



TECHNICAL GROUP

Final Report by the CSLF Task Force on Technical Challenges in the Conversion of CO₂-EOR Projects to CO₂ Storage Projects

Background

At the September 2011 CSLF Ministerial Meeting in Beijing, a Task Force was formed to investigate Technical Challenges in the Conversion of CO₂-EOR Projects to CO₂ Storage Projects. The task force mandate was to review, compile and report on technical challenges that may constitute a barrier to the broad use of CO₂ for EOR and to the conversion of CO₂-EOR operations to CCS operations. This document is the Final Report from the Task Force and concludes the Task Force's activities.



Technical Challenges in the Conversion of CO₂-EOR Projects to CO₂ Storage Projects

**Report Prepared for the CSLF Technical Group
by the CSLF Task Force on
Technical Challenges in the Transition from CO₂-EOR to CCS**

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EXECUTIVE SUMMARY

The 40 years of experience and the current number of CO₂-EOR operations currently active in the world indicate that there is sufficient operational and regulatory experience for this technology to be considered as being mature, with an associated storage rate of 90-95 % of the purchased CO₂. Application of CO₂-EOR for CO₂ storage has a number of advantages: 1) it enables CCS technology improvement and cost reduction; 2) it improves the business case for CCS demonstration and early movers; 3) it supports the development of CO₂ transportation networks; 4) it may provide significant CO₂ storage capacity in the short-to-medium-term, particularly if residual oil zones (ROZ) are produced; 5) it enables knowledge transfer, bridging the experience gap and building and sustaining a skilled CCS workforce; and 6) it helps gaining public and policy-makers acceptance.

The current number of CO₂-EOR operations in the world is negligible compared with the number of oil pools in the world, and the main reason CO₂-EOR is not applied on larger scale is the unavailability of high-purity CO₂ in the amounts and at the cost needed for this technology to be deployed on a large scale. The potential for CO₂ storage and incremental oil recovery through CO₂-EOR is significant, particularly if residual oil zones (ROZ) and hybrid CO₂-EOR/CCS operations are considered. Besides the main impediment in the adoption and deployment of this technology of the unavailability of CO₂ at economic prices, the absence of infrastructure to both capture the CO₂ and transport it from CO₂ sources to oil fields suitable for CO₂-EOR is also a key reason for the lack of large scale deployment of CO₂-EOR.

There are a number of commonalities between CO₂-EOR and pure CO₂ storage operations, both at the operational and regulatory levels, which create a good basis for transitioning from CO₂-EOR to CO₂ storage in oil fields. However, currently there are a significant number of differences between the two types of operations that can be grouped in seven broad categories: 1) operational, including CO₂ purity and quality; 2) objectives and economics; 3) supply and demand; 4) legal and regulatory; 5) assurance of well integrity; 6) long term CO₂ monitoring requirements; and 7) industry's experience.

The analysis presented in this report indicates that there are no specific technological barriers or challenges *per se* in transitioning and converting a pure CO₂-EOR operation into a CO₂ storage operation. The main differences between the two types of operations stem from legal, regulatory and economic differences between the two. While the legal and regulatory framework for CO₂-EOR, where it is practiced, it is well established, the legal and regulatory framework for CO₂ storage is being refined and is still evolving. Nevertheless, it is clear that CO₂ storage operations will likely require more monitoring and reporting 1) of a wider range of parameters, 2) outside the oil reservoir itself, and 3) on a wider area, and for a longer period of time than oil production. Because of this, pure CO₂ storage will impose additional costs on the operator. A challenge for CO₂-EOR operations which may, in the future, convert to CO₂ storage operations is the lack of baseline data for monitoring, besides wellhead and production monitoring, for which there is a wealth of data.

In order to facilitate the transition of a pure CO₂-EOR operation to CO₂ storage, operators and policy makers have to address a series of legal, regulatory and economic issues in the absence of which this transition can not take place. These should include:

1. Clarification of the policy and regulatory framework for CO₂ storage in oil reservoirs, including incidental and transitioned storage CO₂-EOR operations. This framework

should take into account the significant differences between CO₂ storage in deep saline aquifers, which has been the focus of regulatory efforts to date, and CO₂ storage in oil and gas reservoirs, with particular attention to the special case of CO₂-EOR operations.

2. Clarification if CO₂-EOR operations transitioning to CO₂ storage operations should be tenured and permitted under mineral/oil & gas legislation or under CO₂ storage legislation.
3. Clarification of any long-term liability for CO₂ storage in CO₂-EOR operations that have transitioned to CO₂ storage, notwithstanding the CO₂ stored during the previous phase of pure CO₂-EOR.
4. Clarification of the monitoring and well status requirements for oil and gas reservoirs, particularly for CO₂-EOR, including baseline conditions for CO₂ storage.
5. Addressing the issue of jurisdictional responsibility for pure CO₂ storage in oil and gas reservoirs, both in regard to national-subnational jurisdiction in federal countries, and to organizational jurisdiction (environment versus development ministries/departments).
6. Examination of the need to assist with the economics, particularly the cost of CO₂ and the infrastructure to bring anthropogenic CO₂ to oil fields.

The Policy Group should take note of these issues and establish ways to address them within CSLF, and make appropriate recommendations to the governments of its members.

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1. INTRODUCTION

1.1 CSLF PURPOSE

The Carbon Sequestration Leadership Forum (CSLF) is a Ministerial-level international climate change initiative that is focused on providing a government-level framework for international cooperation in research, development, demonstration and commercialization of improved cost-effective technologies for the separation, capture, transportation, utilization and storage of carbon dioxide (CO₂). The mission of the CSLF is to facilitate the development and deployment of such technologies via collaborative efforts that address key technical, economic, and environmental obstacles. The CSLF also promotes awareness and champions legal, regulatory, financial, and institutional environments conducive to such technologies. The CSLF seeks to realize the promise of CO₂ capture, utilization and storage (CCUS) over the coming decades, and to ensure that CCUS is both commercially competitive and environmentally safe.

The CSLF comprises 25 members, including 24 countries and the European Commission. CSLF member countries represent over 3.5 billion people, or approximately 60% of the world's population.

The CSLF seeks to:

1. Identify key obstacles to achieving improved technological capacity;
2. Identify potential areas of multilateral collaborations on carbon separation, capture, transport and storage technologies;
3. Foster collaborative research, development, and demonstration (RD&D) projects reflecting Members' priorities;
4. Identify potential issues relating to the treatment of intellectual property;
5. Establish guidelines for the collaborations and reporting of their results;
6. Assess regularly the progress of collaborative R&D projects and make recommendations on the direction of such projects;
7. Establish and regularly assess an inventory of the potential areas of needed research;
8. Organize collaboration with all sectors of the international research community, including industry, academia, government and non-government organizations; the CSLF is also intended to complement ongoing international cooperation in this area;
9. Disseminate information and foster knowledge-sharing, in particular among Members' projects;
10. Build capacity of Members;
11. Consult with and consider the views and needs of stakeholders in the activities of the CSLF;
12. Develop strategies to address issues of public perception; and
13. Initiate and support international efforts to explain the value of CCUS, in developing legal and regulatory frameworks and markets, and promote broad-based adoption of CCUS; and
14. Support international efforts to promote RD&D and capacity building projects in developing countries.

The Carbon Sequestration Leadership Forum comprises a Policy Group and a Technical Group. The Policy Group governs the overall framework and policies of the CSLF, and focuses mainly on policy, legal, regulatory, financial, economic and capacity building issues. The Technical

Group reports to the Policy Group and focusses on technical issues related to CCUS and CCUS projects in member countries.

The Technical Group has the mandate to identify key technical, economic, environmental and other issues related to the achievement of improved technological capacity, and establish and regularly assess and inventory of the potential areas in need of research.

At the CSLF Ministerial meeting held in Beijing, P.R. China in September 2011, the CSLF Charter was amended to, among other things, include CO₂ utilization technologies as an important aspect of a CO₂ emission reduction strategy, in addition to carbon capture and storage technologies that have been the main focus of CSLF efforts since its inception in 2003.

1.2 TASK FORCE MANDATE

At the same meeting in Beijing in 2011, the Technical Group has identified the following twelve Action Plan items:

- 1) Technology Gaps Closure
- 2) Energy Penalty Reduction
- 3) CCS with Industrial Emissions Sources
- 4) Best-Practice Knowledge Sharing
- 5) Risk and Liability
- 6) CO₂ Transport and Compression
- 7) Monitoring for Commercial Projects
- 8) Technical Challenges for Conversion of CO₂-EOR to CCS
- 9) Competition of CCS with Other Resources
- 10) Life Cycle Assessment and Environmental Footprint of CCS
- 11) Carbon-neutral and Carbon-negative CCS
- 12) CO₂ Utilization Options

Canada volunteered to take the lead on “Technical Challenges for Conversion of CO₂ EOR to CCS” (EOR stands for enhanced oil recovery), the US volunteered to take the lead on “CO₂ Utilization Options” (this would cover all forms of CO₂ utilization except for CO₂ enhanced oil recovery), Australia volunteered to take the lead on “Technology Gaps Closure” and Norway volunteered to take the lead on “Monitoring for Commercial Projects”. CSLF Task Forces were created to address these four themes.

The action on “Risk and Liability” is being covered by a new Joint Policy and Technical Group Task Force on this topic, while the International Energy Agency Greenhouse Gas Programme (IEA-GHG) is addressing the “Competition of CCS with Other Resources”. Also, the Clean Energy Ministerial (CEM) and the International Energy Agency (IEA) are addressing how industrial emissions relate to CCS, and this would relate to the action on “CCS with Industrial Emissions Sources”. The United Kingdom’s Department of Energy and Climate Change (DECC) already is completing a report on “Energy Penalty Reduction”. Finally, the Global CCS Institute (GCCSI) is already heavily involved in Best Practices Knowledge Sharing, but the CSLF Project Interaction and Review Team (PIRT) will also undertake this action for CSLF-recognized projects. Thus, nine out of the twelve actions in the Action Plan developed at the CSLF Ministerial-level meeting in Beijing in 2011 are being acted on one way or another.

Since its inception in 2003, the Technical Group has focused its efforts on the facilitation of information and knowledge dissemination regarding research, development, demonstration and

deployment of effective, low-cost carbon capture and storage (CCS) technologies as a viable option to reduce greenhouse gas emissions in an effort to combat the effects of global warming. Although deep saline formations have been assessed as having the largest storage potential (IPCC, 2005), possessing also the advantage that they are present worldwide in all sedimentary basins, oil and gas reservoirs have been recognized as having significant storage potential, possessing the advantages that their storage properties have been demonstrated by the presence of oil and/or natural gas and that they are better known (understood) as a result of exploration and production activities. A particular sub-class of CO₂ storage in hydrocarbon reservoirs is CO₂ storage in enhanced oil recovery (CO₂-EOR) operations where CO₂ is used in tertiary oil recovery to produce additional oil. From a CO₂ storage point of view, this technology presents the economic advantage of reducing CO₂ storage costs by producing oil, which has a well-defined market value. In fact, CO₂-EOR is a form of CO₂ utilization that has not been sufficiently explored to date. In today's economic and financial environment where a market signal regarding CO₂ storage is lacking, this makes CO₂ storage in CO₂-EOR operations particularly attractive. However, although there are currently more than 100 CO₂-EOR operations in the world, only the CO₂-EOR Weyburn-Midale project in Canada has been identified and recognized as a CCS project, but it is widely recognized that all CO₂-EOR projects store a significant amount of the purchased and injected CO₂ by various trapping mechanisms.

On the geological-storage side, the focus of CO₂ Utilization is on the use of CO₂ in CO₂-EOR operations. A task force to implement Action Plan #8 was approved by the Technical Group at the Ministerial-level meeting in Beijing in 2011, chaired by Canada and with membership from Brazil, P.R. China, Mexico, Norway, Saudi Arabia and United States.

Oil and gas reservoirs have long been considered to be likely the most advantageous sites for CO₂ storage because they have demonstrated confinement (sealing) properties in regard to buoyant fluids, they are well known and characterised, and in most cases access infrastructure is already in place. Carbon dioxide can be stored in hydrocarbon reservoirs after abandonment (at depletion), or can be stored while hydrocarbons are still being produced, during EOR operations. The latter option provides the advantage that some of the CCS costs will be offset, or, most likely, an economic profit will be realized as a result of incremental oil production. CO₂-EOR is a growing industry but has not yet found wide application outside of the Permian basin in west Texas and other locations in the United States where CO₂ is produced on a large scale and at a very affordable cost from several natural CO₂ reservoirs and a few gas processing, ammonia, ethylene and fertilizer plants, and coal gasification plants. The high capital costs of CO₂ capture and transport, along with cyclic oil prices tend to keep most areas from implementing CO₂-EOR.

The Mandate of the CSLF Task Force on "Technical Challenges for Conversion of CO₂-EOR to CCS" is to review, compile and report on technical challenges that may constitute a barrier to the broad use of CO₂ for enhanced oil recovery and/or for the conversion of CO₂-EOR operations to CO₂ storage operations or dual oil production/ CO₂ storage operations. There are recognized economic and policy barriers and challenges, such as the high price of CO₂, the lack of market value on stored CO₂, and the interest of the operators of CO₂-EOR operations in maximizing oil production and minimizing "concurrent" or "incidental" CO₂ storage. These economic and policy barriers and challenges are outside the scope of the Task Force, which will focus on purely technical challenges.

1.3 HISTORY OF CO₂-EOR AND CCS

Enhanced oil recovery (EOR) refers to the introduction of heat, chemicals, and/or gases to stimulate the production of oil unrecovered during primary and secondary oil production. Oil pockets not accessible to secondary methods of recovery (such as water/steam floods) can be recovered using miscible CO₂-EOR, when the injected CO₂ becomes miscible with crude oil. In reservoirs where the injected CO₂ and oil are immiscible with each other, oil production may be enhanced by swelling and thinning the crude oil. The recovery of oil up to 10-12% of the original oil in place (OOIP) extends the productive life of the flooded oilfields. The first patent on the use of CO₂ to recover oil was granted in 1952 (Whorton et al., 1952). CO₂-EOR was first tested on a large scale in the Permian Basin of west Texas and southeastern New Mexico. A successful small field-scale CO₂-EOR pilot test was conducted in the Mead Strawn field, Jones County, TX in 1964 (Meyer, 2007). The Scurry Area Canyon Reef Operators Committee (SACROC) flood in Scurry County, TX (January 1972) and the North Crossett flood in Crane and Upton Counties, TX (April 1972) were the first commercial CO₂-EOR projects (Melzer, 2011). CO₂ for the early commercial tests was sourced from the Val Verde natural gas processing plants. Oil production from CO₂-EOR increased incrementally over the next five to ten years with additional CO₂ flood projects. The discovery of large, natural CO₂ source fields such as Sheep Mountain, McElmo Dome (Colorado), Jackson Dome (Mississippi), and Bravo Dome (New Mexico), and the construction of pipelines in the 1980's connecting CO₂ sources to Permian Basin oilfields led to an expansion in U.S. CO₂-EOR production (Melzer, 2011). For example, current EOR operations at the SACROC field store ~6.5 million metric tonnes (MT) of CO₂/year (NETL, 2008). Currently, the SACROC field (49,900 acres) is operated by Kinder Morgan, and contains 503 CO₂ injection wells and 390 oil producing wells (Koottungal, 2012). It is estimated that about 55 MT CO₂ has been stored in the SACROC unit from 1972 to 2005 (Han et al., 2010). The growth in world, U.S., and Permian Basin CO₂-EOR production is represented in Figure 1.

Figure 1 indicates that a North American CO₂-EOR production is a major fraction of world CO₂-EOR production. The Permian Basin was historically the major focus of CO₂-EOR operations due to the availability of relatively pure natural CO₂ sources connected to oil fields via pipeline infrastructure. CO₂-EOR projects are fairly long-term, the first CO₂ floods at the SACROC and Crossett fields are producing 1 million barrels of oil/year currently (Melzer, 2012). It is estimated that CO₂-EOR production in the Permian Basin contributed to 18% of its total oil production (Melzer, 2012). Analysts point to a tightening of CO₂ supply for the Permian Basin, and projects in other regions in the United States (Rocky Mountains, Midwest/Mississippi/Gulf Coast, Mid-continent) also have contributed significantly to CO₂-EOR production growth in the past decade.

Future growth in North American CO₂-EOR production is expected in the Permian Basin, Rocky Mountains, Midwest/Mississippi/Gulf Coast, Mid-continent regions and Canada. The volume of CO₂ used for EOR in North America grew from approximately 110 million standard cubic feet per day (MMSCFPD) in 1983 to 3380 MMSCFPD (~65 MT/y) in 2011, and is estimated to reach 6500 MMSCFPD by 2018 (Murrell and Melzer, 2012).

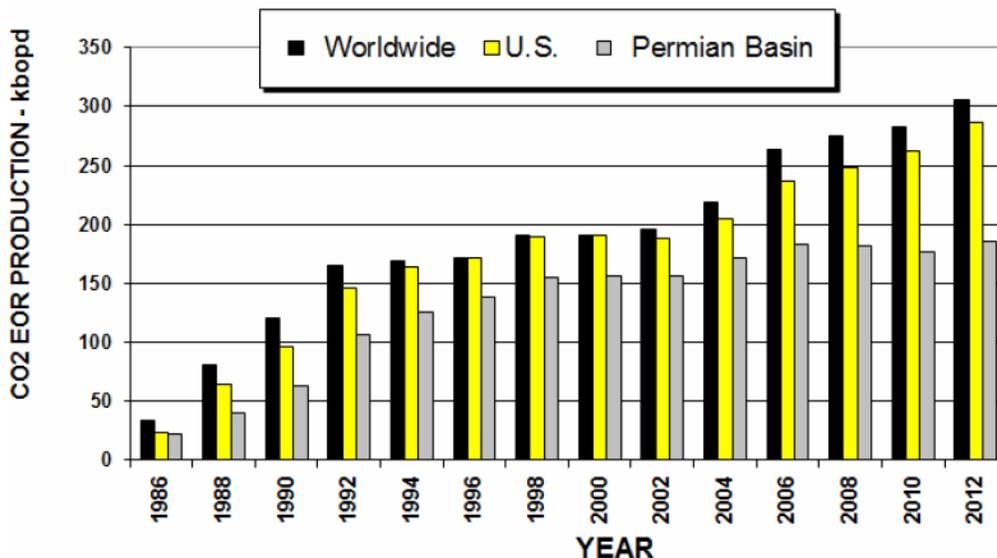


Figure 1: Global, U.S., and Permian Basin CO₂-EOR production, 1986-2012. Source: O&GJ Biennial CO₂-EOR Editions, UTPB Petroleum Industry Alliance (Murrell and Melzer, 2012).

One difference between historic CO₂ injection for EOR and current/future practice is that in the past, operators used small-volume injections of CO₂ (0.4 to 0.5 hydrocarbon pore volume [HCPV]) to maximize profitability. Higher oil prices, coupled with technology advancements in subsurface characterization and monitoring currently favor higher-volume CO₂ injections, and CO₂ slug sizes of 0.8 to 1.0 HCPV are not uncommon (Kuuskraa et al., 2011). The use of higher quantities of CO₂, combined with intelligent well placement, injection and effective monitoring has the potential to result in greater CO₂ utilization and oil recovery.

Oilfield CO₂ floods have been occurring for over 40 years and, although the incidental storage of CO₂ from the EOR projects is undocumented in aggregate, the reservoir retention volumes are projected to be in excess of 800 Mt of CO₂. For example, one large west Texas flood was recently singled out to have cumulatively purchased 115 Mt of CO₂ of which 99.7% was sequestered¹. Another thorough carbon balance analysis of CO₂ EOR was conducted in 2009 on the SACROC EOR project². It concluded the project had cumulative purchases of CO₂ of 260.0 Mt, direct/indirect emissions of 18.5 Mt and emissions from installing the surface capital equipment of 2.0 Mt. This analysis gives a total sequestered volume of 239.5 Mt or 92+% of the purchased CO₂.

The quantities of CO₂ stored by EOR are large, although in the end they are expected to be typically less than those that would be stored in saline aquifers, and the vast body of operational and safety experience gained from CO₂-EOR could be applied to carbon capture and geologic storage (CCS). For example, the technical aspects of CCS during EOR operations have been studied under the IEAGHG Weyburn-Midale CO₂ Monitoring and Storage Project at commercial EOR operations in the Weyburn and Midale oilfields in Saskatchewan, Canada from 2000 to 2012. The Weyburn unit is operated by Cenovus Energy, and covers 17,280 acres, and has 170 CO₂ injection wells and 320 oil production wells (Koottungal, 2012). The Midale field is operated by Apache Corp. and covers 30,483 acres, and the first phase of implementation has 5 CO₂ injection wells and 43 oil producers (Koottungal, 2012). About 20 MT CO₂ from the

¹ http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2012-06-20_OEHI_Project_Overview_workshop_presentation.pdf {Slide 15}

² (<http://www.co2conference.net/wp-content/uploads/2013/05/Fox-KM-Presentation-SACROC.pdf>)

Dakota Gasification Company's coal-gasification-based synthetic gas plant in North Dakota has been stored in these oilfields since 2000 (Wildgust, 2012). CO₂ is transported to Saskatchewan by a 205 mile-long (330 km) pipeline from Beulah, North Dakota. EOR is expected to enable the recovery of an additional 130 million barrels of oil at Weyburn and Midale, and extend the life of the Weyburn oilfield by 25 years.

Geologic storage of large quantities (1 MT/y) of CO₂ (commercial-scale CCS) in deep saline aquifers has been occurring at Sleipner, Norway (1996-present), Snøhvit, Norway (2008-present), and In Salah, Algeria, (2004-2011). Together, more than 16 MT CO₂ has been stored in the subsurface as of 2010 (Eiken et al., 2010). In all three cases, CO₂ is sourced from natural gas separation plants, transported over distances ranging from 14 km to 150 km, and is injected into offshore (Snøhvit, Sleipner) and onshore subsurface sandstone saline aquifers, with widely varying geophysical and flow characteristics (MIT, 2012). The Snøhvit field is located in the Barents Sea at a depth of ~330 m, and CO₂ is stored (~0.7 MT/y) at a depth of 2400 m below the sea floor in the Tubåen Formation. The Sleipner field is located in the North Sea, at a depth of 80 m, and CO₂ is stored (~1 MT/y) in the Utsira Formation at a depth of ~700 m below the sea floor. The In Salah field is located at an altitude of ~470 m and CO₂ storage (~1 MT/y) occurs at depths of 1700 m below the surface in the Krechba Formation (Eiken et al., 2010).

A variety of monitoring, characterization, and risk management technologies have been deployed at each site to ensure CO₂ containment and to establish best practices for CCS operations. Of all three projects, the Sleipner field has injected the largest quantity of CO₂ to date. The injected CO₂ contains 0.5% to 2% of methane at all three sites (Eiken et al., 2010). CO₂ injected at Sleipner is wet, whereas at In Salah and Snøhvit, it is dried to <50 ppm water content. Other future large-scale CCS facilities with relatively long project lifespans include the Quest CCS project in Canada (~1.2 MT CO₂/y), and the Gorgon project in Australia (3.4 to 4 MT CO₂/y) (GCCSI, 2013).

1.4 POTENTIAL OF RESIDUAL OIL ZONE (ROZ) FOR CO₂-EOR

All reservoirs have a transition zone (TZ) below the oil-water contact (OWC) (Figure 2). The oil saturation below the OWC falls rapidly in the transition zone. This transition zone is generally thin and its thickness is controlled by the pore throat sizes, capillary forces and wettability behavior of the rock. A reservoir may flow some oil especially at the top of the zone but produces mostly water when perforated in the transition zone.

