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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

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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.

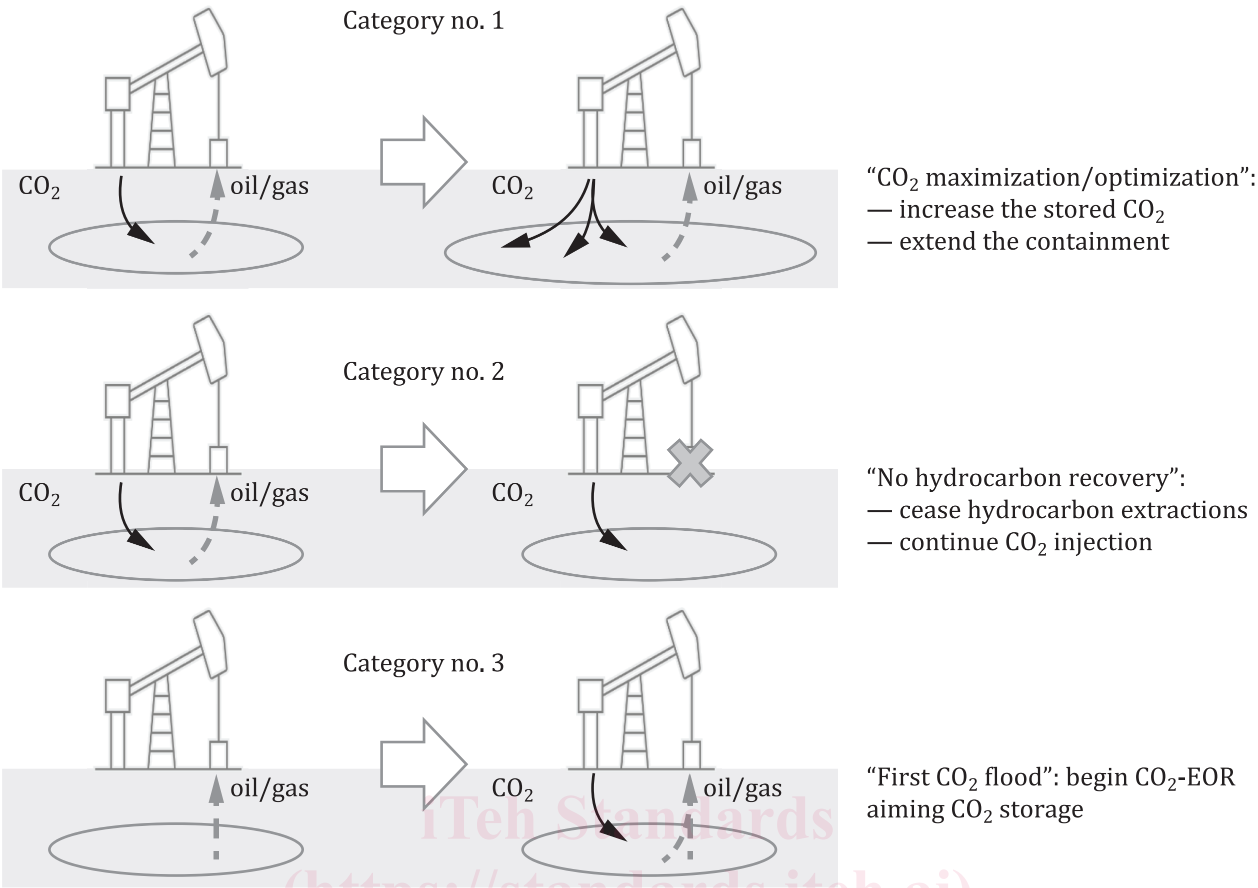

Figure 1 — Operational scenario categories

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);