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

Captage, transport et stockage géologique du dioxyde de carbone — Stockage du dioxyde de carbone au moyen de la récupération assistée du pétrole (RAP-CO_2)

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Foreword

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

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights. Details of any patent rights identified during the development of the document will be in the Introduction and/or on the ISO list of patent declarations received (see www.iso.org/patents).

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

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

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

Introduction

This is the first edition of the standard entitled: *Carbon dioxide capture, transportation and geological storage — Carbon dioxide storage using enhanced oil recovery (*CO_2*-EOR).* The subject matter of this document is a new work product and does not cancel or replace any other documents in whole or in part related to the subject of CO_2-EOR.

Carbon dioxide enhanced oil recovery (CO_2-EOR) is a technique for increasing the recovery of hydrocarbons from an oil field.

The process involves using wells to inject volumes of CO_2 at pressures where the injected CO_2 usually mixes with the oil, changing the properties of the oil and enabling it to flow more freely to production wells. In most cases, a CO_2-EOR project is designed as a closed-loop system whereby some of the injected CO_2 is co-produced with the oil and then separated in above-ground recycling facilities prior to being reinjected into the oil reservoir. CO_2 that is injected into the project reservoir is contained as an inherent element of the injection and production operations, and this document requires that such containment be demonstrated. CO_2 that is injected and remains trapped in the project reservoir (or EOR complex) during and after oil production activities is not released to the atmosphere, and this trapping is referred to as "associated storage". Annex A provides a detailed description of the CO_2-EOR process as presently used (and potential "next generation" uses) and the associated storage that occurs as an intrinsic part of those operations. Although methane is often present in EOR project reservoirs, this document does not specifically address methane or other greenhouse gases. The demonstration requirements for safe, long-term containment, however, address assessment of trapping and potential leakage pathways that would likely assure containment of methane as well as CO_2. As detailed in Annex A, CO_2-EOR has been deployed internationally for several decades and has potential to expand. CO_2-EOR is commercially valuable today because it allows for the additional recovery of hydrocarbon resources while simultaneously trapping injected CO_2 for safe, long-term containment as a part of the process.

This document applies to quantifying and documenting the total CO_2 (and optionally the anthropogenic portion of the CO_2) that is stored in association with CO_2-EOR. The document recognizes that CO_2-EOR is principally an oil recovery operation. Associated with this oil recovery, however, safe and long-term CO_2 storage occurs. The absence of an accepted standard for demonstrating the safe, long-term containment of CO_2 in association with CO_2-EOR and documenting the quantity of associated stored CO_2 constitutes one of the barriers to the increased use of anthropogenic CO_2 in CO_2-EOR operations. The purpose of this document is to remove that barrier and thereby facilitate the exchange of goods and services related to the increased use and emissions reductions through associated storage by providing methods for demonstrating the safe, long-term containment of, and determining the quantity of CO_2 stored in association with CO_2-EOR. The document does not address the financial consequences that may or may not result from documenting storage of CO_2 in association with CO_2-EOR operations.

This document does not provide requirements for the selection, characterization or permitting of sites for CO_2-EOR projects because those sites are selected, characterized, and permitted pursuant to requirements and standards applicable to oil and gas exploration and production. Likewise, this document does not specify environment, health and safety protections or corrective action and mitigation requirements that are provided by the regulations and standards applicable to all hydrocarbon production operations. (A list of many of the existing standards applicable to CO_2 injection wells and oil and gas operations is presented in the Bibliography.) This document does provide requirements for demonstrating that the site in question is adequate to provide safe, long-term containment of CO_2, for demonstrating that the CO_2 flood is operated in a way to assure containment of the CO_2 in the EOR complex, and for quantifying associated storage.

This document provides for the quantification of the CO_2 that is stored in association with CO_2-EOR operations. The results of quantifications under this document could be used as input for calculations conducted in accordance with a number of other standards, protocols or programs for the quantification or reporting of greenhouse gas emissions, mitigation, or reductions, including those complying with ISO 14064-1, ISO 14064-2 and ISO 14064-3. Specifically, this document provides for the identification and quantification of CO_2 losses (including fugitive emissions) and quantification of the amount of CO_2

stored in association with CO_2-EOR projects. Such quantification could be used in a broader scheme for the quantification and verification of emissions and emission reductions over the entire carbon capture, transportation and storage chain. Specifically, using this document will provide quantification results that could be used as input to approaches described in ISO/TR 27915 for Quantification & Verification (Q&V). In addition, the quantification of CO_2 stored in association with a CO_2-EOR project pursuant to this document could be combined with the quantifications generated under ISO 27920, Carbon dioxide capture, transportation, and geological storage — Quantification and Verification, which is currently under development. The quantification of the storage associated with a CO_2-EOR project that occurs as part of a CCS project chain could be combined with the quantification of one or more capture, transportation and geological storage systems to produce a total quantification for the entire CCS project chain. Under some emissions quantification and reporting regimes, CO_2 quantities stored in association with CO_2-EOR are either treated as not emitted and excluded from calculations or subtracted as offsets.

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

1 Scope

1.1 Applicability

This document applies to carbon dioxide (CO_2) that is injected in enhanced recovery operations for oil and other hydrocarbons (CO_2-EOR) for which quantification of CO_2 that is safely stored long-term in association with the CO_2-EOR project is sought. Recognizing that some CO_2-EOR projects use non-anthropogenic CO_2 in combination with anthropogenic CO_2, the document also shows how allocation ratios could be utilized for optional calculations of the anthropogenic portion of the associated stored CO_2 (see Annex B).

1.2 Non-applicability

This document does not apply to quantification of CO_2 injected into reservoirs where no hydrocarbon production is anticipated or occurring. Storage 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. If 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.

1.3 Standard boundary

1.3.1 Inclusions

The conceptual boundary of this document for CO_2 stored in association with CO_2-EOR includes:

a) safe, long-term containment of CO_2 within the EOR complex;

b) CO_2 leakage from the EOR complex through leakage pathways; and

c) on-site CO_2-EOR project loss of CO_2 from wells, equipment or other facilities.

1.3.2 Exclusions

This document does not include the following:

a) lifecycle emissions, including but not limited to CO_2 emissions from capture or transportation of CO_2, on-site emissions from combustion or power generation, and CO_2 emissions resulting from the combustion of produced hydrocarbons;

b) storage of CO_2 above ground;

c) buffer and seasonal storage of CO_2 below ground (similar to natural gas storage);

d) any technique or product that does not involve injection of CO_2 into the subsurface; and

e) emissions of any GHGs other than CO_2.

NOTE Some authorities might require other GHG components of the CO_2 stream to be quantified.

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 terminological 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 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)

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

Note 2 to entry: If CO_2 that meets the definition of anthropogenic CO_2 is not included in a supplemental quantification of associated storage of anthropogenic CO_2 (e.g., because it was received and injected by a CO_2-EOR project prior to the quantification period) it will generally be treated as non-anthropogenic CO_2 in that quantification.

3.2
associated storage
CO_2 stored in association with *CO_2-EOR* (3.4) that occurs as an inherent result of a dedicated hydrocarbon production operation

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

3.3
authority
competent governmental entity or entities with legal power to regulate or permit *CO_2-EOR* (3.4), to regulate storage of CO_2 in association with a *CO_2-EOR* (3.4) operation, or to regulate quantification of the storage of CO_2 in association with a *CO_2-EOR* (3.4) operation

3.4
CO_2 enhanced oil recovery
CO_2-EOR
process designed to produce hydrocarbons from a reservoir using the injection of CO_2

Note 1 to entry: The process of CO_2 enhanced oil recovery is explained in detail in Annex A

3.5
CO_2 enhanced oil recovery project
CO_2-EOR project
EOR complex (3.10), underground equipment, wells, surface or above seabed equipment, activities and rights necessary to an enhanced oil recovery operation, including any necessary or required surface or subsurface rights regulated by the authority

3.6
CO_2 injection well
well used to inject CO_2 into a *project reservoir* (3.19)

3.7
CO_2 stream
stream consisting overwhelmingly of carbon dioxide

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

[SOURCE: ISO 27917:2017, 3.2.10, modified — Note revised to added "to improve performance of hydrocarbon recovery operation".]

3.8
containment
status of CO_2 being confined within the *EOR complex* (3.10) by an effective *trap* (3.23) or combination of traps

3.9
containment assurance
demonstration that the features and geologic structure of the *CO_2-EOR project* (3.5) are adequate to provide *safe, long-term* (3.21) *containment* (3.8) of CO_2, and that the CO_2 flood is operated in a way to assure containment of the CO_2 in the *EOR complex* (3.10)

3.10
EOR complex
project reservoir (3.19), *trap* (3.23), and such additional surrounding volume in the subsurface as defined by the *operator* (3.16) within which injected CO_2 will remain in *safe, long-term* (3.21) *containment* (3.8)

3.11
injection-withdrawal ratio
ratio, during a defined period, of the volume of all fluids and gases injected into the *project reservoir* (3.19) to the volume of all fluids and gases produced from the project reservoir as determined using consistent temperature and pressure conditions

3.12
leakage
unintended release of CO_2 to the atmosphere or out of the *EOR complex* (3.10)

[SOURCE: ISO 27917:2017, 3.2.14, modified — Added to the atmosphere or out of the EOR complex.]

3.13
leakage pathway
geological or artificial conduit for *leakage* (3.12) of CO_2 out of the *EOR complex* (3.10)

3.14
loss
leakage (3.12), intended releases, and transfers of CO_2 from the *CO_2-EOR project* (3.5)

3.15
native CO_2
CO_2 present and indigenous within the *project reservoir* (3.19) prior to hydrocarbon production or any CO_2 injection

Note 1 to entry: Native CO_2 is also known as "in situ CO_2".

3.16
operator
entity responsible for the *CO_2-EOR project* (3.5)

3.17
plug & abandon
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.

3.18
post-termination
period of time after *termination* (3.22)

3.19
project reservoir
geologic reservoir in to which CO_2 is injected for production of hydrocarbons in paying or commercial quantities

3.20
quantification period
period of time during which *associated storage* (3.2) is being quantified

3.21
safe, long-term
period necessary for *associated storage* (3.2) to be considered environmentally safe by the system under which the quantification is being implemented

3.22
termination
process beginning with the cessation of quantification of *associated storage* (3.2), and ending with both the termination of hydrocarbon production from the *project reservoir* (3.19), and the plugging & abandonment of wells unless otherwise required by the *authority* (3.3)

3.23
trap
any feature or mechanism that alone or in combination provides *safe, long-term* (3.21) *containment* (3.8) below a low-permeability confining geologic layer (cap rock or seal), including in the pore spaces of the *EOR complex* (3.10) (physical, stratigraphic, or structural trapping), by capillary pressure from the water in the pore spaces between the rock (residual trapping), by dissolution in the in situ formation fluids (solubility), by hydrodynamic trapping, by adsorption onto organic matter or by reacting in geologic formations to produce minerals (geochemical trapping)

4 Documentation

4.1 Purpose

The provisions of this clause are intended to facilitate documentation of the safe, long-term containment, and the quantification of associated storage.

4.2 Use of existing data

Documentation and demonstration requirements throughout this document may be satisfied by information that has already been required, is held, approved by, and available from the authority, because in many cases EOR operations are addressed by existing oil and gas regulations. To the extent that information fully satisfies the requirements, has already been provided and is available from the authority, such information is not required to be developed again for purposes of this document. References to information that is available do not include information held by another entity but not available to the operator.

4.3 Initial documentation

At the beginning of the quantification period, initial documentation shall be prepared and shall include:

a) a description of the EOR complex and engineered systems (see Clause 5);

b) the initial containment assurance (see 6.1.2);

c) the monitoring program (see 6.2);

d) the quantification method to be used (see Clause 8 and Annex B); and

e) the total mass of previously injected CO_2 within the EOR complex at the start of quantification period (see 8.5 and Annex B).

The initial documentation shall be offered to the authority.

4.4 Periodic documentation

Periodic documentation should be prepared at least annually and shall provide the following information:

a) the quantity of associated storage in specified units of CO_2 mass, or volumetric units convertible to mass, (see 8.2 m_{stored}) during the period covered by the documentation;

b) the cumulative quantity of associated storage in specified units of CO_2 mass, or volumetric units convertible to mass, (see 8.2 m_{stored}) since the beginning of the quantification period;

c) the formula and data used to quantify the mass of associated storage, including the mass of CO_2 delivered to the CO_2-EOR project and losses during the period covered by the documentation (see Clause 8 and Annex B);

d) the methods used to estimate missing data and the amounts estimated as described in 9.2;

e) the approach and method for quantification utilized by the operator, including accuracy, precision and uncertainties (see Clause 8 and Annex B);

f) a statement describing the nature of validation or verification of the statement including the date of review, process, findings, and responsible person or entity; and

g) source of each CO_2 stream quantified as associated storage (see 8.3).

The periodic documentation shall be offered to the authority.

NOTE The operator can determine that more frequent recordkeeping and documentation are required to meet the goals or requirements of the CO_2-EOR project.

5 EOR complex description, qualification, and construction

5.1 General

A general EOR operations management plan shall be prepared and periodically updated; shall provide a description of the EOR complex and engineered system [see 4.3 a)], shall establish that the EOR complex is adequate to provide safe, long-term containment of CO_2 and shall include site-specific and other information pertaining to:

a) geologic characterization of the EOR complex;

b) a description of the facilities within the CO_2-EOR project;

c) a description of all wells and other engineered features in the CO_2-EOR project; and

d) the operations history of the project reservoir.

5.2 Geological characterization and containment assessment of the EOR complex

The general geologic characterization of the EOR complex shall be based on subsurface and other data collected at the site (augmented where appropriate with data from analogous fields), including any features that may affect safe, long-term containment of CO_2 and evidence of the integrity of the reservoirs and traps. The operator shall define the EOR complex in the geologic description to contain all likely subsurface locations to which the CO_2 could reasonably move beyond the project reservoir. For projects desiring to quantify associated storage, the geological characterization and engineering description shall provide evidence of the integrity of the reservoirs and traps that supports a conclusion that the EOR complex is suitable for safe, long-term containment. The description of the EOR complex should include, but not necessarily be limited to:

a) general lithologic description of the stratigraphic column above the EOR complex;

b) depth to the top of the EOR complex;

c) thickness of the defined stratigraphy within the EOR complex;

d) structural and geophysical properties;

e) lateral boundaries and any spill points relevant to containment;

f) hydraulic/petrophysical/geochemical/geomechanical properties;

g) associated storage capacity of CO_2 in the project reservoir, recognizing that EOR operations are typically designed for maximum economic hydrocarbon production; and

h) engineering data as described in 6.1.3.

5.3 Description of the facilities within the CO_2-EOR project

The description of the facilities within the CO_2-EOR project shall provide an overview of the equipment, downstream of the CO_2 custody transfer meter, used to handle CO_2 and production, including design specifications. This should typically include piping, separators, processing and dehydration equipment, pumps, compressors, and any other equipment relevant to CO_2 handling and production. It should specifically address vent, release, sampling, and metering points, including a description of metering accuracy and estimation techniques.