In some circumstances, primarily related to hydrogeological or changed tectonic (geological) conditions, the original oil zone can be invaded by water. This creates a transition zone that exists right below the current OWC and the free water level (FWL), and a residual oil zone (ROZ) or paleo oil zone that exists between the FWL and the paleo FWL (PFWL or the original FWL). This is shown diagrammatically in Figure 2. Using primary or secondary production technologies, the residual oil zone produces only water. The oil in the ROZ is immobile (i.e., at irreducible saturation) and cannot be produced by primary or secondary recovery means. In many situations, the oil saturations in the ROZ are similar to the residual oil saturation in the swept zone of a waterflood in an oil reservoir. The difference resides in the timescale of the sweep of this oil. As mentioned, the oil in the ROZ is from a paleo trap that has been partially or completely invaded by water after post-entrapment tectonic adjustments. Depending on the degree and extent of tilting or uplifting, a reservoir can have a large ROZ that may contain significant quantities of residual oil resource. This residual oil left in place after either a natural or man-made waterflood of the reservoir is oil that has not been displaced by the injected water.

Little is known about the size TZ/ROZ resource as it has not been considered a resource in the past. But ongoing work is characterizing these zones in several areas and is showing that this resource exists both below and between oilfields. Currently, a concerted effort is being made in the United States to target this residual (or 'stranded') oil. Several operators are flooding this resource, exclusively now through the use of CO₂ injection. Currently, there are twelve commercial and field pilots in the west Texas Permian Basin region exploiting CO₂-EOR technology to target this oil.

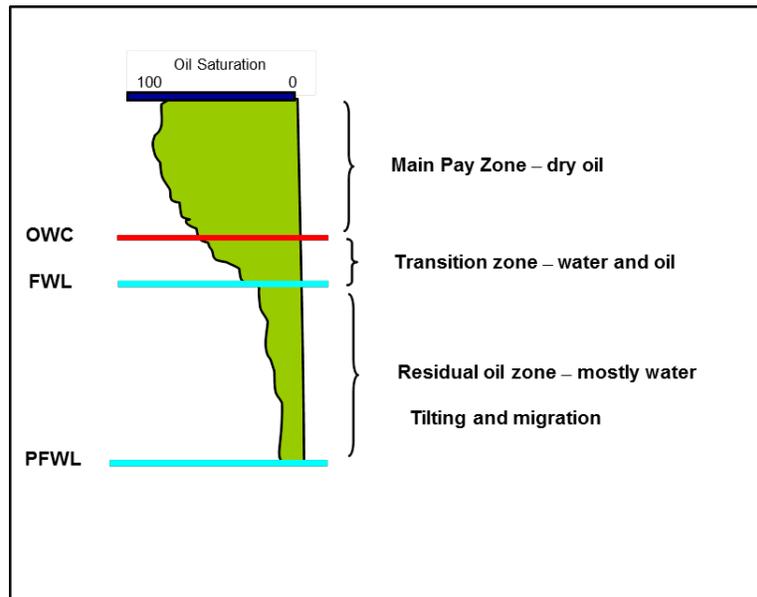


Figure 2: Definition of TZ and ROZ (from Koperna et al. 2006)

At present, CO₂ injection is the favored method to produce this oil because CO₂ properties led by its ability to greatly swell the oil (high solubility of CO₂ in oil), create large oil viscosity reductions, low to no injectivity issues, achievable operating miscibility pressures for reservoirs below depths of 3000-4000 ft (~900 to 1200 m), insensitivities to variations in reservoir water salinity and high oil recovery potential, notwithstanding the additional advantage of CO₂ capture, utilization and storage potential. A significant case history data base has been generated in the industry to evaluate the potential of CO₂-EOR in the main pay zones (MPZ). The data base includes rock and fluid property studies, estimating the minimum miscibility pressure (MMP) with CO₂, relative permeability (water/oil/CO₂) testing asphaltene studies, coreflood experiments of different injection modes, phase behavior studies, and compositional simulation studies. The industry's know-how on CO₂-EOR (in the MPZ) provides a golden opportunity to apply this technology to recover oil from the 'paleo' or residual oil zone.

1.4.1 Literature Review

The industry experience on recovery from the ROZ is limited, with only few examples reported in the literature; exclusively in the Permian Basin in west Texas. However, it is known that the hydrocarbon resource in west Texas ROZ rivals the volumes of in-place oil resource in the MPZ. It has been shown that the San Andres (carbonate) formation ROZ in west Texas fields was created from a huge paleo entrapment that was partially swept of oil when later stage geological structural changes took place. The key changes took place as the west side of the basin was uplifted, exposing the reservoir rocks to meteoric water invasion from the uplifted highlands, and the previously deep San Andres rocks were uplifted and exposed on the west side of the

Permian Basin (Koperna et al. 2006; Melzer et al. 2006). The karsted San Andres outcrop provides the source waters for the sweep. The sweep moves through the high energy (porous) facies of the formations in what have been termed “fairways” of water flushing. As currently characterized five carbonate oil field areas in the Permian Basin have been shown to possess evidence of significant paleo oil reserves in the ROZ:

1. Northern Shelf: Wasson (in particular, Denver unit and Bennett Ranch unit)
2. North Central Basin platform (San Andres/Grayburg Formation): Seminole unit
3. South Central Basin platform (San Andres/Grayburg Formation)
4. Horseshoe Atoll: Kelly-Snyder (SACROC) and Salt Creek
5. Eastern New Mexico: San Andres

The following is a summary of some CO₂-EOR pilots and projects targeting the ROZ paleo oil in Permian Basin, west Texas (Melzer. 2006, Honarpour et al. 2010; Koperna et al. 2006):

- In **Wasson Denver Unit**, the first pilot was initiated in 1991 with six pattern CO₂ flood and then expanded to 21-pattern flood. The success of the pilots led to a two additional phased development projects in 1997 and 2002, respectively.
- In 1995, Shell planned to deepen active wells into the transition and ROZs of the **Bennett Ranch unit**. However, oil prices delayed the project until 2003 when the deepened wells penetrated the ROZ and the resources were added to the MPZ.
- **Seminole San Andres Unit (SSAU)** is considered one of the largest and best documented fields with a ROZ. CO₂ injection into the ROZ in the SSAU started in 1996 with the first of two pilots. Phase 1 was developed using a 2:1 line drive, 80-acre pattern configuration with comingled injection and production into both the MPZ and ROZ. The Phase 2 pilot commenced in 2004 using nine inverted 5-spot, 40-acre patterns. In this pilot the injection was dedicated to the ROZ but MPZ and ROZ production was comingled. In 2007, full field implementation in the ROZ started with 29 each 80-acre patterns and comingled (deepened) producers, with new-drills for dedicated ROZ injectors. Currently, CO₂ injection has moved to Stage 2 full-field deployment and plans are to move field wide to the 382 producers and 190 injectors-CO₂ and water.
- In the **Kelly-Snyder (SACROC)** field, the potential of ROZ gained attention in the mid 1990's when wells were deepened to evaluate the potential of paleo oil. One watered-out well was deepened into the ROZ and produced 20,000 barrels of oil in 18 months from ROZ CO₂ flood. This encouraged the operator to initiate a deepening program to CO₂ flood the ROZ from 1990-1999.
- **Salt Creek field** had a 120 feet (36.58 m) thick ROZ with an average oil saturation of 50% and similar properties to the MPZ. In 1996, a 16-well CO₂ pilot program was initiated to flood the ROZ with ten water-alternating-gas (WAG) injectors and six producers. The pilot was then followed by an expansion of the ROZ CO₂ flood.
- **Means San Andres Unit (MSAU)** is being currently producing in the main pay zone by CO₂-EOR in a WAG mode with 465 producers and 175 CO₂/water injectors. In more recent years, the ROZ in this unit has been carefully characterized and has begun to be exploited. The characterization effort included a full oil saturation assessment and documentation for the purpose of ROZ CO₂-EOR implementation. Some of the utilized methods to assess the oil saturation include log-inject-log (LIL), single well chemical

tracer testing (SWCTT), core analysis, and open-hole logs. The oil saturation was found to be around 23% on average (ranging from 5% to more than 50%). One striking trend is that the oil saturation does not follow the conventional distribution where higher saturations are found at the top of the reservoir. In the ROZ, it was noticed that higher oil saturations can be found in the middle or even at the bottom of the ROZ (Pathak et al., 2012).

The following is a summary of the few papers that targeted the producibility of the transition zone oil, many of which were reported before it was recognized that these were often better characterized as transition zones overlying a thick ROZ. These studies found in the literature focus on the intervals just below the oil/water contacts or transition zone as shown in Figure 2. This work indicates the difficulty to fundamentally study and simulate the TZ and or ROZ in the laboratory. The avoidance of drilling into this zone during primary and secondary productions and the presence of only irreducible oil saturations poses the challenge to capture representative oil samples for ROZ studies.

Nighswander et al. (1994) used live (upper) transition zone fluids to conduct displacement tests and tune the equation of state (EoS). In this study, a slim-tube apparatus was used to measure the produced fluids displacement properties within the transition zone. The slim-tube was modified such that sampling is more refined (small pore volume samples of 0.04) for better resolution in the analysis. The tests consisted of displacing Swan Hills live oil by a multicomponent hydrocarbon mixture. This study proved that the modeling of the transition zone fluid should not follow the conventional methods as seen by the modified analysis of slim-tube tests and EoS characterization.

Masalmeh (2000) presented an experimental study to evaluate residual oil saturation and relative permeability as a function of initial oil saturation. The purpose of this study was to assess the oil mobility in the transition zone. The study concluded that the oil relative permeability increases with decreasing initial oil saturation (S_{oi}). On the other hand, the residual oil saturation is independent of S_{oi} . Therefore, the study suggests that oil is more mobile in the transition zone than initially assumed.

Skauge and Surguchev (2000) compared CO_2 injection to recover paleo oil to flue and hydrocarbon gases. The study used 2D and 3D sector models to simulate down dip gas injection with vertical and horizontal wells. The results of the simulation models showed that CO_2 injection has the potential to produce paleo oil in the transition zone by vaporization and the swelling of the oil. The simulation results also showed that CO_2 is far more efficient (6-8 times higher) than flue and hydrocarbon gases even at immiscible conditions, with a potential recovery of 50% of remaining oil in place. However, these operations are characterized by high water production (60-70% water cut) before first oil is expected. This can be mitigated by injecting up dip together with the use of horizontal wells.

Yulin et al. (2000) reported on the development of the transition zone in the Daqing field in P.R. China. The field analysis indicated deeper OWC than the original OWC, resulting in a 5-25 m transition zone. The study showed that extending the test wells to target the transitional zone will encounter thick formations with high reserves. However, the oil viscosity in the transition zone is 5-30 cP (mPa·s) higher than the original oil viscosity. It was concluded that expanded development is the optimum strategy to increase the recovery in the field.

Fanchi et al. (2000) described the conventional practices to estimate transition zone recoveries and defined the procedure of their experiments to measure trapped oil relationship for water-wet

media. They used two methods to describe trapped oil relationship on reserves estimates: an extended black oil simulator and an analytical model. The study showed analytically the effect of varying residual oil saturation on the primary recovery reserves of the transition zone. It suggests that the current reservoir simulators do not include a relationship between the trapped oil and relative permeabilities, which is important in calculating the reserves. It also showed the importance of including the total reservoir volume of the transition zone when calculating primary reserves available in the transition zone.

Koperna et al. (2006) helped define the distinction between the transition zone (TZ) and residual oil zone (ROZ); and, as shown earlier, discussed four pilot projects targeting residual oil zone. Two of the projects are included in Wasson oil field, one in the Seminole San Andres unit, and one in Salt Creek. All projects confirmed the viability of CO₂-EOR to produce the TZ/ROZ resource and were conducted when oil prices were considerably lower than current prices. Different development strategies were evaluated for the fields using reservoir simulation including: selectively producing the ROZ (a. top 60%, b. full interval) and simultaneously producing the ROZ and the main pay zone (MPZ). It was found that simultaneously implementing the flood in both the ROZ and MPZ is a more viable option than separately completing either the MPZ or the ROZ. The estimated recoverable TZ/ROZ reserves, in both San Andres and Canyon Reef formations in Permian Basin, are 12 billion barrels out of the 31 billion barrels TZ/ROZ OOIP.

Melzer et al. (2006) discussed the origins of residual oil zone (ROZ) examining the different types of ROZ sources and documenting some of the TZ/ROZ EOR pilots for the first time. As for the types of ROZs, the main sources covered in the study are: basin uplift and tilting, breached seals, and lateral hydrodynamic sweep. The study defines the basin uplift and tilting as a gravity-dominated OWC adjustment. This type of ROZ can translate to significant amounts of trapped oil especially if the field has large lateral extent. The breached-seals ROZ comprises a paleo oil zone that never or only partially refilled an entrapment with oil. In the later case, the ROZ lays below oil that did not escape during a temporary breach in the reservoir seal. The containment or partial refilling of the oil entrapment is a result of a reservoir reseal after geochemical and/or biological processes reformed the seal. The most common and significant ROZ in the studied basins to date is formed as a result of altered hydrodynamic conditions. These changes will occur after an uplift and infiltration of surface waters in the regional trapping formation. The Permian Basin (San Andres Formation), the Bighorn Basin (Tensleep formation) and the Panhandle and Hugoton fields are examples of such ROZs. Different ROZ development examples were also presented in this study, all at an oil price of \$15-20/barrel at the time and still producing economically (*time of the paper*). In addition to the Seminole and Wasson Denver Unit pilot case histories, the paper also showed a sensitivity study on parameters that can affect the formation of the ROZ. Examples include aquifer flow rate, horizontal permeability and permeability anisotropy k_v/k_h .

1.4.2 Advantages and Challenges of Paleo Oil Recovery Using CO₂ Injection

Recovery from the residual oil zone (paleo oil) poses great benefits to operators mainly because it will contribute significantly in booking additional reserves. As shown by the west Texas examples, there are significant volumes of paleo oil available in that area and maybe around the world. So, this section will list the challenges as well as advantages of exploiting these resources using CO₂ as an injectant.

Advantages

- Research in this area will develop an understanding of an unconventional resource that will recover significant volumes of overlooked reserves. As a result, this will contribute directly to booking of additional reserves.
- The nature of residual oil zone (being in the water leg) can assist with mobility control to the injected CO₂ without the need for more expensive solutions, and can delay the need for water-alternating gas (WAG) operations.
- Injecting CO₂ in the residual oil zone offers a great opportunity to sequester CO₂. The solubility of CO₂ in water is very high and since the paleo oil is in the water leg zone, CO₂ has to go through the water. However, the solubility of CO₂ in oil is even higher, which will not compromise the recovery of the oil. Sequestering CO₂ in this case will be justified economically by the production of paleo oil.

Challenges

- Collecting an oil sample at reservoir conditions from the residual oil zone represents a great challenge since the oil will not flow by primary or secondary means. This challenge adds a risk factor in simulating reservoir conditions in the laboratory. Techniques to acquire residual oil samples involve additives that change the properties of the irreducible oil and lead to questions about their representative properties.
- The contact of CO₂ into the oil phase is key to commercial CO₂-EOR. If water shields significant amounts of CO₂ and prevents it from contacting the paleo oil, the economics of the process can be affected.
- Paleo oil is available only in few reservoirs and has been overlooked for years, which makes the available data and industry experience on the subject very scarce. Only researchers from the Permian Basin, west Texas, have had significant contribution to the subject.
- Paleo oil is a difficult resource and will require significant additional research efforts and resources to mobilize and recover it.

1.4.3 Summary

- Geological and hydrodynamic structural changes can cause huge amounts of oil to be stranded, creating large volumes of residual paleo oil, due to capillary and wetting force trapping along with gravitational forces. The larger the lateral extent of the reservoir, the greater the amount of stranded oil.
- There is limited publicly-available research on paleo oil in the industry and only few researchers have looked at its potential. Main efforts and most of the data on the subject come from the Permian Basin, west Texas. In that area, significant amounts of paleo oil have been mapped, developed and are being commercially produced (exclusively in San Andres formation).
- CO₂ injection has been suggested as the leading method to exploit this oil because of its highly favorable properties including its ability to swell the oil (high solubility in oil), oil viscosity reduction, low to no injectivity issues, achievable operating conditions above miscibility pressures, insensitivities to variations in formation water salinities, and high recovery potential.
- The residual oil zone (ROZ) has been regarded in the industry as the most optimum part of an oil reservoir to store CO₂ because of the size, high water saturation, and hydrocarbon availability (paleo oil). It has all three aspects of a successful geological

storage location while recovery of the paleo oil will provide the economical solution to offset the costs of the carbon capture and storage (CCS) project.

2. SUBSURFACE AND OPERATIONAL CHARACTERISTICS OF CO₂-EOR OPERATIONS

In the oil industry, recovery operations are chronologically divided into three categories: primary, secondary and tertiary (Green and Willhite, 2003). The primary production is the initial oil flow out the reservoir due to natural reservoir energy. Secondary production usually follows the primary stage once the production declines. Nowadays, it almost always corresponds to waterflooding; however, it traditionally includes operations such as waterflooding, pressure maintenance and gas injection. Tertiary recovery is the third stage of production after the waterflooding and includes miscible gas, chemicals and thermal injection operations (Green and Willhite, 2003).

Sometimes, this order could change due to different technical and economic (e.g. thermal operation in heavy reservoirs without any waterflooding). This is why the concept of “enhanced oil recovery” (EOR) has become more popular than tertiary recovery (therefore primary, secondary and EOR operations). Other terminology being commonly used in the oil industry is “improved oil recovery” (IOR) which is a broader concept and includes EOR operations as well as advanced reservoir characterization, improved reservoir management and infill drilling (Green and Willhite, 2003) which has evolved today to include the adding of horizontal wells

A commonly used but hybrid definition of enhanced oil recovery today would be when an injectant (e.g., steam, miscible gas, chemicals) is used that changes the properties of the oil to make it more mobile within the reservoir. Since water and oil do not mix, water flooding would be excluded from EOR.

The residual oil after the primary and secondary production phases consists of the remaining oil either trapped due to capillary forces in very small pores of the reservoir rock and/or bypassed by the injected or displacing fluid (e.g. during waterflooding). It would also include any oil wetting the surface of the rock. These trapped or un-swept patches of oils are the main target of any subsequent enhanced oil recovery (EOR) operations.

2.1 OBJECTIVES AND PRINCIPLES OF CO₂-EOR

2.1.1 Objectives of CO₂-EOR

Numerous scientific as well as practical reasons account for the large volume of “stranded” oil, unrecoverable with primary and secondary methods. These include: oil that is bypassed due to poor waterflood sweep efficiency; oil that is physically unconnected to a wellbore (“compartmentalized”); and, most importantly, oil that is trapped by viscous, capillary and interfacial tension forces as residual oil in the pore space (Kuuskraa and Ferguson, 2008; Shen, 2010; Luo et al., 2012). Injection of CO₂ helps lower the oil viscosity and reduce trapping forces in the reservoir. Additional well drilling and pattern realignment for the CO₂-EOR project helps contact bypassed and occluded oil. These actions enable a portion of this “stranded oil” to become mobile, connected to a wellbore and thus recoverable. (Kuuskraa and Ferguson, 2008; Shen, 2010).

Based on an intensive study of CO₂-EOR technology applied in USA, the National Energy Technology Laboratory (NETL) proposed four specific “next generation” CO₂-EOR technology options. These involve:

- 1) Increasing the volume of CO₂ injected,
- 2) Optimizing well design and placement,
- 3) Improving the mobility ratio, and

4) Extending miscibility.

In an example light-oil field with 2,365 million barrels of original oil in-place (OOIP), the use of “next generation” CO₂-EOR technology will produce an estimated 665 million barrels of additional oil in 43 years versus only 381 million barrels in 31 years under current application of “best practices” CO₂-EOR technology. Based on reservoir-by-reservoir assessment of the 1,111 large oil reservoirs in USA amenable to CO₂-EOR, the result shows that a significant volume, 87.2 billion barrels, of oil may be recoverable with the application of “next generation” CO₂-EOR technologies. This is a significantly larger volume of oil than the 67 billion barrels of oil recoverable with current “best practices” technologies (Kuuskraa and Ferguson, 2008; Kuuskraa et al., 2009, 2011).

CO₂-EOR not only produces more oil, but also offers the potential for storing significant volumes of carbon dioxide emissions for the world. Three notable benefits would accrue from integrating CO₂ storage and enhanced oil recovery (Kuuskraa and Ferguson, 2008; Kuuskraa et al., 2009, 2011):

- First, CO₂-EOR provides a large, “value added” market for sale of CO₂ emissions captured from new coal-fueled power plants;
- Second, storing CO₂ with EOR helps bypass two of today’s most serious barriers to using geological storage of CO₂ - establishing mineral (pore space) rights and assigning long-term liability for the injected CO₂;
- Third, the oil produced with injection of captured CO₂ emissions is 70% “carbon-free”, after accounting for the difference between the carbon content in the incremental oil produced by EOR and the volume of CO₂ stored in the reservoir . With “next generation” CO₂-EOR, it would also increase the amount of CO₂ stored in the oil reservoirs and the oil produced by EOR could be as high as 100+% “carbon free”;

Thus, the objectives of CO₂-EOR today are:

1. Producing the unrecoverable oil with primary technology for low permeability reservoirs which are unfavorable for water flooding;
2. Producing the unrecoverable oil with primary or secondary technologies for the reservoirs with water flooding;

to which one may add for the future:

3. Storing CO₂ for reducing CO₂ atmospheric emissions.

2.1.2 Principles of CO₂-EOR

According to Fanchi (2006), the recovery efficiency (E_R) of an EOR process is defined as the product of its volumetric sweep efficiency (E_V) and displacement efficiency (E_D):

$$E_R = E_V \cdot E_D$$

The volumetric sweep efficiency is defined as the ratio of contacted oil volume by the displacing fluid to the original oil volume in place. The displacement efficiency is the ratio of the oil displaced to the amount of oil contacted by the displacing fluid. In other words, the first term is a measure of how different EOR operations could contact the reservoir, while the second one is a measure of how different EOR operations could mobilize the trapped oil. Overall, EOR techniques increase the volumetric sweep efficiency, the displacement efficiency, or both. The volumetric sweep efficiency could be increased by reducing the mobility ratio of the displacing to displaced fluid, which strongly depends on the viscosity of the two fluids. The displacement

efficiency increases by increasing the ratio of viscous to capillary forces. The displacement efficiency can be increased by either increasing the viscosity of the displacing fluid or by lowering the interfacial tension between the two fluids, which cannot be achieved in the case of water. This is why water flooding is unable to mobilize the trapped oil. In contrast, chemical and miscible gas (solvent) flooding operations are successful in lowering the interfacial tension and improving the displacement efficiency, thus mobilizing trapped oil.

In contrast to water flooding, which increases macroscopic sweep efficiency, CO₂ flooding increases the microscopic displacement efficiency (Garcia, 2005). On the other hand, due to the large density difference and also adverse mobility ratio between the displacing (CO₂) and displaced fluid (oil), CO₂ flooding results in unfavorable displacement efficiency (e.g. channelling, gravity instability) and therefore, poor sweep efficiency. However, the adverse mobility ratio could be controlled by alternating the gas injection with a less mobile fluid such as water or foam in a process called Water-Alternating-Gas (WAG), illustrated in Figure 3. During a WAG process, the macroscopic and microscopic displacement efficiency of the water flooding and CO₂ flooding are combined together, leading to significantly higher incremental oil recovery compared to that from each of these processes separately (Garcia, 2005).

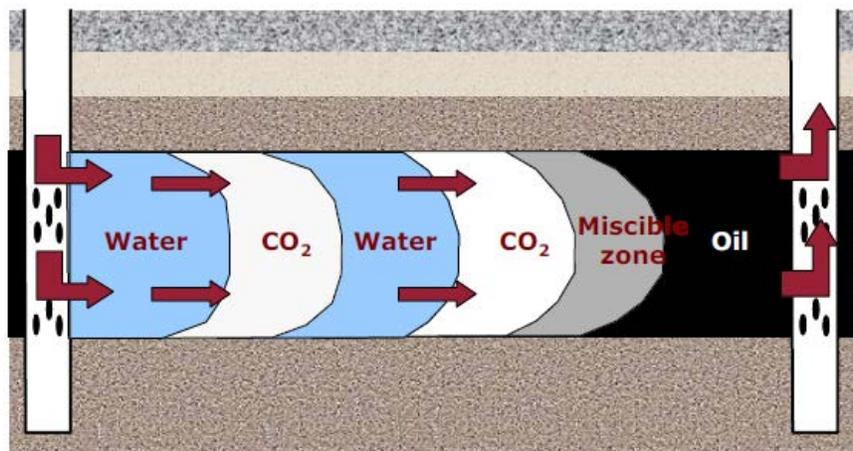


Figure 3. Water alternating gas (WAG) process for enhanced oil recovery.

