TECHNICAL REPORT

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Carbon dioxide capture, transportation and geological storage — Injection operations, infrastructure and monitoring

Captage, transport et stockage géologique du dioxyde de carbone — Opérations d'injection, infrastructure et surveillance

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Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular, the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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For an explanation of the voluntary nature of standards, the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT), see www.iso.org/iso/foreword.html.

This document was prepared by Technical Committee ISO/TC 265, *Carbon dioxide capture, transportation, and geological storage*.

Any feedback or questions on this document should be directed to the user's national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

Introduction

Carbon capture and storage (CCS) is a key technology to reduce CO_2 emissions to the atmosphere and contribute to the abatement of global warming. To have a significant impact it needs to be deployed globally. ISO 27914 on geological storage of carbon dioxide presents the elements necessary to define performance expectations for onshore and offshore geological storage of carbon dioxide with an aim to establish investor and other stakeholder confidence, regulatory support, and public credibility to encourage deployment of CCS around the globe. ISO 27916 on CO_2-EOR presents the elements for confirming and quantifying associated storage of CO_2 during the production of hydrocarbons, to encourage increased use of anthropogenic CO_2.

The application of these International Standards by project developers for planning, design, and operation will be assisted by information based on existing operational practices and infrastructural requirements for both onshore and offshore geological storage projects. This document supports the implementation of ISO 27914 and ISO 27916 by providing information from selected existing CCS projects that are operated under a variety of geological settings.

Carbon dioxide capture, transportation and geological storage — Injection operations, infrastructure and monitoring

1 Scope

This document covers:

— A description of the existing legal frameworks and associated laws and directives covering current and planned projects.

— Specific information about CO_2 injection facilities based on existing and planned projects that include storage of CO_2 in both saline aquifers and CO_2-EOR as relevant. This information includes aspects of materials used, surface infrastructure, well design considerations, concepts around well placement strategies, considerations for downhole monitoring tool deployment, well completions, and well and infrastructure maintenance and remediation practices.

— Descriptions of current practices regarding operating projects including monitoring, safety, and reporting activities associated with both surface and downhole components of the projects.

— Discussion on operational aspects of storing CO_2 in hydrocarbon reservoirs including depleting gas fields and reusing facilities.

— A description of monitoring requirements and methods including measurements to establish baselines.

— A description of existing and emerging tools, accuracy, and expectations for quantification.

— A description of regulatory requirements for operating and decommissioning CO_2-EOR with associated storage and CCS projects around the world.

— A description of decommissioning activities and timelines associated with end-of-project.

2 Normative references

There are no normative references in this document.

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminology databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at https://www.electropedia.org/

3.1
abandonment
process and procedures used to permanently end the operation of a well

Note 1 to entry: Well abandonment is designed to eliminate the physical hazard of the well (the hole in the ground), eliminate a pathway for migration of contamination, and prevent changes in the hydrogeologic system, such as the changes in hydraulic head and the mixing of formation fluids between hydraulically distinct strata.

[SOURCE: ISO 27914:2017, 3.1]

3.2
acceptable risk
risk borne by the project operator and others having regard to legal obligations and management policies

Note 1 to entry: A tolerable risk is a risk of significant level considered as temporarily or conditionally acceptable. It is tolerated in order to facilitate a gradual response (e.g. monitoring of risk treatment) until the risk has been reduced.

[SOURCE: ISO 27917:2017, 3.4.7]

3.3
anthropogenic carbon dioxide
anthropogenic CO_2
carbon dioxide that is initially produced as a by-product of a combustion, chemical, or separation process (including separation of hydrocarbon-bearing fluids or gases) where it would otherwise be emitted to the atmosphere (excluding the recycling of non-anthropogenic CO_2)

Note 1 to entry: The chemical symbol "CO_2" is synonymous with "carbon dioxide". Accordingly, the two ways of writing out "carbon dioxide" and "CO_2" are used interchangeably in this document.

[SOURCE: ISO 27916:2019, 3.1]

3.4
area of review
geographical area(s) of a *storage project* (3.76), or part of it, designated for assessment of the extent to which a storage project, or part of it, could affect life and human health, the environment, competitive development of other resources, or infrastructure

Note 1 to entry: The delineation of an area of review defines the outer perimeters on the land surface or seabed and water surface within which assessments will be conducted as may be required by regulatory authorities.

[SOURCE: ISO 27917:2017, 3.3.10]

3.5
associated storage
CO_2 stored in association with CO_2-EOR that occurs as an inherent result of a dedicated hydrocarbon production operation

Note 1 to entry: The requirements of ISO 27916 are intended to ensure that CO_2 stored in association with a CO_2-EOR operation is stored as effectively as CO_2 stored in a geologic storage operation that complies with ISO 27914.

[SOURCE: ISO 27916:2019, 3.2]

3.6
authority
governmental entity or entities with legal power to regulate or permit CO_2-EOR, to regulate storage of CO_2 in a CCS project or in association with a CO_2-EOR operation, or to regulate quantification of the storage of CO_2 in a CCS project or in association with a CO_2-EOR operation

[SOURCE: ISO 27916:2019, 3.3, modified to add "a CCS project or in" and delete "competent"]

3.7
baseline
reference basis for comparison against which project status or performance is monitored or measured

[SOURCE: ISO 27917:2017, 3.3.2]

3.8
carbon dioxide capture and storage
CCS
process consisting of the separation of CO_2 from industrial and energy-related sources (or capture directly from the atmosphere), transportation and injection into a geological formation, resulting in long-term isolation from the atmosphere

Note 1 to entry: CCS is often referred to as Carbon Capture and Storage. This terminology is not encouraged because it is inaccurate: the objective is the capture of carbon dioxide and not the capture of carbon. Tree plantation is another form of carbon capture that does not describe precisely the physical process of removing CO_2 from industrial emission sources.

Note 2 to entry: The term "sequestration" is also used alternatively to "storage". The term "storage" is preferred since "sequestration" is more generic and can also refer to biological processes (absorption of carbon by living organisms).

Note 3 to entry: Long-term means the minimum period necessary for geological storage of CO_2 to be considered an effective and environmentally safe climate change mitigation option.

Note 4 to entry: CCS should also ensure long-term isolation of CO_2 from oceans, lakes, potable water supplies and other natural resources.

[SOURCE: ISO 27917:2017, 3.1.1, modified to add " (or capture directly from the atmosphere)"]

3.9
carbon dioxide capture and storage project
CCS project
consists of one or more connected CO_2 capture systems, transportation systems, and geological storage systems

Note 1 to entry: Each system (capture, transportation, or storage) might be operated by independent operators.

[SOURCE: ISO 27914:2017, 3.56]

3.10
carbon dioxide enhanced oil recovery
CO_2-EOR
process designed to produce hydrocarbons CO_2 from a reservoir using the injection of CO_2

Note 1 to entry: The process of CO_2 enhanced oil recovery is explained in detail in ISO 27916:2019.

[SOURCE: ISO 27916:2019, 3.4]

3.11
carbon dioxide enhanced oil recovery project
CO_2-EOR project
EOR complex, underground equipment, wells, surface or above seabed equipment, activities and rights necessary to an enhanced oil recovery operation, including any necessary or required surface or subsurface rights regulated by the authority

[SOURCE: ISO 27916:2019, 3.5]

3.12
carbon dioxide injection well
CO_2 injection well
well used to inject CO_2 into a project reservoir

[SOURCE: ISO 27916:2019, 3.6]

3.13
carbon dioxide plume
CO_2 plume
region within geologic strata where injected CO_2 is present in free phase

[SOURCE: ISO 27914:2017, 3.6, modified to add “injected”]

3.14
carbon dioxide stream
CO_2 stream
stream consisting overwhelmingly of carbon dioxide

Note 1 to entry: The CO_2 stream typically includes impurities and may include substances added to the stream to improve the injection process or performance of hydrocarbon recovery operation and/or to facilitate CO_2 detection.

[SOURCE: ISO 27916:2019, 3.7, modified to add “the injection process or”]

3.15
carbon dioxide stream composition
CO_2 stream composition
comprehensive description of the CO_2 stream contents that lists the fraction of each component

Note 1 to entry: The CO_2 stream composition is usually subject to regulatory discretion and approval. It is commonly documented on a volumetric basis but may also be documented as a mass fraction.

3.16
casing
pipe material placed inside a drilled hole to prevent the surrounding strata from collapsing into the hole

Note 1 to entry: There are many acceptable variations on casing design but typical types of casing in most injection wells are:

a) surface casing, i.e. the outermost casing that extends from the surface to the base of the lowermost *protected groundwater* (3.58);

b) intermediate casing is one or more strings of casing installed between the surface and long-string casing for various design reasons;

c) long-string casing, which extends from the surface to the bottom of the well.

[SOURCE: ISO 27914:2017, 3.8, modified to delete “to or through protected groundwater”]

3.17
closure period
period between the cessation of CO_2 injection and the demonstration of compliance with the criteria for site closure

[SOURCE: ISO 27917:2017, 3.1.7]

3.18
communication plan
document describing when, what and how to communicate with project stakeholders

Note 1 to entry: A communication plan may provide information relating to issues such as monitoring and verification, environmental impacts, risk treatment.

[SOURCE: ISO 27917:2017, 3.5.4]

3.19
containment
status of CO_2 being confined within the *storage complex* (3.74) or *EOR complex* (3.30) by an effective trap or combination of traps

[SOURCE: ISO 27916:2019, 3.8, modified to add "storage complex or"]

3.20
containment assurance
demonstrating that the features and geologic structure of the CO_2 storage project or CO_2-EOR project are adequate to provide safe, long-term containment of CO_2, and that the CO_2 flood is operated in a way to assure containment of the CO_2 in the EOR complex

[SOURCE: ISO 27916:2019, 3.9, modified to add "the CO_2 storage project or"]

3.21
corrective action
action taken to correct material irregularities or to contain breaches in order to prevent or minimize damage to, or release of CO_2 from, a *storage complex* (3.74) or *EOR complex* (3.30)

Note 1 to entry: Corrective actions are implemented after an irregularity has occurred to help prevent or minimize damage.

[SOURCE: ISO 27914:2017, 3.12, modified to add "or EOR complex"]

3.22
decommission
take an engineered system or component out of service, render it inoperative, dismantle and decontaminate it

[SOURCE: ISO 27914:2017, 3.13]

3.23
demulsifiers or emulsion breakers
specialty chemicals used to break emulsions (that is, to separate the two phases), for example, water in oil

Note 1 to entry: They are commonly used in the processing of crude oil, which is typically produced along with significant quantities of saline water.

Note 2 to entry: The type of demulsifier selected depends on the type of emulsion, either oil-in-water or water-in-oil.

Note 3 to entry: Demulsifiers are used in the chemical analysis of oil and synthetic muds and to treat produced hydrocarbons.

3.24
dense phase CO_2
CO_2 in its liquid or supercritical phases

Note 1 to entry: Compression and transport of dense phase CO_2 are commonly achieved using compressors and pumps.

Note 2 to entry: Because liquid CO_2 is also considered dense phase, not all dense phase CO_2 is supercritical.

[SOURCE: ISO 27917:2017, 3.2.2, modified Note 1 to entry to add "compressors and" and delete "Compression and transport at lower densities are commonly achieved with turbo-compressors." Note 2 to entry - "Not all supercritical CO2 is in a dense phase and" has been modified to "Because liquid CO2 is also considered dense phase" - Note 3 to entry has been deleted.]

3.25
detection threshold
smallest value of a property of a substance that can be reliably detected by a specified method of measurement in a specified context

[SOURCE: ISO 27917:2017, 3.3.3, modified to change "limit" to "threshold"]

3.26
element of concern
valued element or objective for which *risk* (3.60) is evaluated and managed

[SOURCE: ISO 27914:2017, 3.14]

3.27
emergency response plan
systematic procedures that clearly detail what is to be done, how, when, and by whom before, during and after the time an emergency occurs

Note 1 to entry: In some jurisdictions, it can be called "emergency and remedial response plan", "contingency plan", etc.

Note 2 to entry: Emergency response plans often also cite preparations to be completed before an emergency occurs.

[SOURCE: ISO 27917:2017, 3.4.12]

3.28
emissions
CO_2 stream releases to the atmosphere over a specified period of time

3.29
environmental impact
change, which may be adverse or beneficial, to the environment, wholly or partially resulting from CCS project activities

[SOURCE: ISO 27917:2017, 3.4.13]

3.30
EOR complex
project reservoir (3.57) *trap* (3.84), and such additional surrounding volume in the subsurface as defined by the operator within which injected CO_2 will remain contained long-term

[SOURCE: ISO 27916:2019, 3.10, modified from "in safe, long-term containment" to "contained long-term"]

3.31
event
material occurrence or change in a particular set of circumstances

[SOURCE: ISO 27914:2017, 3.16]

3.32
geological storage
long-term *containment* (3.19) of CO_2 streams in subsurface geological formations

Note 1 to entry: Long-term means the minimum period necessary for CO_2 geological storage to be considered an effective and environmentally safe climate change mitigation option.

Note 2 to entry: The term "sequestration" has been used by a number of countries and organizations instead of "storage" (e.g. the international "Carbon Sequestration Leadership Forum"). The two terms are considered to be synonymous, and only "storage" is used in this document.

[SOURCE: ISO 27914:2017, 3.17, modified to delete Note 3 to entry]

3.33
greenhouse gas
GHG
gaseous constituent of the atmosphere, natural or anthropogenic, that absorbs and emits radiation at specific wavelengths within the spectrum of infrared radiation emitted by the Earth's surface, the atmosphere, and clouds

Note 1 to entry: The most common greenhouse gases are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), nitrogen trifluoride (NF_3) perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6). Emissions from these gases are reported under the UNFCCC and aggregated into carbon dioxide equivalents (CO_2 -e) using factors called global warming potentials (GWPs).

[SOURCE: ISO 14064-2:2019, 3.1.1]

3.34
impurities
non- CO_2 substances that are part of the CO_2 stream that may be derived from the source materials or the capture process, or added as a result of commingling for transportation, or released or formed as a result of sub-surface storage and/or leakage of CO_2

Note 1 to entry: As a subset of impurities, contaminants are non- CO_2 substances whose presence in the CO_2 stream is generally unwanted.

Note 2 to entry: As a subset of impurities, additives are substances added to the stream for the purposes of managing its physical or chemical behaviour (e.g. hydrate and corrosion inhibitors), for or from interaction with equipment (e.g. lubricants), and to track its distribution in the subsurface after injection (geochemical tracers).

[SOURCE: ISO 27917:2017, 3.2.12]

3.35
injectivity
rate and pressure at which fluids can be pumped into the storage unit without fracturing the storage unit

[SOURCE: ISO 27914:2017, 3.19]

3.36
Joule-Thomson effect
thermodynamic process that occurs when a fluid expands from high pressure to low pressure at constant enthalpy such as across a valve

Note 1 to entry: Under the right conditions, this can cause cooling of the fluid.

3.37
leak
leakage
unintended release of CO_2 out of a pre-defined containment

Note 1 to entry: Containments can include both surface containers (e.g. compressors, pipelines, trucks, ships, trains) and subsurface containments (e.g. storage complex).

[SOURCE: ISO 27917:2017, 3.2.14]

3.38
leakage pathway
geological or artificial conduit for leakage of CO_2 out of the storage complex or EOR complex

[SOURCE: ISO 27916:2019, 3.13, modified to add “storage complex or”]

3.39
likelihood
chance of something happening, expressed qualitatively or quantitatively and described using general terms or mathematically, e.g. by specifying a probability or frequency of occurrence over a given period

[SOURCE: ISO 27914:2017, 3.22]

3.40
liner
casing (3.16) string that does not extend to the surface

[SOURCE: ISO 27916:2019, 3.23]

3.41
loss
emissions, leakage, intended releases, and transfers of the CO_2 stream to outside of the CCS project defined boundary

Note 1 to entry: The terms "emissions", "leakage" and "losses" are all used in this document to refer to CO_2 that would be deducted from quantities captured, transported or stored, but the terms have distinct meanings. The term "emissions" refers to CO_2 entering the atmosphere. The term "leakage" refers to CO_2 emitted but also includes CO_2 that escapes containment without entering the atmosphere, such as CO_2 that escapes a geological storage complex without moving into the atmosphere. The term "loss" is even broader and would include, in addition to emissions and leakage, CO_2 that is transferred out of a CCS project for some other use, which might or might not result in emission to the atmosphere.

Note 2 to entry: The term "loss" as used in this document is to be distinguished from the term "loss" as sometimes used in conjunction with CO_2-EOR operations to mean injected CO_2 that is not returned to the surface for recycling, i.e. is "lost" to the geological formation, necessitating purchase of more CO_2 for injection.

[SOURCE: ISO 27916:2019, 3.14]

3.42
make-up
purchased CO_2
CO_2 newly received from offsite

3.43
management of change
procedure used when making a change to the process equipment or operating procedures to detail changes made and to document steps taken to inform and train operating personnel and relevant stakeholders on process changes

[SOURCE: ISO 27914:2017, 3.24]

3.44
measurement
determination of quantities using physical devices

Note 1 to entry: Examples of measurements are temperature, flow, concentrations, length, distance, etc. Measurement may be direct (e.g. length with a meter) or indirect. Indirect measurements may require two steps, firstly sampling and then analysis. Indirect measures may also use a model to convert the measurement of a given quantity into the measurement of another one, e.g. from velocity to flow rate, taking into account the pipe and fluid characteristics.

3.45
mechanical integrity
mechanical condition of a well, such that engineered components maintain their original dimensions and functions, solid geological materials are kept out of the wellbore, and fluids including CO_2 are prevented from uncontrolled flow into, out of, along, or across the wellbore, cement sheath, annulus, *casing* (3.16), *tubing* (3.86), and/or *packers* (3.52)

[SOURCE: ISO 27914:2017, 3.25]

3.46
mechanical integrity test
MIT
test performed on a well to confirm that it maintains internal or external *mechanical integrity* (3.45)

Note 1 to entry: MITs are a means of measuring the adequacy of the construction of a well and a way to detect problems within the well system.

[SOURCE: ISO 27914:2017, 3.26]

3.47
mitigation
limitation or reduction of actual or potential undesirable effects of a particular event or process

[SOURCE: ISO 27917:2017, 3.4.10]

3.48
monitoring
continuous or repeated checking, supervising, critically observing, measuring or determining the status of a system to identify change from a baseline or variance from an expected performance level

Note 1 to entry: In case of geological storage, monitoring is not restricted to the technical infrastructure of an operator, it also includes the wider surroundings of the surface and/or subsurface storage site.

[SOURCE: ISO 27917:2017, 3.3.1]

3.49
nomination process
pipeline transportation process whereby a shipper enters a “nomination” to put a specified quantity of gas into the pipeline at an entry point, and the same nomination states where and by whom the gas will be removed from the pipeline at the delivery point

3.50
operator
person or entity that is legally responsible for the CCS project or the CO_2-EOR project

[SOURCE: ISO 27917:2017, 3.5.2, modified to add “person or” and “or the CO_2-EOR project”]

3.51
overburden
geological material overlying an area or geological formation of interest in the subsurface

[SOURCE: ISO 27914:2017, 3.29]

3.52
packer
mechanical device that seals the outside of *tubing* (3.86) to the inside of *casing* (3.16) or the outside of casing to the drilled geological formation, isolating an annular space

[SOURCE: ISO 27914:2017, 3.30, modified to add “or the outside of casing to the drilled geological formation”]

3.53
post–closure period
period that begins after the demonstration of compliance with the criteria for site closure

Note 1 to entry: In some countries, demonstration of compliance may need approval from a third party.

[SOURCE: ISO 27917:2017, 3.1.8]

3.54
pressure limit
pre-defined extrema of pressure for safe and effective operation of components of a CCS project

[SOURCE: ISO 27917:2017, 3.2.13]

3.55
primacy
primary enforcement responsibility
authority for a US state to implement the UIC Program

Note 1 to entry: To receive primacy, a US state, territory or tribe must demonstrate that its Class VI UIC Program is at least as stringent as the federal standards; the state, territory or tribal UIC requirements may be more stringent than the federal requirements. (For Class II UIC Program primacy, states must demonstrate that their programs are effective in preventing pollution of USDWs.) A state may obtain primacy for all or part of the UIC Program, e.g. for specific classes of injection wells.

3.56
primary seal
continuous geological unit (known in reservoir engineering as caprock and in hydrogeology as aquitard or aquiclude) above a *storage unit* (3.78) that is part of a *storage complex* (3.74) and effectively restricts migration of fluids out of the storage unit and *leakage* (3.37) out of the storage complex

[SOURCE: ISO 27914:2017, 3.32]

3.57
project reservoir
geologic reservoir into which CO_2 is injected for production of hydrocarbons in paying or commercial quantities

[SOURCE: ISO 27916:2019, 3.19]

3.58
protected groundwater
water found beneath the water table in fully saturated soils and geologic formations that is used for human consumption, agricultural, or industrial uses or is protected from contamination by legislation or regulation

[SOURCE: ISO 27914:2017, 3.37]

3.59
remediation
process of correcting a failure or impacts on affected elements of concern

[SOURCE: ISO 27917:2017, 3.4.11]

3.60
risk
effect of uncertainty on project objectives [e.g. on performance metrics for an *element of concern* (3.26), expressed in terms of the severity of consequences (negative impacts) of an *event* (3.31) and the associated *likelihood* (3.39) of their occurrence

Note 1 to entry: An effect is a deviation from the expected and can be either positive or negative.

Note 2 to entry: Objectives can have different aspects (such as financial, health and safety, and environmental goals) and can apply at different levels (such as strategic, organization-wide, project, product and process).

[SOURCE: ISO 27917:2017, 3.4.1]

3.61
risk analysis
process for understanding the nature and level of *risk* (3.60)

[SOURCE: ISO 27914:2017, 3.40]

3.62
risk assessment
overall process of *risk identification* (3.66), *risk analysis* (3.61), and *risk evaluation* (3.64)

[SOURCE: ISO 27914:2017, 3.41]

3.63
risk control
measure whose purpose is to reduce a specific *risk* (3.60) or avoid escalation of risk

[SOURCE: ISO 27914:2017, 3.42]

3.64
risk evaluation
process of comparing the results of a *risk analysis* (3.61) with *risk evaluation criteria* (3.65) to determine whether the *risk* (3.60), its magnitude, or both are acceptable or treatment is required to reduce the risk

[SOURCE: ISO 27914: 2017, 3.43]

3.65
risk evaluation criteria
terms of reference against which the significance of *risk* (3.60) is evaluated

[SOURCE: ISO 27914:2017, 3.44]

3.66
risk identification
process of finding, recognizing, and describing *risk* (3.60)

[SOURCE: ISO 27914:2017, 3.45]

3.67
risk management plan
scheme specifying the approach, management components, and resources to be applied to the management of *risk scenarios* (3.68)

[SOURCE: ISO 27914: 2017, 3.46]

3.68
risk scenario
combination or a chain of circumstances through which a *threat* (3.81) can cause an *event* (3.31) to occur and through which the consequences of an event can have a negative impact on *elements of concern* (3.26)

[SOURCE: ISO 27914:2017, 3.48]

3.69
risk treatment
process to reduce a specified *risk* (3.60) through implementation of *risk controls* (3.63)

Note 1 to entry: Risk treatments could reduce the likelihood or impact severity of a risk.

[SOURCE: ISO 27917:2017, 3.4.4, modified to add Note 1 to entry]

3.70
safe, long-term
period necessary for storage to be considered environmentally safe by the scheme under which the quantification is being implemented

Note 1 to entry: Long-term means the minimum period necessary for CO_2 geological storage to be considered an effective and environmentally-safe, climate change mitigation option.

[SOURCE: ISO 27916:2019, 3.21]

3.71
site characterization
detailed evaluation of one or more candidate sites for CO_2 storage identified in the screening and selection stage of a CO_2 *storage project* (3.76) to confirm and refine *storage complex* (3.74) integrity, storage capacity, and *injectivity* (3.35) estimates and provide basic data for initial predictive modelling of fluid flow, geochemical reactions, geomechanical effects, *risk assessment* (3.62), and *monitoring* (3.48) and *validation* (3.89) program design

[SOURCE: ISO 27914:2017, 3.51]

3.72
site closure
end of the *closure period* (3.17), which occurs when the project *operator* (3.50) has demonstrated compliance with criteria for site closure

[SOURCE: ISO 27914:2017, 3.52]

3.73
stakeholder(s)
individual, group of individuals, or organization whose interests are or could be affected by a *storage project* (3.76)

Note 1 to entry: Stakeholders can include decision makers, employees, shareholders, academia, insurance companies, banks, community residents, suppliers, customers, non-governmental organizations, governments, regulators, labour unions, and other individuals or groups.

[SOURCE: ISO 27914:2017, 3.36, modified]

3.74
storage complex
subsurface geological system extending vertically to comprise storage units, and identified seals, and extending laterally to the defined limits of the CO_2 storage project

Note 1 to entry: Limits are defined by natural geological boundaries, regulation or legal rights.

Note 2 to entry: Some jurisdictions could allow boundaries to be redefined if CO_2 moves outside the original boundary yet still achieves safe, long-term containment.

[SOURCE: ISO 27914:2017, 3.54, modified to add Note 2 to entry]

3.75
storage facility
area on the ground surface or, in offshore cases, in the sea or on the sea bed, defined by the operator and/or regulatory agency, where CO_2 injection facilities are developed and operational activities [including *monitoring* (3.48)] take place

Note 1 to entry: In many instances, the storage facility and the *area of review* (3.4) may be coextensive. Because the areas have different derivations — the area of review being based on potential impacts and the storage facility being based on operational activities — there is a potential for the areas to be different for a specific project. Therefore, each term is used in this document to reflect its specific derivation and application.

[SOURCE: ISO 27914:2017, 3.55]

3.76
storage project
physical and temporal extent of activities associated with a project for the *geological storage* (3.32) of CO_2 that includes site selection and characterization, *baseline* (3.7) data collection, permitting, design and construction of site facilities (site pipelines, compressors, etc.), well drilling, receipt of CO_2 at the *storage site* (3.77) and CO_2 injection during the active injection phase, and *site closure* (3.72) (including well and facilities abandonment)

Note 1 to entry: It also includes testing and *monitoring* (3.48) during all project phases.

[SOURCE: ISO 27914:2017, 3.56]

3.77
storage site
site that comprises the *storage facility* (3.75), *storage project* (3.76) wells, and the *storage complex* (3.74)

[SOURCE: ISO 27914:2017, 3.58]

3.78
storage unit
geological stratum (or strata) into which CO_2 is injected for the purpose of storage

[SOURCE: ISO 27914:2017, 3.59]

3.79
supercritical CO_2
CO_2 at pressures and temperatures above both the critical pressure and critical temperature

[SOURCE: ISO 27917:2017, 3.2.1]

3.80
termination
process beginning with the cessation of quantification of associated storage, and ending with both the termination of hydrocarbon production from the project reservoir, and the plugging and abandonment of wells unless otherwise required by the authority

[SOURCE: ISO 27916:2019, 3.22]

3.81
threat
element that alone or in combination with other elements has the potential to cause damage or produce a negative impact

[SOURCE: ISO 27914:2017, 3.60]

3.82
threshold
limit value, which can be a function of time, space or other variables, beyond which an action or frame of reference is triggered

[SOURCE: ISO 27917:2017, 3.3.4]

3.83
transfer of responsibility
transfer of all rights, responsibilities, and liabilities associated with a *storage site* (3.77) to a post-closure steward

[SOURCE: ISO 27914:2017, 3.63]

3.84
trap
any feature or mechanism that alone or in combination provides safe, long-term containment below a low-permeability confining geologic layer (cap rock or seal), including in the pore spaces of the EOR complex (physical, stratigraphic, or structural trapping); by capillary pressure from the water in the pore spaces between the rock (residual trapping); by dissolution in the in situ formation fluids (solubility); by hydrodynamic trapping; by adsorption onto organic matter; or by reacting in geologic formations to produce minerals (geochemical trapping)

[SOURCE: ISO 27916:2019, 3.23]

3.85
treater
vessel used to treat oil-water emulsions, so the oil can be accepted by the pipeline or transport

Note 1 to entry: Treaters use heat, gravity segregation, chemical additives, or electric current to break emulsions and are sometimes called heater treaters or emulsion treaters.

Note 2 to entry: Residence time in treaters varies, with residence generally shorter in vertical treaters than in horizontal ones.

3.86
tubing
tubular string normally run inside the injection or production *casing* (3.16) that acts as the primary conduit for fluids

[SOURCE: ISO 27914:2017, 3.62]

3.87
unacceptable risk
risk of a nature and level that is regarded as unacceptable by the project operator and others or by an authority whose approval is required for the project to proceed

[SOURCE: ISO 27917:2017, 3.4.8]

3.88
uncertainty (of measurement)
parameter associated with the result of a measurement that characterizes the dispersion of values that could reasonably be attributed to the measurement property

[SOURCE: ISO 27917:2017, 3.3.7]

3.89
validation
confirmation that the system under consideration meets in all respects the specification of that system

[SOURCE: ISO 27917:2017, 3.3.6]

3.90
venting
intended release of a gas into the atmosphere from pre-defined containment

3.91
verification
confirmation by examination and provision of objective evidence that specified criteria are met

Note 1 to entry: Verification examines what has happened in the past. The objective of verification is to express a conclusion designed to enhance the degree of confidence in the declared outcomes of the CCS project quantification as evaluated against agreed criteria.

[SOURCE: ISO 27917:2017, 3.3.5]

3.92
well
wellbore
holes created into the ground in which are emplaced combinations of tubing, casing and cement to be used for conveying fluids

Note 1 to entry: In this document "well" is used to refer generally to the entire well (including wellhead, valves, etc.) whereas "wellbore" refers to the downhole portion of the well.

4 Symbols and abbreviated terms

3D	Three dimensional
ADM	Archer Daniels Midland Company
AEP	American Electric Power
AOR	Area of review
API	American Petroleum Institute
BPM	Best practice manual
BSEM	Borehole to surface electromagnetic
BTC	Buttress thread casing
CBL	Cement-bond log
CCI	Continuous CO_2 injection
CCS	Carbon dioxide capture and storage
CCS Directive	Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide
CFR	US Code of Federal Regulations
CO_2	Carbon dioxide
CO_2-EOR	CO_2-Enhanced oil recovery
CSA	CSA Group (formerly Canadian Standards Association)
CSEM	Controlled source electromagnetic
DAS	Distributed acoustic sensing
DOE or USDOE	US Department of Energy
DTS	Distributed temperature sensing
EEA	European Economic Area
ELD	Environmental Liability Directive
EOS	Equations of state
EPA or USEPA	US Environmental Protection Agency

ETS Directive	Directive 2003/87/EC
FRP	Fiber reinforced plastic
FWKO	Free water knockout
GPS	Global positioning system
H_2S	Hydrogen sulfide
HCl	Hydrochloric acid
IEAGHG	International Energy Association Greenhouse Gas Programme
InSAR	Interferometric synthetic aperture radar
KCl	Potassium chloride
KSpG	Carbon dioxide storage law
LACT	Lease automatic custody transfer
LNG	Liquefied natural gas
MD	Measured depth. The length of the wellbore
MMscf	Million standard cubic feet
MMV	Monitoring, measurement and verification
N_2	Nitrogen
NACE	National Association of Corrosion Engineers
NETL	US DOE National Energy Technology Laboratory
NOx	Nitrogen oxide(s)
O_2	Oxygen
PISC	Post injection site care
ppg	Pounds per gallon
PVT	Relation between pressure, specific volume, temperature
RA	Risk assessment
ROV	Remotely operated vehicle
SCADA	Supervisory control and data acquisition
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SWP	Southwest Partnership on Carbon Sequestration
TD	Total depth
UIC	Underground injection control

USDW	Underground source of drinking water
Vshale	The volume of shale in a given volume of rock
VSP	Vertical seismic profiles
WAG	Water alternating gas

5 Legal framework

5.1 General

In this clause, some general introduction and observations on regulatory frameworks relevant to CO_2 storage operations and the case studies selected for this document are highlighted.

For most jurisdictions, CO_2-EOR operations are subject to the regulatory framework for petroleum operations whereas other types of geological storage are regulated separately under dedicated CCS frameworks. For some jurisdictions, such as the United States, this distinction has consequences for the activities required by the operator and the legal liability to which the operator is subject. In other jurisdictions, as in many countries in the European Union, the distinction is not of the same significance. The EU regulatory framework contains identical requirements for storage of CO_2, regardless of the primary intended purpose of the CO_2 injection (i.e. CO_2-EOR or CCS).

Subclauses 5.2 to 5.9 present the regulatory frameworks for the US, Germany, France, Norway, Canada, Japan, and Australia. These jurisdictions are chosen as case studies and presented in this document as they have different legal traditions and maturity level regarding CO_2 injection and storage.

The United States has a well-developed regulatory framework for CO_2 storage onshore, both associated storage during CO_2-EOR and non-associated geological storage. However, there is currently no regulatory framework to regulate such activities offshore in federal waters. In state waters, the same regulations that govern onshore operations are generally applicable. Further, the distinction between Class II and Class VI permits for storage associated with CO_2-EOR and geological storage, respectively, results in some differences regarding post-injection responsibilities and liability for the operator. Some of these issues are subject to federal regulation and others are subject to state requirements and permitting. Regulatory frameworks in other countries with a federal governmental structure (for example Canada and Australia) also distinguish between federal and state/province regulation and the content and maturity of the federal and state/province regulations vary. For the European Union and the UK, the framework for CO_2 storage is applicable for 31 countries and covers both onshore and offshore operations for CCS and CO_2-EOR. Despite some distinct differences among the member states' frameworks, the default responsibilities and liabilities for the operators storing CO_2 are the same. Meanwhile, the regulatory framework for CO_2 storage in Japan is still developing.

5.2 United States

5.2.1 General

Onshore underground injection projects in the US are regulated through the Underground Injection Control (UIC) program adopted by the US Environmental Protection Agency (EPA) in the 1980s under the federal Safe Drinking Water Act (SDWA). The UIC program is directed at protecting underground sources of drinking water (USDWs) from underground injection activities that would endanger human health through contamination. At present, very few wells are injecting CO_2 solely for the purpose of geological storage as compared with a much larger number of wells injecting CO_2 for the purpose of EOR. The permitting, operation, and closing of oil and gas related injection wells is governed by a vast body of contracts, industry practice, mineral property ownership and leasing, judicial decisions, as well as statutory law and regulation, in addition to the provisions of the UIC Program. Wells used exclusively for the storage of CO_2 are not subject to the pre-existing framework for CO_2 injection wells, which presupposes linkage of the activity to the extraction of a valuable economic commodity, resulting in the UIC Program being the predominant framework for the injection of CO_2 solely for storage purposes.

Under the SDWA, responsibility for regulating well permitting, operation, and closure is divided between the state and federal governments. The federal UIC program establishes minimum standards or requirements for regulation of certain types of injection wells, while allowing states to assume primary authority (called “primacy”) for implementation and enforcement of the program, while EPA retains oversight to ensure compliance with the minimum standards.