5.4 Existing wells within the EOR complex

The description of wells shall identify each well penetrating the EOR complex and shall provide evidence it has been constructed and/or plugged & abandoned in such a manner as to provide safe, long-term containment of CO_2. Such wells include injection, production, monitoring, temporarily abandoned, shut-in, and plugged & abandoned wells. The following information shall be provided where available:

a) well name;

b) unique well identifier;

c) spud and completion dates;

d) well status (e.g. injection, production, monitoring, temporarily abandoned, shut-in, plugged & abandoned);

e) surface or seabed location;

f) total and measured depth;

g) plugging & abandonment information;

h) well construction, completion, and well integrity technical details;

i) significant equipment remaining in the well; and

j) well intervention details and history.

In some cases, remote sensing methods or field or aerial surveys to locate old wells may be necessary.

5.5 Operations history of the project reservoir

The operations history of the CO_2-EOR complex should include:

a) production and injection data for the project reservoir;

b) temperature and pressure history, including current distribution;

c) interaction with adjacent reservoirs;

d) any known leakage incidents; and

e) history of seismic activity.

6 Containment assurance and monitoring within the EOR complex

6.1 Containment assurance and EOR operation management plan

6.1.1 EOR operations management plan

The EOR operations management plan (see 5.1) shall specify the procedures for field management, including:

a) project data as described in Clause 5, to be used for monitoring and quantification;

b) engineering controls for injection and production;

c) periodic assessment of reservoir performance as compared with expected behaviour in accordance with 6.1.3;

d) assessment of containment by geologic features and engineering systems in accordance with 6.1.3;

e) assessment and management of potential leakage pathway risks and monitoring technologies and procedures (see 6.1.3), including definition of detection thresholds, that are sufficient to meet the requirements of 8.6;

f) method of quantification of CO_2 below the detection threshold in accordance with 8.6;

g) corrective measures for potential leakage or unexpected events;

h) providing data for associated storage quantification; and

i) developing a termination plan for the CO_2-EOR project that specifies criteria for termination and outlines the termination qualification process sufficient to meet the requirements of Clause 10.

6.1.2 Initial containment assurance

The EOR operations management plan shall provide an initial containment assurance plan to identify and assess potential geologic, engineered, and engineering-affected leakage pathways that might lead to loss of CO_2 from the EOR complex.

6.1.3 Operational containment assurance

The EOR operations management plan shall provide operational containment assurance during the quantification period, based on engineering data encompassing such items as the results of reservoir management practices, including injection-withdrawal ratio monitoring, well integrity monitoring, pressure monitoring, monitoring of CO_2 movement within leakage pathways identified in the initial containment assurance and monitoring of pressure response within the boundary of the EOR complex. The operational containment assurance may include results from other monitoring. These results shall be used in periodically providing evidence of containment, including the supporting rationale.

Containment assurance and reservoir management shall be reviewed, and the EOR operation management plan shall be revised as necessary if changes occur that have the potential to adversely affect containment, which may include:

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;

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.

6.2 Monitoring program, methods, and implementation

6.2.1 Monitoring of potential leakage pathways

The monitoring program shall address the identified inventory of potential leakage pathways from the containment assurance plan [see 6.1.1 e)] to determine, for each potential leakage pathway, whether it is:

a) not active and thus excluded from the monitoring program;

b) not active, but might activate under operation of the CO_2-EOR project and is thus to be addressed by the monitoring program; or

c) active.

The operator shall conduct the potential leakage pathway assessment in accordance with the EOR operation management plan or as required by the authority. A final leakage pathway assessment shall be conducted prior to project termination.

NOTE It is likely that the monitoring program could require collection of data prior to start of the quantification period and during the operational life of the project (see 5.5).

6.2.2 Monitoring methods

The monitoring program shall describe tools, methods, applicability, and frequency for detecting and quantifying losses (see 8.4). Details of the monitoring program and data assessed (including relevant data prior to the quantification period) shall be provided in the initial documentation (see 4.3), along with the threshold beneath which there would be no detection. The method of quantification for quantities of CO_2 below the detection threshold shall be specified in the EOR operations management plan (see 8.6).

6.2.3 Monitoring program implementation

The monitoring program shall be implemented to address facility and project losses in accordance with the EOR operations management plan (see 6.1) as applied to the inventory of potential leakage pathways (see 6.2.1). The monitoring program shall be reviewed and revised as EOR operational practices are modified.

7 Well construction

7.1 New well construction

A description of the new wells shall provide evidence that they are designed, constructed, and tested to provide safe, long-term containment of CO_2. Well materials, including metals, cements, and elastomers, shall be selected based on their ability to withstand the expected operational environment including the thermomechanical stress of operation and the geochemistry (including CO_2 where present) of the subsurface. At a minimum, wells that penetrate the EOR complex shall be cemented through each cap rock using cement that is suitable for the thermomechanical and geochemical environment for the safe, long-term containment of CO_2. To the extent not provided by other evidence of suitable construction (for example: reference to information that has been provided to the authority during permitting of CO_2-EOR operations), the following information shall be provided:

a) well name;

b) unique well identifier;

c) spud date, completion date;

d) status (e.g. injection, production, monitoring, temporarily abandoned, shut-in, plugged & abandoned);

e) surface or seabed location;

f) total and measured depth;

g) well construction, completion, and well integrity technical details; and

h) significant equipment remaining in the well.

7.2 Well intervention

A description of the well modifications shall provide evidence that they are designed, constructed, and tested to provide safe, long-term containment of CO_2. Well materials, including metals, cements, and elastomers, shall be selected based on their ability to withstand the expected operational environment including the thermomechanical stress of operation and the geochemistry (including CO_2 where present) of the subsurface. To the extent not provided by other evidence that the well modifications performed are suitable (for example: reference to information that has been provided to the authority during permitting of well intervention), the following information shall be provided:

a) well name;

b) unique well identifier;

c) intervention type and date;

d) status after intervention (e.g. injection, production, monitoring, temporarily abandoned, shut-in, plugged & abandoned);

e) surface or seabed location;

f) total and measured depth;

g) plugging and abandonment information (if applicable);

h) well intervention details; and

i) significant equipment remaining in the well.

8 Quantification

8.1 General

The quantification of associated storage [m_{stored}] (see 8.2) includes calculation of loss (see 8.4) and shall be conducted as specified in the EOR operations management plan (see 6.1.1) at least annually. All factors and variables defined in Clause 8 shall be quantified and documented.

Data collected from monitoring a CO_2-EOR project can be used in the quantification of associated storage. Any loss of CO_2 in association with a CO_2-EOR project shall be characterized and quantified.

NOTE 1 In some jurisdictions, an authority might require the operator to document information related to project CO_2 emissions such as (a) incremental emissions from the CO_2-EOR project from power or heat generation, (b) electricity and heat which are imported and the carbon intensity of generation of power (direct or average grid carbon intensity, if available), and (c) exported electricity. Such additional information could be included in the periodical documentation and utilized as appropriate for additional quantification procedures but would not change the quantity of anthropogenic CO_2 stored in association with the CO_2-EOR project. ISO/TR 27915 describes several mechanisms/protocols which utilize quantification of such additional CO_2 emissions.

NOTE 2 Some operators could also quantify the anthropogenic portion of m_{stored}. An example quantification calculation for the anthropogenic portion is shown in Annex B.

8.2 Quantification principles

Any method of quantification used by the operator shall follow these quantification principles:

a) The mass of CO_2 stored in association with CO_2-EOR [m_{stored}] shall be determined by subtracting loss from input [see Formula (1)].

b) The manner by which associated storage is quantified shall assure completeness and preclude double counting. The CO_2 that is recycled and reinjected into the EOR complex shall not be quantified as associated storage. Loss from the CO_2 recycling facilities shall be quantified.

c) Native CO_2 produced and captured in the CO_2-EOR project [m_{native}] should be quantified and documented and may be included in m_{input} if approved by the authority (see Note 2).

d) The operator shall quantify any CO_2 that is subsequently produced from the EOR complex and transferred offsite (see 8.4.5).

e) Quantification results shall be expressed either in units of mass or in volumetric units convertible to mass.

The method defined by Formula (1) should be used to document the associated storage of the mass of CO_2 [m_{stored}] within a defined period. m_{stored} should be calculated by quantifying the following variables:

$$m_{stored} = m_{input} - m_{loss\ operations} - m_{loss\ EOR\ complex} \tag{1}$$

— m_{input}; the total mass of CO_2 $m_{received}$ by the EOR project, approved m_{native}, (see 8.3);

— $m_{loss\ operations}$; the total mass of CO_2 loss from project operations (see 8.4.1 to 8.4.5); and

— $m_{loss\ EOR\ complex}$; the total mass of CO_2 loss from the EOR complex (see 8.4.6).

NOTE 1 In some jurisdictions $m_{loss\ operations}$ could be considered as fugitive emissions.

NOTE 2 Typically native CO_2 present in the project reservoir prior to starting a CO_2-EOR project is separated from produced hydrocarbons during production and emitted to the atmosphere. When hydrocarbon production progresses to CO_2-EOR and if recycling facilities are installed, the native CO_2 is no longer emitted, but is captured and retained for direct use by the CO_2-EOR project (see Figure 1) and is combined with the CO_2 received from other sources.

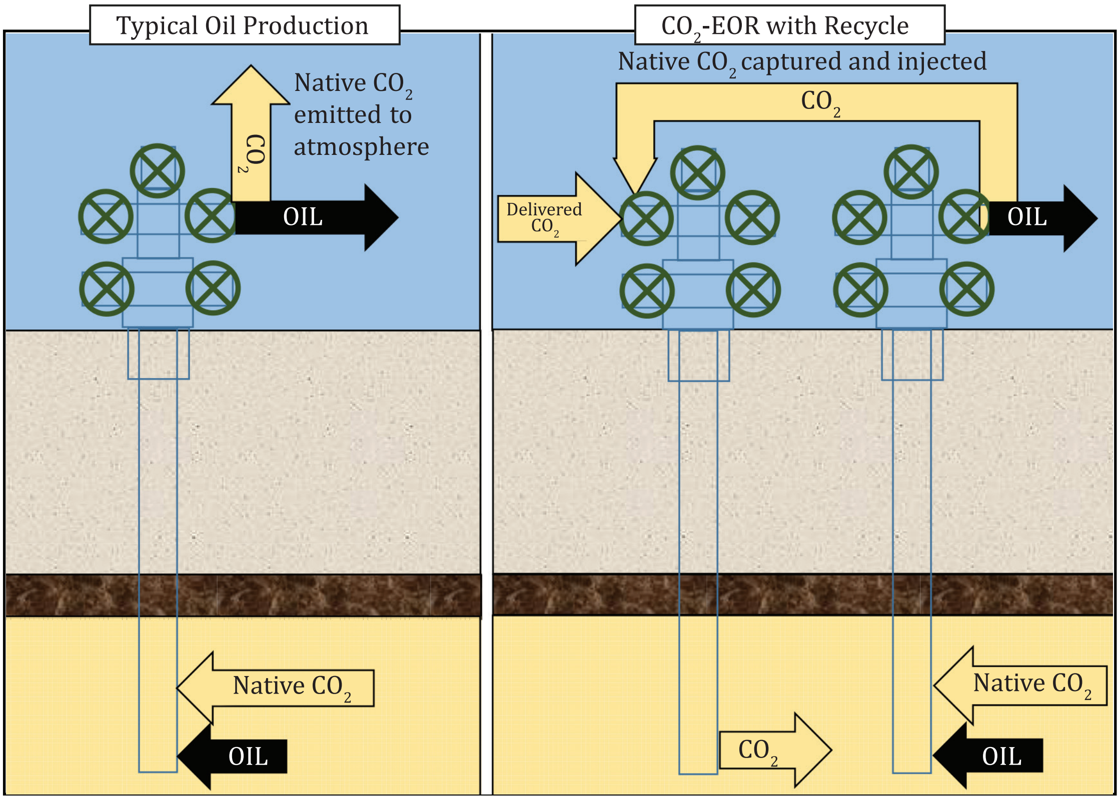


Figure 1 — Illustration of native CO_2, previously being emitted with typical production and now being captured and injected with CO_2-EOR (This diagram is to show movement of native CO_2 only and not meant to demonstrate production of other sources of CO_2)

8.3 Quantification of input [m_{input}]

The total CO_2 received at the custody transfer meter by the EOR project [$m_{received}$] shall be documented. The CO_2 stream received (including CO_2 transferred from another CO_2-EOR project) shall be metered. The native CO_2 recovered and included as m_{native} shall be documented.

CO_2 delivered to multiple CO_2-EOR projects shall be allocated among those CO_2-EOR projects. This allocation may be accomplished by contract. The sum of the quantities of allocated CO_2 shall not exceed the total quantities of CO_2 received.

NOTE Some operators could also quantify the anthropogenic portion of m_{input} (see 8.5).

8.4 Quantification of loss

8.4.1 Quantification of operational loss [$m_{loss\ operations}$]

The operator shall quantify the total mass of CO_2 loss from project operations within a defined period.

The $m_{loss\ operations}$ is composed of the following variables:

a) Loss of CO_2 due to leakage from production, handling and recycling CO_2-EOR facilities (infrastructure including wellheads) [$m_{loss\ leakage\ facilities}$];

b) Loss of CO_2 from venting/flaring from production operations [$m_{\text{loss vent/flare}}$];

c) Loss of CO_2 due to entrainment within produced gas/oil/water when this CO_2 is not separated and reinjected [$m_{\text{loss entrained}}$]; and

d) Loss of CO_2 due to any transfer of CO_2 outside the CO_2-EOR project [$m_{\text{loss transfer}}$].

$m_{\text{loss operations}}$ may be calculated using Formula (2):

$$m_{\text{loss operations}} = m_{\text{loss leakage facilities}} + m_{\text{loss vent/flare}} + m_{\text{loss entrained}} + m_{\text{loss transfer}} \tag{2}$$

NOTE Formula (2) is evaluated over a period of time in accordance with the documenting periods (see 4.4).

8.4.2 Leakage from facilities

The CO_2 loss from facilities (including wellheads) shall be quantified and documented. The total CO_2 leakage should be measured when possible. Leakage shall be estimated when not measured. The operator shall describe in the initial documentation how the loss is quantified and whether leakage is measured or estimated [$m_{\text{loss leakage facilities}}$].

NOTE Leakage is likely to be extremely small or zero in well managed operations; however, quantification of leakage is required.

8.4.3 Venting and flaring from operations

Venting of gases including CO_2 can be necessary during emergencies, planned maintenance activities or well intervention operations. The vented total mass of CO_2 shall be quantified based on the metered mass (if planned) or estimated mass (if unplanned).