There are several different factors (ranging from reservoir rock and fluid properties to operating scenarios) controlling the performance of a WAG operation such as reservoir heterogeneity, rock wettability, miscibility conditions, fluid properties, trapped gas, injection practice and also WAG parameters (slug size, WAG ratio and injection rate) (Sanchez, 1999).

An important issue in CO₂-EOR is miscibility between CO₂ and reservoir oil. In general, there are two types of miscibility between fluids: first-contact miscibility and multiple-contact miscibility. Two fluids can develop miscibility once the pressure is raised above a minimum value called minimum miscibility pressure (MMP). Once they become miscible, they form a single phase and, therefore, one could completely displace the other (Jarrell et al., 2002). The first-contact miscibility occurs if two fluids become miscible and form a single phase upon first contact in all proportions. Typical examples of this group are water-ethanol and butane-oil. Multiple-contact miscibility, on the other hand, occurs after many contacts, which are required to transfer different components of the two fluids back and forth between them to eventually become miscible, which is the case of CO₂ and crude oil (Figure 4). Multiple-contact miscibility between CO₂ and oil develops as mass transfer occurs between them (condensing/vaporizing mechanism) until the oil-enriched CO₂ and the CO₂-enriched oil become miscible and indistinguishable, with similar fluid properties (Jarrell et al., 2002).

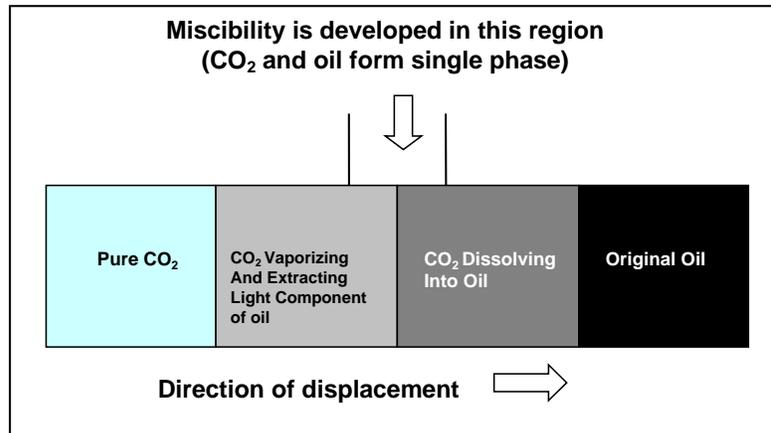


Figure 4. One-dimensional schematic showing the CO₂ miscible process (after Jarrell et al., 2002).

The advantages of using CO₂ over other gases are due to its favorable ability in the following processes (Martin and Taber, 1992a):

- 1) Swelling of the oil;
- 2) Reduction of oil viscosity;
- 3) Lower minimum miscibility pressure (MMP);
- 4) Solubility in water and reducing water density to have less gravity instability, and
- 5) Vaporizing a wider range of oil components resulting in easier miscibility development.

CO₂-EOR includes both miscible and immiscible flooding. Miscible or immiscible flooding depends on reservoir's pressure, temperature and on the properties of oil in the reservoir. The higher the pressure, the lower the temperature, and the lighter the oil, the more miscible the oil and CO₂ (Kuuskraa and Ferguson, 2008; Kuuskraa et al., 2009; Shen, 2010; Luo et al., 2012).

The primary objective of either miscible or immiscible CO₂-EOR is to mobilize the oil and dramatically reduce the residual oil saturation in the reservoir's pore space after water flooding. Miscible CO₂-EOR adds an important component involving a single or multiple-contact process that singly or progressively interacts the injected CO₂ and reservoir's oil during which the lighter oil fractions condense or vaporize into the injected CO₂ phase and facilitate CO₂ solution into the reservoir's oil phase. This leads to two reservoir fluids that become miscible, forming a single phase, when they come in contact, with favorable properties of low viscosity, enhanced mobility and low interfacial tension (Figure 4). With miscible CO₂-EOR many projects can recover 7-23% of a reservoir's OOIP (Jarrell et al., 2002; Kuuskraa and Ferguson, 2008; Kuuskraa et al., 2009; Shen, 2010; Luo et al., 2012).

Immiscible CO₂-EOR occurs when insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier). When oil is heavier or the reservoir's pressure is not sufficiently high and reservoir's temperature is higher, the oil and CO₂ could not form a single phase and the fluids are immiscible. This leads to limited volumetric CO₂ contact within the reservoir (spreading of the sweep front) because the viscosity of the drive fluid is that of unmixed CO₂ instead of the miscible CO₂/oil fluid. The main mechanisms involved in immiscible CO₂ flooding are: (1) oil phase swelling, as the oil becomes saturated with CO₂; (2) viscosity and interfacial tension reduction of the swollen oil. Some extraction of lighter hydrocarbons (up to C6) into the CO₂ phase can occur as miscibility pressure is approached. The fluid drive plus

pressure is present in all types of CO₂ flooding. This combination of mechanisms enables a volumetric portion (sweep volume) of the reservoir's remaining oil to be mobilized and produced. When implemented in a pattern flood configuration, immiscible CO₂-EOR contacts smaller volumes than miscible CO₂-EOR; field data show that with immiscible CO₂-EOR generally recovers only less than 5% of a reservoir's OOIP (Martin and Taber, 1992b; Jarrell et al., 2002; Kuuskraa and Ferguson, 2008; Kuuskraa et al., 2009; Shen, 2010; Luo et al., 2012). However, when deployed in a vertical/gravity assisted configuration, immiscible floods can be very efficient and easily exceed the recovery factors mentioned above.

2.2 SCIENCE OF CO₂ INTERACTION WITH RESERVOIR OIL

Because of its special properties, CO₂ as a supercritical fluid is extensively used in different industrial processes. Depending on pressure and temperature, CO₂ is in solid, liquid, gaseous or supercritical state. Figure 5 shows the phase diagram of CO₂ at different pressure and temperature. When temperature is 31.1 °C and pressure is 7.38 MPa (about 71.5 atm) CO₂ gas and liquid are coexist; this point is called the critical point. For higher pressures and temperatures the vaporization boundary between liquid and gaseous phases disappears and CO₂ is in supercritical state. Supercritical CO₂ has lower viscosity than liquid CO₂ and higher density than gaseous CO₂. In most cases, CO₂ is in supercritical state for miscible CO₂-EOR (Shen, 2010; Luo et al; 2012).

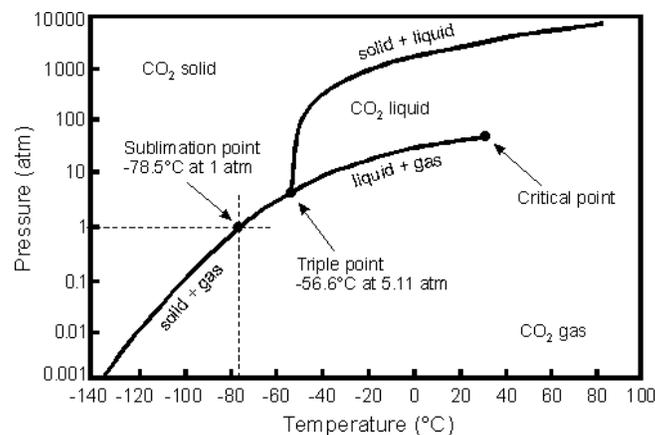


Figure 5: Pressure -Temperature phase diagram for CO₂.

Under atmospheric pressure and room temperature the solubility of CO₂ in oil is very low. As pressure increases the solubility of CO₂ in oil increases, and increases more rapidly when CO₂ is near the critical point or in supercritical state. Consequently, the oil swells and the oil viscosity decreases significantly. Due to the decrease in viscosity, the oil has more favorable flow properties in the reservoir and is more easily pumped out. The swelling of oil by dissolving of CO₂ under higher pressure is the most important factor for CO₂-EOR. In general, when temperature remains constant and as pressure increases, the volume of oil and CO₂ (gas or liquid) decreases, respectively. However, as CO₂ dissolves in oil, the volume of oil increases, and, for the same conditions, the lighter the oil is, the larger is the oil volume increase.

The study of Yang et al. (2012 a,b; 2013 a,b) shows that CO₂ disperses in oil (organic liquid) at near critical and under supercritical conditions of CO₂. Not only CO₂ molecules and oil molecules form individual molecule aggregates, respectively, but CO₂ and oil (alkanes) form CO₂-oil molecule aggregates. Because the distance (space) between CO₂ molecule aggregates, oil molecule aggregates or CO₂-oil molecule aggregates at near critical and supercritical condition of CO₂ is larger than that between CO₂ molecules or oil molecules as liquids,

respectively, the volume of oil increases significantly as CO₂ disperses (dissolves) in oil. The micro-dispersion state of CO₂ and oil molecules depends mainly on the intermolecular forces that operate within the CO₂ molecules, oil molecules, and between CO₂ and oil molecules, molecular structure of oil (organic liquids), pressure and temperature.

Intermolecular Forces between CO₂ and Oil. There are three forces that affect the solubility of CO₂ in the oil and the oil volume expansion: (1) Pressure force, which squeezes CO₂ molecule into oil phase; (2) Intermolecular (attractive) force between CO₂ molecules and oil molecules, which drags the CO₂ molecule into the oil phase; and (3) Intermolecular force operating between oil molecules, which prevents CO₂ molecules to get into the oil phase and squeezes CO₂ molecules out of the oil phase. The CO₂ and hydrocarbon molecules are nonpolar. Therefore, the main intermolecular force operating within the oil molecules, the CO₂ molecules, and between the oil and CO₂ molecules is the London force (London dispersion force or dispersion force) (Kidahl, 2011; Hiemenz and Rajagopalan, 1997).

Dispersion forces depend on two features of the molecular structure. First, they increase in magnitude with the size and distortability (usually called the polarizability) of the electron clouds of the interacting particles. Size and polarizability increase as molecular weight increases. It follows that dispersion forces increase as the molar mass increases. For substances of large atomic or molecular mass, dispersion forces are strong enough that the substances are solid or liquid at room temperature. Second, the larger the surface area of molecule contact, the stronger the dispersion forces is. Molecules that are roughly spherical in shape are able to contact each other only minimally. In contrast, molecules that are planar or linear in shape can maintain a large surface area of contact, with correspondingly larger dispersion forces (Kidahl, 2011).

Effect of Pressure. When the temperature is at standard conditions, because the distance between CO₂ (gas) molecules is large at atmospheric pressure, the London force between CO₂ molecules is weak, and the London force between CO₂ and oil molecules is very weak as well. Even though the intermolecular force operating between oil (liquid) molecules and CO₂ molecules is of the same type, the strength of the London force operating between oil molecules is sufficiently strong such that it is difficult for CO₂ molecules to get into oil phase. Therefore, the solubility of CO₂ in the oils is very low and, as a result, the volume of the oil does not increase. With increasing pressure at constant temperature, the distance between CO₂ molecules is reduced dramatically and, as a result, the potential energy and the strength of the London force operating between CO₂ molecules increase more rapidly than that operating between oil molecules, such that the two forces become close in magnitude. Consequently, the solubility of CO₂ in oil increases and the volume of the oil increases as well. In fact, pressure plays a dominant role in squeezing CO₂ molecules into the oil phase. As a result of the CO₂ molecules being squeezed into the oil phase, the distance between oil molecules increases, such that the London force operating between oil molecules, which normally tends to squeeze CO₂ molecules out of the oil phase and prevent CO₂ molecules to get into the oil phase, is reduced. Meanwhile, the London force between CO₂ molecules and oil molecules, which tends to drag CO₂ molecule into oil phase, also increases. The increase in the London forces between CO₂ molecules and between the CO₂ and oil molecules, and the decrease in the London force between the oil molecules results in increasing CO₂ solubility in oil, with a corresponding increase in the volume of the CO₂-oil system. When the pressure is close to the CO₂ critical pressure (7.38 MPa) or above it, the volume increase of the CO₂-oil system is greater than the solubility of CO₂ in the oil (Yang et al., 2012 a,b).

Effect of Temperature. For constant pressure, the solubility of CO₂ in oil decreases with increasing temperature for all CO₂-oil systems, with a corresponding decrease in volume. As temperature increases, the distance between CO₂ molecules, oil molecules, and CO₂ and oil molecules increases. As a result, the intermolecular forces become weaker, in some cases dramatically (Yang et al., 2012 a,b). As temperature increases, the molecules' Brownian motion is enhanced to the point that CO₂ molecules get off the drag of oil molecules by London force, such that CO₂ molecules escape from the oil phase. Therefore, the solubility of CO₂ in the oil and the volume of oil decrease with increasing temperature.

Effect of Oil Molecular Structure. Besides the effects of pressure, temperature and intermolecular forces, the molecular structure of the oil (alkanes) has an important effect on oil volume.

The length of CO₂ molecule is about 0.33 nm (Cao and Zhang, 1986), while the length of the hexane molecule is 1.03 nm, which is about 3 times longer than that of the CO₂ molecule. Due to the linear shape of hexane, octane and decane molecules, they are able to contact each other along the entirety of their length. Therefore, for the longer molecule, the molecules have a larger surface area of contact, with correspondingly larger dispersion force. Consequently, under the same conditions of pressure and temperature, the solubility of CO₂ in the alkane and the volume of the alkane decrease as the length of the alkane molecule increases. This phenomenon indicates that the longer the alkane molecule, the London force between the alkane molecules is stronger, and it is more difficult to squeeze the CO₂ molecules into the alkane phase.

The cyclohexane molecule has a shape of a chair or boat. The cyclohexane molecules have a large surface area of contact and larger dispersion force than the hexane molecules. Therefore, for the same pressure and temperature, the solubility of CO₂ in cyclohexane and the volume of cyclohexane are less than that of hexane (Yang et al., 2012 a,b).

It should be noted that the London force is also affected by the polarizability of the molecule. For the alkane with a shorter alkyl chain, the molecular length is shorter and the polarizability is weaker, so the London force is smaller and the distance between the alkane molecules is bigger. Therefore, it is easier for CO₂ molecules to be squeezed into the alkane with a shorter alkyl chain, and the solubility of CO₂ in alkane increases as the alkyl chain length of the alkane decreases.

In summary, pressure, temperature, intermolecular forces and oil molecular structure play an important role in squeezing CO₂ molecules into the oil phase, affecting the solubility of CO₂ in oil and the oil volume expansion. It explains why CO₂ dissolves preferentially in the light oil fractions than in the heavy fractions, why CO₂ is more miscible with lighter oil, and why CO₂ miscibility with oil increases with increasing pressure, decreasing temperature and increasing oil ° API (light oils have a high ° API and heavy oils have a low ° API).

2.3 SUITABILITY OF OIL RESERVOIRS FOR CO₂-EOR

In 2012 there were 119 CO₂ miscible and 16 immiscible active EOR projects in the world (Koottungal, 2012 in the Oil & Gas Journal biennial EOR survey), of which the great majority are in the United States (112 miscible and 8 immiscible, with the oldest one in operation since 1972). According to OGJ (2012), the US total production in 2011 in CO₂-EOR operations was 308,564 b/d in miscible floods and 43,657 b/d in immiscible ones, accounting for more oil production than by any other enhanced oil recovery method. Other countries where CO₂-EOR

operations are active are Canada (three commercial and three pilot miscible EOR), Brazil (one miscible and 2 immiscible operations), Trinidad (five immiscible operations) and Turkey (one immiscible operation). It is worth noting that Apache Canada operates an acid gas enhanced oil recovery operation in the Zama oil field in northwestern Alberta, Canada, where acid gas with a composition of 70% CO₂ and 30% H₂S is used for enhanced oil recovery (Trivedi et al., 2007). A CO₂-EOR project has been operating in Hungary for a long time, but it is not mentioned in the latest review of CO₂-EOR operations in the world (it could be that it is not active at this time). A pilot project has been run in Abu Dhabi, and pilot projects are run in the Jilin and Shengli oil fields in China, and another project has recently started in Croatia.

Reservoir lithologies in these CO₂-EOR operations include both carbonate and sandstone. Table 1 presents the main characteristics of the miscible CO₂-EOR operations by reservoir lithology, and Table 2 presents the main characteristics of the immiscible CO₂-EOR operations, of which only two are in carbonate reservoirs and the remainder of 15 are in sandstone reservoirs (from Koottungal, 2012).

Table 1: Characteristics of miscible CO₂-EOR operations by reservoir lithology³ (from Koottungal, 2012).

Reservoir Parameter	Sandstone (52 reservoirs)	Carbonate (67 reservoirs)
Depth (ft)	1150 to 11,950	3000 to 11,100
Temperature (°F)	82 to 250	86 to 232
Porosity (%)	7 to 30	3 to 20
Permeability (mD)	2 to 2000	1 to 170
Oil Gravity (°API)	35 to 45	28 to 44
Oil Viscosity (cP)	0.4 to 3	0.4 to 6
Oil Saturation at Start (%)	29 to 64	30 to 89

Table 2: Characteristics of immiscible CO₂-EOR operations (from Koottungal, 2012).

Reservoir Parameter	Range of Values
Depth (ft)	1150 to 8,500
Temperature (°F)	82 to 198
Porosity (%)	17 to 30
Permeability (mD)	30 to 1000
Oil Gravity (°API)	11 to 40
Oil Viscosity (cP)	0.6 to 592
Oil Saturation at Start (%)	30 to 86

In three cases of miscible CO₂-EOR there was no prior production from the reservoir (actually these are cases of CO₂-EOR from the residual oil zone, see below), in 20 cases CO₂ injection started immediately after primary production, in five cases CO₂ injection started after primary production and hydrocarbon gas injection, and in all other cases CO₂ injection started after primary production and water flooding. In the case of immiscible CO₂-EOR, in seven cases CO₂ injection started after primary production, in one case CO₂ injection started after primary production and gas injection, and in all other cases CO₂ injection started after primary production and water flooding (from Koottungal, 2012). The remaining oil in the reservoir at the

³ Values are provided in imperial units, as per the original publications. For this and similar other tables, conversion factors are: m = 0.3048 ft; kPa = 0.145 psi; °C = (°F - 32) × 5/9; mPa·s = cP; oil density (kg/m³) = 1000 × 141.5/(131.5 + °API).

start of CO₂ enhanced recovery averages 47%, although in a few reservoirs it reaches values higher than 80%.

It can be seen from Tables 1 and 2 that, based on publicly-available data, there are no significant differences between the characteristics of sandstone and carbonate oil reservoirs suitable for miscible CO₂-EOR, the main difference being in oil gravity (hence viscosity). The average oil gravity for miscible CO₂-EOR operations is 36.3° API, compared with an average of 27.8° API for immiscible CO₂-EOR operations. Unfortunately, no information is available in the public domain about critical data such as initial reservoir pressure, reservoir pressure at the start of CO₂ injection, oil composition; and minimum miscibility pressure (MMP), as well as about reservoir anisotropy (ratio of vertical to horizontal permeability) and heterogeneity, which both affect sweep efficiency.

Not all oil reservoirs are suitable for miscible CO₂-EOR, thus screening criteria must be applied for the identification and selection of oil reservoirs for CO₂ flooding because most CO₂-EOR operations are based on the miscibility between oil and CO₂ and their phase behaviour. Based on the experience with CO₂-EOR in the United States, a series of authors have published between 1973 and 1997 various criteria for the identification of oil reservoirs technically suitable for CO₂-EOR, reviewed in Shaw and Bachu (2002), but CO₂-EOR is still an immature technology and these criteria are out of date by now. These criteria referred to reservoir depth, temperature, permeability, initial pressure, oil gravity and viscosity, and remaining oil fraction (same as in Tables 1 and 2 except for two publications were a minimum initial reservoir pressure of 1100 and 1500 psia is advised). To these criteria one should add that reservoir pressure at the beginning of CO₂-EOR operation should be above the minimum miscibility pressure (MMP), i.e., the pressure at which CO₂ and oil become miscible. On the other hand, the injection pressure should be less than the lesser of capillary displacement pressure in the caprock, P_{cd} , (to avoid CO₂ penetration in the caprock), minimum stress, S_{min} , (to avoid opening of existing fractures) or fracturing pressure of the caprock, P_f (to avoid fracturing the seal). Based on the previous review, oil reservoirs suitable for CO₂ flooding should meet the following criteria listed in Table 3.

It is important to note that the great majority of enhanced recovery operations, including CO₂-EOR, are based on a horizontal sweep of the reservoir. In these configurations, carbon dioxide injection can present a significant challenge because of the density and viscosity contrast between reservoir oil and CO₂ even at high injection pressures of supercritical CO₂ in low-viscosity light oils. As a result, CO₂ has the tendency to rise to the top of the reservoir (due to buoyancy) and also to flow through high permeability “channels” and reach quickly the producing well (due to the much lower viscosity than the oil). In these cases large banks of oil are not reached by the CO₂, leading to a poor oil sweep efficiency. This challenge is more pronounced in thick reservoirs with no vertical baffles to keep CO₂ from segregating at the top of the reservoir. However, in the case of oil reservoirs in carbonate pinnacle reefs, a vertical sweep is preferable and more efficient than a horizontal sweep. A gravity-stable flow is established by injecting CO₂ at the top of the reservoir, which pushes the oil bank vertically down through the reef (Trivedi et al., 2007).

Table 3: Characteristics of oil reservoirs suitable for CO₂-EOR (metric values are given in brackets).

Reservoir Parameter	Miscible CO ₂ -EOR
Depth (ft/m)	≥1150 (≥350)
Temperature (°F/°C)	82 to 250 (28 to 121)
Pressure	> MMP and < min (P_{cd} , S_{min} , P_f)
Porosity (%)	≥3, preferably >10

Permeability (mD)	≥ 1 , preferably > 10
Oil Gravity ($^{\circ}$API)	> 11 and ≤ 40 for immiscible floods, and > 27 and ≤ 45 for miscible floods
Oil Viscosity (cP/mPa·s)	< 10 for miscible floods and < 600 for immiscible floods
Remaining Oil Fraction in the Reservoir (%)	≥ 30 and preferably < 50

Núñez-López et al. (2008) have developed a screening methodology, based on the same principles, for screening of oil reservoirs suitable for CO₂-EOR starting from reservoir size as the first screening criterion and consider only reservoirs with a cumulative production greater than 1 million standard barrels (MMstb), thus eliminating small reservoirs from consideration. However, instead of cumulative oil production, a more suitable criterion indicative of reservoir size would be the recoverable oil in place (ROIP), which is given by the product of the recovery factor (R_f) and original oil in place (OOIP).

In addition Núñez-López et al. (2008) consider only reservoirs that have already been water flooded (secondary recovery) or that have a strong water-drive mechanism because only these reservoirs would be at the stage in their production life where CO₂-EOR would be suitable (i.e., most of the mobile oil would have been produced and the remaining oil is residual oil that cannot be produced without EOR, in addition to pressure being most likely above the minimum miscibility pressure, MMP). Previous water flooding is not applied as a screening criterion for large, deep reservoirs where vaporizing gas-drive miscibility can be achieved and where CO₂-EOR can be applied directly after primary production. Finally, Núñez-López et al. (2008) apply a geological ranking based on structural regime, structural style, stratigraphic heterogeneity and depositional system, where complexity is categorized as high, intermediate and low.

2.4 OPERATIONAL CHARACTERISTICS OF CO₂-EOR OPERATIONS

Once a proper screening process identifies CO₂-EOR as the most suitable method for recovery enhancement for a given oilfield, its operational dimensioning and management strategies come into focus. Basically, the adoption of CO₂-EOR methods gives rise to three main practical concerns as described by Jarrell et al. (2002):

- The definition of volumes to be injected and how fast to inject them into the reservoir.
- The management of well artificial lifting methods and flow assurance problems that may be strengthened in the presence of CO₂.
- Facilities management.

