Technical Report

ISO/TR 27926

First edition
2024-12

Carbon dioxide capture, transportation and geological storage — Carbon dioxide enhanced oil recovery (CO_2-EOR) — Transitioning from EOR to storage

Captage du dioxyde de carbone, transport et stockage géologique — Récupération assistée du pétrole par le dioxyde de carbone (RAP-CO2) — Transition de la RAP au stockage

Reference number
ISO/TR 27926:2024(en)

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Foreword

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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

Across the globe, interest in and development of projects for the geological storage of captured anthropogenic CO_2 continues to increase. One subset of these projects consists of those that would find some way to increase CO_2 storage through the use of existing hydrocarbon fields and infrastructure. There is a continuum of projects from hydrocarbon fields near the end of their lives that start CO_2 injection before the end of production, thereby accelerating transition to storage and potentially reducing costs, to full-fledged carbon dioxide enhanced oil recovery (CO_2-EOR) projects that can be optimized to maximize CO_2 storage while still producing oil. Alternatively, operators of a producing field can decide to begin storage operations in that field before ceasing production. Such operations would instead be designed to achieve storage simultaneously with production.

Due to the availability of existing infrastructure for CO_2 transport, handling, injection and storage, modifying CO_2-EOR projects nearing maturity to increase CO_2 storage can be a particularly cost-effective way to reduce atmospheric emissions of CO_2. Some such modified projects can also defer project decommissioning, again helping to expand commercial carbon capture and sequestration (CCS) as an emissions-reduction option. CO_2 transport and injection infrastructure, as well as the generally well-characterized geologic formations where CO_2-EOR operation are already undertaken or where operations at CO_2-bearing geological formations occur, can be modified too for CO_2 storage.

Similarly, for producing oil and gas fields, starting CO_2 injection before cessation of production (i.e. having overlapping storage and production licenses) can have significant economic benefits. The CCS project can have certainty in timing and can potentially avoid having to compensate the hydrocarbon operator for “lost production”. There is also no gap between production and storage leading to no challenging questions over who pays for mothballed infrastructure.

There is considerable overlap in technology and infrastructure between standard CO_2-EOR, other hydrocarbon recovery processes and dedicated geological storage of CO_2. Each of the processes – and many of the operational variations discussed in this document – can present different advantages or disadvantages. For example, a number of the operational techniques for maximizing CO_2 storage would tend to increase reservoir pressures affecting the containment risk assessment, CO_2 movement through the storage complex or certain subsurface-engineered facilities. The technical and operational portion of this document examines these issues.

Similarly, the legal, regulatory and even consensus standards framework developed for typical CO_2-EOR operations can no longer be applicable to a modified operation. A given framework can be appropriate for some operational changes, but not for others. Clause 10 provides an overview of these issues.

This document does not address the quantification of greenhouse gases (GHGs) other than CO_2 for carbon dioxide storage projects. CCS projects can address quantifying, monitoring, reporting, and validating or verifying other GHG emissions reductions or removals through the application of ISO 14064-2 or other documents in the ISO 14064 series.

Carbon dioxide capture, transportation and geological storage — Carbon dioxide enhanced oil recovery (CO_2-EOR) — Transitioning from EOR to storage

1 Scope

This document examines various CO_2 injection operations that involve modifications to CO_2-EOR or other complementary hydrocarbon recovery operations that can be conducted in conjunction with CO_2 storage. The document also examines potential policy, regulatory or standards development issues that can arise in evaluating such operational changes.

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
anthropogenic CO_2
anthropogenic carbon dioxide
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)

[SOURCE: ISO 27916:2019, 3.1, modified — Notes 1 and 2 to entry have been deleted.]

3.2
area of review
AOR
geographical area(s) of a carbon capture and sequestration (CCS) project, or part of it, designated for the assessment of the extent to which a CCS project, or part of it, can 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.

[SOURCE: ISO 27917:2017, 3.3.10, modified — "may be required by regulatory authorities" has been deleted from Note 1 to entry.]

3.3
enhanced oil recovery complex
EOR complex
project reservoir, trap and such additional surrounding volume in the subsurface as defined by the operator within which injected CO_2 will remain in safe, long-term containment

[SOURCE: ISO 27916:2019, 3.10]

3.4
injection/withdrawal ratio
IWR
relationship, during a defined period, of the volume of all fluids and gases injected into the project reservoir to the volume of all fluids and gases produced from the project reservoir as determined using consistent temperature and pressure conditions

[SOURCE: ISO 27916:2019, 3.11]

3.5
natural-sourced CO_2
gaseous accumulations of CO_2 found in geological settings, such as sedimentary basins, intra-plate volcanic regions, faulted areas or quiescent volcanic structures

3.6
plug and abandon
P&A
permanently close a well or wellbore to prevent inter-formational movement of fluids into strata, into freshwater aquifers, and out of the well

Note 1 to entry: In most cases, a series of cement plugs is set in the wellbore, with an inflow or integrity test made at each stage to confirm hydraulic isolation.

[SOURCE: ISO 27916:2019, 3.17]

3.7
produced water
naturally occurring water in the reservoir that is extracted as part of oil and gas production operations

3.8
produced water cut
ratio of water to total fluids that are produced at the well during oil and gas production operations

3.9
purchased CO_2
CO_2 injected in a formation that is not attributable to recycling of CO_2 previously injected at that site, regardless of whether the supply is acquired through a purchase and sale transaction

Note 1 to entry: Other terms include “incremental”, “new”, “off-site” and “acquired” CO_2. Accounting protocols to preclude double-counting of CO_2 storage are presented in ISO 27916:2019, 8.2, 8.7 and Clause A.14 b).

3.10
spill point
structurally lowest part of a reservoir that can contain buoyant fluids within the trap

3.11
thief zone
geological formation to which fluids used or produced during CO_2 enhanced oil recovery drilling or production operations are lost

3.12
water-alternating gas
WAG
enhanced oil recovery production technique in which injections of water are alternated with injections of CO_2 (as opposed to continuous injections of CO_2)

3.13
water out
point in time beyond which the proportion of water in a production stream is so great that recovery of the remaining hydrocarbons in the stream is no longer economically justified

4 Abbreviated terms and symbols

4.1 Abbreviated terms

AOR	area of review
API	American Petroleum Institute
BIO LLC	Brilliant Idea Oil LLC
CCI	continuous CO_2 injection (i.e. not alternating with water injections)
CCS	carbon capture and sequestration
CCUS	carbon capture utilization and storage
CO_2-EOR	carbon dioxide enhanced oil and gas recovery
FPSO	floating production storage and offloading vessel
GOR	gas/oil ratio
HC	hydrocarbon
HCPV	hydrocarbon pore volume
IPL	injection profile logging
IWR	injection/withdrawal ratio
LACT	lease automatic custody transfer
LNG	liquid natural gas
M	one thousand
MDF	mature and depleted field
MIT	mechanical integrity testing
MM	one million
MMRb	one million reservoir barrels
OOIP	original oil in place
PDO	plan for development and operation
P&A	plug and abandon

psi pounds per square inch

Rm^3 reservoir cubic meter (i.e. cubic meter at reservoir temperature and pressure)

ROZ residual oil zone

STB standard barrel (i.e. barrel of liquid at standard temperature and pressure)

Tcf trillion cubic feet

USDW underground source of drinking water

WAG water alternating gas

4.2 Symbols

T_i initial temperature

B_{OI} oil formation volume factor at initial reservoir pressure

P_{BP} bubble point pressure

P_i initial reservoir pressure

R_s solution gas/oil ratio

R_b reservoir barrel

5 Overview

During CO_2-based enhanced oil or gas recovery operations (CO_2-EOR), CO_2 is injected into a hydrocarbon-bearing geological formation to restore reservoir pressure and to mobilize oil that is trapped in the pore spaces of the rock. As explained in ISO 27916:2019, Clause A.3:

> "Once injected, the CO_2 contacts and swells the oil in the reservoir. At certain pressure and temperature conditions, the CO_2 becomes miscible (mixing in all phases) with the oil, creating a more mobile oil that is more easily displaced through the reservoir. Oil, CO_2, and brine are then produced to the surface at production wells. This mixture of produced fluids is delivered to a separation plant in which pressure is dropped, and oil, water, and CO_2 and other gases are separated from one another. [...] Oil is sent to market and brine is reinjected for flooding as part of the operation or injected in permitted disposal wells."

ISO 27916:2019, Clause A.4 states that, as a natural part of CO_2-EOR operations, CO_2 is “effectively stored in the subsurface and securely isolated from the atmosphere, underground sources of drinking water, and other subsurface resources.” Furthermore, ISO 27916:2019, Clause A.4 explains that:

> "a significant fraction of injected CO_2 becomes trapped in place and is physically unrecoverable. Modelling and core plug studies illuminate the trapping that occurs; it includes CO_2 trapped by capillary processes and in dead end pores, dissolved in immobile oil, dissolved in brine, or moved into 'attic' areas and outside of the active flow paths. Some discussions of CO_2-EOR operations characterize only this non-recyclable CO_2 as 'stored' (e.g. Whittaker and Perkins, 2013).[1] However, others follow the same approach as is used in accounting for saline formation storage projects, where all forms of effective trapping in the reservoir are counted as stored (including CO_2 trapped as a mobile phase beneath the confining system)."

Adsorption counts as another trapping mechanism. A dense layer of CO_2 forms at the solid surface increasing the storage capacity of a reservoir on one hand and reducing the possibility of CO_2 leakage through overpressure on the other. However, residual water or oil films adhering to the surface can prevent the formation of closed adsorption layers.

The first commercial CO_2-EOR projects began over 50 years ago. The vast majority of the 140 or more projects worldwide are still operational today. Until recently, there has generally been no economic value to be derived from the associated storage of CO_2 that occurs in a CO_2-EOR operation. As a result, in seeking to maximize the ultimate recovery of the hydrocarbon mineral resource (as typically required by the applicable law, permit or commercial agreement), operators have generally sought to economically optimize (i.e. minimize) the quantity of CO_2 injected and stored during the operation. The economic incentives change; however, when a legal or regulatory framework or a commercial agreement creates an economic value for the long-term secure containment of the stored CO_2, in effect, creating a dual revenue stream for a project: revenue from hydrocarbon sales plus revenue from CO_2 emission reduction or avoidance incentives.

In these circumstances, the operator can explore various operational changes to maximize the total economic recovery of the project. While some operational changes can alter spatial distribution and spread of the injected CO_2, others cannot. Increasing the amount of CO_2 that is stored can also affect operating pressures, particularly in the subsurface. These, and related changes, can affect the area of review (AOR) for assessing potential leakage pathways and other aspects of the containment assurance. In addition, legal, regulatory, contractual or mineral property leases or permits can need revising as well. Clauses 6, 7 and 8 examine various potential operational modifications that can be pursued to achieve higher levels of CO_2 storage while Clause 10 addresses related legal, regulatory and property management issues.

6 CO_2 operational scenarios addressed

Operations and facility prerequisites for each field operation, whether oil and gas recovery or CO_2 storage are site specific, depending upon the circumstances for that project. Operations are designed, conducted and modified in accordance with multiple factors, including, for example, geology, infrastructure availability, input costs and availability, projected market prices and costs over time, potential changes in government regulation and public perceptions, and a host of other factors. Accordingly, the operational scenarios discussed in this document are intended to illustrate the range of scenarios that can be considered by different operators; they are not real-world projects.

Transitioning from hydrocarbon recovery to storage can necessitate additional or upgraded infrastructure, depending upon the nature of the project and the regulatory regime in which the project resides.

There are three broad categories of operational changes discussed, together with potential variations. The categories define the facility considerations and operational considerations for the project. The three broad categories (see Figure 1) are:

— Scenario category 1: Maximizing or optimizing CO_2 storage quantities in an actively producing CO_2-EOR project. This set of operational changes consists of actions aimed at increasing the amount of CO_2 injected and stored in CO_2-EOR operation either by increasing the amount of pore space in a defined containment that is filled with CO_2 or by extending the previously defined containment either laterally or vertically. These project variations will generally have existing facilities that can be sufficient for the immediate needs of CO_2 storage, but over time can necessitate upgrades for injection system operating pressures, recycle rates and field distribution and gathering. These projects can be termed “CO_2 maximization/optimization” projects.

— Scenario category 2: Projects that do not envision continued hydrocarbon recovery, meaning that no additional production facilities be required. However, if additional saline water production is necessary to provide accommodating pore space for CO_2 storage, some production facilities can be necessary. In addition, the prerequisites for CO_2 injection can necessitate additional injection pressure capability and possibly rate capacity as well. These variations are sometimes referred to as “top off the tank” operations where CO_2 injections continue after hydrocarbon production is terminated.

— Scenario category 3: Projects that are hydrocarbon-recovery related projects that have not previously undergone CO_2 flooding. These projects have hydrocarbon production related facilities, but no existing CO_2 injection capability at all. Such projects need CO_2 injection and compression facilities. In addition, the continued production capability can need adapting to capture CO_2 extracted from the hydrocarbon production stream as well as the capability for handling increased CO_2 concentrations. Field injection infrastructure are needed and upgrades to gathering infrastructure is likely to be necessary.

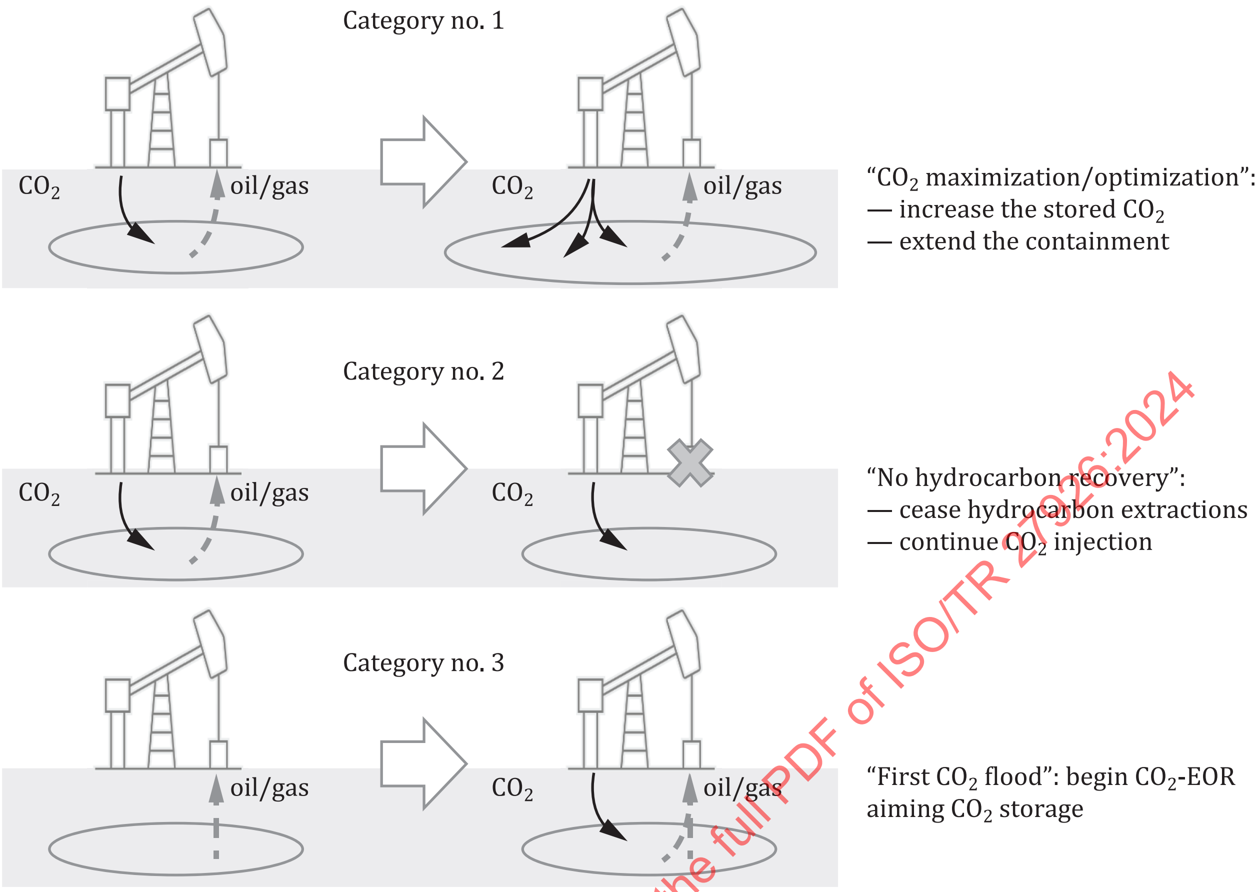


Figure 1 — Operational scenario categories

Although an operator can pursue these operational strategies at any stage, the most likely cases for their implementation are projects in the mature stage of hydrocarbon operations when operators will be looking to either abandon their operations or extend the economic life of the asset. The economic life can be extended through continued or new enhanced recovery processes or in combination with storage incentives, if applicable. However, extending operations in this manner can present questions as to the use of the original equipment. Wellbores and surface facilities that are no longer new can be reviewed vis-à-vis their remaining operating life. Certain equipment will have been maintained but other equipment can be nearing the end of its useful life. Operators will forecast end-of-life relative to expenditure outlays many years in advance and plan and conduct maintenance operations accordingly. Maintenance can well be reduced, allowing the mechanical integrity of wellbores and surface facilities to decline from optimum manufacturer-specified rates or pressures. Replacements or remediation costs most likely will need to be figured for the go-forward storage option.

7 Technical and operational aspects of transition

7.1 General considerations

7.1.1 Storage volume assessment and estimation of pore volume

One of the key parameters for determining the maximum amount of CO_2 that can be stored in a defined formation is the pore volume available for CO_2 storage within that interval. That pore volume is a function of area, thickness and porosity of the formation. Hence, to calculate the pore volume (V_{pi}) within the CO_2-EOR's producing intervals (i) of the petroleum reservoir, some form of the following volumetric formula is needed:

$$V = A \times h \times \varphi$$

where

V is the pore volume;

A is the area;

h is the thickness;

φ is the average porosity of the producing intervals.

The inputs for these estimates will come from well and petrophysical data. The locations of the production and injection wells can be used to define the A_i. The thickness from which fluid flows into or out from wells can be calculated by identifying original depth of oil-water contact, as defined by well log measurements, minus the depth to the top of the reservoir. These thickness values calculated for all of the production and injection wells within the CO_2 project area can then be used to estimate the h_i. Porosity values derived from well log estimates or physical measurements can be used to estimate the average φ_i across the h_i of each well.

To estimate the pore volume of an entire geological trap that contains the producing intervals, the volumetric formula can be used with different input values. The area and the thickness of the trap can be defined by locating the spill point of the reservoir, which is defined as the structurally lowest part of a reservoir that can contain buoyant fluids within the trap. As CO_2 is generally less dense than other in situ formation fluids (except CH_4 or light hydrocarbons), it is buoyant relative to those fluids and therefore tends to move upwards in the subsurface. Once the cumulative CO_2 injected "fills" the trap, any additional CO_2 injected into the trap can then "spill" outside of the trap and buoyantly move upwards into the adjacent strata. The spill point can be identified using seismic data if available, or cross-sections based on well log interpretations, or structural maps of the reservoir. The trap as defined by the spill point gives a maximum CO_2 column thickness, and a maximum area of the trap. The bulk volume ($A_i \times h_i$) can be estimated from the spill point, typically using stratigraphic software. If the spill points are not known, the area defined by the location of active and previously active production wells can serve as a proxy for A_i, but the potential CO_2 column thickness will need to be estimated. The well logs, core and well-based measurements used in the volumetric formula, can also be used to calculate the φ_i and the maximum CO_2 column thickness for the h_i within the defined area of the trap.

Due to the density difference between CO_2 and other in situ fluids, the CO_2 column thickness used in the volumetric method is subject to limitations. If CO_2 immediately underlies the seal to the trap, the pressure of the CO_2 can be excessive, depending on the thickness of the vertically continuous CO_2 column. As the CO_2 column thickness increases, there is a corresponding increase in the pressure at the top of the column and hence the vertically continuous CO_2 column must be compared to the thickness of the trap. The maximum CO_2 column thickness is determined by using the minimum of the seal's fracture pressure and capillary entrance pressure and the average CO_2 density in the column. If the calculated maximum CO_2 column is greater than the thickness of the trap, the entire trap can be used to store CO_2. If the calculated maximum CO_2 column is lesser than the thickness of the trap, the entire trap cannot be used to store CO_2, and the thickness used in the volumetric formula equals the maximum CO_2 column thickness.

7.1.2 Current fluid saturations, including CO_2, in the reservoir/storage zone at the time of transition

To facilitate the transition from CO_2-EOR to CO_2 storage, the distribution of fluids within the pore volume of the intervals defined by the CO_2-EOR well patterns at the time the transition begins is important in determining the predominant storage mechanisms and thereby quantify CO_2 storage for each mechanism. The challenge is to determine which of the remaining fluids will be displaced from the CO_2-EOR patterns to accommodate storage of the injected CO_2, and hence identify the storage mechanisms.