The mass of any CO_2 released through the flare line excluding combustion products, shall be quantified as loss.

The summation of vented or flared loss shall be the mass of total CO_2 vented and flared [$m_{\text{loss vent/flare}}$].

8.4.4 Entrained CO_2 in products

CO_2-EOR produces oil, gas and brine from the project reservoir into which CO_2 is injected. Entrained CO_2 is the mass not completely separated from the produced streams and that exists in solution after the separation of gas and liquid at the surface facilities. The entrained CO_2 is considered a loss when the oil is sold or when the produced water is not reinjected into the reservoir.

The operator shall quantify and document the CO_2 loss by entrainment [$m_{\text{loss entrained}}$].

8.4.5 Transfer of CO_2

Any CO_2 transferred out of the CO_2-EOR project shall be quantified through metering and documented as loss from the project [$m_{\text{loss transfer}}$]. Any CO_2 transferred out of a CO_2-EOR project may be transferred and quantified as associated storage in another CO_2-EOR project or quantified as CO_2 stored in a geological storage project.

NOTE For any CO_2 transferred from one CO_2-EOR project to another CO_2-EOR project, an alternative approach could be to obtain approval of the authority to enlarge the CO_2-EOR project to include both projects, meaning that no transfer or loss of CO_2 would occur.

8.4.6 Loss from EOR complex

The operator shall describe the procedures used to detect and characterize the total CO_2 leakage from the EOR complex. All CO_2 leakage shall be quantified and documented as loss [$m_{\text{loss EOR complex}}$].

8.5 Allocation ratio for anthropogenic CO_2

If only the mass of anthropogenic CO_2 will be considered for m_{stored}, the operator should devise and document an anthropogenic CO_2 allocation ratio for all the terms described in 8.1 to 8.4.6 and these allocation ratios may be utilized as appropriate for additional quantification procedures. These allocation ratios should be documented based on the fraction of the anthropogenic CO_2 of the total CO_2. Annex B presents an example of how such allocation ratios can be used to quantify the anthropogenic portion of CO_2 associated storage (see B.4).

The previously injected volume of CO_2 within the EOR complex at the start of quantification period [$m_{previous\ injection}$], which is required to be documented in the initial documentation may be utilized to derive the allocation ratio [see 4.3 e) and Annex B].

For any quantification of the anthropogenic portion of CO_2 associated storage, the allocation ratio should be documented for CO_2 transferred out of a CO_2-EOR project that will be quantified as associated storage in another CO_2-EOR project or quantified as CO_2 stored in a geological storage project.

8.6 De minimis losses

The operator should specify for each monitoring method (i.e. meter type, technology, etc.) the threshold beneath which there would be no detection. For quantification purposes, calculations may use either some fraction of the detection threshold or nil, subject to authority requirements.

8.7 Avoidance of double-counting

The operator shall detail how CO_2 that is produced, captured, recycled and injected in the CO_2-EOR project is quantified and how that quantification assures completeness and precludes double-counting of CO_2.

Transfer of CO_2 from one CO_2-EOR project to another CO_2-EOR project should not be double counted for purposes of quantification in associated storage.

9 Recordkeeping and missing data

9.1 Record retention

Records supporting documentation as described in Clauses 4 to 10 of this document shall be retained for the duration of the operator's involvement in the CO_2-EOR project. Such supporting documentation shall be offered to the authority after termination of the lease/permit pertaining to the CO_2-EOR project.

9.2 Missing data procedures

The operator shall specify the procedures used to estimate monitoring, sampling and testing data for periods during which actual data are unavailable, such as periods of maintenance, equipment failure, or power outages. These procedures should avoid overestimations of the amounts of CO_2 stored.

10 Project termination

10.1 General

This clause provides requirements for the termination and documentation of a CO_2-EOR project that are in addition to the existing permitting, regulatory, and contractual framework that generally define the rules for safe and secure termination of hydrocarbon recovery projects. Compliance shall be demonstrated as part of the termination process through documentation provided to the authority or in the final periodic documentation under 4.4.

10.2 Periodic assurance of containment

If injection of the anthropogenic CO_2 ceases and the CO_2-EOR project continues to operate for hydrocarbon extraction purposes, periodic documentation (see 4.4) shall be provided as defined by the operations management plan or authority until CO_2-EOR project termination is completed.

NOTE CO_2 injection cessation is discussed further in Annex A.

10.3 Termination plan

The operator shall develop a termination plan for the CO_2-EOR project that specifies criteria for termination and documents the termination qualification process. This plan shall be developed to coincide with the initial documentation statement; shall be reviewed regularly; and shall be updated as appropriate during the project operation. The plan should specify:

a) criteria that confirm compliance with the containment assurance and EOR operations management plan requirements of Clause 6;

b) the termination process and anticipated timing;

c) monitoring consistent with requirements of 6.1 and 6.2;

d) corrective measures to address potential leakage pursuant to 6.1.1 e) and g); and

e) provisional plans for site decommissioning, including plans for plugging & abandonment of wells and decommissioning of facilities as referenced in 5.2 and 7.2 g).

10.4 Requisites for termination

Relying on CO_2 quantification, monitoring and operational information collected within the project, the operator shall satisfy the following requisites to demonstrate proper termination and compile them in the termination documentation:

a) the absence of detectable leakage (see 6.2) or open conduits to the surface out of the EOR complex, and that the injected CO_2 is, at the time of project termination, safely contained;

b) 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;

c) the injected CO_2 is safely contained with sufficient documentation of the characteristics of the EOR complex and operational history of the CO_2-EOR project to demonstrate long-term stability and predictability of the associated storage;

d) risks and uncertainties relating to the associated storage of CO_2 were managed throughout the EOR project life; and

e) facilities and ancillary equipment associated with the CO_2-EOR project have been removed, except those required to be retained by lease or contractual obligations, integral to other operations, or intended for different uses which may be left in place with approval of the authority.

The termination documentation shall describe the location of the injected CO_2. The termination documentation shall be offered to the authorities after termination of the CO_2-EOR project.

10.5 CO_2-EOR project termination

CO_2-EOR project termination is completed when all of the following occur: cessation of CO_2 injection, cessation of hydrocarbon production from the project reservoir, and wells are plugged & abandoned unless otherwise required by the authority.

10.6 Post termination

Assurance of safe, long-term containment shall consider fluid movement to ensure that leakage out of the EOR complex is unlikely. Some jurisdictions might require post-termination monitoring or follow up activities.

NOTE Regulatory requirements for project termination (or closure) and transfers of responsibility exist in some jurisdictions that could apply to CO_2-EOR projects. An example of such requirements is the EU CCS Directive: DIRECTIVE 2009/31/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006 (See Bibliography).

Annex A
(informative)

Introduction to CO_2-EOR

A.1 General

Annex A provides background information on CO_2 Enhanced Oil Recovery (CO_2-EOR) determined to be relevant to discussion of storage associated with, and incidental to CO_2-EOR, based on current operations. It does not attempt to provide information on how to design and optimize an economic project. Additionally, many of the concepts discussed herein are applicable to other types of hydrocarbon bearing reservoirs.

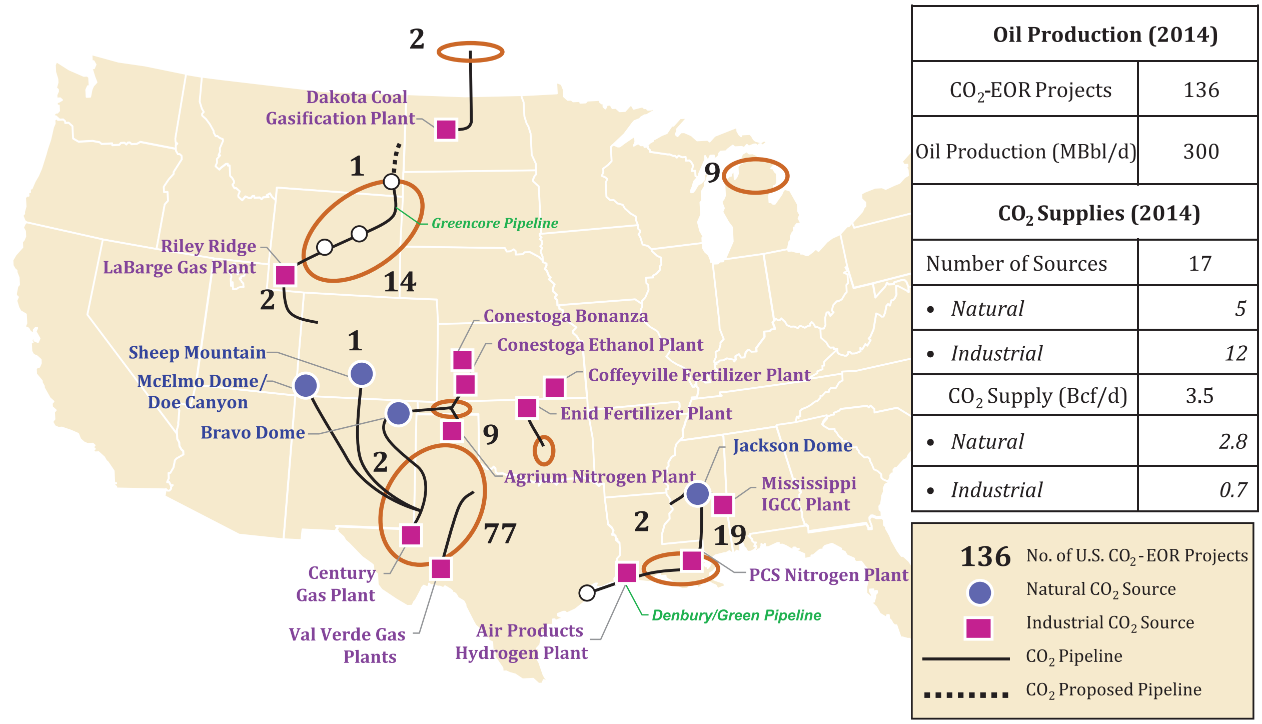
A.2 CO_2-EOR overview

CO_2-EOR is a mature technology. The first documented field trials of CO_2 for EOR were in Oklahoma (U.S.) during 1958. The first successful field CO_2 injection for the purposes of EOR took place beginning in 1964 at the Mead Strawn Field near Abilene, Texas (U.S.) (Holm and O'Brien, 1971). The commercial CO_2 industry began with the first successful large-scale CO_2 flooding in 1972 at the Budafa field (Hungary) and SACROC field in west Texas (US), the latter of which continues today. Initially, the SACROC project was supplied with CO_2 produced from CO_2 native to natural gas fields that was separated and captured from the raw production stream at several southern Permian Basin natural gas plants and transported via pipeline, totalling approximately 300 miles in length, and built specifically for CO_2 transport. Prior to this project, large quantities of CO_2 were being extracted from the natural gas production at these fields and vented to the atmosphere (Holtz, Nance and Finley, 1999). Since this time, CO_2-EOR has seen growth and expansion. It is estimated that by 2012, approximately 600 Mt (million metric tonnes) of CO_2 net of recycle had been injected for CO_2-EOR in the Permian Basin of west Texas. By 2015, an estimated one billion metric tonnes (1 Gt) net of recycle have been injected in the United States (Hill, Hovorka, and Melzer 2012). Approximately 75 to 80 percent of this quantity has come from naturally-occurring sources while the remainder has been captured from anthropogenic sources.

In 2014 (Kuuskraa and Wallace, 2014), there were 136 U.S. CO_2-EOR projects with approximately 7,100 CO_2 injection wells and 10,500 producing wells (see Figure A.1). Serving these projects are approximately 5,000 miles of CO_2 pipelines. See "Annual Report Mileage" from U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (2015 data). According to a 2011 report of the U.S. National Petroleum Council, approximately 3 BCF (billion cubic feet) per day of CO_2 (57 Mt/y) were injected in the United States for CO_2-EOR, producing about 300,000 bbls of oil per day (over 100 million bbls per year). Since the 1970s, the number of CO_2-EOR projects in the world has continued to grow, nearly doubling in each of the first three decades. In the U.S., the Permian Basin of west Texas has been the most active CO_2-EOR region, with 77 projects producing 200,000 bbl/d in 2014. Following the Permian Basin in that year were the Gulf of Mexico coastal states (50,000 bbls/d), the Rocky Mountains (39,000 bbls/d), and the Midcontinent (including Oklahoma, in particular) (10,000 bbls/d). Other U.S. regions, such as the Michigan Basin, have shown growth as well.

Additionally, there are several CO_2-EOR projects underway in other parts of the world (Kuuskraa and Wallace, 2014). Second to the U.S. in CO_2-EOR is Canada (e.g. Weyburn project, one of the world's largest CO_2-EOR projects is planning CO_2-EOR operations that will result in the associated storage of over 32 Mt of anthropogenic CO_2). There are also projects in China (Jilin, Daqing, Shengli, Jingbian, and others), Brazil (Bahia Oil and Lula oil fields), Saudi Arabia (Ghawar field), Turkey (Bati Raman) and Trinidad (Forest Reserve and Oropuche fields). Significant potential for CO_2-EOR has been reported for many parts of the world.

See Table A.1.



Source: Advanced Resources International, Inc., based on Oil and Gas Journal, 2014 and other sources.

