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TECHNICAL ASPECTS OF CO_2 ENHANCED OIL RECOVERY AND ASSOCIATED CARBON STORAGE

This paper was prepared by Dr Steve Whittaker and Dr Ernie Perkins, respectively Principal Manager–Carbon Storage and Consultant–Projects, during their time at the Institute.

October 2013

1.1 Background

The injection of carbon dioxide into oil fields is one method of enhancing oil recovery that has been used commercially for more than 40 years. For enhanced oil recovery (EOR), carbon dioxide gas (CO_2) is compressed at surface and injected as a liquid into the oil reservoir at depth where it effectively acts as a solvent to increase the amount of oil that can be produced from the field. Typically, CO_2 EOR is a tertiary method applied to reservoirs that have declining oil production and that have progressed through primary and secondary production stages.

Primary production uses the reservoirs' natural pressure to drive the oil to surface whereas secondary production typically involves pumping the oil to surface and injection of water to restore or increase reservoir pressure to drive oil production. The reason CO_2 is used in a tertiary method is because water does not mix with the oil (they are immiscible) whereas CO_2 and oil can mix (they are miscible) at reservoir conditions. This results in the oil becoming less viscous so that it flows more easily. Very generally, if a secondary water injection program is successful, it bodes well for a CO_2 EOR program being successful. It must be noted that not all oil fields are suitable for CO_2 injection as oil composition, depth, temperature and other reservoir characteristics significantly influence the effectiveness of this method (Melzer, 2012).

The amount of oil that can be recovered during the different production stages is again highly dependent on the nature of the geological reservoir and oil composition, but in very general terms fields typically targeted for CO_2 EOR have had primary recovery of about 10–20 per cent of the original oil in place, secondary recovery of an additional 10–20 per cent, and expectations from CO_2 EOR of another 10–20 per cent. Thus CO_2 EOR provides an opportunity to improve the efficiency of resource extraction and clearly can lead to significant economic benefits through sales from additional oil production and through extending the productive life of suitable oil fields by decades. An additional noteworthy benefit of this method is that when the CO_2 mixed with the oil is produced it can be separated and re-injected and ultimately retained in the reservoir so that incidental geological storage of CO_2 is an intrinsic part of the overall process.

A number of excellent overview papers on the geological and engineering aspects CO_2 EOR, including potential for storage, have been released recently (such as Hill et al, 2013; National EOR Initiative, 2012; Melzer, 2012; Berenblyum et al. 2011; Kuuskraa et al. 2011; and Hovorka and Tinker, 2010).

Currently, about 130 commercial CO_2 EOR operations, also called CO_2 floods, have been deployed around the world, although the vast majority are in the United States. Roughly half of the American projects are within a geologic setting known as the Permian Basin located in west Texas where commercial CO_2 EOR operations were first attempted in Scurry County at the Scurry Area Canyon Reef Operators Committee (SACROC) site in 1972. It is notable that SACROC initially used an anthropogenic source of CO_2 (A-CO_2) from capture at natural gas plants as most of the subsequent development of CO_2 EOR sites in the Permian Basin and surrounding regions was driven by the availability of relatively inexpensive CO_2 produced from reservoirs that contained geologically (*i.e*. naturally) sourced CO_2 (N-CO_2).

Geological structures such as the McElmo Dome in Colorado and Bravo Dome in New Mexico are features that contain enormous quantities of naturally occurring CO_2 (Allis et al., 2001). The McElmo Dome alone contained more than 280 billion m3 of high purity CO_2 and together with the Bravo Dome these natural sources supply more than 40 million m3/d of CO_2 to oil fields in Texas, Utah and Oklahoma (DiPietro and Balash, 2012). Today, about 7,000 km of CO_2 pipelines (Dooley et al., 2009) transport about 70Mt CO_2 per year for use in North American CO_2 EOR operations of which about 75 per cent originates from natural geological sources and the remainder from anthropogenic sources such as gas plants and fertiliser plants. Two commercial-scale capture projects to supply anthropogenic CO_2 for EOR from coal-fired power plants are in construction at the Boundary Dam Power Plant in Saskatchewan, Canada and in Kemper County, Mississippi, USA.

Most, if not all, CO_2 EOR operators do not implement procedures to optimise opportunities for storage of CO_2 in association with their floods because there is no present financial or regulatory impetus to consider storage as a component of their business. Rather, the cost of purchasing CO_2 leads companies to minimise the amount of CO_2 required to produce a barrel of oil, and operators continuously attempt to optimise economic return based around the price of oil and cost of CO_2. For operators to consider carbon storage a part of the business some form of price, tax or policy on carbon will need to be implemented. In the instance that regulatory or economic drivers do arise, transitioning CO_2 EOR operations to more actively include storage and ultimately become dedicated carbon storage sites will involve some operational modifications and likely require additional monitoring and verification activities than typically implemented for oilfield, including EOR, operations at present.

1.2 How CO_2 EOR works

Enhanced, or tertiary, oil recovery methods involve techniques that alter the original properties of the oil allowing it to be more easily produced. Injection of CO_2, other solvents, or steam (heat) are among the most common forms of EOR. CO_2 EOR can be applied to a range of reservoir settings including sandstones, limestones and dolostones; in structural or stratigraphic traps; in small isolated buildups or giant fields; and onshore or offshore (although no commercial offshore CO_2 EOR has yet been performed). Limitations to deployment are largely influenced by depth (temperature) of reservoir, oil composition, previous oil recovery practices and internal reservoir features that may hinder effective distribution of the injected CO_2. Access and proximity to a relatively pure and consistent stream of low-cost CO_2, however, is among the more critical factors limiting wider deployment of CO_2 EOR.

