closed and responsibility transferred, monitoring may continue at a reduced level to provide ongoing assurance. Such activities are intended to confirm that the site remains secure and that no unexpected behaviour has emerged. The cost and scope of post-termination monitoring should be proportionate to the residual risk and may be supported by financial mechanisms such as stewardship funds or insurance guarantees.

Given the long duration of the post-injection phase, MMV plans should be designed with flexibility to incorporate emerging technologies. Advances in fibre-optic sensing, machine learning for anomaly detection, and satellite interferometry (e.g. InSAR) offer opportunities to enhance monitoring efficiency and reduce costs. Regulatory frameworks should support the integration of such innovations, provided they meet performance standards and maintain public and environmental safety.

06

Post-injection risk and monitoring in the context of site closure and potential liability transfer

Photo: Adobe Stock

6. Post-injection risk and monitoring in the context of site closure and potential liability transfer

Identifying risks and understanding residual risks of the CO_2 storage project as it progresses through the post-injection phase is critically important, particularly in the context of some regulatory regimes that have mechanisms enabling the transfer of long-term liability to the state.

For the operations phase of a CCS project, liability is typically borne by the store operator however subject to the operating regime and any subsequent conditions that must be satisfied (e.g., MMV requirements or elapsed time since site closure), there is a variety of regulatory models and mechanisms in place that allow for the transfer of liability to the state.

The difference in the provisions made for liability across the global operating regimes is underpinned by not only the development (or potentially lack of) of CCS specific legislations from country to country, but also the negotiations and necessary stakeholders to whom have helped shape the regulatory frameworks of each operating regime. For example, a short overview of how liability provisions differ between notable jurisdictions is provided in Table 6. with additional commentary on how each regime compares also provided below:

TABLE 6. Overview of liability provisions for CCS activities by operating regime, (adapted from Global CCS Institute, 2019).[58]

Operating regime	Australia		Canada		United States		EU	
Regulatory Level	Federal	States*	Federal	Provinces**	Federal	States***	Directive	Member states
Provision as to the ownership of the pore space, within CCS-specific legislation	✓	✓		✓		✓		✓
Liability to be borne by the operator during the operational phase	✓	✓		✓	✓	✓	✓	✓
MMV requirements	✓	✓		✓	✓	✓	✓	✓
Transfer of liability	✓	✓		✓		✓	✓	✓
Conditions for transfer	✓	✓		✓		✓	✓	✓
Post-closure time limit for transfer	✓	✓		✓		✓	✓	✓
Scope of transfer	✓	✓		✓		✓	✓	✓
Financial security requirements	✓	✓		✓	✓	✓	✓	✓

* Commonwealth, Victoria, Queensland, Western Australia ** Alberta, British Colombia, Saskatchewan
*** State examples provided are illustrative not exhaustive

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[58] Global CCS Institute, 2019, Lessons and Perceptions: Adopting a Commercial Approach to CCS Liability

Liability transfer mechanisms do not exist in all regimes; however, they are of importance for developers of CO_2 storage sites. Assuming long-term liability for a project can deter developers from investing in the deployment of CO_2 storage projects. Regulatory frameworks that address liability can provide additional certainty for an operator's concerns and remove barriers to widescale deployment of CCS.

It is important to consider what enables the transition from the post-injection phase to the post-closure phase for CO_2 storage projects. Typically, at this transition there is a milestone for a "regulatory closure" where an operator is required to prove with confidence both containment and conformance. The timeframe for this milestone differs by jurisdiction, for example in Europe under the EU CCS Directive, the post-injection period is set as no shorter than 20 years. Should the competent authority be satisfied that certain criteria have been met, this period may be shortened.

In the development of this report, DNV engaged with stakeholders from various regulatory jurisdictions globally presenting themes from this work. Figure 21 provides insight into the views of these stakeholders with respect to the important elements relevant for the regulatory closure of a CO_2 storage project. Whilst these elements are interlinked, they are discussed further below.