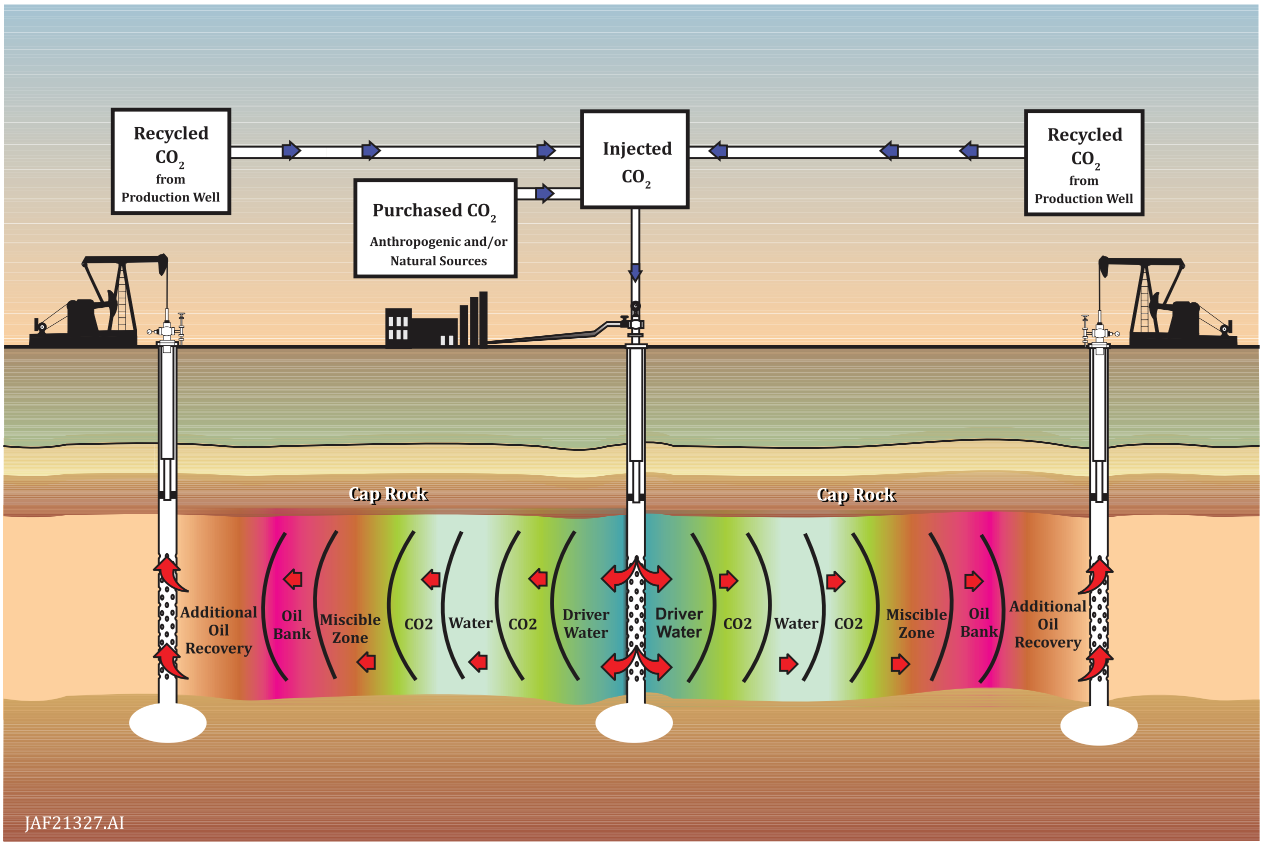
Figure A.1 — CO_2-EOR Operations and CO_2 sources in the U.S. (Kuuskraa and Wallace, 2014)

Table A.1 — International potential for CO_2-EOR and associated CO_2 storage (ARI, 2009)

Region name	CO_2-EOR oil recovery (MMBO)	Miscible basin count	CO_2/oil ratio (tonnes/bbl)	Potential CO_2 stored (giga-tonnes)
Asia Pacific	18,376	6	0.27	5.0
Central and South America	31,697	6	0.32	10.1
Europe	16,312	2	0.29	4.7
Former Soviet Union	78,715	6	0.27	21.6
Middle East and North Africa	230,640	11	0.30	70.1
North America (non-US)	18,080	3	0.33	5.9
North America (United States)	60,204	14	0.29	17.2
South Asia	0	0	N/A	0
Sub-Saharan Africa and Antarctica	14,500	2	0.30	4.4
TOTAL	**468,524**	**50**	**0.30 (weighted average)**	139.0

Sources: IEA Greenhouse Gas R&D Programme, CO_2 *Storage in Depleted Oilfields: Global Application Criteria for Carbon Dioxide Enhanced Oil Recovery*, Report IEA/CON/08/155. Prepared by Advanced Resources International, Inc. and Melzer Consulting (August 31, 2009).

The ratio of CO_2 volume injected per barrel of oil produced (and hence the potential demand for CO_2 by CO_2-EOR operations) varies widely over the life of a particular CO_2-EOR project and among such projects. See, e.g. Kuuskraa and Wallace (2014); Bachu (2016) and Azzolina, *et al* (2015).



NOTE Other fields use continuous injection of CO_2. Note that CO_2-EOR is a closed-loop process and the recycling does not allow CO_2 to be released into the atmosphere.

Figure A.2 — Schematic of CO_2-EOR using WAG method (water alternating gas)

A.3 How CO_2-EOR works

In the process of CO_2 flooding (see Figure A.2), CO_2 is acquired from a CO_2 source and delivered to the oil field, typically by pipeline, and injected into the reservoir. 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. Figure A.3 illustrates existing facilities in operation in Texas (U.S.). In most operations, the produced CO_2 is dehydrated, compressed, and reinjected within the same oilfield or transported to another nearby oilfield. Oil is sent to market and brine is reinjected for flooding as part of the operation or injected in permitted disposal wells.

Figure A.3 — CO_2 injection well and segment of CO_2 recycle facility

CO_2-EOR is typically developed in phases across a field, with areas of the field organized into sets of injection and production wells known as patterns. CO_2-EOR is usually designed in a closed loop so that atmospheric release of CO_2 is limited (as detailed below in A.4). In the U.S., for example, any releases of CO_2 (whether natural or anthropogenic) to the atmosphere from the surface facilities are reported to the Environmental Protection Agency (EPA) under the greenhouse gas reporting regulations (40 CFR Part 98 Subpart W). Also, in Canada, where the world's largest depleted oil field CO_2 storage and joint

CO_2-EOR project is located, under Saskatchewan's Oil & Gas Conservation Act, all injected and produced or released volumes of CO_2 are reported to the provincial government.

Injection of CO_2 for EOR is sometimes combined with injection of other fluids. A very common example of this is the "WAG" (water alternating gas) method, where recycled produced brine (or other water) is injected in alternation with CO_2 (see Figure A.2). This process could improve the vertical distribution of the injected CO_2 in the subsurface (referred to in the industry as "conformance") and/or manage pressure. The net quantity of CO_2 used to produce a barrel of oil is highly project specific, depending on the geology and the CO_2 injection practice used (e.g. WAG versus continuous CO_2 injection). In addition, the ratio varies immensely as a CO_2 flooding project proceeds, since CO_2 injections sometimes proceed for a year or even longer prior to the initial barrel of incremental oil production resulting in a very high initial ratio, diminishing sharply over time as a relatively constant level of CO_2 injection allows for an increase in oil production. Azzolina, et al. (2015), a study of actual experience at a number of projects in the U.S., calculated that the net quantity of CO_2 required per barrel of oil production varied by more than an order of magnitude, with average utilization in the range of 4.8 Mcf to 10.5 Mcf (0.25 tonnes to 0.5 tonnes) of CO_2 per barrel of oil production. Projects using continuous CO_2 injection use roughly twice as much CO_2 per barrel of oil produced as WAG projects.

Operating a CO_2-EOR flood requires both a robust, model-driven plan and considerable monitoring and operational adjustment during the flood. The basic planning and management system is guided by the injection-withdrawal ratio, which also serves to maintain control of the subsurface pressures. At the beginning of the flood, injection operations dominate the pressure behaviour; however, fluid withdrawal is generally brought into balance so that reservoir pressure is maintained at the designed and permitted optimum pressure at the injection wells and across the flood patterns. The ratio during a defined period of the volume of fluid and gas injections to the volume of fluids and gases produced from the reservoir is known as the "injection withdrawal ratio" (IWR).

The production response to CO_2 injection is monitored by periodic production sampling of the fluids at test facilities, where oil, water, and gas are separated and measured. Generally, testing at production facilities is conducted at a rate of one well per day and is rotated among wells so that, at many fields, each production well is tested monthly. Produced CO_2 quantities are monitored to allow the field operator to make adjustments to the flood, particularly in the case of WAG CO_2-EOR floods, to optimize the use of the CO_2 and maximize the oil production, while minimizing cost of handling excessive volumes of produced CO_2. This intensive field observation means that a substantial quantity of data is collected and used to update the operational plan and provide knowledge of the subsurface CO_2 movement for monitoring, verification and accounting (MVA) purposes and/or reporting purposes.

A.4 Associated storage of CO_2 in CO_2-EOR operations

The purpose of CO_2-EOR operations is to recover oil, and this purpose dominates the operation, including (in the U.S.) permitting, and mineral and property leasing.

However, as a natural part of CO_2-EOR operations, as well as by commercial necessity and regulation, CO_2 is effectively stored in the subsurface and securely isolated from the atmosphere, underground sources of drinking water, and other subsurface resources. This retention of CO_2 in the reservoir has been termed an "intrinsic part" of a CO_2-EOR operation (Whittaker and Perkins 2013) in which CO_2 is "inherently stored" (Carbon Sequestration Leadership Forum, Task Force on Technical Challenges in the Conversion of CO_2-EOR Projects to CO_2 Storage Projects, September 2013). This *associated storage* (sometimes termed in the literature "incidental storage") serves a valuable function in offtake agreements with sources that capture and want to confirm associated storage of CO_2. This "associated" storage of CO_2 that occurs during CO_2-EOR operations has been recognized by expert studies from around the world (Carbon Sequestration Leadership Forum, 2013; Whittaker and Perkins, 2013; Kuuskraa, et. al., 2012; and Melzer, 2012).

While CO_2 separation from the oil in the production stream is a necessary part of oil production, the process of CO_2 recycling is a very important, but not mandatory, part of a CO_2-EOR project. Recycling of the separated CO_2 is done to minimize the cost of additional CO_2 purchases. Discussion of this element has created confusion between CO_2-EOR project designers, CO_2-EOR carbon offset protocols, and geologic storage accounting systems. It is important to note that recycle is a closed loop system in which essentially all the CO_2 produced is separated and reinjected a short time later. Inventory of the recycle system could be conducted using the same approaches used for other industrial processes, with quantification of and accounting for fugitive emissions and venting or flaring. In a GHG accounting system, energy connected to other operations related to extraction, separation, and injection such as pumping, heating, and compression could also need to be included.

It is important to correctly account for recycle, and confusion has occurred because the description of recycle depends on the purpose of the description. In a GHG accounting framework, the difference between mass extracted and mass reinjected could be inferred to equal emissions to the atmosphere. In contrast, from the oil production standpoint, where most previous work has been focused, the most important metric is the total mass of CO_2 injected (newly acquired CO_2 plus recycle), in terms of how much of the pore volume of the rock is contacted per unit of time to contact and mobilize oil. In this case, the ability to re-inject large volumes of CO_2 that have previously been injected, produced and captured could be an advantage. Additional quantities of “make up” CO_2 will need to be acquired to operate a mature field because 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). 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).

In accounting for the associated stored CO_2: (1) recycled and reinjected volumes are counted a single time, which is to say that no matter how many times the same molecule is injected and produced, it is counted as only one molecule stored; and (2) recycled CO_2 retained within a closed loop is not mistakenly counted as a loss from storage. Quantification of recycled CO_2 could be difficult if mixed gasses (CO_2 plus light hydrocarbons and other gases) are metered. The volume-to-mass conversions are complex for mixed gasses and could lead to measurement errors. Since repeated measurement of the large volumes extracted, separated and reinjected during the recycle process could lead to an accumulation of potentially large errors, the direct measurement of losses from the system would be more accurate.

Losses from venting and fugitive emissions have been published in a few cases and amount to a few percent or less of the originally injected CO_2 (i.e. net of recycle). For example, an assessment by Kinder Morgan of its large volume CO_2-EOR operation at the SACROC oilfield indicates that vented and fugitive emissions were less than 0,875 percent of the total CO_2 injected (net of recycle) (Fox, 2009). Occidental Petroleum has stated that experience at its Denver Unit (a very large field) indicates that about 0.3 percent of the original purchased volume is lost from fugitive and operating emissions (Docket Number 08-AFC-8A). This is consistent with the operator’s desire to conserve and re-use as much of the CO_2 commodity as possible.

A.5 Potential advantages of associated storage of CO_2 in EOR operations

In general, CO_2-EOR is undertaken in pre-existing mature oilfields (sometimes referred to as brownfields), in communities that are already accustomed to oil and gas drilling and production operations. As a result of the prior oil production via primary and/or water injection, CO_2-EOR sites also provide a known geologic reservoir, with known injectivity and capacity, a demonstrated seal and could include pre-existing roads, well pads, and other access infrastructure, and oil and water handling infrastructure. The storage potential for oil fields is further indicated as the hydrocarbons have been securely trapped within the producing reservoirs, indicating that the primary seal is likely to be effective. The trapping potential is also demonstrated by in-situ retention of the CO_2. Existing reservoir production and surveillance knowledge contributes to improved geologic understanding.

Pressure management is a routine component of CO_2-EOR. CO_2 management is also a routine part of every CO_2-EOR operation with injection and production, and many recycle CO_2 in a closed loop system. Development of monitoring, reporting and verification (MRV) will be easier because of the monitoring and management already conducted, but it will be more difficult to observe CO_2 fluid behaviour because of the presence of hydrocarbon gases. The subsurface is well characterized because of the presence of many existing wells, but the number of wells also poses a challenge because some of the wells could be in unacceptable condition. It could be expensive to remedy the wells; operators will need to identify and re-enter wells to plug or repair them prior to CO_2-EOR operations. The areal extent necessary to contain a given quantity of CO_2 is relatively small (due to more efficient use of pore space including CO_2 replacing produced fluids). (See, e.g. Figure A.4). The existing legal framework under oil and gas law and regulation will simplify ownership issues in some locations, yet leases held by oil production typically expire at the end of oil recovery operations. Oil and gas production provide revenues that could serve to offset CO_2 capture costs.

Table A.2 provides a comparison of some aspects of CO_2-EOR operations and geologic storage of carbon dioxide in saline formations.