When continuous injection is adopted, one must basically decide for the optimal rates in which CO₂ will be injected considering its availability, well injectivity and recovery ratio achieved. Although adopted in some cases, continuous injection is not commonly used. Most CO₂-EOR operations are otherwise performed through alternating gas and water (WAG). As so, operational parameters must be set in order to achieve the best from the method. Masoner et al. (2003) describe a strategy of using field data with the aim of optimizing important WAG project parameters in the Rangely Weber Sand Unit, Colorado, USA.

The first operational decision in WAG management is the setting of the so called half-cycle slug size. This parameter corresponds to the volumes of CO₂ (or water), expressed in terms of reservoir volumes, that must be injected before switching to the alternate fluid. The half-cycle slug size is directly related to the controlling of gas and water production after these fluids break through at producer wells, which impact predictability and could imply problems for artificial lifting (e.g., pumping or gas lifting) and flow assurance (scale, asphaltene or paraffin deposition).

Combined with the half-cycle slug size is the WAG ratio, the ratio between water and CO₂ volumes injected in a cycle. These two parameters define the reservoir volumes of water and CO₂ injected in a complete cycle. As a reservoir manager, one must bear in mind that WAG ratios should be adjusted during the life of the project. The optimal volumes and ratios injected at the beginning of the process may not be sufficient to recover oil with the same efficiency in later stages. Once a project area reaches a level of maturity, it is expected that the ratio of barrels of oil recovered for unit volume of CO₂ injected diminishes over time.

As the field ages, another important operational concern is the processing of gas and water produced. Facilities offer a maximum processing capacity that almost always restrict the desired CO₂ injection rates when gas or water recycling start.

The well injectivity determines how fast the volumes can be injected into the reservoir hence defining the calendar time needed for a cycle to be complete. Therefore, well injectivity monitoring and management must be performed. Depending on near wellbore effects, the reservoir three-phase relative permeability characteristics, pressure build-up, scaling, and other factors, well injectivity may emerge as a problem for achieving the injection volumes needed. Hence, the adequate number of injectors, an appropriate completion scheme and methods of initial and continued stimulation must be taken into consideration when defining a WAG project.

Setting the operational bottomhole pressures must be guided by miscibility considerations and a number of geomechanical limits. When it is not suitable to fracture the reservoir, under the risk of connecting injectors and producers directly, and then creating preferential paths inside the reservoir, reservoir parting pressure would be the most important constraint. Alternatively, caprock integrity must be respected and fault reactivation should be strongly avoided in order to prevent environmental damages.

Another well management decision is the artificial lifting method for producer wells. This decision can have an important impact over the ultimate recovery factor of the project (Yang et al., 1999). This must be optimized based on the rates and fluids produced. Issues like operational costs also must be taken into account when deciding which artificial lifting method to use. Pumps, either rod or submersible, are adequate for wells with moderate-to-high liquid productivity and low gas/liquid ratio (GLR), while gas-lifting requires low water-cut in general. In the context of WAG processes, liquid and gas production can change significantly. Hence, a policy of altering artificial lifting method of production well must be considered as necessary in order to optimize production and maximizing enhanced oil recovery.

In turn, flow assurance demands particular attention in field undergoing CO₂-EOR projects (Jarrell et al, 2002). In the presence of CO₂, higher flow rates are generally witnessed and problems like paraffin deposits, asphaltenes and scale are reported to increase. Thus, studies on the interaction between CO₂ and formation rock and fluids must be conducted previously with the objective of dimensioning of future chemical treatment and/or the programming of well workover operations.

Corrosion is also a serious problem in wells that produce both water and CO₂, as well as in injection wells in the Water Alternating Gas (WAG) process. It can be the cause of important economic drawbacks during the lifetime of a field (Kermani and Morshed, 2003). Adequate tubing metallurgy (or the use of lined pipe) must be used for well completion, and inhibition treatments are most generally adopted for producing well operations. If water is not used in injection wells, then no special metallurgy and lined pipe is need in the injection wells.

Facilities management refer to the monitoring and optimisation of operational parameters as well as managing the plant integrity. As in the case of well tubing, due to the formation of carbonic acid, corrosion monitoring and mitigation is an important part of a facility management

routine. The use of proper inhibition treatment can make corrosion to drop significantly in CO₂-EOR projects.

Where water is not present as in the case of CO₂ supply pipelines, conventional carbon steel is preferred and widely used.

2.5 MATERIALS CORROSION IN CO₂-EOR OPERATIONS

As already mentioned in section 2.2.2, CO₂ is well known as a corrosive agent in the oil industry when dissolved in an electrolyte, typically water naturally present in the formation, due to flooding, or condensation. Dissolved CO₂ might cause corrosion due to the formation of carbonic acid (H₂CO₃), which can cause corrosion in producing wells, valves, pipelines, tanks and other facilities.

The corrosion speed and severity depends mainly on the water chemistry. Frequently, the dominant factor is the CO₂ partial pressure (Eckert, 2012) and the damage might be generalized or localized. Carbon steel, a very common material in the oil industry, is associated to several specific CO₂ corrosion damages, including pitting, mesa attack and flow-assisted damage.

CO₂ pitting is usually associated with low speed flows; corrosion increases with temperature and CO₂ partial pressure. Mesa damage appears at low to medium flow speeds, when corrosion products, like iron carbonates, which provide protection against corrosion, are gradually removed. Under high speed and turbulent flow conditions, CO₂ produces both pitting and mesa areas; the damage under these conditions is the result of the continuous removal of the corrosion products and the increasing presence of corrosion species (flow-assisted damage).

CO₂ corrosion in the oil industry facilities. Along with H₂S, CO₂ corrosion is one of the most common corrosion mechanisms of the carbon steels used in the oil and gas production and process systems (ISO 21457: 2010). Temperature, partial pressure, pH, organic acids content, and flow conditions are the most important parameters governing the corrosion process. Historically, corrosion accounts for up to 33% of the failures in the oil industry, and 28% are related to CO₂. (Kermani and Harr, 1995). CO₂ also impacts the performance of process equipment, as well as it affects the metallurgy and the corrosion rate of existing facilities. In process plants, the separation unit is made of carbon steel with an inner layer of corrosion resistant alloy (CRA) such as duplex and Ni-based alloys described in the American Petroleum Institute specifications (API, 2009), suited to resist high concentration of CO₂. However, the process accumulates corrosive species, which demand replacement of the usual carbon steel pipes for rigid CRA pipelines in accordance to API requirements (API, 1998). For most CO₂-EOR projects, this implies high cost investment to replace existing pipelines with CRA materials. (Saadawi et al; 2011)

Internal corrosion in injection systems. The most relevant corrosion mechanisms associated to injected gas, formation water, or aquifer water are similar to those described for hydrocarbon transportation systems, thus, evaluation of the corrosion speed is mandatory. There are several models available to predict CO₂ corrosion in carbon steel. (ISO 21457:2010)

Corrosion in production and process systems for crude oil and gas. To process wet hydrocarbons, it is necessary to evaluate, as a base case option to select materials including for pipelines, the response to corrosion of the carbon steel. This evaluation might include successful experiences during operation, or might be based on the corrosion annual rate calculated considering corrosion control and mitigation measures against the design life time corrosion accepted tolerance.

Corrosion in process systems for wet/condensed gas. Processing wet/condensed gas often causes very high corrosion to carbon steel due to the low pH of condensed water. Besides, corrosion inhibition is not practical in these systems, therefore carbon steel with higher tolerance or CRA materials are sometimes adequate. In hydrocarbon systems with condensed water, CO₂ corrosion is diminished with inhibitors based on chemicals to increase the pH.

Corrosion in process systems for dry gas/crude/condensate. Processing dry gas/crude/condensate usually is possible with using carbon steel without internal corrosion control requirements, although greater wall thickness is considered, especially if periods of wet gas processing are expected at any stage of the construction, tests, or operation stages.

Acid gas injection. Some operators have found more economical to reinject the acid gases (CO₂ and H₂S) removed from the production line, than processing them. The gases are compressed and reinjected either into the producing reservoirs or into separate formations. During the compression virtually all the water is removed.

Supercritical CO₂. As mentioned in Section 2.2, supercritical CO₂ has been compressed above 7.4 MPa and its temperature is higher than 31.1°C. Due to its special properties, between liquid and gas, lines are used to transport it (capture and storage), and in EOR. If high purity CO₂ is used in these applications, the probability of internal corrosion is very low; however if water vapor has not been removed prior to the compression, it might condense and increase the possibility of internal corrosion in the pipelines. The recommended water content after CO₂ purification, drying and compression should be 24 ppm, as reported for the Kingsnorth Carbon Capture & Storage Project in the UK⁴. A common standard of 20-30 lbs per mmcf has been adopted in the U.S.

Corrosion management. When the selected corrosion resistant alloys cannot be justified, measures should be considered to ensure corrosion control of the carbon steel materials during the expected service lifetime of the facilities. A corrosion management strategy should be developed considering all the equipment, not only the carbon steel components. The strategic management procedure documents recommended by E.ON UK plc for CCS projects must include the following: 1) CMM, Corrosion Management Manual; 2) MRP, Maintenance Reference Plan; and 3) RBI, Risk-Based Inspection². Field tested plastic- and/or polymer-lined pipe is widely used in CO₂ applications in the United States and Canada.

2.6 MONITORING AND SURVEILLANCE IN CO₂-EOR OPERATIONS

An important, if not the most important, objective of monitoring and surveillance of CO₂-EOR operations has been to acquire data on how CO₂ injection impacts oil production and affects the reservoir. The focus has been on the injected and produced fluids and on the reservoir, particularly pressure, and less attention was paid to other aspects except well integrity. Monitoring results affect decisions related to flood management but are designed to have limited interference with the commercial operation. This and costs influence the design of the surveillance/monitoring program. Monitoring CO₂-EOR operations usually cease when production stops.

More specifically, the objectives of monitoring CO₂-EOR operations include:

⁴ E.ON UK plc, Report No. KCP-GNS-PLD-REP-0009: Materials Selection and Integrity Protection Report for Offshore Infrastructure, Kingsnorth Carbon Capture & Storage Demonstration Project.

- Maintenance of working pressures in the reservoir above the minimum miscibility pressure and below the parting pressure. Monitoring of the fluid mass injected and mass produced are the key inputs. The terms associated with this process are most commonly referred to as pattern balancing and material balance. Observation of the dynamic response of the reservoir to CO₂ flooding, e.g. pressure changes, is part of this objective.
- Tracking the spatial distribution of CO₂ in the reservoir and assessing the interaction with other reservoir fluids, including evaluation the reservoir sweep efficiency and identification of regions of bypassed oil by the CO₂ slug.
- Ensuring that the CO₂ does not impact the integrity of any well that penetrates the CO₂ EOR pattern;
- Ensuring that CO₂ remains within the project area reservoir, e.g., does not migrate or leak into other reservoirs or, drinking groundwater or to the surface.

Below follow brief descriptions of some commonly used monitoring methods for CO₂-EOR operations.

Production and Pressure Data. Fundamental production data, such as injected and produced volumes of gas, oil and water (sometimes even injection and production rates), and reservoir pressure, recorded on a well by well basis, allow monitoring the individual reservoir flow units response to CO₂ injection and oil production, and allow tracking of CO₂ flow at least between injection and production wells. These data then can be used in history-matching modelling (matching of injection/production and/or pressure) to infer the movement of CO₂ in the reservoir over time and can be used to calibrate other monitoring methods. After a period of time since the start of CO₂ injection one will commonly see an increase in oil production and a decrease in water production successively in wells as the distance from the CO₂ injection well increases. Usually CO₂ is injected in patterns of one injection well in the centre and several production wells surrounding it.

Geochemical Analysis of Produced Fluids. The injected CO₂ will have a different isotopic composition than the reservoir carbon and fluids, which allows tracking it by chemical analysis of the produced fluids. The method may be supplemented by use of artificial tracers to trace the CO₂ movement through the reservoir. The approach requires a baseline against which to compare the monitoring results.

Sonic Properties. The sonic velocity contrast of CO₂ rich oil or water with unaffected formation fluids is significant. For that reason, seismic techniques have become more commonplace to track areas of CO₂ contact. Sleipner, Weyburn, Postle and Vacuum fields are noted examples of 4-D seismic surveys which have been reported in the literature (refs)

Downhole Monitoring. A common method used to evaluate geological formations, including oil reservoirs, and monitor subsurface processes, is the use of well logs. These acquired by lowering instruments into the injection wells and obtaining vertical profiles of one or more properties along the well. This approach is valuable for exploration, for CO₂-EOR and other operations, as well as for general CO₂-storage operations. It is also possible to install fixed sensors in the well bore that will sample at fixed time intervals or continuously transmit data to the surface. Monitored parameters can include temperature, pressure, radioactive tracers, CO₂ saturation, resistivity and casing integrity.

2.7 REGULATORY REQUIREMENTS FOR CO₂-EOR OPERATIONS

CO₂-EOR operations are typically regulated through permitting agencies associated with hydrocarbons and/or minerals extraction. For example, in the United States and Canada basic oil and gas laws are the regulating authority, while oil and gas or mining codes could apply in EU member states. These laws are typically based on historical development of oil and gas activities and are focused on the impact that oil or gas production has, rather than CO₂ storage. The storage of CO₂ is usually viewed as incidental during a CO₂-EOR operation and, although the degree of CO₂ retention in the reservoir is always of interest, it is not typically directly measured or verified.

CO₂-EOR operations are most prevalent in North America, with some of the most significant projects being the Weyburn-Midale project located in Canada which measured and monitored the CO₂ used for EOR injection, and activities in the Permian Basin located in the United States, which accounts for over half of the oil produced by CO₂-EOR. Because of the extensive history of CO₂-EOR in the United States, the following paragraphs provide an overview of the regulatory requirements related to CO₂-EOR operations there. However, this does not imply that the regulations in other countries are any more or less developed or strict than those in the United States.

In the United States, CO₂ injection is regulated under the Safe Drinking Water Act (SDWA). The act, which was passed in 1974, seeks to protect sources of drinking water from pollutants. SDWA sets up the Underground Injection Control (UIC) program at the US Environmental Protection Agency (EPA), which specifically covers the injection of materials into the subsurface and aims to protect those sources of drinking water which are underground. The UIC program evolved from the regulatory expertise developed at the state level, specifically at the Texas Railroad Commission, and has evolved over the years to establish six classes of wells which regulate various types of injections. Class II wells cover injections related to oil and gas activity, including CO₂-EOR. Also, if a state's existing or newly promulgated rules are at least as stringent as the rules established by EPA, the state may have primary enforcement authority, or primacy. This allows a state agency to issue permits for the program. Currently 39 states have Class II primacy.

Class II well regulations provide for both construction and operations requirements.⁵ The construction requirements cover the cementing and well casing.⁶ The construction requirements also call for the logging of wells and other relevant testing as needed during drilling and construction. Operating requirements limit the injection pressure such that new fractures in the confining zone are not initiated by the injection. The operator is required to monitor the nature of the injected fluids and observe the injection pressure, flow rate and cumulative volume. Additionally, mechanical integrity testing must occur every five years over the life of the well. Prior to the permitting of the site, the operator must provide the permitting authority with information about the subsurface, the injectate, the construction materials and procedure, and the planned operational review.

In addition to the injection requirements established, monitoring and quantification of injected CO₂ is covered by the Clean Air Act. EPA has been delegated the authority to track and

⁵Information about the EPA Class II program can be found at:

<http://water.epa.gov/type/groundwater/uic/class2/index.cfm>

⁶The specific text of the regulation covering the injection of CO₂ can be found at:

<http://water.epa.gov/type/groundwater/uic/regulations.cfm>

quantify the creation and movement of CO₂ through the US economy. EPA has promulgated regulation in several subparts that cover every sector in the US economy. CO₂ injection is covered by two subparts, RR and UU.

EPA created a tiered approach for EOR facilities. Conventional, business as usual EOR facilities can continue to operate as-is. Subpart UU covers these facilities and only requires that operators report the quantity of CO₂ delivered to the site.⁷ CO₂ EOR operators that want to “opt-in” and count as geologic sequestration will have additional monitoring requirements. Subpart RR requires a report of the CO₂ received, injected, emitted from the subsurface, and emitted from surface equipment.⁸ In addition to the emissions, quantification of the quantity of CO₂ in the produced gas, the quantity remaining in the oil and gas, and finally the total quantity sequestered. In addition to these quantification requirements, an operator will need to develop a plan outlining the area to be monitored, an identification of leakage pathways, a strategy for developing a baseline of soil flux, and a leak detection and quantification plan, as well as a post-closure plan that can require a monitoring time frame of up to 50 years.

Unlike in the United States, in Canada, injection of fluids in the subsurface is under provincial, not federal jurisdiction. For example, in Alberta the Alberta Energy Regulator regulates the oil and gas industry, including CO₂-EOR, acid gas disposal and CO₂ storage. Wells for injection of CO₂, acid gas (CO₂ and H₂S) and other gases are classified as Class III wells, with corresponding cementing and casing requirements, logging requirements and other tests, including an area of review of 1.6 km (one mile) in radius) and a well head pressure limited to 90% of the formation fracture pressure⁹. Additional requirements have to be met at the time of applying for the permit to inject and during the operation, including reporting of the wellhead injection rate, fluid composition, temperature and pressure, and of volumes of produced fluids (oil, gas, water, CO₂) in the case of CO₂-EOR¹⁰.

⁷ Information about Subpart UU can be found at: <http://www.epa.gov/ghgreporting/reporters/subpart/uu.html>

⁸ Information about Subpart RR can be found at: <http://www.epa.gov/ghgreporting/reporters/subpart/rr.html>

⁹ AER Directive 51: Injection and Disposal Wells.

¹⁰ AER Directive 65: Resources Applications for Conventional Oil and Gas Reservoirs.

3. SUBSURFACE AND OPERATIONAL CHARACTERISTICS OF CO₂ STORAGE OPERATIONS IN OIL RESERVOIRS

Carbon dioxide capture and storage is a technologically complex process that has three major components: industrial capture of CO₂ from large stationary sources; transportation, most likely by pipeline but also by ship at some point in the future, and storage in geological media at depths where, for efficacy of storage, CO₂ is in a dense-fluid phase (supercritical) (IPCC, 2005). It should be noted that monitoring, verification and accounting (MVA) are key elements in site operation, closure and post-closure (IOGCC, 2005, 2008). The security of CO₂ storage is a common thread throughout all the stages of the storage chain, and it has to be demonstrated when applying for tenure of the storage unit and permit to operate, during operations, and after cessation of operations and site abandonment (site closure) (CSA, 2012). In addition to being safe and secure, CO₂ storage sites have to be economic, environmentally acceptable, and generally acceptable to the public.

In a CO₂ storage project, the primary objective is to store as much CO₂ as possible in the respective geological medium for extremely long periods of time (centuries to millennia; IPCC, 2005). Carbon dioxide storage in uneconomic coal beds and potentially in organic-rich shales is based on CO₂ adsorption onto the coal/shale surface, but, as understood today, storage in these media has relatively small potential and also poses issues of resource sterilization (IPCC, 2005; Field et al., 2012). In contrast, CO₂ storage in hydrocarbon reservoirs and deep saline aquifers is based on storage in available pore space by compressing the fluids present in the pores and/or displacing them. In the case of CO₂ storage in depleted hydrocarbon reservoirs, storage space has already been created by producing oil and/or gas from the reservoir. In the case of CO₂ storage in deep saline aquifers, storage space is created by compression as a result of pressure increase and by displacement of the saline water, which could be managed (engineered) to maximise the storage capacity for CO₂. A particular case of CO₂ storage in hydrocarbon reservoirs is CO₂ utilization in enhanced oil recovery (CO₂-EOR) where, just as a result of the process, 40% to 50% on average of the total volume of injected CO₂ is trapped in the reservoir (Hadlow, 1992) when the objective is to maximize oil production and minimize CO₂ loss in the reservoir given the ‘scarcity’ and cost of CO₂. Note that the total volume includes the recycled volumes; when only the purchased, or “new” CO₂ is considered, the storage efficiency is greater than 90-95% (see, e.g., Hill et al., 2012). The CO₂ produced with oil is separated and recirculated in the reservoir, such that the demand for new CO₂ decreases in time unless expansion of the CO₂-EOR operation is undertaken. The amount of CO₂ stored in CO₂-EOR operations could increase if the objective would become optimization of oil production and CO₂ storage, but this requires an economic value for stored CO₂. Another motivation to increase the amount of stored CO₂ in depleted oil reservoirs is to provide incentive (e.g., carbon credit) to operators. This would encourage them to capitalize on existing infrastructure before abandonment and continue injecting CO₂ for storage after oil production had stopped.

3.1 CO₂ STORAGE SITE SELECTION

Various criteria have been developed in the last decade for the screening and selection of CO₂ storage sites (e.g., Bachu, 2010). These criteria can be grouped into the following broad categories:

- 1) Capacity and injectivity;
- 2) Confinement, including avoidance or minimization of risks to other resources, equity and life, as well as of the potential return of CO₂ to the atmosphere;
- 3) Legal and regulatory restrictions, including access;

- 4) Economic, including costs, infrastructure, financing, etc.,
- 5) Societal attitudes.

Site screening and selection criteria in the last three categories will not be discussed here as they are a matter of policy, regulatory framework and economics. The criteria in the first two categories are technical matters and will be addressed accordingly. Although capacity and injectivity were listed as separate criteria for site selection in the past, more recent work indicates that they are not completely independent of each other, at least not during the active period of injection. Because of the link between the two, they are hence considered as a single criterion. Injectivity and/or capacity can be increased by increasing the number of injection wells, or by controlling reservoir pressure. A storage site, in this case an oil reservoir, meets the containment requirement if the injected CO₂ does not migrate or leak out of the reservoir. Also, the first criterion (injectivity and capacity) applies to the active period of CO₂ injection, which is in the order of decades, while the second one applies to a much longer period. Failure to properly assess site capacity and/or injectivity can and will be identified during the operational (injection) period, and, in the case that either of these is lacking, measures can often be taken immediately, such as increasing well injectivity, drilling additional CO₂ injection or water production wells, or moving to another site if there is insufficient capacity. However, it should be pointed out that the significant investments for CO₂ capture and transport are predicated on the storage capacity being available, and insufficient capacity or even perceived capacity risks will negatively affect the capture decision or economics of the operation. Meeting the second criterion (site security and safety) must be demonstrated prior to injection, based on site knowledge and predictions of the fate and effects of the injected CO₂. Lack of confinement, with corresponding CO₂ migration and/or leakage out of the storage reservoir, may occur much later (years to centuries) after cessation of injection, particularly if this may occur through a well that will degrade in time, in which case different remedial measures have to be taken that no longer affect the selection and operation of the site. Many other detailed site selection criteria derive from these two, related to reservoir petrophysics and heterogeneity, pressure, temperature, etc., but all these criteria can be subsumed into the broad requirements of capacity, injectivity and confinement. Some conditions, particularly in the last three categories, may change in time, but the first two usually do not change, although sometimes they can be engineered to fit.

3.1.1 Site Screening Criteria

The following are screening criteria on which basis a prospective CO₂ storage site would be disqualified.

- 1) Located at shallow depth. Generally a depth of minimum 800 m has been considered as desirable or even necessary for CO₂ storage to maximize storage efficacy (amount of CO₂ stored per unit of pore volume). The congruence of this and other criteria such as groundwater protection, and the general acceptance of this threshold depth, makes this generally an eliminatory criterion. However, shallow hydrocarbon reservoirs may be the exception to this criterion since they have demonstrated confinement of buoyant fluids and there is no groundwater or other resource to be protected in the reservoir itself. Their contribution to large scale storage may be small, or significant, depending on the size of existing shallow gas reservoirs.
- 2) Lacking at least one major, extensive, competent barrier to upward CO₂ migration. This obviously relates to the requirement of security and safety of storage, i.e., containment within the primary storage unit. A highly fractured region, with fractures reaching to the surface will also fall into this category. This criterion normally would not apply to oil reservoirs since, if they would have been fractured to the surface, the oil would have leaked out.