5.2.2 UIC Class II and Class VI

The UIC program originally divided fluid injection wells into five different classes, depending on the activity and the nature of the injectate. Class II wells are used to inject fluids associated with production of oil or natural gas. Thus, Class II wells include principally (a) disposal wells for injecting produced water and oilfield wastes; (b) wells used to inject brine, freshwater, steam, polymers, or carbon dioxide to enhance oil recovery; or (c) wells used for underground storage of liquid hydrocarbons.

In 2010, EPA added a Class VI program for wells used for injection of CO_2 for the purpose of geological storage. The Class VI rules provide well design and permitting requirements for the injection of CO_2 for storage in saline formations. Adapting the existing UIC regulatory framework to address the unique buoyant and corrosive nature of CO_2 injectate, the Class VI rule sets minimum technical criteria for permitting, geologic site characterization, delineating an area of review (AOR), corrective action on existing wellbores, financial assurance, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care (PISC), and site closure. Following issuance of the Class VI rule in 2010, the EPA issued multiple non-binding guidance documents providing additional information to assist those operating under the rule (https://www.epa.gov./uic/final-class-vi-guidance-documents).

At the time of publication, the regulatory bodies of essentially all of the oil and gas producing states have obtained primacy for administration of Class II injection wells. Initially, EPA directly administered the Class VI well program in every state, and has issued permits for six Class VI wells since 2010 including provisions governing post-injection site care and closure (see 11.5.4), although only two of these wells have ever been operated. More recently, individual states are requesting and obtaining primacy for the UIC Class VI well program.

5.3 The European Union

5.3.1 General

The European Union (EU) consists of 27 member states, and three other European Economic Area (EEA) states (Iceland, Liechtenstein and Norway) that collaborate with the EU. The UK also adopted the EU approach before leaving the Union.

The member states of the EU and to a large extent the EEA states are obliged to implement all legally binding directives and regulations and adopt all measures of national law necessary to do so. For both regulations and directives, the EU can pass legislation that sets minimum standards, which do not preclude member states from setting more stringent standards and enables member states to maintain more stringent regulatory provisions than those prescribed, if these are otherwise compatible with EU law.

Below, the two most relevant EU legal instruments for CCS and CO_2-EOR, which are relevant for 31 countries, are summarized.

5.3.2 The EU CCS Directive

The EU CCS Directive (EU Directive 2009/31/EC) was adopted in 2009 to provide for environmentally safe deployment of CCS. Specifically, it aims to ensure that there is no significant risk of leakage of CO_2 or damage to public health or the environment, and to prevent any adverse effects on the security of the CO_2 transport network or storage sites. As per the CCS Directive’s definition, enhanced hydrocarbon recovery (EHR) – including CO_2-EOR - is not in itself included in the scope of this directive. However, where combined with geological storage of CO_2, the provisions apply accordingly.

Pursuant to the CCS Directive, CCS activities are subject to permit requirements which include having separate exploration and storage permits issued pursuant to the ETS Directive. The CCS Directive harmonizes administrative procedures for the whole cycle of carbon capture, transport and storage across member states, however leaving each member state with the freedom to decide how site operators are to prove their ability to safely operate and monitor a storage site up to the point of closure and later transfer of responsibility to the competent authority.

The storage permit contains information about the operator, location and delimitation of the storage site and administrative information about the permit itself. As well, the permit requires a large amount of technical data comprising characterization of the storage site, identification of CO_2 stream composition, an approved monitoring plan, a plan for corrective measures to prevent significant irregularities, a proposed plan for corrective measures in case of leakage and significant irregularities, reporting criteria, criteria for closure, and an approved provisional post-closure plan. Prior to granting the permit, the application with supporting material, as well as information of the designated authorities planned decision relating to the permit, are sent to the European Commission for review. State regulators are obligated to ensure that the operator is "financially sound and technically competent to operate and control the site".

The CCS Directive contains a number of detailed requirements to be implemented for the operational phase, leaving room for member states to decide on the details and to take into consideration the commercial and operational specifications. As an example, the CCS Directive requires monitoring of the injection facilities, the storage complex and the surrounding environment based on what is set out in the operator's monitoring plan. The purpose is to detect significant irregularities, migration and leakage of CO_2 and significant adverse effects on the surrounding environment. In case of leakage or significant irregularities, the operator is obligated to immediately notify the designated authorities and to take necessary corrective measures. In case the operator fails to take the appropriate measures, the designated authorities need to initiate such measures themselves, recovering the costs from the operator. Consequently, the CCS Directive requires the operator to establish and maintain a mechanism for financial security prior to start of injection and throughout the operational phase. The CCS Directive does not provide the details on how this financial security should documented. It is up to the Member States to decide what type of instrument is desired.

5.3.3 The Environmental Liability Directive

EU's Environmental Liability Directive (ELD) establishes the framework for environmental liability, based on the polluter pays principle, to prevent and remedy environmental damage. Where CCS operations result in damage to the local environment, the CCS Directive relies upon the ELD for allocation of liability. This framework thus applies in parallel with the requirements to monitor, report, prevent and implement corrective measures pursuant to the CCS Directive and ensures that damage to the environment beyond the storage site is not neglected.

Under the ELD, liability for both preventive and remedial action is assigned to the operator, who is in control of the activity which causes or threatens to cause the environmental damage. That responsibility remains even after active storage operations have ceased, throughout the post-closure period until responsibility is transferred to the Competent authority. More details regarding closure, post-closure and transfer of liability are provided in Clause 11.

5.4 Germany

In 2012, Germany passed a law entitled the 'Demonstration and application of technologies for the separation, transport and permanent storage of carbon dioxide' (or 'KSpG'). The KSpG represents an almost direct implementation of the EU CCS Directive containing the prerequisites for examining the subsurface for its suitability for CO_2 storage and for the planning approval of a CO_2 storage facility. The planning approval is subject to strict environmental requirements and is only adopted if these are met. The operator needs to demonstrate that the CO_2 storage does not adversely affect the general interest, its long-term safety is guaranteed, that no danger to humans and/or the environment will be caused and that the necessary precautions will be taken.

The KSpG limits the annual storage quantity of CO_2 both with regard to each CO_2 storage facility as well as the total amount in Germany. Not more than 1,3 Mt of CO_2 is stored per storage facility, nor more than 4 Mt nationwide. The KSpG further requires that requests for permits for investigation, construction and operation of a CO_2 storage facility must be submitted by 31 December 2016. No applications came in prior to the deadline.

5.5 France

France started the transposition of EU CCS Directive in 2010 and Decree 2011-1411 completed the transposition into French national law. Whereas the scope of the CCS Directive excludes R&D pilots with a storage capacity below 100 kt, French law regulates these operations. Pursuant to the French Environmental Code, the quantity of CO_2 injected for testing purposes should not exceed the quantity strictly required for the characterization of the formation and cannot exceed 100 kt. Pursuant to the decree 2012-384, geological storage of CO_2 facilities must comply with specific regulations regarding the protection of the environment.

5.6 Norway

5.6.1 General

The current Norwegian regulatory regime for CO_2 storage is based on implementation of the EU CCS Directive and the EU ETS Directive. CCS activities in Norway (Sleipner project) preceded Norway's implementation of the CCS Directive by almost 20 years.

The competent authorities have implemented the CCS Directive through three regulations. The Storage Regulations were adopted under the Continental Shelf Act ("CSA"). Amendments were also made to the original Petroleum Act and Regulations and Pollution Regulations. Petroleum related CO_2 storage activities, including CO_2-EOR, are regulated pursuant to the petroleum framework, whereas non-petroleum related CO_2 storage activities are regulated pursuant to the new Storage Regulations. The operator also needs a permit pursuant to the Greenhouse Gas Trading Act.

5.6.2 The permitting regime for CCS activities

During the lifetime of a project, there are several required permits and operator obligations for either petroleum related or industrial CO_2 storage in compliance with the CCS Directive. Also, in order to develop a storage site, the Plan for Development and Operation stands out as being of special importance, containing considerations relating to for example economic, commercial, resource management, technical, safety and environmental aspects, as well as preliminary plans for decommissioning. The plan is not a permit per se, however it is subject to the approval of the Ministry of Petroleum and Energy. The Pollution Control Act and the subordinate Regulation are applicable for any injection of CO_2. Further, the operator needs a "permit for injection and storage" from the Norwegian Environment Agency. The permit is mainly aimed at ensuring the environmental aspects of CCS projects are secured, i.e. monitoring, reporting and corrective measures.

5.6.3 Financial security

Norway has implemented its own regulations for financial security in which the Competent authority is provided with flexibility and discretion based on a case-by-case basis assessment regarding how the operator is able to fulfil this requirement. The use of parent company guarantees has a long tradition in the Norwegian petroleum industry. In both the Sleipner and Snøhvit CCS projects, a parent company guarantee was provided by the operator and approved by the Ministry of Petroleum and Energy.

5.6.4 Monitoring

The operator issues a plan for monitoring and this plan is to be updated every five years. The Storage Regulations specify the kind of monitoring required during operations and after closure. The monitoring objectives fall into three main categories:

— Conformance monitoring: ensuring that the behaviour of CO_2 in the reservoir is understood.

— Containment monitoring: ensuring that CO_2 stays within the storage unit.

— Contingency monitoring: assessing effect of contingency measures in the case of leakage.

5.7 Canada

In Canada, governing authority is divided between the federal government and the ten provinces, each having primary authority within defined limits and with some areas of dual authority (Krupa, 2018). Jurisdiction over the environment is shared. CO_2-extraction activities such as EOR fall under provincial authority because the provinces have primary authority over local works, property rights, groundwater protection and nonrenewable resources. The authority of the federal government with respect to CCS stems from its responsibility for matters of national concern as well as international cooperation and agreements (e.g. international agreements on GHG emissions). The federal and provincial governments have worked together and in cooperation with other nations and international organizations to foster the development of specific CCS projects and activities related to CCS operations, such as Saskatchewan's Boundary Dam project and monitoring activities at Weyburn-Midale. All Canadian jurisdictions have environmental, safety and resource conservation regulations that could apply to the component systems of CCS projects (capture, transport, and storage) through the issuance of licenses or permits as appropriate. Most aspects of CCS projects, including storage related issues, are covered by the existing provincial regulations for oil and gas production and mining. Component systems also require a federal or provincial environmental assessment to evaluate potential impacts and the need for mitigation.

Alberta has built the regulation of CCS into its framework for exploitation of fossil fuels, under which it has historically regulated EOR and acid-gas injection. The province amended its Mines and Minerals Act (hydrocarbons being considered a mineral in legislation) and Energy Resource Conservation Act in 2010 with the Carbon Capture and Storage Statutes Amendment Act to address long-term CO_2 storage liability, underground property rights (land tenure and pore space), and financial responsibility for post-closure monitoring, maintenance, and remediation. The concept of pore space was not previously identified in legislation. However, the legislation further clarifies that no expropriation of title occurred as a result of the legislation, rather the legislation provides clarity that the Crown (or freehold owner of mines and minerals) has and will continue to have title of the pore space as well as the minerals and water contained in the pore space. The legislation also clarified the right to explore and develop those lands for the purpose of CO_2 sequestration (storage). In addition to the existing oil and gas regulations which cover many aspects of CO_2 storage projects, the Carbon Capture and Storage Funding Act, Carbon Capture and Storage Funding Regulation, Carbon Capture and Storage Amendment Act, and Carbon Sequestration Tenure Regulation are also in place.

In British Columbia, amendments to the Petroleum and Natural Gas Act and the Oil and Gas Activities Act were passed with the purpose of enabling CCS under existing regulations for natural gas storage and acid gas disposal (Krupa, 2018). The legislation authorizes storage and disposal of CO_2 as a "prescribed substance" in naturally occurring underground reservoirs and also addresses capture, transport, storage, ownership and liability issues relating to CCS.

In Saskatchewan, many aspects of CCS projects also fall under the oil and gas and mining regulations of the established Oil and Gas Conservation Act, which regulates the storage of other substances in addition to oil and gas storage. Some of the main pieces of legislation governing the CCS related activities in Saskatchewan include The Crown Minerals Act, The Oil and Gas Conservation Act and its regulations, The Management and Reduction of Greenhouse Gases Act and its regulations, as well as amendments to these regulations.

5.8 Japan

The foundation for the Japanese regulatory framework for CO_2 storage operations offshore is the London Protocol and especially its CO_2 Waste Assessment Guidelines. These guidelines form the backbone of Act on Prevention of Marine Pollution and Maritime Disaster (2007 amendments) that were implemented to support the deployment of CO_2 storage demonstration projects in Japan. The amendments were followed up by a guideline “For Safe Operation of a CCS Demonstration Project” in 2009.

The current Japanese framework for CO_2 storage requires an operator to obtain a permit prior to operations. The permit is granted by the Japanese Ministry of Environment and needs to be renewed every five years. Such permits are limited in time and contain strict criteria to monitor and report to the Japanese Ministry of Environment. Several documents are required to apply for a permit including a project plan, a monitoring plan, a site selection report, an environmental impact assessment report and documents to demonstrate financial and technical capabilities. The Ministry will evaluate this documentation to decide whether the CO_2 to be stored meets official requirements, and that the operator’s pre-assessment demonstrates that only minor influence and changes to the surrounding sea area results in the case of potential leakage, and that the monitoring plan adequately takes into account leakage detection and a recovery plan to minimize the influence on the marine environment. The CO_2 injectate must be captured by a method using chemical reaction between amines and CO_2, with a CO_2 concentration of 99 % or more (98 % or more if captured for hydrogen production for oil refining) and have no waste or other matter added.

The guideline “For Safe Operation of a CCS Demonstration Project” focuses on site characterization to define pre-operational baseline conditions, detailed modelling of the storage system including the reservoir, simulations to predict the behaviour of the CO_2 plume, and water injection tests. During operation, monitoring of both the storage site and the overlying sea area is required including injection volume, temperature and pressure, CO_2 location and extent, changes in geological properties, seawater chemistry and marine organisms.

5.9 Australia

Australia has comprehensive legal and regulatory regimes for storage of CO_2 offshore under the Australian Federal and Victorian jurisdictions and onshore frameworks in Queensland, South Australia, and Victoria (Gibbs, 2018). Western Australia lacks a generic framework but has specific legislation for the Gorgon LNG Project’s storage of CO_2 under Barrow Island. Regulation of CCS in Federal offshore waters, Victorian offshore waters and onshore in South Australia has been accomplished through modifications to the regulations for oil and gas exploration and production, whereas Queensland and Victoria have developed separate regulatory frameworks for the onshore geological storage of CO_2. The frameworks commonly require obtaining a GHG tenure first to undertake exploration for acceptable geological storage reservoirs (including injection testing) and second to inject CO_2 for storage in the covered reservoirs. Detailed risk management plans are required to be submitted in the form of work plans. For example, the Victorian onshore regulations require a demonstration that even the testing during exploration will not present an unacceptable risk to public health or the environment or a significant risk of contaminating or sterilizing other resources in the area permitted for exploration. Similar demonstrations are required to support approvals for storage injection operations. After storage injection operations cease, project operators apply to surrender their tenures by making risk-based demonstrations that they have complied with all legal requirements, that the wells have been plugged or secured, that the stored CO_2 is conforming to predicted behaviour, that risks have been reduced to as low as reasonably practical, and that stored CO_2 will not present a risk to human health or the environment. After closure, the relevant State or Federal government assumes responsibility for monitoring and verification of the stored CO_2 at the project operator’s cost. Regulators have considerable discretion to impose more requirements backed by their authority to suspend or cancel storage operations and to withhold closure approval, subject to normal administrative requirements of reasonableness and procedures for review (Gibbs, 2018). The regulations impose detailed monitoring, verification, and reporting requirements beginning with establishing baselines and continuing through the life of the project, including after injection ceases. A variety of enforcement tools are available for regulators to ensure appropriate risk-based compliance. Regulators have authority to intervene and require actions to avoid, remedy, or mitigate a “serious situation,” including ceasing injection (Gibbs, 2018). In addition, regulators require "removal of property, plugging or closing wells, conservation and protection of natural resources, and making good any damage to the seabed or subsoil" (Gibbs, 2018).

6 Well design

6.1 General

Wells play a key role in CCS projects. They act as conduits for injection and house technology for monitoring purposes. In the simplest terms, wells are a nested series of casing (pipe) and cement installed in a hole in the earth. Perforations are shot through the casing and cement into the injection zone to allow the well to access the injection formation. Figure 1 presents a general well schematic to present the basic components of a well. Since wells represent a possible leakage pathway for CO_2 out of the storage unit, because they penetrate the confining system to reach the storage formation, care must be taken in their design and construction.

The design, construction and completion of wells is dictated by their purpose, age, depth, rate of injection and regulatory regime. Further, the drilling program is designed to achieve the safe drilling to the targeted formation while also facilitating the acquisition of key geologic and reservoir data and end use of the well. For example, an additional casing string is required if abnormally pressured (either much higher or lower) horizons are penetrated prior to reaching the final total depth of the well. Drilling practices also play a role. For example, lower weight on bit, and its resulting longer drilling time, yields a straighter hole with drill bit selection perhaps improving those slower drilling times. Higher mud circulation rates and pressures improve drilling rates but result in more washout and poorer quality cementing. Regulatory requirements, such as groundwater protection, require deeper surface casing setting depths than would otherwise be required for blowout prevention or lost circulation control.

The well completion is the final installation of piping (tubing string) and associated equipment such as packer assemblies that will convey the injection of the CO_2 stream from surface to the storage zone. The completion tubulars will isolate the injection stream from the casing strings, thereby protecting the integrity of the casing from the surface to the injection zone. Once again, the design of the completion string will be fit-for-purpose for the specific well's objective. For example, a commercial injection well has a simple tubing assembly and injection packer set above the storage zone while a monitoring well completion includes an array of instrumentation like fibre-optic cables.

As CO_2 storage is a relatively new technology and additional study has been conducted to assess the ability and security of the CO_2 injected and stored, wells are drilled for research purposes in advance of commercial projects. Research wells have a variety of objectives and are designed to test different aspects of geology, seal characterization, regional hydrology and injection zone quality and characterization. As a result, the design of the drilling program and well construction attributes for research wells are not necessarily considered as a best practice for commercial wells.

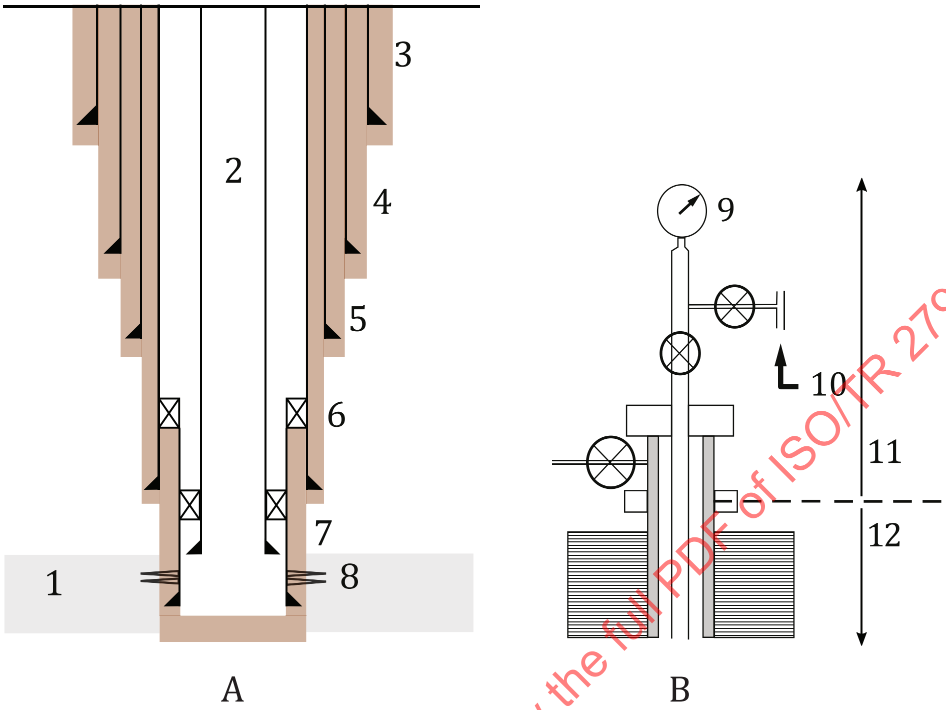
6.2 Components

6.2.1 Conductor casing

Conductor casing (see Figure 1) is a short section of casing pipe that is used to initiate the drilling of the well. Often it will comprise a single joint of casing placed at surface to facilitate the return of drilling mud during drilling of the surface hole. In some cases, it is set prior to the drilling rig arriving on the drilling location.

6.2.2 Surface casing

Surface casing (see Figure 1) is the first primary string of pipe cemented into the drill hole to provide integrity to the wellbore. In the early oil and gas industry, surface casing was primarily used to mount blowout preventors and provide pressure containment while drilling of the main hole. This meant that the setting depth of the surface casing was dependent upon the anticipated pressures that would be encountered while drilling the main hole and the ability to contain those pressures based upon the parting pressure at the surface casing shoe setting depth. The casing pipe itself needed to have sufficient collapse or internal yield burst strength to contain the anticipated pressures. Over time, surface casing became the means of protecting potable water zones and, as a result, surface casing depths are now set deeper than previous practices to protect those potable water zones. Surface casing strings are cemented to surface.



Key

A casing plan
B wellhead & Christmas tree
1 storage unit
2 tubing
3 conductor casing
4 surface casing
5 1st casing
6 2nd casing
7 liner
8 perforation
9 pressure gauge
10 CO_2 stream
11 Christmas tree
12 wellhead

Figure 1 — General well schematic showing the basic components of a well

6.2.3 Main section casing

Drilling of the main section of hole is protected by at least one string of casing often referred to as the long string or production casing. If additional strings of casings are required it is referred to as the intermediate casing or first, second, etc., casing string. To facilitate drilling the well, intermediate casing strings are used where pressures above or below the intermediate setting depth possibly create unsafe drilling conditions and/or mud weights which are either too great (resulting in fracturing of the formation, or differential sticking) or too low (resulting in formation fluid influx and possibility of a blowout).

In the past, main hole casing strings were cemented to ensure isolation of porous formations and therefore may not have been cemented to surface. Modern day drilling practices for CO_2 storage are to cement the main string to surface to provide coverage over all formations penetrated. In cases where the hydrostatic head of the cement column exceed the formation fracture pressure, stage tools are used to cement the upper portion of the main hole.

The casing pipe itself must be of sufficient strength (internal yield pressure, tensile strength and collapse pressure) to facilitate placement of the pipe, drilling of the remainder of the well (if necessary) and containing the formations pressures expected. In the case of CO_2 storage, the casing strength must be suitable for the anticipated maximum storage pressure. The metallurgy of the casing may also be modified for those portions of the well that are exposed to CO_2, for example some operators place Nickel-based alloy or 13Cr-L80 pipe over the storage zone.

6.2.4 Liner

Liners (see Figure 1) are sections of casing that are set inside the last casing string, but sometimes do extend back to surface. The strings are landed in the last casing string with hanger and packer assemblies and may or may not be cemented in place. Liners are typically used where the cost of extending the pipe to surface would be cost prohibitive or where cementing of the pipe is not required. Liners are not typically used in CO_2 storage applications.

6.2.5 Tubing and completion assemblies

Once the well has been drilled and cased, the wellbore is secure and will contain the formation pressures and fluids. To facilitate injection of CO_2, a tubing (see Figure 1) and completion assembly is installed. The casing at the injection zone may be perforated with wireline conveyed perforating guns before the completion string is installed or with tubing conveyed perforating guns as part of the completion string. The completion string isolates the casing from the injected CO_2 and provides a secure conduit for the transport of the CO_2 to the injection zone. As a result, the metallurgy of the tubing material and completion assemblies are typically more corrosion resistant or corrosion resistant coatings are applied to protect the tubing and completion equipment. Tubing connections in CO_2 injection applications will often have seals, either Teflon or other CO_2 resistant material, to prevent CO_2 from leaking through mechanical thread connections.

6.2.6 Wellhead and Christmas tree

The wellhead and Christmas tree assembly (see Figure 1) are the surface equipment installed on the well to connect the well to surface pipelines and for hanging the tubing string inside the well. The Christmas tree is essentially the valves installed on the wellhead to contain the wellbore fluids and pressure and to facilitate running of wireline equipment into the well. The gauges for monitoring surface injection pressures are installed on the Christmas tree and other pressure gauges for monitoring the tubing/casing annulus and casing/surface casing annulus are also installed on the wellhead equipment. The material selection for the wellheads and Christmas tree equipment may be specialty alloys but often are internally coated steel. Valves will also have specialty trim materials (internals) for corrosion protection.

6.3 CO_2 Injection wells

Injection wells for both CCS and CO_2-EOR projects have included wells used for injecting smaller masses of CO_2 for research purposes (kt-scale) and larger masses (Mt-scale) for commercial-projects. The earliest CO_2 injection wells were constructed as part of CO_2-EOR projects, such as SACROC and Seminole floods in the Permian Basin, and Joffre and Weyburn-Midale in the Western Canadian Sedimentary Basin. Many research-scale CCS projects started earlier than commercial-scale projects and have longer history of injection and include, for example, the AEP Mountaineer, Ketzin, Illinois Basin Decatur Project, Lacq, Tomakomai and Nagaoka projects. Commercial-scale projects for CCS include, for example, Sleipner, Illinois Industrial CCS Project (IL-ICCS), Quest and numerous CO_2-EOR Projects within North America.

6.3.1 Well design and construction

Well construction for CO_2 injection wells is site specific for the geologic conditions and applicable government regulations. Additional consideration may be given to the corrosive nature of CO_2 through the installation of sections of specialty casing (i.e. Nickel-based alloy or 13Cr-L80) over the primary seal and injection zone. This interval would correspond to the injection packer setting depth and perforated interval where the casing would be most exposed to corrosion.

In addition to specialty materials, efforts to mitigate corrosion can also be applied through material selection, chemical additives, and regular monitoring. When corrosion has an impact, replacement of well components may be necessary, which adds expense and down-time to injection projects. Corrosion mitigation impacts well design and operation in the following ways.

— CO_2 resistant cement - selection of a cement which resists chemical, and subsequent mechanical degradation of the cement. Typically, cement is circulated to surface to provide full coverage over the well, with specialty cements placed over and proximal to the injection zone. A baseline cement log run prior to completion will provide a reference to subsequent integrity logging (see 8.5.4.3).

— Coated or lined injection tubulars are typically used in portions of the well that are exposed to water. In the case of injection wells that also inject water, this would constitute the entire string.

— The annular space filled with diesel or corrosion inhibited fresh water provides additional corrosion protection to both casing and injection tubulars.

6.3.2 Well completion

The well completion will provide the conduit for the transport of the CO_2 stream to the injection zone. Depending upon the corrosive nature of the CO_2 stream, specialty tubulars may or may not be needed. Dehydrated CO_2-streams are not necessarily corrosive and therefore the material selection is dependent on-site specific conditions. Other equipment on the completion string, such as packer assemblies and profiles may often be coated or made of specialty alloys. Injection packers, whether permanent or retrievable, typically have packer element materials that are resistant to CO_2 and the swelling effects that may pose issues with seal integrity and tool operability.

Since the injection tubulars and packer assemblies protect the casing strings, the injection packer is placed as close as practical to the injection zone perforations and in intervals with strong casing cement bond.

The decision to install permanent packers, with the appropriate stinger assembly on the tubing string, or retrievable packer assemblies is another site-specific decision. With either approach, should replacement portions of the tubing string need to be replaced, it is important to be able to place a plug in the packer such that the tubing string can be removed from the well without having to pump kill fluids into the injection zone.

Lastly, the design of the tubing string will also be dependent upon the injection rates required for the project. Restrictions in the completion string (i.e. profile nipples or injection stinger ID) will reduce the injection capacity. The well's casing ID will dictate the size of injection tubulars and packer assemblies, therefore flow modelling is required prior to the drilling of the well such that the total system configuration will provide the injection capacity needed.

6.3.3 CO_2-EOR injection well construction

CO_2-EOR wells represent the most mature class of wells used to inject CO_2 as CO_2-EOR has been employed commercially for approximately 50 years. Wells can vary from being converted oil production wells with conventional well construction and materials to fit-for-purpose CO_2 injection wells constructed with special materials and cements. Wells at SACROC and Weyburn oilfields provide some examples of construction practices.

SACROC

The Scurry Area Canyon Reef Operators Committee (SACROC) unit was the first CO_2-EOR project in the US, with injection operations started in 1972. The field has both vertical and horizontal wells. Vertical wells are typically completed at approximately 2 100 m using a 140 mm (5 1/2 inch)[1)] or 178 mm (7 inch) long-string casings with 219 mm (8 5/8 inch) and 244 mm (9 5/8 inch) surface casing, respectively. The surface casing is cemented to surface using Class C Portland cement. The long-string casing is generally cemented several thousand feet up from TD, leaving portions of the long-string annulus uncemented within the surface casing. Sometimes, the long-string cement job does not extend into the surface casing, which also leaves a portion of the wellbore uncemented. These production well construction scenarios are common within the field and many of the CO_2 injection wells in the SACROC field are converted production wells.

Weyburn

Similar to SACROC, the well construction design for Weyburn wells has evolved over time. The field was initially developed using vertical wells, cased and perforated over the producing zone. Over time, producing wells were converted to water injection wells for secondary (waterflood) recovery. During the 1990's, to improve sweep efficiency, horizontal wells with open hole completions (uncased over injection zone) were drilled and successfully improved the field's productivity. To facilitate CO_2 flood, dedicated horizontal CO_2 injection wells were drilled, most with dual laterals to target specific reservoir zones. To allow the use of dual laterals, the casing was set above the producing zone. Later the design changed to set the casing in the injection zone itself. Other variations of CO_2 injection wells were used including recompletion of existing vertical water injection wells, but these were prone to well integrity issues and replaced with horizontal injection wells with the casing landed in the injection zone (Majer et al., 2018).

6.3.4 Research injection well construction

Research injection wells represent the first set of injection wells developed specifically to inject CO_2 into saline formations for storage. The construction of these wells is very similar to that used for oil and gas production or CO_2-EOR.

Nagaoka

The Nagaoka project CO_2 injection well was constructed in 2003. It was constructed using mild steel (Grade J-55) casing, with buttress thread and coupling (BTC) casing on the 244 mm (9 5/8 inch) 53,6 kg/m surface string, and 8 round thread (RD-Long) on the 140 mm (5 1/2 inch) 23,1 kg/m long-string casing. Both casing strings were cemented using common oilfield Class A well cement. The injection tubing in the well was a 60 mm (2 3/8 inch) 6,8 kg/m chrome string (13Cr-L80) for improved corrosion resistance.

Ketzin

The Ketzin project CO_2 injection well was constructed and completed in 2007 with injection commencing in 2008. It was constructed using a 632 mm (24 7/8 inch) 186,8 kg/m St 37 steel stand pipe (welded), a 473 mm (18 5/8 inch) 130 kg/m X56 steel conductor string, a 340 mm (13 3/8 inch) 81,1 kg/m K-55 surface casing, a 244 mm (9 5/8 inch) 54 kg/m K-55 steel intermediate string (all three strings with BTC connection), and a 140 mm (5 1/2 inch) 30 kg/m 13Cr80 production string. All casings reached from the top of the well down to their respective depths, and the longest was the 140 mm (5 1/2 inch) production string ending at 755 m. The cement selected in all casing cementations was standard class-G cement with fresh water and no additives, with the exception of the plug cementation of the 140 mm (5 1/2 inch) casing for which a specially designed CO_2-resistant class-G salt cement was used (Prevedel et al., 2009).

Mountaineer Project

1) 1 inch = 25,4 mm

The American Electric Power (AEP)-1 CO_2 injection well was drilled as a stratigraphic test well in 2002 and 2003. It was later completed as an injector in 2009. AEP-1 was constructed with a 508 mm (20 inch) 140 kg/m H-40 steel surface casing set at 79 m, a 244 mm (9 5/8 inch) 60 kg/m L-80 steel intermediate casing set at 1 191 m, a 178 mm (7 inch) 34 kg/m P-110 steel intermediate casing set at 1 918 m, and a 114 mm (4 1/2 inch) 17,3 kg/m N-80 long-string casing set at 2 803 m. The well was plugged back to 2 608 m. The surface casing had a BTC thread, the 244 mm (9 5/8 inch) intermediate casing had an 8 rd short-thread connection (STC) connection, the 178 mm (7 inch) intermediate casing used an 8 rd long-thread connection (LTC) connection, and the long-string casing also employed an 8 rd LTC connection. The surface casing was cemented from its setting depth to surface with Class A cement. The 244 mm (9 5/8 inch) intermediate casing was cemented with a 50/50 pozzolan mix lead slurry and a Class A tail slurry. The 178 mm (7 inch) intermediate casing was cemented from with cement consisting of a 65/35 pozzolan mix lead slurry and a Class A tail slurry. The long-string was cemented in two stages, with the stage collar positioned at 1 657 m. The first stage was a C-poz cement slurry. The second stage consisted of a 65/35 poz mix lead slurry and a Class A tail slurry. Cement bond logs revealed poor cement quality, with zones of missing cement and a micro-annulus attributed to a high-pressure acid job, and gas intrusion across the long-string casing (described in Duguid et al., 2018).

Tomakomai

In the Tomakomai Project, two CO_2 injection wells were constructed in 2014 and completed in 2015. They were drilled from an onshore site targeting the Takinoue Formation and the Moebetsu Formation offshore reservoirs, respectively. They were constructed using an 800 mm conductor casing set at 10 m, a 508 mm (20 inch) surface casing, 340 mm (13 3/8 inch) intermediate casing, a 244 mm (9 5/8 inch) production casing and 178 mm (7 inch) liner. The surface and intermediate casing strings were steel. The production casing was CO_2 corrosion resistance steel (TN110CR13S) with a TSH-W563/TSH-Blue threads. The intermediate and production casings were cemented with CO_2 resistant cement.

The injection well for the Takinoue Formation had a maximum inclination of 72° with a measured depth of 5 800 m, vertical depth of 2 753 m and horizontal reach of 4 346 m. The injection interval of the well for the Takinoue Formation was completed with slotted liners achieving a length of 1 134 m.

The injection well for the Moebetsu Formation was an extended reach drilling (ERD) well with a maximum inclination of 83°. It had a measured depth of 3 650 m, vertical depth of 1 188 m and horizontal reach of 3 025 m. The injection interval of the injection well for the Moebetsu Formation was 1 194 m in length and completed by perforated liners covered by sand control screens. The perforated liners and sand control screens help minimize sand flow back into the well.

6.3.5 Commercial-scale injection

Commercial-scale CO_2 injection wells for storage are still uncommon. There are two permitted injection wells in the United States that are part of the Decatur, Illinois projects at ADM's facility, three injection wells at the Shell Quest project in central Alberta, Canada, one at the Aquistore (Boundary Dam) project in Estevan, Saskatchewan, Canada, and one each at Sleipner and Snovit in the Norwegian North Sea. These wells represent the beginning of commercial CCS and their design and construction may provide insight to future projects.