The possible fluids present are hydrocarbon gas, non-hydrocarbon gases such as nitrogen or H_2S, hydrocarbon liquid (oil), formation fluid or injected water (brine), and CO_2. If the CO_2-EOR project was a miscible flood, it is less likely that hydrocarbon gas is present. Furthermore, due to the vaporization/condensation process of CO_2-EOR, the oil will be enriched with CO_2, and the CO_2 will be enriched with hydrocarbons; therefore, there can be minimal native oil or pure CO_2 in the subsurface. The distribution of the fluids at the end of CO_2-EOR operations can be assumed using material balance calculations, which provides average estimates for the system and numerical flow modelling methods, which can provide more granular insight into the fluid distribution.

7.2 Mechanisms for additional storage

When evaluating the storage available within the volume of the intervals defined by the CO_2-EOR well patterns, using the operating practices at the time of the transition to storage, additional storage can be available via:

— an increase in CO_2 saturation within the CO_2-EOR patterns;

— an increase in storage pressure above CO_2-EOR operating pressure;

— an expansion of the storage area beyond the volume defined by the CO_2-EOR patterns or in different geological formations; or

— a change in operating practices to improve CO_2 sweep efficiency (e.g. change in pattern shape or size) or to optimize CO_2 storage (e.g. horizontal to vertical flooding).

To increase CO_2 saturation, hydrocarbon gas, hydrocarbon oil or water must be displaced or produced. The removal of water used during a water-alternating- gas (WAG) CO_2-EOR project, for example, can create significant additional CO_2 storage volume. Furthermore, displacement of hydrocarbons can be difficult to achieve, because a primary reason to transition from a CO_2-EOR to storage is that the CO_2-EOR project is producing high volumes of CO_2 relative to oil, which would be a consequence of high CO_2 saturation.

Depending on the operating pressure of the CO_2-EOR project, it is possible to increase storage pressure. However, if the CO_2 was injected near the regulated injection pressure, which is common with CO_2-EOR projects, then it is not possible to increase reservoir pressure. Nevertheless, the additional pressure within the same pore space would increase the density of CO_2 and therefore increase CO_2 storage.

Within the CO_2-EOR patterns, storage can be increased by increasing CO_2 sweep efficiency. This can be achieved by changing the injection well locations by increasing or decreasing the pattern size and thereby changing CO_2 flow paths from those developed from the previous injectors (during CO_2-EOR) to those during storage.

7.3 Assessing containment assurance in modified operations

The operator of a hydrocarbon recovery operation can use one or more operational changes to increase the quantity of CO_2 safely contained long-term in the EOR complex. Many of these changes can utilize elements of the existing physical infrastructure, the geological and geophysical data acquired from the prior operations, and general practical operational experience. Regardless of whether the particular action is viewed as coming within the scope of ISO 27916 or ISO 27914, the key operational concern will be on continuing to evaluate the containment assurance and, in particular, the impact that pressure changes can have on existing engineered systems and the EOR complex itself. As such operations are intensely site and project specific, the various scenarios discussed in this subclause are given for illustrative purposes only. Actual projects can resemble one or more of the scenarios discussed in this subclause or can follow different approaches or combinations of approaches over time or can apply different techniques for different sectors of an overall operation.

In each case, however, the containment assurance can be impacted by the proposed operational modification. In many instances, the key parameter will be potential changes in operational pressures, whether on the engineered systems (including surface facilities, wells and well components), the subsurface movement of the injected CO_2, or the geological formations themselves. Hence, the review and revision of the operational containment assurance and the EOR operations management plan as required by ISO 27916:2019, 6.1.3 would play an integral role in reviewing whether the proposed changes “have the potential to adversely affect containment”, considering the factors enumerated in ISO 27916:2019, 6.1.3 a) through g), i.e.: "a) unexpected changes in project performance that have potential to influence associated storage of CO_2; b) addition or abandonment of injection zones; c) change to the areal extent of the project reservoir; d) addition or abandonment of wells; e) anomalous change of injection-withdrawal ratio (IWR);

f) development of reservoirs which are located above or below the project reservoir; or g) discovery of CO_2 beyond the boundary of the CO_2-EOR complex."

Within the context of this review of containment assurance, 7.4 to 7.7 explore a number of operational modifications that can be undertaken.

7.4 Reservoir management

7.4.1 General

A critical component of any successful and secure CO_2-EOR project is a reservoir management plan that coordinates the injection for CO_2 and production of fluids (water, oil and gas, including CO_2) to maintain reservoir pressure and balance, and to progress the flood front. In a transition from EOR to increasing CO_2 storage, the reservoir management strategy would transition on a continuum towards increased storage effectiveness and generally decreased fluid production.

7.4.2 New CO_2 volumes — Increase of supply

In a typical EOR operation, the CO_2 purchase volumes decrease over time as quantities of CO_2 recycled from the production stream increase. Eventually, the need for incremental CO_2 decreases to a minimal volume that allows for pressure maintenance or even to zero if water chase is used. To transition a field to an operation that increases CO_2 storage, the CO_2 purchase volumes likely will be increased and managed throughout the reservoir to replace remaining free water.

7.4.3 Management of displaced water

Although displacing and producing oil allows for some associated storage in an EOR project, most opportunities for increasing CO_2 storage space are through displacement of water in the formation. In a typical reservoir management plan, the patterns or areas of the flood are managed by allocating CO_2 injection to the most efficient patterns that produce the most oil. As patterns become less efficient and oil production declines, the injectors in those patterns generally spend more time on water injection and less on CO_2. The patterns maintain pressure and continue producing, but eventually water out.

In a transition scenario, the oil production efficiency of a pattern would not play nearly as large of a role on CO_2 injection distribution as in a typical EOR project. Additional purchase CO_2 would be distributed to all patterns, effectively drying them up and filling some portion of the space from which the water is produced or displaced. This would allow the final state of the project to include mainly CO_2 in the pore space.

To dry up the system, an additional zone must be located, if disposal wells do not already exist, to inject the produced water to make room for the CO_2. This need for disposal capacity would be the highest initially as the wells are dewatering and would decrease with time as the CO_2 gets closer to production wells and decreases their produced water cut.

The reservoir management strategy for a transition project likely will include the reduction of recycled CO_2 where possible. This would include shutting in higher gas/oil ratio (GOR) wells while still balancing the overall injection/withdrawal ratio. Effectively this would mean tapering down the flood as the CO_2 gets to and dominates the production wells until eventually the project ceases and the CO_2 is safely and securely stored within the EOR complex.

7.4.4 Redesign of patterns

Pattern development for an EOR operation is designed to maximize the value of the flood given defined operating and capital costs as well as oil price. This optimization will generally lead to patterns that minimize capital spending while accelerating oil response as quickly as possible to offset large initial capital costs. This pattern development would not be the same optimization in a transition to storage where additional revenue streams other than oil sales are available.

As with the base design in any EOR flood, pattern redevelopment would involve updates to reservoir characterization including geological and simulation modelling. An updated history match of the flood performance would be critical to understanding where the current CO_2 is stored and predict what opportunities there are to increase the storage efficiency of the project. All these mechanisms would be modelled together and then, alternate pattern designs can be investigated and economics can be calculated to drive to the ultimate pattern reconfiguration. At a high level, the pattern reconfiguration is likely to involve an increase in well spacing that allows for a greater retention time of CO_2 injection between the injection well and the producers.

A critical component of any reservoir management plan, whether in EOR or through the transition, is to maintain reservoir pressure at the target levels. Elevating the pressure would cause a decrease in injectivity, distribution of gas beyond the pattern boundaries and decreased storage efficiency, all of which run counter to maximizing the efficiency of the project. In most cases, reservoir pressure balance is monitored and maintained through balancing the IWR at a pattern, area and full field level.

7.5 Well operations

7.5.1 General

As the presence of existing wellbores, transitioning existing hydrocarbon fields, particularly CO_2-EOR fields, provides an opportunity to access a high-quality reservoir for use as CO_2 storage. However, the existing wellbores can also be a risk for containment assurance due to the potentially large number of well penetrations and vintage completions of those wellbores. Clause 7 will explore the issues involved to allow the successful transition from CO_2-EOR to storage.

7.5.2 Creating a well inventory

Regardless of the age of the existing hydrocarbon field there can be wells that are no longer active and have been previously plugged and abandoned or are penetrations to deeper producing horizons. Creating a thorough well inventory is the first step to containment assurance and is one that has likely been done in preparation for CO_2-EOR. Depending upon the storage approach and the wellbores required, it can be necessary to deactivate or secure many wells. Other wellbores can be useful for their location, but their condition can be unknown. With a complete well inventory, a systematic review of the wellbores in comparison to the future needs, can be conducted. Potential future use of wells for injection, monitoring or production can be identified for further evaluation and integrity testing based on the known condition. Screening of wellbores for casing size, landing depth and known integrity issues can provide planners the ability to design the injection scheme and conduct additional reservoir performance modelling. Other factors such as surface casing setting depth and top of cement can provide insight to other storage considerations such as groundwater protection.

7.5.3 Repurposing wellbores for storage injection

Existing CO_2 injection wellbores can provide continued use as injectors for CO_2 storage. Operators and regulatory authorities can require additional assurance of integrity prior to commencement of conversion from injection for CO_2-EOR to CO_2 storage operations. While the type of well permitting required, if applicable, will vary by jurisdiction, the basic engineering and well construction issues involved are likely to be similar regardless of how a particular well permitting regime addresses them.

For example, in the United States, CO_2 injection wells used in EOR operations are permitted as Class II injection wells, while CO_2 injection wells for storage are normally permitted as Class VI wells [although continued permitting under Class II is possible where there is no increased risk to underground sources of drinking water (USDWs)]. Both well permitting processes serve to protect the USDWs and to ensure that there are no conduits for CO_2 to adversely impact usable drinking water.

When transitioning an EOR field to a non-EOR, dedicated CO_2 storage operation, several technical considerations will be reviewed to determine whether the wells can qualify for conversion to Class VI injectors. These considerations will be site-specific and weighed under the prevailing rules for the jurisdiction, as appropriate, including for example:

— Is the AOR sufficient for the updated development and reservoir management plan?

— Does changing the source of CO_2 from natural to anthropogenic impact the well permit or operations?

— Does the well construction provide sufficient protection to the USDW considering proposed changes to the reservoir management plan?

— Will there be adjustments to the operational monitoring plan to ensure containment?

— Is there a post-injection monitoring plan in place?

— How do the changes to the reservoir management plan impact field abandonment plans?

7.6 Application of operational modifications — Illustrative analysis

7.6.1 Containment assurance assessment in base case — Typical EOR

ISO 27916:2019, 3.9 defines the term “containment assurance” as a demonstration that the features and geological structure of a CO_2-EOR project are adequate to provide safe, long-term containment of injected CO_2 and that the CO_2 flood is operated in a way to assure containment of the CO_2 in the EOR complex. ISO 27916:2019, 6.1.3 specifies that the containment assurance and the EOR operation management plan “shall be revised as necessary if changes occur that have the potential to adversely affect containment.” ISO 27916:2019, 6.1.3 a) through g) provides a non-exclusive enumeration of some of the changes that can lead to such revisions. Hence, containment assurance is an active process applied by the operator to create a project that provides safe, long-term containment of the injected CO_2.

During typical EOR, the CO_2 plume is managed by fluid injection and fluid withdrawal by wells that are systematically arranged in patterns to achieve control. (See ISO 27916:2019, Clauses A.3 and A.13). The control of injected fluids is motivated by hydrocarbon production. The main factor that limits the production rate is the need to maintain pressure that creates miscibility with CO_2 in the hydrocarbon phase while avoiding viscous fingering or channelling of the CO_2 in direct paths from injection to production wells. This can be complicated by reservoir heterogeneity where preferential flow paths can be established via high permeability streaks within the formation.

To maintain the pressure sufficient to maintain miscibility, while maximizing the extraction of hydrocarbon, the operator will “balance” the flood project by assuring the sum of all injection (I) equates to the sum of all withdrawals (W) at reservoir conditions. This leads to an IWR of 1, which is to say a balanced system. The result of maintaining a balance between injections and withdrawal (i.e. where IWR = 1) is that both the magnitude and the area of elevated pressure reaches a quasi-equilibrium, and the project impact is aerially limited. This means that the appropriate AOR closely overlies the project area.

The impact of the pattern of injection and withdrawal wells is that hydrocarbons and CO_2 are drawn to production wells. Although cases of CO_2 by-passing the nearest production well are known, the pressure sink provided by production is reasonably effective at controlling the CO_2 migration. In a risk management context, the effect of the pattern flood is therefore to limit the area of the CO_2 flood. If the injection and withdrawal patterns are well designed and the reservoir properties cooperative, the area occupied by CO_2 is effectively limited to the project area.

In addition, EOR conducted in a hydrocarbon trap also has an important impact on CO_2 migration risk reduction. The lateral migration of CO_2 down-dip from injectors can be calculated from a review of a balance of viscous forces and gravitational forces.[2] Far from the injection well (100 m to 1 000 m), the drop off in viscous forces will cause gravitational forces to dominate and CO_2 downdip migration will reach a geographic limit.

Additional CO_2 and pressure management strategies have been used in EOR operations to manage the pressure distribution and extent and thickness of the CO_2 plumes. In many projects, CO_2 injection is augmented by water injection. This can take the form of alternating water injections with CO_2 gas injections, a technique known as WAG in the same injection wells to reduce preferential flow in high permeability thief zones or dedicated water injection wells that form curtains that limit CO_2 migration, for example into areas of the field that are not in part of the CO_2-EOR project. These strategies add control and reduce risks of unexpected CO_2 migration. Other combinations of strategies to optimize the CO_2-oil contact are available, including for example strategic perforations or additives to control relative permeability with additives of CO_2.

Another type of control is production management. Production is an essential part of pressure balancing the system. The ratio of hydrocarbon, CO_2, and water components in the production stream can vary considerably since it is not the composition of the production stream but the overall quantity of production withdrawal that is used to balance the pressure of CO_2 injections. One main limit on the amount of production is CO_2 breakthrough. When a production well produces more CO_2 or water than the operator wants to handle, the operator can choose to stop or reduce production in addition to changing injection strategies.

7.6.2 Assessing containment assurance in modified operations

7.6.2.1 General

If the operator seeks to increase the quantity of CO_2 stored in the reservoir, the operator can choose a different management strategy. It is important to assess if such modifications affect the assurance of secure long-term containment.

7.6.2.2 No change to operations (base case)

In some cases, the operator can continue to inject CO_2, recycle and produce decreasing hydrocarbons without changing the operational strategy. In this case, the risk profile of the project would not change and the same process can be used to ensure containment.

7.6.2.3 Changes in injection strategy

There are a number of changes that can be made to the injection strategy that can impact the project, including:

a) Substituting the CO_2 for water injection in a WAG (case 1A): This likely will cause minimal change in the risk profile but benefits the overall storage efficiency of CO_2. However, after a short time, it will likely result in faster CO_2 cycling and perhaps decreasing CO_2 storage amounts over time as the benefits of WAG injection will be lost. The storage assurance assessment will therefore be similar to the “no change” case.

b) Increasing fluid extraction to offset injection (case 1B): If the CO_2 injection rate is increased such that the overall injection volumes increase, fluid production will need to rise to maintain an IWR of 1. This additional fluid handling will have a cost. In some cases, well locations and completions can be changed to preferentially extract water, which would then be disposed of in a different zone.

7.6.3 Project IWR exceeds 1 (case 2)

7.6.3.1 General

This case arises when more CO_2 is added and is not completely offset by production volumes. Either the magnitude of pressure or the area of elevated pressure will therefore increase, thereby increasing the risk of the project. Issues such as exceeding the regulatory pressure limits, induced seismicity or hydraulically fracturing the reservoir or seal can arise. Wells at the periphery of the project will likely continue longer than wells in central patterns.

7.6.3.2 Project start is strongly pressure depleted (case 2A)

If a reservoir is strongly pressure depleted prior to start of the conversion operations, the “pressure space” available before the maximum safe operating pressure can be large. Hence, injection volumes can be much larger than production volumes as the reservoir system builds pressure. In some cases, production can become negligible as the operator “shuts-in” production wells to build reservoir pressure more quickly and allow for miscible operations. However, such an approach can prompt a desire for re-evaluating any geomechanical risk associated with this depleted to overpressure condition (e.g. on wells, thermal effects or induced seismicity).

7.6.3.3 Storage assurance assessment of CO_2 migration outside of the previously qualified EOR complex (case 2B)

Once the IWR exceeds 1, the risk of CO_2 migration outside of the CO_2-EOR project increases. The risks associated with this fugitive movement are dependent on the makeup of the neighbouring wellfield. Wells outside of the project can belong to another operator and not be prepared to receive CO_2 service. Thus, the risks for loss of containment due to zonal isolation, including corrosion-induced failures, can increase. Anomalous increases in oil and water production outside of the project can be indicative of a loss of areal integrity.

Movement outside the project also provides CO_2 access to geology that can contain transmissive features. These can be a vertical or horizonal transmissive section of a fault or fracture system that defined the original hydrocarbon-water contact. Additionally, this lateral movement can move CO_2 beyond the structural trap's spill point, resulting in a loss of containment.

7.6.3.4 Risks of pressure increase beyond the original project area (case 2C)

If IWR exceeds 1, the additional injection quantities will result in a pressure increase. This can become a problem if it encounters pathways that allow formation fluid to be lifted into a USDW or to the surface. In this instance, there can be an impact to water quality, which can necessitate remediation. In addition, this elevated pressure can cause unacceptable geomechanical impacts, such as induced seismicity, reactivation of faults or changes in land surface elevation.

7.6.4 Change in storage assurance assessment related to long term stabilization change during transition (case 3)

During EOR, active control of CO_2 is an important aspect of maximizing hydrocarbon recovery. As the reservoir management plan changes, the value lies in assuring storage. In most cases, after EOR conversion, containment assurance is high because there is a proven trap and the solubility of CO_2 into oil increases trapping. However, the long-term containment assurance of storage can be assessed to identify outlying cases, where long term migration of CO_2 cannot be ensured. For example, if the project does not include the crest of the structure or has incomplete coverage of the crests of the structure, understanding the long-term movement of the CO_2 and its ultimate position will become important. In addition, some hydrocarbon fields are dynamically charged, leaking hydrocarbons and possibly increasing the rate of CO_2 leakage as well.

7.7 Wells

7.7.1 Re-use

During the transition process, the existing well field must be evaluated to ensure the wells are suitable for further use. While wellhead equipment and tubing/packers can be changed, if necessary, reconfiguring the wells for more rigorous use can be more challenging.

The first step is to evaluate each well and its completion. The metallurgy employed in the casing strings and the quality, composition and coverage of the cement sheaths are evaluated to ensure:

— a lack of micro-annuli that can encourage fugitive CO_2 movement,

— the coverage of cement meets regulatory guidelines (e.g. some jurisdictions require cementing back to surface) and provides adequate coverage to provide storage complex integrity,

— the installed casing is compatible with the injectant, and

— the installed casing is free of pitting, wall thinning or other defects that can necessitate remediation.

In addition, the well service history can be reviewed as the past history of intervention can be predictive of possible future issues with the well. Also, it can be necessary to run new wireline logs (i.e. casing integrity or cement bond logs) and pressure testing to provide a current snapshot of the well's condition and integrity.

In most cases, if intervention is necessary to place additional cement to ensure a well is suitable for further use, this can be accomplished through cement squeeze operations. This is a process whereby the casing is perforated, and cement is “squeezed” through the perforations until the desired coverage is obtained. A casing pressure test then follows to ensure integrity has been re-established.

In some cases, existing wells are not suitable for operational use (e.g. injection or production). If completion is appropriate within the jurisdiction, these wells can be converted to deep monitoring wells for pressure, fluid sampling or time-lapse logging.

7.7.2 Abandonment

If the well is in such a state that it is no longer useful to the project due to integrity concerns, the well is plugged and abandoned commensurate with the field development plan. This process can include the following steps:

— removal of all non-permanent tubulars and downhole equipment,

— squeeze cementing the perforations,

— placing cement across the perforations and over the confining unit,

— cement plugs at key positions throughout the wellbore, including above the primary confining unit, at casing shoe locations, above any notable hydrocarbon producing zones (if applicable), just below any underground sources of drinking water, and at surface,

— cutting off the casing and welding a plate cap with the well details inscribed.

This process is designed to meet or exceed the minimum requirements of the regulatory authority and can require advanced approval of field abandonment executions by the jurisdiction.

7.8 Facility operations

7.8.1 Design assessment

Facilities designs for CO_2 storage projects are approached in the same manner as any oil and gas production project, with a needs assessment based upon the reservoir and production (injection) circumstances. Facility design will be dependent upon operating pressures, fluid compositions, rate projections and fluid dynamics. Therefore, a project assessment is necessary to identify the gaps between the existing facility components and design to those needed for the storage project. This gap assessment also needs to consider the remaining lifespan of the existing facilities within the context of an extended storage project to identify those modifications that would reasonably be expected in the future.