Table A.2 — Comparison of CO_2-EOR and saline storage
(adapted from Hill, Hovorka, and Melzer 2012)

Type	Storage only — Saline formations	Storage only — Non-producing depleted oil or gas fields	CO_2-EOR with associated storage
Land	Greenfield	Brownfield — already impacted by oil industry operations	Brownfield — already impacted by oil industry operations
CO_2 management	CO_2 injection	CO_2 injection	CO_2 injection, production, many have recycle in closed loop system
Geographic availability (i.e. relative proximity to CO_2 sources)	Relatively widely distributed geographically with relatively high proximity to major CO_2 sources	Relatively limited due to geographic distribution of hydrocarbon-bearing formations	Significantly limited to the subset of hydrocarbon-bearing formations that are technically and commercially amenable to CO_2-EOR operations
Worldwide CO_2 storage potential	Very great (individual country estimates range from tens to hundreds to >1,000's of gigatonnes of potential storage capacity) (Consoli et Wildgust 2016)	Medium (perhaps as much as 1,000 gigatonnes (IEAGHG 2000)	Modest (roughly on the order of ~120 gigatonnes to 140 gigatonnes or more) (IEAGHG 2009)
Pressure build-up risk	Potential for pressure increase; pressure management may be needed	Often depleted; pressure management may not be needed but phase behaviour may need management	Pressure management is routine component of CO_2-EOR
CO_2 trapping	Trapping demonstrated in pilot projects	Demonstrated mechanisms	Demonstrated trapping by in-situ retention of the CO_2
Density of potential leakage pathways from existing wellbores	Low density of existing wellbores, since tend to be "greenfield" development sites	High density of existing wellbores due to prior hydrocarbon recovery operations	High density of existing wellbores due to both prior hydrocarbon recovery operations and newly constructed injection wells
Solubility of CO_2 in formation fluid	CO_2 weakly soluble in formation brine	CO_2 weakly soluble in formation brine and residual hydrocarbon phases	High solubility of CO_2 in oil if miscible, particularly under higher pressures; weakly soluble in formation brine
Subsurface information density	Few wells: if any, sparse information	Subsurface well characterized	Many wells: subsurface well known and characterized in detail

Table A.2 *(continued)*

Type	Storage only — Saline formations	Storage only — Non-producing depleted oil or gas fields	CO_2-EOR with associated storage
Mechanical integrity/risk of well failure	Few wells, recently drilled, cased and cemented; may have legacy wells from other subsurface activities, some of which might require careful assessment and remediation	More wells anticipated, may need work to convert to CO_2 injectors; some older wells may be in unacceptable condition	Many existing wells, including older wells some of which may be in unacceptable condition. Expense to remedy: identify, and re-enter to plug/repair prior to CO_2-EOR operations. Easier to show containment.
Access to surface and subsurface (including pore space)	Variable by jurisdiction; evolving	Variable by jurisdiction; evolving	Existing legal framework defined under oil and gas law and regulation; leases held by oil production and expire at the end of oil recovery operations
Revenues to offset CO_2 capture cost	Variable by jurisdiction; evolving	Variable by jurisdiction, evolving	Yes
Monitoring, reporting and verification, (MRV)	MRV is based on comprehensive geologic study and may cover large area	MRV is based on comprehensive geologic study and may cover large area	Existing reservoir production and monitoring knowledge contributes to improved geologic understanding and development of MRV; integrity of existing wells in the field a principal leakage concern; difficult to observe CO_2 fluid behaviour; pressure maintenance reduces MRV 'footprint'
Public acceptance	On-shore has had some challenges in areas without oil and gas production, off-shore likely to be good (positive public response to existing storage operations)	Likely to be good. Public generally familiar/ comfortable with oil production	Likely to be good. Public generally familiar/ comfortable with oil production; communities benefit from royalty payments; severance taxes; income from oil sales, etc. Siting or policy concerns in some areas
Areal extent required to contain a given quantity of CO_2	Depending on storage management strategy. If no pressure maintenance planned area may be relatively large.	The area is comparable to original HC extent: may be comparable to CO_2-EOR operations.	Relatively small (due to more efficient use of pore space including CO_2 replacing produced fluids). (See, e.g. Figure A.4.)

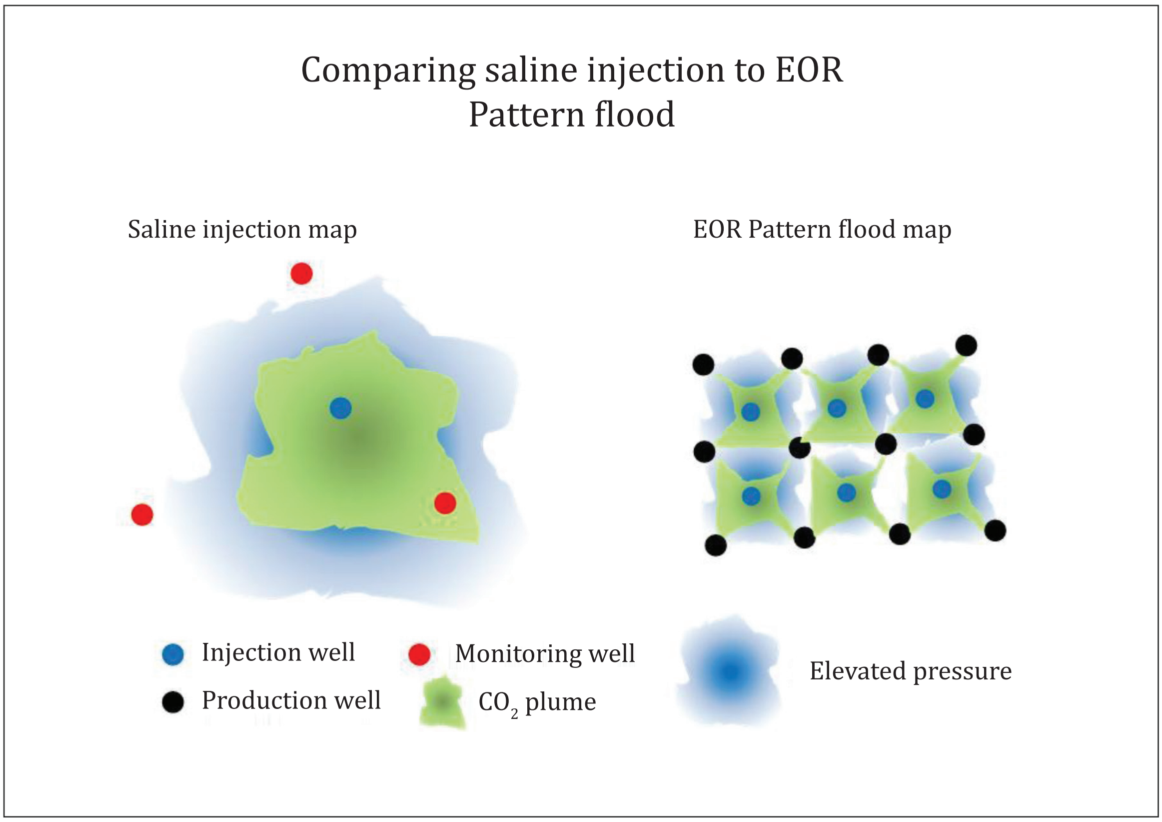


Figure A.4 — In CO_2-EOR, the CO_2 (green) is carefully controlled by production wells during injection and production operations

A.6 Possible challenges for associated storage during CO_2-EOR operations

There are also several aspects of CO_2-EOR operations to be considered with respect to providing assurance that CO_2 will be retained in the injection zone.

A.6.1 Inventory and assessment of existing wells

Poorly plugged or damaged wells penetrating targeted formations could become pathways for injected CO_2 to leak into other formations (including overlying formations that could contain underground sources of drinking water) or into the soil or to the atmosphere. CO_2-EOR operations are typically conducted in previously producing oil fields which could contain large numbers of pre-existing wells, which could have been drilled many decades before. Some of these older wells could not have been identified in the relevant records; others could have been improperly plugged or suffered damage. Some of these existing wells could develop well integrity flaws or could have been degraded during prior primary or secondary production operations. Flaws in well construction could lead to micro-annuli or damage to the cement seal during past production operations. The objective is to identify all wells penetrating the reservoir seal and, if necessary, to remediate them prior to CO_2 injection activities. Although rare, wellbore leakage is an issue of concern for injection projects, both in oilfield and waste disposal context. A considerable body of academic research in recent years has examined CO_2 leakage through well cements (e.g., Bachu and Bennion, 2009; Huerta, 2009; Carey and others, 2010) as well as U.S. State experience with older wells (including orphaned well programs). Management of the risk could be conducted in three steps: characterization, pre-injection remediation, and during EOR and possibly post-injection operations. CO_2-EOR projects also make substantive investments in well monitoring and maintenance. Corrosion-management programs such as the introduction of corrosion-inhibiting chemicals or cathodic protection are common. Field technicians make regular rounds to inspect well and pipeline infrastructure, and monitoring results are being increasingly reported to supervisory control and data acquisition (SCADA) systems, which allow the whole system to be monitored from a central location.

A.6.2 Review of sealing formations

Sites are reviewed for possible geomechanical damage to the sealing formation during strong pressure depletion or water injection if significantly above the initial pressure. The mechanical integrity of the reservoir seal is assessed for damage during injection as a part of selection of robust CO_2 storage sites.

A.6.3 CO_2 movement out of CO_2-EOR project acreage

CO_2 containment is inherently demonstrable. It is important for operators to plan for the CO_2-EOR project to encompass the entire surface and subsurface area under which the injected CO_2 could move beyond the EOR complex. Significant commercial and legal issues would arise in certain jurisdictions if injected gas or fluids move outside of the owned, leased, or permitted if publicly owned acreage and interfere with adjacent mineral owners, and CO_2 is not exempt from these concerns. For example, natural gas storage operators ensure that natural gas injected for storage remains in the storage formation — and does not migrate under adjacent land where it could be produced through a well on that property and sold. Similarly, operators injecting water in waterflood operations seek to ensure that the injected water does not interfere with or damage oil or gas recovery operations from adjacent property. Over the last century, oil and gas regulators and courts (and legislatures) have developed a vast body of law, regulation and precedent that addresses a host of variations on these types of issues. Hence, CO_2-EOR operators are keenly aware of this concern and plan and design operations to avoid incurring these costs as well as the loss of a valuable CO_2 commodity.

A.6.4 Re-use of injected CO_2 in other portions of a field or other EOR projects

Another issue that has been of concern to stakeholders is the potential for subsequent withdrawal of CO_2 that had previously been injected. For example, the infrastructure such as production wells and pipelines would allow transfer of CO_2 from one part of the reservoir to another. Increasing injection in some patterns could be accomplished by increasing withdrawal in less productive patterns. Pressure could also be decreased. Alternatively, when a WAG flood is employed, the ratio could be changed to all water resulting in more CO_2 being removed than injected. The same processes could theoretically be used to transfer CO_2 that was injected into one field by placing it back in the pipeline and sending it to another field, in effect in another part of the CO_2-EOR closed loop system. Such between-field recycling will, however, require attention to accounting to avoid double-counting any such transfers.

A.7 “In-situ” or “native” CO_2

There are many oil and gas fields that contain CO_2 that is found in-situ (also referred to as “native” CO_2), that is, contained within the hydrocarbon reservoir at discovery. This type of occurrence is common in the Southwest U.S., in Southeast Asia, and in the Middle East. As such fields are developed through primary production and then by applying secondary production techniques (e.g. waterflooding), any native CO_2 that is produced is typically vented to the atmosphere through routine production and separation processes. However, in oil projects where CO_2-EOR techniques are applied and CO_2 recycling is introduced, this native CO_2 will be captured rather than vented, as would otherwise occur. The portion of the captured CO_2 that was initially native to the reservoir becomes anthropogenic in such a case because absent the intervention of the man-made and installed capture equipment, the CO_2 would have been emitted to the atmosphere. As an analogue, it is noted that capture of CO_2 inherently existing within natural gas fields occurs at Sleipner, Snøvit, Molve, Penon, Gorgon, and Shute Creek Fields. The CO_2 that is captured at these fields is anthropogenic CO_2 since it is co-produced and would otherwise be vented to the atmosphere. The CO_2 content of separator gas at pre-CO_2 injection oil fields varies but is generally in the range of 0 % to 30 %. CO_2 re-cycling facilities have been built to capture these native CO_2 molecules which would otherwise be emitted to the atmosphere.

An example calculation of how the quantification of native CO_2 may be carried out is presented in Annex B (see B.4.1). The method utilizes the content of “native CO_2” volume per volume of oil produced, which would be determined by the operator and if necessary be agreed to by the authority. This content could take into account the native CO_2 content at the initial condition and modified appropriately if the reservoir pressure has fallen below the bubble point. Various approaches, including numerical simulation, could be utilized to derive the appropriate content value.

A.8 Offshore CO_2-EOR

Use of CO_2 in offshore, sub-seafloor reservoirs for EOR is widely thought to be technically feasible (e.g., Alekemode, 1995; Tzimas and others, 2005; Holloway and others, 2006; Manrique and others, 2010). Despite nearly a half century of technological maturity onshore, only a few offshore projects have tested or employed CO_2-EOR. While the production mechanisms are principally the same in both settings, offshore CO_2-EOR poses additional challenges since the operations are conducted from a platform, creating both technical and financial hurdles. A list of the advantages and disadvantages of offshore CO_2-EOR is shown in Table A.3.

Table A.3 — Advantages and disadvantages of offshore CO_2-EOR

Advantages	Disadvantages
Federal/State owned leases make production and CO_2 storage less complex (in the U.S. avoids unitization of private mineral rights)	High capital cost (long pipelines, separation facilities, drilling wells)
Large fields have higher upside	Well placement challenges & subsea completions; Wide well spacing, wells expensive to drill
New fields could be designed for future EOR more cost effectively	O&M more costly
	High conventional recoveries means smaller EOR targets
	Retrofitting wells & facilities with corrosion resistant materials

A.9 Residual oil zones could be produced by CO_2-EOR methods

An oil-bearing zone where natural processes have resulted in water displacement and/or the opening of a spill point to greatly reduce the oil in place (typically 20 % to 40 % of original pore volume) is known as a residual oil zone (ROZ). Often, these saturations are too low to allow oil production under primary depletion methods or by waterflood. ROZs are commonly recognized as largely unexploited oil accumulations that could exist below the original oil-water contact as well as in areas that were completely swept to a residual hydrocarbon saturation and would have no primary production potential (see Figure A.5). A ROZ could exist if certain tectonic or deformation occurs after a hydrocarbon trap develops. ROZs are distinct from capillary transition zones found below many oil reservoirs because they deviate from the imbibition profile and are economically important because they could be relatively thick. ROZs were initially described in the Texas Permian Basin but are now being found and described in other regions of the world. Recognition of ROZ potential adds to the traditional post-waterflood pay horizons targets for CO_2-EOR. The significance of these ROZs for CO_2-EOR and for the associated storage of CO_2 is that they have the potential to boost CO_2 demand significantly beyond current volumes of CO_2 supply and thereby offer an additional geologic storage option for anthropogenic CO_2 that is captured for emissions reduction purposes.