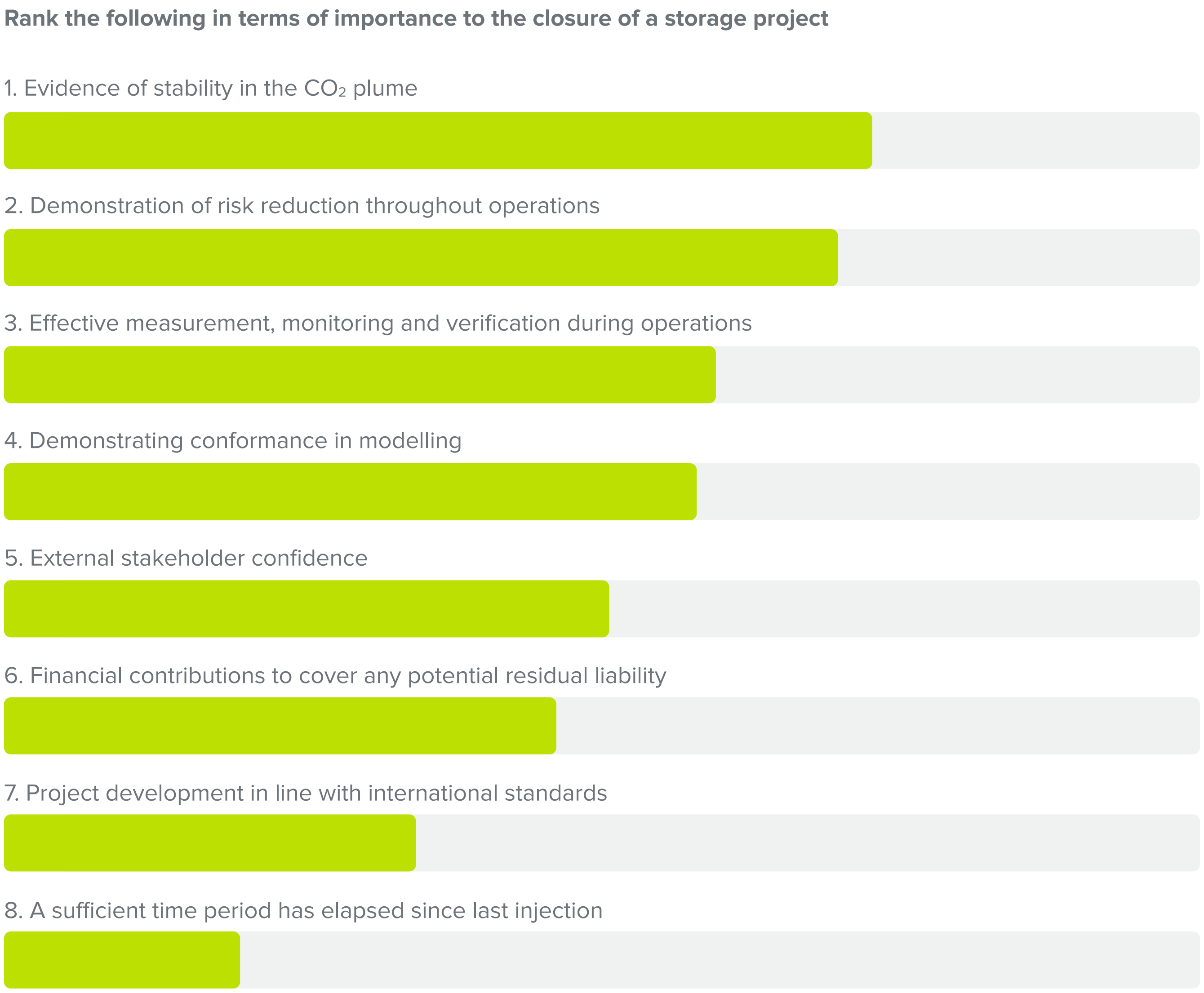

FIGURE 21. Results from stakeholder engagement sessions

Evidence of stability in the CO_2 plume

CO_2 plume stability is often defined as a requirement in regulatory regimes to demonstrate a project is ready for closure. Across different regimes the definition varies,[59] with some non-exhaustive examples listed below:

- demonstrate “clear evidence that the storage complex is evolving towards long-term stability before liability transfer”[60]
- demonstrate that the injected CO_2 plume “essentially no longer expands vertically or horizontally and poses no threat to USDWs, human health, safety, or the environment, as demonstrated by a minimum of three consecutive years of monitoring data.”[61]
- demonstrate that the CO_2 plume “has become stable,” or that the plume is “essentially stationary or, if it is migrating or may migrate, that any migration will be unlikely to cross the storage reservoir boundary.”[62]

Over time following the cessation of injection the CO_2 plume will become immobile as the pressure within the reservoir dissipates and secondary trapping mechanisms come into play. The mobility of the CO_2 plume is impacted by the geological setting of the storage project and should be assessed on a project-specific basis, where dissolution rates and the contribution of different trapping mechanisms vary based on the site-specific subsurface characteristics.