7.8.2 Facility integrity testing

The existing infrastructure for the current project can be assessed to identify whether it meets the requisites for the CO_2 storage project. Based upon the design assessment for the project, the existing infrastructure can be complementary and useful, need upgrades or need to be replaced entirely. Inspection of original design and as-built documents (design basis memoranda, process flow diagrams, regulatory applications, etc.), if available, will be a useful first step as not only will the capacities and design considerations be stated but will inform potential design change or upgrades as well.

A second step can include a review of recent inspection documents like pipeline smart pig log data and interpretations, corrosion tests, and vessel internal inspections. These inspections can be done at periodic facility turnarounds where vessels are depressured, drained and internally inspected to identify corrosion or defects in internal coatings.

Lastly, if there are areas of specific interest or concern, further inspections can be designed and carried out to assess the viability of the infrastructure for ongoing storage operations. Conducting these inspections prior to finalization of design basis documents would allow any necessary upgrades or replacements to be included in the cost estimate for the storage project instead of revising documents and cost estimates during the construction phase.

7.8.3 Measurement

For existing oil and gas production projects, lease custody transfer metering is the most rigorously maintained and calibrated method as it is the basis on which the operator is compensated for sales (i.e. oil and gas sales) or expensed for supply (i.e. CO_2 purchases). Field measurement at a well level is more often done for regulatory and reservoir management purposes and can be less frequently maintained. In the situation where CO_2 storage becomes a part of the project, additional scrutiny will be necessary for the recycle stream volume and mass estimates and compositions. In CO_2 storage projects, the compositional data becomes important for both reservoir management and storage quantification purposes, making meter calibration and accuracy particularly important. This can necessitate upgraded field measurement facilities on both the injection and production streams. At a field level, if a second CO_2 source is delivered to the project, then additional lease custody transfer meters will be necessary.

The ultimate goals for measurement is financial (CO_2 supply, oil and gas sales, water disposal), regulatory (quantification of storage, facility permits and well reporting) and reservoir management. Each of those goals will prompt their own individual and overlapping design and operational requisites.

7.8.4 Projects that are not currently CO_2-EOR projects

Oil and gas fields with no prior CO_2 will need new CO_2 injection facilities. This will primarily be those fields that have previously produced oil or gas but where no hydrocarbons are expected to be produced (unless as part of a dewatering scheme necessary for pore space voidage) or where ongoing hydrocarbon production continues concurrently with CO_2 storage injection (see case study no. 3).

For those fields where water removal is requisite, the facility infrastructure can make use of hydrocarbon production pipelines and facilities, although upgrades will be necessary for corrosion control when CO_2 breakthrough occurs. It can be reasonably assumed that if water production is conducted during CO_2 injection operations, CO_2 breakthrough will occur. The operator can simply mitigate breakthrough and the impact on facilities by shutting in those wells when CO_2 breakthrough occurs.

Methane and other components dissolved in produced water can also necessitate management. If the project is a gas field, the existing inlet separation will likely be for higher operating pressures and liquids handling capacity, which can become the concern. On the injection side, the CO_2 injection infrastructure will need to be installed, much in the same manner as for a new CO_2-EOR system, except for CO_2 recycle compression. If CO_2 breakthrough is expected as part of the reservoir management plan, then some small CO_2 compression will be necessary to conserve and re-inject the produced CO_2.

For those fields where future production is not necessary for reservoir management and therefore no production capability is necessary, minimal additional infrastructure will be needed; only those injection distribution pipelines, injection well metering satellites/manifolds and injection well flowlines will be needed.

7.8.5 Recycle compression capacity

For storage projects that would be extensions of existing CO_2-EOR projects one of the significant benefits is the pre-existence of recycle compression. If the current CO_2-EOR utilizes a WAG recovery approach, the existing infrastructure will be undersized if the WAG cycles become drier (less water injected and more CO_2 per cycle) or if the recovery process changes to continuous CO_2 injection. Additional trains of CO_2 compression can be installed, but a site and design reassessment will be necessary to ensure the necessary plant site footprint can accommodate the additional equipment. Furthermore, if electrically driven, electrical power supply through wired connections and substations will be needed as compression power demand will be significant. If powered by natural gas, then alternatively an adequate fuel supply will be needed for the increased compression demand.

Furthermore, inlet separation and cooling facilities are also associated with additional recycle compression. WAG operations use larger free water knockout vessels for inlet separation and often have lower pressure ratings. If the CO_2 storage approach is targeting increased CO_2 pore saturation in the reservoir, then over time, the produced fluid stream will consist less of water and more of CO_2. The pressure of the inlet stream to the facility will also increase which together will necessitate the replacement of free water knockout vessels with higher pressure rated inlet separators. Naturally, if the inlet separation vessel operating pressure increases, the capacity of the existing compression can benefit in terms of rate capacity. However, the field gathering infrastructure can be challenged as the requisite higher operating pressures can exceed its design and licensed operating pressure.

In the case of increasing the operational reservoir pressure, modifications to the existing compression will likely be necessary to accommodate the higher compression discharge pressure. While often the compression units themselves can be able to operate at higher discharge pressures, the discharge piping and any associated vessels (like interstage cooling or dehydration) can necessitate recertification or replacement. This would also be necessary for the injection pipelines and well flowlines.

7.9 Monitoring

7.9.1 Monitoring design

Monitoring is designed to provide assurance that the containment of CO_2 based on the geological characteristics and operational processes is attained and that no damaging events occur. During transition, project monitoring needs can remain the same or change gradually or sharply from what was previously needed. Risk changes during transition and the monitoring design will be altered to help ameliorate those risks. The number of possible adjustments is large, and can include:

— the development of a new monitoring plan (e.g. in response to accepting CO_2 for storage when previous injection had not involved CO_2 or did not necessitate a monitoring plan);

— the adaptation of an existing monitoring plan to produce the data that are needed to document confinement for accounting of the final project, if this was not done previously;

— the adaptation of an existing monitoring plan to produce data that are needed to meet public acceptance, environmental assurance or regulatory goals, if the change in conditions necessitates such adaptation;

— the establishment and re-establishment of baseline data can be required as the project develops over time.

It is also possible that maintaining the status quo is acceptable if the monitoring plan sufficiently meets the monitoring needs during the transition.

Transitioning a project from EOR to storage can result in a change in the regulatory authority or a change in governing protocols (see Clauses 9 and 10), necessitating review of the monitoring program to ensure the desired changes and schedules remain consistent with those required by the oversight authority. Possible monitoring plan alterations can include:

— more formal accounting for fluids injected and removed (e.g. increasing accuracy, frequency, calibration, recording or summation activities);

— the addition of subsurface measurement in the reservoir zone or in the overburden, for example of pressure or temperature, fluid composition(s), chemistry or tracers, wireline logging for saturation, or state of stress;

— geophysical monitoring techniques such as time-lapse seismic, gravity, electrical methods, or other geophysical methods to track CO_2 dispersal and document conformance in the injection zone;

— additional testing or reporting to demonstrate well integrity, for example downhole or surface-based surveillance of active, temporarily abandoned or plugged and abandoned (P&A) wells involving tools such as pressure, temperature, wireline-based inspection, groundwater or soil gas testing; and

— focused or regional monitoring of groundwater, soil gas, ecosystem to document no damage caused by project.

The selection of monitoring protocols is based on

a) the identification of the need that the monitoring will fill,

b) evidence that the monitoring is cost-effective and appropriate to that need, and

c) a process for interpreting monitoring results, including finding success as planned or creating a corrective action if needed.

7.9.2 Role of baseline

The role of baseline in a project in transition is very different from its role in a greenfield project and will likely necessitate a monitoring design adapted to this different role. The establishment of a transition baseline will be essential in evaluating the project, from both commercial and regulatory points of view, over its life. The issues to be considered include the following.

— Anomalies related to hydrocarbon accumulation dominate in the reservoir and can impact rocks and fluids that are brought to the surface in ways that affect the options for monitoring. For example, the presence of hydrocarbons can limit physical and chemical techniques for detection of CO_2. The impedance contrast between pre- and post-CO_2 injections is reduced by the presence of gas and, to a lesser extent, the presence of oil. The conversion of hydrocarbons to CO_2 by biogenic processes above the reservoir can create CO_2 concentration anomalies in overburden, water or soil.

— Preceding extraction operations will have created a strongly perturbed setting. While subsurface pressures are typically reduced by extraction, CO_2 injections can elevate these pressures and can create a complex pressure field. Fluid distribution likely has changed because of extraction and natural or engineered replacement by allochthonous fluid. Zones besides the intended injection zone can be affected and the equilibration period can be lengthy.

— Surface and ecosystems likely have been perturbed and can be in non-equilibrium states. Perturbation includes road, pad and drainage construction, brine and hydrocarbon spills and mud pits, and remediation and clean-up operations (if legacy issues prompt them).

7.9.3 Development of model(s) prior to storage

Modelling is a very powerful tool that interlocks with monitoring. Models serve as proxies for dynamic geological systems that aid in predicting the evolution of the system under CO_2 injection. Well-designed monitoring allows for calibration of models and the demonstration and improvement of the predictive capabilities. The accuracy of a model depends in great part on its design.

If the model is used to determine the response of the storage complex to an unexpected but unacceptable event, then the distinctive indicators of such an unacceptable event are identified. The indicators that precede the event can also be identified. Monitoring targeted to detect distinctive indicators then can be used to demonstrate that the project is avoiding unexpected but unacceptable events. If the modelling does not reflect the results of the monitoring and is simply used as a history match without substantially changing the model, the modelling can become less valuable because many “matches” can be possible, not all of which uniquely eliminate uncertainties.

Modelling is also used to design an effective monitoring design that is sensitive to the expected or indicator signals, that is deployed at the relevant times, focused on the appropriate locations, and that has suitable sensitivity.

7.10 Quantification

7.10.1 Existing quantification practices

Oil and gas operators have for decades monitored and measured (e.g. quantified) the volumes of CO_2 utilized in their operations for operational and commercial purposes, due to the cost of the CO_2 injectant. Quantification is critical for CO_2-EOR as it relates to contractual obligations as well as evaluating the efficiency of CO_2 use within a project. Even if an oil and gas operator has broadly recognized any losses on a field-wide basis, there has been no need or regulatory requirement until recent years to account for or report sub-surface or the *de minimis* surface losses (fugitive emissions) associated with normal operations. More recently, because of the value potentially available through various carbon dioxide accrediting schemes, quantification practices have now become better defined.

ISO 27916 includes detailed quantification practices and protocols for projects for new or expanded CO_2-EOR projects used for CO_2 storage purposes. Typical data collected from monitoring CO_2-EOR projects for EOR operational purposes can be used in the quantification of the associated CO_2 storage. ISO 27916 has adopted the following quantification principles:

— the determination of the CO_2 mass stored in association with CO_2-EOR by subtracting surface and subsurface losses from inputs;

— the quantification of associated storage to ensure completeness and precludes double counting; the CO_2 that is recycled and reinjected into the EOR complex is not quantified as additional associated storage;

— the quantification and documentation of native or in situ CO_2 produced and captured in a CO_2-EOR project as an input, where existing; in situ CO_2 exists in many locations worldwide (e.g. Permian Basin 4 % to 20 %, West Texas Trans-Pecos region 30 % to 70 %, South China Sea 70 %); and

— the quantification of the loss of any CO_2 that has previously been quantified and subsequently produced from the EOR complex and transferred offsite.

For expanding projects which can previously have included inputs of in situ or native CO_2, naturally sourced CO_2, previously non-accredited or accredited anthropogenic CO_2, or any combinations of which, such volumes must be documented or quantified, and ratioed or tracked.

7.10.2 Application to transitioning CO_2 storage scenarios

The illustrated scenarios can be broadly described as either existing CO_2-EOR projects transitioning to CO_2 storage or expanded CO_2 storage (scenario categories 1 and 2 in Clause 6), or as non-CO_2 projects being converted to CO_2-EOR with a specific storage focus (scenario category 3 in Clause 6). As such, the existing quantification standards of ISO 27916:2019, Clause 8 and Annex D would be applicable to associated storage in the CO_2 storage complex if hydrocarbon production occurs. In the second case, if hydrocarbon production ceases before CO_2 injection occurs, ISO 27916 is not applicable but a similar quantification can be used.

The scenario category 1 of an existing CO_2-EOR project with incidental CO_2 storage transitioning to CO_2 storage with ongoing hydrocarbon (HC) or incidental HC production under status quo operational practices does not change the quantification calculation. Hence, the quantification protocols of ISO 27916 or an approved equivalent can be applied.

The scenario category 2 presumes that the transition to storage eliminates production in the project and will result in a relatively short-lived, low volume storage project. If CO_2 injection occurs with production, ISO 27916 or an approved equivalent can be practiced, and if not, can simply be initiated. This scenario can involve H_2O-extraction wells downdip/off structure (on-structure H_2O-production will carry entrained CO_2) to make room for additional desired storage in the project. However, such practice does not impact the quantification approach within the CO_2 storage complex. If the project does not include hydrocarbon production with CO_2 injection, ISO 27914 is appropriate. See Clause 9.

The scenario category 3 is simply the initiation of a new CO_2-EOR project with either a primary or secondary purpose of storage. ISO 27916 or an approved equivalent can be used to quantify the associated storage resulting from the project.

8 Case studies

8.1 General

To better illustrate how the technical analysis in Clause 7 can apply in particular cases, Clause 8 reviews three hypothetical case studies. While actual commercial projects can include a variety of variations on these general themes, the cases that are reviewed are hypothetical only and are intended to highlight key technical characteristics presented by the proposed operations. How a particular operation can be viewed under ISO 27914 or ISO 27916, and under some selected legal and regulatory frameworks is addressed in

Clause 9 (which provides a comparative review of ISO 27914 and ISO 27916) and Clause 10 (which examines legal and regulatory frameworks).

8.2 Case study no. 1: Optimization of CO_2 storage in an actively producing CO_2-EOR project

8.2.1 General

This set of operational changes consists of actions aimed at increasing the amount of CO_2 injected and stored in CO_2-EOR operation either by increasing the amount of pore space in a defined containment that is filled with CO_2 or by extending the previously defined containment either laterally or vertically. These project variations generally have existing facilities that can be sufficient for the immediate needs of CO_2 storage, but over time can necessitate upgrades for injection system operating pressures, recycle rates, and field distribution and gathering. These projects can be termed "CO_2 maximization or optimization" projects.

This case study is a hypothetical oil field (the "Soda Field") where CO_2 enhanced oil recovery has been underway for several years. This case study explores the additional storage potential, which can result in a change in risk profile, for the field using:

— an increase of the pore saturation with CO_2;

— an increase of the reservoir pressure; and

— the injection into downdip areas to increase accessible pore volume to CO_2.

This hypothetical field was discovered in 1963 when the well Soda no. 1 was drilled to a depth of 1,550 m and encountered an oil-bearing zone at a depth of 1,500 m. To facilitate this example, the oil qualities of the Joffre Viking oilfield (an actual field) are used[3]. Some of the key reservoir characteristics are:

— P_i = 7,75 MPa (1,124 psi[1]);

— T_i = 56 °C (133 °F);

— 40° API paraffinic crude;

— P_{BP} = 7,8 MPa (1,130 psi);

— B_{oi} = 1,24 Rm^3/m^3 (1,24 Rb/STB);

— R_s = 73 m^3/m^3 (410 scf[2]/STB);

— original oil in place (OOIP) is equal to 84 million stock tank barrels (MMSTB).

— The formation fracture pressure is equal to 24,7 MPa (3,575 psi).

The reservoir is a stratigraphic trap of sands deposited in a near-shore, shallow marine depositional environment. The sand is overlain and underlain by a thick section of marine shale. Deep burial of the sands and shale with erosion of overlying strata has resulted in the reservoir being underpressured compared to a typical hydrological gradient. The field was developed on a 32,4 ha (80,0 acre[3]) well spacing for primary production prior to waterflood on 64,7 ha (160 acre) pattern spacing.

In 1994, CO_2-EOR was implemented using CO_2 captured from a nearby petrochemicals plant. The reservoir and hydrocarbons are suitable for CO_2-EOR with a slimtube analysis indicating the miscibility pressure is 12 MPa (1,740 psi). The patterns and water injection wells used for waterflood were converted to CO_2 injection. Due to limited CO_2 source availability, cost and reservoir sweep management, WAG was applied as part of the flood. The general design of the flood was to inject approximately 0,3 HCPV of CO_2 at a design reservoir operating pressure of 14 MPa (2,030 psi) prior to initiating the first water injection cycle. A WAG ratio of 1:1 was used for the entire life of the flood. Produced CO_2, including hydrocarbon gases absorbed

1) pounds per square inch.

2) standard cubic foot (i.e. cubic foot of a gas at standard temperature and pressure).

3) 1 acre = 0,405 ha.

from the in situ oil, was recycled and mixed with purchased CO_2 prior to re-injection. Purchased CO_2 volumes decreased with time as increased recycled CO_2 accumulated and over the project life approximately 5,0 million tonnes (Mt) of purchased CO_2 was injected, which is approximately 46 % of the HCPV of the flooded patterns.

CO_2-EOR has continued at the Soda Field, and the project is nearing its economic end. The operator of the field has been approached to receive additional CO_2 volumes for a fee which would provide the operator with additional cash flow to continue operations. To accommodate the additional CO_2 to be stored, the operator needs to:

— discontinue WAG and implement continuous CO_2 injection or modify injections to reduce water cycle to shorter periods to maintain a good distribution of CO_2 within the reservoir,

— develop 16 additional downdip and edge patterns that were not initially developed due to lower oil saturations or low OOIP, and

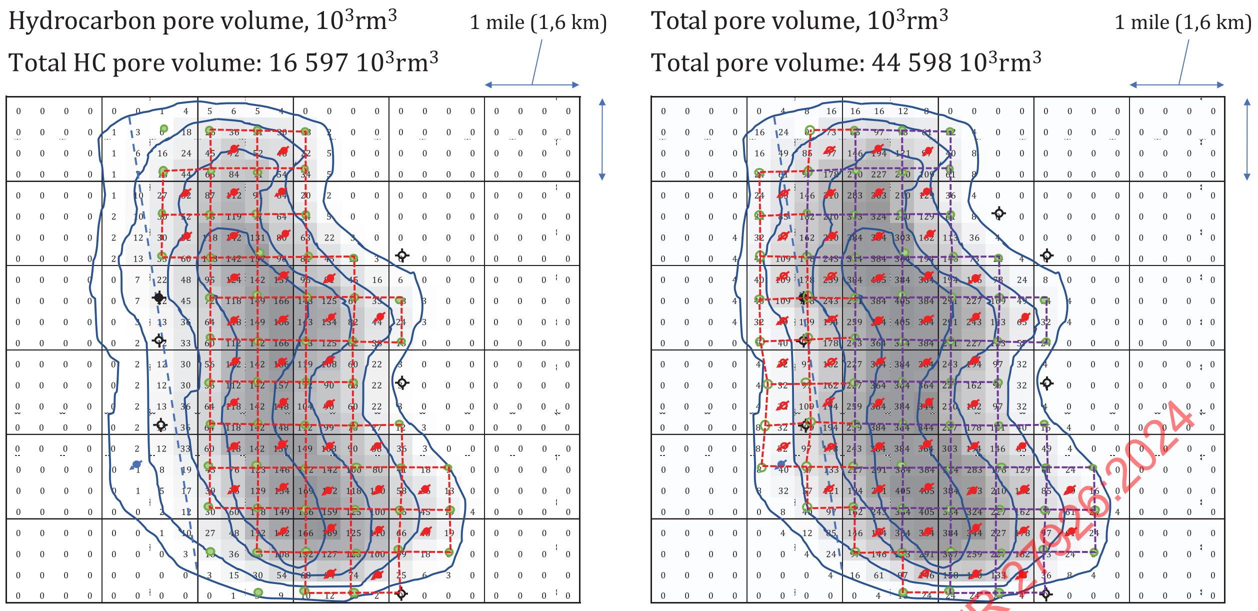
— increase the operating pressure of the field to 95 % of the seal hydraulic fracture pressure.

8.2.2 Storage phase 1: Discontinuation of WAG and implementation of continuous CO_2 injection

At the time storage operations commence, the field WAG recovery scheme has resulted in an in situ CO_2 gas (recycle) saturation of approximately 46 %. Converting the existing field to continuous CO_2 injection (CCI) will result in a higher ultimate CO_2 gas pore saturation, estimated to be 60 % HCPV and, in the process, the existing water saturation of the pore space will be reduced. Any mobilized oil will also reduce its pore saturation. Therefore, a higher demand for water disposal capacity and continued oil sales capability will be triggered. The ultimate CO_2 gas pore saturation at the end of storage operations depends on the sweep efficiency of the reservoir through active pattern management. For the first phase of additional CO_2 storage via CCI, the reservoir operating pressure continues to be 14 MPa. Based on a well-managed pattern flood, the target of 60 % HCPV CO_2 saturation will result in an approximate additional 0,82 Mt.