- 3) Located in an area of very high natural or induced seismicity. This relates to the security and safety of storage.
- 4) Located in over-pressured strata. The risks of leakage and/or losing control of the well are higher in highly over-pressured strata (approaching lithostatic pressure with a pressure gradient of 21-23 kPa/m) than in slightly overpressured (pressure gradients up to 14 kPa/m), normally-pressured and sub-hydrostatic aquifers and/or reservoirs.
- 5) Lacking monitoring potential. Regulatory requirements for site permitting, operation and abandonment will include monitoring of the fate and effects of the injected CO₂, hence sites where monitoring may not be possible will most likely not be approved, and, therefore, should be avoided. This may be the case where geophysical monitoring will not be able to elucidate and track the CO₂ plume because the aquifer or reservoir is below seismic resolution (too thin) or has such low porosity that the replacement of oil or brine with dense-phase CO₂ is not discernible in band-limited seismic data, or it is located below thick salt beds that blur the seismic signal. It may also be the case that wells are not available for monitoring, particularly in marine environments, or that there is no surface access for geophysical surveys to be conducted at all, or where monitoring will be difficult due to high population density or protected natural environment (e.g., Sørensen et al., 2009). It is emphasized here that lacking monitoring potential refers to the absence of any kind of monitoring ability. If one monitoring technique in particular is not available or applicable (e.g., seismic), other techniques should be available and the site would qualify for storage. Only in the total absence of **any** monitoring possibility a site would disqualify.

3.1.2 Site Selection Criteria

While the previous criteria were of an eliminatory nature, the following criteria are of a selection nature in the sense that these are favourable characteristics that would make any particular site preferable to another, all other considerations being equal. Failure to meet a particular criterion will not eliminate a site from consideration; it will only reduce its “suitability” or “desirability”.

- 1) Sufficient capacity and injectivity. It is important to note that the contribution of mineral trapping is negligible during the active period of CO₂ injection, particularly in the case of oil reservoirs, and should not be considered in storage capacity estimations. It is very important to assess both the “static” storage capacity based on ultimately-available pore volume and the “dynamic” storage capacity, i.e., the storage capacity that can be achieved during the active lifetime of the project by injecting CO₂ at rates and pressures that meet safety and regulatory requirements. This refers to maintaining maximum bottom hole injection pressure (BHIP) at injection wells, and/or reservoir pressure below one of, or some combination of, the following:
 - a. Initial reservoir pressure,
 - b. Fracture and/or fault opening or reactivation (shearing) pressure (for pre-existing fractures and faults) in the reservoir,
 - c. A fraction of the fracturing threshold in the caprock (usually established by regulation),
 - d. Caprock displacement pressure and rate (pressure and rate at which the injected CO₂ intrudes into the caprock system).
- 2) Sufficient thickness. Thick reservoirs are preferable to thin ones not just because of assumed higher storage capacity, but also because they allow various injection strategies. On the other hand, thin or interbedded oil reservoirs are preferable because

of better sweep efficiency. Vertical sweep is preferable for steeply dipping or reef-type oil reservoirs.

- 3) Sufficient porosity. While many recommend porosity of at least 10% for CCS projects, the North American experience with CO₂-EOR, acid gas disposal and natural gas storage suggests that, depending on the size of the project and other factors, porosity can be as low as 3%.
- 4) Adequate permeability. European studies recommend permeability to be at least 200-300 mD. However, the experience in North America indicates that, depending on the required injection rate, permeability in the order of 10-20 mD is also sufficient. Many reservoirs have been successfully flooded with permeabilities below 10 md but many wells are required.
- 5) Low temperature (as defined by low geothermal gradients and/or low surface temperatures). This increases storage efficacy at an equivalent depth (reservoir pressure) by ensuring higher CO₂ density, yielding higher storage capacity for the same pore volume. It also increases storage security by decreasing the density difference between CO₂ and brine or oil, hence decreasing the buoyancy force that would drive the CO₂ upwards. Since increasing depth of a reservoir target means both higher working pressures and higher temperatures, it should be noted that temperature and pressure work in opposite directions on CO₂ density so that both should be considered in concert.
- 6) Hydrodynamic regime. In the case of oil reservoirs supported by an underlying aquifer, water invasion may have a negative effect in the case of CO₂ storage by reducing the storage capacity if regulatory agencies limit the pressure increase in the reservoir to the initial reservoir pressure (Bachu et al., 2004), although otherwise aquifer support has a positive effect in the case of CO₂-EOR operations by helping maintain pressure. The negative effect of water invasion may be addressed by either allowing pressure in the reservoir to increase beyond the initial reservoir pressure, as is the case of CO₂ storage in deep saline aquifers, thus pushing the invading water back, or by producing water from the water leg of the oil reservoir, as proposed for CO₂ storage engineering.
- 7) Low number (density) of wells penetrating the area of influence. The presence of wells increases the potential and risk of leakage. Although studies in Alberta, Canada, and The Netherlands, have shown that various well characteristics, including time of drilling and/or abandonment, affect the potential of wells to leak, generally the larger the number of wells is, the higher is the potential for leakage. The presence of wells constitutes a conundrum for the following reasons. A larger number of wells leads to a better characterization of the storage unit, increases confidence and certainty, and increases the potential for monitoring through fluid sampling, pressure monitoring and/or well-based seismic methods (e.g., microseismic surveys or 3D vertical seismic profiles). On the other hand, as stated, the potential for leakage increases with an increasing number of wells. In the case of oil reservoirs, particularly after they underwent improved oil recovery (IOR) through water flooding and infill drilling, the number of penetrating wells may be quite significant. Remediating a leaky wellbore is a well known technology, while containing flow from an unrecognized, leaky seal or fault is not.
- 8) Presence of a multi-layered overlying system of aquifers/reservoirs and aquitards/caprock. This increases the safety and security of storage (secondary containment in case of leakage), and is particularly important in the case of sites with a significant number of well penetrations.

- 9) Potential for attenuation of leaked CO₂ near and at surface (in shallow groundwater, soil and in the air for onshore operations, or in the sea and air for offshore operations). Sites with characteristics more favourable for CO₂ attenuation and dispersion near and at the ground or sea surface as a result of topographic, climatic and/or vegetation conditions should be preferred to sites where CO₂ will have a tendency to stagnate and accumulate.

It could be seen that criteria 1 to 6 refer to the efficacy of storage (capacity and injectivity) and criteria 5 to 9 refer to the safety and security of storage (criteria 5 and 6 belong in both efficacy and safety categories).

Storage of CO₂ in EOR operations represents a special case that requires additional or different selection criteria. Once an oil reservoir has been identified as suitable for CO₂-EOR, only storage security and economic criteria would apply in the decision to pursue CO₂-EOR, hence storing CO₂. All other criteria are either not applicable or are satisfied automatically.

Generally, there are both advantages and disadvantages of storing CO₂ in enhanced oil recovery operations (Hovorka, 2010):

Advantages:

- a) Reservoir properties are very well known and characterized, leading to more reliable and robust prediction of the long-term fate of the CO₂;
- b) Pressure and fluid flow throughout the reservoir could be controlled by production;
- c) Likely better trapping of CO₂ within the reservoir as more CO₂ is dissolved in both unswept oil and water rather than remaining as a separate phase;
- d) Oil reservoirs have demonstrated trapping and sealing of buoyant fluids in structural and stratigraphic traps.

Disadvantages:

- e) In some reservoirs, CO₂ can migrate laterally and/or vertically and could be produced from surrounding non-project wells and may not be recycled; and
- f) CO₂ may leak out of the reservoir through or along numerous drilled wells, and even if the leakage rate may be low, over a long time the amount of leaked CO₂ could be significant unless detected in time and remediated. The same issue applies also in the case of CO₂ storage in deep saline aquifers, with the main difference being the much higher density and number of wells drilled into and oil reservoir compared to a deep saline aquifer,

Currently CO₂-EOR operations are selected and permitted under a different set of regulations than CO₂ storage operations; however, for a CO₂-EOR operation to be converted into a CO₂ storage operation it will have to meet the criteria for CO₂ storage.

3.2 MONITORING AND SURVEILLANCE FOR CO₂ STORAGE

Monitoring will be a key factor to verify that CO₂ injection and storage projects perform as expected. It is also important to ensure that long-term containment is achieved. More specifically, the reasons to implement monitoring programmes include (e.g., IPCC, 2005):

- Ensuring health and safety. After injection and storage of CO₂ it must be ensured that health and the environment are not jeopardised;
- Demonstration that the geological seal has integrity and is intact;
- Verification of the stored CO₂ (mass balance). The intended CO₂ storage project must meet existing regulatory requirements, permitting and legislation, and must demonstrate storage

for receiving carbon credits.

- Improvement of the understanding of the behavior, migration and future state of the injected CO₂ within the storage unit.
- Verification and updating of models to achieve more correct predictions.
- Development of techniques and methodologies regarding monitoring subsurface storage of CO₂ and possibly of other gases.

There are several factors that distinguish monitoring and surveillance for CO₂ storage from that for the incidental storage that occurs with CO₂-EOR operations:

- The much longer time frame for CO₂ storage; perhaps for several decades after cessation of injection;
- The significantly larger area that needs monitoring for CO₂ storage (follows at least partly from the time frame);
- The absence of production fluids that can be sampled, and of injection and production wells that can be used for monitoring; however dedicated monitoring wells that will allow monitoring will likely be left in place;
- Differing legal requirements for CO₂ storage; e.g., storage rights vs. mineral rights;
- Stronger political and public attention on CO₂ storage, e.g., waste disposal vs. resource recovery with incidental storage.

Public opposition and that of some environmental non-governmental organizations which oppose the continued use of fossil fuels can be a hurdle for large scale injection and storage of CO₂ with either CO₂ EOR or saline storage. Successful demonstration of monitoring technologies may be a key to convincing the public and other third party stakeholders that geological storage of CO₂ can be done safely and predictably in qualified sites, thus enabling broad, global implementation of the technology.

Monitoring technologies

Many of the measurement technologies for monitoring geologic storage are drawn from applications in the oil and gas industry, including reservoir surveillance for waterflood and EOR projects, natural gas storage, reinjection of produced water and oil-based drilling mud as well as disposal of acid gases and liquid and hazardous waste in deep geologic formations. Other applications from which monitoring CO₂ storage sites can learn include groundwater monitoring, and ecosystem research. Some technologies, such as reservoir modeling, mass balancing and seismic imaging, have reached a highly sophisticated level due to many decades of research, development, and application in the petroleum industry.

In addition to the above, several reports, papers and guidelines written specifically for CO₂ storage describe a range of traditional monitoring technologies and approaches that may be used for CO₂ storage sites, amongst others CO2STORE (2006), CCP (2009), Chadwick et al. (2009), NETL (2009, 2012) and Myer (2011). Particularly the NETL (2009, 2012) Best Practice Manuals are comprehensive, with benefits and challenges for a range of technologies. The IEA GreenHouse Gas R&D Programme has designed a Monitoring Selection Tool that contains a full description, including illustrations and indications of suitability, of 40 monitoring techniques¹¹. Some of the above references, e.g. CO2STORE (2006), CCP (2009), NETL (2009) as well as DNV (2011), outline how to plan a monitoring programme for CCS sites. Table 4 lists some commonly applied and potential monitoring approaches, grouped into four categories:

¹¹ <http://www.ieaghg.org/index.php?/Monitoring-Selection-Tool.html>

Table 4: Some monitoring approaches for CO₂ storage site.

Application	Examples of Instrumentation	Readiness Level* (after NETL, 2012)
Plume pathways monitoring	<ul style="list-style-type: none"> • 3 or 4 D seismic, including in which the source and recording instrumentation are at the surface; vertical seismic profiling, in which the source is at the surface but the recording instruments are in wells; and cross well seismic in which both the source and recording instruments are in wells • Gravity methods, surface and well based, that use the difference in density between CO₂ and water as a means of detection • Electrical and electromagnetic methods that use the difference in electrical conductivity between CO₂ and water, which is generally assumed to be saline for the purposes of CO₂ storage. • Tiltmeters • Pressure and water quality above storage formation 	<p>Generally at commercial or demonstration stage.</p> <p>Controlled-source electromagnetic (CSEM) surveys is at development stage</p>
Near-surface, surface and atmospheric monitoring	<ul style="list-style-type: none"> • Water samples extracted from vadose zone, near-surface or shallow groundwater formations and analysed for CO₂ (pH), and/or CO₂-water-rock reaction products and/or for tracers. • Sensors placed at ground surface in the vicinity of the well to measure CO₂ concentrations in the air. • Soil gas surveys • Atmospheric CO₂ concentrations • Eddy covariance sensors • Flux accumulation chambers • Optical sensors • Sea water sampling • High resolution acoustic sampling • Multibeam echosounding 	<p>Generally at commercial or demonstration stage.</p> <p>New solutions, such as multi-tube remote samplers, wind-vane samplers and portable isotopic carbon analyzers, fiber optic sensors for soil-CO₂, are under development</p>
Air- and satellite-borne monitoring	<ul style="list-style-type: none"> • InSAR • Hyperspectral • Gravimetry 	<p>Generally at demonstration stage.</p>

*The following categories are used for readiness:

- Development: first step in the development of novel tools for effective CO₂ release detection and monitoring.
- Demonstration: technologies deployed at a limited number of commercial-scale operations; technologies used in the oil and gas industry with limited applications in CCS; validated prototypes used in multiple stand-alone demonstration projects.
- Technologies in the commercial stage of development, have been systematically tested and utilized in multiple commercial-scale injection sites across a wide variety of geological settings and site conditions.

Wellbore Integrity Monitoring. Wellbores that intersect the EOR/storage formation could provide pathways for CO₂ migration. Petroleum industry experience suggests that leakage from the injection well itself is one of the most significant risks for injection projects (IPCC, 2005). Some approaches for monitoring for wellbore leakage are listed in Table 4. It should be noted that some have proposed that, for many sites, there may be a need to develop advanced Data Integration and Analysis systems, e.g. combining GPS, InSAR data with seismic and geochemical data, integrating seismic techniques with other geophysical tools (e.g., electromagnetic, gravity) and to develop continuous and autonomous monitoring of CO₂ storage by pressure monitoring (NETL, 2012). Wellbore monitoring methods should be tailored to the risk profile of both the well construction methods and for the particular sites where employed.

Plume Pathways Monitoring. The second major category, plume pathways and potential leak paths, refers to subsurface geological features, of which reactivation of transmissive fractures and faults are considered to represent the greatest risks, but changes in caprock lithology should not be disregarded. Examples of approaches to mapping the movement of CO₂ in the subsurface, which can also detect leakage out of the storage reservoir through fractures and faults, are listed in Table 4.

Subsurface monitoring of CO₂ migration in the subsurface includes geophysical methods that have been developed over many years in the oil industry. In particular, geophysical time-lapse or 4D techniques, whereby repeated datasets are acquired over a period of time, have proved a powerful means of identifying and mapping subsurface changes, such as fluid movement. Such methods include seismic, gravity measurements and electrical/electromagnetic methods. Because of the evolution of seismic technology and the contrast of sonic properties of CO₂ vs. oil and water, seismic methods are generally considered able to provide higher resolution data about the presence of CO₂ in the subsurface between wells than any other technique. However, these methods cannot detect the presence of CO₂ dissolved in reservoir fluids (oil and/or water), in thin plumes, or in thin strata of low porosity. Each method has a specific detection threshold.

Gravity and electrical methods create lower-resolution images of the subsurface, and are less widely tested for CO₂ applications, but should provide additional information on movement of the CO₂ plume. Gravity methods use the difference in density between CO₂ and water as a means of detection, whereas electrical methods use the difference in electrical conductivity between CO₂ and water, which is generally assumed to be saline for the purposes of CO₂ storage. Gravity and electromagnetic methods have seen limited field applications. They have been explored in simulation studies, e.g. Gasperikova and Chen (2009), and likely have application at certain sites.

The technologies for plume pathway detection in deep geological structures can be applied both onshore and offshore, albeit with different logistic and cost implications.

Near-surface, Surface and Atmospheric Monitoring. The third group of monitoring technologies involves near-surface, surface and atmospheric monitoring. For onshore applications, a wide range of established techniques for the detection and measurement of CO₂ and other gases in spring and well waters and in the soil are available for monitoring potential migration and leakage pathways.

Surface-flux monitoring can directly detect and measure leakage. Direct measurement techniques include covariance towers, flux accumulation chambers, and instruments such as a field-portable, high-resolution infrared (IR) gas analyzer. Year-round monitoring is needed to

distinguish leakage from the highly variable natural biological CO₂ fluxes caused by microbial respiration and photosynthesis at the surface.

Technologies for the direct measurement of CO₂ leakage offshore are very much in their infancy (Chadwick et al., 2009) and presently the options seem fewer. Seabed sampling systems are under development, and acoustic methods have been employed to detect possible bubbles from leaks through the sea bed (Eiken et al., 2010).

Air- and Satellite-borne Monitoring. The fourth group includes Synthetic Aperture Radar (SAR) Interferometry (InSAR), which is a technique that uses the phase differences contained in multi-temporal satellite-borne SAR datasets and in effect converts these to distances. The change in distances over time can be used to detect and monitor relative motion on the Earth's surface. There are several versions of InSAR. The technology has been used with success to monitor the pressure build-up effects (pressure propagation) at In Salah (e.g., Wright et al., 2010). There may be some challenges in applying InSAR technology to regions subjected to soil freezing and thawing, muskeg areas, or in areas of dense vegetation, but these challenges can be overcome.

There are at least two approaches to detect CO₂ surface leakages from air and space using spectral methods:

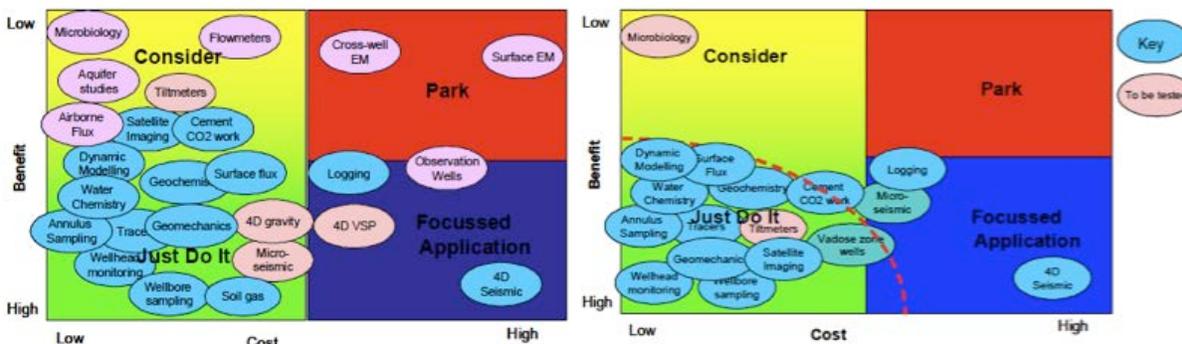
1. Indirect detection of CO₂ via its effects on vegetation
2. Directly sensing the CO₂ gas via its absorption effects in certain spectral bands

Both of these methods are in their infancy and more research and development is needed before they can be applied operationally.

InSAR and spectral methods are not applicable offshore. This triggered a feasibility study on the use of air- and satellite-borne gravimetry (Eide, 2012). The results were negative for satellite gravimetry, but it may be feasible to use air-borne gravity measurements given a low flight height and relatively large plume.

Adapting monitoring methods

Much has been learned over the many years of oil and gas reservoir management. Continuing experience there is being achieved through “learning by doing” and will increase the applicability and value of several monitoring techniques. Figure 6, from Wright et al. (2010), shows how an operator evaluated different monitoring technologies before and after initial testing. During



evaluation, some were found to be ineffective at the sampled site and others showed promise, see the left Boston Square in Figure 6. After initial testing, the cost-effectiveness of the remaining technologies was re-evaluated and the technologies moved around the Boston Square until the current view is shown on the right-hand chart. The red line indicates a conversation that should take place between a developer and regulator around monitoring technologies that may be necessary to satisfy regulatory requirements in a cost-effective manner.

Figure 6: In Salah CO₂: Storage monitoring options – before (left) and after (right) evaluation (from Wright et al., 2010)

Many of the same monitoring technologies and methods can be used for CO₂ storage and CO₂-EOR operations. In general monitoring CO₂-EOR operations will employ fewer approaches than CO₂ storage, due to less stringent requirements, shorter time-frame, smaller area and possible interference with the operations for CO₂-EOR. In both cases one will want to keep costs manageable and under control. Thus, the technologies and methods described for incidental storage during CO₂-EOR in Section 2.6 will be a sub-set of those for pure CO₂ storage projects, although monitoring approaches that require wells may be less common in pure CO₂ storage than in CO₂-EOR operations.

3.3 REGULATORY REQUIREMENTS FOR PURE CO₂ STORAGE

Many countries throughout the world, as well as international bodies, have either enacted or proposed regulatory requirements, or are developing standards or guidelines, for pure CO₂ storage. The regulatory requirements for CO₂ storage operations are similar to those for CO₂-EOR operations, but typically are more stringent, given the emphasis on long-term storage of CO₂. For example, CO₂ storage operations typically require more detailed plans the selection of storage sites, for testing and monitoring of the injection wells, for monitoring of the CO₂ plume and pressure build-up; for post injection site care and closure, and for emergency and remedial response.

These requirements can typically be described by the phase of the project: permitting, construction, operation, closure, and post closure periods¹². They also typically include requirements for financial liability and reporting, and record keeping that may be required

¹² The text of the final regulation can be found at: <http://www.gpo.gov/fdsys/pkg/FR-2010-12-10/pdf/2010-29954.pdf>

throughout multiple phases of a project. Also, the context of the development of regulations is also an important consideration. For example, in the United States, regulatory requirements for EOR operations and CO₂ storage were developed under the Underground Injection Control (UIC) program that protects underground sources of drinking water (USDWs) (EPA). Unlike wells for CO₂ injection in CO₂-EOR operations, which are classified as Class II wells, wells intended for CO₂ injection in CO₂ storage operations are classified as Class VI wells¹³. The requirements for Class VI wells are more stringent than those for Class II wells.

Permitting. In the United States, during the permitting stage, the operator must provide the regulatory authority with extensive geological, geochemical, geophysical, and hydrogeological characterization and modeling of the site to ensure it is adequately characterized and that storage wells are appropriately sited. Operators must determine, often through some form of modeling, the Area of Review (AoR), defined as the region that may be endangered by injection operations. The operator must also demonstrate control of the necessary subsurface rights within the AoR. The owner or operator of the CCS project must typically also provide several plans related to injection operations. For example, an emergency and remedial response plan may be required that describes actions the owner or operator must take to address movement of the injection or formation fluids or any adverse impacts. Also, plans related to testing and monitoring, injection well plugging, and post-injection site care and closure may also be required.

Construction. Requirements for the construction and operation of the wells for CO₂ storage, such as casings and cement, should have sufficient structural strength and be designed for the life of the storage projects. Well materials should be compatible with the materials that may be expected to come into contact. During construction, some regulations may require that the wells have surface casing through the deepest drinking water source and long string casing from the surface to the injection zone (EPA). In the United States, some of the standards that are considered applicable for well construction are those developed by the American Petroleum Institute and ASTM International.

During drilling and well construction, various data collection and monitoring is typically required to ensure the well is properly constructed. In some cases, this may be more involved than what is typically required for an EOR operation.

Operation. During injection operations, the operator needs to monitor the movement of the plume, groundwater, and pressure, as well as the integrity of the operation (e.g., wellbores). Rigorous testing and monitoring of well integrity typically includes the following: a mechanical integrity test of the injection well; recording devices to monitor injection pressure, rate, volume or mass and temperature of the CO₂ stream; and corrosion monitoring. Monitoring of the location of the injected CO₂ can utilize direct and indirect methods, and the frequency and spatial distribution for any surface monitoring must be decided by using baseline data.

Periodic re-evaluation of the AoR around the injection well to incorporate monitoring and operational data and verify that the CO₂ is moving as predicted within the subsurface may also be required during operations. The purpose is to ensure the operation is going according to plan and if not, to take the necessary corrective action. Finally, alarms and shutoff systems to check for fluid movement into unintended zones may also be required.