Illinois Basin Decatur Project (IBDP)

CCS#1 well planning began in 2008. The injection well was initially permitted as a Class I nonhazardous injection well because U.S. EPA Class VI CO_2 injection well regulations had not been finalized. However, the well was constructed to the draft Class VI standards. After the final UIC Class VI regulation was adopted, the permit was converted to Class VI status. The well was constructed with a 508 mm (20 inch) surface casing set at a depth of 110 m. A 445 mm (17 1/2 inch) open hole was drilled to 1 391 m where circulation was completely lost. Traditional lost circulation methods failed to regain circulation. Five cement plugs were placed, and circulation was reestablished; the intermediate hole was drilled to 1 627 m where a 340 mm (13 3/8 inch) casing was set. The casing was cemented to surface in two stages. After the intermediate casing was set, a 311 mm (12 1/4 inch) hole was drilled to TD (2 204 m). After reaching TD the well was logged and tested extensively.

A 244 mm (9 5/8 inch) long-string casing was set and cemented to surface in one stage. The casing had 244 mm (9 5/8 inch) 70 kg/m 13Cr-L80 from TD up to 1 608 m, where 244 mm (9 5/8 inch) 60 kg/m N-80 was used to the surface. The long string was cemented using a 1 898 kg/m^3 (15,84 ppg) CO_2 resistant cement from TD back to around 1 500 m. A 1 498 kg/ m^3 (12,5 ppg) pozzolan cement was placed from 1 500 m to the surface. Cement simulators were employed during the design phase to set centralizer placement and model mud removal. Following completion, the well was logged using an ultrasonic radial cement evaluation tool and a cement bond logging too, which showed good integrity despite the presence of a micro-annulus (Duguid, 2018).

Shell Quest Project

Three injection wells have been drilled and placed on CO_2 injection. The basic well design includes a conductor pipe set at 20 m, the 406 mm surface hole section was cased with 340 mm, 107 kg/m, L-80 IRP LTC R3 seamless and set at approximately 445 m and cemented to surface with Class G cement. The intermediate holes section was drilled with a 311,1 mm bit and the intermediate casing string consisting of 245 mm, 60 kg/m L-80 IRP LTC R3 seamless was cemented to surface (using a stage tool set at approximately 835 m with Class G cement. The main hole was drilled with a 216 mm bit and cased with 178 mm, 39 kg/m, L-80 LTC R3 seamless (surface to above the injection zone) and 178 mm, 34 kg/m, 25Cr-125 seamless set over the injection zone to TD, all cemented to surface with Class G cement.

Aquistore (Boundary Dam) Project

The Aquistore CO_2 storage project drilled and completed one injection well and an observation well in 2012, bottoming at depths of 3 324 m and 3 400 m, respectively. The injection well (PTRC INJ 5-6-2-8 W2M) was constructed with a 508 mm conductor to 36 m depth, pressure cemented to surface. The surface casing extended to 620 m, with 340 mm outer diameter L-80 casing, 107 kg/m, BTC joint type, cemented with a lightweight cement blend plus 2 % calcium chloride. The production casing extended to 3 324 m, with 194 mm OD, 50 kg/m, L-80 casing except over the interval of 2 150m to 3 200m, where 58 kg/m Q-125 was used. Joint types varied from top to bottom to accommodate the varying casing hardware installed in the well. A stage tool was set at 2 143 m and the well was cemented using an expanding cement followed by a CO_2 resistant cement placed from TD to 2 825 m depth. Above the stage tool to surface a lightweight lead cement blend was followed by Class G cement with good returns to surface reported.

6.4 Monitoring well construction

6.4.1 General

Monitoring wells borrow heavily from conventional wells and CO_2 injection wells in terms of construction. Monitoring wells are often drilled and cemented using the same technologies, and the specific monitoring objectives will guide construction design and materials. Differences between CO_2 injection and monitoring wells are largely the technology that is employed including pressure and temperature sensors, fibre-optic lines, sampling lines, electrodes, and other equipment.

6.4.2 Perforated monitoring well

The Illinois Basin Decatur Project had one fluid sampling well that penetrated the storage reservoir, which also allowed sample collection from zones overlying the reservoir. The well, VW#1, was constructed in a similar manner to the project's injection well (CCS#1). VW#1 was constructed using 340 mm (13 3/8 inch) surface casing, 244 mm (9 5/8 inch) intermediate casing, and a 140 mm (5 1/2 inch) long-string casing. Like CCS#1 construction, loss of circulation occurred in the Potsosi Formation, which was sealed with two plugs when encountered. The 311 mm (12 1/4 inch) intermediate hole was drilled to 1 623 m. the 244 mm (9 5/8 inch) intermediate casing was run to 1 623 m and cemented to surface in two stages. A 216 mm (8 1/2 inch) open hole was then drilled to a TD of 2 216m. After logging, the 140 mm (5 1/2 inch) casing was run into the well. The casing string consisted of 140 mm (5 1/2 inch) 25 kg/m 13Cr-L80 casing from TD to 1 541 m and 140 mm (5 1/2 inch) 25 kg/m N-80 casing from 1 541 m to surface.

The cement slurry design was adapted from CCS#1 and eliminated the hollow microspheres and added an expansion agent. A computer simulation of the drilled hole trajectory was used to guide centralizer placement. The displacing fluid was changed from fresh water to an 1 054 kg/m^3 (8,8 ppg) NaCl brine. The well was cemented in a single stage with 4,8 m^3 mud flush, 65/35 cement-pozzolan lead mixed at 1 498 kg/m^3 (12,5 ppg) and of CO_2 resistant cement mixed at 1 895 kg/m^3 (15,82 ppg). Cased hole logging results showed almost total cement coverage across all the open hole section and no micro-annulus present.

Completion of VW#1 included installation of a multilevel monitoring and sampling system that continuously monitored pressure and temperature in and above the storage reservoir. The stainless-steel completion system obtained data at 11 different depths in the well; each sampling zone was isolated from other sampling ports by redundant packers. Fluid samples were additionally collected from each port at determined time intervals for geochemical analyses. This system was used for about seven years and was replaced by a new system that samples from three discrete intervals, two in the storage reservoir and one above.

Cranfield

Two monitoring wells, CFU31F-2 and CFU31F-3, were constructed on the periphery of the Cranfield oilfield near Natchez, Mississippi in 2008 to access the D and E sands of the Tuscaloosa formation. These wells are down dip from injection well CFU31F-1 and are arranged in a line with CFU31F-2 being approximately 61 m away from CFU31F-1 and CFU31F-3 being approximately 90 m away from CFU31F-1.

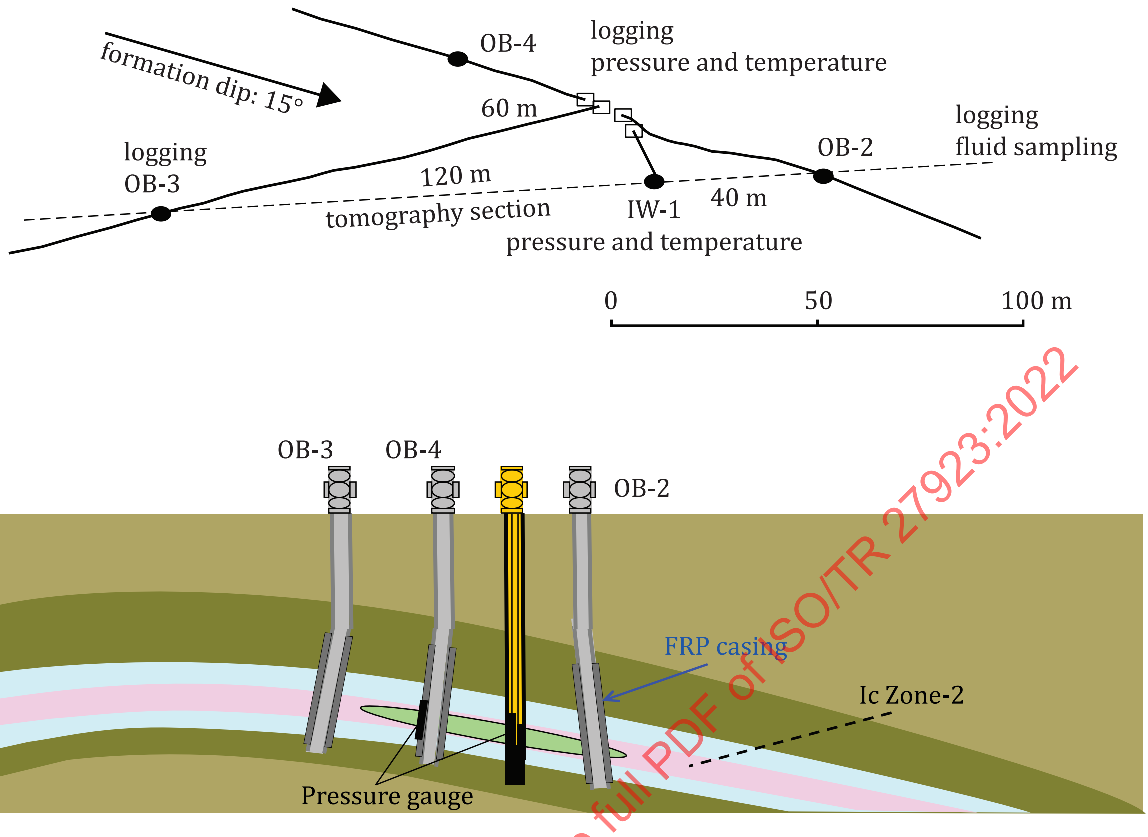
Each monitoring well was constructed with multiple monitoring technologies attached to the long-string casing. The specific construction details of each well are provided in (Duguid et al., 2016). The surface and intermediate strings of each well were of conventional design. The long-string section of each well was made up of N-80 grade steel casing and Bluebox-2500 fiberglass casing. The steel casing section had temperature and pressure sensors mounted on the outside, the fiberglass section held electrical resistivity tomography electrodes in, above, and below the storage reservoir. Fiberoptic systems were mounted to the outside of the casing and extended from the reservoir to the surface on both wells.

These wells were logged after construction in 2009 using cement bond logging tools and ultrasonic imaging tools. After the project was completed the wells were re-logged using similar tools and a sidewall coring tool was employed to collect samples of the casing and cement (Duguid et al., 2016). The time-lapse study revealed all cores had at least some carbonization and indicated that the CO_2 was moving along the control lines behind the casing.

6.4.3 Induction logging monitoring well (Plastic casing: Nagaoka, Cranfield)

The Nagaoka project installed three monitoring wells named OBS-2, OBS-3 and OBS-4 designed to allow induction resistivity logging for monitoring purposes. The location of these monitoring wells is shown in Figure 2. The injection well is denoted as IW-1 and three observation wells are shown as OBS-2 to OBS-4. The fiber reinforced plastic (FRP) casing portion was set through the target reservoir in all three monitoring wells of which two wells, OBS-2 (952,2 m to 1 210,5 m, Total FRP length 258,3 m) and OBS-3 (1 044,2 to 1 142,0 m, Total FRP length 97,8 m) were extensively utilized for logging. Cement evaluation logging using ultrasonic and cement bond logging tools was carried out in both wells, indicating that the cement bond is good across the FRP interval.

Permanent pressure gauges were also placed in IW-1 and OBS-4.



Key

well location

□ ground surface

● top of Zone-2

Figure 2 — Nagaoka well locations

Ketzin

The three wells drilled at the Ketzin project in 2007 were equipped in the storage reservoir with coated casing segments within the 140 mm (5 1/2 inch) production casing string to allow the application of permanent downhole electrodes. The coated casing segments were positioned as follows in

1. Ktzi 201 (injection well) from 595 m to 735 m depth,
2. Ktzi 200 (monitoring well) from 595 m to 735 m depth, and
3. Ktzi 202 (monitoring well) from 590 m to 730 m depth.

The stainless-steel casing was internally coated by an epoxy resin layer and externally by a two-layer coating made of an epoxy resin matrix and a Ryton (polyphenylene) membrane. This electrically insulated region of the borehole completion allowed electrical resistivity tomography in the near-wellbore area, as well as in-hole measurements as a kind of permanent CO_2 saturation log.

6.5 Discussion

All wells described were successful for their specific application. As the application changed from CO_2-EOR to commercial storage, well designs changed, including both the casing and cement. Some of the CO_2 wells discussed in Clause 6 had been the subject of significant well integrity studies. These studies looked at the well materials and construction execution to identify possible well integrity issues and mitigations.

Changes to casing design consisted of the selection of more corrosion resistant materials and proprietary threads to address leakage of CO_2 from the casing. The change from mild steel to 13Cr-L80 steel provides additional protection from corrosion. However, 13Cr-L80 requires special handling during installation and adds significant cost to the well. One way to reduce this cost is to employ 13Cr-L80 casing across the storage zone and caprock with mild steel continuing to the surface as was done at the Illinois Basin Decatur Project wells.

Cementing programs were also changed in response to exposure to wet CO_2 and carbonic acid. In conventional cements, the calcium hydroxide and calcium silicate are susceptible carbonation. In cements with high amounts of calcium hydroxide, like conventional well cements, can be severely altered by CO_2 interactions. The AEP1 well used a C-poz slurry which is a mixture of reactive pozzolans (siliceous material) and Portland cement. The addition of the pozzolans changes the hydration chemistry of the cement; it reduces or eliminates the calcium hydroxide phase. This provides a level of CO_2-resistance because calcium hydroxide is most susceptible to carbonation. CCS#1 and VW#1 employed a highly engineered proprietary slurry that controlled both the hydration chemistry to eliminate calcium hydroxide and the matrix permeability to slow fluid transport reducing the availability of fresh carbonic acid if the cement comes in contact with any.

Several of the wells detailed in Clause 6 had been the subject of well integrity studies as part of the project or as parts of related projects. Many of the wells detailed in Clause 6 were logged using conventional cement bond logging tools and radial mapping tools. The use of two tools provides multiple metrics to assess the integrity of the cement job. In the case of the Nagaoka monitoring wells the variable density measurement provided some assurance of competent cement in the FRP section where the ultrasonic image could not provide information.

AEP1, CCS#1, VW#1, and the Cranfield wells provide information that provide valuable insight into well construction. The cementing issues identified during the AEP#1 and CCS#1 show that more than just CO_2 compatibility is important. The inflation of the external casing packer and the hydration properties of the cement may have combined to affect the cement job after successful returns to surface. This was possibly further exacerbated by high pressures applied to the well after cementing. The cement slurry for CCS#1 was affected by the mixing equipment before it was even pumped down the well. The smooth 13Cr-L80 casing and the temperature difference between the bottom hole static temperature and cementing circulating temperature may have contributed to the development of a micro-annulus. The construction of VW#1 built on the lessons learned from the construction of CCS#1 and did not exhibit a micro-anulus in the log results.

Monitoring wells have deployed many different technologies depending on the needs of the project. These include temperature gauges, pressure gauges, fibreoptic lines, sampling lines, sampling ports, and electrical resistivity hardware. Many of these technologies are on the outside of the casing and can present leakage pathways if not properly installed and cemented.

The Cranfield wells provide examples of construction and monitoring choices that affected the integrity of the wells. The control lines were visible in all if the image logs that were run. The analyses of the cement sections with the sidewall cores showed carbonation at every zone collected. The sidewall core that cut through the control line and sampling port exhibited severe carbonation. It is likely that CO_2 was able to move up the sampling line and the other control lines. In addition, the fiberglass section was severely affected by the downhole conditions in the storage zone. It is important to point out that the objectives of the wells were met and that the monitoring was successful. Furthermore, the monitoring wells did not allow any detectable amounts of CO_2 to leave the reservoir. However, the Cranfield project was relatively short compared to a commercial-scale project and similarly complicated wells on a long-term project may have affected the project negatively. The complicated external geometry of the control and sampling lines affected the placement of the cement. The overall lesson is that complicated geometry and material choices need to be reviewed and simplified to the extent possible.

Each of the well integrity analyses point to places for learning that can be applied to future projects. In general, each of the problems identified could be summed up to problems with design, execution, and operations. The overall lesson is that careful detailed design and planning need to be followed by thorough execution and operation.

7 Surface infrastructure concepts (non-well)

7.1 Design and materials

7.1.1 General

Clause 7 describes technical situations of surface facilities from the CO_2 custody transfer meter to the injection wellhead, which would include such equipment as compressors, booster pumps, dehydrators, metering and distribution manifolds.

CO_2 capture systems or CO_2 transportation infrastructure are not included here (note that CO_2 pipelines sometimes exist, not only between the capture section and the pressurization section, but also between the pressurization section and the injection wells).

A typical process flow of CO_2 storage is shown in Figure 3. The non-well infrastructure for CO_2-EOR is also included in Clause 7, which is described in 7.3.

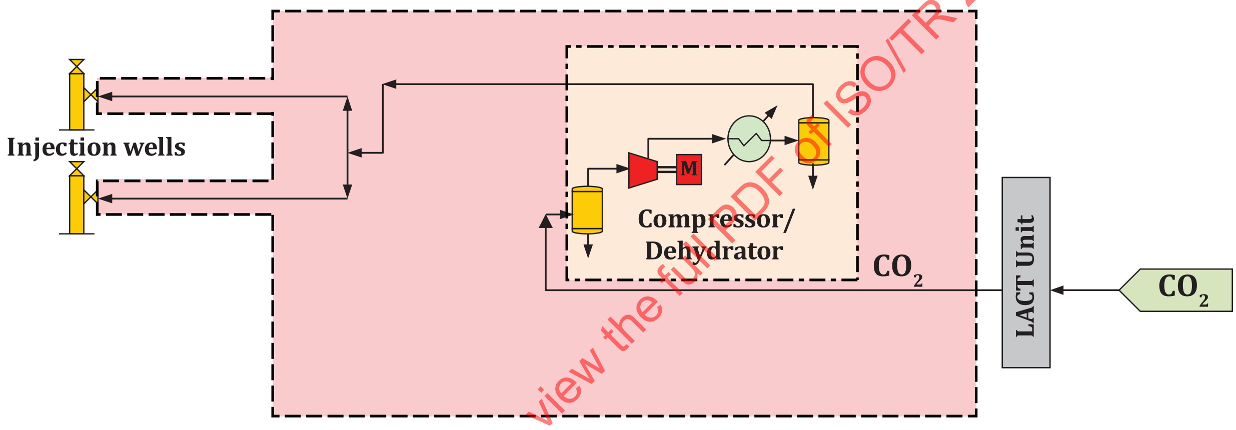


Figure 3 — CO_2 storage facilities refer to the surface infrastructure from the point of receipt to the injection wells

NOTE This schematic shows the case of pipeline transportation.

7.1.2 Material selection

Material selection needs to consider the composition, including impurities, of the CO_2 stream. For example, insufficient dehydration could result in the formation of carbonic acid and hydrates. Other typical impurities include O_2, N_2, NO_X and SO_X. If there is H_2S in the CO_2 stream (so called the "sour conditions"), engineers need to consider making use of alternative materials that resist corrosion. In most cases, impurities, including H_2O, are removed in the capture process as the CO_2 stream needs to be dehydrated before transport and injection into the wells. Also note that the CO_2 supply contract will specify the impurities allowed in the CO_2 stream. These contracts are out of scope of this document.

There are many guidelines, rules and standards for material selection. CCS operators and major engineering firms often have their own standards for design and construction based on their experiences.

7.1.3 Carbon steel

Because of its availability and cost performance, carbon steel is most often used in CCS facilities where no corrosive constituents are present in the CO_2 stream. If CO_2 stream is dehydrated sufficiently, the CO_2 stream is not corrosive because carbonic acid does not form without water. Dehydration is discussed in 6.3.2, 7.2.3, and 7.3.7.

Generally, operating pressures are maintained such that the CO_2 is transported as a liquid or supercritical fluid to avoid turbulence of two-phase flow. Operating pressures will dictate the grade of steel and wall thickness necessary, which impacts overall piping costs.

7.1.4 Stainless steel

The use of stainless steel is considered to protect against erosion and corrosion under wet conditions. Stainless steel is also used where it is predicted that the CO_2 stream temperature is too low for normal carbon steel to meet mechanical strength. Because stainless steel is more expensive, operators generally try to limit its use.

7.1.5 Alloys

Under special circumstances, where even stainless steel is not suitable, expensive alloys containing nickel, titanium, or other metals are used.

7.2 Equipment

7.2.1 Tie-in to CO_2 injection well

A specification change (or specification break) usually exists at the tie-in point between a flow line and an injection well. For example, in the United States, the injection wellhead is subject to the UIC Program (see 5.2), whereas the flowline tied into the well is subject to pipeline codes (see Bibliography: Regulatory Framework). Around the tie-in point, care needs to be taken regarding changes in flange materials, joints, inside diameters, etc.

7.2.2 Pressurization to supercritical phase

CO_2 is pressurized to inject into the injection wells to overcome the reservoir pressure but not to exceed the formation fracture pressure of the storage zone or seal. Pressure and temperature conditions at the discharge of the pressurization equipment are back calculated from such restrictions predicted by reservoir studies.

Interlock systems or other safeguarding needs to be installed on the pressurization equipment in case of any abnormal conditions.

The major method of CO_2 pressurization is by compressors because the captured CO_2 is supplied as gas flow on almost all operating projects. If CO_2 is transported by ship in a liquid form, it is able to be pressurized by pumps.

7.2.3 Dehydration

CO_2 gas is dehydrated to protect against not only plugging by hydrate at high pressure and low temperature conditions but also corrosion by carbonic acid. The following are typical methods to remove water content from the CO_2 stream:

— Absorption by absorbents (i.e. triethylene glycol).

— Molecular sieve.

— Refrigeration.

The maximum amount of water content is determined in the design phase in accordance with site specific facility and subsurface requirements and potentially local regulations or requirements.

7.2.4 Valves

Valves are used throughout the supply system and their sizing and design are important to minimize flow restrictions. In addition to pressure losses, flow restrictions could create a Joule-Thomson effect leading to lower temperature of the CO_2 stream that might result in dry ice formation and cooling below the tolerance for that grade of steel. Valve design and sizing are able to mitigate this effect.

7.2.5 Measurement

There are various types of meters currently being used. Coriolis meters measure the mass flow rate of a stream by measuring oscillation in meter piping. Orifice flow meters measure volumetric flow rates from differential pressure and temperature. Wedge meters similarly use differential pressure to measure flow but uses a wedge-shaped restriction rather than an orifice plate to create the pressure restriction. Differential flow meters require the use of equations of state based on the composition of the flow stream to calculate the rate of flow.

7.2.6 Leak detection

It is operator's responsibility to maintain the pipeline system safe and sound by monitoring in an appropriate manner. There are several ways to detect leaks:

— CO_2 gas detectors are installed in buildings.

— CO_2 gas-detecting tubes are installed adjacent to buried pipeline.

— Readings from pressure and temperature transducers and flow meters are used to calculate material balance between key pieces of equipment.

7.2.7 Venting

While venting of the CO_2 stream to the atmosphere is typically avoided, when equipment needs to be depressurized to allow for maintenance and repair, venting of the product to the atmosphere may be necessary. Vent stacks are typically used to control the release of fluids in a safe manner. Impurities such as H_2S in the vent fluid, for example, would require high vent stacks for the toxic content to be diffused sufficiently. At facility lease sites, permanent flare/vent stacks are typically installed and for venting at more remote locations, portable flare/vent stacks are sometimes used.

7.3 Considerations for storage incidental to CO_2-EOR

7.3.1 General

Where CO_2 storage is incidental to an ongoing CO_2-EOR project, the surface facilities requirements are much more intensive due to the need to process produced fluids. As Figure 4 illustrates, there are additional processes and equipment required to manage those produced fluids.

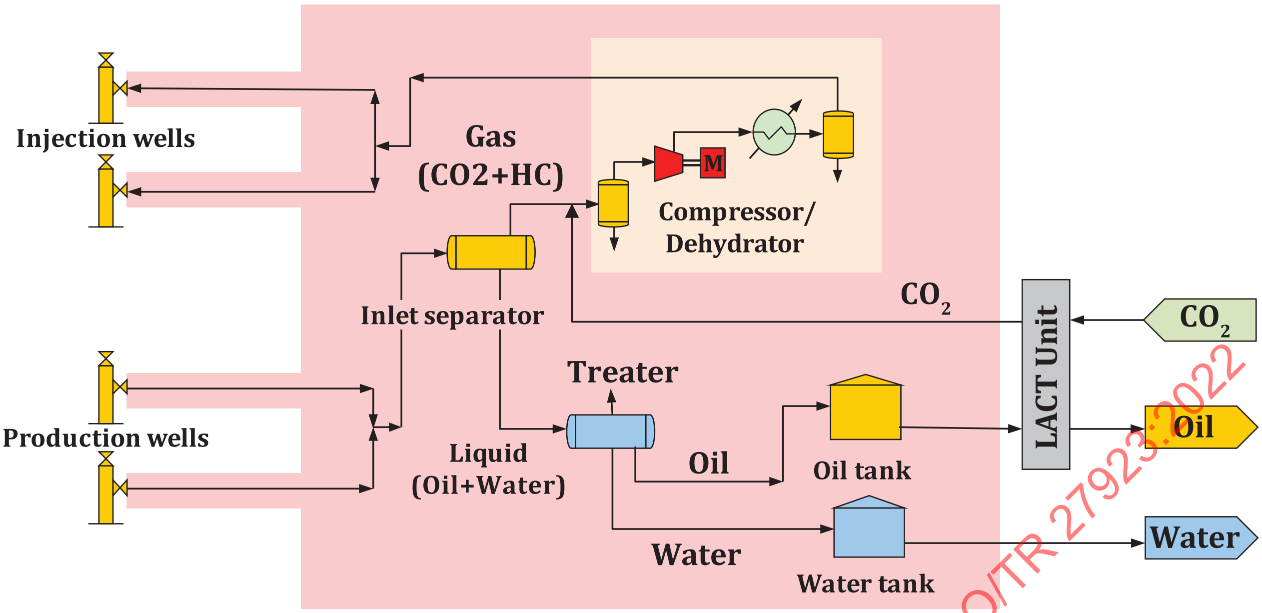


Figure 4 — CO_2 storage facilities on CO_2-EOR

NOTE The lease automatic custody transfer (LACT) unit measures CO_2 received and oil produced for sale.

7.3.2 Liquids

7.3.2.1 Water

Regardless of the CO_2 flooding approach (continuous CO_2 injection or water-alternating-gas), water is likely the first fluid produced and is an inherent part of the process. The presence of water in the produced fluids stream represents an issue for corrosion, hydrates, and pressure drops. Water produced from the reservoir also provides a means of providing heat to the system which often helps to counter Joule-Thomson cooling effects which could lead to hydrate formation.

Inlet separation is used to separate water from produced gas and oil. With continuous CO_2 injection (CCI) projects, inlet separation is similar to natural gas production systems and is focused on larger gas/liquids ratios and higher operating pressures. Where WAG recovery processes are used, inlet separation is more similar to an oil processing plant where a free water knock out vessel is used to separate free water from oil/water/gas emulsions. These vessels are usually much larger and operate at much lower pressures to allow produced gas to flash away from the oil emulsion.

Oil treating vessels are operated at low pressure and elevated temperature and provide an oil having basic sediment and water content specification suitable for oil sales, which also results in additional water volumes being separated and captured.

Water recovered from inlet separation and oil treating processes is treated and stored in surface tanks prior to being re-injected into the reservoir (WAG processes) or disposed into another formation (CCI). Often at the start of an EOR project, even for a WAG project, more water is produced than ability of re-injection and disposal into a separate formation is required. The quality of the water needed for injection for either disposal or re-injection is dependent upon the quality of the reservoir for the specific project. Often, water storage tanks have internal components that facilitate the gravity separation of organics (oil particulates) and inorganics (clays, suspended solids). Given sufficient retention time, tank treating is often enough, especially when coupled with chemical treatment. Where sufficient tank retention time is not available, filtration is often used as a final treatment.

Lastly, automated pumping equipment, often using booster pumps to prime a higher-pressure system, delivers the water to the injection system. Since water volumes tend to be large, centrifugal pumps are often used for water injection, but reciprocating pumps are still being used in some projects.

7.3.2.2 Oil

The process flow equipment for managing the oil stream from CO_2-EOR operations is essentially the same as any oil recovery process and involves cleaning or treating the oil to meet pipeline specifications. With CO_2-EOR, additional considerations include the corrosion aspects of CO_2 (when dissolved in water) and the formation of emulsion pads in the treater. The emulsion pads consist of asphaltenes and paraffin waxes in water which usually require chemical and additional heat to breakdown. The pads usually form at the oil/water interface and build up over time resulting in difficulty treating the oil to meet pipeline specifications. Operators of CO_2-EOR facilities work with oilfield chemical suppliers to determine the optimal chemical additives, usually some variation of demulsifiers that when combined with the heat in the treater, improve the effectiveness of the treatment process.

Treated oil, or sales oil as it is more commonly known, is stored on site in dedicated tanks, to feed the transfer pumps in the Lease Automatic Custody Transfer (LACT) metering unit.

7.3.3 CO_2 stream production and recycling

Once CO_2 breakthrough to production wells has occurred, the produced CO_2 is either vented or captured and processed to be reinjected into the reservoir. The exact process for handling CO_2 depends upon the reservoir operating conditions, the recovery mechanism involved, water-alternating-gas (WAG) or continuous CO_2 injection (CCI), and the CO_2 purity needed for reservoir management.

7.3.4 Operating pressure regime

The design of the CO_2-EOR flood will dictate the requirements for handling any produced CO_2. CCI projects tend to operate at higher surface pressures than WAG projects, and the gas/liquid ratio increases over time. In this situation, gas processing resembles a gas conservation or re-injection process. This process includes a high-pressure inlet separator where any liquids are dropped out from the CO_2 stream with the separated gas feeding recycle compression to increase the pressure for re-injection along with any make-up CO_2 (additional CO_2 supplied to replace oil produced from the reservoir). Depending upon the operating pressure of the flood and processing facilities, the thermodynamic behaviour of the recycled gas stream sometimes creates difficulty in liquids separation. Heat exchangers or line heaters are sometimes required to increase the temperature of the produced gas stream to allow for increased liquid dropout. Heating the stream is usually favoured instead of reducing the operating pressure of the system which would require additional compression horsepower.

If the reservoir flood process requires the injection of water (i.e. WAG), the operating pressures are often much lower. Artificial lift is required to bring the liquids to surface and any produced CO_2 will require additional compression to enable re-injection. In this situation, high pressure inlet separation is replaced with lower pressure free water knockout (FWKO) separation as described for the water stream above. Downstream of the FWKO, the produced CO_2 will require booster compression to feed the main recycle compressors.

7.3.5 Recycle Compression

The critical aspect of storage incidental to CO_2-EOR is a requirement to recycle the produced CO_2. The design of the compression is dependent upon the recovery process including inlet conditions and discharge requirements for injection. The greater the difference between the discharge pressure and inlet pressure, the greater the number of compression stages and horsepower required.

Two types of compression are typically used in industry: reciprocating and centrifugal. The most commonly used approach is reciprocating compression due to its simplicity and upfront capital cost. Reciprocating compression usually has a lower throughput per unit so often several units are installed to meet the required volume. The typical throughput of reciprocating compression units is 0,7 $x10^6$ m^3/d to 1,4$x10^6$ m^3/d (25 MMscf/d to 50 MMscf/d), depending upon the inlet and discharge pressure and composition of the gas stream. Centrifugal compression is typically cheaper to operate and maintain per volume throughout, but has higher upfront capital costs than reciprocating compression. Like reciprocating compression, centrifugal compression has stages of compression, the number of which depends upon the inlet and discharge pressures. At the Weyburn CO_2-EOR flood in Canada, two 2,8 x10^6 m^3/d (100 MMscf/d) centrifugal units (2 sections, 7 stages) are in use which constitute the bulk of the operation's recycle capacity (Majer, et al., 2018).

7.3.6 Interstage cooling & separation

Due to the heat generated during the compression of gases, cooling and separation of any condensed liquids, of the compressed stream is often required prior to the next stage of compression. If the heat generated is not be able to be redeployed elsewhere in the facility, cooling facilities (shell and tube heat exchangers or fans) are used to cool the interstage stream and facilitate interstage liquids separation. Any liquids that form at this point, either water or hydrocarbon, would depend upon the saturation pressures of the recycled gas stream at that temperature and pressure.

7.3.7 Dehydration

The application of dehydration units depends upon the design of the injection system, including operating conditions, metallurgy of downstream piping and equipment or coatings used. A key factor for determining, if dehydration is required, is the saturation of the recycle stream and whether condensation of water will occur at any operating pressure and temperature from the recycle facility to the wellbore. As long as the water saturation is sufficiently low to prevent condensation in the injection system, dehydration is not always required. Further, if condensation conditions are expected in the system, it is probably more cost effective to install corrosion inhibition measures, like coatings or specialty materials rather than installing and maintaining dehydration units (typically absorption towers using triethylene glycol or similar product).

If dehydration units are required, they are typically installed at interstage compression conditions, downstream of interstage cooling and separation. The higher operating pressure condition of the dehydration towers allows for greater contact time of the glycol with the gas stream.

One of the disadvantages of dehydration of CO_2-rich streams is fowling of the glycol stream by asphaltene particulates. If left unchecked the glycol will become sufficiently contaminated so that it requires frequent replacement and also deposits asphaltenes on the internals of the dehydration towers, reducing water absorption efficiency.

7.3.8 Booster pumps

After the last stage of compression by either reciprocating or centrifugal approaches, additional pressure increases are sometimes required either at the central facility or the field prior to injection. At this point in the process, the CO_2 stream would typically be at dense phase conditions allowing the use of multistage centrifugal pumps commonly used for pumping liquids (water and/or oil). These pumps are often driven with electric motors with variable frequency drive such that the suction and discharge pressures are able to be tuned with the discharge from upstream recycle compression discharge. Due to the interaction of booster pumps and recycle compression and the need for sophisticated automation controls, these systems are often challenging to commission and operate.

7.3.9 Impact of CO_2 production – asphaltenes

Asphaltene deposition is a common issue for CO_2-EOR floods and occurs anywhere in the system, from production wellbores all the way through gathering systems, process facilities and injection systems. Due to the nature of asphaltenes and CO_2, asphaltenes sometimes are contained in the produced fluids (either water or oil) and contaminate the produced gas. In this type of contamination, the location of asphaltene deposition depends upon the carrying capacity of the gas stream which is a function of the density and velocity of the gas stream. Lowering the velocity of the CO_2 stream at strategic locations in the process will facilitate asphaltene deposition where it is able to be managed, rather than allow further deposition in downstream processes.

7.3.10 Impact of recycle stream composition on metering and operating pressures

The very nature of CO_2-EOR processes results in not only additional oil being recovered from the hydrocarbon reservoir, but also any light hydrocarbon gases being recovered as well. Whereas heavier hydrocarbons (oils) will separate readily from the produced gas stream, hydrocarbon gases will stay in the CO_2 stream. The resulting mixed gas stream has significantly different thermodynamic properties from the CO_2 stream that is purchased and initially injected into the reservoir. Further, the mixed gas (recycled CO_2 stream) is often mixed with purchased CO_2 which results in yet another mixture with yet again different thermodynamic properties. The outcome is a dynamic gas composition that varies not only with location along the process, but also varies with time as the EOR flood progresses and matures. For this reason, increased gas stream compositional analysis is required in various key locations in the process and on a scheduled frequency. Meters need to be properly calibrated to the thermodynamic properties and operating conditions at their installed locations. Some operators choose to recover hydrocarbon gases to minimize the impact of thermodynamic changes on the CO_2 stream and to improve oil recovery.