8.2.3 Storage phase 2: Additional pattern development

In this example of the Soda Field, only a portion of the reservoir pore space was developed for oil recovery. Additional pore space is available downdip and had a higher water saturation (reducing primary, secondary and tertiary recovery economics) or is in edge patterns where the total accessible HCPV was too low for economical production. Depending upon the project economics for CO_2 storage, additional pore space is available but will necessitate additional injection and production wells. The project economics will include revenue for CO_2 storage in addition to oil sales revenue for those new patterns. For discussion purposes, the new infrastructure at the Soda Field will be assumed to be economical and constructed.



Key

- dry and abandoned
- oil producer
- produced and abandoned
- water injection well
- net sand isopach line
- existing pattern boundary
- storage pattern boundary
- proposed storage producing well
- proposed storage injection well
- existing CO_2 injection well

Figure 2 — Comparison showing additional pore volume for CO_2 storage

As shown in Figure 2, 16 new injection patterns have been created to access additional pore volume in the reservoir. During the prior hydrocarbon recovery schemes, the development targeted the economic portions of 23,4 10^6 Rm^3 (147,5 MMRb) of hydrocarbon pore volume. This included the original waterflood patterns have a spacing of 64,7 ha (i.e. 160 acre), which were later converted to CO_2-EOR patterns. With the new goal of maximizing total value from the combined revenue streams of hydrocarbon sales and CO_2 storage revenue, accessing total pore volume (as opposed to hydrocarbon pore volume) can now become an economic driver. In this case study, new patterns will use continuous CO_2 injection and will continue to operate at a reservoir pressure of 14 MPa to facilitate dewatering while continuing to assess reservoir integrity for the new area.

For incremental CO_2 storage, adding these injection patterns to the storage project can provide another 8,2 10^6 Rm^3 (51,3 MMRb) or approximately 37 % of pore volume to flood.

8.2.4 Storage phase 3: Reservoir operating pressure

8.2.4.1 General

Increasing the field's operating reservoir pressure will be achieved through continued CO_2 purchase, continued recycling of produced CO_2/HC gases but with reduced liquids production. As the higher quality (permeability and porosity) patterns will have reached high recycle rates during the prior two phases of storage, the interior production wells can be shut-in which will effectively increase the storage project's

IWR, thereby increasing reservoir pressure. Increasing the reservoir operating pressure will provide additional storage potential by (in the order of impact):

a) compressing the existing dense phase CO_2 (and associated hydrocarbon gases);

b) compressing the remaining oil in place;

c) compressing the remaining water in place (generally negligible for practical purposes); and

d) compressing rock formation (negligible).

For this case study, the additional pore space available due to the compression of the remaining oil and water in place and of the reservoir rock is assumed to be minimal compared to the compression of CO_2. A maximum reservoir storage pressure of 22 MPa is targeted, based on 95 % of the estimated hydraulic fracture pressure.

For incremental CO_2 storage, the resulting additional storage attributable to increasing the pressure of the CO_2 and associated HC gases is 7,1 10^6 Rm^3 (44,6 MMRb) from the injection of an additional 5,2 Mt of purchased CO_2, an increase of 56 % compared to CO_2 purchased for CO_2-EOR and the previous two phases of CO_2 storage.

8.2.4.2 Operational approach

The operational approach for storage will continue the approach used for CO_2-EOR. CO_2 received for storage will enter the injection stream downstream of the recycle compression and will be effectively commingled prior to the injection manifolds. As the proportion of recycled CO_2 (containing HC gases) to new CO_2 can fluctuate, it is important to monitor the stream composition at the injection manifold on a regular basis. Operationally, this would be done monthly such that the metered volumes can be calibrated to the stream composition. As little remaining oil will be liberated during the storage phases, it is expected that the composition of the recycle CO_2 will have a decreasing HC concentration. This will assist the storage operations by increasing the CO_2 density and thereby improving the efficiency of the existing compression.

During storage phase 1, with water no longer being injected into the patterns, recycled CO_2 will breakthrough quickly to the producing wells. Although injection processing rates initially will be similar to CO_2-EOR, once breakthrough occurs, the processing rates can be increased significantly. However, this depends upon the economics of the storage operation and how much investment can be tolerated for additional recycle compression. During storage phase 1, new CO_2 volumes will be reduced significantly as recycle volumes increase. Therefore, it will be important to stage phase 2 pattern expansions to allow the storage project to continue to receive the new CO_2 rates. During phase 1, water disposal needs will be high as CO_2 injection displaces water in the reservoir. After CO_2 breakthrough, water production will begin to decline, but the existing water processing capacity will still be necessary for storage phase 2.

During storage phase 2, the injection stream will continue to be a mixture of new CO_2 and recycled CO_2 from the CO_2-EOR patterns and can often include other produced gases that are recompressed and added to the new injection stream. This will allow flexibility to use a common CO_2 injection source as CO_2 breakthrough occurs in the new patterns. With only CO_2 injection into the new patterns, dewatering from the new production wells will provide the voidage necessary to maintain an IWR of 1,0, necessary to maintain the existing reservoir pressure of 14 MPa. During this time, oil production will be expected to be significant as this area of the reservoir has not previously been processed. This is despite oil saturations being low enough that primary oil production would not have been economical but can be mobilized with CO_2. Therefore, the expense of drilling new wells and installing the necessary injection and production infrastructure will receive some revenue from oil sales. As in storage phase 1, once CO_2 breakthrough occurs, additional recycle capacity will be needed. Again, this will be an economic decision and will depend upon the oil revenue and timing of the commencement of storage phase 3. During phase 2, it is expected that the existing CO_2-EOR liquids handling facilities will be sufficient for continued storage operations and no further investment will be necessary.

During storage phase 3, production wells on the interior patterns of the project will be shut-in as the recycle ratio for those patterns will simply be too high to support ongoing operations. As a result, continued CO_2 injection into those patterns will result in an increasing reservoir pressure for those patterns. Out of pattern CO_2 movement will occur and recycle rates in adjacent patterns will increase unless those producing wells are choked back or shut-in all together. It is expected that as the project matures and new CO_2 deliveries are received, more and more producing wells will be shut-in, and production will move to the extreme periphery of the field. Ultimately, all producing wells will be shut and the recycle compression will no longer be necessary. The timing of the shut-down of recycle compression will be an economic one.

8.2.5 Wells during the additional storage phases

During storage phases 1 and 2, well operations will continue similarly to CO_2-EOR. Initially, artificial lift can still be requisite for producing wells to facilitate dewatering. As CO_2 breakthrough occurs and gas-liquid ratios increase, producing wells can be converted to a flowing well configuration which can include the use of bottom hole packers to minimize surface casing pressures. As part of stage 2 development, all wells will be constructed to be CO_2 compliant (e.g. using coated tubulars, internally coated wellheads and valves with stainless steel trim) as per CO_2-EOR specifications. Similarly, injection flowlines and production flowlines will be internally coated for corrosion resistance. Dependent upon the water content of the CO_2 injection stream, injection flowlines and well tubulars would not need coating.

During storage phase 3, additional downhole inspection of existing wells can be necessary to ensure integrity at higher reservoir and well operating pressures. This can involve well interventions for casing and cement integrity testing. It can also involve replacing tubing and packer assemblies that can be corroded during prior operational periods.

As the project matures and producing wells, and injection wells are shut-in, they will need to be plugged and abandoned to ensure reservoir integrity. As reservoir pressures will continue to rise during the life of the project, the timely plugging and abandonment of wells will be important as plugged wells will be impacted by higher downhole pressures. The higher the reservoir pressure, the more extensive the well control measures will be during plugging and abandonment operations (well kill fluid density, snubbing operations, etc.). Timely plugging and abandonment of wells will also allow continued monitoring to ensure storage integrity during ongoing storage operations.

8.2.6 Other facilities during the additional storage phases

The facilities installed for CO_2-EOR include:

— CO_2 metering receipt station for CO_2 purchase custody transfer;

— injection satellites/manifolds for water and CO_2 to facilitate measurement and WAG cycles;

— multiphase flowlines from wells to test satellites;

— test satellites including pig retrieval manifolds;

— separate liquid and gas group lines from satellites to central facilities;

— central facility with a free water knockout vessel, oil treater and fluid tankage;

— CO_2 recycle compression and field distribution pipelines;

— water treating and injection/disposal pumps; and

— oil sales lease automatic custody transfer (LACT) unit.

During CO_2-EOR operations, the recycle compression included a low-pressure booster and a higher-pressure injection unit. Both units were reciprocating compression units due to the relatively low volumes of CO_2 recycle.

During storage phase 1 the existing field infrastructure will be sufficient for the early dewatering period. As CO_2 breakthrough occurs, additional capacity will be needed to manage the increased CO_2 recycle rates and higher inlet pressures. As CO_2 recycle rates increase and liquid rates decrease, the low-pressure free water knockouts will be replaced with high pressure inlet separation vessels. Field gathering flowlines would need recertification for higher operating pressures or replaced depending upon their condition. Additional CO_2 recycle compression will be needed although inlet booster compression will no longer be needed. Based on the expected recycle rates, reciprocating compression will still be used, and additional units will be installed as incremental ‘trains’ as recycle rates increase.

During storage phase 2, the liquids capacity of the central facility will be sufficient to handle the expected oil and water production from the new patterns. As with the original CO_2-EOR area, as CO_2 breakthrough occurs, additional CO_2 compression capacity and likely inlet separation capacity will be needed to support the higher recycle rates.

As mentioned above, economics will drive all facility investment to ensure that the capacity to manage increased CO_2 recycle is balanced with the expected project life and income streams.

During storage phase 3, the production infrastructure would be scaled back as producing wells and their associated flowlines and test satellites are shut in. The main field gathering lines will be needed until the late stages of storage but well flowlines can be abandoned as wells are decommissioned. Eventually, the central production facility size will be scaled back as production and recycle volumes diminish. Decommissioning of facilities will be an ongoing effort during continued operations to ensure the costs are offset by ongoing storage revenues.

8.3 Case study no. 2: Engineered CO_2 storage following termination of CO_2-EOR hydrocarbon recovery operations

8.3.1 General

This case study explores the scenario of transitioning the oil field from a CO_2-EOR operation to an engineered geological storage operation “without” any incidental hydrocarbon production. Issues include avoiding hydraulic fracturing, activation of any faults present, pressure maintenance, and utilization or abandonment of existing EOR infrastructure. In some jurisdictions it can also be possible to further store CO_2 in water disposal wells. In this hypothetical case study, the operator is Brilliant Idea Oil LLC (BIO LLC), a well-known oil company. CO_2-EOR has been underway for several decades in its largest oil field, mature and depleted field (MDF) following a few initial years of primary production and several decades of secondary water flooding. Produced water cut is currently disposed in water injection wells in local saline formations. BIO LLC has determined that the CO_2-EOR operations at MDF are becoming uneconomical, given lift costs and forecasted oil prices. Given its favourable location near companies that are highly motivated to decarbonize, BIO LLC has determined that repurposing the oil field to accept CO_2 for engineered geological storage only can be more profitable than continuing ongoing CO_2-EOR operations. A key benefit of the transition to engineered geological storage is the potential to utilize existing infrastructure at the oil field and a regional CO_2 pipeline that is currently used to deliver natural-sourced CO_2 for EOR operations.

Case study no. 2 provides some generic considerations to be considered for transition from EOR to engineered storage without additional oil recovery, the areas of the EOR field that can be considered for transition to engineered storage and a simplified issue analysis for this scenario.

Items that encourage technical feasibility in this case study no. 2 are:

a) the ability to utilize existing infrastructure such as pipelines, field lines, wells and pumps;

b) extensive understanding of the geology and reservoir characteristics;

c) avoidance of near-term decommissioning costs and brownfields redevelopment;

d) supply chain and key personnel with institutional knowledge in place;

e) higher incentives with storage versus CO_2-EOR; and

f) value proposition and life cycle analysis of storing CO_2 without oil production.

8.3.2 Points to consider in using existing CO_2-EOR infrastructure

8.3.2.1 Repurposing existing CO_2-EOR injection well infrastructure for geological storage

With regards to planned re-use of well infrastructure, likely questions include:

- Are the well construction and cement integrity acceptable?
- Are well casing materials compatible?
- Are surface casing depths suitable?
- Are recent mechanical integrity test results acceptable?
- Are casing size and tubing sufficient to accept injection rates at new design pressures?
- Are perforation locations and design sufficient to accept desired flow rates at new design pressure?
- Are existing well locations and depths suitable?
- Is the remaining longevity of the wells realistic compared to the cost of drilling new wells?
- Any risks of damage to well(s) with modification or conversion from CO_2-EOR to geological storage?
- Are there any considerations for partial reuse, for example, the reuse surface casing and deviation to a different bottom-hole location or deeper well section?
- Is there a potential for reuse of associated infrastructure: roads, well pads, drainage?

8.3.2.2 Re-purposing wells for water extraction or disposal (if needed for pressure maintenance)

With regards to re-purposing wells for water extraction or disposal, points to consider include:

- Are well locations and depth suitable?
- Are perforation locations and design sufficient to extract or accept the planned water injection rates at planned pressure?
- Are well materials and construction acceptable for transition?
- Are there any risks of damage to well(s) with modification or conversion from CO_2-EOR to geological storage?
- Is there potential for reuse of water handing equipment: pumps, flowlines, tanks?
- Are there methods for handling incidental oil from former reservoir sands?

8.3.2.3 Use of existing CO_2 pipelines and field distribution and gathering lines

Points to consider when evaluating the use of existing CO_2 pipelines and field distribution and gathering lines include:

- Is the capacity at pressure rating sufficient to support reuse?
- Is the remaining longevity of the pipelines realistic compared to the cost of new field lines?
- Any potential for reuse of non-CO_2 pipelines?

8.3.2.4 Use of compression equipment and pumps

For compression equipment and pumps, relevant considerations include:

- Is the throughput sufficient for the injection rates and pressures of the new operation?

— Is the remaining longevity of the compressors and pumps realistic compared to the cost of new equipment and are the compressors and pumps fit to task?

8.3.2.5 Repurposing existing injection, production, or water injection wells as monitoring wells

With regard to re-purposing existing wells (whether CO_2 injection wells, production wells or water injection wells) for monitoring, points to consider include:

— Is well construction suitable for modification for monitoring purposes including, well casing size, casing cement placement and perforations?

— Is well integrity acceptable?

— Are well locations and depths suitable?

— Are well materials and construction acceptable?

— Is the remaining longevity of the wells viable or would it be more cost-effective and technically feasible to drill new wells?

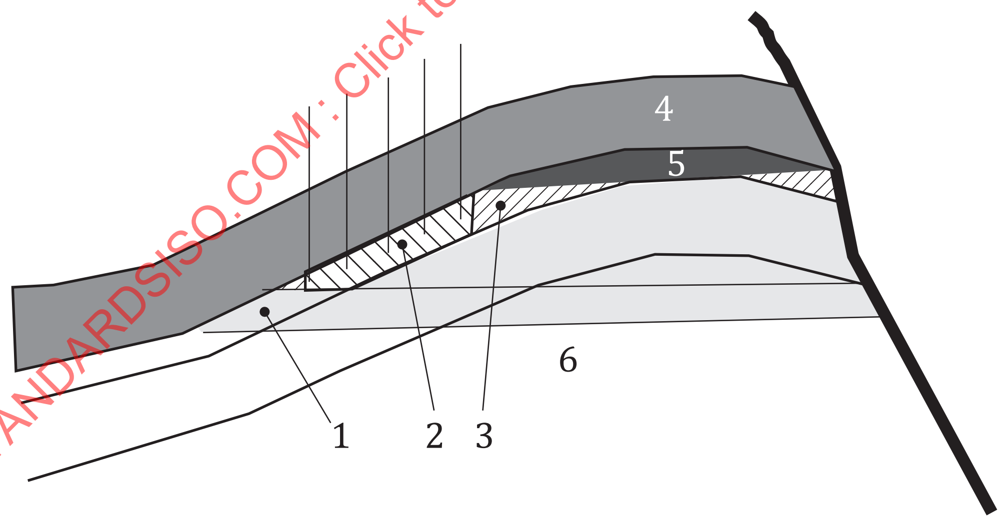
— Is there potential for reuse of existing water handing equipment: pumps, flowlines, tanks?

— Is there a risk of damage to well(s) with conversion?

8.3.3 Areas of the oil field considered for transition to engineered CO_2 storage

8.3.3.1 General

This subclause gives a brief overview of the areas of the oil field that are being considered for engineered geological storage following CO_2-EOR operations. Note that the field can range from a simple, well-connected geological feature to one that is highly compartmentalized. If the field is compartmentalized, activities in one compartment will have little or no impact on pressure or fluid composition changes in other compartments. Figure 3 shows the five separate areas of an oil field that can be considered for engineered geological storage.



Key

1 ROZs, were or were not flooded

2 former EOR flood

3 area of conventional production in reservoir not selected for EOR

4 seal

5 former gas cap

6 water leg

Figure 3 — Potential areas of an oil field for CO_2 geological storage

8.3.3.2 Area of former CO_2-EOR flood

The area of former CO_2-EOR flood includes the area of the oil reservoir where CO_2 has been injected to produce oil. This can be a continuous CO_2 injection or a WAG operation where both CO_2 and water have been injected for oil recovery. A WAG process entails injecting a slug of gas into the reservoir followed by water, which serves as the chasing fluid. During the operational part of EOR, pressure is usually maintained to keep CO_2 miscible with oil. Under such conditions, there would not be a lot of pressure headroom to store CO_2. However, in cases where the final stage of EOR included pressure blowdown to strip out CO_2 and producing the last possible fluids; such areas can be pressure depleted.

Since EOR operations were performed in this area, existing infrastructure can be used to inject CO_2 for engineered geological storage, as discussed previously. Several options exist:

a) “top up” pressure – if the pressure in the field was decreased at the end of the EOR phase, some injection can be used to elevate pressure to the regulatory limit;

b) water extraction rather than extracting oil, water and CO_2 to manage pressure and sweep as was done during EOR, selected wells can be deepened, reperforated, deviated, or new wells drilled, in order to continue to balance the injection/withdrawal ratio by extracting water even though there is no oil production.

c) in fields with a strong water drive, CO_2 injection pressure can be balanced by displacement of brine into the water leg; in such a case, the injection rate would have to be equilibrated with the rate of brine displacement.

All these operations are in a non-steady-state and likely to decline over time with the field's ability to accept CO_2. At some point in injection, the amount of CO_2 injected can exceed the storage capacity of the reservoir. The rate at which this transition occurs can be managed because the limiting factors include pressure build-up and efficiency of pore volume occupancy (e.g. reduced by preferred flow in “thief zones” and gravity override).

8.3.3.3 Former gas cap

Under some conditions, hydrocarbon gas accumulates in the upper portions of a reservoir. The gas cap can be present at the discovery of the field or it can build as gases come out of solution during production in which case the energy provided by the expansion of the gas cap can provide the primary drive mechanism for oil recovery. The gas cap is managed in different ways during primary, secondary and tertiary recovery, depending on the reservoir and fluid properties and the operator’s strategy. The gas cap can have been produced, depressurizing the reservoir, or managed during production to maintain pressure. Managing hydrocarbon gases during CO_2-EOR is important because they impact miscibility and, therefore, the effectiveness of the CO_2-EOR operation.

Depending on production history, the gas cap volume can provide additional storage or pressure management capacity, which can be accessed by shallower reperforation of existing wells. Mixing of CO_2 with methane results in slightly decreased density, potentially altering CO_2 storage capacity.

8.3.3.4 Residual oil zone

A ROZ is an irreducible oil saturation below the traditional oil-water contact of a reservoir that necessitates an EOR technique to mobilize the oil. ROZs are like reservoirs in the mature stage of waterflooding, in which water has been injected into a formation to sweep oil toward a production well. The ROZ can be produced during the EOR phase, but with current technology, it is more likely that it has not had active EOR operations.

If present, the ROZ is available for use with an engineered CO_2 storage operation, but its use can necessitate re-placement of wells, deepening of wells or a change in perforations. An issue with ROZ engineered storage is that if there are any water production wells to relieve pressure for more CO_2 accommodation space, oil can be potentially liberated that can move to the water wells. Connectivity between the ROZ and the main pay zone also needs to be considered in the new balancing of the field, as the pressure and fluid flow connectivity vary field-to-field. Under some conditions, it is possible to operate the ROZ differently than the main pay, for example, to stop oil production and use the ROZ for CO_2 injection. The pressure would have to be balanced, in this case, by sufficient water drive or water extraction.