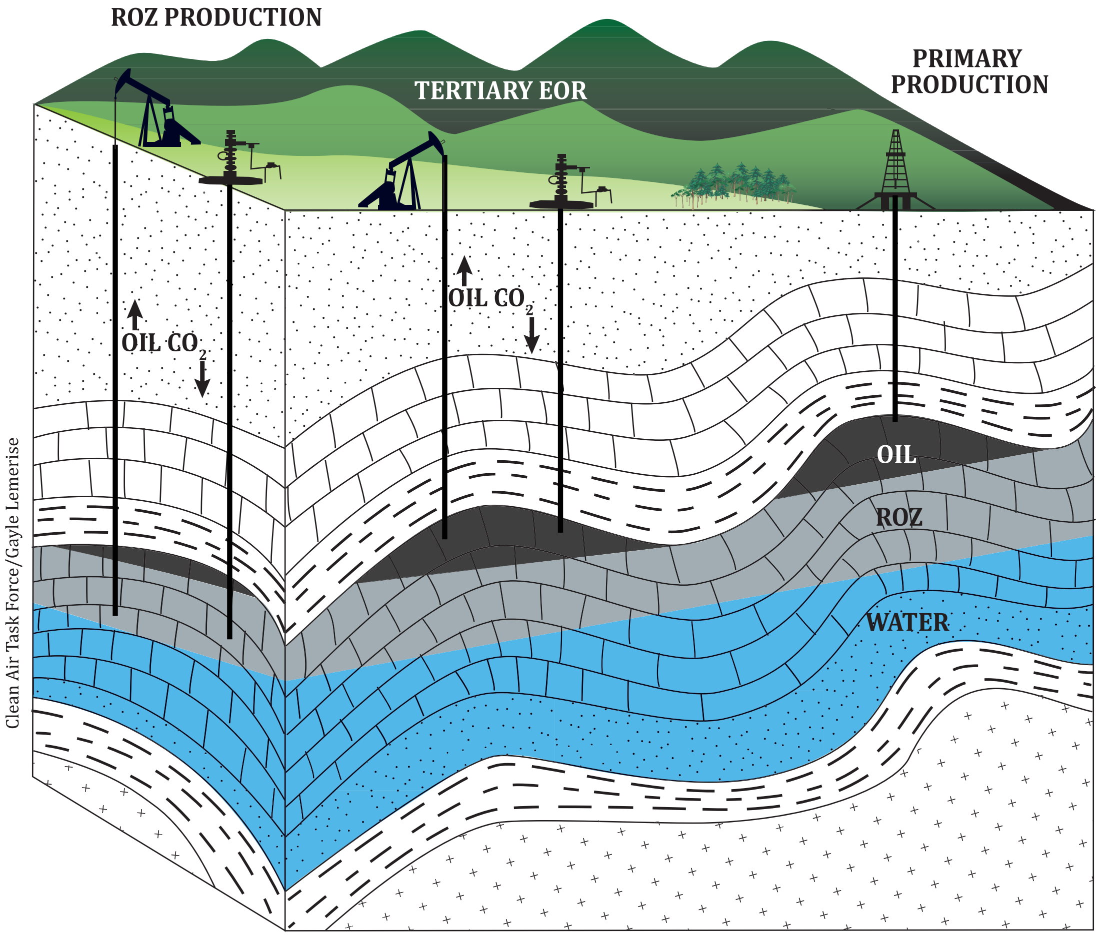


Figure A.5 — ROZ Schematic. Where present, the residual oil zone is a naturally waterflooded zone below the main pay zone that could be produced by miscible CO_2-EOR methods (Hill, Hovorka, Melzer, 2013)

A.10 Adaptation of existing CO_2-EOR subsurface characterization, planning and monitoring activities for associated storage during CO_2-EOR

A number of operational characteristics for CO_2-EOR are different from those of a saline formation storage project (see Table A.2). Therefore, the spectrum of monitoring activities selected to document associated storage during CO_2-EOR will not be the same as in a non-EOR context. In particular, the data from CO_2-EOR monitoring for commercial purposes would be available as well as data and information describing the geology, characterizing the reservoir and seal, and depicting the historical reservoir and well performance during active oil injection/production. The same objectives are met with this CO_2-EOR data as those initially required or recommended for saline sites.

Documenting associated storage during EOR operations will rely on

a) data relevant to containment that is extracted from proprietary data to justify the purchase volume of CO_2, design of flood, and for CO_2-EOR operations optimization, and

b) additional data collection targeted to the areas where uncertainties exist.

Data generated during the commercial design of the CO_2-EOR flood provides much of the same information developed during characterization and initial operation of a saline storage project, and this data is valuable for documenting associated storage. There are numerous CO_2-EOR operations that include additional monitoring to test methods for documenting associated storage in the U.S. and Canada, as summarized in Table A.4. A principal advantage of CO_2-EOR is the wealth of existing information and data that could be mined to demonstrate knowledge of the subsurface and the CO_2 movement/containment. This means that MVA programs designed to work within the context of the specific field are intrinsically different than for a saline site. When techniques for confirming associated storage are considered alongside data collection used for field development and operational activities, a high standard of assurance, possibly at relatively low additional costs, is expected at a CO_2-EOR site compared to a saline storage-only site. Moreover, any additional monitoring could lead to increased oil recovery and improved CO_2 utilization.

Some limitation in monitoring could be more common or severe in hydrocarbon fields where CO_2-EOR is deployable. For example, seismic surveys would be of more limited utility in areas where natural gas remains in the reservoir or overburden. Similarly, biodegradation of natural or man-made hydrocarbon in near surface geologic formations could lead to false indication of CO_2 beyond containment or completely “mask” the presence of CO_2 out of containment. Pressure and fluid chemistry perturbations could induce long-lived transients, rendering some monitoring tools of limited use.

Table A.4 — CO_2-EOR fields with monitoring programs designed to provide additional information about storage (Hill, Hovorka, and Melzer 2012)

Field name	Location	Operator	Monitoring lead	Flood start date	Web resource
Weyburn	Saskatchewan, Canada	Cenovus, Apache	Petroleum Technology Research Centre	2000	http://ptrc.ca/+pub/document/Summary_Report_2000_2004.pdf
SACROC	Scurry County, Texas	Kinder Morgan	Bureau of Economic Geology, Southwest RCSP	1972	http://www.netl.doe.gov/... /10-SWP_SACROC EOR Sequestration_Oil.pdf
Zama	Alberta, Canada	Apache Canada	Energy & Environmental Research Center, PCOR RCSP	2006	http://www.netl.doe.gov/.../7-PCOR_Zama Field Validation.Oil.pdf
Cranfield	Adams County, Mississippi	Denbury Onshore LLC	Bureau of Economic Geology, SECARB RCSP	2008	http://www.secarbon.org/files/early-test.pdf
Hastings	Alvin, Texas	Denbury Onshore LLC	Bureau of Economic Geology, Denbury	2001	Hovorka; unpublished
Farnsworth	Farnsworth, Texas,	Tabula Rasa Energy LLC	Southwest Regional Partnership on Carbon Sequestration	2010	https://www.southwestcarbonpartnership.org/
Bell Creek	Montana	Denbury Onshore LLC	Energy & Environmental Research Center, PCOR RCSP	2012	https://www.undeerc.org/pcor/CO2sequestrationproje cts/BellCreekDemonstration.aspx

References on monitoring tools and practices are found in Bibliography.

A.11 What information is needed to demonstrate the safe and long-term containment of anthropogenic CO_2 stored in association with a CO_2-EOR operation?

During CO_2-EOR operations, virtually all of the delivered and injected CO_2 will ultimately be trapped in the reservoir as an inherent part of the oil recovery operation even though the purpose of the CO_2 injection is to enhance oil recovery, not to store CO_2. The process of documenting the quantity of associated storage is essentially a two-step process. It consists of

a) determining throughout the EOR operation the net quantity of CO_2 that is injected, net of recycle, re-use, and any surface emissions, and then

b) demonstrating that this net quantity will be contained in the EOR complex long term.

A.12 Determining the quantity of CO_2 from a commingled stream that is to be quantified for associated storage

In order to determine the quantity of CO_2 to be quantified for associated storage in a CO_2-EOR operation, the operator needs first to know the portion of the total CO_2 stream delivered to the site that is to be so quantified. If the EOR operator receives CO_2 exclusively from suppliers that seek quantification of the associated storage, this is straightforward since the relevant portion would be 100 percent of the CO_2 delivered to the site. The current (and likely future) reality is more complex, however, since in the United States, for example, supplies of various sources of CO_2 are commingled in the pipeline such that the pipeline delivers a “system average” CO_2 stream, only a portion of which may represent CO_2 for which quantification as associated storage during EOR is sought. The percentage of such CO_2 may vary with changes in the operational levels at the power plant or other industrial source facility supplying the CO_2 to be quantified, as well the needs of the EOR project for total CO_2.

The contractual agreement between a CO_2 capture facility and a receiving pipeline may address the measurement of the quantity of total CO_2 supplied (information required for both billing and for operational purposes). Knowing the quantity received from each supply source and any contractual allocation to particular delivery points, the pipeline operator can then determine the relative portion of CO_2 in the commingled stream delivered to each delivery point (including each CO_2-EOR site) that is attributable to each relevant source of supply. Similarly, CO_2 to be quantified as associated storage may be delivered to the CO_2-EOR site separately from a supplying pipeline and commingled with the pipeline supply on site for injection into the reservoir.

Once the EOR operator knows the quantity of the total CO_2 stream delivered at the site and the percentage that is to be quantified as associated storage in that operation, the operator can then measure and account the quantity of CO_2 injected at the CO_2-EOR site to be used as part of a CO_2 injection input calculation and then carry forward the relevant percentages in accounting during recycle operations. The operator can also measure and account for any off-site dispositions, removals or emissions of CO_2, such as transfer of CO_2 (including previously injected CO_2) off-site for use in another EOR operation, venting/flaring during maintenance operations or due to equipment failure, repairs, etc.

This kind of framework may thus serve as the basis for identifying and accounting for the portion of the total CO_2 received at a CO_2-EOR site that is to be injected and (assuming appropriate accounting, monitoring and documentation) ultimately recognized as associated storage.

A.13 Demonstrating the net quantity of CO_2 that is safely contained long-term in the EOR complex

In the normal course of developing a project, obtaining permits from the regulator, and conducting operations, including maintaining and verifying the mechanical integrity of wells that penetrate the formation and actively managing subsurface fluid flow to confine the injected fluids in the intended formations, the operator of the project undertakes the key steps required for ensuring that injected CO_2 stays safely contained in the EOR complex and will not interfere with other uses of the subsurface or endanger underground sources of drinking water. Here, the principal objectives with site evaluation and selection are to ensure that injection formations are properly overlain with non-permeable rock formations and do not communicate with either drinking water sources, permeable formations, leakage pathways, or with nearby wells outside of the EOR complex that could allow injected CO_2 to move to the surface; maintaining and verifying the mechanical integrity of wells that penetrate the formation; and actively managing subsurface fluid flow to confine the injected fluids in the intended formations.

In a CO_2-EOR operation, the target reservoir is selected with care and intensive evaluation to make sure that it is a formation that lends itself to a CO_2-EOR flood. The hydrocarbon resource has itself been trapped in the target formation for many millions of years. This fact provides assurance that injected CO_2 will be similarly trapped.

The planned operation of the field is modelled to calculate the in-reservoir volume of fluids that will be injected (CO_2, water and other fluids) and the volume of fluids (hydrocarbon liquids and gases, CO_2, water and other fluids) that will be withdrawn by production to optimize the flood. Overall, the injection/withdrawal ratio (IWR) of all fluids is managed so that the CO_2 and the oil that it contacts are drawn toward producing wells and does not escape out of the planned reservoir. The IWR could be audited, monitored, and operationally managed to determine if the flood is performing as planned such that there is little or no loss of CO_2 outside of the project reservoir. There will be times where IWR is imbalanced, for example at the start of the flood where pressure is increased to achieve an optimized flood and periods where fluids (oil and CO_2) are preferentially extracted from some patterns to allow development of a new part of the field. An assessment of these imbalanced IWR periods could be conducted and monitored as a practice to ensure that there is little or no loss of CO_2 from the EOR complex.

The pattern of the injection and withdrawal wells could be important in providing assurance that the CO_2 is retained in the intended reservoir. For example, water injection could be used to create a "water pressure curtain" that keeps CO_2 within the reservoir. Alternatively, extraction wells could also be strategically placed to contain the fluids. This active fluid management is valuable in assuring that CO_2 does not move outside the EOR complex.

An operator tracking the fluid management via these mechanisms could provide assurance that the CO_2 has been retained in the EOR complex. Many kinds of monitoring are possible to provide additional assurance that this goal has been accomplished or account for any losses. Monitoring of pressure is commonly used; other methods including geophysics and geochemical techniques could also be used where applicable.

At the end of the CO_2-EOR operation (which could come years after the cessation of injections of anthropogenic CO_2), all the wells penetrating the formation will be plugged and abandoned in accordance with local and regional regulatory and permitting requirements. The stable configuration of the injected CO_2 could be relatively easily assessed, as it typically will mimic the original distribution of hydrocarbons in the reservoir. Well construction is important as well. Existing petroleum industry standards and regulatory requirements address well construction and provide that materials used be compatible with the fluids with which they come into contact and designed for the pressures at which they will operate. In this respect, while the particular materials or techniques used could vary, CO_2-EOR operations are no different than any other oil field operations involving subsurface injections (whether the fluids contain hydrogen sulfide, natural gas or natural gas liquids, brine, polymers or other substances). Occasionally well design fails to provide the intended isolation of the reservoir zone from other zones. Fluids, including CO_2, oil, gasses, and brine could move through the failed elements into shallower (or deeper) zones or to the surface. Oil and gas regulations require routine testing of well construction so that zonal isolation is maintained. If isolation is lost, the well is repaired and CO_2 losses could be estimated. Loss of fluids from the intended zone does not necessarily mean that they will escape to the surface or impact freshwater resources. However, long term assurance of CO_2 isolation from the atmosphere becomes uncertain and such losses could be quantified.

A.14 Addressing other issues

a) *Matching* CO_2 *supply to demand.* Before a power plant or other industrial facility installs CO_2 capture equipment, it will of course make arrangements for the sale or disposition of the CO_2 expected to be captured. Where the generator of the CO_2 contracts to send the CO_2 to markets for CO_2-EOR, it will need to contract with one or more EOR operators to take the contractually-agreed portion of the CO_2 output over the life of the facility. The agreement may address how the parties plan to deal with planned or unplanned variations in actual CO_2 quantities and compositions supplied or taken. In addition, a given CO_2 source may need multiple agreements timed to take the supply because the inherent nature of CO_2-EOR projects may require less new CO_2 in each successive year. Such matters are a routine part of business planning in any long-term contract. Potential suppliers and purchasers of anthropogenic CO_2 are thus no different than suppliers and purchasers of countless other goods in the world economy.

b) *Ensuring that associated storage of anthropogenic* CO_2 *is not subsequently vented to the atmosphere or double-counted*. Upon termination of hydrocarbon recovery operations, the termination documentation should identify the EOR complex within which the anthropogenic CO_2 will remain stored, the mass of CO_2 stored, and describe how risks and uncertainties relating to the geologic storage of anthropogenic CO_2 were managed and reduced throughout the EOR project life.

c) *Lateral location of injected* CO_2*.* CO_2-EOR projects are long-lived operations that normally occur after secondary recovery operations (e.g., waterflood). Studies conducted as part of the planning and development of earlier phases are valuable in the planning and development for CO_2-EOR. As a result, many of the geological characteristics of the CO_2-EOR operation will have been defined years before any CO_2 is ever injected. The operators will consider the movement of the injected water during the waterflood phase and may consider how waterflood operations may affect the subsequent tertiary recovery phase.