Studies suggest that structural settings exert a primary control on the contribution of various trapping mechanisms, where for sites that allow mobile CO_2 to migrate over long distances, residual and dissolution trapping can be enhanced. On the other hand, sites that inject into closed compartments may see the CO_2 plume remain in the gaseous phase, however, still being confined to a relatively smaller geographic area.[63] Demonstration of stability is typically indicated through conformance modelling, reliant on appropriate risk-based monitoring programs.

Demonstration of risk reduction throughout operations

As discussed within Section 4.6, proper site selection and detailed risk assessments, tied directly to the result of comprehensive site characterisation efforts, provide storage operators with site-specific insights into the likelihood and consequence of the various risks associated with a given CO_2 storage project. In turn, this enables informed decision making throughout the project lifecycle, as well as the efficient allocation of any necessary project resources.

Once injection commences, the identified natural, engineered and reactive safeguards are “tested.” Should monitoring data spot an irregularity, corrective measures (reactive safeguard) can be employed to address a risk. The reduction of subsurface and operational uncertainties combined with optimal operational limits, reservoir and site management can help to characterise the risk during the injection phase. Monitoring data throughout operation helps to reduce uncertainty and better characterise the residual risks identified prior to the project commencing, demonstrating risk reductions.

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[59] Hunt, John and Dotzenrod, Neil and Templeton, John and Regorrah, Josh and Connors, Kevin, Demonstration of Plume Stability for Carbon Storage Projects (December 18, 2024). Proceedings of the 17th Greenhouse Gas Control Technologies Conference (GHGT-17) 20-24 October 2024, Available at SSRN: https://ssrn.com/abstract=5064536 or http://dx.doi.org/10.2139/ssrn.5064536

[60] European Union Directive 2009/31/EC, Chapter 1, Article 18(2)

[61] Wyoming Code of Regulations § 24-2(hh)

[62] North Dakota Century Code § 38-22-17(5)(d)

[63] IEAGHG, “Evolution of Conformance and Containment Risk Over Time in CO_2 Storage Projects – The Link to Post Closure Stewardship and Handover”, March 2026, doi.org/10.62849/2026-04.

Effective measurement, monitoring and verification during operations

An important aspect of demonstrating confidence to the regulator that the project is ready for closure is the effective monitoring during the injection and post-injection phases to build confidence in an operator's understanding of the behaviour of the injected CO_2.

Early risk assessments identifying inherent risks associated with a storage location, and development of potential risk controls to understand residual risk, are key elements to demonstrate to the regulator that risk associated with a storage location can be brought to an acceptable level. In particular, during the post-injection phase the information gained until the point of cessation of injection through monitoring programs is critical to build an understanding of the behaviour of injected CO_2. Monitoring data helps to reduce uncertainty and optimise storage management to reduce risks into the post-injection phase and build confidence in the ability to demonstrate a project's readiness for closure.

Demonstrating conformance in modelling

Conformance is the evidence-based demonstration that a storage site's observed behaviour through monitoring data, e.g. CO_2 plume position and migration, pressure evolution, and containment performance, matches dynamic modelling predictions and ultimately supports the ability to provide evidence around the stability of the CO_2 plume. Again, this is a site-specific exercise which is linked to uncertainties in both the measurements and the modelling efforts.[64]

External stakeholder confidence

When considering the main elements to a successful CO_2 storage project (Section 3.1), non-technical risks often involve ensuring that the project has support from the relevant stakeholders, such as the regulator, financial and insurance companies and the general public. This remains relevant in the post-injection period, particularly in achieving project closure. Third party or independent assurance of operations is a potential means to provide additional confidence to stakeholders in the development, operation and closure of the storage project.