8.3.3.5 Saline water leg

The water leg of an oil field is the area of saline water that does not contain oil. The oil is buoyant, in effect floating on top of water-filled pore space. The connectivity and permeability of the water leg have an important effect on the primary, secondary and tertiary recovery strategy of the field and continue to influence the field during storage life. To some degree, the water leg can accept fluid displaced from the former EOR flood area; this can be water, which will reduce pressure increase in the reservoir, or CO_2, which migrates out of the reservoir. As the CO_2 accumulates and is not stopped by production wells, the CO_2 can build downward and overfill the structure below the original oil-water contact. Such migration can be either a problem or a benefit. It can be a problem if the CO_2 migrates out of the lease and area of confinement. It can be a benefit where some fields are not filled to the spill point such that some parts of the water leg lie within the trap. Another benefit can be that downbuilt CO_2 can be effectively trapped. Over time, gravity can pull mobile water down below the CO_2 (since the water is less buoyant than CO_2), resulting in the increasing CO_2 saturation in the water. Additionally, it is possible to inject into the water leg near or distant from the original oil accumulation, and have the CO_2 migrate toward the trap, thus adding to capacity. The downdip water leg can have existing wells suitable for reuse if they were installed for water management, e.g. for water pressure support. It is possible that such wells can be reused for water extraction or for pressure monitoring. The water leg can also be accessed passively from inside the former EOR field by downbuilding.

8.3.3.6 Areas with primary and secondary recovery but not CO_2-EOR

These are areas of an oil field where CO_2-EOR operations have not been implemented that do not fall into the areas of the field discussed above. It is common for some parts of fields to have not been of sufficient value or otherwise unsuitable for development for CO_2-EOR. This can also include areas that underwent various types of secondary recovery or chemical floods. Such areas can have a benefit of strong pressure depletion, as pressure would not have been maintained to ensure miscibility.

While CO_2-EOR operations have not been performed in this area of the field, it can be used as a depleted reservoir for storage, making use of retrofit wells where possible. In addition, water injection wells and oil production wells can be present that can be used as monitoring wells for CO_2 storage operations.

8.3.4 Analysis of case study no. 2

As noted above in this hypothetical case of the MDF field, located in southeast Texas, USA, CO_2-EOR has been underway for several decades, following a few initial years of primary production and several years of secondary water flooding. The produced water cut is currently disposed in water injection wells in local saline formations.

An issue with any of the areas of an oil field to be considered for engineered geological storage would be volumetric analysis and pressure maintenance because CO_2 injection would occur without subsequent oil or water production as in previous operations. With the extensive historical production history of MDF, hypothetically a complete geological model and associated history matched dynamic model has been created. These models have identified the various aspects of potential storage and allows the operator to provide predictive estimates of the storage potential. They have also helped identify the limitations of using the field for continued storage and informs the risk assessment for the storage operation. The field is a classic sandstone reservoir with widespread high permeability sands with high porosity with internal fluvial channel fills containing both higher and lower porosity zones. The reservoir caprock is shale. The reservoir is in a salt-cored domal closure that is not fault bounded.

Through a risk assessment, the static model has identified as negligible seal integrity risks such as a fault at the top of structure as the risk for leakage is low because the fault does not juxtapose the reservoir with shallower permeable strata. Due to the high quality (permeability and porosity) of the reservoir sand and the sands being semi-consolidated, prior injection testing has determined the fracture pressure, and hence the maximum injection pressure. Since the integrity of faults is not known at higher pressures, operational experience along with historical 4D seismic surveys can be used to show that under CO_2-EOR operations any faults maintain integrity. The concern for storage capability will not only be the bottom hole injection pressure, but also the height of the buoyant CO_2 column at the top of structure and the density profile in that column which can result in a reservoir pressure at the sealing fault exceeding the fracture pressure.

There can be an increase in pressure on the sealing fault due to a compounding effect of the CO_2 column where, in addition to storing CO_2 into the original gas cap, CO_2 is stored in swept oil zones, residual oil zones or in the water leg. The issue can be illustrated in a simple hydrodynamic pressure plot showing the reservoir pressures at discovery and the potential pressure on the sealing fault if a continuous CO_2 column is formed during storage operations. This illustrates that, to maintain a given pressure at the top of the reservoir, the CO_2 column cannot exceed a certain height. Therefore, not all the gas caps, previous CO_2-EOR zone residual oil zone and aquifer are available for CO_2 storage.

In this hypothetical case, previous well data and dynamic modelling can be used to show that the reservoir sands are of very high quality and as a result, the horizontal transmissibility of CO_2 within the sand is an order of magnitude higher than the vertical transmissibility. This behaviour, as observed during CO_2-EOR operations, has resulted in CO_2 tongues travelling in high permeability sands downdip into the aquifer faster than it can migrate into the lower quality portion of the reservoir. To maintain CO_2 placement within the reservoir, the CO_2 injection rates have been kept lower than the available capacity and flood patterns have been maintained instead of converted to fewer wells employing a top-down flood approach. For CO_2 storage, this implies that several injection wells will be needed rather than relying on a few larger capacity wells. Rather than drill new wells that meet the Class VI requirements, the operator has requested a waiver to use the existing Class II wells based on historical integrity data and analysis. Existing oil producing wells will be plugged and abandoned or redeployed as monitoring wells.

The existing injection well flowlines can continue to be used for the storage operation without modification since their historical use has been subject to ongoing inspection and maintenance. Existing production flowlines won't be needed and can be abandoned.

The number of active well patterns has decreased to three over the past few years because of declining oil cut. In addition, compressors that recycle CO_2 are nearing the end of their useful life and have been taken out of service rather than being replaced. Wells in idle patterns have been temporarily abandoned by placing a removable bridge plug at depth. However, some wells are in poor condition with casing damage and fines accumulation. During the six-month period of final production prior to accepting new captured CO_2, BIO LLC will "blow down" the remining three patterns, decreasing purchased CO_2 and producing as much oil and water as can be handled by the system. This will reduce the load on compressors, strip oil and potentially create void space by removing water. If there is significant solution gas, it can exsolve from the residual oil to help fill the space. The pressure gradient made by blowdown will also promote the migration of formation fluid into the low-pressure area.

During this preparation period, BIO LLC will evaluate and remediate existing wells, and select wells to be retrofitted, and those to be plugged and abandoned. The condition of flow lines will also be evaluated, as well as the risk of any wells in poor condition. A new model will run to optimize injection well placement and determine the amount of water withdrawal needed.

The evaluation of reuse of existing infrastructure to increase the depleted pressure by injecting CO_2 is possible; however, the period of this operation will be short because the reservoir will approach fracture pressure in less than two years. This was not satisfactory for the offtake facilities, so a plan was developed to invest more in a field redevelopment that is projected to allow a 12-year operation period before the field reaches pressure and volumetric capacity.

After evaluation, all but 10 temporarily abandoned wells in the field were P&A. Two wells were found to be high risk even after P&A. To keep pressure low, a decision was made not to inject at the corner of the field where these difficult wells are found. Instead, the wells will be used for pressure surveillance. Roads, bridges, drainage infrastructure and well pads will be reused, although some repairs will be made.

Three wells will be retrofit as injectors. The spacing between the injectors selected is much greater than pattern spacing so that the wells do not interfere with each other in later stages of the project. One injection well is relatively new, has good cement as shown by a cement bond log, has new tubing, has, passed a mechanical integrity test for tubing and casing, has a CO_2-compatible well head and suitable perforations, and can be put into service without significant modification. However, the cement job is oilfield standard, with cemented lifted only to the top of the reservoir seal, so a case will have to be made to the regulator that this cement is acceptable for an injection-only project. As the two existing wells are older, the cement integrity is less ensured, and the casing and perforations can be somewhat damaged. These wells will be retrofit to reuse surface casing but sidetracked in the long string casing; this will allow cementation of the entire long string and perforated to meet project specification. The uncemented casing segments will be cemented. Sidetracked injection wells will have new tubing and CO_2-compatible wellheads. Several flow lines will be salvaged and used for the updated project. However, the amount of CO_2 injected per day will be larger (no water) so that new flowlines were added in places, following existing infrastructure.

The field has moderately good water drive, so some pressure will be attenuated naturally, except in the case where fluids were driven back into the former reservoir which would increase rather than attenuate pressure. Modelling shows that the field can accept more CO_2 if water is extracted so three downdip injectors will be sidetracked and extended as horizontal wells 1,000 feet downdip to the lease edge and below the original oil-water contact. These will be used as water extractors and will help attenuate pressure. Models show that completion of horizonal well segments will keep flow velocity low (although volume will be high); this is intended to reduce the risk of CO_2 being drawn toward water producers. Water will be reinjected into the same shallower zone that was used for EOR, such that using the same water injectors, flow lines, water clean-up and storage tanks can be partly reused. Surveillance for CO_2 breakthrough will be added and will trigger water-producer shutdown.

The four existing wells will be retrofitted as monitoring wells. The key risks identified are:

a) failed production cement allows CO_2 to migrate behind casing toward shallower zones;

b) rapid filling of the reservoir drives CO_2 off structure into the water leg and out of the known containment, or

c) pressure in the reservoir exceeds fracture pressure or engineered cement strength.

Three of the wells will be plugged back, reperforated and fitted with tubing, packer and downhole pressure gauges to survey pressure in a thin, non-productive permeable sand above the injection zone, with a focus on the area of problem wells. Pulsed pressure testing will be used to determine if CO_2 is migrating into this zone because it will detect changes in compressibility. Water leakage is not a problem as this zone is well below the USDWs and isolated from them by secondary and tertiary seals. One monitoring well will be completed near the oil-water contact in an area not covered by brine extraction wells. Brine extraction wells can be used as monitoring points for off-structure migration via fluid testing and pulsed operation. In addition, BIO LLC will work with regulators to develop any needed additional groundwater or near-well surveillance to assure conformance with regulatory guidelines.

The end of injection for storage will occur when either pressure in the reservoir approaches fracture pressure or CO_2 begins to build downward well beyond the original oil-water contact. Some downbuilding is acceptable; however, the risks associated with migration past the spill point (such as off lease migration or risk to production in nearby reservoirs) will be considered and used as a cut-off. The injection wells can be plugged and abandoned. In-zone wells, including water extraction wells and monitoring wells can be used to observe pressure equilibration, and then be plugged and abandoned. Above zone, pressure surveillance can continue to observe geomechanical relaxation post-injection and then provide assurance that there is no vertical out-of-zone leakage.

8.4 Case study no. 3: Conversion of an off-shore gas field to CO_2 storage with associated hydrocarbon recovery

8.4.1 General

Case study no. 3 addresses the mid-ocean field, a hypothetical offshore natural gas reservoir that was discovered in 1998. During the initial testing period it was estimated to be of sufficiently large size to warrant its development with a jack-up platform and six wells. Several of the wells tested with an absolute open flow of 100 million standard cubic feet per day (MMscf/d) (2 832 10^3 m^3/d), but the platform topsides and sales pipeline were designed and constructed with a sales capacity of 250 MMscf/d (7 080 10^3 m^3/d). A subsea pipeline transports the sale gas to an onshore liquid natural gas (LNG) facility supplied by several other onshore and offshore natural gas projects.

The natural gas production stream contains approximately 15 % of CO_2 which is removed onsite to increase the sales gas capacity from the platform. The separated CO_2 is vented to atmosphere. From material balance estimates derived from initial and subsequent reservoir pressures, the mid-ocean field was estimated to contain about 2,0 trillion cubic feet (Tcf) (56 640 10^6 m^3) of raw gas. Approximately 1,07 Tcf (30 302 10^6 m^3) has been produced to date. The field is now in decline at the design operating pressure of the platform, with current raw gas production at 200 MMscf/d (5 664 10^3 m^3/d). With the installation of booster compression, the production can be increased back to 250 MMscf/d (7 080 10^3 m^3/d) and the abandonment pressure can be lowered in order to increase the ultimate recoverable gas reserves.

As part of the corporate and national goals to reduce carbon emissions, two projects have been identified for the mid-ocean field:

— CO_2 capture and injection;

— converting the field to CO_2 storage at the cessation of natural gas production.

8.4.2 Initial phase: CO_2 capture and injection

With changes to the regulatory policy regarding CO_2 emissions, the gas field will no longer be authorized to vent produced CO_2 if material changes are made to the field and associated infrastructure. Furthermore, the government has instituted a carbon tax of US$25 per tonne CO_{2e} which escalates to US$100 per tonne CO_{2e} by 2050. Operators can offset taxes on CO_2 emissions with qualifying CO_2 capture and storage projects. The mid-ocean (MO) gas field can qualify as an offset CO_2 project if its emissions are captured and injected back into the producing reservoir, provided the site is reasonably monitored to ensure storage integrity. Since the booster compression project will need a satellite platform, a CO_2 re-injection compression project is included in the project to reduce the operator's CO_2 emission intensity and carbon taxes payable.

The project will utilize one of the existing producing wells, MO5, which is a downdip producer. That well will be converted to a CO_2 injector. With the anticipated maximum raw gas production rate of 295 MMscf/d (8 354 10^3 m^3/d), it is expected that initial CO_2 injection will average approximately 30,0 MMscf/d (1 587 t/d). Since the booster compression will use fuel gas from sales spec gas, the CO_2 from flue gases from the compression driver will also be captured and included in the injection stream. Although this volume is trivial in comparison to CO_2 captured from the raw gas stream, it is still economical at the current carbon tax level.

Reservoir modelling predicts CO_2 breakthrough to the nearest producer will not occur for four years at which time that producer will be shut-in (once the capacity of the CO_2 capture train is reached) and secured downhole with a bridge plug. It is necessary to identify the breakthrough CO_2 being produced and clearly differentiate this from native CO_2. Since the initial component ratio of CO_2 in the field was determined to be 15 %, any CO_2 component over and above 15 % will be considered as breakthrough CO_2 attributable to the project injections. To avoid double counting, such breakthrough CO_2 must not be accounted as newly acquired anthropogenic CO_2. Both material balance behaviour and reservoir history match suggest a very small, finite aquifer and as such there is little interference or losses of CO_2 downdip during injection. As breakthrough occurs at subsequent producers, they too will be shut-in and secured downhole. Reservoir modelling predicts sufficient production will continue to meet the anticipated reservoir abandonment pressure before CO_2 breakthrough to three highest up-structured wells. The quantification of any native or in situ CO_2 produced in this case is conducted under ISO 27916 to preclude any double counting of injected CO_2.

9 Comparison of ISO 27914 and ISO 27916

9.1 Purpose

Two International Standards have been published that examine the potential relevance to the transition of storage associated with CO_2-EOR to geological storage of CO_2:

— ISO 27916, which is directly applicable and addresses aspects of the storage of CO_2 in association with CO_2-EOR that are not otherwise addressed in applicable standards and recommended practices for enhanced oil and gas production – namely assurance of CO_2 containment within the EOR complex and the quantification of the stored CO_2; and

— ISO 27914, which addresses the geological storage of CO_2 onshore and offshore “within permeable and porous geological strata including hydrocarbon reservoirs where a CO_2 stream is not being injected for the purpose of hydrocarbon recovery or for storage in association with CO_2-EOR”.

This clause provides a high-level review of ISO 27914 and ISO 27916 to identify issues, questions or gaps for consideration in this document and for further consideration in the development and revision of other documents relating to geological storage and storage of CO_2 in association with CO_2-EOR. The first step will be to examine the scope and coverage of ISO 27914 and ISO 27916 as applied to any geological storage of CO_2 within hydrocarbon-containing reservoirs before, after, or during hydrocarbon production. The second step will consider the extent to which either document would apply to the scenarios specifically identified for discussion in this document that relate to the transition from storage of CO_2 in association with CO_2-EOR to geological storage. Finally, the third step will compare the requirements of ISO 27914 and ISO 27916 to provide a greater understanding of the comparability of those requirements, focusing on similarities and dissimilarities (further detailed in Clause A.2).

When analysing ISO 27914 and ISO 27916, it is important to distinguish between the interplay of ISO 27914 and ISO 27916 discussed in this clause and the interplay of the legal, regulatory and permitting regimes for CO_2 injection activities addressed in Clause 10. ISO 27914 and ISO 27916 do not necessarily parallel the applicable regulatory or permitting framework (e.g. US Underground Injection Control (UIC) regulatory framework for Class II and Class VI wells[45]) where operational transitions to maximize CO_2 storage can necessitate additional regulatory or permitting approval, as discussed in Clause 10. This analysis is limited to ISO 27914 and ISO 27916, not well classified and permitting issues. Notably, neither ISO 27914 or ISO 27916 include information about transferring a project from one to the other.

9.2 Scope and coverage of ISO 27914 and ISO 27916

ISO 27914:2017, Clause 1 b) states that it applies to both onshore and offshore operations and establishes requirements and recommendations for geological storage of CO_2 in permeable and porous geological strata, “including hydrocarbon reservoirs”. The applicability to hydrocarbon reservoirs does not include operations that inject CO_2, either for the purpose of hydrocarbon recovery or for storage of CO_2 in association with CO_2-EOR. ISO 27914:2017, Clause 1 NOTE 1 reiterates that “[t]his document does not apply to [...] injection of CO_2 for the purpose of enhancing production of hydrocarbons or for storage associated with CO_2-EOR”. ISO 27914:2017, 3.17 Note 3 to entry for the term “geological storage” states that the definition “is applicable to nonproducing hydrocarbon reservoirs” but – “does not apply to [...] CO_2 injection and storage in any formations containing producible hydrocarbons”.

By comparison, ISO 27916:2019, 1.2 states that the “document does not apply to quantification of CO_2 injected into reservoirs where no hydrocarbon production is anticipated or occurring”. ISO 27916:2019, 1.2 further states that the “[s]torage of CO_2 in geologic formations that do not contain hydrocarbons is covered by ISO 27914 even if located above or below hydrocarbon producing reservoirs”. Finally, ISO 27916:2019, 1.2 states that “[i]f storage of CO_2 is conducted in a reservoir from which hydrocarbons were previously produced but will no longer be produced in paying or commercial quantities, or where the intent of CO_2 injection is not to enhance hydrocarbon recovery, such storage would also be subject to the requirements of ISO 27914”.

However, there are apparent discrepancies between the scope discussions of ISO 27914 and ISO 27916. For example, ISO 27914:2017, 3.17 Note 3 to entry indicates that ISO 27914 does not apply to CO_2 injection and storage in any formations containing producible hydrocarbons, whereas ISO 27914:2017, Clause 1 b) indicates that it does apply to geological storage in any hydrocarbon reservoir if the CO_2 injection is not for the purpose of either enhanced production or storage in association with CO_2-EOR.

Furthermore, ISO 27914:2017, 3.17 Note 3 to entry indicates the pertinent questions for hydrocarbon reservoirs are:

a) Are hydrocarbons currently being produced?

b) Are producible hydrocarbons present in the reservoir?

However, ISO 27914 indicates that the only relevant question is whether the injection of CO_2 is for the purpose of either enhanced hydrocarbon production or storage in association with CO_2-EOR. If not, then

ISO 27914 would apply to any CO_2 injection for storage into a hydrocarbon reservoir that is not part of a CO_2-EOR project, regardless of the presence of producible hydrocarbons.

In short, there is an apparent disconnect between the coverage discussions that would benefit from clarification in future editions of ISO 27914 and ISO 27916. The textual inconsistencies also appear to allow for the application of both standards in some scenarios, such as those addressed in this document where projects can be transitioning from CO_2-EOR to storage in the same reservoir.

9.3 Application of ISO 27916

If a project chooses to apply ISO 27916, ISO 27916 will by its terms continue to be applicable to the operations of that project until all CO_2 injection and hydrocarbon production ceases and all of the injection and production wells are plugged and secured – i.e. until the project itself is terminated. Furthermore, ISO 27916:2019, 10.4 b) states that part of the termination process involves "compliance with all well decommissioning and plugging requirements for all CO_2-EOR project wells [see 7.2 (g)], that wells do not allow fluid movement out of the EOR complex, and that the CO_2-EOR project wells do not pose a leakage risk", which leaves the possibility open that "decommissioning and plugging" is not required for some wells until those wells cease to operate for the purpose of injecting CO_2 for storage.

Hence, for any scenario regarding a movement away from a business-as-usual CO_2-EOR (such as an effort to maximize CO_2 storage), any continuation of hydrocarbon production, regardless of how diminished it is, would continue to be subject to the terms of ISO 27916. This includes the requirements to demonstrate and document continued assurance of containment of the injected CO_2 and to quantify the mass of CO_2 that is so securely contained. In short, following cessation of hydrocarbon production, ISO 27916 contemplates that an operator can continue to inject CO_2 and to demonstrate, document and quantify its safe and secure long-term containment in conformance with ISO 27916 until the CO_2 injection ceases and all wells are plugged and secured. Legal, regulatory and permitting aspects of such operational scenarios are entirely distinct from the continued applicability of ISO 27916 itself.

Alternatively, an operator would appear to have the option of transitioning from ISO 27916 to ISO 27914 after production of hydrocarbons ceases. ISO 27916:2019, 10.4 e) includes the possibility that facilities and equipment can be "left in place" and operated for storage "with the approval of the authority". These provisions appear to provide an operator with the options either to complete the termination process under ISO 27916:2019, Clause 10 or to complete closure under of ISO 27914:2017, Clause 10 instead, for a project that continues operating CO_2 injection wells after ceasing hydrocarbon production.