Compositional analyses are also required to estimate the thermodynamic properties of the produced and injected gas streams at reservoir conditions. These analyses allow for more accurate material balance determination of the reservoir, which aids in EOR flood performance management and also monitoring for CO_2 losses in the subsurface.

7.4 Maintenance and remediation

Regular maintenance of equipment is required to keep the system under sound conditions. The maintenance interval for each machine and device depends on codes and standards, or operations and maintenance manuals. Usually the maintenance timing is adjusted to maximize availability. If the CO_2 source (i.e. boiler, power turbine, refinery, etc.) is shut down for maintenance, the facility is also planned to shut down correspondingly.

7.5 Onshore case studies

At Shell's Quest Project in Alberta, Canada, approximately 1,1 Mt/year CO_2 is captured at 3 Hydrogen Manufacturing Units (HMUs) in the Scotford Upgrader by amine technology by which more than 99 % pure CO_2 is obtained (Shell, 2014). Three injection wells were drilled: two for normal operations and one for back-up (see Figure 5).

Compression used by the Quest project consists of an eight-stage centrifugal machine. Cooling, separation and dehydration are all components of the compression system. Cooling and separation occur at the interstage pressure of 5 MPa where the stream is expected to become saturated with water at 36 °C. To achieve water separation after the sixth stage of compression, the CO_2 stream is cooled, and the condensed water is removed at an interstage scrubber and further dehydrated in a triethylene glycol contactor tower. The dehydrated CO_2 stream returns to the compressor and is compressed to a dense-phase fluid at a discharge pressure of between 8 MPa to 11 MPa. The CO_2 stream is cooled to 43 °C before entering the CO_2 pipeline.

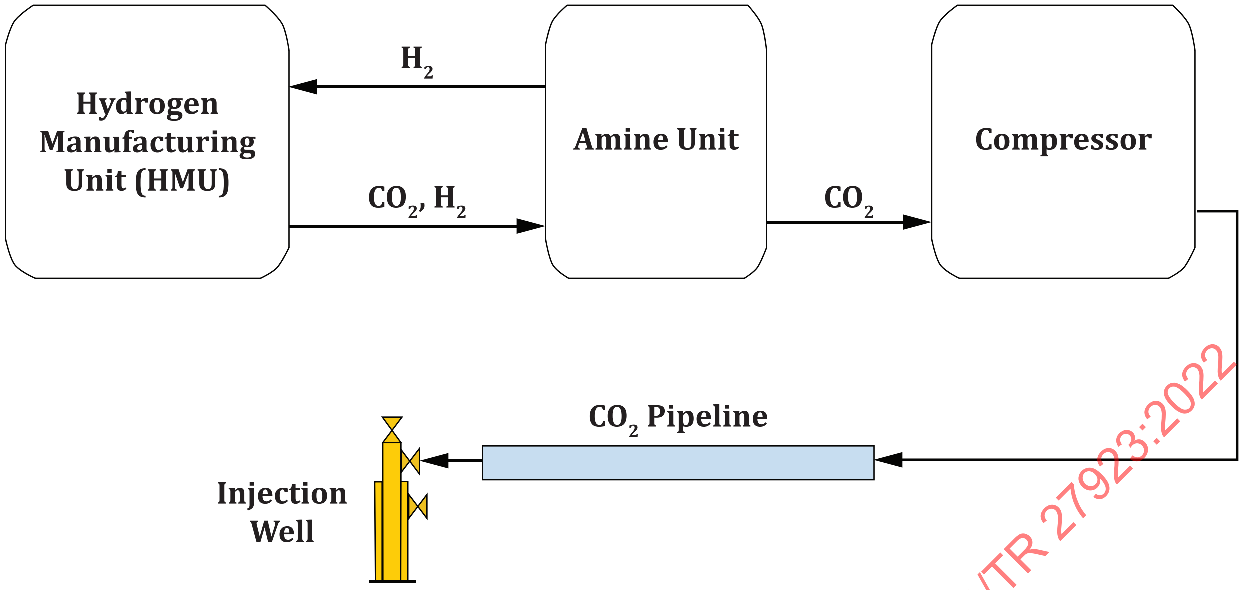


Figure 5 — General concept of Quest CCS Project

A 100 km long, 41 cm diameter pipeline transports the dense-phase CO_2 stream from the capture facility to the injection site where it is distributed to three injection wells. At each injection well a skid-mounted module has been installed to provide control and measurement of the CO_2 stream into the injection well. Communications equipment in the module relays injection and MMV information back to the overall control system.

7.6 Offshore case studies

Snøhvit is the second CCS project operating in Norway (the first is Sleipner). The Snøhvit field is an offshore gas field, developed on the Norwegian continental shelf to produce natural gas with condensate at the water depth around 250 m to 345 m (Hansen et al., 2013). One of the characteristics of this field is that all wells are installed as subsea wells, i.e. there is no fixed or floating unit (see Figure 6).

Hydrocarbon is produced with 5 % to 6 % CO_2 at subsea production wells connected to a subsea production system, and the CO_2 stream is transported by a 711mm (28 inch) 143 km subsea pipeline to an onshore processing facility in Hammerfest, northern Norway in the Arctic Circle. CO_2 is captured, dehydrated and pressurized at the facility, then it is transported by a 203mm (8 inch) pipeline to a re-injection well. So far this is the only existing offshore pipeline for transporting CO_2.

Produced natural gas is exported as liquefied natural gas (LNG) by ship.

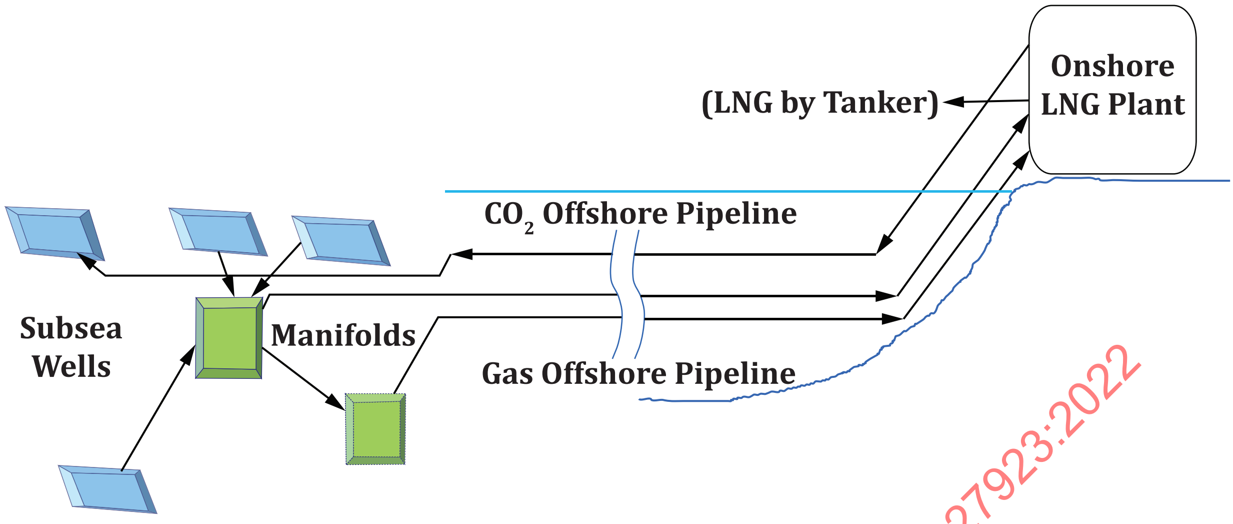


Figure 6 — General concept of Snøhvit Project

8 CO_2 storage site injection operations

8.1 General

The primary objective of CO_2 storage injection operations is the safe, effective, and efficient injection of the project's target mass of CO_2 at acceptable rates. CO_2 storage site injection operation starts once required authorizations have been received.

Key to the successful injection and storage of the desired mass of CO_2 into a storage unit or a CO_2-EOR project reservoir at the desired rates are operational practices that ensure this occurs in a manner that both is safe and efficient and also meets all applicable regulatory requirements. Appropriate management and monitoring activities will further provide the operator opportunities to evaluate the performance of the project compared with original expectations and to incorporate the learnings in a continuous improvement process.

This clause discusses operational practices that facilitate the safe and efficient storage of CO_2.

8.1.1 Objectives

In addition to ISO 27914 and ISO 27916, Clause 8 provides complementary information and practical insights into operational details of CO_2 injection processes.

8.1.2 Scope of operations

The knowledge compiled here is based on international experience with both geological storage and storage associated with CO_2-EOR. Existing storage projects are used to describe various operational processes in more detail.

The focus is on activities downstream of the CO_2 custody transfer and into the storage unit or project reservoir, from the design phase through cessation of the project.

8.2 Design of CO_2 injection operations

8.2.1 General components of operations design

Significant effort by evaluation teams is undertaken to identify, design, and site a successful CO_2 storage project. To ensure the success of the project, a detailed assessment of the operational aspects is required, often in conjunction with senior operational staff. This assessment identifies the design requirements, site needs, and performance expectations to establish the foundation for interaction with operational performance data, which will provide important feedback information that allows further refinement of the injection operations and project expectations. Subclause 8.2 lists the most relevant components of the CO_2 injection operations design.

8.2.1.1 Storage complex parameters

As part of the appraisal and regulatory approval process, criteria for characterization and assessment of the potential storage sites and surrounding areas are established to allow the sites to be characterized and evaluated.

From the operational engineering point of view, the storage capability is contingent on how the two main operational variables impact the possibility of leakage within a specific underground storage complex or project reservoir:

(a) The total volume to be stored, i.e. the site characterization will consider a specified volume to be stored.

(b) The pressures which are developed at the injection points and other critical points within the storage unit or project reservoir during active injection operations.

8.2.1.2 Operational design parameters for storage facilities or CO_2-EOR projects

This part comprises plant, gathering line(s), and well(s) and is described in more detail in Clauses 6 and 7.

8.2.1.3 Operational protocols and maintenance schedules

Operational protocols and maintenance schedules reflect both the regulatory and technical/engineering requirements for the storage site or CO_2-EOR project. An appropriate organization structure will include the entrepreneur, the CO_2 supplier, and the injection operator.

8.2.1.4 Communication procedures

Depending on the stage of operation, daily or weekly meetings are scheduled to coordinate injection rates and necessary shut-in and re-start phases.

Communication guidelines are part of the major operational plan and are executed as defined therein.

8.2.1.5 Safety procedures

Safety assessment is the process of systematically analysing the hazards associated with the facility and the ability of the site and designs to provide the safety procedures as well as meet technical requirements.

Safety procedure are part of the general risk assessment (RA) framework of the injection site. It could be beneficial to embed the RA into a safety case, which is an integration of arguments and evidence that describe, quantify, and substantiate the safety, and the level of confidence in the safety, of the geological storage facility.

8.2.1.6 Site security

Typically, the CO_2 injection operation facility is equipped with a gas warning system, pressure monitoring and pressure limiting controls, emergency shut-in, emergency power supply, fire alarm and fire extinguishing systems, lightning protection, lighting, object protection, environmental protection, waste disposal, waste water disposal, emission protection, means of handling hazardous substances.

8.2.2 Storage complex design parameters

As the site for the CO_2 storage project is being evaluated and characterized, a wealth of data is accumulated which likely includes: seismic interpretations, wellbore construction records, formation evaluation records, pressure transient analysis data and interpretations along with much more. All these data typically get assembled and become the basis for the storage performance prediction (storage capacity and injection prediction). The data, analysis and interpretations are distilled into a comprehensive design of the project which is documented and becomes the basis of the project economics, project funding requests and for regulatory approval applications. In the transition to an operating project, all of these data and analyses that provided the foundation for the operational plan provide the bases to compare actual performance against that plan.

Items of interest from an operational perspective include the injected CO_2 stream composition and operating conditions of the surface facilities, wells and storage unit or project reservoir. During the design of the project, the wells and surface facility infrastructure are tailored to the characteristics of the storage complex or project reservoir, including seals and traps. The site characterization and project design are reflected in performance modelling and predictions and be compared to actual performance results to assess conformance. Comprehensive data storage and systematic archiving provide the necessary inputs for the models used to perform these assessments. Depending upon the actual performance of the entire system, adjustments to the operational design will implement an ongoing continuous improvement program. Such a program would be assisted by a management of change process that documents the reasons for changes and expected performance improvements.

8.2.3 Storage project modelling

The modelling program includes not only model selection, but also consideration of model versions. For example, consideration is given to updating a geologic model on a periodic basis as new versions become available. Until the next official version of the model is released, all work on simulation and risk assessment will utilize the same version of the model to provide consistency. The modelling program will fully document exactly what model version is used, as well as what data are used to construct it.

In a geological (static) model, data are interpreted, averaged, and defined on a grid-cell basis that allows for performance modelling. For locations away from the site of the well within the geological model porosity values need to be assigned in some manner to grid-cells, often by the software using defined relationships and interpolating between available data points. Dynamic reservoir modelling comprises four fundamental components:

— Grid cell structure – usually an upscaled version of the static model, usually characterized by a suite of rock facies with their own porosity.

— Permeability and wettability definitions, rock/fluid models – these include the relative permeability curves for the rock facies in the grid cell model.

— Equations of state for the CO_2 stream. Often, pure CO_2 is used for the equation of state used to model the thermodynamic properties of the CO_2 stream throughout the project system. In many cases, however, the CO_2 stream is not pure CO_2 which will impact not only the applicability of the equation of state model, but also the deviation from predictions to actual conditions.

— Well location and completion details.

Clearly defining the objectives of the dynamic model helps to focus the construction of the model on meeting those objectives. Regional scale models could improve the understanding of saline aquifer projects whereas depleted hydrocarbon reservoirs will have substantially more input data and different operational concerns. Storage in CO_2-EOR projects will involve the evaluation of reservoir properties, relative permeability, stress dependence, and other factors throughout the life of the field, from primary production, through a waterflood if one is employed, and into tertiary recovery/storage with CO_2.

8.2.4 Case Study - Aquistore

The Aquistore project (A.2) has been the focus of extensive pre-injection evaluation and post injection performance analysis which has been documented and published. The researchers studying the Aquistore project conducted pre-injection static modelling of the targeted aquifer, the Deadwood Formation. At a depth of approximately 3 150 m, the Deadwood Formation overlies pre-Cambrian igneous rock and has very few well penetrations (Peck et al., 2014). The data used to construct the static and dynamic models came from open hole log data and core recovered from two wells drilled as part of the project in conjunction with 3D seismic shot for the project as well as from public sources of regional data including 15 well penetrations. The regional model was reduced to a static model with an areal extent of 33,9 km^2. The regional model provided the structural and stratigraphic settings for the model. Petrophysical analyses and core data provided Vshale, porosity and permeability for the net-to-gross with uncertainty analysis used to optimize the distribution of petrophysical properties.

The dynamic modelling used a grid cell size of 76 m x 76 m with local grid refinement of 7,6 m x 7,6 m surrounding the injection site. Relative permeability data required for the model were evaluated in three approaches: two independent lab studies using core plugs from the project wells and one analogue from other published studies.

The key Aquistore learnings from the comparison of pre-injection flow modelling with field performance include:

— Field operational performance did not match the initial forecasts which was attributed in part to the behaviour of near wellbore formation damage.

— The intermittent receipt of CO_2 created issues with thermal equilibrium in the near wellbore area which needed to be accounted for in the history matching process.

— The variable CO_2 supply quantities provided significant data for the history matching process.

— The use of wireline logging, specifically spinner surveys, was key in identifying the relative contribution of each of the perforated intervals which information was then useful for a more complete model history match.

8.2.5 Contractual agreement impacts on injection design parameters

Once the capacities and injection rate capabilities have been estimated to a reasonable degree of certainty, negotiations with the CO_2 supplier could be finalized and contracts prepared to address key elements from an operational perspective.

8.2.5.1 Contracted gas composition

Based on the CO_2 capture source and process, the CO_2 stream composition could include several impurities that impact storage capabilities and operational practices. Supply contracts often specify maximum concentrations of impurities to minimize safety risk (e.g. hydrogen sulfide gas), corrosion impact (e.g. water), or negative storage capacities (e.g. nitrogen). Controlling those potential impurities will minimize negative effects on the storage operations. Supply contracts often oblige the CO_2 supplier to remove or lower the concentrations of detrimental impurities.

8.2.5.2 Contracted volumes and rates

Whereas the ultimate volume of CO_2 stored is dependent upon the nature and size of the storage complex, the supply rates will impact how the storage operator manages those rates through the number of injection wells and facilities design. Rate variability and interruptions are key operational considerations that are typically specified in supply contracts. Operationally, consistent supply rates and pressures are preferable, but the nature of the capture process will affect the feasibility of meeting those objectives. Accordingly, those supply considerations are considered in the operational plan.

8.2.5.3 Delivery pressures

Supply contracts often state a minimum delivery pressure to the storage project. Operationally, a maximum delivered pressure might be dictated by the pressure capability of the supply pipeline. Further, regulatory limitations on maximum injection pressure (in the US this is often based on fracture pressure for a formation) will also restrict the delivery pressure to the project. Operational planning for such contingencies helps to manage periods where delivery pressures exceed the permitted injection pressure.

8.3 Operations and maintenance plan

8.3.1 General - Definition of the main operational conditions

The operator of the CO_2 injection facilities and any approved subcontractors have the responsibility of handling the CO_2 from the custody transfer to the wellhead master valve. The injection operator ensures the safety of personnel who perform these tasks according to their company safety policy and procedures. The operator of the CO_2 injection facilities is also responsible for inspecting and maintaining the monitoring equipment used for measuring temperature and pressure at the wellhead, as well as any CO_2 leak detection equipment placed around the surface facilities. The operator is also responsible for inspecting the surface equipment exposed to CO_2 and responding to any signs of corrosion or potential leakage as they might appear that might compromise safety conditions for personnel operating surface equipment. The operator is also responsible for any potential issues related to existing wells, either abandoned or active on site.

Furthermore, the operator is responsible for training personnel in proper operation of valves, transfer pumps and connection equipment to avoid any damage due to improper settings that could compromise safety at the surface site.

To facilitate continued safe and efficient operations of the storage project the key operational parameters of the project need to be identified and operating conditions for those parameters need to be defined. Detailed process and instrumentation diagrams (P&IDs) are key components of the operational plan. Instrumentation measuring points along with control points are identified on the drawings and facilitate operational teams in determining the set points and control logic for the process.

Typically, a step rate test (SRT) is performed to define operating parameters such as reservoir pressure limitations. In the Ketzin project (see A.10), for example, a maximum rate of 3,2 t/h was determined to be a safe and stable rate.

8.3.2 Operational protocols and maintenance schedules

After a successful trial run of the injection facility, the start of the regular commissioning phase will take place according to operational protocols that rely on reservoir simulation results. CO_2 is continuously injected and the evolution of the reservoir pressure is monitored in part to ensure that the maximum pressure limitation under the applicable regulatory framework is not exceeded. In case of existing observation wells, the CO_2 break-through at these wells will be confirmed.

Declining pressure (Pressure Fall Off) during shut-in phases provide indications of how the required overpressure for injection is being influenced by near wellbore effects and the intrinsic reservoir properties.

8.3.3 Recording management of change

There are situations where the storage facilities and reservoir behave differently than originally projected. If these situations occur, a redesign of the facilities, well or operational procedures could be necessary. A formal management of change process includes evaluating the situation and engineering solutions to work within the project. Without a formal management of change process, a remedy or change in operational procedure could result in other issues within the project causing safety or containment events. As part of the management of change process facility drawings would be updated to ensure all personnel are aware of the changes made to the system.

8.3.4 Communication plan

A good communication plan is essential for successful management of CCS project operation. It will facilitate stakeholder's understandings of the CCS project. It will also assist smooth communications among and between personnel and sections within a CCS project. A communication plan would be tailored for each audience; internal personnel, external stakeholders such as legislative authorities, communities of CCS site vicinity, NPOs and public. A communication plan could include information relating to issues of CCS project operation, impacts and risk treatment (see ISO 27914: 2017, ISO TR 27918). Some CCS specific communication guidelines offer practical and useful information when developing a communication plan, (NETL 2017, Ashworth 2011). Typically, a communication plan is routinely reviewed and revised to maintain currency.

8.3.5 Nomination process for CO_2 delivery and receipt

A key operational protocol that is often included in CO_2 supply contracts details is the nomination process for supplying and receiving CO_2. Even if there is a single supplier of CO_2 to a storage project, this formal communication process allows the supplier to inform the receiver of any upcoming events that could impact CO_2 supply. A nomination is often provided weekly and would begin with the supplier giving a forecast of quantities to be supplied during the upcoming week. In the nomination, the supplier would report anticipated reductions in supply due to planned maintenance or perhaps even increases in supply due to improvements to capture performance. Upon receipt of the nomination from the supplier, the storage operator would respond stating its ability to receive the identified volumes of CO_2, identifying any planned maintenance or injection operations performance that would impact its ability to receive those volumes. Nominations allow the parties to coordinate with each other's operational situation and agree on alternative actions to minimize disruption to their respective operations.

8.3.6 Safety plan

Injection operators develop safety plans to establish site-specific health and safety procedures, detail emergency response procedures, identify emergency response teams, and specify the training requirements for operating personnel. Often emergency response procedures are developed based on a worst-case scenario for an outflow of the CO_2 over the full piping cross section at maximum storage pressure. Responding to this scenario will involve developing and coordinating procedures for safety, health protection, emergency response, site security, and the communications. Plans are revised and updated to adapt to significant changes in the composition of the CO_2 to be injected and changes in facilities, processes, and equipment with a potential to impact the effectiveness of the safety plan.

The principles and structure of oil and gas industry safety and emergency response plans could be easily adopted for CO_2 storage projects. In Canada, the Alberta Energy Regulator (AER) has published requirements for emergency response plans (see AER, Directive 71). The requirements stipulated by the AER include considerations for emergency preparedness at a corporate level, setting up emergency planning zones, interacting with the public during emergencies, and risk matrices for classifying incidents. The plan outlines response procedures to take in the event of an emergency including plans to protect the public. Also included in emergency response plans are maps of the project, contact information for local first responders (fire departments, police, hospitals, etc.) and contact information for residents.

8.4 Injection operations

Injection operations incorporate the injection design of the storage project and follow the documented procedures in the operations and management plans and protocols described in the sections above. The handling and injection of CO_2 is dependent upon the nature of the project. For example, pilot projects like Ketzin that are supplied with trucked in CO_2 must manage the delivery, storage, pumping, and conditioning of the CO_2 on site. Volumes at pilot projects are typically much smaller than demonstration or commercial projects and therefore have unique requirements for onsite CO_2 handling. For larger, onshore commercial projects, CO_2 is typically delivered by pipeline, and often requires little further conditioning or handling before injection.

8.4.1 Initial (start-up)

At the beginning of the injection process, operators often ramp up the injection rate and to keep a rather conservative pressure limit. This helps to approach safely towards a smooth and continuous injection operation, track failure causations to improve scheduled routine maintenance programs, and improve the critical equipment replacement inventory.

8.4.2 Shutdowns

Shutdowns include the cessation of injection due to planned events, unscheduled events, and emergency events. Planned shutdowns, which include scheduled maintenance, supply interruptions or perhaps even periodic storage zone monitoring, allow operational teams to not only plan the safe shutdown of equipment, but also to incorporate factors that allow for safe work on equipment and smoother restart. For example, piping and vessels are often purged with water or nitrogen to allow depressurization and entry for inspection. How operational teams respond to unscheduled events is often documented in the operations and maintenance plan for the project with the learning from each unscheduled event being reviewed and used to update the operations and maintenance plan.

Facility design elements will include safety relief equipment and shutdown valves amongst other equipment to facilitate the safe shutdown of the project. Similarly, injection operations staff will have guidance in the operational and maintenance plan on procedures to manage emergency shutdowns. Training of operation staff will improve their ability to respond appropriately in emergency situations to minimize damage to equipment and the environment and eliminate or minimize injury.

Emergency shutdowns are usually the result of a critical failure of equipment or conditions that could result in the failure of equipment (for example the sudden plugging of equipment piping). Operations teams will have procedures in place similar to unscheduled shutdowns to minimize the impact on the remainder of the operation, but the priority of shutdown steps would be altered to protect further damage to equipment or failures that would impact human or environmental safety. In the event of a critical failure, protecting human safety, both of operations personnel and surrounding residents are the prime concern. Depending upon the nature of the failure, the emergency response plan will be activated which will further dictate the actions of the operations personnel.

8.4.3 Start-up following shutdowns

Similar to commencing injection at the very beginning of the project, re-start operations are thoroughly planned and are documented in the procedures of the operations management plan. The start-up procedure will vary depending upon the scope, nature and duration of the shutdown. Further, learnings from previous start-ups are incorporated and documented in the operations management plan to facilitate restarts. Since the start-up will commence in a controlled, stepwise fashion, it is important to coordinate with outside parties, such as the CO_2 supplier, to facilitate a smooth resumption of injection. Any special inspections or field studies that were being conducted during the shutdown are completed and test equipment removed if necessary.

8.5 Data acquisition, monitoring and testing

8.5.1 General

With the advance of digital data capture and control logic, instrumentation allows not only operational control, but the capacity exists to record and store data from each sensor for continuous or later analysis. The growth in automation and data capture could create data management issues if not carefully designed and used. There could be a temptation by operators and regulators to capture data at a multitude of locations, only to have to limit data capture later due to data storage limitations.

8.5.2 Surface equipment and injection line data

8.5.2.1 CO_2 receipt monitoring

CO_2 that is received at the field, is metered in, and reported at intervals required by the supplier or regulatory bodies. Once the CO_2 is in the storage complex accounting becomes more complex with periodic planned and unplanned losses due to compressor blowdowns, planned or unplanned maintenance, and potentially less reliable metering in site. To the extent that these losses could be measured or estimated they need to offset the CO_2 received at the field entry port and not counted as storage.

8.5.2.2 Injection flowline metering

Infield injection flowline meters are intended to measure the distribution of the CO_2 stream amongst the various injection wells in the project and are therefore not typically used for custody transfer. Injection well metering is often connected to the overall control and automation system. This allows for flow rate information, at an injection well level, to be coupled with other monitoring data such as wellhead pressure or other monitoring equipment.

8.5.3 Wellbore monitoring

8.5.3.1 Annulus pressure and temperature

As addressed in 10.4.1.1, continuous monitoring of annulus pressure (and temperature via DTS) could give an early indication of failure. This would not replace the regularly scheduled mechanical integrity testing regime.

8.5.3.2 Surface injection tubing pressure and temperature

Capture of surface injection tubing pressure and temperature data is done quite simply and is digitally transmitted via field automation systems. Sudden changes in either pressure and/or temperature could indicate a failure in either the upstream delivery flowline or in the downstream wellbore injection system. Operations personnel often use deviations from set-points as a way of failure detection. Longer term trend data could also be useful for identification of plugging of upstream delivery flowlines or in the injection wellbore and completion.

8.5.3.3 Downhole injection pressure and temperature

Downhole injection pressure and temperature data is typically obtained on a periodic basis, usually with retrievable bottom hole gauges. Permanently installed gauges with real-time data capture at surface have been used but are often prone to failure in prolonged use applications. Other real-time downhole injection pressure and temperature measurement technologies include the application of fibre-optics, as e.g. fiber Bragg grating (FBG) pressure transducers and distributed temperature sensing (DTS) which allow measurement at any point in the wellbore. On the long-term perspective, this monitoring technique could also support the control of CO_2 injection tubing integrity, which is a prerequisite for any secure long-lasting CO_2 injection and storage.

8.5.4 Well surveillance

8.5.4.1 General

A schedule of mechanical integrity tests is required by the appropriate regulatory agency. These tests result in a short down time of the injection well, and if an issue is found, potentially a much longer down period. A properly operated site will have redundancy in injection capacity amongst all injectors to allow for regular testing, and periodic downtime of individual injection wells for maintenance activities. An alternative to injection well redundancy would be to allow for periodic maintenance in the

CO_2 supply contracts or to conduct downhole integrity testing in conjunction with periodic scheduled maintenance.

8.5.4.2 Pressure transient testing

In order to assess the average reservoir pressure, flow capacity (permeability), or damage (skin) of the storage zone, the operator can conduct static gradients or injection pressure fall-off tests. The issue with static gradients is the amount of shut-in time required to provide confidence that the reservoir pressure has stabilized sufficiently.

An alternative method, which does have the burden of a longer interruption to injection, is an injection pressure fall-off test. These tests require pressure (and temperature) gauges to be installed in the well, preferentially adjacent to or below the injection zone. Injection would resume after installation of the gauges to provide a baseline pressure at the established rates and allow for the shut-in behaviour and subsequent fall-off behaviour to be recorded on the pressure gauges. The analysis can also inform the operator the amount of shut-in time needed to allow for meaningful use of static gradients as an alternative to injection pressure fall-off testing and in the process reduce the amount of shut-in time for the injection well.

8.5.4.3 Well integrity testing and monitoring

Well integrity testing is an important component of an ongoing regularly scheduled maintenance program. Well integrity testing is conducted at a regular interval, often annually, but other continuous methods are also available. For example, a pressure transducer installed on the annulus between the tubing and casing can be monitored through the project's SCADA system.

Pulsed neutron gamma logs (PNG) to determine CO_2 saturation along the well and check that there is no CO_2 in the caprock range. This is a recognized procedure to prove that there are no leakage paths along the casings, i.e. the tightness of the pipes and surrounding cement is given.

8.5.4.3.1 Casing-tubing annulus, cement, surface casing

As mentioned above, continuous monitoring of the tubing and casing annulus is one method of ongoing integrity testing. If this approach is used, thermal effects in the well will result in pressure variation in the annulus and therefore, operational teams will need to assess whether these variations are within normal operational expectations or whether follow-up investigation is required.

In the absence of continuous monitoring of the well, or in addition to continuous monitoring, the operator may undertake (or may be required be the regulating authority to undertake) annual mechanical integrity testing. This is essentially a pressure test of the tubing/casing annulus to a preselected pressure and monitoring for pressure leakage. If a potential leakage is identified, the operator would commence additional diagnostic tests to identify the source of the leakage.

More often than not, in the event of a leak in the tubing/casing annulus, it is the injection packer that has failed and it can be tested by removing the tubing string (if a permanent packer is in place) and running in the well with a temporary packer assembly which when set above the injection packer can be used to pressure test the packer, isolated from the remainder of the casing.

If the injection packer integrity is confirmed, follow-up diagnostic tests using casing inspection logs (caliper and magnetic flux) and cement bond evaluation logs to identify potential leakage sites.

8.5.4.3.2 Injection profile logs

Injection profile logs are a wireline logging method that assesses the emplacement of injected fluid from the well to the targeted injection zone. Often injection profile logging is done to evaluate the completion effectiveness (quality or conductivity of the perforations) and quality of the injection zone itself at a specific depth. Profile logs can use a variety of techniques, often in conjunction, to establish the injection profile (relative amount of injection at any one depth within the total injection zone).

Spinner logs essentially use a small propeller to evaluate the flowrate within the tubing itself. Spinner logs are run while the well is on injection and are often run both upward and downward. An additional up & down set of spinner passes is made with the well shut in to determine if there is crossflow between layers within the injection zone. In the event of a suspected casing leak, spinner logs can be used as part of larger wireline logging suite to identify leakage zones. However, unless the leak is very sizable, spinner logs do not have the resolution required to identify small leaks.

Temperature logs are often run as part of a suite of production logging tools. Temperature logs are most effective when a sufficiently long shut-in period is allowed prior to logging. With the well in a static state, a baseline logging pass can be made to the bottom of the well. Static runs can identify cooling of the well adjacent to the injection zone or in the event of a casing leak, adjacent to the leaking interval. Injection is resumed and logging passes are conducted at several time intervals to observe cooling associated with injection which is then compared to the static pass to identify the injected zone(s).

Tracer logging is a method where a radioactive isotope (with a short half-life) is ejected from a wireline tool set above the injection zone during injection. The tracer flows with the injected fluid (which can be either CO_2 or water) into the injection zone and the wireline tool with a gamma ray tool identifies where the tracer is 'stored' in the injection zone. The tracer can be repeated with different isotopes depending upon the objectives of the profile logging evaluation. In the event of a casing leak, tracers can also be used identify leakage pathways in a similar manner to injection zone profiling described above.

8.6 Well intervention (workovers)

In addition to well integrity testing described above, well interventions may also be required in the event of failures identified in integrity testing or due to other issues like reduced injectivity. Using procedures developed in the oil and gas industry, the safety of well servicing personnel and the general public are primary considerations. Prior to entering the well to allow for the removal of any well equipment (like injection tubing and packer assemblies), the well pressure must be controlled and reduced to atmospheric pressure at surface (i.e. killing the well). This is done by injecting a fluid of sufficient density, for example a brine solution using potassium chloride, into the tubing string displacing the CO_2 in the tubing string and tubing/casing annulus. This weighted fluid column will counteract the pressure in the injection zone thereby rendering the well pressure at surface to atmospheric state. In this state the well equipment can safely be removed from the well and any damaged equipment replaced and re-run back into the well. Any changes in well equipment and configuration are recorded in the well file for future reference.

Backup injection capacity on site, or flexibility on delivery schedules, or some sort of buffer storage is important for maintaining operations during workovers.

8.7 Considerations for storage using enhanced oil recovery (CO_2-EOR)

The operational aspects of storage incidental to CO_2-EOR are more complex than for geological storage due to the production of reservoir fluids for economic oil recovery. As described in Clauses 6 and 7, there are many more wells involved in the project for both injection and production and the facilities are more extensive to manage not only the production of the produced fluids (including gas phase products), but the recycle of the produced CO_2 stream.

The primary focus of the operational team is the safe and economically efficient operation of the CO_2-EOR flood, with revenues from oil production being the key economic driver. Further, if the CO_2 used for EOR includes CO_2 from non-anthropogenic sources mixed at some point of the supply chain with anthropogenic CO_2 various considerations could require additional measurement and accounting.

A key operational consideration is the composition of the CO_2 stream during the life of the CO_2 storage project. As CO_2 is injected and recycled through the reservoir, it liberates hydrocarbon gases into the CO_2 stream which increase in concentration during the life of the project unless removed. Therefore, the CO_2 stream's thermodynamic properties change, which amongst other things can result in lower CO_2 stream density and result in higher surface injection pressures (to maintain the desired reservoir pressure). CO_2 streams with higher concentrations of hydrocarbon gases, especially methane, have a higher miscible pressure than pure CO_2, reducing the miscible performance of the flood. In some projects, it becomes economically viable to install the necessary facilities infrastructure to remove these hydrocarbon gases. If left in the CO_2 stream, these hydrocarbon gases will reduce the pore space ultimately available for CO_2 storage.