   Since the purpose of injecting the CO_2 in an EOR flood is to bring the CO_2 into contact with as much of the remaining residual oil in the reservoir as is feasible, the operator needs to design the flood with this in mind. As a result, CO_2-EOR operators will monitor the behaviour of the injected CO_2 in the reservoir (including its lateral extent) as an integral part of prudent and economic operations. Various production monitoring techniques are used, including a number that involve modifying the subsurface pressures in order to guide the CO_2 — and the petroleum that it mobilizes — on the optimum flow path to the production wells. Thus active pressure monitoring and management are essential elements of successful and prudent CO_2-EOR operations. The operator may alter the development plan over the years in response to actual experience with injections in a given field. In North America, information regarding these operational changes is continually presented before the oil and gas regulator.

d) *Vertical movement of the injected* CO_2*.* In CO_2-EOR operations the subsurface is a four-dimensional space. It involves the two lateral dimensions of length and width of the operation; the vertical dimension of the depth and thickness of the producing formation (which depth and thickness of course may vary greatly as one moves across the lateral dimensions of the reservoir); and time (e.g. initial CO_2 injections may be conducted for more than a year before production operations commence in order to achieve miscible pressure requirements). All four of these dimensions are managed in the flood. Because supercritical CO_2 is less dense than brine, there is a tendency for CO_2 to rise above the native reservoir fluids. Operators take this fact into account in designing and operating the flood in order to maximize the amount of oil that is contacted by the CO_2 and thus achieve the optimal value from the injections.

e) *Providing notice to future potential users of existence of injected* CO_2. The documentation is supplied to the regulatory authority and will apply to the same surface unit area plat that was originally filed with the public records where the operation takes place, as approved by the regulatory agency. Thus, any person proposing to make any later use of that subsurface space would have notice of the prior injection and production history occurring in the relevant formations.

A.15 Cessation of CO_2 injection and hydrocarbon recovery: “coincident” and “non-coincident” cessation of CO_2 injections

Typically, the oil recovery operations will have begun years, or even many decades, prior to the commencement of CO_2 injection operations and may continue for years after CO_2 injections have ceased.

In all CO_2-EOR operations, both onshore and offshore, a significant portion of the hydrocarbon resource will remain in the formations even after hydrocarbon recovery operations become uneconomic and injection and production wells are plugged and abandoned. Published estimates of the percentage of the Original Oil in Place (OOIP) that will remain at the end of CO_2 injections in the project vary broadly, typically from 30 % to 50 %.

Because of the presence of the remaining hydrocarbon resource and the ever-changing economic and technical parameters of oil recovery operations, there are various possibilities for when and how CO_2 injections in a CO_2-EOR operation could come to an end.

— *"Non-coincident" cessation of* CO_2 *injections and oil recovery.* Injections of anthropogenic CO_2 in an oil recovery operation could be ended even as hydrocarbon recovery continues. This could result from a variety of different factors, including, for example, an interruption or failure of the CO_2 supply; a change in CO_2 source from anthropogenic to non-anthropogenic; an adverse change in economics or in the applicable regulatory rules affecting the CO_2 supply; or a change in the recovery technique applied in the oil recovery project. In this scenario, the hydrocarbon recovery operations continue (or are re-commenced at a future time) even though the anthropogenic CO_2 injection has come to an end. In such a case, oil recovery operations continue, perhaps for decades following the end of injections, and the various wells penetrating the hydrocarbon formations are not plugged and abandoned, but EOR complex monitoring might continue. Hence, in this scenario cessation of anthropogenic CO_2 injection operations are *non-coincident* with the cessation of oil recovery operations. Conceivably CO_2 injections could begin again at some future time as economic changes dictate or technical advances allow, moving this to a coincident cessation model.

— *"Coincident" cessation of* CO_2 *injections and oil recovery.* Anthropogenic CO_2 injections could, however, also be ended *coincident* with the oil recovery operation. While this scenario could apply to either an onshore or an offshore operation, it would be found most frequently in future offshore operations because of the higher capital cost of offshore operations, or the operational constraints imposed by platform-based operations. Measurement, reporting and documentation of the disposition of the produced CO_2 (e.g., if it is reinjected, shipped offsite or released) could continue until the project is terminated.

These differing operational scenarios suggest differing potential documentation periods for the quantity of CO_2 that is incidentally stored in association with a CO_2-EOR operation since a given documentation period could either "nest within" an ongoing oil recovery operation or come to an end coincident with the end of the oil recovery operation. However, since subsequent hydrocarbon production would continue to produce injected CO_2 long after the actual CO_2 injection has been terminated, periodic assurance of containment of the stored CO_2 would continue until the final plugging and abandonment of the project wells.

Annex B
(informative)

Example quantification calculation

B.1 Introduction

Annex B provides guidance for how the quantification principles and documented values outlined in Clause 8 could be utilized for the quantification of associated storage. First, the total associated storage of CO_2 is calculated using the approach set forth in Clause 8. Second, the Annex supplements the initial quantification of total CO_2 associated storage by calculating the portion of associated storage that represents anthropogenic CO_2. This supplemental calculation would use mass or volumetric (at standard conditions) allocation ratios based on the fraction of the anthropogenic mass of CO_2 to the total mass of CO_2. The example identifies the variables used in, or derived from, the calculation procedures along with the applicable allocation ratio for each.

The example considers the quantification period of one year from the start of quantification; the likely first documentation period. Although quantification results normally would be converted into mass, this example for simplicity of demonstration uses standard oil and gas industry volumetric units (see Annex C for SI conversions) and converts the results to mass as a final step.

NOTE Please note that in the following example calculation, SI Units will use standard ISO Numerical Format ("Comma" will be used to denote decimal point and space will segregate every three digits) and Oil Field Units will utilize "Decimal Points" and using "Commas" to segregate every three digits.

In this example, the total CO_2 associated storage is calculated (see B.3) as a first step and then the second step calculation (see B.4) uses allocation ratios to show how the anthropogenic portion could be quantified. The calculations assume non-leap year (365 days) and use a four digit significant figure.

Annex C contains a table for converting the standard oil and gas industry units of the Society of Petroleum Engineers (SPE) used in this hypothetical example into International System of Units (SI) units.

In this example, operational loss [$m_{\text{loss operations}}$] is deemed to be composed of two variables defined by Formula (B.1):

$$m_{\text{loss operations}} = m_{\text{loss operations inlet}} + m_{\text{loss operations other}} \quad \text{(B.1)}$$

a) $m_{\textbf{loss operations inlet}}$; the total mass of CO_2 loss occurring in operations between the custody transfer meter and the point where the CO_2 received at the custody meter is first combined with CO_2 recovered from production. This variable is composed of leakage from facilities (see 8.4.2) and venting/flaring (see 8.4.3) related to the inlet portion.

b) $m_{\textbf{loss operations other}}$; the total mass of CO_2 loss occurring in operations during injection into the EOR complex, and production and during processing of the produced fluids and CO_2, from all aspects of CO_2-EOR project excluding only the portion covered by $m_{\text{loss operations inlet}}$. This variable is composed of leakage from facilities (see 8.4.2), venting/flaring from operations (see 8.4.3), entrained CO_2 in products (see 8.4.4) and transfer of CO_2 (see 8.4.5).

In most cases, different allocation ratios would be utilized for the $m_{\text{loss operations inlet}}$ and $m_{\text{loss operations other}}$ because the proportion of anthropogenic CO_2 likely would be different for each of these variables (See Figure B.1).

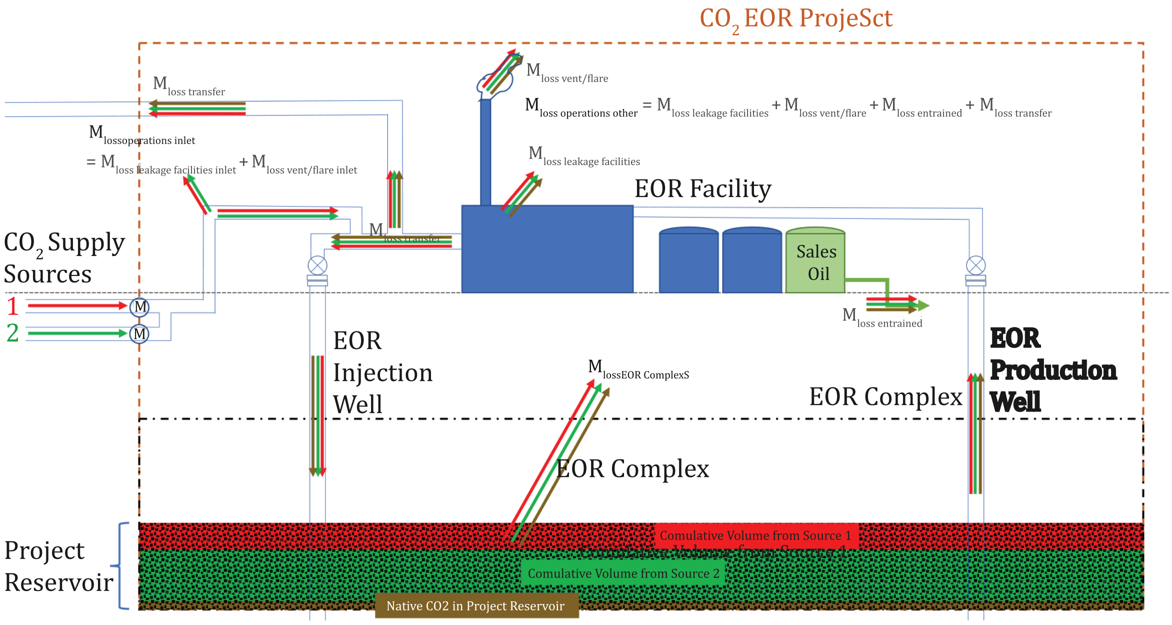


Figure B.1 — Illustration of CO_2 allocations and loss variables

B.2 Hypothetical project

For this illustration, a hypothetical CO_2-EOR project is provided as an example. To encompass various scenarios, a relatively small-scale CO_2-EOR project is presented as having ongoing CO_2-EOR operations using non-anthropogenic CO_2 (irrelevant of source) prior to receiving anthropogenic CO_2 for injection. Additionally, a small concentration of native CO_2 is also assumed to have existed in the project reservoir at the time of field discovery. Further, the CO_2 received is comprised of both non-anthropogenic CO_2 (irrelevant of source) and anthropogenic CO_2. It is assumed that the Project has recycling facilities. The parameters necessary for this quantification example are as follows.

B.2.1 Previously received and injected total and anthropogenic CO_2 within the EOR complex

In the project, the total volume of previously received and injected CO_2 (no anthropogenic portion is assumed) within the EOR complex at the start of the quantification period is known to be 6,000 MMscf (169 900 000 Sm^3). This term is to be documented as part of the initial documentation [see 4.3 e) and 8.5]. If CO_2 meeting the definition of anthropogenic CO_2 had been received and injected during CO_2-EOR operations prior to the beginning of the quantification period, it would be treated as non-anthropogenic CO_2 for purposes of quantifying the anthropogenic portion of associated storage.

B.2.2 New CO_2 received and the percentage of anthropogenic CO_2

New CO_2 received during the first documentation period for this example will be 10.00 MMscf/D (283 200 Sm^3/D), of which 40 percent is anthropogenic CO_2. This example would represent a CO_2-EOR project that might have a non-anthropogenic supply of CO_2 now being supplemented by a new source of anthropogenic CO_2.

B.2.3 Native CO_2 content

The native CO_2 content is 100.0 scf/stb (17,81 Sm^3/Sm^3). It is assumed that the inclusion of captured native CO_2 as anthropogenic CO_2 has been approved by the authority.

B.2.4 Oil production

During year one, the oil production average from this project was 1,000 stb/D (159,0 Sm^3/D).

B.2.5 Operational inlet loss [$m_{\text{loss operations inlet}}$]

The loss from facilities of the inlet portion (after custody transfer from CO_2 delivery and prior to the point where the CO_2 received at the custody meter is first combined with CO_2 recovered from production) is measured, calculated or estimated to be 2.000 Mscf/D (56,64 Sm^3/D). This loss is the total CO_2 loss including both anthropogenic and non-anthropogenic CO_2 components.

B.2.6 EOR complex loss [$m_{\text{loss EOR complex}}$]

The loss from the EOR complex is measured, calculated or estimated to be 1.000 Mscf/D (28,32 Sm^3/D). This loss is the total CO_2 loss including both anthropogenic and non-anthropogenic CO_2 (inclusive of previously injected non-qualifying volumes injected prior to the quantification period).

B.2.7 Other operational losses [$m_{\text{loss operations other}}$]

The total loss from all operations through production facilities, only excluding the inlet portion, is measured, calculated or estimated to be 15.00 Mscf/D (424,8 Sm^3/D). This loss is the total CO_2 loss including both anthropogenic and non-anthropogenic CO_2 (inclusive of volumes injected prior to the quantification period). This loss is an aggregate of the following:

a) Loss of CO_2 due to leakage from production, handling and recycling CO_2-EOR facilities (infrastructure including wellheads) [$m_{\text{loss leakage facilities}}$];

b) Loss of CO_2 from venting/flaring from production operations [$m_{\text{loss vent/flare}}$];

c) Loss of CO_2 due to entrainment within produced gas/oil/water when this CO_2 is not separated and reinjected. [$m_{\text{loss entrained}}$]; and

d) Loss of CO_2 due to any transfer of CO_2 outside the CO_2-EOR project. [$m_{\text{loss transfer}}$].

Daily metering could be used to minimize calculation errors through this quantification process.

B.3 Calculation procedures for the first year (for the total CO_2)

The calculation of total CO_2 associated storage is shown as the first step. (see B.3.1 to B.3.6).

B.3.1 Calculation of native CO_2 recovered

If the authority approval to include the native CO_2 is obtained, the following parameters are used to calculate the mass of native CO_2 included in m_{input}:

a) Native CO_2 content is 100.0 scf/stb (17,81 Sm^3/Sm^3).

b) Production rate is 1,000 stb/D (159,0 Sm^3/D).

Calculation:

(1,000 stb/D × 365.0 D/Year) × (100.00 scf/stb) / (1,000,000 scf/MMscf) = 36.50 MMscf

[(159,0 Sm^3/D × 365,0 D/Year) × (17,81 Sm^3/Sm^3) = 1 034 000 Sm^3 = 1 931 t]

This value is the total native CO_2 recovered during the first year.

B.3.2 Total CO_2 input [m_{input}]

The daily quantity of CO_2 received by the project, if no native CO_2 is approved and received, is multiplied by 365 days to obtain the annual total m_{input}.

10.00 MMscf/D × 365.0 D/Year = 3,650 MMscf

[(283 200 Sm^3/D × 365,0 D/Year) = 103 400 000 Sm^3 = 193 100 t]

If authority approval to include native CO_2 is obtained, then m_{input} includes the m_{native} volume (see B.3.1).

3,650 MMscf + 36.50 MMscf = 3,686.50 MMscf

103 400 000 + 1 034 000 Sm^3 = 104 434 000 Sm^3 = 195,000 t]

B.3.3 Operational loss [$m_{loss\ operations}$]

The daily loss from both injection and production facilities (see B.2.5 and B.2.7) is converted from Mscf to MMscf and is then multiplied by 365 days to obtain the annual $m_{loss\ operations}$, where:

$m_{loss\ operations} = m_{loss\ operations\ inlet} + m_{loss\ operations\ other}$

[(2.000 Mscf/D + 15.00 Mscf/d) / 1,000 (Mscf/MMscf) × 365.0 D/Year) = 6.205 MMscf

[481,4 Sm^3/D × 365,0 D/Year = 175 770 Sm^3 = 328,2 t]

B.3.4 EOR complex loss [$m_{loss\ EOR\ complex}$]

The daily loss from the EOR complex (see B.2.6) is converted from Mscf to MMscf and is multiplied by 365 days to obtain the annual $m_{loss\ EOR\ complex}$.