¹³ General information about the EPA Class VI program, including guidance documents on the implementation of various provisions of the regulation can be found at:
<http://water.epa.gov/type/groundwater/uic/class6/gsregulations.cfm>

Post-injection Site Care. Extended post-injection monitoring and site care is required to track the location of the injected CO₂ and monitor subsurface pressures until it can be demonstrated that there is no longer any danger. After plugging of the well, post-injection site care can range from 20 years (UNFCC CDM-Durban) to 50 years (US EPA), but in some cases, these timeframes can be raised or lowered if the owner or operator can demonstrate there is no endangerment to the environment or public.

Financial Responsibility. Operators must have approved financial instruments to cover all obligations typically starting with the injection phase and covering all the way through the post injection site care period. Typically, financial obligations are necessary to cover injection well plugging, post-injection site care and closure, and emergency and remedial response and corrective actions. There are multiple instruments that can be used to cover financial responsibility, such as self-insurance by the owner or operator via a financial test or corporate guarantee, or third-party instruments such as insurance, trust fund, surety bond, or escrow account.

Reporting and Record Keeping. Reporting requirements and record keeping are critical components to ensure safe CO₂ storage operations. In most cases, regular or frequent reporting is necessary. For example, in the United States, the EPA Class VI wells require semi-annual reports; reports within 24 hours if there is an event that triggers a shut-off system, non-compliance with a permit condition, or failure to maintain mechanical integrity; and 30-day advanced notice of any planned well workovers or stimulation activities. Data typically needs to be retained for the life of the project and for 10 years following site closure.

In addition, in some cases, operators may also be required to report the quantities of CO₂ received, injected, emitted from the subsurface and from surface equipment.¹⁴ From these values the operator must report the quantity sequestered in the formation. In addition to these quantification requirements, an operator will need to develop a plan outlining the area to be monitored, an identification of leakage pathways, a strategy for developing a baseline of soil flux, and a leak detection and quantification plan.

Regulations for Transitioning from CO₂-EOR to Pure CO₂ Storage. Currently, the only example of regulations or guidelines for transitioning from a CO₂-EOR project to a pure CO₂ storage project is in the United States. Under the regulations, EOR operators may “opt-in” to the regulations for CO₂ storage, or the appropriate regulatory authority can make this decision based on increased risk to USDWs. For those projects that do transition from CO₂-EOR to pure CO₂ storage, the permitting authority can authorize EOR wells for a pure storage operation and will use risk-based criteria to understand if conversion is appropriate and/or necessary.

Other International Examples of the Status of Regulations for CO₂ Storage. As mentioned in Section 2.7, injection of fluids in the subsurface in Canada is under provincial jurisdiction. Alberta has over 23 years of operational and regulatory experience in the injection of CO₂-containing acid gases (CO₂ and hydrogen sulfide [H₂S]) which are produced and separated from natural gas¹⁵. The quantities of CO₂ and H₂S injected via acid gas disposal in to the subsurface

¹⁴ Information about Subpart RR can be found here: <http://www.epa.gov/ghgreporting/reporters/subpart/rr.html>

¹⁵ IEAGHG, 2003. Acid gas injection – A study of existing operations. Phase I: Final report, Report Number PH4/18, Available at:

are considerably lower than the quantity of CO₂ injected for EOR in the US and Canada for CO₂-EOR, but nevertheless provide a useful reference for saline aquifer CO₂ storage. Acid-gas disposal is overseen by provincial regulators in Alberta and British Columbia. The permitting process requires detailed information on surface facilities, injection well layout and design, characteristics of the injection reservoir or aquifer and injection operations. These applications are evaluated to ensure maximum hydrocarbon conservation, minimal environmental impact, and the safety of the public. A set of licensed operating parameters is established by regulators and verified at biannual intervals. Because H₂S is considerably more toxic than CO₂, regulations framed for acid gas disposal should be more stringent than those for CCS. However, current regulations for acid gas disposal require less comprehensive storage accounting and monitoring compared to those for CCS, and do not require any monitoring after cessation of injection and site abandonment. Recently, Alberta passed legislation under which the Crown (province) owns the pore space and for lease of the pore space for the purpose of CO₂ storage¹⁶, and is reviewing its regulatory framework for CO₂ storage, which will cover the closure period after permanent cessation of injection.

The European Union (EU) Storage Directive¹⁷ on CCS removes CO₂ storage from waste legislation, requires captured CO₂ to be stored permanently, establishes a regulatory regime for long-term liability and stewardship, and provides pipeline access and capacity expansion rules to ensure growth in CO₂¹⁸. The EU directive covers elements such as site selection, permitting, CO₂ stream composition, monitoring, reporting, corrective measures, closure, and post-closure obligations, transfer of responsibility, and financial security. The EU directive permits CO₂-EOR to be combined with CCS, but requires storage to occur. It likely does not accept recycle and re-use of CO₂ required for EOR operations¹⁸.

CCS was formally included in the Clean Development Mechanism (CDM) under the Kyoto Protocol in December 2011. Currently, CCS under CDM is restricted to capture, transport and storage of CO₂ within the boundaries of a nation. CO₂ EOR/EGR was not included in CDM at that point¹⁹.

Due to the global nature of both CCS and CO₂-EOR, there is a need for standards detailing the requirements and recommendations for the safe, long-term containment of geologically stored CO₂. International standards are also needed to verify CO₂ storage, containment, and ensure additionality for carbon offset and trading schemes such as the CDM. The Canadian Standards Association (CSA) Group and the International Performance Assessment Centre for Geologic Storage of Carbon Dioxide (IPAC-CO₂) recently developed a US-Canada bi-national standard (CSA Z741) with a primary focus on CO₂ storage in saline aquifers and depleted hydrocarbon reservoirs²⁰. CSA Z741 could also be applicable to CO₂-EOR project sites. The CSA Z741

http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/CarbonSequestration/Documents/IEA_Acid_Gas_Apr03.pdf

¹⁶ Alberta Regulation 68/2011, Mines and Minerals Act, Carbon Sequestration Tenure Regulation.

¹⁷ EU, 2009. 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. Available at: <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0031:EN:NOT>

¹⁸ Havercroft, I., Marston, P., 2012. Bridging the gap: An analysis and comparison of legal and regulatory frameworks for CO₂-EOR and CO₂-CCS. Available at:

http://www.iea.org/media/workshops/2012/ccs4thregulatory/Ian_Havercroft2.pdf

¹⁹ Carbon Capture Journal, 2012. CCS included under CDM at COP17. Available at:

<http://www.carboncapturejournal.com/displaynews.php?NewsID=903>

²⁰ http://www.gwpc.org/sites/default/files/event-sessions/04Leering_Michael.pdf

consensus standard is intended to meet the needs of multiple interests, to provide accredited third-party oversight, and to complement existing regulations for geologic storage of CO₂. The scope of CSA Z741 standard covers site screening, selection, site characterization, design and development, CO₂ injection operations, monitoring, verification, risk management, site closure, and long-term stewardship. The International Standards Organization (ISO) is also developing an international standard for CCS (ISO/TC 265) based on CSA Z741.

4. DUAL CO₂-EOR AND CCS, AND TRANSITIONING CO₂-EOR TO CCS

4.1 CO₂ STORAGE INTEGRITY IN OIL RESERVOIRS

Oil and gas reservoirs are generally considered as appropriate candidates for CO₂ storage partly because they have been capable of holding in place buoyant fluids, similar to CO₂, and some even contain CO₂, hence it is assumed that they will act in a similar manner in the case of CO₂ storage. Nevertheless, the integrity of these reservoirs for CO₂ storage is not always guaranteed and it should not be taken as granted, particularly if their integrity might have been affected during their production history. The most likely pathways for fluids to migrate/leak from an oil reservoir are through faults and fractures or along wells, driven by the increased pressure due to injection and by buoyancy in the case of lighter fluids such as CO₂. The integrity of oil reservoirs in regard to CO₂ storage may be affected through capillary, geomechanical and geochemical processes.

Capillary leakage through the caprock occurs when a non-wetting phase (in this case CO₂) flows into the caprock as a result of pressure being higher than the capillary entry pressure of the caprock. The capillary entry pressure is mainly controlled by the caprock pore distribution, wettability, and interfacial tension between the displacing and displaced fluids in the caprock, in this case CO₂ and brine (as oil is not present in the caprock). The thickness of the caprock is also a very important parameter for controlling this type of leakage. Because the interfacial tension between either natural gas or oil and water is greater than the interfacial tension between CO₂ and water, the assumption that a reservoir will hold CO₂ in place if it held oil may not be necessarily true, depending on pressure. In addition, more recent laboratory studies have shown that rock wettability, particularly in the case of shales, may change in the presence of supercritical CO₂, with CO₂ becoming medium wet (see, e.g., Chiquet et al, 2007 and Chalbaud et al., 2009), with the effect of lowering further the capillary entry pressure. Thus, necessary studies must be performed to ensure that capillary leakage is not a threat for the hydraulic integrity of the caprock. However, the potential for capillary leakage through the caprock is less of an issue than the geomechanical and geochemical effects of oil production before and during CO₂-EOR.

4.1.1 Geomechanical Effects

During primary and secondary production, including infill drilling, oil reservoirs may be exposed to acid stimulation and/or hydraulic fracturing. These operations are designed to alter the initial properties of the reservoir and can create questions related to the degradation of the caprock seal integrity. They also create new fractures, can re-open existing fractures, reactivate faults, and can even propagate to abandoned and/or operating wells in the field (e.g., Grasso, 1992; Zoback and Zinke, 2002). Any of these geomechanical effects may create pathways for fluid (CO₂) leakage out of the reservoir and threaten the hydraulic integrity of the reservoir. However, depleted reservoirs (including those that have undergone CO₂-EOR) are normally at a lower pressure than the initial pressure since they have produced oil and gas, and may still be sealed. During the transition to CO₂ storage, the reservoirs will be re-pressurized, their temperature will change as a result of the lower temperature of the injected CO₂, and, consequently, the risk of leakage will increase.

The major geomechanical potential risks related to underground injection and storage of CO₂ include:

- induced seismicity;

- ground movement (subsidence during production or heaving during injection), depending on reservoir thickness, rock type, pressure, and overburden; and
- CO₂ leakage.

Several cases have been documented in which earthquakes, sometimes as large as 5.5 on the Richter scale, have been induced by production or injection of gas or water (e.g., Grasso, 1992; Ottemöller et al., 2005), but still there is no tool to predict induced seismicity. The mechanisms of ground surface movement during production have been under study for many years, but still prediction is difficult (e.g., Hettema et al., 2002). The most significant effect of ground movement is when this results in well failure and/or faults sliding (e.g., Bruno, 1992).

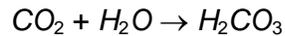
Initial in-situ stresses change during production and injection as a result of pressure and temperature variations. These changes may lead to different geomechanical issues in the field including wellbore instability, fault reactivation, and fracturing. Wellbore instabilities are very common in oil and gas fields. Significant pressure and temperature changes in the vicinity of a borehole may cause different problems such as borehole collapse, uncontrolled fracturing, sand production, casing failure, etc. In addition, stress changes may reactivate inactive faults in the field, if present. This not only can result in induced seismicity and ground movement, but may also change the sealing properties of the fault gauge and affect its role as a sealing barrier acting against fluid leakage. Perturbation of in-situ stresses will induce new tensile and shear fractures in the reservoir and its surrounding rocks if the stresses exceed the rock strength. Furthermore, as a result of stress changes, existing fractures may be re-opened and act as flow conduits or even propagate progressively in the caprock and open up new pathways for fluid flow out of the reservoir. Mechanical stresses induced by pressure variations are of lesser concern as long as the injection pressure is maintained below a certain threshold (fracture pressure or minimum stress), usually imposed by regulatory agencies when permitting a CO₂-EOR or CCS operation, to avoid fracturing or fracture opening. Of greater concern are thermal stresses induced by the difference in temperature between the colder water and/or CO₂ injected in the reservoir and reservoir initial conditions. For example, there are documented cases in western Canada where geological disposal of acid gas (a mixture of CO₂ and H₂S separated from produced sour natural gas) has led to reservoir cooling.

Because in the short-to-medium term the caprock is the main trapping mechanism in a reservoir, its hydraulic integrity is of paramount importance. Thus, studies are required to ensure that the reservoir integrity, including both the caprock and penetrating wells, has not been compromised during its production life and it will not be threatened by future CO₂ storage operations.

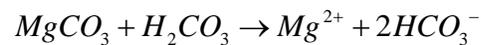
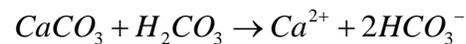
4.1.2 Geochemical Effects

The oil and gas industry has gained a lot of practical experience with geochemical issues, especially when producing slightly acidic waters during oilfield operations. For example, hydrogen sulfide is a commonly associated gas and weak sulfuric acid solutions are ubiquitous in many regions of the world. Thus, developing experience with CO₂ injection in oil reservoirs for tertiary oil recovery and geochemical simulations is not entirely new. Specific CO₂ experiences indicate that, over short time periods (up to several tens of years), the majority of the injected CO₂ remains in free state or it mixes with the reservoir oil. The mixing includes both the formation of a new, combined CO₂/oil liquid and solution into static (unswept) oil. If the injected CO₂ comes in contact with the formation water or injected water (either from secondary water flooding, or in water-alternating-gas, or WAG, processes), CO₂ will dissolve in water, which is a slower and lower-solubility process than the mixing with oil. However, over time the dissolution of CO₂ in reservoir oil and water is the second largest geochemical “sink” for CO₂ in oil reservoirs.

Carbon dioxide dissolves in water to form a weak carbonic acid according to the following reaction:



Carbonic acid reacts slightly and reversibly in water to form a hydronium cation, H_3O^+ , and the bicarbonate ion, HCO_3^- . The formation of carbonic acid can cause corrosion in producing wells, valves, pipelines, tanks and other facilities. Another issue of concern is that CO_2 dissolution in water results in a more acidic water that can dissolve reservoir minerals, primarily carbonate minerals, according to the following reactions:



These reactions lead to an increase in the concentration of Ca^{2+} and Mg^{2+} in water. As pressure or temperature change, Ca^{2+} forms $CaCO_3$, and precipitate out.



and similarly for Mg^{2+} . Because in the short- to medium-term (tens to a few hundred years) precipitation of solid phases is very limited, the main effect of CO_2 injection on the reservoir could be an increase in porosity and permeability as a result carbonate mineral dissolution, which is a positive effect. Significant precipitation of carbonate minerals is controlled by the presence of silicate and other minerals containing divalent cations which react slowly with the acidified water. However, significant decrease of pressure or temperature, and exsolution of CO_2 from water in the vicinity of production wells can cause precipitation of carbonate minerals in the pores of reservoirs, the wall of the borehole and the pipelines used to transport the produced oil and water. Precipitation of carbonate minerals could decrease oil production, well clogging or blocking the pipelines.

The acidification of reservoir water, however, may have negative effects on reservoir caprock and wells, hence on the reservoir as a whole. The acidic water can interact with the caprock, particularly clay minerals, affecting seal integrity, and/or well cements. Cements are alkaline in nature, thus, contact with acidified water can result in significant cement carbonation and degradation, depending on initial well conditions and flushing of reaction products by the injected water (see Zhang and Bachu, 2011). If existing wells that penetrate the oil reservoir have some initial mechanical defects particularly relating to cement integrity, then these defects can be enhanced in the presence of acidified water. Thus, the main concern is that the geochemical reactions at the reservoir-caprock and reservoir-well interfaces may increase fluid movement across the caprock or along wells, resulting in fluid migration out of the storage complex and loss of storage integrity. Nevertheless, the evidence so far from the existing CO_2 -EOR operations indicates that these effects are either minor or have not demonstrated themselves on the time scale since these operations started.

Evaluation of reservoir integrity under CO_2 -injection conditions requires geochemical modeling based on representative reservoir fluid and mineralogical samples, pressures and temperature. Geochemical modelling of CO_2 storage operations in a former CO_2 -EOR reservoir presents some challenges. The first challenge is that the effects of primary, secondary (generally water flooding) and CO_2 -EOR production on reservoir mineralogy and fluid compositions are generally not known. Particularly in some older operations, generally no analyses of the injected water composition (which could vary widely) exist, often very limited information of the water source

exists, and there is little or no information on the amount and composition of the recycled water. The second challenge is operational. Reservoirs are not developed in a fashion where one area is completely developed and all hydrocarbons recovered and CO₂ stored before moving on to the next one. Rather, reservoirs are initially developed in an area, with perhaps multiple stages of infill drilling, and several stages of different recovery methods with individual wells being used as an injector or a producer, depending on hydrocarbon recovery. This makes it very difficult to define a good baseline and model the geochemical reactions that take place during CO₂-EOR operations and subsequent conversion to CCS.

4.1.3 Well Leakage

A fundamental component in the process of assessing the suitability of utilizing an existing oil reservoir for subsequent storage of CO₂ is that all wells penetrating the respective reservoir must be investigated for vertical hydraulic integrity or leakage potential. New wells for CO₂ injection should be drilled, cased, cemented and completed specifically to maximize vertical hydraulic integrity. Older wells converted to CO₂ injection have a higher potential for leakage than wells drilled for purpose, as shown by a study of CO₂ and acid gas injection wells in Alberta (Bachu and Watson, 2009). All other wells penetrating the reservoir should be investigated to assess their leakage potential.

Wells penetrating an oil reservoir should be assessed for both deep and shallow leakage potential. The potential for deep leakage, defined as leakage (cross-flow) from a production zone or CO₂ injection zone back into the wellbore or outside the well casing up and into an overlying permeable zone (another reservoir or a deep saline aquifer) depends on a number of factors such as hydraulic fracturing, acid stimulation, cement type, number of completions and perforations, and abandonment type in the case of abandoned wells (Watson and Bachu, 2008).

Shallow well leakage is defined as the loss of hydraulic isolation in the upper part of the well, including the shallow protected groundwater. It is observed when gas flows up inside the well annulus or outside the casing above a low cement top to the surface casing shoe. From there the gas will flow up inside the surface casing, pressuring-up the surface casing annulus thereby inducing sustained casing pressure (SCP) or gas flow out of the surface casing vent (surface casing vent flow, SCVF) at surface. Gas can also flow outside the surface casing and vent to atmosphere out of the ground at the surface (gas migration, GM). Watson and Bachu (2009) have identified the following criteria to assess the potential for shallow well leakage based on well history: spud date (when drilling of the well began), abandonment date, surface casing size, well type (cased or open-hole), total depth, well deviation and cementing (low cement tops are a major contributing factor to SCVF/GM).

Assessment of well leakage potential using these and possibly other criteria should identify wells that require special attention and maybe field testing for integrity. Wells that have confirmed cases of surface casing vent flow (SCVF), sustained casing pressure (SCP), gas migration (GM) or casing failure (CF) and wells with extended histories of multiple recompletions (re-perforating), acid and especially fracture stimulation in the proposed EOR/CCS reservoir should be investigated further and plans should be put in place for re-entering the well and conducting remedial work-over operations to remedy any leakage issues when converting from a CO₂-EOR project to a CO₂ storage project.

4.2 SUITABILITY OF OIL RESERVOIRS FOR BOTH CO₂-EOR AND CO₂ STORAGE

Fundamentally there are no special requirements for CO₂ storage in oil reservoirs through CO₂-EOR operations. As Hadlow (1992) has shown, about 40-50% of the total injected CO₂ (as contrasted to just the purchased or “new” volumes) remains in the reservoir just as a result of

the process. However, many reservoirs, including ones with mobile oil in the pore space, have small CO₂ storage capacity. For example, Bachu and Shaw (2005) applied the screening criteria developed by Taber et al. (1997) and the additional miscibility criterion to approximately 10,300 oil reservoirs in western Canada and identified that less than 5000 would be suitable for CO₂-EOR. Most of these reservoirs are quite small, with an average CO₂ storage capacity of ~135 kt CO₂, which does not justify the costs of building the necessary infrastructure for storing CO₂ from a large CO₂ emitter such as a power, chemical, steel or cement plant. Thus, Bachu and Shaw (2005) introduced an additional screening criterion, namely of the reservoir having a CO₂ storage capacity of preferably 5 Mt CO₂, but at least 1 Mt. This additional criterion reduced the number of reservoirs suitable for both CO₂-EOR and CO₂ storage to 81. This capacity criterion is similar to the criterion introduced by Núñez-López et al. (2008) of the oil reservoir having a cumulative oil production of at least 1 million standard barrels (MMstb). Application of either one of these criteria would eliminate small oil reservoir from consideration.

The problem of CO₂ storage capacity in CO₂-EOR operations is compounded by the issue of water invasion in the case of oil reservoirs with strong aquifer support or by water flooding (secondary recovery) prior to CO₂ flooding (tertiary recovery). In many/most cases oil reservoirs are underlain by an aquifer. Oil can be produced from a reservoir as a result of reservoir pressure (primary drive), but in many cases the underlying aquifer has sufficiently-large permeability to provide pressure support to the oil reservoir, thus helping oil production. However, the downside of this is the fact that the same large permeability that allows pressure support to the oil reservoir allows also the flow of aquifer water into the reservoir (water invasion), thus reducing significantly the amount of CO₂ that can be stored in the reservoir. On the other hand, water invasion from the underlying aquifer helps in maintaining pressure, which is beneficial to miscibility. Using simple mass-balance modelling for oil reservoirs in the Alberta basin, Bachu and Shaw (2005) have shown that the reduction in CO₂ storage capacity in the case of oil reservoirs with strong aquifer support is in the order of 40% on average if the reservoir is allowed to reach its initial pressure but not higher. Of course, if pressure is allowed to increase beyond the initial pressure, then the reduction in CO₂ storage capacity will be less because some of the water that invaded the oil reservoir will be pushed back. However, raising reservoir pressure beyond the initial pressure may lead to geomechanical problems (see previous section) and may not be allowed by regulatory agencies. Water flooding of an oil reservoir has a similar effect on CO₂ storage capacity as water invasion from a strong underlying aquifer, if not even worse, in reducing the CO₂ storage capacity of the reservoir (e.g., the same study by Bachu and Shaw, 2005, has shown that the CO₂ storage capacity in more than 400 very large, water-flooded oil reservoirs in Alberta, Canada, is comparatively quite small and insufficient for a medium-size power plant).

Considering the widely accepted criteria for CO₂ storage (see Section 3.1), it seems that the minimum depth for CO₂-EOR and CO₂ storage should be 2500 ft (~760 m) and reservoir temperature should be greater than 90 °F (32.2°C), although there is no real reason not to store CO₂ in shallower reservoirs if the broad conditions of capacity, injectivity and confinement are being met.

In addition to the capacity and depth criteria discussed above, the condition of injectivity is implicitly satisfied in the case of oil reservoirs, and the only other condition that has to be met for CO₂ storage is the condition of confinement (security and safety of storage). Thus, oil reservoirs located in areas of high seismicity or in over-pressured strata, lacking monitoring potential, or having the caprock geomechanically or geochemically affected as a result of prior production (see previous Section 4.2), should generally not be used for CO₂ storage even if they are suitable for CO₂-EOR (the concept here is that the CO₂ that normally would remain in the

reservoir as a result of CO₂-EOR will stay there, but that no additional CO₂ should be stored). Figure 7 below presents the process of technical selection for CO₂-EOR and CO₂ storage (Hill et al., 2013).