Another factor influencing the pore space available to CO_2 storage is the CO_2-EOR flood process: water alternating gas (WAG). In this recovery process, to control CO_2 mobility and breakthrough, produced water is reinjected into the reservoir, typically using the same injection well, at regular intervals. This process reduces the amount of CO_2 purchased for the project and also reduces the amount of recycle compression required to manage the recycled CO_2 stream. The detrimental factor for storage then becomes the reduced amount of reservoir pore space available for CO_2 storage because it is now occupied by water.

Regardless of whether the CO_2 project applies continuous CO_2 injection (CCI) or WAG, as the EOR flood matures, less new CO_2 is required as recycle volumes increase or WAG injection increases. This will impact the CO_2 supply and purchase volumes and suppliers may need to find additional customers to maintain take-away. Alternatively, the CO_2-EOR flood operator may design the flood to allow for lower CO_2 purchase rates and longer-term flood expansion to maintain the CO_2 supply volumes for a longer period. This balance often is an economic decision: offsetting larger capital expenditures for increased project capacity and short project life in favour of smaller facility infrastructure investments with a longer recovery life.

9 Storing CO_2 in petroleum reservoirs

9.1 General

Based on numerous decades of experience with carbon dioxide enhanced oil recovery (CO_2-EOR), storing CO_2 within depleted petroleum reservoirs offers several advantages over saline storage applications. First, there is an existing field that has been actively managed for hydrocarbon production. Integrity of the wells has been assessed and maintained by the field's operator, thus, providing a good history that allows distinguishing those wells that are well constructed from those that might still require interventions to maintain integrity or that needs to be replaced for storage operations.

Second, the field has been well characterized. This characterization includes original well logs, cores, possibly seismic surveys, and other geologic data collections used to construct representative 3-dimensional geologic models of the subsurface. Prior active operations of the field provide reservoir production and injection data, including water, oil, and gas flow rates, and an accompanying pressure history for each well within the field. The operator typically has also performed dynamic, time-lapse characterization of the production or injection flow streams via spinner surveys with radioactive tracers, geophysical well logs, or seismic techniques that provide additional reservoir monitoring data. Often, these data are included in the creation of full-field or type-section reservoir simulation models to understand the interrelation of reservoir characteristics and the associated production and injection behaviour. This understanding offers a wealth of data that can be utilized in the design of CCS infrastructure and its operation.

Third, the depleted petroleum field will contain operational infrastructure – wells, surface facilities, gathering lines, etc. – that is potentially useable for the storage operations. Table 1 summarizes the potential requirements to repurpose existing infrastructure for storage operations. These requirements depend on the type of petroleum field, which may be EOR, conventional, unconventional, or offshore, and on whether water injection operations had been conducted within the field.

Fourth, if the field was developed using secondary recovery via waterflood, the reservoir is already at or near miscibility pressure, and the latter stages of the waterflood might be used to pressure the reservoir, if needed in order to achieve a miscible or near-miscible CO_2 injection pressure.

Finally, during the operation of the petroleum field, the operator would have interacted and built relationships with the land and mineral owners associated with the reservoir. Further, these stakeholders would be familiar with wellfield and infrastructure buildout for petroleum operations, potentially creating a simplified pathway for public acceptance.

Whereas each of these points identifies a distinct advantage over saline storage developments, there are some potential drawbacks to consider. First, the storage industry is relatively new and the understanding of how and when to alter mineral leases and surface access agreements for the specific purpose of CO_2 storage is not yet well understood. Whereas the pathways are simpler in countries where the mineral and surface estates are national assets, it is relatively complicated for onshore storage applications in other countries, such as the United States, in which the mineral and surface rights are privately held. As such, new leasing protocols are required to co-develop hydrocarbon production and subsequent CO_2 storage. At the very least, surface owners are engaged to negotiate continued field operations for a CO_2 storage project.

Table 1 — Comparison of field infrastructure needs for different types of projects[a]

Infrastructure Categories		Project Conversion Type			
		EOR	Conventional	Unconventional	Offshore
Production facilities[b]					
	Satellite batteries	D	D	D	D
	Fluid gathering	D	D	D	D
	Gas gathering (lines, meters)	D	D	D	D
Water injection facilities[c]					
	Disposal	D	D	D	D
	Distribution system	D	D	D	D
CO_2 injection system					
	Injection skids	NC	N/NC[d]	N	N
	Flowlines	NC	N/NC[d]	N	N
Production wells[c]					
	Wellhead	NC	U/NC	U/NC	U/NC
	Artificial lift equipment	NC	NC	NC	NC
Injection wells					
	Wellhead	NC	N	N	N
	Downhole equipment	NC	N	N	N

N = new

U = upsize capacity or psia

D = downsize capacity or psia

NC = no change

[a] Modified from Jarrell et al. (2002).

[b] Applicable only if the project plans to extract water for pressure management.

[c] Assumes existing water disposal infrastructure is present.

[d] If project under water injection, assumes existing water injection lines and wellhead can be modified for CO_2 injection.

Second, the well-density in the field presents additional potential leakage pathways. Prior reservoir stimulations provide information about the caprock integrity, particularly in instances where the primary caprock is relatively thin and directly overlays the petroleum reservoir. This type of information is of paramount importance for storage operations. This is easier to demonstrate in cases where fluid injection has occurred within the field, including water injection and EOR applications, where out-of-containment leakage is more readily identifiable.

Third, existing infrastructure, especially in mature waterfloods might be out of date, and require significant upgrading or adaptive measures to allow safe usage for the geological storage of CO_2. Field infrastructure needs to be updated to allow for transport of CO_2, which is corrosive in the presence of water. CO_2 supply lines must be installed, tank batteries and transfer stations need to be upgraded to handle CO_2, and in some cases, gases in general. Injection wells need to be adapted for the injection of high-pressure gases, including lined or chrome tubulars, to be more corrosion resistant. This is of particular importance in fields that will utilize WAG operations to improve the vertical sweep and better control reservoir pressure during CO_2-EOR activities. Finally, after CO_2 breakthrough at the production wells, the installation of gas recycling equipment is needed to minimize CO_2 losses during operations.

The use of depleted petroleum reservoirs for CO_2 storage projects has many advantages as long as the potential drawbacks are identified, addressed, and managed. Such management is typically based on previously gained knowledge and leveraging of existing infrastructure to help reduce the cost of storage operations.

Clause 9 provides more information, drawing on industry's experience with CO_2-enhanced hydrocarbon production operations as storage operation experience is limited. It will emphasize the operational aspects of storing CO_2 in depleted petroleum reservoirs, drawing comparisons and contrasts between different project types.

9.2 Reservoir screening

Prior to beginning storage operations in association with a depleted hydrocarbon reservoir, a number of scoping activities are required to ensure the project is adequate to safely and securely accept, inject, and store CO_2.

To guide the assessment, the geology and previous production performance history of the reservoir is typically available to draw upon. Based on this available knowledge, existing geologic and numerical flow models are updated, or constructed, and used to provide forecasts of the CO_2 injection performance for the field area. Field wide injection rates and the accompanying subsurface pressures are reviewed to ensure the reservoir is able to accept the volume of CO_2 and limit the risk of hydraulically fracturing the reservoir. If the reservoir is not able to accept the full CO_2 volume, fluid production and/or the use of additional reservoirs are required to meet the demand.

These results will then be used to design/modify and cost the necessary injection field infrastructure. In instances where fluid injection is already ongoing in the field, the changes required to transition from enhanced recovery or waterflooding to storage operations is significantly reduced.

9.2.1 Storage complex integrity

There are a variety of hydrocarbon-bearing reservoirs that offer the possibility of safe, long-term storage. These reservoirs, generally thought to offer a sound confining system due to their trapping of hydrocarbons, need to be carefully reviewed to ensure that the integrity of the proposed storage system has not been compromised due to well stimulation, poorly constructed wells, or known geologic features that preclude safe, long-term storage.

9.2.2 Project transition type

Once the integrity of the storage complex is considered, the type of hydrocarbon fluid production project could dictate how the storage project is carried forward. In instances where fluid injection is ongoing in the reservoir, there are advantages gained in surface distribution, injection, and gathering infrastructure (see Table 1). However, the average reservoir pressure will be at a higher value as compared to, say, a pressure depleted gas field, which might limit the ultimate storage capacity of the reservoir. Further, where unconventional reservoirs, tight oil and tight gas, are concerned, the ability to store within these low permeability strata is controlled by the ability to fill the stimulated rock volume and limited by the matrix permeability.

9.2.3 Geological data

There are many sources of data for geological modelling and reservoir characterization. These data depend on the stages of exploration (seismic, outcrops, basin studies), appraisal (cores, logs, fluids), and development (fluid from production test, well test etc.) of the reservoir. These available data are typically integrated at each stage to create a subsurface geological model. A best practice is to update static models whenever new data becomes available to improve reservoir characterization and subsequent dynamic models. Structural models are often constructed by integrating well logs with seismic data, when available. Geostatistical models such as kriging and stochastic methods have been employed in reservoir property distribution. This is essential to populate properties in areas without well control. These processes, however, introduce a significant amount of uncertainty in modelling efforts.

9.2.4 Historical production and reservoir performance

When storing CO_2 in a hydrocarbon production reservoir, significant amounts of historical field data exist for both primary and possibly secondary recovery processes to ascertain how the target reservoir would behave during storage operations. Data required to predict storage performance includes standard fluid properties (formation volume factor for gas and oil, viscosity for oil and gas, and solution gas/oil ratio), relative permeability curves for both water/oil and gas/oil (Jarrell et al., 2002), rock properties, and field operating conditions.

9.2.5 Hydrocarbon compositional analysis (PVT)

Equations of state (EOS) are used extensively in the fluid characterization process to describe the volumetric and phase behaviour and other thermodynamic properties of pure substances and mixtures. The use of an EOS helps in establishing consistency over all phases in the reservoir processes. In EOR projects, laboratory data are tuned to the EOS to fully describe the fluid phase behaviour in compositional reservoir simulation to ensure accuracy in predicting miscible flood performance. The application of hydrocarbon EOS for other project types are often tuned in the laboratory for the addition of CO_2 to understand the thermodynamic processes of mixing of the remaining in situ hydrocarbons in a depleted hydrocarbon reservoir with CO_2 during storage operations.

9.2.6 CO_2 storage capacity

Storage capacity, similar to hydrocarbon reserves estimation in the oil and gas industry, is an important tool to assess the future of any CCS project, irrespective of scale. Capacity is defined as those storable quantities anticipated to be commercially stored by application of development projects from a given date forward under defined conditions (SPE, 2017). To estimate capacity, methods such as analogy, volumetric, performance trend analysis (material balance and decline curve analysis), and reservoir modelling are typically employed.

The volumetric method is used most frequently due to their reliability. This method utilizes geology, geophysics, and engineering data gathered from the subject reservoir in determining the potential volume of storage resources. Much as in hydrocarbon production operations, probabilistic approaches, such as parametric and Monte-Carlo methods have been recommended over deterministic estimation to assess uncertainty in volumetric estimation. (Ampomah et al., 2016)

9.2.6.1 Volumetric estimates

Capacity estimates for the CO_2 storage in depleted hydrocarbon reservoirs are generated using the volumetric equation listed below. This approach is based on a static volumetric equation developed by the DOE-NETL (U.S. Department of Energy - National Energy Technology Laboratory, 2015).

$$G_{CO2} = A\, h_n \phi_e\, (1\text{-}S_w)\, B\, \rho_{CO2res} E_{oil/gas}$$

For the DOE-NETL approach, the equation includes total area (A), net formation thickness (h_n), and total porosity (ϕ_e) to represent the total pore volume of a formation. This pore volume is equated to a CO_2 storage volume and the calculated CO_2 density at reservoir conditions (ρ_{CO2res}), formation volume factor (B), and the oil and gas saturations (1-S_w) are then used to derive a mass of CO_2 stored (G_{CO2}). The storage efficiency factor ($E_{oil/gas}$), is the fraction of total pore space occupied by injected CO_2, which is often derived from experience or numerical modelling.

When fluid production occurs in association with CO_2 injection, the use of an appropriate formation volume factor ($B_{oil/gas/water}$) is necessary to convert the volume of these fluids at surface to their equivalent volume in the subsurface. These subsurface volumes are then converted to an equivalent CO_2 storage volume by employing the appropriate CO_2 formation volume factor (B_{CO2}) on a volume-by-volume basis. While these static estimates are suitable for planning purposes, they lack the rigor provided by numerical reservoir modelling to account for geologic, reservoir, and fluid property variations. These factors affect the final volume of CO_2 that can be stored.

9.2.6.2 Material balance

The material balance equation, as developed in the petroleum engineering discipline, is a volumetric analysis. It illustrates that the initial volume of reservoir is constant, therefore the sum of changes in oil, free gas, water, and rock volumes within the confined reservoir must be equal to zero. This concept was first developed by (Schilthuis, 1936). Subject to the prevailing drive mechanism, material balance is utilized to estimate the total volume of remaining fluid within the reservoir. The required information to employ material balance in estimating remaining fluid in reservoir include pressure measured at reservoir temperature, production history, and representative pressure-volume-temperature data.

Similar to hydrocarbon production, material balance techniques are used for storage applications. In CO_2 storage capacity estimation, Lai et al. (2015), presented the modified material balance equation to estimate CO_2 storage capacity for gas reservoirs. A pressure-Z factor (P/Z) plot was used to calculate the amount of CO_2 storage potential at any reservoir pressure condition. A theoretical material balance estimation of CO_2 storage has successfully been applied to candidate gas and oil reservoirs. (Clarke et al., 2017)

9.2.6.3 Numerical modelling

Hydrocarbon production projects have a wealth of subsurface geological and reservoir performance data and numerical models are the primary means for forecasting storage performance through reservoir simulation. In order for a reservoir simulator to predict the performance of a storage project accurately, the reservoir description must realistically represent the geological characteristics of the reservoir.

The typical minimum input data for a simulation model includes, but is not limited to, a 3D geological model with petrophysical properties, in addition to structural features, special core analysis data (relative permeability curves), fluid properties from compositional analysis, well completions, and production and injection history. The model input parameters are adjusted to match historical data in an inverse type of problem solving. There are several approaches utilized in history matching which are predominately divided into manual and assisted history matching processes.

The overall workflow includes defining the objective function, selecting uncertain parameters through sensitivity analysis, developing a proxy model (training and validation), performing optimization to minimize an objective function (Ampomah et al., 2017). This process is repeated for all stages of the recovery processes (primary, secondary, and tertiary). Once an acceptable calibrated model is attained, a forecasting analysis could be performed to optimize storage field operations.

9.2.7 Reservoir pressure history

One important attribute for understanding potential performance of a CO_2 storage project is the reservoir pressure. Knowledge of the reservoir pressure history is essential to screen a candidate reservoir for storage. The behaviour of this parameter during hydrocarbon production is indicative of how it will change during CO_2 storage operations, thereby being a direct indicator of storage capacity.

When injection projects are screened, the formation fracture pressure is also very important. This parameter represents the maximum pressure typically allowed at the wellbore to mitigate the injection pressure from hydraulically parting the reservoir and perhaps the reservoir confining system, preventing leakage from the storage reservoir. To preclude hydraulic fracturing during injection operations, thermal effects must also be understood as cooler injection fluids reduce the reservoir and confining unit's parting pressure.

9.2.8 Aquifer considerations

Typically, hydrocarbon reservoirs are located in a structural high of a much larger geological formation. In effect, these oil and gas reservoirs are connected to saline aquifers at the periphery or base of the hydrocarbon accumulation. The relative strength of these saline aquifers needs to be well-understood to quantify the volume of water influx and associated pressure gain within the productive portion of the reservoir during its depletion, which either limits or enhances the ability to store CO_2. If sufficient structural or stratigraphic closure exists, there might be more accommodation space for CO_2 by expanding the hydrocarbon/storage reservoir into pore space previously occupied by water.

9.2.9 Water extraction

Injection of CO_2 into porous reservoirs will increase in situ reservoir pressure, which increases cost due to decreasing injectivity attributed to pressure build up. Such phenomena increase subsurface storage risks, such as induced seismicity. Fluid extraction from CO_2 storage reservoirs mitigates pressure buildup and/or reduces pressure in the formation. This will therefore decrease the risks associated with over-pressurization and subsequently increase CO_2 storage capacity. In a storage context, this process is often simulated using subsurface reservoir flow modelling to optimize the quantity, position, and injection/production rates of water extraction and CO_2 injection wells for in situ pressure management.

9.3 Surface production and injection facilities

Design of surface infrastructure for a petroleum reservoir CO_2 storage project will draw upon the field's historical data, including the production history and its variability throughout the field, the existing field development systems, including production and injection well placement and flow line infrastructure, as well as the state of field depletion. In cases where the petroleum field had undergone waterflooding, some of the existing equipment is repurposed for the storage project, which reduces the capital requirements for the project.

As such, the first step in the process is to evaluate the existing infrastructure to assess its utility for a CO_2 storage project. A second step includes pilot injection testing utilizing existing infrastructure where possible. Pilot operations will assist the operator to identify gaps in the infrastructure or areas where the existing infrastructure is at risk for ongoing CO_2 storage operations.

9.3.1 CO_2 distribution system

The design of the CO_2 distribution network is dependent on the location of the CO_2 entry point. This delivery network includes field pumping, distribution lines, metering, and water knockout systems to minimize corrosion. Since most anthropogenic sources of CO_2 do not contain appreciable water content, water knockout systems are not always required, but the system must be monitored for water to ensure a lack of corrosivity. Without water in the system, materials selection for piping and valves is often simplified to standard oilfield carbon steel equipment, which is often readily available and much more cost-effective than corrosive-care applications employing stainless steel, fiberglass, coated pipe, etc. However, valves need to be certified for cold temperature service due to gas expansion and cooling. The requirements for surface operating processes will help dictate materials selection as, for example, fiberglass is not always appropriate at higher system transmission pressures.

Isolation systems are developed along the distribution system to allow the depressurizing (blowdown) and segregation of a particular segment of the system for inspection and/or repair purposes. Blowdown stations include vertical pipes and valves to isolate a portion of the system and then evacuate the CO_2 from within it. Large pressure drops and gas cooling due to gas expansion are significant design considerations for these stations, as are the safety concerns to minimize hydrate formation, noise, and CO_2 accumulation.

Often, the CO_2 is delivered to the injection project at pressures and temperatures resulting in liquid phase CO_2 (10,3 MPa and 32 °C). This results in relatively efficient transportation of the CO_2 due to minimized frictional pressure losses. Should the dimensions of the project result in significant pressure drop in the distribution system, whereby less efficient multi-phase flow occurs, or should the injection requirements for the wells dictate higher delivery pressures, additional pump stations might be necessary to either maintain or boost pressure to the desired specifications. In these cases, performance checks to ensure the high pressures do not violate the pressure ratings of the flow lines and connective equipment need to be performed.

Depending on whether a primary trunkline/flowline or a central manifold injection system is used, the costs for Supervisory Control and Data Acquisition (SCADA) systems leading to the injection wells could vary significantly. SCADA systems typically include CO_2 metering, pressure and temperature measurement, a choke (for pressure control), a screen/filter to protect the equipment, and isolation valves for safety purposes. Depending on the SCADA system employed, some or all of these items are monitored and actuated remotely. These facilities are often skid-mounted, housed for safety, and have access to power and some form of communication telemetry.

For more information on non-well infrastructure, see Clause 7.

9.3.2 Production facilities

In cases where hydrocarbon production continues simultaneously with CO_2 injection, production infrastructure is necessary. Because of the corrosive nature of the CO_2, especially when introduced to deep, subsurface pressures, and reservoir brines, careful selection of materials is necessary to maintain the integrity of the wells, wellheads, surface equipment, and flow lines. Material choices available to the storage operator include stainless steel, fiberglass, and coated pipe, among other options. Often, chemical corrosion inhibition programs are combined with the corrosion resistant tubulars and valves to mitigate the risk of integrity failure further. In some cases, EOR applications, specifically, the chemical inhibition program is more than sufficient to mitigate integrity failure, allowing the use of standard carbon steel tubulars.

Producing from the storage reservoir during concomitant injection of CO_2 results in multi-phase production (gas, oil, water, CO_2) that will require separation at the surface. The location of the separation facility (at the well site or more centrally located), its capacity, and technology to be employed are dependent on operational design parameters such as the hydrocarbon composition, inlet pressure, and water content, as well as regulatory guidelines for the discharge of any gases. In these cases, either flare systems or vapor recovery units could be employed to meet these requirements.

Gathering systems, with production streams powered by pumping or compression, move the separated phases to either sales tanks, pipelines, and/or fluid re-injection facilities. If CO_2 is entrained within the production fluids, its separation, recompression, and re-injection forms part of the design specifications and operational execution. Pumping and compression design will also be dictated by the inlet and required outlet pressures, total fluid volumes, hydrocarbon composition, presence of CO_2, and water content of the production stream.

As a result, of the required pressure needed for product sales lines or CO_2 movement, if necessary, the types of compression (reciprocating or centrifugal or both), number of stages, horsepower, coolers, and scrubbers are designed to meet operational design for the project. Procurement lead times are up to a year or more, which makes advanced planning critical. Where liquids are concerned, compressors are not needed as pressure pumping via horizontal pumps are the effective choice for moving fluids through the gathering system.

Within the production gathering system, SCADA and emergency shutdown systems are necessary to monitor and control the production system. Much like the makeup of injection system SCADA, these operational oversight and control systems for the production system are similar and are essential to track the project and maintain safe operations.

In select cases, H_2S is produced along with the hydrocarbon gases. In such cases, the gas stream is termed “sour,” which is extremely corrosive and deadly. The H_2S must be removed or re-injected along with the CO_2. In CO_2-EOR operations, the addition of H_2S improves the miscibility of the solvent in-situ. However, proper safety, dehydration, and materials are necessary to ensure the process is carried out effectively. To remove the gas, adsorption or scavenger systems are typically employed.

For more information on non-well infrastructure see Clause 7.

9.4 Production and injection wellbores (subsurface infrastructure)

In addition to the re-use of existing surface infrastructure, the deployment of CO_2 storage operations in depleted oil and gas fields offers the benefits of a previously operational field, possibly consisting of both injection and production wells. Well integrity must be reviewed to assess the potential utility of the wellbore for use in a CO_2 application. See Bibliography: Relevant Standards and Recommended Practices for wells employed for CO_2 storage operations.

There are many factors that impact well integrity. The age of the well, the type and grade of casing employed in the completion, the type and quantity of cement used to install the casing, the corrosiveness of the production stream, and how closely the well construction meets the recommended practices and standards for storage operations are all major considerations in understanding the risks the wellfield possesses. These need to be assessed using a techno-economic risk-based strategy to understand which wells are abandoned and which wells are useful in future CO_2 storage applications.

9.5 Operating considerations

Since the storage project is a continuation of operations from hydrocarbon recovery, the existing operating practices become a basis for operating the storage project. Depending upon the size of the pre-existing oil and gas project, an operations management plan is typically in place for the field; this too is adoptable for the storage project.

9.5.1 Operations management plan

When considering the operations of a storage project, documentation is required to capture the design parameters of the project, regulatory requirements, safe operations practices, and best practices for managing any changes that are required during the project. Details of the components of an operational management system are available in the following documents:

— CSA Group, Z741-12 Geological storage of carbon dioxide, October 2012[128]

— ISO 27914

— ISO 27916

Operational management plans form the basis of this documentation and are usually created as a joint effort between operations and technical staff. Operations management plans document the scope of the project in terms of the facilities description, storage complex, and surface and subsurface boundaries of the project.

9.5.2 Measurement calibration

There are several types of meters used for measurement of CO_2 streams including orifice, wedge, and mass flow meters. Each style of metering has its requirements or recommended practices for calibration. For a storage project, the stream composition does not vary significantly over the life of the project. However, the ability to monitor the CO_2 stream for variability in contaminants, which sometimes occur due to upsets in the capture process, will ensure the appropriate meter calibration factors can be applied to the measurement system. Monitoring the CO_2 stream composition becomes even more important if multiple sources of CO_2 are transported to the storage site.

The need for an increased emphasis on measurement calibration is especially important for storage incidental to CO_2-EOR projects where production of CO_2-rich gas streams is underway. Contamination of the CO_2 stream with reservoir hydrocarbon gases during production recycle creates a dynamic composition, which requires more frequent metering calibration. Care must be taken to select representative process sampling locations to account for potential changes in the stream composition. These include the well test separator, group separation, recycle compression discharge, and field injection manifolds.

Regardless of the CO_2 stream composition, routine meter calibration is required and operational staff will need guidance on the frequency of calibration of each meter. This guidance is captured in the operational management plan.

For more information on injection & production facilities, see Clause 7.

9.5.3 Well interventions

Well servicing is one of the high-risk activities in the operation of a CO_2 storage project. While the initial completion of an injection well is typically low-risk due to lower reservoir pressures and pore saturations that are primarily water, once CO_2 has been injected, however, care must be taken to address well control during well interventions. Like oil or gas wells, servicing of CO_2 injection (or EOR production) wells usually begin with pumping of a kill fluid into the injection/production tubing string. Depending upon the bottom hole pressure and the density head pressure of the kill fluid, water alone is often not sufficient to balance (or kill) the near wellbore pressure needed to prevent a kick during servicing. Therefore, a weighted kill fluid is necessary to achieve the necessary bottom hole pressure. Weighting of the kill fluid is often done with potassium chloride (KCl), but other weighting products like calcium carbonate ($CaCO_3$) are used to achieve the density required without causing formation damage. For any well intervention, it is recommended that a detailed program be prepared in advance that outlines not only the procedures to repair the well equipment but also emphasizes well control procedures. Key tasks need to be identified and addressed in the well intervention program with a pre-job safety meeting prior to initiating that task.

9.6 Monitoring

CO_2 storage in petroleum reservoirs will follow much of the same monitoring protocols outlined in Clause 10; however, there are some added considerations with these storage settings. The first consideration is that the number of well penetrations associated with petroleum reservoirs will likely be significantly higher than in saline formation storage targets, due to the evolution of the production history of the reservoir. These well penetrations serve as the most likely source of leakage from the storage reservoir to overlying strata or the surface. Therefore, an accounting of all known wells drilled into or through the storage reservoir target, and their locations at the surface, needs to be done prior to CO_2 injection. A magnetic survey could also reveal the locations of undocumented well locations that could be potential point sources of leakage.

There are other indirect and direct monitoring activities that are petroleum reservoir specific as well. Seismic line coverage of petroleum reservoirs will typically be greater than in situations dealing with saline formations. These seismic lines, or 3-D seismic if available, are used as a baseline for comparisons with seismic data acquired post- CO_2 injection, to assess the location and migration of CO_2 within the reservoir. However, since the physicochemical properties of crude oil and supercritical CO_2 are very similar, it may not be possible to understand the CO_2 behaviour in petroleum reservoirs by seismic survey.

During petroleum production from the reservoir, records of reservoir pressure are typically kept, covering the periods of hydrocarbon production from beginning to end. These records could be used to determine the threshold pressure at which pressure management becomes necessary.

The presence of wells completed within and above the storage reservoir, which are still open prior to plugging and abandonment, offers the unique opportunity of converting some of the wells to monitoring wells, without having to drill new ones. These wells are used to monitor the pressure within and above the reservoir to help identify where the CO_2 and pressure plumes are migrating within the target reservoir.

9.7 Transition to storage

For CO_2-EOR projects nearing maturity, CCS might be an alternative to project decommissioning that also expands the market for commercial storage projects. Evaluating near end-of-life CO_2-EOR projects with a focus on transitioning them into storage projects, with the intention of utilizing parts of or the entire existing infrastructure might demonstrate a viable afterlife for CO_2-EOR projects. If transitioning from a CO_2-EOR project to a storage project is viable, it provides additional financial motivation to accelerate deployment of more storage projects.

9.7.1 Reservoir considerations

A CO_2-EOR project could be considered a well-defined storage complex as the long-term production and injection history of the field, combined with the geological data collection and analysis of the complex, provide a wealth of knowledge and understanding regarding the reservoir and its viability for CO_2 storage operations. This pre-existing knowledge is critical in understanding how large, or discontinuous, the hydrocarbon reservoir system is, which could dictate how the storage operations are conducted.

In the case of extremely large systems, production wells might be shut-in and the structure filled with CO_2 over some time, perhaps with little risk to increasing the system pressure. However, in discontinuous systems, production operations are continued for some time, to remove formation brines, which are incompressible, to increase the CO_2 storage space. If additional hydrocarbons are produced, they often bring enough value to offset the use of the gas processing facility to ensure all CO_2 is ultimately recycled to the field and stored.

Typically, a CO_2-EOR project would have been conducted in a balanced manner. That is, each production pattern withdrew a similar volume as compared to the injected volume. This process maintained reservoir pressure, limiting the movement of the CO_2, and reducing the containment risk due to reservoir over-pressuring, which could cause leakage through the confining system. Provided the stimulation and waterflooding operations were also carefully conducted, the likelihood the CO_2 is confined to the reservoir strata is improved.

Other leakage pathways, which might impact the storage operation, include the injection, production, and monitoring wells within the oil field. These wells must be carefully surveyed to ensure they maintain integrity and are not leakage risks. Furthermore, these surveys need to extend to those wells, which are permanently and temporarily abandoned. Because the CO_2-EOR operations were conducted at or near original reservoir pressure, many operators must actively review the wellfield to maintain integrity. Mechanical integrity testing, using radioactive tracers, casing inspection logs, and pressure tests, are routinely performed by industry, further mitigating this risk.

9.7.2 Legal/regulatory considerations

In many jurisdictions, the legal frameworks treating storage and CO_2-EOR are separate and, as a result, different. Whereas geological storage frameworks typically focus on permanence in retention of the CO_2, the frameworks for CO_2-EOR, and the rights to occupy an oil and gas lease, are focused on resource production. Moreover, any framework for transitioning from a CO_2-EOR project to a storage project is often either non-existent or vague due to the nascent stages of the CO_2 storage industry.

Often, the frameworks anticipate that the exiting CO_2-EOR projects, regulated under an oil and gas regulatory system, is going to be decommissioned, plugged, and abandoned once oil/gas production has stopped. Other times, there is little or no reference in the framework related to CO_2 behaviour or liability following plugging and abandonment. Furthermore, there typically is no guidance on how to potentially convert or transfer the project into a storage project. These aspects will consequently lead to different operational and financial considerations in accounting for the in-situ behaviour of the CO_2.

It is expected that, due to the early state of the CCS industry at large, these frameworks will continue to evolve as they are applied/tested by hydrocarbon producers and storage operators.

9.7.3 Financial considerations

When transitioning a CO_2-EOR project to a storage complex, there are more considerations to be made in addition to the operational, technical, legal, and regulatory challenges. Costs related to projects prior to, during, and after transitioning are important to assess. Moreover, the costs relating to monitoring, reporting and verification, operating wells, equipment, and surface and subsurface facilities are all part of these considerations as well.

Certainly, taking advantage of the existing infrastructure and wells within the CO_2-EOR project significantly reduces the costs of storage. However, there are still costs associated with updating or modifying the oil field such that it is able to accept CO_2 for storage purposes. In many cases, incentives, or tax relief, such as the U.S. Section 45Q tax credit, are used to return a value for the stored CO_2.

9.8 Closure

Project closure for depleted hydrocarbon reservoirs will follow a similar process to that for non-hydrocarbon bearing reservoirs. The closure period involves a series of activities implemented after CO_2 injection ceases for economic reasons, attainment of reservoir capacity, regulatory considerations, technical challenges, or other reasons. The intent of the closure period is to ascertain that the injected CO_2 is retained within the identified reservoir and that there are only minimal ongoing risks associated with the project. At the end of the closure period, the area in which injection facilities were present needs to be suitable for other uses and no interventions in the future are required. To date, no commercial projects injecting CO_2 into hydrocarbon reservoirs have reached the closure period.

10 Monitoring

10.1 General

Requirements for CO_2 storage monitoring are specified in ISO 27914 and ISO 27916. The most pertinent clauses regarding monitoring are ISO 27914:2017, Clause 9 and ISO 27916:2019, Subclause 6.2. The purpose of Clause 10 is to describe current monitoring practices and results from CCS projects in various geologic settings, which can be used to support implementation of the existing standards. Clause 10 focuses on methods for monitoring of CO_2 containment within the storage complex. A survey is presented of the broad range of existing and emerging methodologies, their accuracy and uncertainties. The use of appropriate monitoring methods is considered according to various stages of a CO_2 injection project. Differences in monitoring objectives, requirements and methodologies are considered based on varying injection scenarios such as CCS vs. CO_2-EOR and onshore vs. offshore. Case studies are utilized to demonstrate real-life experience with CO_2 monitoring.

10.2 Monitoring objectives

The primary purpose of monitoring is to assist in managing health, safety and environmental risk as well as to assess storage performance. Monitoring is an integral part of risk management, enabling an assessment of the storage project performance and providing confidence that CO_2 containment is effective. Specific objectives are to:

— ensure safe and secure containment of CO_2 within the storage complex;

— ensure protection of underground natural resources including groundwater, mineral and hydrocarbon resources;

— track the fate of injected CO_2, pressure fields and reservoir fluid displacement;

— detect any loss of CO_2 containment and assess potential impacts of leakage on elements of concern;

— ensure that any associated ground uplift/subsidence or induced seismicity is managed to avoid damage to the storage facility or other surface infrastructure;

— assess the effectiveness of risk control measures such as mitigation and remediation.

10.3 Monitoring plan design

A monitoring plan is typically established according to the risk assessment analysis conducted as part of developing an operational plan at the start of the project. The monitoring plan will address the objectives identified above and is necessarily project-specific in accordance with the operational environment (e.g. storage vs. CO_2-EOR, land vs. marine), geological setting, and local regulatory requirements. The plan accounts for different monitoring needs during different stages of a storage project (pre-injection, operation, closure, post-closure). In general, attainment of the objectives specified above requires tracking the subsurface migration of CO_2 and the associated pressure field either directly or indirectly. The monitoring plan commonly includes components of atmosphere, near-surface, and sub-surface monitoring depending on the project-specific risk analysis.

10.3.1 Geological Storage vs. CO_2-EOR storage projects

EOR fields are most often very well characterized based on:

— existing operational experience;

— direct reservoir access via multiple wells;

— knowledge of original reservoir integrity due to the presence of trapped hydrocarbon gas/fluids.

In contrast, non-EOR storage sites usually have no operational history and limited reservoir access (fewer wells) and thus performance characteristics and seal integrity are based on limited data. However, EOR fields typically have many seal penetrating wells that represent potential leakage pathways, and the effects of long-term production on reservoir integrity are uncertain. The different nature of these types of storage projects will affect the risk assessment which shapes the monitoring plan. These differences are reflected in ISO 27916:2019, Subclause 6.2.1 which focuses on categorizing the identified potential leakage pathways and determining whether monitoring is required.

10.3.2 Land vs. marine storage project

Offshore regulatory regimes are distinct from land-based regimes. In comparison to land CO_2 storage projects, marine projects will typically have even fewer wells (injection and/or observation) due to the higher cost of drilling and operating offshore wells. Thus, most of the comments made in 10.3.1 regarding non-EOR storage sites are applicable and accentuated in the case of marine storage. Methods for containment monitoring at and below the sea floor are complicated by the presence of the water column above the sea floor.