9.4 Application of ISO 27914

In the context of transitioning from production to CO_2 storage, almost no set of circumstances would comply with ISO 27914 rather than ISO 27916. If all production and CO_2 injection ceases, with all wells plugged and abandoned and then CO_2 injection begins into the same reservoir with new wells, ISO 27914 would apply. That is the sole example of a CO_2-EOR to straight geological storage transition scenario in which a project would necessarily apply ISO 27914 rather than ISO 27916. As noted above, ISO 27914 can be optionally applicable where there is true transition from CO_2-EOR to storage with the approval of the regulatory authority. There are other scenarios where ISO 27914 can apply if CO_2 geological storage has some loose association with hydrocarbon production, including:

— CO_2 geological storage in a depleted hydrocarbon reservoir with no production of hydrocarbons;

— stacked reservoirs used for CO_2 injection with a disposal well expanding into CO_2 storage;

— disposal wells (acid gas-CO_2 mix) used for CO_2 storage with no production from the same reservoirs; and

— CO_2 injection is initiated into a hydrocarbon reservoir with fluid production to maximize CO_2 storage but with no hydrocarbon production (ISO 27914 applies unless hydrocarbon production resumes and this becomes a CO_2-EOR project, in which case ISO 27916 can be used).

In general, however, for storage in a hydrocarbon reservoir still in production, a shift to ISO 27914 (as opposed to a change in regulatory or well-permitting category) will occur only if the project ends production and plugs all wells before initiating a new project for storage of CO_2 in the same reservoir without hydrocarbon production. Under the terms of ISO 27914 and ISO 27916, the new geological storage project will fall within ISO 27914.

9.5 Conclusion

The analysis and comparison of ISO 27914 and ISO 27916 yield the conclusion that ISO 27916 – including the containment assurance requirement and the associated storage calculation in Clause 8 – would continue to apply to a project where CO_2 injection occurs into a reservoir previously used for CO_2-EOR until the project plugs all injection and production wells.

There is a gap, however, in the comprehension of the application of ISO 27914 and ISO 27916 to CO_2 storage in a still producing depleted gas (condensate) field (concurrent production and storage), either to take advantage of early access to storage resources while still aiming for optimal hydrocarbon recovery or to maintain pressure to optimize condensate yield. For example, it is unclear which standard would apply to CO_2 storage in an up-dip gas cap with potential continued production in the oil rim. This type of project would appear to be more closely aligned with the approach in ISO 27916 than with that of ISO 27914, especially where the CO_2 injection is limited to the proven past operating envelope for gas containment and avoids repressurizing the reservoir above original reservoir pressure.

It would be particularly useful to have applicability of the standards to such projects clarified in forthcoming revisions of the respective standards when applicability to hydrocarbon reservoirs is clarified more generally. For reservoirs with concurrent production and storage, it is essential that the governance of reservoir integrity, risk management, financial and tax status be clearly defined to avoid ambiguity in its treatment, especially if ownership of production operations is not fully aligned with ownership of the storage project.

10 Legal, regulatory and permitting issues

10.1 General

This clause addresses some of the legal, regulatory and permitting issues to be considered in the development of storage or utilization projects similar to those represented by the operational scenarios and case studies described in Clause 8. The focus is on the steps to be taken or the potential barriers that can arise under existing legal and regulatory frameworks when pursuing those operational scenarios.

A caveat that must be kept in mind is that evaluating legal or regulatory issues presented by a project is essentially project specific.

Legal aspects, in particular of real property, are subject to the law of the particular jurisdiction. For purposes of the discussion, this generally means individual states in the United States, individual provinces in Canada, individual Member States of the European Union, Norway, Japan, Brazil, the constituent jurisdictions of the United Kingdom, the states and territories of the Commonwealth of Australia and similar or analogous jurisdictions around the world – a very large and extremely diverse set of legal systems.

In addition, with regard to offshore projects, legal regimes are at present being significantly revised or created in a number of jurisdictions. As a result, Clause 10 only provides a high-level overview of some of legal issues to be considered and can in no way be considered an opinion or legal conclusion regarding any specific project.

10.2 Pre-existing legal and regulatory paradigm

10.2.1 General

As the initial operation is an oil and gas recovery operation, the basic legal framework governing oil and gas operations in the relevant jurisdiction governs the operator’s legal authorization to engage in the basic steps of the project, including:

— accessing and using the surface (including the seabed) and the subsurface;

— drilling wells and injecting CO_2 and other substances;

— accessing and using infrastructure; and

— leaving the injected CO_2 in place along with various other substances that can be injected as part of the operation, following the completion of hydrocarbon recovery.

This framework typically comprises both a public law component that governs operations authorized by a governmental entity and a private law component that defines the rights, duties and remedies for the private parties to structure, consummate and operate the various governmentally authorized activities.

10.2.2 Comparison of legal and regulatory frameworks for mineral recovery versus frameworks for managing geological injections for storage

10.2.2.1 Comparing the two activities

The pre-existing legal and regulatory framework for oil and gas operations consists among other things of statutes, regulations, judge-made case law, well permits, health, safety and environmental approvals and practices, mineral property leases, and unitization or pooling agreements. This framework has been developed in jurisdictions across the world over 160 years since the first modern oil well was completed in 1859. In some respects, it is built on mining and property law that was developed long before that.

When proposals began to be made in the past 20 years or so to inject CO_2 in operations that were not associated with hydrocarbon recovery, it was quickly recognized that much of this oil and gas legal framework would not apply by its own terms. From a textual standpoint, the various legal instruments spoke only of hydrocarbon or other mineral recovery operations. From an operational and risk management standpoint, there were material differences in pressure management regimes, appropriate geographic areas of review and other factors. This is shown in ISO 27916:2019, Clause A.4, Clause A.5, Table A.2 and Figure A.4.

In short, the pre-existing laws, regulations and industry practices typically presupposed that the entire purpose of the project was the recovery of an economically valuable mineral resource: oil and gas (other minerals such as salt, helium, sulfur). Thus, the legal framework is generally aimed at maximizing the total ultimate recovery of the valuable hydrocarbon resource while restricting or prohibiting outright use of the subsurface for injecting substances for any other purpose. In contrast, the legal and regulatory framework for geological storage of CO_2 that is not associated with hydrocarbon recovery (i.e. “dedicated” or “non-associated” storage of CO_2) is focused on the deliberate storage of non-commercial CO_2 for purposes of reducing atmospheric CO_2 emissions. In addition, between these two “poles”, a hybrid approach can apply in some instances where one or more infrastructure or operational elements of a project are constructed or permitted under a petroleum law framework even though they begin to be used for injecting CO_2 for non-hydrocarbon storage.

These differences are great enough that significantly differing legal and regulatory regimes are used for the two activities, despite the commonalities that also exist.

Evaluating projects that would transition an existing site from hydrocarbon recovery to dedicated storage of CO_2, as described in the operational scenarios discussed above, thus calls for an examination of the boundaries between the two legal and regulatory paradigms to identify potential steps to take under both private law (e.g. property rights, mineral leases, unit operation agreements) and public law (e.g. permitting, licensing, environmental regulatory compliance). Various amendments or revisions to private agreements or regulatory permissions can be necessary. The inability to obtain a necessary amendment or revision, absent some alternative solution, can pose an insurmountable barrier to a particular project. Nevertheless, the existence of a production license does not exclude the co-existence of a storage license. However, storage does trigger additional risks that can be managed and incorporated in regulatory guidance. Continuing production would prompt updated storage calculations, additional risk management and long-term containment assurance.

The differing paradigms are also reflected in ISO 27914 and ISO 27916, which have been developed for demonstrating, documenting and quantifying the secure long-term containment of CO_2 injected in the CO_2-EOR and non-CO_2-EOR operations. See Clause 9 and the comparative analysis in Annex A.

10.2.2.2 Illustrative environmental and related permitting regimes

10.2.2.2.1 Australia

Australia is a federal system under which each of the Australian state, territory and federal governments have their own set of Acts and Regulations that make up the legal and regulatory framework for hydrocarbon extraction or greenhouse gas storage in their jurisdiction. To date, the Australian jurisdictions that have specifically covered greenhouse gas storage in new or existing legislation include Queensland, South Australia, Victoria, Western Australia and the Federal Government for offshore waters.

In terms of permitting, these Australian jurisdictions have two separate license categories that cover hydrocarbon extraction and greenhouse gas storage. As a result, a hydrocarbon extraction licensee in Australia is not permitted to also store carbon dioxide gas in the geological units underlying their license, unless they also have rights to a greenhouse gas storage license for the same area.

With the introduction of greenhouse gas storage licenses under Australian legal frameworks over the last 20 years, each jurisdiction has generally ensured that pre-existing hydrocarbon extraction license holders are given first rights to an equivalent license for greenhouse gas storage.

Australian legislation that covers greenhouse gas storage defines greenhouse gas to include CO_2 (in gaseous or liquid state), prescribed substances or mixtures of the same[4].

For a project authorized by a greenhouse gas storage license or hydrocarbon extraction license in Australia, all liabilities associated with the operation of the project will rest with the license holder.

Once a greenhouse gas storage license or hydrocarbon extraction license is surrendered, the relevant Australian jurisdiction becomes the owner of sequestered greenhouse gas and remaining infrastructure (if any) that can be used in long-term monitoring. For this case, an Australian jurisdiction will only allow a license to be surrendered once the relevant Minister is satisfied that the risk of adverse impacts resulting from the license are acceptably low. For example, risks associated with greenhouse gas leakage from a storage reservoir must be addressed through a monitoring and verification plan that demonstrates long-term containment to the Minister's satisfaction.

The Federal Government offshore legislation and South Australian Government onshore legislation both provide a mechanism whereby ongoing liabilities can be transferred from a greenhouse gas license holder to the government, subject to approval by the relevant Minister. For this mechanism, the Federal Government requires post-closure monitoring for at least 15 years, while the South Australian Government leaves the period of post-closure monitoring to be determined in an independently verified monitoring plan. This provision is only available to a licensee (not a former licensee) and therefore must be exercised prior to license surrender. No other Australian greenhouse gas storage legislation provides for the relevant government to indemnify the former authority holder after surrender of the injection and storage authority[4].

10.2.2.2.2 Canada: Alberta

Canada is a federal union of its provinces and territories evolving from a union originally organized by the United Kingdom in 1867. Additional provinces were admitted to the union over the ensuing decades. One consequence of that history is that the legal framework governing real property can vary significantly among the provinces (and territories). In addition, there is generally no federal regulator for CO_2 storage in Canada. Rather, the regulatory function is exercised by the provinces.[4)]

Currently, this subclause applies principally to Alberta, where conservation of hydrocarbon resources is a priority. An application for carbon sequestration tenure must include an analysis of the likelihood that the operations will interfere with mineral recovery. A proponent must also satisfy the Alberta Energy Regulator (AER) that the injection of the captured carbon dioxide will not interfere with the recovery or conservation of oil or gas, or existing use of the underground formation for the storage of oil or gas.[5]

NOTE 1 The frequently referenced Sask Power project and the Weyburn CO_2-EOR operation are located in the neighbouring province of Saskatchewan, not in Alberta.

4) For a more general overview of Canadian regulation, see "Bridging the Gap: an Analysis and Comparison of Legal and Regulatory Frameworks for CO_2-EOR and CO_2-CCS" (Report to the Global CCS Institute) (2013), pp. 98-103.

NOTE 2 The terms “sequestration” and “storage” are used synonymously in this document.

At a high level, the tenure and regulatory framework in Alberta for CO_2-EOR and carbon sequestration do have some key differences. With respect to land tenure, in Alberta proponents seeking to undertake enhanced oil recovery using carbon dioxide must acquire the rights to the minerals, either through the Crown in Right of Alberta (obtained from the Alberta Department of Energy), or through the freehold mineral owner(s). In Alberta, the Crown owns 81 % of the province’s mineral rights (approximately 537 billion square metres). The remaining 19 % are ‘freehold’ mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies.[5]

With a petroleum and natural gas (PNG) tenure agreement from the Government of Alberta or agreements with freehold mineral owners, proponents can approach the AER for approval of the CO_2-EOR scheme. The AER ensures operators undertake subsurface energy related activities and resource development in a safe and environmentally responsible fashion. CO_2-EOR operators must adhere to any monitoring and reservoir management activities and conditions put forward under an AER approval. The injected CO_2 is considered an integral part of the approved hydrocarbon recovery operation and no separate land tenure is required apart from the mineral.

Under legislation adopted in 2010 (“Bill 24”)[46], proponents seeking to undertake sequestration of captured carbon dioxide from large industrial facilities, with no related oil production, can do so under a carbon sequestration tenure agreement from the Alberta Department of Energy. The 2010 statute declared the subsurface pore space to be the property of the Crown[6]. An evaluation permit allows for evaluation and testing for the purposes of determining a formation’s suitability for carbon sequestration. A carbon sequestration lease provides for the injection and sequestration of carbon dioxide into pore space. Leases include requirements for establishing plans for monitoring, measurement and verification (MMV) activities (i.e. to confirm containment), as well as closure plans, to be updated regularly. MMV plans set out the monitoring, measurement and verification activities that the permittee will undertake and contains an analysis of the likelihood that the operations or activities that can be conducted under the permit will interfere with mineral recovery.

Carbon sequestration lessees must also pay into the Post-closure Stewardship Fund at a rate established by the Minister. This fund is used to offset the costs of long-term monitoring and maintenance when the Crown in Right of Alberta assumes liability for the injected carbon dioxide. This liability transfer occurs following the issuance of a closure certificate when the Minister is satisfied that, among other things, the lessee has abandoned all wells and facilities and the captured carbon dioxide is behaving in a stable and predictable manner, with no significant risk of future leakage.

The transition of a CO_2-EOR operation into a carbon sequestration operation presents some regulatory considerations, particularly if the objective would be to ensure CO_2-EOR meet the same conditions as a carbon sequestration operation discussed above and given that the CO_2-EOR operation is likely operating for some time by that point. Other considerations include scenarios with mixed hydrocarbon ownership (i.e. both Crown and freeholder owners) and the potential for some hydrocarbons to remain in the reservoir. Carbon sequestration leases are still fairly non-routine, and to date, such a lease has not been granted within a depleted hydrocarbon field. Furthermore, CO_2-EOR projects do not transfer liability or make payments into the Post-closure Stewardship Fund for the carbon dioxide that will have been injected up to the point of transition.

10.2.2.2.3 Canada: Saskatchewan

The Saskatchewan Ministry of Energy and Resources (ER) has jurisdiction over the CO_2-EOR and CO_2 storage activities in the province. Injection activities are governed by laws, orders and guidelines relating to enhanced oil recovery production. The provincial legislation recognizes the right to inject CO_2 to enhance oil recovery as part of the rights to extract sub-surface minerals.

The Oil and Gas Conservation Act (OGCA) of Saskatchewan[46] is the primary piece of legislation governing EOR and the injection and storage of CO_2 in the oil fields. The OGCA is supplemented by *The Oil and Gas Conservation Regulations*[54], and orders and guidelines made under the authority of the Act. Provisions in the statute and its regulations govern development, operation and decommissioning of CO_2-EOR operations.

Where the Crown holds 100 % ownership of the mineral title, a project proponent needs a Crown disposition to proceed. In general, any access to the subsurface necessitates the consent of the owner(s) as well as all relevant regulatory permit and license approvals. Surface access also needs to be obtained from the owner (which can be freehold) and other municipal and utility approvals can be necessary.

The well licensing process in particular requires consent(s) to be obtained from the owner(s) within the drainage unit or area of the well within the storage formation(s) (not the formations(s) above the storage pool). In addition, the offsetting parties to the storage pool, who will be impacted by the storage operation, must be notified through the public notice process or provide consent-in-lieu of public notice proceedings.

As per above, the same well licensing processes for consent and public notice apply. Where freehold mineral rights owners fall within the public notice area their notice or consent-in-lieu of notice will be required.

The Reclaimed Industrial Sites Act[48] includes most of the provisions that can be used for transfer of liability for a CO_2 storage site to the Crown.

10.2.2.2.4 European Union and related jurisdictions

The European Union (EU) consists of 27 member states (after the exit of the United Kingdom).[7] Three other states (Iceland, Liechtenstein and Norway) collaborate with the EU through the European Economic Area Agreement (the EEA Agreement). The member states of the EU and to a large extent the EEA states are obliged to implement legally binding EU framework (the most important category of acts contains directives and regulations) and adopt 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[4].

The EU implemented a regulatory framework for CO_2 storage in 2009 through the CCS Directive[8]. This instrument has been transposed into binding national law in all the EU member states and the three EEA members. Furthermore, the United Kingdom transposed it into national law prior to exiting the EU and to date, the United Kingdom has not replaced the national regulatory framework for CO_2 storage. It thus follows the EU Directive as originally transposed. The CCS Directive applies to CCS operations, while CO_2-EOR is not explicitly included. However, the Directive provides in Recital 20 that if CO_2-EOR is combined with associated storage of CO_2, the provisions of the CCS Directive apply accordingly.[8] Therefore, the following applies to both geological storage of CO_2 and associated storage during CO_2-EOR (at least where the project's purpose includes maximizing CO_2 storage or where the operator seeks to document and quantify the amount of CO_2 that is stored for purposes of the ETS Directive[12] or other qualifying regime).

The CCS Directive harmonizes administrative procedures, and to a certain extent the substantive requirements, for geological storage, across member states, however leaving each member state with considerable 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 of the storage site and later transfer of responsibility to the competent authority. The main requirements for capture and transport are found in other documents,[5)] as the primary focus of the CCS Directive is storage.

Any European geological storage activity with the intended amount of CO_2 stored of 100 kilotonnes or more has to be commissioned pursuant to a national storage permit according to the Directive 2009/31/EC, Article 6, and also see Article 2(2).[8] Important attachments to the storage permit are descriptions of the storage site and storage complex, requirements for the storage operations, the approved monitoring plan and a provisional post-closure plan according to Directive 2009/31/EC Article 9[8]. This approach ensures that the operational framework is to a degree tailored to each individual project and built on technical considerations and operator experience and capabilities pursuant to the minimum criteria of the CCS Directive. Also included in the permit is "the requirement to establish and maintain the financial security or other equivalent pursuant to Article 19", to ensure the operator will be able to cover the financial burdens of the permit requirements, including closure and post-closure obligations and liabilities.

5) Such as the Environmental Impact Assessment Directive (2011/92/EU) and the Industrial Emissions Directive (2010/75/EU).

Generally, the permits stipulate detailed requirements supplementing the provisions in Directive 2009/31/EC, Article 4[8], covering aspects such as monitoring, reporting and an obligation to implement measures in case of leakage or significant irregularities (see Directive 2009/31/EC, Article 9[8]).

National draft permits have to be reviewed by the European Commission before being finalized. A number of project applications have been filed with Dutch authorities for permits or licenses to store CO_2 offshore. The EU Commission has so far reviewed three such applications with non-binding opinions to guide the Dutch regulators. The Porthos CCS project currently holds two such licenses. Porthos has received storage permits for the P18-2 and P18-4 fields.[9] On 16 August 2023, the Administrative Law Division of the Council of State ruled positively on the ecological assessment of the Porthos project[9], which enabled the completion of its FID[9].

The criteria for monitoring are based on the proposed monitoring plan stipulated in the permit application pursuant to the requirements provided in Annex II of the CCS Directive[8]. The monitoring plan is subject to updates and changes based on both a five years' time interval and otherwise as required by Annex II of the CCS Directive. A similar approach applies to the obligation to implement measures in case of leakage or significant irregularities, according to Directive 2009/31/EC Article 16(2), sections 7(7) and 9(6)[8]. The operator is required to provide both a description of measures to prevent significant irregularities and the proposed corrective measures plan in the permit application and the permit will contain the requirements based on these.

A CO_2 storage project is operated under the assumption of strict liability for the operator, which can be read from, for example, the obligation to implement corrective measures in case of leakages or significant irregularities and to surrender allowances in case of such leakage. The obligation to surrender emissions allowances lies upon the emission source (e.g. according to the emissions trading system (ETS) Directive[49]) until the CO_2 is stored and thereafter on the storage operator until a transfer of responsibility to the competent authority post-closure. Consequently, the operator must notify competent authorities pursuant to the directive governing the EU's ETS in case of any "leakages or significant irregularities which imply the risk of leakage" and surrender allowances accordingly.

The CCS Directive[8] does not provide for exceptions to this responsibility and liability in case of earthquakes or other externally inflicted irregularities to the storage site. Additionally, the operator is subject to the same obligations post-closure, for a minimum period of 20 years after injection ceases and the storage site is closed. After the lapse of this minimum period, the operator is eligible to transfer the liability to the competent authorities, provided it demonstrates that the stored CO_2 is "completely and permanently contained", the injection site has been "sealed and the injection facilities have been removed", and that the operator has made a financial contribution available to the competent authorities, which is to replace the operator's financial security.