(1.000 Mscf/D) / 1000 (Mscf/MMscf) × 365.0 D/Year = 0.3650 MMscf

[28,32 Sm^3/D × 365,0 D/Year = 10 340 Sm^3 = 19,31 t]

B.3.5 Associated storage calculation [m_{stored}]

The total CO_2 associated storage for the first year is calculated based on following formulas:

$m_{stored} = m_{input} - m_{loss\ operations} - m_{loss\ EOR\ complex}$

3,686.5 MMscf – 6.205 MMscf – 0.3650 MMscf = 3,680 MMscf

[104 400 000 Sm^3 – 20 670 Sm^3 – 155 100 Sm^3 – 10 340 Sm^3 = 104 213 890 Sm^3 = 194 700 t]

NOTE If the previously injected volume of 6,000 MMscf is included, then the total CO_2 within the EOR complex will be 9,680 MMscf (274 100 000 Sm^3 = 512 100 t).

B.4 Calculation procedures for the first year for the anthropogenic portion of m_{stored}

Calculation of the anthropogenic portion of CO_2 associated storage will follow the same approach, using the same formula (see 8.3), and using variables that have been adjusted to reflect the application of allocation ratios. Note that if there were no previously received and injected CO_2 at this hypothetical project (i.e. a new project) and the new CO_2 received was 100 % anthropogenic CO_2, the calculations below will reduce to simply losses subtracted from the amount of CO_2 received. The example provided herein is intended to address a relatively complex scenario, albeit in a simplified manner for ease of understanding.

B.4.1 Calculation of native CO_2 if included

If the authority approval to include the native CO_2 is obtained, the following parameters are used to calculate the mass of native CO_2 included in m_{input}:

a) Native CO_2 content is 100.0 scf/stb (17,81 Sm^3/Sm^3)

b) Production Rate is 1,000 stb/D (159,0 Sm^3/D)

Calculation:

(1,000 stb/D × 365.0 D/Year) × (100.0 scf/stb) / (1,000,000 scf/MMscf) = 36.50 MMscf

[(159,0 Sm^3/D × 365,0 D/Year) × (17,81 Sm^3/Sm^3) = 1 034 000 Sm^3 = 1 931 t]

This value is the total native CO_2 recovered during the first year.

B.4.2 Anthropogenic CO_2 m_{input} calculation using a ratio

To derive the volume of anthropogenic CO_2 received at the project, a three-step process is used. First, the total CO_2 received at the custody transfer meter for the project is calculated, and then it is reduced by the proportion of non-anthropogenic CO_2 within the total CO_2 stream. Finally, m_{native} is added to the anthropogenic stream, if approved by the authority. The following parameters are used:

a) New CO_2 received is 10.00 MMscf/D (283 200 Sm^3/D), of which 40 % is defined as anthropogenic CO_2; and

b) First Year of anthropogenic native CO_2 is 36.50 MMscf (1 034 000 Sm^3) (see B.4.1).

Calculation:

B.4.2.1 Total CO_2 $m_{received}$ for the first year

(10.00 MMscf/D × 365.0 D/Year) = 3,650 MMscf

[(283 200 Sm^3/D × 365,0 D/Year) = 103 400 000 Sm^3 = 193 200 t]

The anthropogenic allocation ratio for $m_{received}$ is deemed to be 40 % (0,400 0), and this allocation factor is to be utilized for calculating the anthropogenic CO_2 portion of $m_{loss\ operations\ inlet}$ (see B.4.3).

B.4.2.2 Total CO_2 m_{input} for the first year

$m_{input} = m_{received} + m_{native}$

(10.00 MMscf/D × 365.0 D/Year) + 36.50 MMscf = 3,687 MMscf

[(283 200 Sm^3/D × 365,0 D/Year) + 1 034 000 Sm^3 = 104 400 000 Sm^3 = 195 000 t]

B.4.2.3 Anthropogenic CO_2 m_{input} for the first year

The anthropogenic portion of m_{input} is calculated by applying the anthropogenic ratio (40 %) to $m_{received}$ and adding m_{native}, all of which is anthropogenic.

(10.00 MMscf/D × 365.0 D/Year) × 0.400 0 + 36.50 MMscf = 1,497 MMscf

[(283 200 Sm^3/D × 365,0 D/Year) × 0,400 0 + 1 034 000 Sm^3 = 42 380 000 Sm^3 = 79 170 t]

B.4.2.4 First year anthropogenic ratio for m_{input}

The anthropogenic portion of m_{input} (see B.4.3) is divided by the total m_{input} (see B.3.2), including m_{native} (see B.4.1), when allowed by the authority.

1,497 MMscf/(3,650 + 36.50) MMscf = 0.406 0

[42 380 000 Sm^3/104 400 000 Sm^3 = 0,406 0]

B.4.3 Operational inlet loss [$m_{\text{loss operations inlet}}$] of anthropogenic CO_2

Because the anthropogenic ratios will vary across the system, this first calculation quantifies the anthropogenic CO_2 loss between the custody meter and the point where the CO_2 received at the custody transfer meter is first combined with CO_2 recovered from production and recycling for reinjection purposes. The following parameters are used:

a) Operational inlet loss of 2.000 Mscf/D (56,64 Sm^3/D) for the inlet CO_2 stream (see B.2.5).

b) First year anthropogenic CO_2 received ratio of 0,400 0 (see B.2.2).

Calculation:

B.4.3.1 Total CO_2 operational inlet loss [$m_{\text{loss operations inlet}}$] for the first year

Operational inlet loss daily rate is converted from Mscf to MMscf, and then multiplied by 365 days to yield the total annual $m_{\text{loss operations inlet}}$.

(2.000 Mscf/D/1,000 (Mscf/MMscf) × 365.0 D/Year) = 0.7300 MMscf = 38.62 t

[56,64 Sm^3/D/28 320 Sm^3/28 320 Sm^3 × 365,0 D/Year = 20 670 Sm^3 = 38,62 t]

B.4.3.2 Anthropogenic CO_2 operational inlet loss [$m_{\text{loss operations inlet}}$] for the first year

Multiplying the total annual $m_{\text{loss operations inlet}}$ by the anthropogenic ratio yields the annual anthropogenic $m_{\text{loss operations inlet}}$.

0.7300 MMscf × 0.4000 = 0.2920 MMscf = 15.45 t

[20 674 Sm^3 × 0,400 0 = 8 270 Sm^3 = 15,45 t]

B.4.4 EOR complex anthropogenic CO_2 ratio

This ratio represents the proportion of anthropogenic CO_2 existing within the EOR complex at the end of the first year of the quantification period. It is utilized to calculate the quantity of anthropogenic CO_2 portion of operational loss production and loss from EOR complex. This ratio changes with time and could be calculated at shorter intervals (to tie in with monitoring and loss measurement events) to improve accuracy. The following parameters are used:

a) Previously injected CO_2 within the EOR complex at the start of the quantification period (see B.2.1) of 6,000 MMscf (169 900 00 Sm^3);

b) Total CO_2 received for the first year is 3,687 MMscf (104 400 00 Sm^3), including native CO_2 (see B.3.2 and B.4.1);

c) Total first year anthropogenic CO_2 received is 1,497 MMscf (42 395 000 Sm^3) (see B.4.2.2);

d) First year total CO_2 operational inlet loss is 0,730 0 MMscf (20 670 Sm^3) (see B.4.3.1); and

e) First year anthropogenic CO_2 operational inlet loss is 0,292 0 MMscf (8 270 Sm^3) (see B.4.3.2).

Calculation:

The anthropogenic ratio for $m_{\text{loss EOR complex}}$ and $m_{\text{loss operations other}}$ is derived by taking the anthropogenic portion of m_{input} (including m_{native}) minus the anthropogenic portion of $m_{\text{loss operations inlet}}$ and dividing that result by the total of ($m_{\text{previous injection}} + m_{\text{input}} - m_{\text{loss operations inlet}}$). The resultant formulation is:

(1,497 MMscf − 0.2920 MMscf)/(6,000 MMscf + 3,687 MMscf − 0.7300 MMscf) = 0.154 5

[(42 395 000 Sm^3 − 8 270 Sm^3)/(169 900 000 Sm^3 + 104 400 000 Sm^3 − 20 670 Sm^3) = 0,154 5]

B.4.5 Anthropogenic CO_2 portion of operational other loss [$m_{\text{loss operations other}}$] and EOR complex loss [$m_{\text{loss EOR complex}}$]

This calculation derives the anthropogenic portion of the operational other loss and EOR complex loss by applying the anthropogenic ratio derived in B.4.4 to total operational other loss and total EOR complex loss.

Parameters used:

a) EOR complex anthropogenic CO_2 ratio is 0,154 5 (see B.4.4);

b) EOR complex loss is 1.000 Mscf/D (28,32 Sm^3/D); and

c) Operational other loss is 15.00 Mscf/D (424,8 Sm^3/D).

Calculation:

B.4.5.1 Total CO_2 operational other loss [$m_{\text{loss operations other}}$]

Other loss daily rate is converted from Mscf to MMscf, multiplied by 365 days to yield the annual total $m_{\text{loss operations other}}$.

(15.00 Mscf/D) / (1,000 Mscf/MMscf) × 365.0 D/Year = 5.475 MMscf

[424,8 Sm^3/D × 365,0 D/Year = 155 100 Sm^3 = 289,6 t]

B.4.5.2 Total CO_2 EOR complex loss [$m_{\text{loss EOR complex}}$]

Total CO_2 EOR complex loss daily rate is converted from Mscf to MMscf, multiplied by 365 days to yield the annual total $m_{\text{loss EOR complex}}$.

(1.000 Mscf/D) / (1,000 Mscf/MMscf) × 365.0 D/Year = 0.3650 MMscf

[28,30 Sm^3/D × 365,0 D/Year = 10 340 Sm^3 = 19,31 t]

B.4.5.3 Anthropogenic CO_2 operational other loss [$m_{\text{loss operations other}}$]

Total CO_2 operational other loss is multiplied by the anthropogenic ratio derived in B.4.4 to obtain the anthropogenic portion of annual $m_{\text{loss operations other}}$.

(5.475 MMscf) × 0.1545 = 0.8459 MMscf

[155 100 Sm^3 × 0,154 5 = 23 960 Sm^3 = 44,75 t]

B.4.5.4 Anthropogenic CO_2 EOR complex loss [$m_{\text{loss EOR complex}}$]

Total CO_2 EOR complex loss is multiplied by the anthropogenic ratio derived in B.4.4 to obtain the anthropogenic portion of annual $m_{\text{loss EOR complex}}$.

(0.3650 MMscf) × 0.1545 = 0.05639 MMscf

[10 340 Sm^3 × 0,154 5 = 1 598 Sm^3 = 2,980 t]

B.4.6 Quantification of anthropogenic CO_2 stored in association with EOR operations

Parameters used:

a) Anthropogenic CO_2 operational inlet loss: 0.2920 MMscf (8 270 Sm^3) (see B.4.3.2);

b) Anthropogenic CO_2 operational other loss: 0.8459 MMscf (23 960 Sm^3) (see B.4.5.3);

c) Anthropogenic CO_2 EOR complex loss: 0.05639 MMscf (1 598 Sm^3) (see B.4.5.4);

d) New CO_2 received and the percentage of anthropogenic CO_2: 10.00 MMscf/D (283 200 Sm^3/D) (40 % anthropogenic); and

e) Native CO_2 received: 36.50 MMscf (1 034 000 Sm^3) (see B.4.1).

Calculation

To quantify the portion of anthropogenic CO_2 stored for the first year, the calculation also considers m_{native}, which is included in the m_{input} portion of the calculation, and is calculated based on the anthropogenic CO_2 inputs to the following formula:

$$m_{stored} = m_{input} - m_{loss\ operations} - m_{loss\ EOR\ complex}$$

$$m_{stored} = (m_{received} + m_{native}) - (m_{loss\ operations\ inlet} + m_{loss\ operations\ other}) - m_{loss\ EOR\ complex}$$

[(10.00 MMscf/D × 0.400 0 × 365.0 D/Year) + 36.50 MMscf] − (0.2920 MMscf + 0.8459 MMscf) − 0.05639 MMscf = 1,495.3 MMscf

[(283 200 Sm^3/D × 0,400 0 × 365,0 D/Year) + 1 034 000 Sm^3] − (8 270 Sm^3 + 23 960 Sm^3) − 1 598 Sm^3 = 42 347 000 Sm^3 = 79 110 t

Table B.1 — Example table documenting the variables and allocation ratios calculated for the anthropogenic CO_2 case

Variable	For Total CO_2 (in MMscf)	Anthropogenic Ratio	For Anthropogenic CO_2 (in MMscf)
m_{input}	3 687	0,406 0	1497
m_{native} (CO_2 per unit of oil = 100.0 scf/stb)	36.50	1,000	36.50
$m_{previous\ injection}$	6 000	0,000 0	0.000
$m_{loss\ operations\ inlet}$	0.7300	0,400 0	0.2920
$m_{loss\ operations\ other}$	5.475	0,154 5	0.8459
$m_{loss\ EOR\ complex}$	0.3650	0,154 5	0.05639
m_{stored}	3 643		1 495

Annex C
(informative)

Unit conversion

Standard oil and gas industry units

barrel(s) of oil	stb
barrels of oil per day	stb/D
million standard cubic feet	MMscf
million standard cubic feet per day	MMscf/D
standard cubic foot	scf
standard cubic feet per barrel	scf/stb
standard cubic feet per day	scf/D
thousand standard cubic feet	Mscf
thousand standard cubic feet per day	Mscf/D

International system of units (SI) metric conversion factors

1 barrel = 0,158 9 Sm^3

1 M = 1 000

1 MM = 1 000 000

1 t = 1 000 kg

International system of units (SI) metric conversion factors at 60 °F (15,555 6 °C), 1 atm[1)]

	Volume m^3	**Mass** kg	**Volume** scf	**Mass** lb
Volume (m^3)	1,000	1,868	35.31	4.118
Mass (kg)	0,535 3	1,000	18.90	2.204
Volume (scf)	0,028 32	0,052 90	1.000	0.116 6
Mass (lb)	0,242 8	0,453 6	8.575	1.000
NOTE In this table, for columns (m^3) and (kg), comma (",") is used to denote decimal point (".").				

SOURCE: NIST Chemistry WebBook, SRD 69 Thermodynamic properties of carbon dioxide.

1) Conversion is valid for pure CO_2 only.

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