10.3.3 Monitoring vs. project stage

Monitoring requirements vary according to the stage of the storage project: pre-injection (or pre-storage in the case of EOR), injection, closure, and post-closure.

10.3.3.1 Pre-injection stage monitoring

Site characterization occurs during this stage (ISO 27914:2017, Subclauses 5.4, 5.5, 9.2.2; ISO 27916:2019, Subclauses 5.2, 6.1.1). The area of review (AOR) is determined for the project and a broad variety of data are acquired or assembled. This is the period during which initial storage modelling is done, baseline states or rates are established and during which initial risk-based analyses identify targets and parameters that requires monitoring after start-up. Much of the data acquired during characterization can serve as the baseline for monitoring that is specified in the monitoring plan. Subsequent monitoring typically occurs within the project boundaries.

10.3.3.2 Operational monitoring

Storage projects are likely to be active (i.e. injecting CO_2) for periods ranging from years to decades. During this operational stage, monitoring activities are conducted that provide sufficient information to manage safe injection operation and containment risk, assess storage complex integrity, and calibrate predicted storage and injection performance. Monitoring plans are evaluated and adapted periodically during the course of injection to ensure that they continue to be appropriate. Monitoring results are used to inform project operations and to trigger the investigation of non-conformance and mitigation and/or remediation activities as required.

10.3.3.3 Closure period monitoring

Closure periods will range in duration depending on local regulations. For example, Alberta-Canada has recommended a 10-year closure period whereas the US EPA has adopted a default 50-year closure period for Class VI wells. The duration of monitoring after site closure may be determined on a site-by-site basis by observing changes in CO_2 behaviour over time. It is expected that monitoring efforts during this stage is less intensive than during the operational stage. Monitoring is continued for the purposes of containment assurance and demonstration that CO_2 behaviour is predictable and trending towards stability for the site.

10.4 Monitoring methods

10.4.1 Wellbore monitoring

10.4.1.1 Pressure

Wellbore monitoring for pressure falls into two categories: monitoring of well-integrity and monitoring for reservoir pressure. Monitoring of well-bore integrity is accomplished by monitoring pressure in the annular space at the wellhead, or with an in-place sensor. In the case of a tubing or casing failure, pressure changes are used to give early warning. This type of monitoring is in addition to, rather than in the place of periodic Mechanical Integrity Tests (MITs).

Pressure monitoring is also deployed at the reservoir interval, by boring a hole in the tubing just above the packer to directly measure pressure (and temperature) just above the storage zone. These sensors are deployed at the end of an installed fibre array. Memory gauges deployed via slick lines are also used. It is important in any case to use materials which tolerate CO_2-rich environments.

10.4.1.2 Reservoir fluids

Sampling of reservoir fluids provides important information for multiple purposes, including modelling efforts and compliance reporting. Numerous sample collection methods exist. Some methods use specific equipment (e.g. a wireline sampler) that allow samples to be collected downhole to approximate reservoir conditions. Other methods use samples taken at or near the surface (e.g. at the well head, from a test separator at a gathering point). Sample integrity and planned use of sampling results are important factors to be considered when selecting a sample collection method. Each sampling method has inherent benefits and drawbacks. For CO_2-EOR storage projects, periodic fluid sampling from production wells provides a context to 1) establish a record of fluid compositions and chemical concentrations in each well, and 2) evaluate spatial and temporal changes in fluid quality. For CCS projects, periodic fluid sampling from monitoring or brine extraction wells, if they exist, provide a similar context to interpret reservoir fluid quality.

10.4.1.3 Time-lapse logging

Multi-parameter wireline logging is a fundamental tool for characterizing various aspects of a wellbore, casing, completion, surrounding geology and fluid flow within a well. Geological parameters are measured within centimetres to metres from the well. Logging can be used in a time-lapse sense to directly measure injection-related changes in all of the above. The primary application is to ensure the ongoing integrity of the well over time, but it is also very useful for directly measuring the presence of CO_2 within the formation adjacent to the well and physical property changes due to CO_2 injection.

Logs most commonly employed for monitoring in CO_2 storage projects are neutron, sonic and resistivity logs which are all sensitive to the replacement of brine by CO_2. The neutron thermal capture cross-section (pulsed neutron) generally decreases with increased CO_2 saturation as does compressional wave velocity, whereas resistivity increases. Recovery of CO_2 saturation values from log values requires calibration with either a mixing model or laboratory measurements. The Nagaoka project has conducted the most extensive set of repeat logging measurements (neutron, resistivity, and sonic) with 38 repeat logging runs made over 880 days (Sato et al., 2011).

10.4.1.4 DTS/DAS

Distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) technologies utilize fibre-optic cables to provide a continuous measure of temperature and acoustic signal along the length of the optical fibre. In vertical wellbore deployments, this provides a vertical profile of these parameters along the length of the borehole. Temperature measurements are useful in constraining models of fluid flow and determining the phase of CO_2 versus depth in injection wells. Passive acoustic measurements can be utilized to detect CO_2 leaking along the wellbore as well as providing microseismic monitoring (see 10.4.2.2). Acoustic monitoring can also be used to record vertical seismic profiles (VSP as described in the next section).

Optical fibre cables for DTS and/or DAS can be deployed temporarily (via wireline) or are often part of permanent installations (e.g. strapped to injection tubing or cemented external to the well casing during well completion).

10.4.1.5 Seismic, gravity and electrical

Time-lapse geophysical measurements made using instruments deployed in wellbores are typically focused on details of the storage reservoir. Wellbore monitoring is designed to measure or image injection-related changes in the immediate vicinity of the wellbore but over a broader range than geophysical logging methods. As such, the primary application of these methods is to directly image the CO_2 plume. Cross-well techniques (seismic and electrical resistance tomography) are capable of imaging injection-related changes in seismic velocity and electrical resistivity, respectively, in the inter-well region (100's of metres) with resolution on the scale of metres. Surface-to-wellbore measurements (seismic VSP and electrical) deploy sensors in the well to record sources deployed at the surface and are capable of imaging 100's of metres from the recording well. For seismic acquisition the sensors are geophones, hydrophones or more recently DAS cables. Gravity measurements are conducted like conventional wireline logs but are sensitive not only to injection-related density changes at the wellbore, but also changes occurring much further from the measurement well.

10.4.2 Surface-based monitoring

Surface-based monitoring methods fall into one of three categories:

— direct monitoring for the presence of CO_2 leaking from the subsurface;

— dynamic measurements of processes that may represent compromise of the storage container (surface deformation, passive seismic);

— remote sensing data that track CO_2 saturation and/or pressure changes due to the effect they have on physical properties (elastic, electric, permeability).

10.4.2.1 Near-surface direct monitoring

10.4.2.1.1 Soil gas chemistry

Shao et al. (2019) have described the context of soil gas monitoring in CCS contexts. The following is an excerpt from their recent publication.

Soil gas monitoring aims to detect leakage of injected CO_2 into the soil vadose zone before it is released into the atmosphere. Demonstration that leakage to the surface has not occurred provides assurance to the public that CCS operations are safe. However, discrimination of leaked CO_2 and naturally occurring CO_2 in the soil vadose zone is often challenging, as there are a large number of dynamic processes that generate or consume soil CO_2 (Leuning et al., 2008).

Schloemer et al. (2013) suggested that, to characterize the natural variations, baseline measurements for CCS projects begin years before CO_2 injection. In contrast, Romanak et al. (2012) developed a "process-based" geochemical approach to leakage detection that can be applied without baseline measurements. However, Beaubien et al. (2015) pointed out that baseline surveys of near-surface gas geochemistry are important for CCS because they define the range of natural variation attributable to near-surface processes to minimize false positive or negative detections, and can also identify pre-existing gas migration pathways that represent a risk for gas-permeable faults.

Another strategy for CO_2 leakage detection at CCS sites is the use of geochemical tracers. Isotopic tracers provide important information about the origin of soil gases (CO_2, CH_4, N_2) and the processes that give rise to their formation (e.g. Schoell, 1988). Natural tracers, especially the stable isotopic composition of carbon ($\delta^{13}C$) in soil gas CO_2, have been used in CCS monitoring programs (e.g. Johnson et al., 2009; Leuning et al., 2008; Myrttinen et al., 2010). However, the $\delta^{13}C$ values of injected CO_2 may overlap with those of pre-injection soil gas CO_2 which limits the application of this method at some CCS sites (Mayer et al., 2015). For example, at the Weyburn enhanced oil recovery (CO_2-EOR) site, the $\delta^{13}C$ value of injected CO_2 (−21 ‰ to −20 ‰) was comparable to that of the typical soil gas CO_2 composition (Beaubien et al., 2013). Mayer et al. (2015) suggested a minimum 5 ‰ to 10 ‰ difference in $\delta^{13}C$ values between injected and baseline CO_2 for this tracer approach to be reliable in determining CO_2 movement and potential leakage.

Radioactive carbon (^{14}C) in soil gas CO_2 is a useful tracer for leakage detection (Klusman, 2011). The near-zero concentrations of ^{14}C in fossil-fuel-derived CO_2 (ancient) relative to that produced recently by soil respiration processes (modern), makes ^{14}C a useful discriminant for leakage detection at sites where injected CO_2 is derived from the combustion of fossil fuels (Anderson et al., 2017). Nevertheless, the application of ^{14}C in CCS has been very limited (Beaubien et al., 2013).

10.4.2.1.2 Flux tower

Flux towers are used worldwide to measure the gas concentrations (water vapour, CO_2, CH_4 and N_2O) and energy flux exchanged between the terrestrial ecosystem and atmosphere. Flux towers have been tested at CCS projects. However, wind direction, atmospheric stability, adverse weather, and surface heterogeneity all impose difficulties in making accurate flux measurements (Leuning et al., 2008).

Eddy covariance is a micrometeorological method that measures minor fluctuations of air mass and energy on several time scales (hour, day, season and year) and on spatial scales of 100 m to 2 000 m. For the purposes of leakage monitoring, baseline CO_2 flux measurements are required to determine diurnal and annual cycles. Global micrometeorological studies show that maximum hourly average flux densities of CO_2 range from −40 µmol CO_2 m^{-2} s^{-1} during the day due to photosynthesis to +15 µmol CO_2 m^{-2} s^{-1} at night due to respiration (Leuning et al., 2008).

Spatial averaging is inherent in the micrometeorological approach. This makes quantification of any CO_2 emissions from geological storage difficult due to variable background concentrations of atmospheric CO_2 that range from about 380 ppm (parts per million mole fraction in dry air) during the daytime to greater than 500 ppm at night in the lowest 10 m to 20 m of the atmosphere (Leuning et al., 2008). The ability of eddy covariance methods to detect CO_2 leakage from a storage site depends on the ratio between the integral CO_2 flux from the footprint area and the seepage rate from a point source (IEAGHG, 2012).

10.4.2.1.3 Laser-ranging

Laser-ranging methods make line measurements of the optical absorbance along the light path, measured at a characteristic CO_2 Infra-Red absorption wavelength (e.g. Hirst et al., 2017). This provides determination of the total path-integrated mass concentration of CO_2 along the beam path. Measurement path lengths of about 100 m have been used in demonstration with lasers and detectors commonly located at 1 m to 2 m above ground level. Zones of anomalous CO_2 concentration relative the local ambient CO_2 saturation can be identified by application of tomography to measurements made for intersecting laser paths.

10.4.2.1.4 Groundwater chemistry

Groundwater monitoring is a mature technique that is used to document and quantify subsurface flow and aqueous chemical conditions through time. Typically, the goals of a shallow groundwater monitoring program in the context of a CCS/CO_2-EOR project are to:

— understand the shallow hydrogeological environment in and around a project site by taking measurements and samples from monitoring wells;

— establish pre-project groundwater conditions and variability;

— be able to detect and quantify the extent of CO_2 and/or brine migration out of a storage complex into overlying and adjacent geologic horizons;

— meet regulatory monitoring requirements of a project;

— demonstrate that project activities were protective of human health and the environment.

Groundwater samples are periodically taken using standard methods (e.g. U. S. Geological Survey, 2020). Measurement of field parameters such as pH, temperature, specific conductance, dissolved oxygen, and oxidation-reduction potential are generally recorded to determine representativeness of a groundwater before a sample is collected. Once it is determined that fluids are sufficiently representative of in situ conditions, groundwater is collected and treated by a variety of methods (e.g. filtering, acidifying, chilling) to ensure integrity of analytes of interest. The collected samples are then transferred for field and/or laboratory analysis. Analytical results are then evaluated for changes in conditions that would indicate that the groundwater environment has been affected. If measurements or trends in groundwater chemistry indicate that leakage of brine or CO_2 from a storage complex has occurred, then a project would need to consider mitigation actions.

10.4.2.1.5 Ecosystems

Ecosystem-based monitoring can be used to qualitatively assess impacts of CCS operations on the environment (IPCC, 2005). The health of terrestrial and subsurface ecosystems can be determined directly by measuring the productivity and biodiversity of local flora and fauna or, indirectly, by using remote-sensing techniques. However, leakage quantification based on vegetation may not be possible as above certain levels (or duration) of leakage, further damage will not occur (IEAGHG, 2012).

Remote sensing (spaceborne or airborne) may offer one way to efficiently monitor storage and assess impacts over wide areas. Vegetation generally reflects the local ecological conditions and land uses at a site making vegetation a good integrator of ecological dynamics (TOTAL, 2015). Multispectral and hyperspectral images can help identify vegetation areas that may be stressed due to high concentration of CO_2 in the soil, and that are worthy of further surface investigation for possible CO_2 leakage (IEAGHG, 2012). Bateson et al. (2008) tested airborne remote-sensing techniques and concluded that subsequent detailed site monitoring is necessary and must include surface measurements to ascertain whether the anomaly is caused by deep CO_2 leakage or by some other, unrelated process. False positives can be reduced at CO_2 geological storage sites by the careful acquisition of baseline data prior to injection.

10.4.2.2 Surface dynamics monitoring

10.4.2.2.1 Surface deformation

Time-lapse monitoring of surface deformation has been instrumental for identifying non-conformance in large-scale CO_2 storage projects (e.g. Rutqvist et al., 2010; Vasco et al., 2010). GPS and tiltmeter measurements provide very accurate ground deformation values local to the individual stations whereas InSAR (interferometric synthetic aperture radar) has the capability of providing areal coverage of ground deformation at the monitoring site. However, the implications of observed ground displacements in terms of the subsurface CO_2 distribution and pressure field requires a geomechanical model for the area (e.g. Rutqvist et al., 2010).

InSAR is a satellite remote sensing technique that is capable of identifying and accurately measuring vertical ground displacements on the scale of millimetres per year, over areas ranging from 1 km^2 to 10 000 km^2. It provides an unobtrusive means of monitoring large areas for ground displacement associated with CO_2 injection operations. Vertical and horizontal ground deformation can be measured with precisions of 0,3 cm/year and 0,2 cm/year, respectively (Samsonov et al., 2015). In continental climates and landscapes, at least one full season of pre-injection monitoring is beneficial in assessing the seasonal variations in ground movements that are unrelated to CO_2 injection operations.

Global Positioning System (GPS) stations can provide a continuous record of ground displacement on the scale of millimetres per year at discrete locations. As such, GPS measurements complement the areal coverage and discrete time measurements provided by InSAR. Vertical velocities determined from GPS monitoring as small as 2,0 mm/year can be measured (e.g. Craymer et al., 2015).

Tiltmeters (Dunicliff, 1993) also provide a continuous record of surface deformation (tilt) at discrete locations. Tiltmeters are capable of measuring sub-µradian-scale rotations. Background tilt noise is variable. For example, Earth tide and precipitation effects of 0,1 µradians to 2,0 µradians have been measured (Wang, 2015). In comparison, model-based tilt estimates at the same location exceed 10 µradians. These estimated signal levels are small but detectable and are based on CO_2 and pressure communication being restricted to the reservoir zone. If this is not the case (e.g. CO_2 migrates to, or pressure communicates with, shallower depths) then greater ground deformation can be expected.

10.4.2.2.2 Passive seismic

The aims of passive seismic monitoring are to identify and characterize seismic events related to CO_2 injection and to distinguish them from seismic events that are unrelated to the storage project such as naturally occurring earthquakes or other local industrial activities. Furthermore, the monitoring of injection-related microseismicity can be used as a means of adjusting injection operations to mitigate the potential effects of induced earthquakes. Experience from underground wastewater injection has demonstrated that the frequency and magnitude of induced seismic events can be controlled by decreasing the injection volume and pressure (e.g. Kansas Corporation Commission, 2016).

Passive seismic monitoring commonly employs an array of 3-component surface seismographs and/or downhole seismic sensors. Surface-based seismic arrays require a minimum of 3 stations to allow effective triangulation for locating local events. The accuracy of epicentral locations is highest for events occurring within the boundaries of the surface array. Thus, station locations are chosen to encompass the area where the majority of seismic events occur. Typically, this would include the area of the CO_2 plume as a minimum but generally is much broader as injection-related pressure perturbations occur over a much larger area. The portability of surface stations allows for subsequent station location adjustments based on the areal distribution of any induced microseisms. Decatur is a good example of this where basement fault reactivation results in significant microseismic activity at several kilometres from the injection well (Kaven et al., 2015). Surface-based seismographs are typically capable of detecting seismic events of magnitude 0 and greater, and thus are usually sufficient for the purposes of detecting induced seismicity that could damage surface infrastructure.

Well-based passive monitoring arrays provide higher sensitivity for detecting and locating small magnitude injection-related events (-4 to -1; e.g. Wilson and Monea, 2004). Most recently, DAS fibre cables have also been tested for this purpose. Wellbore deployments also improve the depth locations for local events particularly if the microseismic event occurs within the depth range covered by the array. Hypocentres of detected events are determined from the direction of seismic waves and P-and S-wave arrival time differences. The epicentre location accuracy of small magnitude microseismic events is greatly improved if multiple wells are instrumented. Whereas small magnitude events are of little concern in regard to potential damage of surface infrastructure, they can be informative about stress changes in the storage container as well as identifying zones that are being reactivated.

Off-shore seismic monitoring, systems utilize either conventional 3-component ocean-bottom seismographs or telemetered seismograph networks. Conventional OBS (ocean-bottom seismographs) are used mostly for temporary observations as the data aren't available until the seismographs are recovered. Telemetry systems provide continuous real-time monitoring from sea-bottom seismographs (e.g. Fujiwara et al., 2010; Shinohara et al., 2014).

10.4.2.3 Indirect monitoring

The utility of indirect methods for CO_2 monitoring relies primarily on the changes in physical properties of the host-rock/fluid composite that occur from the partial replacement of pre-existing pore fluids (brine, hydrocarbons) by CO_2. The introduction of CO_2 generally results in changes in density, electrical conductivity, seismic velocity, and impedance. Pressure variations result in additional changes in some circumstances. The expected magnitude of the rock property changes can be estimated by a combination of laboratory measurements and modelling.

The ability of the various remote sensing methods to detect or image CO_2 in the subsurface will depend on depth and the amount of CO_2 injected. The minimum size of a detectable CO_2 zone that can be detected increases with depth for gravity and electromagnetic measurements, whereas for seismic methods, resolution is less sensitive to depth. Sensitivity of all of these methods is dependent on noise levels and repeatability. Also, because of the large increase in compressibility and decrease in the density of CO_2 that typically occurs at depths less than about 700 m to 800 m, the sensitivity of gravity and seismic methods increases dramatically at shallow depths.

10.4.2.3.1 Seismic

Time-lapse seismic methods are a well-established means of monitoring the sub-surface at depths suited for CO_2 storage. They are well tested having been utilized for hydrocarbon reservoir monitoring for two decades. Seismic monitoring can be applied to track the subsurface distribution of CO_2, including mapping the location of CO_2 within the primary injection zone (the reservoir), and/or monitoring for CO_2 that is “out-of-zone”. Advantages include applicability in a wide variety of geological settings, large areal coverage, monitoring of the reservoir and the overburden, and a well-established service industry. Limitations include minimum detectability levels influenced by the mass and distribution of injected CO_2 (typically considered to be in the range of kt), relatively expensive compared to other surface geophysical methods, requires surface access, and cultural/natural noise sources can degrade effectiveness. Furthermore, there are geological settings where seismic methods are not well-suited due to problems with signal penetration.

In designing a seismic monitoring program, the following aspects need to be considered. Both lateral and vertical resolution of CO_2 hosting layers is dependent on the dominant wavelength of the seismic source. Resolution at greater than 1 000 m depth is typically limited to layers that are about 10 m thick although CO_2 within thinner layers can be detected. CO_2 plumes must achieve a radius of greater than 50 m to be detectable. Repeatability ultimately determines the ability to detect CO_2. Standard seismic acquisition results in repeatability values of greater than 20 % whereas repeatability values of less than 10 % have been achieved using permanent monitoring installations.

10.4.2.3.2 Electromagnetic

Surface-based, time-lapse electromagnetic methods are in the development stage for the purpose of deep CO_2 monitoring. They are based on the premise that the electrical conductivity of a rock formation will decrease when saline pore waters are replaced by more resistive CO_2. Controlled-source electromagnetic (CSEM) methods generally have much lower spatial resolution than seismic methods (e.g. Gasperikova and Hoversten, 2006). The minimum diameter of a CO_2 plume that will produce a detectable phase difference in the scattered electromagnetic field is comparable to the depth of the plume below surface (e.g. McLeod, 2016). Therefore, electromagnetic methods are better suited for monitoring of large (Mt) CO_2 quantities, or detecting CO_2 that has migrated into shallower geological formations.

Higher sensitivity has been achieved in the case of surface-based measurements when well casings are used as electrodes to transmit electrical current at the reservoir level (e.g. Ramirez, 2010; Hibbs, 2015). CO_2-resultant signals from a 3 000 m deep reservoir have been obtained at distances of up to 500 m from the well suggesting that such methods are potentially suitable for plume monitoring in the vicinity of the injection well (Hibbs, 2015).

10.4.2.3.3 Gravity

Surface-based, time-lapse gravity measurements have been used for monitoring changes in subsurface fluid composition and distribution (e.g. Liard et al., 2011; Brady et al., 2006; Alnes et al., 2008). The method is based on composite density variations due to changes in pore fluid (or gas) saturation. The density of CO_2 decreases sharply moving upward across the depth of about 700 m where CO_2 changes phase from a supercritical fluid to a gas. The resultant increase in density contrast with other pore fluids such as brine or oil greatly increases the sensitivity of gravity measurements to the presence of CO_2 above this depth.

Gravity changes due to injection of more than 1 Mt of CO_2 at greater than 1 000 m depth generally less than 10 microgals (1 microgal is equal to 10^{-8} m/s^2) which is small as compared to the precision levels for most common gravimeters (2 microgals to 5 microgals), or the seasonal gravity variations of ±10 microgals. For CO_2 at depths shallower than about 700 m, the related gravity changes exceed the measurement uncertainties by an order of magnitude. This suggests that time-lapse gravity measurements are most applicable for monitoring large quantity deep injection or for leakage monitoring at shallower depths.

10.5 Case studies

10.5.1 CCS pilot projects (<100 kt)

10.5.1.1 Ketzin

The Ketzin CCS Project (A.10) injected 67 kt of CO_2 into a thin (15m to 20 m) saline sandstone formation. The shallow depth of injection (630 m) makes this an atypical storage site in that the CO_2 is in a gaseous state (rather than a super-critical fluid) at initial reservoir pressure and temperature conditions. As consequence of the injection process, temperatures up to 36 °C and pressures between 74 bar and 78 bar at the injection point have been reached. As a pilot site, diverse monitoring methods were tested (Bergmann et al., 2016 and references therein). 4D surface seismic and surface-to-borehole electrical resistance tomography provided the most comprehensive monitoring over a 1 km x1 km area. Time-lapse images from both methods outlined the location of the subsurface plume and showed the northwest direction of CO_2 migration was deviating from what had been predicted prior to the start of injection. The 4D seismic data, calibrated by lab petrophysics and log-based saturations, were used to estimate the mass of CO_2 in the subsurface, and accounted for 93 % to 95 % of the injected CO_2. This formed the basis for estimating how much CO_2 may have dissolved in the brine. Time-lapse velocity decreases of 15 % to 17 % were observed in the 4D seismic where corresponding log-measured CO_2 saturation levels were about 50 %.

10.5.1.2 Nagaoka

The Nagaoka Project (A.13) injected 10,4 kt of CO_2 into a 12 m interval of a 60 m thick sandstone formation at 1 100 m depth. Down-hole pressure and temperature were continuously measured in the observation wells to avoid conditions that could cause caprock fracturing during the injection phase. After the cessation of the CO_2 injection, the down-hole pressure decreased to the initial level within a year. This rapid decrease in pressure after cessation of injection indicates that if seal formation fracture conditions were reached within the reservoir, stopping injection would likely ameliorate the fracture risk.

The main highlight of the monitoring at Nagaoka is the long-term (over 15 years) logging campaign carried out in this field. Time-lapse well logging programs involved pulsed neutron, sonic, and induction logging. The results of the pulsed-neutron logging demonstrated the changes in the state of water saturation in the pore space, which enabled interpretation of changes of CO_2 saturation over time. Sonic logging revealed the presence of injected CO_2 at the observation wells. The results of the induction logging, which measures the resistivity of the rock and fluids near the wellbore, showed the process of formation water displacement by CO_2 and through CO_2 dissolution. Resistivity increases indicated a correlative increase in CO_2 saturation whereas resistivity decrease indicated an increase of dissolved

CO_2. Time-lapse resistivity results indicated that gravity effects caused phase changes within a two-year period after the cessation of injection. Subsequently, minimal changes were observed.

Time-lapse cross-well seismic tomography provided images of CO_2 saturation in the inter-well region after 32 kt of injection. Deep fluid sampling provided direct evidence of CO_2 saturation changes that explain observed changes in the tomographic and well log data. Integration of monitoring data acquired by different generations of tools poses a challenge to obtaining consistent measurements over the lifetime of a project. For example, time-lapse logging data were acquired at Nagaoka using different tools over a period of 16 years.

10.5.1.3 Otway

The initial phase of the CO_2CRC Otway project injected 65 kt of CO_2 into the down-dip flank of a fault-bounded, 31 m thick, depleted gas reservoir at a depth of 2 100 m. As with other pilot projects, a comprehensive suite of monitoring methods was applied or tested at the site including atmospheric, groundwater, soil gas, and microseismic measurements, as well as reservoir fluid sampling and 4D seismics (Sharma et al., 2011). Unique to this project initially was an atmospheric monitoring strategy to detect and quantify potential leakage of injected CO_2 (Etheridge et al., 2011). Measurements of CO_2 fluxes were taken at the surface with an eddy-correlation flux tower. A seasonal cycle was apparent in CO_2 fluxes with the lowest variability occurring during the dry conditions of late summer and autumn. This period of relatively low background variability improved the potential of detecting CO_2. The absence of CO_2 leakage indicated by this method during phase I of the project led to a change in approach whereby the sensitivity of this method was tested for detecting emissions from surface activities at the Otway facility.

10.5.1.4 Rousse-Lacq pilot

The Rousse-Lacq project injected 51 kt of CO_2 into a dolomite/dolomite breccia reservoir at 4 500 m deep. The monitoring plan included reservoir pressure, microseismic monitoring, and environmental monitoring (groundwater, surface water, fauna, flora, soil gases and atmosphere). Ecosystem monitoring has been implemented in which faunal and floral inventories have been collected for native plants, insects, amphibians, and reptiles among others environmental parameters. Counts took place twice a year in late June and early September over a five-year period, from 2009 to 2013. Any relationship between the injection of CO_2 and the changes observed in the plant, insect and amphibian populations was established (TOTAL, 2015). Fluctuations were observed from year-to-year, but were ascribed in most cases to natural changes, obvious human disturbance, or weather conditions.

10.5.2 Industrial-scale CCS projects

10.5.2.1 Onshore

10.5.2.1.1 In Salah

The In Salah CCS project injected a total of 3,8 Mt of CO_2 into a 20 m interval at 1 700 m depth on the flank of a gently domed sandstone formation. Of the wide range of monitoring techniques utilized at In Salah (e.g. see Mathieson et al., 2010), InSAR monitoring proved critical as it imaged surface deformation during injection and identified otherwise undetected reservoir non-conformance (e.g. Rutqvist et al., 2010). Subsequent analysis of a 2009 repeat seismic survey (against an existing 1997 3D survey) identified pressure-related amplitude changes. The non-conformance of the project indicated by the monitoring program led to the decision to suspend injection in 2011 (Ringrose et al., 2013).

10.5.2.1.2 Decatur

The Illinois Basin – Decatur Project (IBDP) completed the injection of 1 Mt of CO_2 at a depth of 2 100 m within the largest-capacity deep saline sandstone formation in the Illinois Basin. The project employed a number of dedicated monitoring installations including two deep monitoring wells, 17 shallow groundwater monitoring wells, microseismic monitoring with Four-component downhole sensors in the injection well, and an in-well geophysical monitoring array for repeat plume monitoring using VSP methods (Bauer et al., 2017 and references therein). The surface infrastructure at the project site proved to be a serious challenge to 3D time-lapse seismic imaging.

An extensive monitoring program comprised 3D surface seismic (two surveys), 3D VSP (6 surveys), soil flux monitoring, atmospheric monitoring, shallow groundwater monitoring, and a deep verification well for pressure/temperature and fluid sampling. Monitoring data were collected for 18 months prior to injection, for 36 months of injection, and during 36 months post-injection period. Passive seismic monitoring has been a critical component of the monitoring program. Small magnitude microseisms started two months after the start of injection, with a total 4 747 locatable events being detected over the three years of injection (Bauer et al., 2017). 97 % of events had magnitudes of less than 0 and only two events had magnitudes above 1 (1,08 and 1,14). The hypocentres of these events were located at the base of the sedimentary column, but also extended into the underlying Precambrian basement. Passive monitoring provided a means of making operational decisions that could be required if the magnitude of induced seismicity were to become significant.

Following the termination of CO_2 injection, a more targeted monitoring program was implemented to address specific regulatory requirements (Locke et al., 2017). For example, groundwater sampling was expanded to 30 parameters from 11, and sampling from three deeper locations was added. The frequency of shallow ground water sampling was reduced from monthly to quarterly, and weekly soil flux monitoring was reduced to monthly and then terminated the year after injection. The frequency of monitoring for other methods was also reduced (e.g. well logging, seismic surveys, microseismic monitoring).

10.5.2.1.3 Quest

The Shell Quest CCS Project has stored 4 Mt of CO_2 (as of 2019) in the Basal Cambrian Formation which unconformably overlies Precambrian granitic basement at greater than 2 000 m depth. (IEAGHG, 2019). The MMV plan for Quest was developed based on a storage risk-management framework. As described in Shell Canada Ltd (2017) and IEAGHG (2019), 37 different monitoring methods were adopted in the initial MMV plan. Key components in the initial period of operation included:

— groundwater sampling;

— time-lapse VSP which showed that the plume extended 200 m across and was smaller than modelling estimates;

— microseismic monitoring which identified only 3 locatable events (magnitude 0,7);

— time-lapse pulsed neutron logs demonstrating containment in the reservoir;

— and successful demonstration of laser-ranging technology for atmospheric monitoring for leaking CO_2.

Early demonstration of low leakage risk led to a reduction in the scope of the MMV plan. The primary emphasis of the revised MMV plan was downhole monitoring techniques as wellbores were identified as the highest risk to CO_2 leakage, which was supplemented by periodic well integrity tests and seismic data acquisition.

10.5.2.1.4 Aquistore

The Aquistore CO_2 storage site has injected about 300 kt of CO_2 as of June 2020. The storage reservoir is a brine-saturated clastic sequence that extends from 3 130 m to 3 350 m depth and lies immediately above the Precambrian crystalline basement. Whereas a variety of monitoring methods have been employed at the site, those required by regulation include water well sampling, soil gas monitoring and microseismic monitoring. An extensive list of geophysical methods has been demonstrated at the site including various seismic techniques (4D surface, 4D VSP, passive), electromagnetic methods (passive and controlled source), gravity, surface-deformation measurements (InSAR, GPS, tilt). Additionally, a number of emerging methodologies have been tested comprising BSEM, DAS, seismic interferometry, and downhole gravimetry. The injection well and an observation well are equipped with permanently installed pressure and temperature gauges as well as DTS/DAS fiber cables.

Time-lapse seismic monitoring has tracked the evolution of the CO_2 plume at the reservoir level with pulsed neutron logs from an observation well providing ground truth for the seismic images. Seismic surveys conducted at cumulative injection amounts of 36 kt, 102 kt, 141 kt and 272 kt show a main plume with an early maximum extent of less than 200 m expanding to almost 500 m extent by the time of the fourth monitor survey. The seismic images show that the CO_2 is migrating in the up-dip direction and is partly controlled by the predominant structural and porosity/permeability fabric in the reservoir (Roach and White, 2018). Passive seismic monitoring has documented an absence of injection-related microseismicity, and the well and soil gas monitoring has shown no evidence for deep CO_2 reaching the near-surface.

10.5.2.2 Offshore

10.5.2.2.1 Sleipner

Statoil's (now Equinor) Sleipner project began injecting more than 1 Mt per year of CO_2 under the North Sea in 1996 and reached a total of 16 Mt injected by 2017. The CO_2 is injected using a single well into the Utsira saline formation at a depth of 1 000 m below the sea floor. The Utsira saline formation constitutes a 200 m to 300 m thick unconsolidated sand interval with a very high net-to-gross ratio of 95 % interbedded with thin (less than 1 m) shale stringers. Monitoring methods employed at the site include wellhead pressure and temperature, 4D seismic and time-lapse sea-bottom gravimetry.

The following description is summarized from Eiken et al. (2011). The 4D seismic surveys have documented both containment of the CO_2 within the reservoir, as well as the vertical distribution and lateral spread of the CO_2 plume. The seismic detection threshold is estimated to be of order one kt of CO_2. Seafloor gravity surveys were conducted in 2002, 2005 and 2009. The replacement of water with less dense CO_2 (675 kg/m^3 to 715 kg/m^3) reduces the local gravity. These density values, combined with temperature measurements, were used to estimate both the CO_2 density distribution within the plume. Further, since dissolution of CO_2 into the formation water causes an increase in density, the same gravimetric and temperature measurements allowed for an estimate of the amount of CO_2 dissolved in the formation water. Data and model precision gives a detectability level of 1,8 % absorption per year. A trial CSEM survey was carried out in 2008, but no interpretable signal from the CO_2 plume has been detected. This lack of a measurable or discernable signal is likely due to pipeline noise and moderate CO_2 response. The seafloor has been mapped with multibeam echo sounding and side-scan sonar. Videos have been taken by ROV, as a routine precaution, and no seafloor changes (pockmarks, bubbles) have been observed.