The financial contribution (named financial mechanism in the CCS Directive[8]) covers as a minimum the anticipated monitoring cost for the competent authorities for a period of 30 years after transfer and takes elements such as site history into consideration. Articles 19 and 20 of the CCS Directive[8] contains more detailed criteria for financial security and financial contribution. The European Commission has further issued a non-binding guidance document on the financial security and financial mechanism for the member states and some member states and EEA states have set their own additional criteria based on these. The CCS Directive opens for the possibility of a shorter period than 20 years of post-closure obligations, provided the competent authority is "convinced that all available evidence indicates that the CO_2 stored will be completely and permanently contained".

The CCS Directive[8] currently holds no explicit provisions on transitioning a CO_2 storage project form CO_2-EOR to CCS or from CCS to CO_2-EOR (see 10.3.2.3.2). There is, however, a provision on changes to the storage permit, which states that "[t]he operator shall inform the competent authority of any changes planned in the operation of the storage site [...]" Furthermore, the provision endorses updates to the permit or permit conditions "[w]here appropriate".

Transitioning from CCS to CO_2-EOR would indeed imply a change in the operation of the storage site, given that there are, for example, other operational elements, monitoring requirements and infrastructure utilization to consider. Storage of CO_2 would no longer be the main purpose of the storage site. Conversely, transitioning from CO_2-EOR to CCS, would imply a change from focusing on petroleum extraction to CO_2 storage, with the consequential changes in infrastructure, monitoring and other operational elements.

The CCS Directive does not explicitly state what changes in an operation make it "appropriate" to update the permit or permit conditions. However, it is stated that the member states after a review, "where necessary, [shall] update or, as a last resort, withdraw the storage permit" under certain pre-defined conditions, none of which includes transition to a completely different operation. The nearest condition is "if it appears necessary on the basis of the latest scientific finding and technological process". A mere update to the permit can thus not be considered "appropriate" for transitioning, as referred to in the paragraph above, from a structural interpretation of the CCS Directive[8].

Though a transition is not necessarily eligible for an updated permit the CCS Directive[8] does state that "Member States shall ensure that no substantial change is implemented without a new or updated storage permit issued in accordance with [the CCS Directive]". As such, a transition can most certainly qualify as a "substantial change". The statutory language seems to leave it up to the Member States to decide whether to update or issue a new permit in a situation of transition, depending on how the CCS Directive[8] is transposed and the contents and criteria of the original permit. However, the abovementioned interpretation can restrict the member states' ability to transition without going through the motions and issuing a new permit.

Regardless of the national transposition, if the original project was not operated pursuant to the CCS Directive[8], the original project permit would have to be terminated and decommissioned according to its license or permit requirements, and a new permit issued. Consequently, the storage site would have to be characterized and assessed again to document whether the storage site and storage complex are capable of safe, long-term storage of CO_2. Additionally, the updated site characterization would include information regarding the CO_2 in place already because of the preceding CO_2-EOR operations, as this would most likely be considered "in situ" for the new project. Such categorization of the CO_2 in place has consequences for such issues as liability and ETS allowances in the event of potential future leakages.

10.2.2.2.5 Norway

The start of CCS in Norway, at the natural gas field of Sleipner in 1996, was the result of the fact that the natural gas was bought and sold in Europe, requiring the operators to strip CO_2 from the natural gas stream to meet the relevant technical specification for the delivered natural gas stream. Furthermore, a CO_2 tax was introduced in Norway in 1991[10] as a mitigating measure against CO_2 emissions from the offshore industry[11]. Thus, instead of venting the CO_2 stripped during production to meet the technical specification for the natural gas stream and paying the CO_2 tax, the operators of the Sleipner project decided to store the CO_2 in adjacent geological formations.

In 2005, the tax was followed up by the implementation of the European Trading Scheme pursuant to the EU ETS Directive.[12] This trading regime-imposed allowances within a cap-and-trade scheme for emissions, applicable to both onshore and offshore industries.[6] This framework is applicable in parallel with the offshore CO_2 tax, implying that the total cost of emitting CO_2 from for petroleum operations offshore Norway became substantial.[7]

None of these frameworks were implemented solely as tools to enforce implementation of CCS but to reduce emissions in general. They have, however, worked as enablers for CCS offshore in Norway, first for Sleipner and later for Snøhvit. When issuing a license and emissions permit for the offshore natural gas project Snøhvit, implementation of CCS to deal with excess CO_2 was made mandatory.

A framework specific to CCS, to ensure safe long-term storage for CO_2, was implemented in Norway 2014, through the transposition of the EU CCS Directive[8]. In the period between 1996 and the transposition of the CCS Directive, the CO_2 storage operations at Sleipner and Snøhvit were both regulated and operated pursuant to the legal framework for petroleum operations and were included in the plan for development

6) The EU Emissions Trading System was implemented through the Act relating to greenhouse gas emission allowance trading and the duty to surrender emission allowances, LOV-2004-12-17-99. The cost of EU Emission allowances per ton of CO_2 is approximately 22,3 euros, per 14. January 2019. https://www.eex.com/en/market-data/environmental-markets/spot-market/european-emission-allowances#!/2019/01/14.

7) For 2022, the tax rate is at NOK 1,65 per standard cubic meter of gas or per liter of oil or condensate. For combustion of natural gas, this is equivalent to NOK 705 per tonne of CO_2. For emissions of natural gas, the tax rate is NOK 10,66 per standard cubic meter. For 2023, the carbon tax is NOK 1,78 per standard cubic meter of gas and NOK 2,03 per liter of oil or condensate. For combustion of natural gas, this corresponds to NOK 761 per tonne of CO_2. For emissions of natural gas to air, the rate is NOK 13,67 per standard cubic meter.

and operation (PDO) for petroleum operations, as these CO_2 storage activities were considered to be an integrated part of the petroleum operations.

The objective and approach of the CCS Directive[8] gave Norway some leeway regarding how and by which instruments the Directive's provisions were to be implemented. Consequently, when Norway transposed the Directive, the regulatory authorities honoured the ongoing activities in Norway and implemented a two-track regulatory system for CCS CO_2 storage associated with the petroleum industry, as, for example, Sleipner and Snøhvit or future CO_2-EOR projects would continue to be regulated according to the petroleum framework, with permits and projects to be in compliance from 2016 onwards.[13] The other track is for CO_2 storage not associated with the petroleum industry, as, for example, the Longship project which intends to store CO_2 offshore from onshore industrial sources such as cement.[14] For both tracks, the Norwegian Pollution Control Act and Regulation[55], as well as the Emissions Trading Act and Regulation[56] apply.

To a large extent many of the provisions provided for in the Directive are translated and transposed directly into the Norwegian instruments. Also, even if the framework is split in two tracks, the provisions and requirements related to geological storage of CO_2 are to a large extent identical.

10.2.2.2.6 United States

In the United States the environmental permitting frameworks for the two activities differ significantly. The Environmental Protection Agency (EPA) has defined two permitting frameworks under the Underground Injection Control program for fluid injection wells. Class II well permitting applies among other things to wells injecting CO_2 for the purpose of enhancing recovery of oil or natural gas. 40 CFR §146.5(b)(2). Class II permitting is generally administered by state regulators that have been granted "primacy" by the EPA. Under a coordinated federal and state statutory and regulatory scheme, individual state regulatory bodies can qualify to implement the federal regulatory program, but under their own state law (i.e. be granted "primacy") by meeting certain federally prescribed requirements.

Class VI geological sequestration permitting applies to wells injecting CO_2 for the "primary purpose" of long-term storage. At present, only a very small number of states have qualified for primacy for Class VI permitting. Accordingly, the federal EPA itself directly administers most of the Class VI permitting.

The regulations require that operators of Class II-permitted wells that inject CO_2 for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI permit when there is an increased risk to USDWs as compared to Class II operations. 40 CFR §144.19(a). The regulation enumerates various criteria to be considered in making that determination, such as increased reservoir pressure within the injection zone (see 10.3.2.3.1).

In 2015, the EPA discussed the criteria for reviewing potential transitions from the hydrocarbon-focused permitting framework to the storage-focused framework and provided high level guidance in the form of six "key principles" related to transitioning wells from Class II to Class VI permitting.8) The memorandum explained that:

> "[Enhanced Recovery ("ER")] operations that are focused on oil or gas production will be managed under the Class II program. If oil or gas recovery is no longer a significant aspect of a Class II permitted ER operation, the key factor in determining the potential need to transition a CO_2 ER operation from Class II to Class VI is the increased risk to USDWs related to significant storage of CO_2 in the reservoir, where the regulatory tools of the Class II program cannot successfully manage the risk.
>
> The most direct indicator of increased risk to USDWs is increased pressure in the injection zone related to the significant storage of CO_2. Increases in pressure with the potential to impact USDWs should first be addressed using tools within the Class II program. Transition to Class VI should only be considered if the Class II tools are insufficient to manage the increased risk."

8) The Office of Ground Water and Drinking Water, in consultation with the Office of General Counsel, interprets these key principles as applicable to Class II-D acid gas wells. EPA, Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI (April 23, 2015) (https://www.epa.gov/sites/default/files/2020-08/documents/class2eorclass6memo_0.pdf).

10.2.3 Pore space ownership and access

10.2.3.1 General

In a successful CO_2-EOR operation, the injected CO_2 diffuses through the pores of the relevant formation, contacting the hydrocarbons and other formation fluids. A portion of the injected CO_2 is brought to the surface in the raw production stream, separated from the other production fluids, and then either recycled to the operation or, where allowed, can be vented to the atmosphere. As the operation progresses however, the injected and re-injected CO_2 gradually replaces the pre-existing formation fluids (e.g. the hydrocarbons and brine) in the pores of the rock.

A threshold issue that distinguishes hydrocarbon recovery-focused operations from CO_2 storage-focused operations is the nature of the land tenure, mineral lease or similar legal instrument providing access to the real property where the operation will be conducted, whether surface, seabed or subsurface. Different countries have different legal systems applicable to subsurface property ownership or access. A project developer or proponent of a project planning a transition from a hydrocarbon recovery-focused operation to one that is focused on CO_2-storage needs to review the applicable underlying property interest or access instruments to ensure that they are adequate for the revised operation.

Legal systems governing mineral interests or other use or exploitation of the subsurface can distinguish between use of commercial hydrocarbon recovery and other uses. In some jurisdictions, the legal right to access the subsurface for CO_2 injection can be explicitly tied in some fashion to hydrocarbon recovery. In addition, the legal right to access the subsurface for CO_2 storage can be held by a party other than the owner of the minerals.

A threshold legal issue for CO_2 storage, both associated storage during CO_2-EOR and non-associated storage in a dedicated CO_2 storage operation, is thus determining the terms and conditions of access to the relevant real property. The real property in question can comprise of a variety of property interests. Principal among these are:

a) the surface;

b) the subsurface rock formations (which can be particularly defined formations or depth horizons); and

c) the microscopic space inside the rock that contains various formation fluids and the injected CO_2.

The pre-existing formation fluids typically include water (i.e. brine) and can include various other gases and minerals.[9] These can include hydrocarbons as well as non-hydrocarbon minerals or gases, which can include such components as nitrogen (N_2), helium (He), salt or hydrogen sulfide (H_2S). It is not unusual for geological formations around the world to contain natural carbon dioxide (CO_2), sometimes in significant percentages[15]-[19].

From a legal standpoint, CO_2 injections for EOR are in general the same as injecting H_2O in a waterflood operation: the mineral lease (or other legal instrument granting access) that contemplates or allows for the injection of substances needed to maximize the total ultimate recovery of the resource would normally include the concomitant right to leave the injected substances in the formation. The injection of additional CO_2 beyond that which is necessary for maximizing recovery can be viewed as more equivalent to the injection of produced water and can be subject to different legal rules regarding surface and subsurface access and indirect migration.

The ownership of these various real property interests is defined quite differently in different legal systems. The legal right to access, mine, extract or make use of a particular real property interest is thus defined by the relevant real property legal regime. The geographical location of a project within a single country's jurisdiction or across a national border can also implicate differing framework and ownership issues. Whether the project is onshore or offshore, and as such how far offshore, can heavily influence this.

In Norway, for example, all the CO_2 storage projects are planned for offshore, in areas that are owned and governed by the Norwegian state. This is also the case for several other European countries planning CO_2 storage or EOR operations. In contrast, most CO_2 storage and EOR projects in the US to date have been

9) The reference is to substances that are gases at standard temperature and pressure conditions (i.e. at the surface).

operated onshore, often on exclusively or primarily privately-owned lands. More recently projects have been publicly discussed for CO_2 storage offshore, particularly in waters offshore Texas and Louisiana. The sub-seabed storage formations can be either state- or federally owned, depending on the jurisdiction and the distance offshore (i.e. the dividing line between federal and state waters is different offshore Texas as opposed to offshore Louisiana because of the unique circumstances governing the two states accession to statehood under applicable law).

10.2.3.2 Observations regarding select jurisdictions

10.2.3.2.1 Australia

In Australia, the legal frameworks that permit access for hydrocarbon extraction and greenhouse gas storage are based on public ownership of the underground resources and pore space. For onshore land, these frameworks are administered by the relevant Australian state or territory government jurisdiction to which the resource or pore space is geographically located. For offshore waters (i.e. beyond the three nautical mile limit of coastal waters), the Australian Federal Government has jurisdiction (for more details, see chapters 11 and 12 of Reference [4]).

10.2.3.2.2 Canada: Alberta

As noted above, under section 15.1(1) of the Bill 24 in 2010[45], pore space in Alberta was declared to be generally vested in and owned by the Crown in Right of Alberta. Regulations implemented this provision and established a process for project proponents to lease pore space for CO_2 storage purposes. As a result, project proponents approach the Government of Alberta for the necessary property rights. This is thus different from CO_2-EOR operations which occur under the mineral rights, which can have mixed ownership (e.g. the Crown, freehold estates).

The legal and regulatory situation for CO_2-EOR and storage in Alberta is dynamic at this writing. For example, recently, there have been some enhancements in how pore space rights for carbon sequestration are being granted, with the government moving to a more competitive process (as opposed to application of “first come, first served” principles). Following much interest in pore space, the government is undertaking a competitive process with the intent of working toward efficient pore space management and avoiding challenges associated with numerous, and potentially overlapping, sequestration proposals/applications. Under this approach, a carbon sequestration “hub manager” would service a number of different emissions sources in a region.

While the new process will build on existing legislation, it likely will lead to some additional requirements related to ensuring open access to the hub and fair service rates. Thus, there will continue to be differences between CO_2-EOR operations (with associated storage) and CO_2 storage regimes, including different tenure regimes and mixed ownership of the oil. In addition, questions remain as to when a reservoir is declared “depleted” enough to transition to dedicated carbon sequestration. In short, challenges related to transitioning from CO_2-EOR to sequestration remain.

10.2.3.2.3 Canada: Saskatchewan

In Saskatchewan, *The Crown Minerals Act*[49] confirms the ownership by the Crown of spaces occupied by or formerly occupied by Crown minerals (ownership on pore spaces on Crown mineral lands has been vested with the Crown as per section 27.2 of *The Crown Minerals Act*[49]). *The Crown Minerals Act*[49] also authorizes the Crown to enter into agreements to lease pore space.

Legislation is not equally as specific on the ownership of pore space where mineral rights are held freehold. The ownership of pore spaces on freehold lands has not yet been clarified through the courts or legislation.

10.2.3.2.4 European Union

Pore space ownership, mineral leasing or other land tenure and potential commercial contracts for land lease or similar instruments are not dealt with under the EU CCS Directive framework. Those matters are the province of the national law within each of the 27 member states, a few of which are themselves federal systems (such as Germany). As a result, property law questions affecting access to injection locations, subsurface storage formations and pore space are likely to be addressed in various ways in different legal systems.

With regards to project permitting, according to the abovementioned approach of setting minimum standards and the general principles of sovereignty, member states can freely choose the areas in which to allow CO_2 storage (and whether to open up for CO_2 storage either onshore or offshore, or both) and restrict CO_2 within their jurisdictions. However, if they decide to permit such activities, the minimum requirements of the CCS Directive[8] are mandatory.

10.2.3.2.5 Norway

In Norway, all CO_2 storage is planned for offshore on the Norwegian Continental Shelf. The ownership and permitting authority belong exclusively to the Norwegian State[20]; there is no question related to separating ownership to the seabed, pore space and other formations below the seabed, implying that there is no need to obtain site access agreements or similar with private parties to construct a platform, fix a floating production storage and offloading vessel (FPSO) or start drilling and injecting. It can be necessary, however, to obtain land lease agreements or other types of access agreements from either private or public parties to establish the necessary land-based facilities (e.g. intermediate storage, loading docks, onshore processing facilities). Furthermore, the municipality will be involved in permitting of such onshore facilities and land use, implying there can be some different practice or conditions relating to how such facilities are permitted and operated. The offshore geological storage sites, however, are permitted and operated under a national regime, in which the objectives and criteria described in the presentation of the EU CCS Directive[8] above apply.

10.2.3.2.6 United States

In the United States, the question of pore space ownership or control is largely a question of the individual states and has been much debated in recent years. A number of states, through legislation or court decision, have now determined that the property interest of the surface owner includes ownership of the pore space itself, even where ownership of the minerals contained in that space (i.e. the “mineral estate”) has been severed and passed to another party. The surface owner’s rights remain generally subject to the reasonable and non-exclusive rights of the mineral owner.[50] However, considerable uncertainty remains in states that have not clearly defined the respective rights of the surface owner and the mineral interest owner as well as in more complex scenarios involving competing or conflicting uses of the subsurface.

The “Model Statute and Regulation” developed and published by the Interstate Oil and Gas Compact Commission[21] recognized pore space uncertainty as an issue to be addressed in the development of policies to encourage expanded CO_2 storage for emission reduction purposes:

> "Because the law recognizes an ownership interest in subsurface pore space, a regulatory program that manages storage (as opposed to water protection) should include clear rules about how these rights will be recognized and protected, as well as a process for assuring that the storer secures the legal property right to store CO_2.[22]"

An additional aspect of US oil and gas law is that a mineral lease is typically maintained in effect (or “held”) by continued commercial production of the relevant minerals as determined by the “habendum clause” of the lease. Such a clause generally provides for the lease to continue in effect for as long as a term as a certain quantity of hydrocarbons is being produced, typically defined as production “in paying quantities” or “in commercial quantities” or various similar terms.10) The legal consequence of the complete cessation of hydrocarbon production is normally that it “automatically terminates the lease”.[23] Conversely, the deliberate, premature cessation of hydrocarbon production can potentially give rise to civil claims under private law of breach of implied covenants to reasonably develop the premises or the like.

10) “Habendum” comes from the Latin phrase “habendum et tenendum” meaning “to have and to hold”. A legal scholar a century ago stated that the change from a fixed lease term began around 1880 after which leases included a *habendum* clause allowing for indefinite extension of the lease as long as such production continued. Veasey, *The Law of Oil and Gas, IV (4): The Habendum Clause*, 19 Mich. L. Rev. 161, 162 (1920). Veasey states that by around 1900, it had become the “almost universal custom” in the industry to include a provision extending the term of the lease on the condition that oil or as is continued to be produced in “paying” or “commercial” quantities.

In sum, the lease is "held" in existence by continuing production operations and when oil recovery operations cease, the wells must be plugged and abandoned. At that point, the remaining mineral property – which can amount to perhaps half of the original hydrocarbon resource originally in place – reverts to the mineral owner who can then grant future leases to develop the remaining hydrocarbon resource or otherwise can contract the subsurface for other uses as the mineral owner sees fit. Thus, the oil or gas operator no longer has a legal right to access either the surface or the subsurface of the property in question. There is a vast body of state case law and statutory law defining these concepts.[11)]

Recognizing these and related legal issues, the United States' National Petroleum Council has termed uncertainty regarding ownership of subsurface pore space a "primary challenge" for geological storage:

> Legal issues also pose a challenge to storage in depleted oil and natural gas fields because hydrocarbon production leases do not address CO_2 injection or storage without the primary objective of hydrocarbon production. Injecting CO_2 into a depleted oil reservoir negates or complicates any future recovery of remaining oil resources if new technology or economic conditions might warrant such a scenario. Once hydrocarbon production ceases for a specified period, a lease agreement between the operator and oil or gas owner is typically terminated. CO_2 storage, therefore, necessitates developing a new contractual arrangement, and a primary challenge with CCUS is the ownership of subsurface pore space. Law reviews suggest it is likely that landowners will retain ownership of the pore space. Therefore, any new framework may require a suite of new criteria to resolve the challenges facing CO_2 storage in depleted hydrocarbon reservoirs.[24]

Over the last decade or more, various states have undertaken to adopt statutes intended to clarify pore space ownership, control, and related issues. While review of those legislative changes is outside the scope of this document, project developers need to review the law applicable in the jurisdiction being considered for a project.

Outside of a hydrocarbon recovery operation, however, access to the pore space can be more difficult to ascertain or acquire. In a non-associated CO_2 storage operation, there is normally no pre-existing mineral lease or land tenure that conveys the right to inject the CO_2 into the subsurface and to leave it in place at the end of the operation. Instead, the right to access the real property has to be separately acquired.