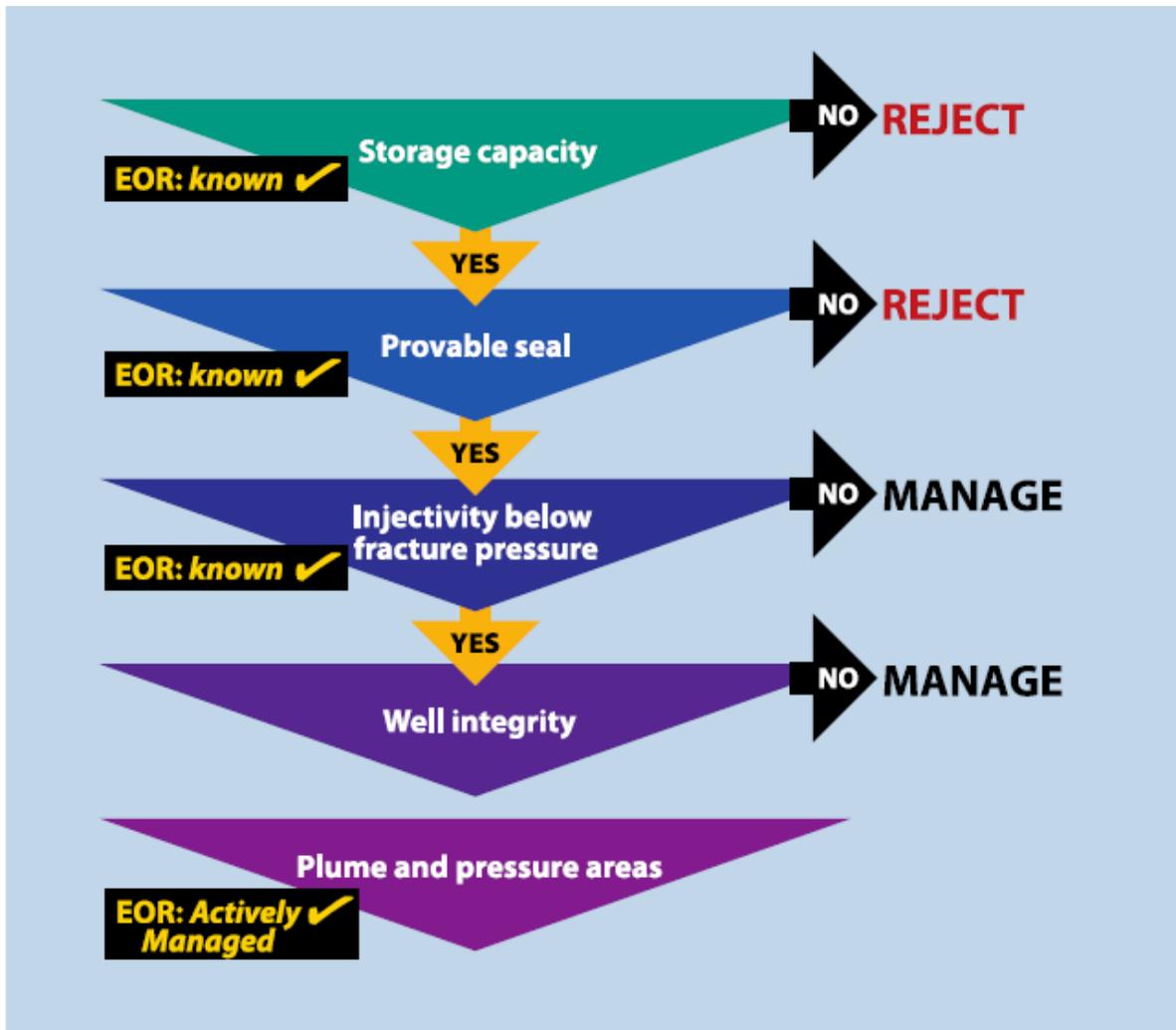


Figure 7: Technical selection of a CO₂-EOR operation for CO₂ storage and associated processes (from Hill et al., 2013).

All other possible screening and selection criteria of oil reservoirs for both CO₂-EOR and CO₂ storage would refer to surface and economic conditions, and legal and regulatory aspects.

4.3 OPERATIONAL SCENARIOS FOR CONVERSION FROM CO₂-EOR TO CO₂ STORAGE

For the purpose of this scenario, it is assumed that the oil reservoir is large, that the oil contains solution gas (methane) in a high gas/oil ratio (GOR), and that the reservoir is underlain by a saline aquifer (water leg). Other deep saline aquifers are present in the sedimentary succession above and/or below the oil reservoir.

In most conventional CO₂-EOR Projects, produced water is injected in an alternating fashion with CO₂ into the oil reservoir to sweep/push oil to production wells. Injection and production

wells are distributed in a pattern designed to optimize sweep efficiency and oil production. At surface, the produced oil, water, solution gas and CO₂ are gathered from all the producing wells and run through a liquid-gas separator. The oil and water are run through another separator, where they are separated, and the oil is sent to sales out of the oil field, while the water is sent to pumps for injection back into the reservoir and for disposal into another deep saline aquifer if there is surplus water. The solution gas and the CO₂ are also separated in another separator, after which the solution gas (methane) is sent to a compressor and dehydrator station and then to sales, while the CO₂ is similarly compressed and dehydrated, and then recycled back into the oil reservoir, being injected together with new CO₂ brought in to the oil field. For small or low GOR schemes, separating the solution gas from CO₂ is uneconomic and both gases are re-injected into the reservoir. When CO₂ breaks through uncontrollably at producing wells, the wells are shut in and additional patterns are developed across the oil field. The conventional CO₂-EOR project terminates when all the potential flood patterns have been developed and/or when the operating costs are higher than the revenue from oil and gas sales. In some cases, rather than abandoning the injection and production wells, they may be suspended, thus allowing restarting the CO₂-EOR scheme if the price of oil goes up. Pressure blow-down of the field for additional gas recovery is commonly reported as standard procedure but uncommonly done at the end for additional gas recovery. Most commonly, the wells are plugged as no further development of the field is contemplated, and the economics of recovered CO₂ is marginal.

Conversion of a CO₂-EOR scheme to a CO₂ storage project makes sense only if there is a monetary value associated with the stored CO₂. The oil reservoir can be converted immediately into a CO₂ Storage Project. The oil and gas production and separation facilities at surface are dismantled, production wells are abandoned, and the land is reclaimed according to regulatory requirements. Only new CO₂ is being injected into the oil reservoir until the maximum reservoir pressure allowed by the regulatory agency through permitting of the CO₂ storage project is reached. The storage capacity of the oil reservoir can be increased if water from the water leg is produced and disposed of into another deep saline aquifer in what is commonly known as “storage engineering” (in which case production wells will have to be re-perforated deeper into the water leg to avoid producing skim oil or oil from the residual oil zone – ROZ). The operating costs are reduced by not producing and separating oil and gas, and the source of revenue is based only on the value of/credits for the stored CO₂. If the costs of increasing the reservoir CO₂ storage capacity by producing and disposing of water are greater than the value of the stored CO₂, then this would be not implemented, or if started, it would be terminated. Some production wells may be converted into monitoring wells rather than be abandoned.

Sometimes, even if the CO₂-EOR scheme becomes uneconomic, it may be more advantageous to continue as Hybrid CO₂-EOR/CCS Project rather than convert directly into a CO₂ storage project (Jafari and Faltinson, 2013). Again, this is based on the stored CO₂ having a monetary value. The objective is to continue production of oil from the oil leg of the reservoir or from the ROZ even if oil production by itself is uneconomic, while at the same time store CO₂, with the value of the stored CO₂ offsetting the “loss” incurred from producing oil. By continuing production, fluid continues to be removed from the reservoir, thus creating additional CO₂ storage space. Water injection into the oil reservoir is terminated, and the produced water is disposed of by injection into another deep saline aquifer. The produced CO₂ and gas are not separated anymore, but are re-injected together with new CO₂ to reduce costs. The remaining injection wells are switched to pure CO₂ injection to contact more oil and sweep it to producing wells. Operating costs are reduced by dismantling the CO₂/solution gas separation facilities, and the gas separation compression and dehydration equipment. Revenue is created by the sale of the produced oil and through the value of the stored CO₂. As the oil production continues to

decrease, at some point the hybrid CO₂-EOR/CCS scheme becomes itself uneconomic, at which point it should be converted to a pure CO₂ storage project.

4.4 REGULATORY AND MONITORING REQUIREMENTS DURING CONVERSION FROM CO₂-EOR TO CO₂ STORAGE

For CO₂-EOR operations to transition to CO₂ Storage, they may likely have to meet some incremental CCS requirements. These include the origin of CO₂ (it should be captured from an anthropogenic source), meeting more stringent operational regulatory requirements than CO₂-EOR operations, and the integration of a robust Monitoring and Surveillance (M&S) program. This is the focus of this section and it will indicate certain parameters to be monitored and verified in order to ensure safe and permanent storage for the CO₂. For each parameter to be monitored, such as well cement and casing, CO₂ concentrations or fluid pressures, there are different technologies/tools that can be used to measure and record values, confirm integrity in the case of wells, and verify the forecasted predictions.

The M&S program for each project should cover three periods of the project lifetime: 1) pre-injection to establish baseline conditions, 2) during injection to monitor the plume and behavior of CO₂, and 3) post-injection, which is monitoring the site after CO₂ injection has permanently ceased and also includes the well abandonment and the removal of the infrastructure. It is similar to the “during injection monitoring” period, but perhaps with lower frequency. The baseline and post-injection data acquisition M&S activities are likely the key differences between CO₂-EOR operations and CO₂-EOR for CO₂ storage in terms of monitoring. From a technical point of view, the post injection period is further divided into two parts: abandonment (termination of the project) and post abandonment. The reason for this subdivision is to further illustrate the proper practices of abandoning the wells and the removal of the infrastructure, which is short in duration, as opposed to monitoring the fate of the stored CO₂ which will likely last several years. Furthermore, from a legal point of view, the post-injection period is divided into a “Closure Period”, during which the operator maintains liability for the CO₂ storage operation, and “Post-Closure Period”, when liability may be assumed by a state (government) agency (CSA, 2012). However, this sub-division is a policy matter and won't be addressed further in this report.

Typically, the M&S program is divided into three categories: Surface, Near-surface and Subsurface monitoring. Surface monitoring is done to verify that the sequestered CO₂ will not leak to the atmosphere and to detect any leak in case it occurs, the near surface monitoring usually involves monitoring shallow ground water for the same reason as surface monitoring, while the subsurface monitoring is performed to confirm the location of CO₂, fluid movement in the reservoir, the isolation of the sequestered CO₂, wells' downhole integrity, reservoir pressures, and the integrity of the reservoir seal.

It should be noted that monitoring techniques, technologies and tools should be project specific as each commercial-scale project has its own geological and operational features and characteristics. Prior to any project, risk assessment and site evaluation should be carried out to identify the appropriate monitoring and surveillance program for the project (pre-injection phase). However, the main goals of any M&S program can be universal (Litynski et al. 2008) and it will be implemented to provide solid technical assessment of a project to support decision making, ensure the health, safety and environment (HSE) of the project, evaluate CO₂ movement and interaction with reservoir fluids, and provide a detailed mitigation and corrective action plans should a leak or a problem occur.

Weyburn and Zama in Canada are the only CO₂-EOR operations that are recognized as a CO₂ storage sites. The Weyburn site has been subjected to very extensive monitoring, as described in, e.g., White et al. (2004). The SACROC field in Texas, the Cranfield project in Mississippi also have had extensive monitoring programmes. All mentioned monitoring programmes have a large degree of research.

4.4.1 Surface and Near-surface Monitoring

The public is mostly concerned about CO₂ leaking to surface or shallow groundwater. When CO₂ is stored in depleted oil reservoirs, the integrity of the reservoir seal is arguably much more competent than other geological storage options (e.g. saline aquifers). This is because the seal has retained reservoir buoyant fluids for very long periods of time (tens of thousands to millions of years). The primary risk of leaking CO₂ is through the wells drilled for injection and production or abandoned wells. This is why for CO₂-EOR for storage, monitoring techniques for the well integrity is receiving attention.

Surface and near surface CO₂ monitoring is established by studying the time varying natural CO₂ concentrations and properties in the atmosphere and ground soil and water. Then, it is compared to the properties of CO₂ from the capturing source and reservoir oil. This will establish a baseline measurement of different CO₂ concentrations and properties (pre-injection phase), including isotopic signature. During the injection phase; surface soil and ground water is periodically monitored for any changes in the CO₂ properties and concentrations. The monitoring needs to take into account the diurnal, seasonal and annual variations in CO₂ emissions from natural sources such as vegetation and soil, and other climatic and terrain conditions.

The challenge in this method is the fact that for some projects, the properties of CO₂ are similar from all locations, which makes it difficult to distinguish the actual source of CO₂. A mitigating approach to distinguish the sources of measured CO₂ is to add tracers in the injected CO₂ to distinguish it from other natural CO₂ emitted by vegetation and soil.

On the other hand, the main advantage of surface and near surface approaches is that most of the technologies used are established and proven, they are relatively inexpensive, and they are usually easy to employ by the use of portable devices. Efforts therefore are exerted to monitor CO₂ concentrations in the atmosphere and in shallow groundwater in a time-lapsed mode throughout the project life, starting before the injection of CO₂ and continue after project abandonment. The following tests are normally used for surface and near surface CO₂ monitoring:

Ambient CO₂ Concentration (Surface). The measurement of CO₂ concentrations in the atmosphere is one monitoring technique to detect CO₂ leakage and seepage from the storage site to the atmosphere. It involves studying the time varying CO₂ concentration in the atmosphere within the vicinity of the injection site. The initial measurement involves determining a temporal baseline where the existing CO₂ concentration is recorded. The use of CO₂ detectors, which analyzes the changes of CO₂ isotopic properties as well as concentrations, is the main technique for CO₂ surface monitoring. Detectors can be stationary positioned at different locations at the surface, or portable devices mounted on different types of mobile vehicles (cars, farm animals, etc.).

Soil and Groundwater Monitoring (Near-surface). Near surface monitoring is important to preserve the quality of soil and shallow groundwater sources, and ensure no migration of

injected CO₂ to nearby surface waters. Soil and vadose zone gas monitoring is based on collecting gas samples from soil and the vadose zone to quantify CO₂ concentration profiles near the surface and to assess the origin of the gas, i.e. biologic-respiration versus other sources. The approach requires samples from a grid and a baseline. Another technique to monitor the surface soil is based on flux measurements where closed chambers can be used to measure the soil flux in and out of the soil. The air in the chamber is circulated through simple infrared analyzers to check the rate of changing CO₂ concentrations (Klusman 2003).

Monitoring groundwater quality is usually done using geochemical techniques such as the isotopic analysis of the water before, during and after CO₂ injection (during all phases of the project). The main advantage of this approach is the simplicity of conducting tests, as most of the techniques to check the quality of groundwater are considered basic. The other technical advantage (over surface monitoring) is that CO₂ retention time in groundwater is longer than it is in the atmosphere, providing a longer window of opportunity to detect leaks. Some of the techniques to monitor near surface groundwater include studying the properties of the water such as conductance, alkalinity and pH levels. Trace elements and chemical tracers have also been used to determine fluid flow paths and origins, while partitioning techniques were used to identify residual gases. Other indicators include dissolved gases and stable isotopes. These approaches need water wells and natural sample points such as springs, as well as a baseline.

Soil sampling has been used at Weyburn to detect possible CO₂ migration from the reservoir to the surface (White et al, 2004) and SACROC has used groundwater monitoring (Smyth et al, 2012)²¹.

4.4.2 Subsurface Monitoring

The purpose of subsurface monitoring is mainly to track the CO₂ plume and its propagation in the reservoir, indicate reservoir pressure profile, and test reservoir and seal integrity and well cement integrity. Subsurface monitoring is the most difficult, labor intensive, and expensive of the three. The following are the main parameters and technologies that need to be considered during CO₂-EOR for storage projects.

Laboratory and Simulation Studies. Prior to any CO₂-EOR project, meticulous laboratory tests are conducted to characterize the phase behavior between CO₂ and the reservoir oil. Examples of laboratory tests include: minimum miscibility pressure (MMP), PVT (pressure-volume-temperature) phase behavior, asphaltene precipitation, relative permeability measurements, and recovery potential (Jarrell et al. 2002; Mungan 1992; Stalkup 1992). The data and results from the laboratory are then used to tune a compositional reservoir simulator and conduct performance predictions, sensitivity analysis and field optimizations. These studies are very important during the pre-injection phase to establish baseline predictions of CO₂ behavior in the reservoir and oil production. The models are updated regularly during the injection phase and laboratory studies are used to explain certain phenomena during the injection period. The updated models are then used to forecast the behavior of stored CO₂ for the post-injection phase.

Rate Monitoring. CO₂ “accounting” is a very important element in CO₂-EOR for storage operations because not all injected CO₂ remains underground; rather some of it (~40%, Hadlow,

²¹ http://www.permianbasinccs.org/conferences/forum_040412.htm

1992) is produced with the oil at surface. Therefore, all wells should be monitored for injection and production rates which will provide accurate data on how much CO₂ has been injected and how much has been produced and recirculated, and eventually stored. In many jurisdictions rate monitoring and reporting of fluids injected and produced is required by oil and gas regulatory agencies. Multiphase flow meters (MPFM) are common equipment used to measure the rates and provide reliable data on production and injection profiles. Trap testing is also used to measure rates but with less accuracy as the wells are not continuously monitored for rates as in the MPFM. The main advantage of the MPFM is the continuous testing without the requirements to shut-in wells or switching to testing lines. This provides sufficient data to determine anomalies such as production or injection decline.

Reservoir Pressure Monitoring. Monitoring pressure throughout the project life span is an essential tool for inferring injection volume, reservoir compatibility with CO₂, and safe storage of CO₂. Monitoring pressure can be done using wellhead and downhole pressure gages or a permanent downhole monitoring system (PDHMS). Other important pressure measurement points include surface casing pressure and annulus pressure, to ensure no leaks are occurring in the casing, tubing and/or well packers (this is covered in the well integrity monitoring). Reservoir pressures are monitored prior to injection to determine the MMP with CO₂ and injection capacity. Monitoring continues during the injection phase to check for injection decline and/or loss of CO₂ underground.

Seal (Caprock) Integrity. Oil reservoirs are trapped under a geological seal known as 'cap-rock' which held the oil in place for tens of thousands to millions of years. The competence of this seal is extremely important to hold the hydrocarbons from migrating to other geological traps, more importantly so when a pressure-depleted oil reservoir is chosen for CO₂-EOR and storage. This seal will be the main mechanism to store the injected CO₂ for geological times. Therefore, geomechanical models are usually built to investigate the integrity of this seal and the likelihood of CO₂ leaks prior to injection. The main objectives of geomechanical studies are to provide a quantitative understanding and risk assessment for cap-rock integrity, natural fracture stability, and induced fracture/wellbore stability for the planned CO₂ injection project. The model usually contains both static and dynamic properties relating to seal geomechanics, including in-situ stresses, rock strengths and elastic properties. The baseline risk assessment data should provide the initial answer whether or not the reservoir is suitable for CO₂ storage. The model is then continuously updated with new field data as the project progresses, including reservoir simulation predictions of temperature and pressure variations in the reservoir, particularly considering that CO₂ is injected at a lower temperature and higher pressure than reservoir temperature and pressure, respectively. During the implementation phase of the project, be it for CO₂-EOR, for CO₂ storage or for monitoring, wells are drilled through this seal (caprock) to reach the intended reservoir. The cement integrity of these wells is an important parameter to monitor during CO₂ storage as well.

Routine Logging and Coring. The routine logging and coring is a common practice in the oil and gas industry to monitor wells for production and injection, changes in fluid saturations, and fluid movement in the reservoir. It is considered nowadays the simplest geophysical measurement to obtain petrophysical information from reservoirs. An array of available logs is usually used for fluid saturation monitoring and lithology assessment, which can also be compared to data obtained from core analysis. This practice is extended to cover the basis for any CO₂-EOR project, especially if the intent is CO₂ storage. The shortcoming of this method is the depth of investigation, which is limited in most cases to a few inches (cm) near the wellbore and it will not read deeper in the reservoir. To overcome this shortcoming, interpolation between

wells is usually carried out. Another option is to use geophysical techniques but that will incur relatively significant costs. Table 5 summarizes the available logs, type of completion, and purpose (Bassiouni 1994):

Table 5: Common well logs used for monitoring in CO₂-EOR operations.

Type	Completion*	Purpose
Resistivity	OH	Fluids saturation
Density	OH	Lithology/ and fluid type
Neutron	OH	Lithology/porosity
Image Log	OH	Rock properties and presence of fractures
ADT	OH	Fluid saturation
NMR	OH	Pore system/ porosity, permeability, and free and bound fluids.
MDT	OH	Formation pressure testing and sampling to identify fluid contacts (GOC & OWC)
ECS	OH	More details on lithology in term of elements and minerals
CBL/USIT	CH	Casing cement condition and communication between zones
Sonic	OH	Porosity, fractures and shear & wave stress for rock properties and geomechanics
CO sigma	OH/CH	Reservoir fluid saturation changes
MPFM	OH/CH	Downhole and surface production for horizontal wells (pressure, temperature, rates for gas/oil/water) by zones

*OH means open hole well; CH means cased well.

Logging is usually done during drilling to take advantage of the open-hole condition of the well to run certain types of logs. However, wells may be left with open-hole completions for the life of the well. When the well is cased, there are other types of logs that can be run to collect data, albeit with limited number. Well logs data are essential to determine fluid saturations throughout the project life. During the pre-injection phase, baseline saturation measurements are collected to indicate the current condition of the reservoir. These data are then compared to saturation measurements from core analyses (e.g. sponge core saturating data). Saturation data are then fed to the reservoir simulator to construct the model and forecast performance. During the injection phase, time-lapse well log measurements are collected to monitor the changes in fluid saturations and movements. When the wells are abandoned during the post injection phase, measurements are taken from the observation wells to monitor any changes in fluid saturations while CO₂ is stored.

Well Integrity. Well integrity usually covers the practice of using CO₂-competent wells and maintaining them throughout the life of the project. Well integrity monitoring should cover the three phases of the project life: pre-injection (baseline monitoring), during injection, and post-injection (abandonment and abandoned). Pre-injection monitoring establishes a baseline measurement on cement quality, casing evaluation, and zonal isolation. During the injection period, monitoring should follow the baseline measurements for meaningful comparison, with the emphasis on areas of pressure increases (front of the plume) because of the higher risk they carry. Annuli surveys are also recommended to monitor the well's pressure and temperature during this phase. During the post-injection phase when the wells are abandoned, observation wells are used for deep monitoring, while surface monitoring can provide a second measure (Hitchon 2012).

For well integrity, cementing is usually the main concern for CO₂ leaks to surface (*provided that the wells metallurgy is CO₂ compatible*) because drilling the wells through the competent seal may introduce a man-made pathway to surface. Potential sources of CO₂ leaks to surface through cement are illustrated in Figure 7. Cement Bond Log (CBL) is a common tool to monitor the integrity of cement in wells.

From Figure 8 it can be seen that the potential places where CO₂ could leak are at the contact between the cement and another surface or through the cement itself. For example, paths 'a' and 'b' show the potential of CO₂ leaking between the cement and casing. Path 'c' shows the potential of CO₂ leaking through the cement while path 'f' shows the potential of CO₂ leaking between the cement and the surrounding rock. Other possibilities around the well, not related to cement, are CO₂ leaking through the casing (path 'd') and through fractures (path 'e').