10.5.2.2.2 Snøhvit

The Snøhvit gas field is located within a fault-bound block in the Barents Sea. Equinor produces approximately 700 kt of CO_2 per year at an on-shore LNG plant during processing of natural gas from the Snøhvit field. Starting in 2008, the separated CO_2 was initially injected to a sandstone formation (the Tubåen Formation) at a sub-sea floor depth of 2 600 m, in a zone beneath the original natural gas reservoir (Stø Formation). Initial injection occurred in a 30 m interval within a near-vertical well (Eiken et al., 2011). However, persistent pressurization to near minimum fracture pressure at the reservoir resulted in moving the injection to the gas-producing interval (Hannis et al., 2017).

A temperature and pressure gauges were installed in the injection well at 1 805 m depth (800 m above the reservoir). 4D seismic data acquired in 2009 identified amplitude differences associated with changes in CO_2 saturation and reservoir pressure increases (Eiken et al., 2011). 4D seismic interpretation suggests that the majority of the CO_2 was entrained within the lowermost reservoir zone and identified pressurized zones. These monitoring observations contributed to the decision to change injection to the Stø Formation.

10.5.2.2.3 Tomakomai

The Tomakomai Project injected a total of 300 kt of CO_2 into two sandstone reservoirs beneath the seabed using highly deviated wells drilled from onshore. The injection intervals in both wells exceed 1 100 m. Monitoring, with a focus on microseismic monitoring and environmental surveying, is conducted both on- and offshore.

The monitoring program consists of components required by Japanese law, augmented by research-based measurements. The monitoring program includes:

— pressure and temperature monitoring at the bottom of the injection well;

— measurement of dissolved gases (O_2, CO_2) and pH in seawater;

— time-lapse seismic surveys.

The two injection wells were drilled into a sandstone layer at 1 000 m to 1 200 m depth and a volcanic/volcaniclastic formation at about 2 400 m to 3 000 m depth, respectively. The Tomakomai project also has three observation wells to observe pressure, temperature, induced seismicity and natural seismicity.

Environmental monitoring surveys are conducted four times per year. They comprise:

— water chemistry analysis;

— plankton composition;

— chemical and biological analysis of seafloor sediments;

— benthos observation;

— seabed surveying for CO_2 bubbles;

— current monitoring.

Terrestrial CO_2 leakage detection methods (Romanak et al., 2012) were adapted to the marine environment (i.e. change in partial pressure of CO_2 (p CO_2) as a function of dissolved oxygen saturation), to monitor CO_2 storage in the Tomakomai project. A threshold was calculated based on data measured at 12 sampling stations over one year. Shortly after the project began, seawater data collected during routine monitoring indicated that the threshold had been exceeded. Confirmation surveys showed that one year of baseline monitoring was not sufficient to determine a threshold. As a result, the operator revised the threshold adding data from early 2017 to early 2018.

2D and 3D seismic surveys were recorded using ocean bottom cables. The first monitor 2D seismic survey, conducted in January to February 2017 after injection of 7,2 kt of CO_2 into the Moebetsu formation, did not detect any CO_2. 2D/3D seismic surveys conducted in July to August 2017, September to October 2018 and January to February 2020, after injection of 61 kt to 69 kt, 207 kt, and 300 kt of CO_2, respectively, observed clear amplitude anomalies that delineate evolution of the CO_2 plume.

Microseismic monitoring is conducted using a network composed of a 3 600 m, 72 geophone ocean bottom cable array, four ocean bottom seismometers, seismic arrays in the observation wells, and an onshore seismic station. The microseismic monitoring area is 6 km by 6 km and covers the injection area. In addition, data from 4 national seismic network stations located around Tomakomai provide monitoring of natural earthquakes over a 50 km by 38 km area to confirm that the injection does not affect natural earthquake activity.

10.5.3 CO_2-EOR projects with monitoring

10.5.3.1 Weyburn-Midale

The Weyburn and Midale CO_2-EOR projects inject CO_2 into a limestone/dolomite sequence that is up to 30 m thick at a depth of 1 450 m. A total of more than 30 Mt of CO_2 has been stored in these fields since the start of injection in 2000. The monitoring program implemented in the Weyburn-Midale project was designed as part of a research project (see Wilson and Monea, 2004; Hitchon, 2012 and references therein) and thus included the demonstration and testing of a variety of different methods that focused on a sub-region (23 of 75 patterns) of the field. Monitoring methods that proved particularly useful were production fluid sampling, soil gas monitoring, passive seismic monitoring and 4D seismic.

Chemical sampling of production fluids identified chemical processes in the evolution of the reservoir chemistry including dissolution of CO_2 into brine, carbonate mineral dissolution and an increase in total dissolved solids in the brine. There is good spatial correlation of these observed processes with zones of highest CO_2 injection amounts and with 4D seismic amplitude changes. Soil gas sampling at the site found gas concentrations and fluxes (for CO_2, O_2, and CO_2 flux) in the range of natural soils and comparable to an off-site reference location. Analysis of carbon isotope compositions in soil gas at the Weyburn site was instrumental in refuting an accusation that deep CO_2 was leaking from the reservoir and migrating to the surface.

Downhole passive seismic monitoring was conducted over a 7-year period during which a total of 200 microseisms were located, documenting a low rate of low intensity microseismicity. The majority of events have magnitudes between -3,0 to -1,0 with a maximum detection distance of 750 m, thus documenting the absence of any significant injection-related seismic that might cause concern

10.5.3.2 Belle Creek

The Bell Creek Field Project is a CO_2-EOR operation located in southeastern Montana. The reservoir horizon is a 20 m-thick oil-bearing sandstone unit at a depth of about 1 370 m. Injection of approximately 1 Mt of CO_2 per year began in 2013.

A variety of monitoring techniques have been utilized at the site to measure the natural variability of soil gas and water chemistry in the near-surface environment, and to track CO_2 migration within the storage complex. Subsurface monitoring focuses on the distribution of fluids (hydrocarbons, brine and CO_2) in the storage complex. Injected and produced fluid rates, pressures, and compositions are monitored to measure performance and calibrate the geologic models.

4-D seismic analysis after 1 Mt of injection tracked the spread of CO_2 and illuminated heterogeneity within the reservoir, delineating pathways of preferential fluid flow (Burnison et al., 2017). This information has been used to improve history matching of dynamic models and increased accuracy of resulting predictive simulations.

11 Decommissioning

11.1 General

Clause 11 surveys the requirements and regulatory frameworks for decommissioning CCS operations and CO_2-EOR operations with associated storage.

11.2 Activities

Decommissioning activities are largely performed during the closure period which starts at the end of injection and continues through to compliance with requirements for site closure. Decommissioning entails the progressive reduction of project activities including dismantling of infrastructure, continued but reduced monitoring and eventual cessation of all project-related activities. Specific activities typically required during the post-injection period include risk management, testing, and maintenance of monitoring wells, and eventual plugging and abandonment of injection and monitoring wells. The closure process is often structured to accept input from project stakeholders. This would include regular engagement between the project operator and regulatory authorities. Reports and data that form the basis for closure or termination usually must be retained for a specified period after decommissioning and then delivered or made available to the appropriate regulator.

Reports and data from the project including operational history and monitoring results are gathered during the operational phase of the project. A risk management plan is usually maintained to demonstrate that individual risks have been managed throughout the project lifetime. Monitoring and testing are conducted to provide information regarding containment assurance and to demonstrate conformance among observations and predictive models. These activities will support the eventual closure of the project and storage site. Typically, the operator is required to demonstrate compliance with closure or termination requirements through technical descriptions of project parameters (geological, geomechanical, geochemical) and simulation models matched to observed site behaviour in order to decommission the site.

Review of general regulatory requirements and project-specific permit conditions reveals four common principal criteria to be satisfied before project closure or termination are approved (Van Voorhees, 2018). The first relates directly back to the critical initial steps in project development and qualification – site selection and characterization. The key to successful closure and termination is the careful identification and thorough characterization of storage complex or EOR complex that will provide secure geological storage as demonstrated through computational modelling of project operations and reservoir or flood management. The second involves the collection of operational data, monitoring and testing results, and other information to be used in history matching to show conformance of project behaviour with operational predictions, including necessary modifications based on improved understanding of project parameters and operating results. The third is the pressure decline and plume stabilization following cessation of CO_2 injection, which are monitored and modelled to demonstrate understanding of future behaviour of the stored CO_2. The fourth is a demonstration of continued containment assurance, which draws on operational history, past containment assurance, verified site characterization, understanding of potential leakage pathways, history matching to show conformance with predictions, and projections regarding potential for future leakage of CO_2 from the storage complex or EOR complex.

11.3 Closure or termination plan

A common requirement in most jurisdictions involving geological storage or CO_2-EOR with associated storage is to develop and regularly update a closure or termination plan during project operations. Such plans address site-specific requirements and processes identified by Competent authorities, including a discussion of ongoing site monitoring with a description of the monitoring technologies and a schedule of the monitoring activities. Corrective actions for events that are most likely are also described.

11.4 Identification of jurisdictions and relevant framework

Most jurisdictions having CO_2 injection into hydrocarbon or other types of reservoirs will have regulatory requirements for the closure or termination of the projects, and some also provide for eventual transfer of CO_2 ownership, responsibility for the facilities and post-injection liability. Criteria for decommissioning varies among jurisdictions, but generally include requirements to demonstrate absence of detectable leakage and potential impacts to human health, the environment, or economic resources. Site operators will need to demonstrate that the storage reservoir, including reservoir pressure and displacement of reservoir fluids, is well understood and that the CO_2 plume dispersion and migration are predictable. This can potentially be demonstrated through an evaluation of production history, using monitoring data, or computer simulations. Additionally, the operator often needs to evaluate and document the integrity of wells, before they are abandoned according to governing regulations. Surface facilities and infrastructure are often required to be removed at closure.

Legal frameworks around the world for decommissioning CCS operations and CO_2-EOR projects with storage vary and are at different stages of maturity. Whereas the US legal framework has different requirements and procedures for Class II and Class VI wells, which include different approaches to post-injection site care, the European framework imposes similar decommissioning criteria for both

CO_2-EOR with associated storage and geological storage without CO_2-EOR. Meanwhile, Japan is still developing its framework for decommissioning, having Tomakomai as a first project navigating the regulatory framework.

11.5 United States

11.5.1 EPA regulations for closure and post-injection site care

The US requirements governing closure, plugging and abandonment of CO_2-EOR wells are regulated by US EPA UIC Program Class II. The requirements governing closure and post-injection site care (PISC) for geological storage are regulated by US EPA UIC Class VI.

11.5.2 Class II well plugging regulations

In addition to the requirements that apply to the ending of hydrocarbon production operations, Class II regulations require that wells be constructed, operated, and plugged with cement when closed to prevent movement of fluids into or between USDWs. The regulator is directed to prescribe aquifer cleanup and monitoring where necessary and feasible to protect USDWs. Operators are required to provide financial assurance for plugging and abandonment and to file a final report certifying that proper procedures were followed. As part of the decommissioning requirements, the framework further mandates the owner or operator to dispose of any soil, gravel, sludge, liquids, or other materials removed from the well or adjacent area.

The Class II regulations address only the injection wells whereas regulations for hydrocarbon production operations, as well as lease and other contractual obligations will govern other aspects of the decommissioning of CO_2-EOR projects.

11.5.3 Class VI well plugging regulations

Under Class VI regulations, a well plugging plan must be prepared and submitted as part of the initial permit application that describes tests, measures, materials and procedures used in the plugging process. This plan must be updated periodically as appropriate during operations and again before execution.

11.5.4 Class VI PISC

A PISC plan must be prepared and updated throughout the project operations and implemented for site closure. PISC plans address a) the pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s); b) the predicted position of the carbon dioxide plume and associated pressure front at site closure; c) a description of post-injection monitoring location(s), methods, and proposed frequency; d) a proposed schedule for submitting PISC monitoring results; and e) duration of the PISC timeframe. Modifications to the PISC plan can be made during project operations and submitted for regulatory approval. When injection ceases, the owner or operator must either amend its plan or demonstrate that no amendment is needed.

11.5.4.1 PISC Monitoring

Class VI regulations require post-injection monitoring of the site to show the position of the carbon dioxide plume and pressure front and to demonstrate that USDWs are not endangered. Although regulations specify that post-injection monitoring must continue for at least 50 years after injections cease, the regulator can approve a shorter, alternative monitoring period. Closure is authorized once a demonstration is made, based on monitoring and other site-specific data, that the project does not pose an endangerment to USDWs and no additional monitoring is needed. The PISC must continue until that demonstration can be made even if the authorized PISC period has expired.

The EPA provides guidance documents for well plugging, post-injection site care and site closure. The guidance documents provide considerable detail into how the agency intends to apply the Class VI rule's provisions on post-injection site care and site closure, including hypothetical examples of PISC monitoring plans and revisions. In addition, there is a detailed review how an applicant might proceed to establish and support an alternative post-injection site care period that is shorter than the 50-year default period.

Once the regulator has authorized site closure, all monitoring wells must be plugged in a manner which will not allow movement of injection or formation fluids that endangers an USDW.

11.5.4.2 Retention of records

A site closure report must be submitted within 90 days of site closure and retained by the owner or operator for 10 years post closure. Following the 10-year period, the records must be delivered to the regulator. In addition, a public notation is required to be recorded in the relevant land records that will provide any potential purchaser of the property with notice that the land has been used for CO_2 geological storage.

11.6 The European Union

11.6.1 Closure

The EU CCS Directive contains detailed regulations regarding closure and decommissioning of injection sites from which member states may deviate and specify own requirements.

Under the EU CCS Directive there are three circumstances in which a storage site may be closed

a) when the relevant conditions of the storage permit have been met,

b) through a special grant from the authorities following a substantiated request from the Operator, or

c) if the permit is withdrawn by the designated authorities.

11.6.2 Post closure

After injection has ceased and the storage site is closed, the projects enters the post-closure period for which obligations are described in a post-closure plan. A “provisional post-closure plan”, is a part of the initial storage permit. For the operator to close a storage site according to either (a) or (b) above, the provisional plan has to be updated and submitted for approval, taking into account risk analysis, best practice and technological improvement. The post-closure plan details the obligations related to the monitoring, reporting, and corrective measures.

11.6.3 Transfer of liability

The CCS Directive regulates transfer of liability to Competent authorities under certain circumstances. In order to initiate the transfer, a minimum period of 20 years must have elapsed, the site must demonstrate that the CO_2 is completely and permanently contained. After transfer, the Competent authority takes over the obligations to monitor the storage site as well as the responsibilities for preventive, mitigating, and corrective measures.

Prior to the transfer of liability, the operator is required to provide a “financial contribution”, interpreted as an actual deposit of funds into a bank account. The CCS Directive, however, emphasizes the member states’ freedom to define arrangements and set the appropriate level of the contribution. One manner of determining the level of contribution is that financing should cover at least 30 years of estimated costs of monitoring.

11.7 Germany

Germany has transposed the EU CCS Directive and has implemented stricter requirements for decommissioning. One requirement is that an updated safety certificate must be submitted with the post-closure monitoring plan that demonstrates mandatory operational requirements are met and describes further preventive and mitigation measures. Additionally, the safety certificate must be accompanied by a statement from the Federal Institute for Geosciences and Natural Resources, and the Federal Environment Agency.

German-specific requirements stipulate that the operator must apply for decommissioning and shut down of the operations if the amount of CO_2 specified in the approved operations plan has been stored, unless a specific approval to increase the amount of CO_2 stored is being issued.

Another deviation from the CCS Directive is an extension of the prescribed 20 years minimum period of post-closure responsibilities to 40 years. This is in consideration that long-term safety must be in line with the state-of-the-art in science and technology, allowing the Competent authority to avoid the assumption of an unsafe storage facility. The Competent authority has discretion to grant an earlier transfer than 40 years if the long-term security of the CO_2 storage has been demonstrated.

The German specifications also require a calculated cash contribution that is to be invested with interest, which becomes part of the financial mechanism.

11.8 France

France has transposed the closure and post-closure obligations, and transfer of liability, of the EU CCS Directive into the French Environmental Code, which includes some deviations regarding the transfer of liability.

Prior to transfer of liability to a Competent authority, the French Environmental Code requires the operator to provide to the State free of charge the equipment, studies, register of quantities and properties of CO_2 delivered and injected, and all other data necessary to perform post-closure monitoring.

The French Environmental Code requires that the draft decision approving the transfer of responsibility is made available to the public. This draft decision includes the operator's report demonstrating that the conditions necessary for the transfer are met and a report by the Competent authorities setting out, if necessary, the requirements or conditions of this transfer.

The French Environmental Code imposes 30 years as the minimum monitoring period between final injection and transfer of responsibility to the Competent authority. If evidence at the end of this period is not considered sufficient for the transfer, the authorities are mandated to impose a new minimum monitoring period of maximum 10 years. Alternatively, the 30-year period may be reduced after a minimum monitoring period of 10 years has elapsed that demonstrates the project is safe.

11.9 Norway

Norway has transposed the provisions in the EU CCS Directive on decommissioning. Consent for closure of the storage site requires that it is accordance with the stipulated conditions in the storage permit, which includes a provisional post-closure plan provided as part of the permit application. This provisional plan is updated by the operator and needs approval prior to closure of the storage site. The final closure plan amends the provisional closure plan based on risk analysis, best practices, and technological improvements.

Norway has regulations that deviate from the EU CCS Directive mandated financial mechanism. On a case by case assessment, Norway may accept a parent company guarantee instead of the financial contribution as the preferred financial contribution. This will consider aspects like the operator's overall financial strength when evaluating whether to accept a parent company guarantee instead of the financial contribution.

11.10 Canada

In Alberta, CO_2 storage activities are governed by the Oil and Gas Conservation Act, which requires an approved monitoring, measurement and verification (MMV) plan, compliance to that MMV plan, reporting of the MMV and fulfilment of the work requirements to the location of the agreement. If the

Crown grants rights to an operator to inject and sequester CO_2, the operator must provide the MMV requirements and submit a closure plan for approval and comply with that plan. The Minister may issue a closure certificate if satisfied that the operator

— has complied that all wells in the project are monitored and closure activities outlined in the plan have been completed,

— has abandoned all wells and facilities in accordance with the Oil & Gas Conservation Act and regulations,

— has complied with the reclamation requires under the Environmental Protection and Enhancement Act,

— has met the closure period specified in the regulations,

— has met any conditions specified in the regulations, and

— has provided assurance that the captured CO_2 is behaving in a stable and predictable manner with no significant risk of future leakage.

The Act then states if a closure certificate is issued, the Crown will become the owner of the captured CO_2 and assumes all obligations of the wells and facilities (under the Oil & Gas Conservation Act) and environmental liabilities (under the Environmental Protection and Enhancement Act) and the Surface Rights Act and in doing so releases the lessee (operator) from any obligations regarding the project.

11.11 Japan

The legal framework for closure in Japan is less specific than for the US, Canada, and the EU. The operator is required to prepare a closure plan for injection well as part of the permitting documentation in the case where closure is planned. Although not fully clarified, ongoing monitoring could end once obligations in the well closure plan are met, seawater monitoring reveals acceptable changes compared to baseline, and the analysis of CO_2 behaviour demonstrates a stable state of injected CO_2. The defined period for monitoring after cessation of injection, and further extent of operator's responsibility and liability are still in consideration.

For the Tomakomai project, the period of post injection monitoring and the well closure plan have not yet been determined.

11.12 Discussion of closure at selected projects

There are few projects that have entered the closure stage and case studies of decommissioning activities are limited. This section intends to highlight a selection of these with focus on particular elements of the decommissioning process.

11.12.1 Illinois Basin Decatur Project

Archer Daniels Midland Company (ADM) and the Midwest Geologic Sequestration Consortium (MGSC) with the Illinois State Geological Survey (ISGS) applied for and received two Class VI permits. The permits approved a Well Plugging Plan and the Post-Injection Site Care and Site Closure plan. The PISC plan describes the activities ADM will perform to meet the regulatory requirements for closure. In this case, EPA approved an alternative post-injection period of ten years (rather than the 50-year default period). The permit holder will monitor groundwater quality and track the position of the carbon dioxide plume and pressure front for ten years following the end of CO_2 injections. Monitoring will nonetheless continue after that date unless and until the regulator approves a demonstration of non-endangerment of USDWs.

All post-injection site care monitoring data and monitoring results are submitted to the U.S. EPA in annual reports that contain information and data generated during the reporting period; e.g. seismic data acquisition, well-based monitoring data, sample analyses, and the results from updated site models.

11.12.1.1 Alternative post-injection site care timeframe

ADM demonstrated that an alternative PISC timeframe of 10 years is appropriate, based on the computational modelling to delineate the Area of Review (AOR); predictions of plume migration, pressure decline, and carbon dioxide trapping; site-specific geology; well construction; and the distance between the injection zone and the nearest USDWs. During this period, groundwater quality monitoring and CO_2 plume and pressure front tracking are continued and reported until ADM demonstrates, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the project does not pose an endangerment to any USDWs. If any of the information on which the demonstration was based changes or the actual behaviour of the site varies significantly from modelled predictions, e.g. as a result of an AOR reevaluation, ADM will be able to update this PISC and Site Closure Plan.

11.12.1.1 Non-endangerment demonstration criteria

Prior to authorization of site closure, ADM will submit a report for the demonstration of non-endangerment of USDWs to the Director of the U.S. Environmental Protection Agency. The demonstration is based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include (or appropriately reference): all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the Director to review the analysis.

The report will include the following components:

— Summary of existing monitoring data.

— Comparison of monitoring data and model predictions and model documentation.

— Evaluation of carbon dioxide plume.

— Evaluation of Mobilized Fluids.

— Evaluation of Reservoir Pressure.

— Evaluation of Potential Conduits for Fluid Movement.

— Evaluation of Passive Seismic Data.

— Site Closure Plan.

— Site Closure Report.

11.12.1.2 Site closure report

A site closure report is prepared and submitted within 90 days following site closure, documenting the following:

— Plugging of the verification and geophysical wells.

— Location of sealed injection well(s).

— Notifications to state and local authorities.

— Records regarding the nature, composition, and volume of injected CO_2.

— Post-injection monitoring records.

The site closure report is submitted to the permitting agency and maintained by the operator for a period of 10 years following site closure.

11.12.2 Ketzin

At the Ketzin demonstration site in Germany, a total of 67 kt of CO_2 was injected between June 2008 and August 2013, after which injection ceased and the site entered the post-closure phase. The criteria for cessation of injection were that conditions stated in the permit had been met. The decommissioning procedures took place during different stages.

Permit criteria for closure:

— The quantity of CO_2 specified in the planning approval decision has been stored.

— The decommissioning and aftercare concept meets the legal requirements.

— It is ensured that after decommissioning and during aftercare.

— The long-term safety of the CO_2 storage system is guaranteed.

— Absence of hazards to humans and the environment can be guaranteed because the necessary precautions are taken against adverse effects on people and the environment.

11.12.2.1 Site dismantling downhole

The CO_2 injection facility was dismantled in December 2013. Reusable components, such as the two CO_2 tanks, the plunger pumps, the heat exchanger, and electrical heater system were recycled by the manufacturer for further applications.

For the five wells, a two-staged abandonment strategy, guided by a mandatory national regulation, was negotiated, and agreed with the mining authority of the federal state of Brandenburg (LBGR). In October 2013, this strategy was first implemented for well CO_2 Ktzi 202/2007 (one of the monitoring wells), aiming for feasibility testing of the procedure.

Because the wellbore was pressurized with gaseous CO_2 and had a formation water level below the filter sections, it had to be ‘killed’ by pumping high-density brine (1,20 kg/l) into the wellhead to achieve a zero-wellhead pressure situation.

Then, the sections of the well penetrating the reservoir and lowest caprock were plugged with CO_2 resistant cement. After the hardening of the cement head, a standard mechanical integrity test was conducted. As part of the extensive research program at this site, a gas-membrane-and-pressure-sensor system monitored the first cement plug of this well for its gas tightness over two years. No gas increase or pressure changes were detected. Afterwards, in June 2015, the uppermost 3 m of this first cement plug were cored, their petrophysical properties were studied and the integrity of the CO_2 resistant cement plug was confirmed.

Figure 7 — Cutting out samples of the casing for corrosion inspection (top) - zoomed view of a sample (bottom) (Photos: GFZ)

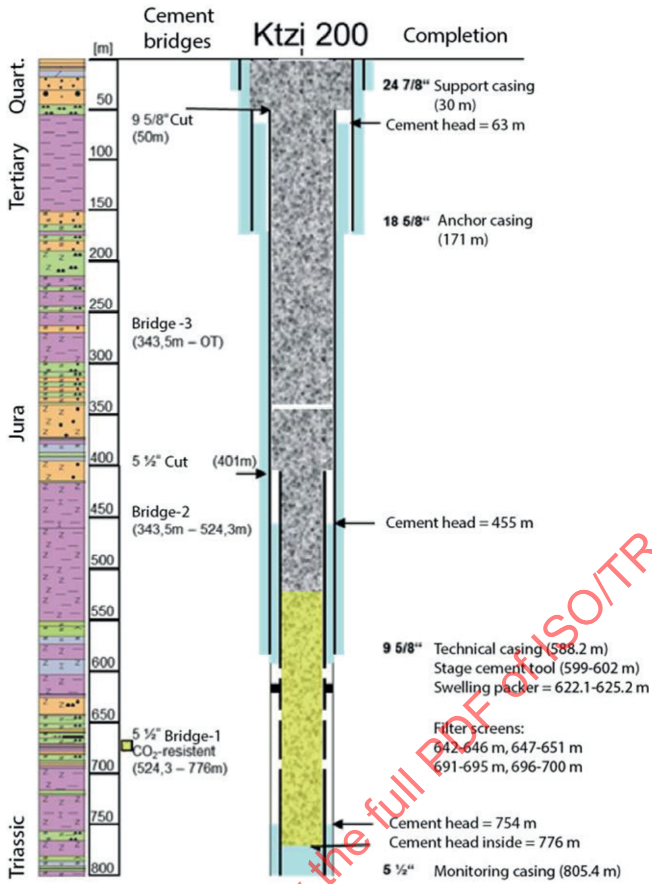


Figure 8 — Two-cement abandonment strategy applied to the Ketzin wells, here displayed for the well CO_2 Ktzi 200/2007

For the second cement bridge, the location of the cement head within the annular space between the 140mm (5 1/2 inch) monitoring and 244mm (9 5/8 inch) technical casing was identified by cement-bond logging (CBL) to define the cutting depth of the 140mm (5 1/2 inch) casing. The casing was cut by a wireline jet cutter, pulled out and back-filled with a standard (API) class G cement bridge plug. This procedure was repeated for the next casing sequence (either second technical or anchor casing) to create a third cement plug. From the retrieved casing, material samples for corrosion evaluation were taken (see Figure 7).

This two-staged abandonment approach was applied in a direct sequence (this time without delay for extended scientific observation) to the remaining three deep wells Ktzi 200 (see Figure 8), Ktzi 201 and Ktzi 203. The final abandonment of these wells was carried out in 2017 and took an average of 20 working days per each well. The 89mm (3 1/2 inch) injection string from the injection well Ktzi 201 was dismantled and the fibre-optic pressure gauge at the end of the string was retrieved for later re-use.

Another research investigation was conducted at the Ktzi 203 well. Its completion with glass fibre reinforced pipes made the well suitable for side-track drilling. Two side-tracks were drilled and cored prior to cementing, covering the lower part of the cap rock and the entire reservoir section. These core samples had been in contact with the stored CO_2 for more than nine years; therefore, they provide a unique sample set to study CO_2-triggered changes in petrophysical and mineralogical reservoir properties.

11.12.2.2 Site dismantling at surface

In the borehole cellars, the remaining outer casings were cut-off at the level of the basement floor. The innermost casing was cut-off about 10 cm to 15 cm above the basement floor and welded to a 10 mm thick sheet steel lid. As an additional protective measure, a cover made of concrete with a thickness of about 0,5 m was inserted.

The concrete foundations of the former injection facility, CO_2 tanks, and containers were broken and cut for disposal. A seismometer array dug into the ground along the outside fence was left behind. Only the cable feeders were disconnected, dismantled, and disposed of.

Lessons learned (Schmidt-Hattenberger et al., 2018 and references therein):

— For gas-filled wellbores, the combined well integrity monitoring program has been proven to be a suitable substitute for CBL logs as demonstrated during the injection and post-injection phase.

— A two-year phase of monitoring the CO_2 resistant cement zone at the bottom of well Ktzi 202 has verified the stable and gas-tight behaviour of the cement.

— The injection tubing could be completely dismantled: the pipes were in good condition, especially their coated interior which was completely undamaged.

— The packer from the injection well was retrieved, the downhole pressure-temperature sensor was recovered, cleaned, and stored for possible further use.

11.12.3 Sleipner

The Norwegian Environmental Directorate stipulates a financial guarantee must be made by the operator (or license group) to cover monitoring obligations, remedial action, closure, post-closure activities, and any obligations derived for the Climate Law. In the permit to store CO_2 at the Sleipner Field, the Directorate emphasized that cost estimates for the Sleipner Field, not planned for closure for 20 years to 25 years, would be of little relevance that far into the future. The current permit assessed that the parent company guarantee fulfils this legal obligation. In the application, Statoil (now Equinor) carried out informal cost estimates for the post closure obligations.

Eventual cost associated with obligations according to the Climate Law has not been assessed, but the parent company makes reference to the most likely scenario having potential leakage rates in the vicinity of 0,1 t/year to 100 t/year. This would not constitute a major cost element even if future emission permits would become more expensive.

11.12.4 Snøhvit

CO_2 injection at the Snøhvit gas field is conducted under Norwegian Petroleum Law, and CO_2 storage and monitoring were first included in a 2014 regulation and subsequently a formal permit was put in place. The regulatory requirements are identical to those of the Sleipner gas field. A plan for the post-injection period has not been submitted yet as this is only required 2 years to 5 years before termination according to the Norwegian petroleum regulations.

Annex A
(informative)

Case studies project overview

A.1 General

The following 18 case studies provide additional background for projects discussed within this document. These projects represent significant pilot and commercial efforts that reflect storage activities across the globe (see Figure A.1). In addition, shorter summaries of note prepared for representative CO_2 projects globally are given.

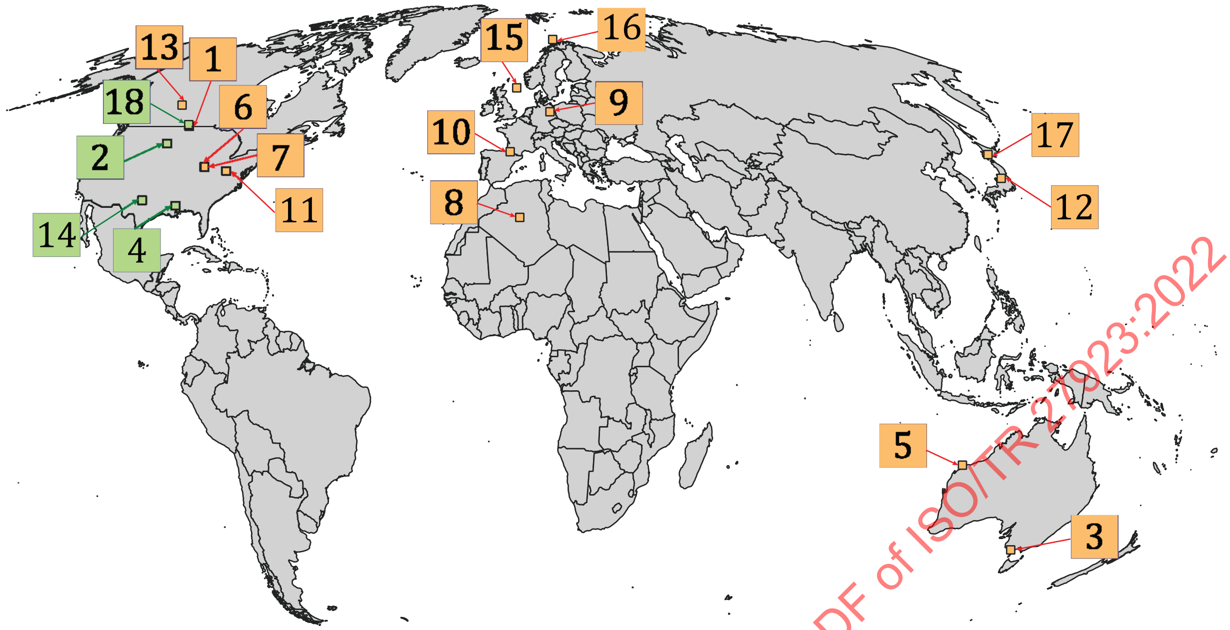


Figure A.1 — CO_2 storage case studies index map

Key

(orange)	CO_2 storage site		
(green)	CO_2-EOR storage site		
1	Aquistore	10	Lacq-Rousse Pilot Project
2	Bell Creek CO_2-EOR project	11	Mountaineer
3	CO_2CRC Otway	12	Nagaoka CO_2 Pilot Project
4	Cranfield	13	Quest
5	Gorgon	14	SACROC
6	Illinois Basin Decatur Project	15	Sleipner
7	Illinois Industrial CCS Project	16	Snøhvit
8	In Salah	17	Tomakomai
9	Ketzin CO_2 Pilot Project	18	Weyburn/Midale CO_2-EOR project

A.2 Aquistore

Project description – The Aquistore CO_2 storage site (see Figure A.2) is located in southeasternmost Saskatchewan, Canada. It is owned by SaskPower, the operator of the Boundary Dam coal-fired power plant where CO_2 is captured at a rate of up to 2 250 t/d. The majority of the captured CO_2 is delivered to the nearby Weyburn-Midale oil field for enhanced oil recovery and the remainder is delivered by a 3 km long pipeline to the Aquistore site where it is injected into a deep saline formation. Injection began in 2015 with sustained injection rates of 400 t/d to 600 t/d, although injection rates have been highly variable due the capture rates and ongoing delivery to Weyburn-Midale. As of July 2020, approximately 300 kt of CO_2 has been injected.

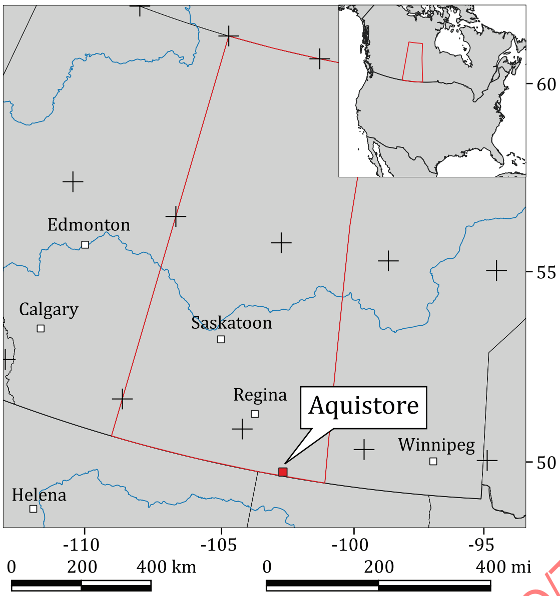


Figure A.2 — Location of Aquistore site

Project focus – The Aquistore Project operates as a research project but at the same time provides operational buffer CO_2 storage for the Boundary Dam power plant. The project is managed by the Petroleum Technology Research Centre and was initially funded by the federal and provincial governments as well as industry sponsors. Research within the project is focused on efficient and effective monitoring methods and providing technical expertise to the storage operation. The site also acts as a test facility for demonstrating new monitoring methods.