10.3 Legal and regulatory aspects of reuse of existing infrastructure

10.3.1 Review of property instruments and contractual agreements

All of the operational scenarios discussed in this document contemplate the re-use of existing infrastructure to varying degrees. That infrastructure can include both surface facilities (e.g. CO_2 pipelines and field distribution lines, ships for transport, CO_2 handling facilities, compressors, pumps, wellheads, platforms, subsea templates and FPSO vessels) as well as subsurface facilities (e.g. wellbores and all downhole equipment, packers, cementing, completion locations).

Any meaningful review of legal or regulatory authorization or compliance issues that can be associated with such operational changes is likely to be highly project specific. For example, in the case of a US mineral lease under which a CO_2-EOR operator has been injecting CO_2 and producing oil, assuming that there are no other relevant provisions of the lease and if the lease provides that it has been granted "for the sole purpose" of recovery of a hydrocarbon, a question immediately arises whether the lease would allow the operator to "transition" from CO_2 injections for hydrocarbon recovery to any other use at all, such as injecting CO_2 as a dedicated storage activity.

11) For discussion of case law addressing how much production is sufficient to maintain a lease under a *habendum* clause, see McDonald and Wallen, *"Defining "Production In Paying Quantities": A Survey Of Habendum Clause Cases Throughout the United States*, 90 N.D. Law Rev. 383 (2014). See also Kramer, *The Temporary Cessation Doctrine: A Practical Response to an* Ideological *Dilemma,* 43 Baylor L. Rev. 536 (1991).

10.3.2 Regulatory compliance review

10.3.2.1 General

An analogous review can be appropriate for regulatory compliance for relevant elements of infrastructure or operation that were originally approved by a governmental or regulatory scheme. Such a regulatory compliance review can be appropriate for various aspects of the operational changes discussed in 10.4. It is likely to be very case-specific and, in many cases, differing components of the operation can receive a particular governmental authorization or can be subject to contractual or licensing conditions.

10.3.2.2 Facilitating use of existing infrastructure

Where a government has decided to pursue policies favouring the reduction of atmospheric emissions of CO_2, it can be particularly important to facilitate the continued use of as much of the existing infrastructure or facilities as appropriate for the modified operations as possible. Specifically engineered solutions can allow re-use of both surface and subsurface facilities. For example, in 2006, the natural gas pipeline regulator in the United States authorized the abandonment of certain underutilized interstate pipeline segments to be converted to CO_2 transportation to support CO_2-EOR operations.[26] Similarly, as noted in 10.3.2.3, in 2010, the US EPA adopted rules that allow continued use of pre-existing CO_2 injection wells where there is no increased risk to drinking water sources. The inability to make use of existing infrastructure will increase the costs of the proposed increased CO_2 storage and can constitute a barrier to greater reductions in CO_2 emissions.

10.3.2.3 Illustrative transition-focused regulatory frameworks

10.3.2.3.1 Illustration of regulatory framework for transitioning existing wells from EOR to storage: USA

In 2010, the US EPA issued CO_2 well-permitting regulations that, among other things, expressly contemplated the conversion [to geological sequestration wells (i.e. “Class VI” wells)] of CO_2 injection wells already being used for CO_2-EOR operations (i.e. “Class II” wells). The rules effectively allowed Class II EOR wells to transition to a “primary purpose” of geological sequestration without qualifying for a Class VI permit unless “there is an increased risk to [underground sources of drinking water or USDWs] compared to traditional Class II operations using CO_2”.[51] Where the modified operation results in such an increased risk, however, the owner or operator of the well “must apply for and obtain a Class VI geological sequestration permit”, absent which the CO_2 injections are prohibited. Id., at 77246. Absent such an increased risk, however, the operator can continue to use the Class-II permitted well even if the “primary purpose” of the CO_2 injection transitions from CO_2-EOR to geological sequestration.

The regulation lists nine “risk-based factors” to use in determining whether a Class VI permit is required:

a) increase in reservoir pressure within the injection zone;

b) increase in CO_2 injection rates;

c) decrease in reservoir production rates;

d) the distance between the injection zone and USDWs;

e) the suitability of the Class II AOR delineation;

f) the quality of abandoned well plugs within the AOR;

g) the owner’s or operator’s plan for recovery of CO_2 at the cessation of injection;

h) the source and properties of injected CO_2; and

i) any additional site-specific factors as determined by the Director. 40 CFR § 144.19(b).

In addition, for wells that are in fact required to obtain a Class VI permit (due to the increased risk to USDWs), the regulation provides for “grandfathering” of previously constructed Class II-permitted wells under certain circumstances. Subpart H of the relevant regulation sets out well construction requirements for Class VI wells. 40 CFR § 146.81(c) provides for performance standards (prevention of fluid movements, ability to use certain testing and workover tools and continuous monitoring of the annulus space) that can be met in lieu of the requirements applicable to newly constructed wells. Under this alternative approach, the operator must demonstrate that the wells "were engineered and constructed" to satisfy the performance standards of § 146.86(a) in lieu of the otherwise applicable requirements of §§ 146.86(b) (regarding casing and cementing during well construction) and 146.87(a) (regarding logging, sampling and testing prior to injection well operation). EPA explained its action (75 Fed. Reg. at 77245):

> "EPA believes that transition to Class VI is necessary to ensure USDW protection but is allowing the constructed components of Class II [EOR] wells to be grandfathered into the Class VI permitting regime at the discretion of the Director and pursuant to requirements at § 146.81(c), in order to facilitate the transition from Class II to Class VI without undue regulatory burden."

Following adoption of the new regulations, EPA issued extensive guidance documents that further address converting CO_2-EOR well infrastructure to use in a geological storage operation:

— Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells (December 2013); and

— Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Well Construction Guidance (May 2012) (Clause 3, "Considerations for Conversion of Other Well Types to Class VI").

10.3.2.3.2 Illustration of the regulatory framework for transitioning existing wells from EOR to storage: Norway

Although not tested, transition from CO_2-EOR to CCS or from CCS to CO_2-EOR, can be challenging in Norway due to the two-track system. Examples of changes within one track and between two tracks are analysed.

Hypothetically, having a CO_2-EOR project transitioning to a CCS project, can be possible pursuant to the original permit, provided the CO_2 comes from petroleum industry. The activities would still qualify as "petroleum activities". As part of the original permit, the PDO defines the work obligations and work program. If there are significant deviations to the preconditions related to the approved work plan and significant changes to the facilities, the operator needs the notify the Ministry of Petroleum and Energy, which can in turn demand a new or updated and approved PDO for approval.

One can imagine, for example a license area with several wells, in which a few of them have been operated as CO_2-EOR wells and the others have been pure production wells, potentially even delivering CO_2 to the aforementioned wells. If the EOR wells no longer produce sufficient petroleum to be economically viable, there is a theoretical potential to transition the wells to pure storage wells and continue operating under the same permit, pursuant to an updated PDO. However, there is also a chance the part of the license area no longer producing petroleum will be relinquished or separated into an independent permit if the area in which the wells are located is easily separated from the remaining license area, as the operator has to pay a license fee per km^2.

If the entire license is potentially considered to change from CO_2-EOR to storage, there are additional issues to be considered. Even if the CO_2 comes from petroleum sources, and thus continues to be associated with petroleum industry and regulated according to the Petroleum Act[52] and Regulations[57], the purpose of the permit will change from production of petroleum to storage of CO_2. Such a transition would not just necessitate a change of work plan, an updated monitoring plan or infrastructural changes. The transition would change the whole foundation of the permit, which can ultimately result in the need to decommission the project, terminate the license and the issuance of a new permit, pursuant to chapter 4a of the Petroleum Regulations[57]. If the CO_2 is planned to be brought in from other industrial sources than petroleum, the operator has to apply for a new permit according to the CO_2 Storage Regulations[20].

To prepare for the transition, the operator can consider reusing infrastructure. As part of decommissioning a petroleum project, the operator is required to present a decommissioning plan, which includes a requirement to include proposals for continued production or closure of production and re-use of the facilities, either for petroleum operations or something else. This proposal can ultimately be approved by the ministry and thus form the foundation of a new permit and PDO.

Beyond the technical aspects and challenges of transitioning from dedicated CCS to CO_2-EOR or vice versa, the permitting framework for the two activities is not the same. The correct and most likely approach is to decommission the existing facilities before applying for a new permit for the new activity. The license area has to be characterized again to establish the applicable baseline in accordance with the framework's purpose (i.e. either petroleum production or CO_2 storage). Like the Petroleum Act[52] and Regulations[57], the CO_2 Storage Regulations[20] contain provisions on closure plan and proposals for continued or re-use of the facilities. These proposals can include using some of the facilities for activities regulated according to the other track, which can allow an easier permitting process for portions of the project.

10.4 Review of case study scenarios

10.4.1 Case study variations in 8.1: Maximization or optimization of CO_2 storage in an actively producing CO_2-EOR project

10.4.1.1 General

This set of operational changes consists of actions aimed at increasing the amount of CO_2 injected and stored in CO_2-EOR operation, either

— by increasing the amount of pore space in a defined containment that is filled with CO_2 (i.e. increasing the pore saturation);

— by increasing the reservoir pressure; or

— by increasing the pore volume access to CO_2 by injecting into downdip areas.

These project variations will generally have existing facilities that can be sufficient for the immediate needs of CO_2 storage, but over time can necessitate upgrades for injection system operating pressures, recycle rates and field distribution and gathering. Hence, these scenarios all involve currently (or previously) operated CO_2-EOR operations that had met the applicable legal, regulatory and permitting requirements for CO_2-EOR operations and the question is whether additional or different legal or regulatory issues arise from altering operations to maximize or optimize CO_2 storage rather than hydrocarbon extraction. See Clause 9 for information on the scope and applicability of ISO 27914 and ISO 27916 to the modified operations.

10.4.1.2 Access to the project site

In many jurisdictions, the underlying mineral lease or land tenure needs to be modified. If the lease or land tenure was granted "solely" or "exclusively" for the purpose of hydrocarbon extraction (or similar terms), the injection of additional CO_2 for the purpose of optimizing or prioritizing CO_2 storage can take the operations outside the scope of the original grant. In addition, if the lease term is maintained in existence by the continued production of identified hydrocarbons in "commercial" or "paying quantities", the diminution or cessation of such hydrocarbon production can lead to lease termination. Renegotiated arrangements would be necessary for a new or extended lease.

More fundamentally, to the extent that reinjection of incremental CO_2 increases the reservoir pressure, the injections can effectively extend the subsurface area of CO_2 saturation beyond the pre-defined lease or land tenure bounds (as well as the regulatorily-defined area of review). Such areal extension beyond pre-existing bounds would presumably necessitate a corresponding extension of the mineral lease or land tenure boundaries.

If there are multiple underlying agreements (such as mineral property leases common in the US), the sheer number of legal agreements involved can be substantial and the practical difficulties of renegotiating such a large number of leases with separate parties can be insurmountable. In other cases, the land can be owned completely in fee simply by the operator such that no renegotiation is necessary.

In addition, the operational changes would presumably increase operational costs over the level of costs previously necessary strictly for hydrocarbon recovery and can result in additional value through the operation of incentives, credits or other financial inducements. Where the EOR project is operated through a unit agreement or similar arrangement, changes in the economics of the operation can be addressed in the various operating agreements and other private agreements among the parties involved or affected. For example, where there are multiple interest owners, there will typically be agreements that limit the costs and operations undertaken by the operator on behalf of all the interest owners and determine how allowed costs are allocated. Those agreements are likely to limit operational changes to those dictated by prudent operation intended to maximize the economic return consistent with aiming at maximizing the total ultimate recovery of the hydrocarbon resource. Undertaking actions that exceed those boundaries is likely to necessitate amending the relevant agreements. Given the multiplicity and complexity of such agreements, the needs for such contractual revisions can pose a significant hurdle.

10.4.1.3 Permitting and other regulatory authorizations

If the modified operations would affect the integrity of the EOR storage complex, the containment assurance and the operations management plan would need to be examined to determine if revisions are appropriate. In jurisdictions where such documents are on file with or require approval by regulatory authorities, appropriate regulatory approvals can be necessary. In essence, the operator can need revisions or additions to existing well permits or other regulatory authorizations if the planned operational changes are expected to increase the risk of CO_2 migration into drinking water sources or releases to the atmosphere.

The responsibility and potential civil liability for injury or damage resulting from the revised operation will also need to be reviewed. The pre-existing instruments can address CO_2 injections solely in the context of enhancing or optimizing hydrocarbon recovery. Modified operations to prioritize CO_2 storage can exceed the coverage of existing insurance arrangements. The scope of legislative provisions addressing waste disposal can be examined to determine the potential applicability of anti-dumping or waste disposal regimes to the injection of any CO_2 that is not necessary for hydrocarbon production. The operator would be wise not to assume that prior legislative or regulatory assurances devised for hydrocarbon recovery necessarily apply equally to what can be deemed injections of CO_2 for waste disposal purposes.

Similarly, regulatory rules governing plugging and abandonment at project termination that apply to CO_2 injections during CO_2-EOR operations would not be wholly applicable if the operation has been changed to inject CO_2 that was not necessary for the previously permitted CO_2-EOR operation. Therefore, the operator needs to ensure that the operation is not in an intermediate state, where a recently developed regulatory framework for CO_2 storage does not clearly apply to the modified operation but the operation can exceed one or more parameters or assumptions of existing regulatory approvals developed for hydrocarbon recovery operations.

10.4.1.4 Project termination and post-termination liability

As with the review of the modified operations themselves, the operator needs to review the applicable permit conditions or regulatory rules governing individual well plugging and abandonment and project termination. Pre-existing mineral leases or other land tenures can be worded in such a way as to mandate well plugging and abandonment and perhaps site remediation and other steps as soon as commercial hydrocarbon recovery operations come to an end. If the modified operations result in a termination of hydrocarbon recovery as described by the underlying land tenure instruments, those documents can need amending. In addition, if the termination of the project itself involves the disposal of CO_2 that is not associated with hydrocarbon recovery, there can be changes in the liability regime governing responsibility and potential civil liability for post-termination events. For example, regulatory or permitting regimes that provide for a transfer of liability to a governmental entity or payment into or qualification for access to trust funds for dedicated storage would not “synch” intuitively with “top up the tank” operations if the dividing line between hydrocarbon recovery and CO_2 waste disposal is not clearly drawn and understood.

10.4.2 Case study variations in 8.2

10.4.2.1 General

The various options addressed in 8.2 have in common the complete cessation of CO_2-EOR production (although in some cases, there can be some incidental hydrocarbon production, as discussed in 8.3.3.3 or 8.3.3.4). The projects in this group can be at sites that previously underwent CO_2 flooding, or in some cases in locations that have (or have had) primary and secondary recovery operations, but not CO_2-EOR operations (e.g. see 8.3.3.6). In many cases, the operator will re-use or re-purpose various elements of the pre-existing infrastructure.

10.4.2.2 Access to the project site

Similar issues arise as in the scenarios addressed in 8.1 that are discussed in 10.4.1.1. If the purpose of the pre-existing mineral lease or land tenure was for hydrocarbon extraction, the operational modifications in the current case studies can take the operations outside the scope of the original grant. Hence, all the same considerations addressed in 10.4.1.1 can be addressed when planning the operational changes in the 8.2 scenarios as in the 8.1 scenarios.

As with scenarios discussed in 8.1, any extension of the subsurface area of CO_2 saturation beyond the existing pre-defined lease or land tenure bounds or regulatorily defined area of review can necessitate a corresponding extension of the mineral lease or land tenure boundaries.

10.4.2.3 Permitting and other regulatory authorizations

Since the activities in the 8.2 scenarios are no longer the extraction of hydrocarbons, the bulk of the pre-existing regulatory and permitting authorizations are likely to need modification in many if not most instances. Many of the operations can technically make use of pre-existing oil and gas infrastructure (e.g. as detailed in 8.3.4) and can also remain within the bounds of ISO 27916 (see Clause 9). Nevertheless, the regulatory authorizations for the new use of the pre-existing infrastructure can fall into different permitting categories.

While the precise legal questions differ in different jurisdictions, they will generally fall into two categories:

a) the extent to which the modified operations can be conducted under pre-existing authorizations; and

b) the ease or difficulty of obtaining new or revised authorization for the revised operation.

As the 8.2 scenarios generally presume the full termination of hydrocarbon recovery operations at the project (or the defined portion of the project being converted to non-associated CO_2 storage), the operator can determine that the new operations need amending or even new well permits or other regulatory authorizations that are based on the new operations and the proposed re-use of existing infrastructure.

In short, while the operations can be technically possible and economically justified and come within the bounds of ISO 27916, there can be significant legal, regulatory or permitting issues to resolve before the modified operations can go forward.

10.4.2.4 Project termination and post-termination liability

As the case study variations discussed in 8.2 assume full termination of hydrocarbon recovery, the regulatory and permit conditions for hydrocarbon recovery will generally require the plugging and abandonment of all wells, but injectors and producers. There can also be site remediation steps required. These actions would be generally inconsistent with the continued operation of the facilities for handling and with the continued injection of CO_2 for storage purposes. As such continued operations would need new or revised regulatory authorizations, the requirements for termination of the modified operations would presumably be specified in the new approvals. These can be according to a straightforward application of the rules governing dedicated storage of CO_2, but these can also be developed on a more ad hoc basis adapted to a specific project.

If the modified operations are viewed as a direct follow-on to the preceding hydrocarbon recovery operations, the regulatory rules for the transfer of liability for the CO_2 to a government entity would not necessarily apply. If, however, new or revised authorizations are obtained under the geological storage framework, then those provisions would apply by their own terms.

Given the uncertainty as to how the follow-on CO_2 injection and storage operations can be viewed by a regulator, it would appear advisable for an operator to obtain regulatory clarity for any specific project before commencing these types of modified operations.

10.4.3 Case study variations in 8.3

10.4.3.1 General

In 8.3, the status quo is a non-CO_2 related hydrocarbon recovery operation that produces native CO_2 with natural gas and that currently vents the produced CO_2 to the atmosphere while transporting the natural gas to a central LNG liquefaction and shipping facility that receives natural gas from multiple fields both onshore and offshore.

The particular field evaluated for CO_2 storage is at or approaching a point of economic depletion of the hydrocarbon production. The suggested change is a multi-year and multi-facility project to install facilities to capture CO_2 produced from combustion emissions at the central LNG facility onshore, reverse the direction of flow of the subsea natural gas pipeline and repurpose it for transporting the CO_2 captured onshore to the offshore site.

In addition, facilities can be installed at the offshore site to capture the native CO_2 produced with the natural gas from the offshore field. Thus, over a period of years the combined CO_2 stream of native CO_2 captured at the offshore site would be combined with the anthropogenic CO_2 captured at the central LNG facility.

Initially, the injectate would aid in producing natural gas. As the natural gas producing wells get gradually depleted and plugged, the project would progressively become a site for dedicated storage of CO_2 not associated with hydrocarbon recovery. When the economic or technical limit to CO_2 storage injection is reached, the project would be secured for long-term secure containment of the stored CO_2. Such an operation combines the environmental benefit of geologically storing significant quantities of native CO_2 that is currently being vented into the atmosphere and CO_2 produced onshore from natural gas combustion, with the economic benefit of efficiently extracting the remaining hydrocarbons from the offshore reservoir to be progressively converted to dedicated storage. It would involve significant changes to facilities and operations that presumably have been licensed or permitted for the original hydrocarbon operation. For example, the flow direction of the natural gas pipeline would be reversed, and it would be re-purposed to transport CO_2 rather than CH_4. The regulatory procedure for such a conversion is likely to vary in different jurisdictions around the world. While such a conversion is unusual, it has already been effected such that there is already real-world industrial experience with such a conversion.[12)]

10.4.3.2 Access to the project site

The project access questions presented in this subclause are more complex than with the earlier cases. In this subclause, the proposed project involves changes both onshore (installation of capture facilities at the onshore central LNG liquefaction facility), along the seabed (repurposing and reversing the flow of the existing natural gas pipeline for CO_2 carried from the onshore facility to the offshore injection site), as well as modified operations at the offshore facility itself (installing capture facility at or adjacent to the platform, facilities for combining the captured native CO_2 at the platform with the CO_2 captured at the onshore LNG facilities delivered via the repurposed and redirected pipeline). Perhaps, additional wells can be necessary for injecting into the formations targeted for long-term storage.

Nevertheless, the basic site access questions are similar to those in the other case studies. For each component, the operator will need authorization under the existing leases or other land tenure instruments to continue to make use of underlying real estate for the modified operations. Depending on the scope of the existing instruments, revision or expansion of the prior rights can be necessary.

The revenue stream from the offshore operation can change significantly if the economic value derived from the CO_2 storage becomes a material element of project revenues. The existing lease provisions governing royalty payments or cost-sharing can be affected in ways that had not been clearly anticipated when the underlying agreements were originally reached. Early recognition and management of such potential changes in the amount and character of project costs and revenues can help facilitate smoothing the proposed operational changes.

12) A similar conversion from natural gas to CO_2 transportation was approved by the US natural gas pipeline regulator (Federal Energy Regulatory Commission) in 2006.