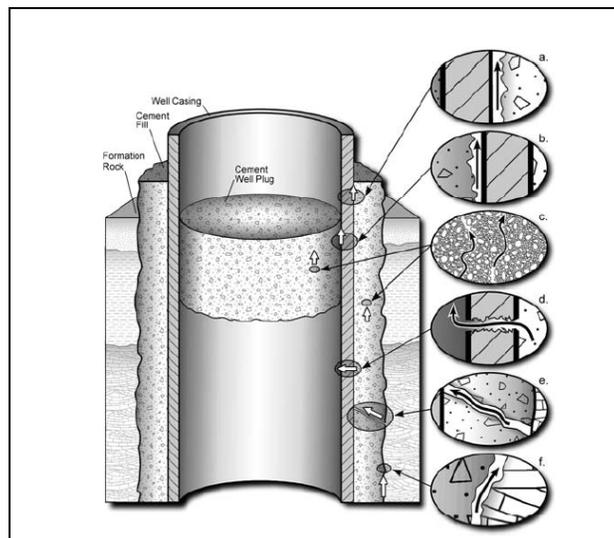


Figure 8: Potential CO₂ leakage due to cement jobs (from Gasda et al., 2004)

Fluid Movement (Single and Inter-well Chemical and Gas Tracers). The main purpose of chemical tracers is to monitor fluid saturations. In the case of single well chemical tracers, the target is to identify the fluid saturations around the well deeper in the reservoir (~20 ft, or ~7 m). Single well chemical tracers are meant to provide saturation measurement a little deeper than the radius of investigation provided by well logs (~12 in, or ~30 cm). Inter-well chemical tracers provide saturation measurement between the wells as well as fluid flow direction. Chemicals are mixed with injection fluid and pumped in the injectors. Then, fluid samples are collected from producing wells and analyzed to infer fluid saturation and preferential flow pathways in the case of multi-well projects. Gas soluble chemicals can also be mixed with CO₂ (gas tracers) and injected in the target formation and collected from producing wells to track the movement of CO₂ deep in the reservoir. The use of chemical tracers is an established technology but it gained more attention lately with the rise in monitoring techniques. This technology is usually used as a complimentary measurement to well logs to verify the results. Single well chemical tracers are usually used during the pre-injection phase to determine the current saturation in the reservoir and quantify changes in saturation caused by CO₂. On the other hand, inter-well chemical tracers are used during the injection phase to track the movement of CO₂ (plume) and changes in fluid saturations. This method is not applicable during the post-injection phase.

Geophysical Monitoring. Seismic monitoring is widely used in oil and gas exploration. In the case of CO₂ storage operations, including CO₂-EOR converting to CO₂ storage, three dimensional seismic surveys (3D) repeated at regular intervals, beginning before injection starts, will allow observation of changes in the reservoir and migration of the CO₂. The technique is known as 4D or time-lapse seismic surveying. Time-lapse seismic monitoring assesses the whole reservoir volume (and beyond if needed) and allows confident identification of the CO₂-front. However, thin plumes may be missed and the response is not linear with CO₂ concentration. There may also be limited environmental impacts from installing the geophones and from the explosions. Seismic surveys may be supplemented by other seismic approaches, e.g. cross-well seismic and vertical seismic profiles (VSP).

Micro-seismic monitoring is a passive seismic survey with origin in seismology. An array of downhole receivers detect microseismic activity triggered by shear slippage. Passive seismic can be used to monitor the formations above the reservoir for detection of CO₂ that migrates through the cap-rock, but this is dependent on systems that produce acoustic signals.

Cross-well tomography can be based on both electromagnetic induction and electrical resistivity. The electromagnetic version uses vertical and horizontal magnetic field detectors in an array of wells whereas the electrical resistivity version uses an array of electrodes. The electrical resistivity method is very challenging for waterflooding because of the mixed water salinity.

Figure 9 presents field operations and associated monitoring, verification and accounting operations in a CO₂-EOR operation with CO₂ storage (Hill et al., 2013). Table 4 gives somewhat more information on the readiness level of monitoring and surveillance technologies. More detailed descriptions about monitoring technologies and their readiness for deployment can be found in, e.g., NETL (2009, 2012).

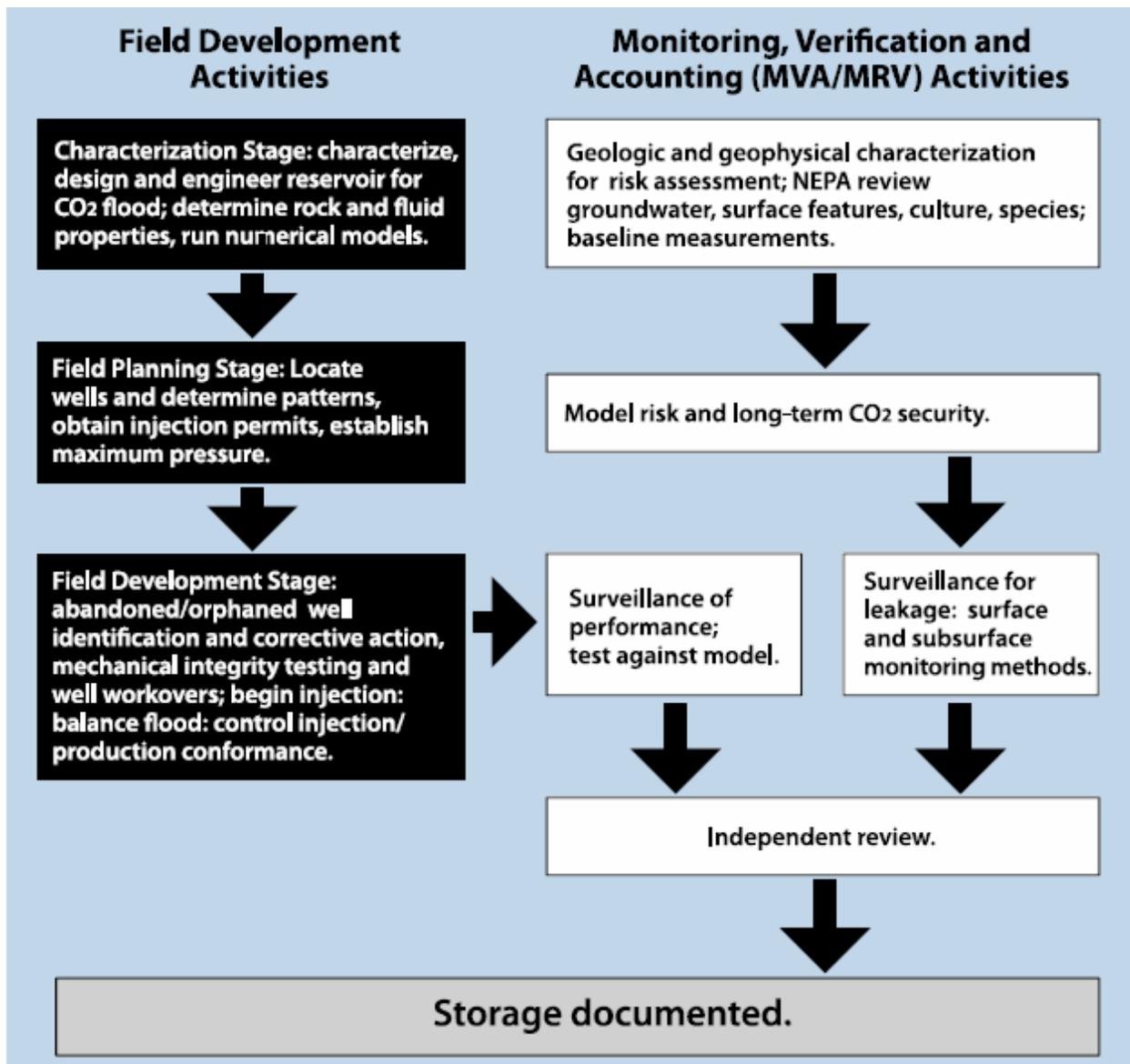


Figure 9: Suggested characterization and monitoring in a CO₂-EOR operation with CO₂ storage (from Hill et al., 2013).

5. SUMMARY AND CONCLUSIONS

The 40 years of experience and the current number of CO₂-EOR operations currently active in the world indicate that there is sufficient operational and regulatory experience for this technology to be considered as being mature. Carbon dioxide is inherently stored in CO₂-EOR operations, with a retention rate of the purchased (new) CO₂ greater than 90-95% (40-50% of the total injected CO₂) is retained in the reservoir, with the balance being produced at producing wells, separated from oil and recycled/re-injected). The CO₂ losses are due mainly to fugitive emissions in surface facilities (although operators try to minimize these due to economic and environmental reasons), and do not originate from the CO₂ injected and lost from within the reservoir. Notwithstanding the fact that almost all of the purchased CO₂ is retained (stored) in the reservoir, the objective of the operators is to maximize oil production and minimize CO₂ purchase (hence utilizing produced CO₂ to increase incremental oil production).

Application of CO₂-EOR for CO₂ storage has a number of advantages and a few disadvantages. The advantages are:

- 1) It enables CCS technology improvement and cost reduction;
- 2) It improves the business case for CCS demonstration and early movers;
- 3) It supports the development of CO₂ transportation networks;
- 4) It may provide significant CO₂ storage capacity in the short-to-medium-term, particularly if residual oil zones (ROZ) are produced
- 5) It builds and sustains a skilled CCS workforce; and
- 6) It helps gaining public and policy-makers acceptance.

The disadvantages are:

- 1) It is geographically limited to oil-producing regions and is capacity limited in the long term;
- 2) Revenue from CO₂-EOR operations alone cannot bridge the current gap from the class of power plants with high CO₂ capture costs; and
- 3) There are gaps in permitting between CO₂-EOR and CCS operations.

All the CO₂-EOR operations to date are onshore, and implementation of CO₂-EOR with ensuing CO₂ storage offshore will pose similar or more difficult technical challenges. Possible regions for offshore CO₂-EOR operations with or without CO₂ storage are in the North Sea, for which several studies have been carried out (e.g., Akervoll and Bergmo, 2010; Mathiassen, 2003; Pershad et al, 2012), in the Gulf of Mexico and offshore Brazil. Specific technical challenges for offshore operations are the small space and weight margins of the platforms, the costs associated with close-down in connection with modifications of the existing platforms, the lack of sufficient amounts of CO₂ and CO₂ transportation, likely by ship for significant distances, with associated compression and decompression facilities onshore and on the platform (NPD, 2005). The costs of abandonment are also likely to be higher offshore than onshore. In addition, if oil reservoirs have already high recovery factors, like in the North Sea, then application of CO₂-EOR may not be profitable enough to justify the associated costs.

The current number of CO₂-EOR operations in the world is negligible compared with the number of oil pools in the world, and the main reason why CO₂-EOR is not applied on larger scale is the unavailability of high-purity CO₂ in the amounts and at the cost needed for this technology to be deployed on a large scale. The potential for CO₂ storage and incremental oil recovery through CO₂-EOR is significant, particularly if residual oil zones (ROZ) and hybrid CO₂-EOR/CCS operations are considered. Again, the main impediment in the adoption of this technology is the

unavailability of CO₂ at economic prices, and also the absence of infrastructure to capture and transport CO₂ from CO₂ sources to oil fields suitable for CO₂-EOR.

5.1 COMMONALITIES BETWEEN CO₂-EOR AND PURE CO₂ STORAGE OPERATIONS

There are a number of commonalities between CO₂-EOR and pure CO₂ storage operations, both at the operational and regulatory levels. These are:

1. In both cases CO₂ needs to be brought to the oil field (infrastructure), currently through pipelines, but in the future possibly by ship especially for offshore oil reservoirs at distances that make pipelines uneconomic.
2. Injection of CO₂ through wells that need to have casing, tubing and all other accessories made of or lined with materials resistant to the effects of CO₂, particularly if it contains impurities or water. Also, cementing of these wells usually has to be circulated to the surface or at least to surface casing, if possible (but not necessarily) using cements resistant to CO₂.
3. Wellhead operational monitoring at injection wells is basically the same: pressure, temperature, flow rate and stream composition (in CO₂-EOR operations production wells are monitored as well at the wellhead).
4. Assuming the CO₂ purity specifications are comparable, in the subsurface (reservoir) the geochemical and geomechanical effects of injecting CO₂ into an oil reservoir are similar, regardless if CO₂ is injected for CO₂-EOR or for storage.
5. In both cases regulations require hydraulic isolation of the production or storage horizon in order to protect other resources, including energy and mineral resources, and underground sources of drinking water.
6. In both cases CO₂ is economically valuable and operators try to minimize losses. To oil companies CO₂ is valuable because of the cost of CO₂, while for CO₂ storage operators CO₂ losses have to be avoided in order to obtain and retain credits.

These commonalities create a good basis for transitioning from CO₂-EOR to CO₂ storage in oil fields. However, currently there are a significant number of differences between the two types of operations.

5.2 DIFFERENCES BETWEEN PURE CO₂-EOR AND PURE CO₂ STORAGE OPERATIONS

The differences between pure CO₂-EOR and pure CO₂ storage operations can be grouped in seven broad categories:

- Operational, including CO₂ quality;
- Objectives and economics;
- Supply and demand;
- Legal and regulatory;
- Assurance of well integrity;
- Long term CO₂ monitoring requirements; and
- Industry's experience.

Operational. This refers to the quality (purity) of CO₂ and reservoir/aquifer pressure. In regard to CO₂ quality (purity), CO₂-EOR operations require high purity CO₂, with absence of impurities that negatively affect the minimum miscibility pressure and the safety of the operation (e.g., N₂, NO_x, O₂ and water, which are found in flue gases from power plants). On the other hand, some

impurities, like H₂S, may be beneficial to CO₂-EOR operations in that their presence lowers the minimum miscibility pressure, as is the case in the Zama oil field in northwestern Alberta in Canada, where an acid gas comprising 70% CO₂ and 30% H₂S is used for enhanced oil recovery, but their presence may pose other challenges, particularly in the case of such a highly-toxic gas as H₂S. In pure CO₂ storage operations, various impurities may be present in quantities determined by the economics and safety of the storage operation (e.g., the cost of removing them during capture versus the cost of them being part of the stored stream, with corresponding consequences for compression, transportation and storage).

In regard to pressure, pure CO₂ storage operations in deep saline aquifers start from the initial aquifer pressure and the bottomhole maximum injection pressure (BHIP) increases up to the maximum pressure allowed by the regulatory agency in the respective jurisdiction (e.g., in Alberta, Canada, the maximum BHIP allowed is 90% of the rock fracturing threshold). Pure CO₂ storage operations in depleted oil and gas reservoirs start from the reservoir pressure at abandonment (if the reservoir has no aquifer support) or from a value between the pressure at abandonment and the initial pressure (if the reservoir has aquifer support), and may not be allowed by the regulatory agency to increase above the initial reservoir pressure because of concerns relating to caprock integrity. In the case of a CO₂-EOR operation transitioning to CO₂ storage, particularly after a waterflood, the reservoir pressure is most likely close to the initial reservoir pressure.

Objectives and Economics. The economic objective of CO₂-EOR operations is to produce additional oil from the reservoir to meet energy demand, and realize a profit for shareholders or revenue for governments in the case of national oil companies. It does, however, lead to on-going “incidental” storage of CO₂, but maximizing oil production is the main technical objective of CO₂-EOR operations. When a CO₂-EOR operation becomes uneconomic it is abandoned, unless incentives are created/provided to continue injecting CO₂, taking advantage of the infrastructure that is already in place. In contrast, pure CO₂ storage has no economic objective (if incentives are not put in place by governments), but rather it is a climate change mitigation strategy, and as such it represents a cost that has to be borne by shareholders, consumers and/or governments. From a technical point of view, the objective is to maximize CO₂ storage beyond the economic life of an oil reservoir. Notwithstanding the incidental storage occurring during pure CO₂ EOR, the different technical objectives of the two operations can translate into different operational strategies, including well patterns, injection rates and strategies, maximum reservoir pressure, and sweeping strategies.

Supply and Demand. Currently demand for CO₂ outstrips the existing supply. There are/may be situations where CO₂ supply from a single CO₂ source satisfies the needs of a CO₂-EOR operation (e.g., Weyburn-Midale in Canada), but for giant oil fields there will need for CO₂ from multiple sources, with the associated infrastructure in place. In CO₂ storage operations, particularly in deep saline aquifers, currently simple source-sink matching satisfies the storage needs (e.g., Sleipner in Norway, Gorgon in Australia and Quest in Canada).

Legal and Regulatory. Although these differences do not constitute *per se* technical challenges in the transition from CO₂-EOR to CO₂ storage, they are mentioned here because they affect or may affect the technical aspects of the operations. In most if not all jurisdictions, rights to an oil reservoir for oil production, including CO₂-EOR, can be acquired under existing tenure legislation based on mineral or petroleum and natural gas (PNG) rights, while for-purpose CO₂ storage requires specific storage rights that are under development. Furthermore, in some jurisdictions, like the United States, the mineral rights belong to the surface land owner, while in other jurisdictions they belong to the state. In other jurisdictions (e.g., Canada) the mineral rights

belong to either the state (Crown) regardless of the surface land owner, or to a specific land owner who was granted in the past also the mineral rights for special reasons and under special circumstances. In addition, there is a difference between ownership of onshore and offshore reservoirs in jurisdictions where land owners or other entities own the mineral rights on land. In such cases the state (or Crown) owns the offshore mineral rights.

In CO₂-EOR operations, the operator obtains producing rights from the owner to the respective oil reservoir. The operator is also allowed to inject (and incidentally store) substances to fit that end. In CO₂ storage operations, the operator needs to operate within the Area of Review, or Area of Influence, as defined by the regulatory agency in the respective jurisdiction. In some cases the Area of Review may extend beyond the area of the oil reservoir leased by the operator into lands owned or leased by a different entity. In this case, operating (e.g., for ongoing or post EOR monitoring) on the surface or in the subsurface, on land owned or leased by another entity may pose operational and legal challenges.

In oil producing countries, regulations are in place at the national or subnational level (state or province), for oil production and field and well abandonment. The regulatory framework for CO₂ storage is being developed and evolving in some countries, and is totally absent in others, but where it is being developed it is different from the regulatory framework for CO₂-EOR. Furthermore, in federal countries with subnational jurisdictions, different regulations may be developed at the national and subnational levels, with the operator having to meet both.

Finally, liability in the case of CO₂-EOR operations is well defined, while the long-term liability for CO₂ storage operations is only being developed and is still evolving only in some jurisdictions. For example, some states in the United States (e.g., Wyoming) have stated that they will not assume the long term liability of CO₂ storage operations, while the Province of Alberta in Canada and the State of North Dakota in the United States have both passed legislation by which they will assume the long-term liability of CO₂ storage operations, although the conditions under which the transfer of liability will take place have not been defined yet. The issue of long-term liability affects operational strategies in the case of CO₂ storage.

The issue of long-term liability is a country-by-country, and/or state/province by state/province issue and it will mature as the industry evolves.

Assurance of Well Integrity. While injection, production, suspended and abandoned wells have to be tested (mechanical integrity testing) and ultimately repaired in both CO₂-EOR and CCS operations, depending on jurisdiction there might be some differences stemming from the definition of the Area of Review and from the regulatory framework in place. In CO₂-EOR operations, wells within the operator's lease must be and are being checked regularly by the operator, and, if leaks are detected and the well has to be fixed immediately or fixing it may be delayed until abandonment, depending on the severity of the leak and on the regulatory requirements in the respective jurisdiction (state/provincial or national). In CO₂ storage operations, at least based on current regulations where storage rules exist, leaky wells have to be fixed prior to the start of CO₂ injection, regardless of the severity of the leak. More importantly, the Area of Review within which wells have to be checked and possibly repaired may extend beyond the operator's lease, in which case checking the status of wells and fixing leaking wells on somebody else's lease may pose a legal and monetary challenge that has to be addressed. It is appropriate to note that some jurisdictions, such as Texas in the United States and Alberta in Canada, have wells drilled more than 100 years ago and have instituted "orphaned well funds" to assist in plugging of wells or remediating leaky wells that do not have

an owner anymore. These funds and activities will apply on lands that might fall within an Area of Review but have no identified owner.

Monitoring. This is the area where the differences between pure CO₂-EOR and pure CO₂ storage operations may be the most obvious. Currently, CO₂-EOR operations do considerable surveillance to assure the injected CO₂ is at work within the reservoir, but for reasons of economics. Regulatory rules to monitor wellhead injection parameters, such as pressure, temperature, rate and composition, and produced fluids are generally required and reported on a periodic basis. Depending on jurisdiction, these have to be reported to the state/provincial or national regulatory agency (e.g., in Alberta, Canada). Generally monitoring ceases when the reservoir and wells are abandoned (abandoned wells may be still monitored for leakage). In the case of pure CO₂ storage, the monitoring and reporting requirements may be more extensive, both in terms of what and in terms of frequency and duration, than in the case of CO₂-EOR or gas storage operations. More specifically:

- a. Assurance monitoring (where and how much CO₂ is in the storage reservoir);
- b. Requirement for more environmental monitoring that may include sensors in, or sampling from, the sedimentary succession above the reservoir, shallow potable-groundwater aquifers, soils and surface within the Area of Review;
- c. Baseline monitoring prior to start of CO₂ injection.
- d. Monitoring after cessation of CO₂ injection for various periods of time, depending on regulations in the respective jurisdiction, such as:
 - i. until stabilization of the CO₂ plume;
 - ii. for a fixed period of time (e.g., 5, 10 or 15 years); and/or
 - iii. until transfer of liability to a designated governmental agency.
- e. Requirement for reporting of CO₂ stored, and of any CO₂ that has migrated out of the storage unit in case of CO₂ movement off lease, or any leakage to the overlying sedimentary succession, including other reservoirs and shallow potable-groundwater (surface leaks currently are required to be reported in the case of both CO₂-EOR and CO₂ storage).

While all these activities are feasible with current technologies and with technologies under development, and while all these requirements can be met by operators where conditions exist, these activities increase significantly the costs and liabilities incurred by the operator in the case of CO₂ storage compared with the case of pure CO₂-EOR and ongoing gas storage operations.

Industry's Experience. While the oil industry has a long and well established experience with CO₂-EOR operations, there is insufficient experience with CO₂ storage operations, particularly in oil reservoirs.

5.3 CONCLUSION AND RECOMMENDATIONS

The analysis presented thus far indicates that there are no specific technological barriers or challenges *per se* in transitioning and converting a pure CO₂-EOR operation into a CO₂ storage operation. The main differences between the two types of operations stem from legal, regulatory and economic differences between the two. While the legal and regulatory framework for CO₂-EOR, where it is practiced, is well established, the legal and regulatory framework for CO₂ storage is being refined and is still evolving. Nevertheless, it is clear that CO₂ storage operations will likely require more monitoring and reporting 1) of a wider range of parameters, 2) outside the oil reservoir itself, and 3) on a wider area, and for a longer period of time than oil production. Because of this, pure CO₂ storage will impose additional costs on the operator. In addition, the integrity of all the wells penetrating the oil reservoir and host formation in the Area of Review will

have to be checked and assured. A challenge for CO₂-EOR operations which may, in the future, convert to CO₂ storage operations is the lack of baseline data for monitoring, besides wellhead and production monitoring, for which there is a wealth of data. The absence of infrastructure for the capture and transportation of CO₂ to oil fields and the high cost of CO₂ are also a challenge.

In order to facilitate the transition of a pure CO₂-EOR operation to CO₂ storage, operators and policy makers have to address a series of legal, regulatory and economic issues in the absence of which this transition can not take place. These should include:

- 1) Clarification of the policy and regulatory framework for CO₂ storage in oil reservoirs, including incidental and transitioned storage CO₂-EOR operations. This framework should take into account the significant differences between CO₂ storage in deep saline aquifers, which has been the focus of regulatory efforts to date, and CO₂ storage in oil and gas reservoirs, with particular attention to the special case of CO₂-EOR operations.
- 2) Clarification if CO₂-EOR operations transitioning to CO₂ storage operations should be tenured and permitted under mineral/oil & gas legislation or under CO₂ storage legislation.
- 3) Clarification of any long-term liability for CO₂ storage in CO₂-EOR operations that have transitioned to CO₂ storage, notwithstanding the CO₂ incidentally stored during the previous pure CO₂-EOR phase.
- 4) Clarification of the monitoring and well status requirements for oil and gas reservoirs, particularly for CO₂-EOR, including baseline conditions for CO₂ storage. Attention should be given to the fact that, unlike a deep saline aquifer, an oil or gas reservoir that has been under production is no longer at initial conditions and the baseline for CO₂ storage is most likely (surely) different. For future CO₂-EOR operations the baseline data can be obtained, but most likely they will be collected only if the operator considers transitioning to CO₂ storage.
- 5) Addressing the issue of jurisdictional responsibility for pure CO₂ storage in oil and gas reservoirs and if it is different from natural gas storage, both in regard to national-subnational jurisdiction in federal countries and to organizational jurisdiction (environment versus development ministries/departments).
- 6) Examination of the need to assist with the economics, particularly the cost of CO₂ and the infrastructure to bring anthropogenic CO₂ to oil fields.

In regard to CSLF, the Policy Group should take note of these issues and establish ways to address them within CSLF and make appropriate recommendations to the governments of its members.

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