Geological setting – The CO_2 storage reservoir at the Aquistore site is located within the lowermost Paleozoic section, immediately above the Precambrian basement. The reservoir comprises the Winnipeg and Deadwood formations that form an about 200 m thick target zone (3 130 m to 3 350 m) for CO_2 injection and storage. These brine-saturated basal sandstones have been used for wastewater disposal elsewhere in Saskatchewan. The overlying Winnipeg Formation includes a lower sandstone unit (Black Island Member) and an upper shale unit (Icebox Member) that forms the reservoir caprock. The Middle Devonian Prairie Formation is an about 200 m thick evaporite sequence at 2 500 m depth that forms a competent regional secondary sealing unit for CO_2 storage at the site.

Permitting and regulation type – CO_2 injection at the Aquistore site was originally permitted under existing oil and gas regulations in the Province of Saskatchewan. Whereas a variety of monitoring methods have been employed at the site, those required by regulation include pressure monitoring, water well sampling, and passive seismic monitoring.

Pertinent data – There are two wells at the Aquistore site; an injection well and an observation well, separated by 150 m. The initial aquifer pressure at the storage site was about 35 MPa at a datum depth of 3 400 m with a temperature of approximately 110 °C. As part of the project there are a total of 40 groundwater wells that are monitored including local domestic wells, SaskPower monitoring wells and 19 Aquistore project wells.

A.3 Bell Creek CO_2-EOR

Project description - The Bell Creek oil field is in southeastern Montana near the northeastern edge of the Powder River Basin (see Figure A.3). The Bell Creek unit is operated by Denbury Resources. The field has been under CO_2 flood since May 2013 and under some form of development for nearly 60 years prior to that. Oil has been produced in the field via primary, secondary (waterflood), and now tertiary recovery methods. The cumulative recovery prior to CO_2 flooding is 21,1 million m^3, 37,7 % of original oil in place (Gorecki, 2012). CO_2 flooding to date has recovered nearly 1 million m^3 of incremental oil production through injection of over 10 Mt.

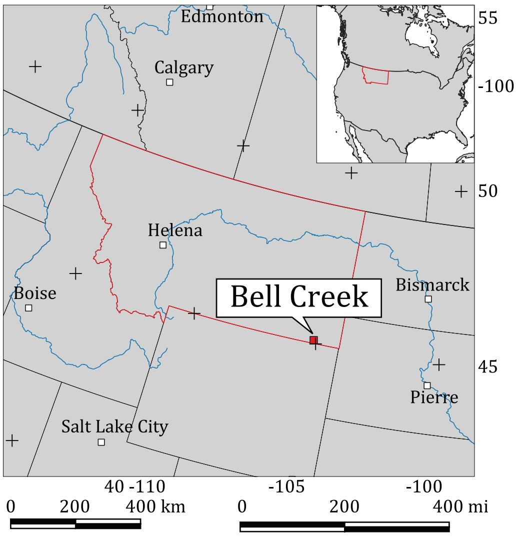


Figure A.3 — Location of Bell Creek CO_2-EOR site

Project focus - Bell Creek is a commercial CO_2 enhanced oil recovery project which has been developed, to date, with six phases of development. The initial development areas (Phases 1 through 4) were developed at 80-acre pattern spacing with 5-spot pattern orientation (injector in the centre of four producers). A combination of previous existing wells and new drills were used to complete the patterns, and most of the original oil in place (OOIP) in each of the phases is covered with patterns. The central injector in each pattern is set up to inject either CO_2 or water. The producers do not have artificial lift equipment (they flow naturally) because the field is kept at elevated reservoir pressure. The field achieved this elevated reservoir pressure through fill-up with water injection once the wells were in place.

Phases 5 and 6 are the most recent developments. They are also completed with 5-spot patterns but are wider spaced at 0,65 k m^2 (160 acres).

The Plains CO_2 Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center (EERC) and supported by the Department of Energy, is working with Denbury Onshore LLC (Denbury) to determine the effect of a large-scale injection of carbon dioxide (CO_2) into a deep clastic reservoir for simultaneous CO_2 enhanced oil recovery (CO_2-EOR) and CO_2 storage. This effort has resulted in several monitoring approaches being tested and extensive reservoir characterization and modelling studies.

Geological setting - The producing formation in Bell Creek is the Lower Cretaceous Muddy (Newcastle) formation at a depth of 1 310 m to 1 370m. The Muddy formation is characterized by clean, high-porosity (25 % to 35 %), and high-permeability (100 mD to-1 175 mD) sandstones deposited in a near-shore marine environment. The Muddy formation in Bell Creek features an updip facies change from sand to shale that serves as a trap. The estimated original oil in place is 56 million m^3 distributed between three main pay sands: B10, BC20, and BC30. The primary seal for the formation is provided by the overlying Mowry shale formation. On top of the Mowry shale are several thousand feet of low-permeability shale formations, including the Belle Fourche, Greenhorn, Niobrara, and Pierre shales, which provide redundant layers of protection in the unlikely event that the primary seal fails.

The reservoir is subnormally pressured with an initial reservoir pressure of only 8,3 MPa (hydrostatic pressure would be 14,5 MPa). The CO_2 miscibility pressure is estimated at 9,25 MPa, as per slim tube and PVT study results. The field is currently operated at 21 MPa to keep CO_2 in the dense phase and the process largely miscible. The pressure is well below the fracture pressure of the reservoir and overlying seal. This operating pressure also allows the wells to flow, reducing the requirement for artificial lift.

Permitting and regulation type – The project is permitted and regulated as an oil and gas project by the Montana Board of Oil and Gas Conservation.

Pertinent data - The CO_2 for field injection is from the ExxonMobil LaBarge gas plant and the ConocoPhillips Lost Cabin gas processing plant in Wyoming. Total CO_2 delivered to the field is approximately 3,26 Mm^3/d. The CO_2 is transported to the site via a 373 km pipeline and is compressed to 15 MPa for injection. New CO_2 acquired to date is over 5,1 km^3 and is scheduled to continue at declining rates as the field matures and full development is reached. An ultimate CO_2 mass of 12 Mt is estimated to remain in the field at project completion. CO_2 produced in association with oil and water production is compressed and reinjected (recycled) into the reservoir.

A.4 CO_2CRC Otway Project

Project description - The CO_2CRC Otway Project is a research-oriented capture and storage project in south-west Victoria, Australia (see Figure A.4), managed by the CO_2CRC, an organization focused on CCS research. The project, now in a third phase, has conducted a wide range of innovative studies into carbon storage mechanisms in the subsurface and monitoring and verification techniques since 2003. Support for the project has come from State and Federal governments, and a wide range of industrial and research partners.

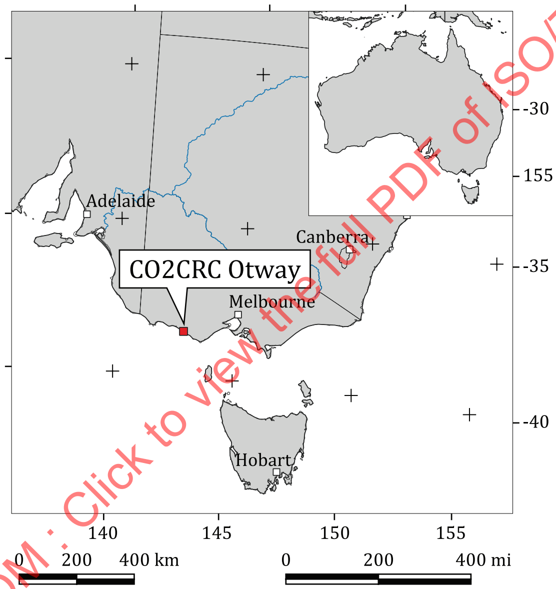


Figure A.4 — CO_2CRC Otway project site

CO_2 Source - A natural undeveloped CO_2 field (Buttress) approximately 2 km from the injection site. A single production well produces 80 % CO_2 and 20 % CH_4 which is removed prior to injection.

Storage type - The first phase used a depleted gas reservoir suspended in 2004 (Naylor Field) in the Waarre Formation (Unit C). The second phase used the Paarratte Formation, a saline aquifer, to test trapping mechanisms (Sharma et al., 2011). The third phase also uses the Paarratte Formation.

Geological setting - The Waarre C unit is poorly sorted sandstone with fine to coarse quartz sands about 35 m to 40 m thick in the area of the Naylor Field. The Belfast Mudstone forms the seal to the Waarre and is about 400 m thick. The Paarrate Formation, from 250 m to 400 m thick, is comprised of sands of low to high permeability (0 mD to 250 mD) with thinly interbedded intra-formational seals. The Pember Mudstone and Massacre Shales are the sealing units.

Pertinent data - During the first phase of the project over 64 kt of CO_2 were injected into the Waarre C Member of the Naylor Field. During Phase 2, 15kt CO_2 was injected into the Paarratte reservoir. This reservoir is also used in Phase 3 with the potential of 40 kt to be injected.

A.5 Cranfield

Project description - The Cranfield Unit is a historic oil producing field (see Figure A.5) which was reactivated for CO_2-EOR operations; the first CO_2 injection commenced in July 2008. The Southeast Regional Carbon Sequestration Partnership (SECARB), led by the Gulf Coast Carbon Center of the Bureau of Economic Geology at the University of Texas, initiated research on the project which included monitoring and assessment technologies focused on CO_2 injection (United States Department of Energy – National Energy Technology Laboratory, 2015). The research consisted of site characterization, risk assessment and the drilling of three wells for cross-well electrical resistance tomography (ERT) and pressure surveillance.

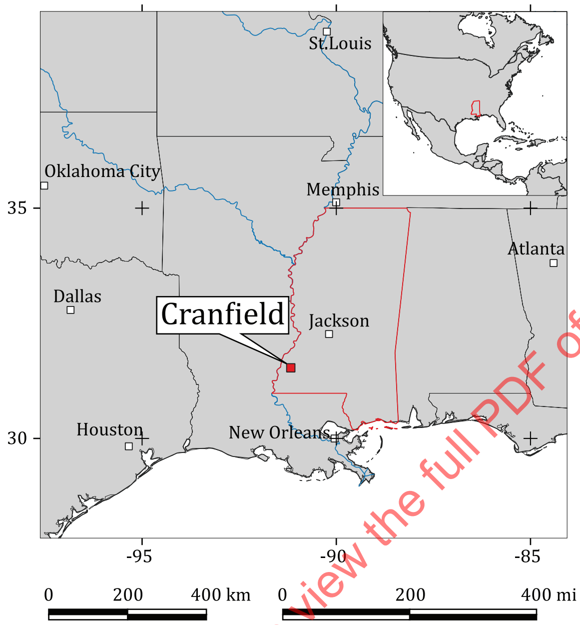


Figure A.5 — Cranfield site

CO_2 source - The CO_2 supplied for the CO_2-EOR project is a natural CO_2 source located near Jackson, MS and is delivered to the project via pipeline. From July 2008 until March 2015 more than 5 Mt of CO_2 had been injected at the site (United States Department of Energy – National Energy Technology Laboratory, 2018).

Storage type - The mechanism for storage is incidental to CO_2-EOR.

Geological setting - The Cranfield Unit consists of the clastic Lower Tuscaloosa formation at a depth of 3 000 m. The Tuscaloosa has been geologically folded into a domed structure due to an underlying salt diaper. The Lower Tuscaloosa at Cranfield is a series of stacked and incised channel fills of sandstones and conglomerates. The primary sealing formation is a thick marine shale of the Mid-Tuscaloosa with additional sealing shales of the Midway Formation. The original oil producing horizon of the Lower Tuscaloosa at the Cranfield structure had an upstructure gas cap and downdip saline water aquifer. During the historical primary production period of the unit the gas cap was blown down prior to the abandonment of the field.

Pertinent data - The Cranfield research project is best known for the Detailed Area Study where 3 closely spaced (interwell spacing of 29,9 m and 69,8 m) wells were drilled; the centre well being a CO_2 injection well and the offsetting wells were for monitoring. The observation wells were cased with fiberglass pipe to facilitate ERT and a time lapsed study was conducted at intervals during the study period. During the study, data acquired and analysed included cross-well seismic, time lapsed VSP, ERT, pulse neutron logging and pressure transient testing (Hovorka et al., 2011).

A.6 Gorgon

Project description - The Gorgon project is located on Barrow Island (see Figure A.6), a class A nature reserve, about 60 km off the coast of Western Australia (Trupp et al., 2013). The project is operated by Chevron Australia and is a joint venture among Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas and JERA. This immense, complex project uses a subsea gas gathering system to produce natural gas from the giant offshore Gorgon and Janz-Io fields which is then brought back to Barrow Island for processing. The carbon dioxide injection component of the project commenced in August 2019 making it the largest carbon injection project in the world.

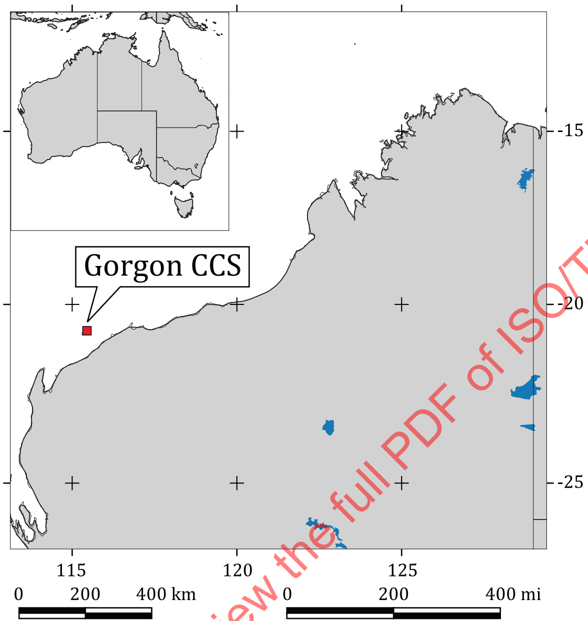


Figure A.6 — Location of Gorgon project site

CO_2 source - The offshore gas fields Gorgon and Jansz contain 14 % and less than 1 % CO_2, respectively, which is separated from the gas at the liquified natural gas plant on Barrow Island. The CO_2 is then transported by pipeline to one of three multi-well centres.

Storage type - Injection and storage of the separated CO_2 is into the Dupuy Formation, an interbedded sandstone and siltstone aquifer. The project will use an active pressure management system by which water is extracted from the reservoir and injected at another interval.

Geological setting - The Dupuy Formation under Barrow Island occurs around 2 300 m depth and is a turbidite fan deposit between 200 m to 500m thick comprising massive sands which is the main storage facies. Trapping mechanisms are mainly through CO_2 solution and residual trapping. The overlying Basal Barrow Group Shale is a marine shale and forms the seal to the storage reservoir.

Pertinent data - Because of the different CO_2 content of each production reservoir, CO_2 injection will vary between around 3,4 Mt/year to 4 Mt/year and involve up to 9 injection wells. A total of 100 Mt is planned for injection over the project lifetime. Monitoring is conducted using time-lapse seismic, observation wells and environmental sensors.

A.7 Illinois Basin Decatur Project

Project description - The Illinois Basin Decatur Project is an integrated bioenergy CCS (BECCS) demonstration project conducted at Archer Daniels Midland Company’s corn processing facility in Decatur, IL, USA (see Figure A.7). The project is led by the Illinois State Geological Survey through the Midwest Geological Sequestration Consortium and industry and research partners. The project was funded mainly by the US DOE National Energy Technology Laboratory.

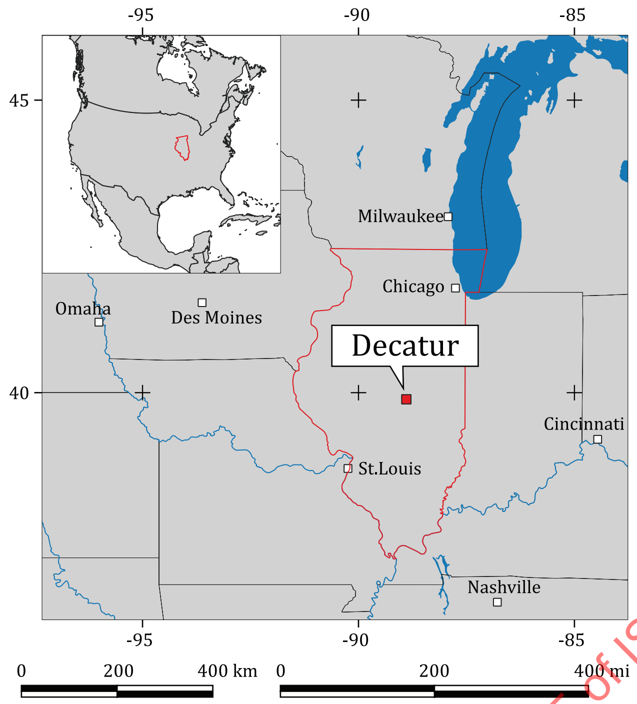


Figure A.7 — Location of Illinois Basin Decatur project site

CO_2 source - The CO_2 is derived from the byproduct of corn fermentation to produce ethanol fuel. It is over 99 % pure and requires minimal treatment (dehydration) prior to injection.

Storage type - Deep saline aquifer in the Cambrian Mt. Simon Sandstone that has over 22,5 % total dissolved solids.

Geological setting - The Mt. Simon Sandstone is a regional sandstone deposited during the initial phases of the formation of the Illinois Basin. At the Illinois Basin Decatur Project (IBDP) site the Mt. Simon includes fluvial, aeolian, barrier sands and tidal flat facies and is about 453 m thick. The lower part of the formation is used for injection where diagenetic processes have enhanced porosity and permeability: average porosities near 20 % and permeability of 185 mD. The Eau Claire Shale is the seal to the reservoir and is about 152 m thick at the site.

Pertinent data - The Illinois Basin Decatur Project (IBDP) site includes one injection well (CCS1), one deep monitoring well (VM1), one dedicated geophysical well (GM1) and a variety of near surface monitoring wells and equipment. 999 kt of CO_2 were injected between 2011 and 2014. Post Injection Site Care monitoring has been ongoing since end of injection. This is the first project to obtain a Class VI permit in the USA.

A.8 Illinois Industrial CCS Project

Project description - The Illinois Industrial CCS project (IL-ICCS) is an integrated bioenergy BECCS commercial project conducted at Archer Daniels Midland Company's corn processing facility in Decatur, IL, USA (see Figure A.8). The project built off the findings of the Illinois Basin Decatur Project and is injecting around 1 Mt/year CO_2 approximately 1,6 km north of the Illinois Basin Decatur Project (IBDP) injection site. The project is managed by ADM with operational and monitoring assistance from Schlumberger and the Illinois State Geological Survey. The project was funded by ADM and the US DOE - National Energy Technology Laboratory.

Figure A.8 — Location of Illinois Industrial CCS project site

CO_2 source - The CO_2 is derived from the byproduct of corn fermentation to produce ethanol fuel. It is over 99 % pure and requires minimal treatment (dehydration) prior to injection.

Storage type - Deep saline aquifer in the Cambrian Mt. Simon Sandstone that has over 22,5 % total dissolved solid.

Geological setting - The Mt. Simon Sandstone is a regional sandstone deposited during the initial phases of the formation of the Illinois Basin. At the Illinois Basin Decatur Project (IBDP) site the Mt. Simon includes fluvial, aeolian, barrier sands and tidal flat facies and is about 453 m thick. The lower part of the formation is used for injection where diagenetic processes have enhanced porosity and permeability: average porosities near 20 % and permeability of 185 mD. The Eau Claire Shale is the seal to the reservoir and is about 152 m thick at the site.

Pertinent data - The IL-ICCS site includes one injection well (CCS2), one deep monitoring well (VW2), one dedicated geophysical well (GM2) and a variety of near surface monitoring wells and equipment. Starting April 2017, approximately 1 Mt/year of CO_2 is being injected into the lower Mt. Simon Sandstone. Injection at CCS2 is about 100 m higher stratigraphically than injection at CCS1 (Illinois Basin Decatur Project) and considerably fewer microseismic events are recorded. This is the first commercial project to obtain Class VI permitting in the USA.

A.9 In Salah

Project description - The In Salah project (see Figure A.9) is an industrial-scale CO_2 storage project, located in the Central Algerian Sahara (see Ringrose et al., 2013 which is the primary source of this summary). The project operated from 2004 to 2011 as is a joint venture (JV) Project between BP, Sonatrach and Statoil, in the Central Algerian Sahara. The source of CO_2 is natural gas processing which removes the 5 % to 10 % CO_2 contained within gas produced in the Krechba field. CO_2 is removed from the production stream to meet gas export specifications of less than 0,3 % CO_2. CO_2 injection started in 2004 and was suspended in 2011 due to concerns about the integrity of the seal.

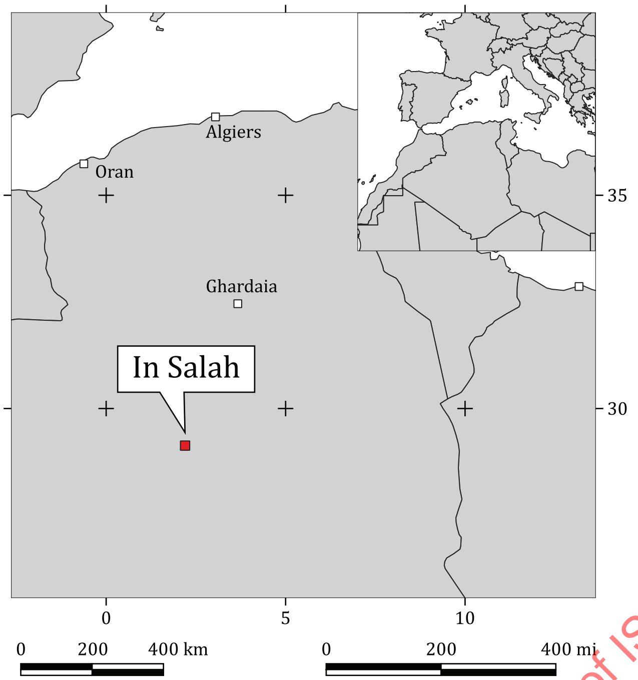


Figure A.9 — Location of In Salah

Project focus - The In Salah project was operated as an experimental demonstration project to study CO_2 storage in a deep saline formation. The original objective was to monitor the CO_2 storage using a variety of geochemical, geophysical, and production techniques over an initial five-year period.

Geological setting - The storage reservoir is a 20m to 25 m thick Carboniferous sandstone unit within a broad anticline at 1 900 m depth. The reservoir sandstones were deposited in a tidal deltaic setting and have average porosity of 15 % and variable permeabilities in the range of 0,1 mD to 300 mD. The sandstone reservoir is sealed by a 905 m thick interval of Carboniferous mudstones that in turn are overlain by approximately 900 m of Cretaceous sandstone and mudstone.

Pertinent data – 3,86 Mt cumulatively injected during 2004 to 2011. CO_2 was injected using three long-reach horizontal wells that were drilled orthogonal to the predominant reservoir fracture direction. The CO_2 was injected in a water-leg on the flank of the anticline, down-dip from the producing gas zone. Initial reservoir pressure and temperature were 17,5 MPa and 90 °C, respectively.

A.10 Ketzin CO_2 Pilot Project

Project description - The first European on-shore CO_2 injection storage site has been operated by the GFZ German Research Centre for Geosciences. The project was a dedicated as a pilot project for studying onshore geological storage in a saline sandstone formation. A total mass of about 67 kt of CO_2 was injected between 2008 and 2013. The CO_2 injection has ceased in August 2013 and the scientific monitoring program ended in 2017 with the back-filling and decommissioning of all wells. The storage site (see Figure A.10) is closed now and the area is used for another purpose. GFZ as operator has co-ordinated a range of national and European CO_2 storage related projects and their published results can be received from the website http://www.co2ketzin.de/en/publications/.

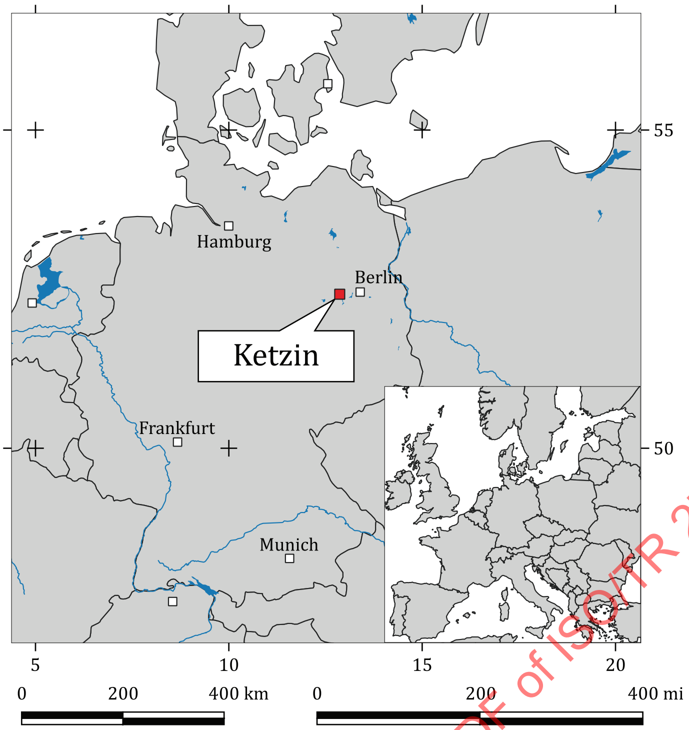


Figure A.10 — Location of Ketzin CO_2 pilotproject site

Project focus - The pilot storage site received funding from the European Commission Framework Programmes FP6 & FP7, the German Federal Ministries of Economic Affairs & Energy (BMWi) and Education & Research (BMBF), and its industrial partners. The Ketzin pilot project was aimed at a better understanding of geological CO_2 storage operation in a saline aquifer. It was characterised by a multi-disciplinary monitoring programme comprising geophysical, geochemical and microbiological investigations. The food-grade quality CO_2 (99,9 %) was delivered from the chemical industry, pre-conditioned at the injection facility onsite, and transported via a short pipeline to the injector well. The project has demonstrated the full life-cycle of a CO_2 storage reservoir, inclusive post-injection and closure phase and transfer of liability. The project was accompanied by broad and transparent public relations work.

Permitting and authorization type – The permitting framework for siting and licensing was administered by the mining law of the federal state of Brandenburg, the licensing authority was the Mining Authority of Brandenburg (LBGR). The GFZ German Research Centre for Geosciences acted as responsible operator and site specialist, the company VNG Gasspeicher GmbH, a German gas storage service operator, was the land owner of the site. In the main operating plan, it was stated that the total storage volume would not exceed 100 kt, thus preserving the characteristic of a pilot project.

Pertinent data – There are five wells drilled, four of them have total depths in the range of about 700 m to 800 m, and one well has the depth of 418 m. One of the deep well acted as injector, the three others for monitoring purposes only, and the shallow well served as above-zone indicator well. The initial aquifer pressure at the storage site is 6,2 MPa at depth of 630 m (storage target zone) with a temperature of 33 °C. The storage zone total thickness ranges from 15m to 20 m. As a consequence of the injection process, the reservoir condition reaches temperatures up to 36 °C and pressures between 7,4 MPa and 7,8 MPa at the injection point. The minimum injection rate was 1,6 t/h and the maximum rate 3,2 t/h. The total amount of CO_2 injected was 67 kt over a period of 5 years.

A.11 Lacq-Rousse Pilot Project

Project description - In 2006, the Total company launched an end-to-end industrial chain CCS project comprising the capture, transport and injection of CO_2 into the depleted onshore gas reservoir of Rousse (see Figure A.11). This CCS pilot was located in the Lacq basin 5 km south of Pau (around 140 000 inhabitants) and approximately 800 km from Paris. Construction started in 2008. In May 2009, Total was permitted to operate the pilot. The whole CCS pilot started on 8 January 2010. The last injection of CO_2 took place on 15 March 2013. More than 51 kt of CO_2 were injected during those 39 months. The three-year post-injection monitoring period ended in 2016.

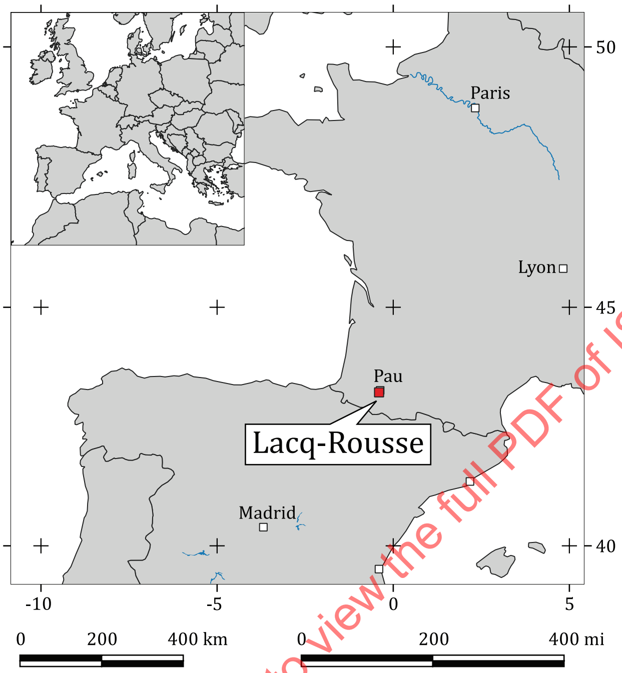


Figure A.11 — Location of Lacq-Rousse pilot project site

Project focus - The Lacq-Rousse project entailed the conversion of an existing air-gas combustion boiler into an oxygen-gas combustion boiler, using oxygen delivered by an air separation unit to obtain a more CO_2 concentrated (and easier to capture) flue gas stream. The 30 MWth oxy-boiler was able to deliver up to 38 t/h of steam to the HP steam network of the sour gas production and treatment plant on the SEVESO-classified Lacq industrial complex. After quenching of the flue gas stream, the rich CO_2 stream was compressed (to 2,8 MPa), dried and transported as a gas phase via existing pipelines to a depleted gas field, 29 km away, where it was injected in the deep Rousse reservoir. Main objectives of the pilot were to demonstrate the technical feasibility and reliability of an integrated chain, to acquire operating experience and data to upscale the oxy-combustion technology from pilot to industrial scale, to develop and apply geological storage qualification methodologies, monitoring methodologies and technologies on site and finally, to promote CCS.

Permitting and authorization type – In 2006, regulation for CCS in Europe was not yet implemented (EU directive 2009/31/EC only came into force on June 2009). French authorities decided to execute the project under both the French Mining Code (for the subsurface aspects) and the French Environmental Code (for surface installations aspects). They took into account all recommendations written in the draft of the EU directive. In May 2009, Total was permitted to operate the pilot for a maximum injection of 120 kt of CO_2 over two years and three years of post-injection monitoring. In 2011, Total requested an 18-month extension to allow for finalization of the R&D program. French authorities answered positively and a complementary permit was issued in November 2011. The amount that could be injected was at that time revised and limited to 90 kt of CO_2.

Pertinent data – The Rousse reservoir is intersected by only one well: Rousse-1. Rousse reservoir is 4 500 m deep and is composed of dolomites and dolomite breccias of Upper Jurassic age. The first overlying aquifer is 2 500 m from the top reservoir. During gas production phase (mid 1970s-late 2000s), reservoir was depleted from about 34 MPa to about 4 MPa. Reservoir pressure rose again to reach about 8 MPa at the end of the CO_2 injection period. The monitoring plan included reservoir pressure, microseismic monitoring, and environmental monitoring (groundwater, surface water, fauna, flora, soil gases and atmosphere). A full report of the project results is available online: https://www.globalccsinstitute.com/archive/hub/publications/194253/carbon-capture-storage-lacq-pilot.pdf.

A.12 Mountaineer

Project description - American Electric Power (AEP) conducted a carbon dioxide (CO_2) capture and storage (CCS) demonstration project at its Appalachian Power Company (APCO) Mountaineer Plant, located near New Haven, West Virginia (see Figure A.12) from October 2009 to May 2011. The project was conducted under the name Product Validation Facility (PVF). A total of 10 kt of CO_2 was injected into the Rose Run sandstone at a depth of 2 362 m to 2 392 m, and 27 kt of CO_2 were injected into the Copper Ridge dolomite at a depth of 2 482 m to 2 545 m. Injection ceased on May 28, 2011. This validation project received no U.S. federal funds; it operated more than 6 500 h, captured more than 50 kt of CO_2, and permanently stored more than 37 kt of CO_2.

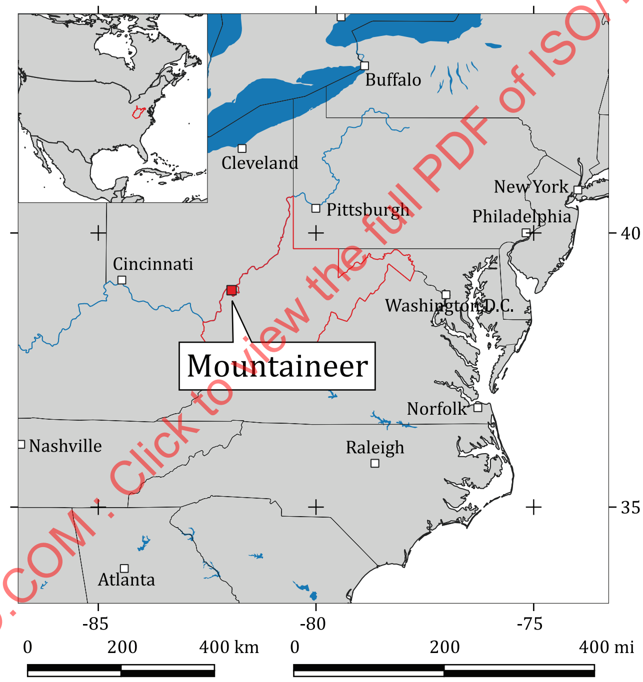


Figure A.12 — Location of Mountaineer project site

Project focus - The project was used to evaluate the feasibility of a commercial-scale storage system (235 Megawatt, or approximately 1,5 Mt CO_2 per year). It was preceded by a U.S. Department of Energy (DOE) funded site characterization and feasibility assessment research project from 2003 to 2007. The DOE study included a seismic survey and drilling of a stratigraphic test well (AEP-1), which identified the Rose Run Sandstone and the Copper Ridge Dolomite as potential injection zones.

CO_2 source - An Alstom system captured up to 90 percent of the CO_2 from a slipstream of flue gas (equivalent to 20 megawatts of generating capacity) at the APCO Mountaineer power plant, which had a total capacity of 1 300 megawatts.

Geology - A total of 10 kt of CO_2 was injected into the Rose Run sandstone at a depth of 2 362 m to 2 392 m, and 27 kt of CO_2 were injected into the Copper Ridge dolomite at a depth of 2 482 m to 2 545 m. Injection ceased on May 28, 2011.

Permitting and authorization - The injection wells were permitted under the West Virginia Department of Environmental Protection (WVDEP) Underground Injection Control (UIC) Permit No. 1189-08-53 as