Financial contributions to cover any potential residual liability

Within existing regulatory frameworks there are methods for assessing liability, namely putting towards a cost to cover a specific liability. In particular, these costs are typically associated with the remaining need for monitoring activities, or any remediation or corrective actions that may be required. Article 19 of the EU CCS Directive requires that Member States ensure that, when applying for a storage permit, the potential operator must provide proof that adequate provisions can be established, by way of financial security or any other equivalent, based on arrangements to be decided by the Member States.

Obligations that must be covered by financial security covering the closure and post-closure phase include:

1. Monitoring, updates of the monitoring plan, and required reports of monitoring results.
2. Updates of corrective measures plan, and implementing corrective measures, including measures related to protecting human health.
3. Surrender of allowances for any emissions from the site, including leakages, in accordance with the ETS directive.
4. Sealing the storage site and removing injection facilities.
5. Making the required financial mechanism available to the competent authority.

The recently updated EU Commission guidance documents on the EU CCS Directive, provide non-binding guidance on how an operator should estimate the financial security required for surrender of allowances in order to calculate the potential financial security requirements. This guidance suggests that

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[64] IEAGHG, "Evolution of Conformance and Containment Risk Over Time in CO_2 Storage Projects – The Link to Post Closure Stewardship and Handover", March 2026, doi.org/10.62849/2026-04

determination of leaked amounts should be based on an evaluation of the site-specific leakage risks and the amount that can leak from each identified leakage pathway. The amount of financial security for surrender of allowances should be based on an assessment of risk of leakage at the time the calculation is made and should reflect the amount of CO_2 that has been injected.

Article 20 of the EU CCS Directive covers financial mechanism and indicates that the post-transfer costs of at least the monitoring obligation for a period of 30 years need to be fully covered by the operator and that necessary funds be made readily available to the competent authority. The recently updated guidance documents recommends that financial contribution post-closure should be calculated in a similar manner as for financial security.

In many US states, even those that do not have transfer of liability provisions, regulatory frameworks require operators to contribute to state-wide funds that are used to manage the potential long-term liabilities related to storage locations. It is not clear what defines the per-tonne contribution for many of these funds. Care should be taken to appropriately value the financial contribution necessary to manage the potential long-term liability.

Project development in line with international standards

International standards such as ISO 27914 and DNV-RP-J203, provide guidance on what is the agreed on good practise for the development of CO_2 storage projects. In many cases, satisfying the regulatory requirements of the jurisdiction in which the project is being developed is the ultimate priority. In regions without developed regulatory regimes, international standards may provide useful guidance to project developers and regulators. The independent assurance of operations considering best practice and international standards is another means to provide a regulator, or other external stakeholders, confidence in the development, operation and closure of the storage location.

A sufficient time period has elapsed since the last injection

To determine the readiness of a project for closure should consider its site-specific characteristics and performance criteria rather than being as opposed to an arbitrary time period. These decisions should consider the residual risks post-injection and the ability to demonstrate plume stability, containment and conformance. Linked to this, the subsequent post-injection monitoring efforts and associated liabilities should consider the site-specific residual risks following cessation of injection.

07

Summary

Photo: Adobe Stock

7. Summary

DNV and OGCI have developed this report anticipating that it will be a useful tool for developers, regulators and other stakeholders in identifying potential post-injection subsurface risks and how those risks may be effectively addressed through the screening, selecting, developing, operating, closing, and transferring of CO_2 storage projects. Although no large-scale commercial CCS projects are near the post-injection phase, the appropriate management of risks in the post-injection phase starts with appropriate CO_2 storage site selection and characterisation during the pre-injection phase and its success is further dependent on cautious CO_2 injection management as well as risk-based MMV plans and operations during the injection phase. Data acquisition through the project lifecycle is crucial to build confidence and enable the effective closure of CO_2 storage projects.

The report also discusses wider implications of the post-injection period, namely milestones in regulatory jurisdictions linked to the ‘closure’ of projects, and in some cases a transfer of responsibility back to the state or competent authority. To achieve closure, operators must demonstrate plume stability, containment, and conformance with predictive models, criteria that rely on high-quality data gathered over the entire project’s lifecycle period. The report explains that post-injection risks often decline naturally as pressures dissipate and trapping mechanisms (residual, dissolution, structural, and eventually mineralisation) secure the CO_2. Effective monitoring, tailored to site specific risks, provides the evidence base regulators require to confirm long-term containment.

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