The cost of initiating a CO_2 flood is significant and a large anchor field is often needed to develop the infrastructure to deliver CO_2 before smaller nearby fields are able to access a supply. In the southern United States the availability of relatively low-cost CO_2 from naturally occurring geological sources in proximity to suitable oil fields is a primary reason for the early development and extensive use of CO_2 EOR in this region. Either geologically sourced CO_2 or anthropogenic CO_2 can be used in CO_2 EOR, although a requirement for CO_2 purity of greater than 95 per cent is a rule-of-thumb. Whereas some A-CO_2 can be obtained quite pure relatively easily (from natural gas processing for example) other captured sources such as from coal-fired power plants must go to greater effort and expense to purify CO_2 to the required specification. Other components in the CO_2-stream may reduce (or enhance) miscibility so most operators prefer to work with relatively pure CO_2.

After capture the CO_2 is compressed and usually pipelined to the field although trains and trucks have also been used to deliver CO_2 for pilots and smaller-scale operations. Ships have also been proposed to move large quantities of CO_2 for offshore use or to areas without other natural-source or capture options (Chiyoda, 2013). In North America an extensive network of pipelines has been transporting compressed CO_2 for decades using well-established protocols, standards and safety procedures. Once delivered to the field the CO_2 is further distributed to the injection well(s) and injected into the reservoir.

The compression of CO_2 for transportation and injection converts the CO_2 from a gas into a denser phase – either to liquid or to a supercritical fluid. Supercritical fluids are physically similar to, but not strictly, liquids or gases, and supercritical CO_2 has a density similar to a liquid and mobility similar to a gas. Many common materials such as water and carbon dioxide become supercritical above specific pressures and temperatures; for CO_2 this is a temperature greater than 31.1°C and a pressure greater than 7.38 Mpa (Bachu, 2008). These conditions are reached naturally in the subsurface generally below about 800 m depth and most CO_2 EOR operations (and saline formation storage projects), therefore, will target reservoirs of this depth or greater. This is to ensure that the injected CO_2 will remain in a dense state and to minimise its buoyancy in the reservoir. Figure 1 depicts the pressure and temperature influence on the density of CO_2. This is an important concept for enhanced oil recovery as supercritical CO_2 has properties that make it an effective solvent for many oils.

When injected CO_2 contacts reservoir oil, the dense CO_2 will begin to dissolve into the oil, and the oil will begin to dissolve into the dense CO_2. This mixing does not occur instantaneously, but with time and repeated contact between the fluids the oil and CO_2 can mix to become a single phase. In the instance where CO_2 and oil mix completely it is termed miscible and CO_2 floods are often referred to as miscible floods. The effect of this miscibility is to cause the oil to swell slightly and become less viscous so that it flows within and through the reservoir pores more easily. The majority of CO_2 EOR projects operate in fully miscible conditions; however incomplete mixing or partially to completely immiscible CO_2 floods may also be operated and can be effective at increasing oil production.

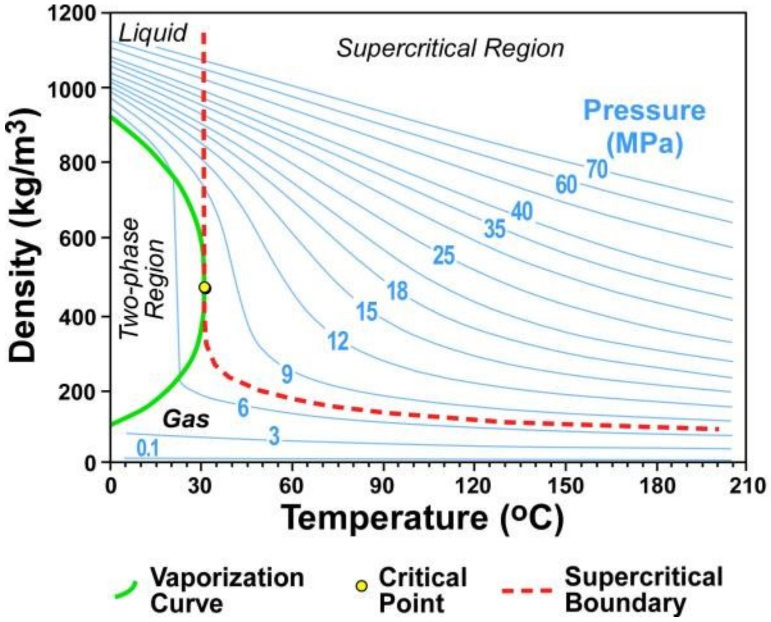

Figure 1: Relation of the density of carbon dioxide to temperature and pressure (Bachu, 2003).

A key parameter for an effective CO_2 EOR project is maintaining oil-CO_2 miscibility which is primarily a function of reservoir pressure. The minimum miscibility pressure (MMP) is the lowest pressure at which an oil and CO_2 are completely miscible. The MMP is specific for individual oil compositions and must be determined by performing laboratory analyses such as using a slim tube apparatus or through a rising bubble experiment (Figure 2). Although numerical models and correlations also exist to estimate MMP for most oils, MMP should be confirmed experimentally for any particular oil reservoir. Oil recovery operations are usually designed to maintain reservoir pressure above the MMP. If the pressure during oil recovery is less than the MMP the lighter hydrocarbon components in the oil (lower molecular weight and generally lower viscosity) may be preferentially produced. This leads to the residual oil becoming progressively more viscous and more difficult to recover, and increases the potential for asphaltenes and waxes (components common in many crude oils) to precipitate and become lodged in pores and small channels connecting pores thereby plugging or reducing flow within parts of the reservoir.

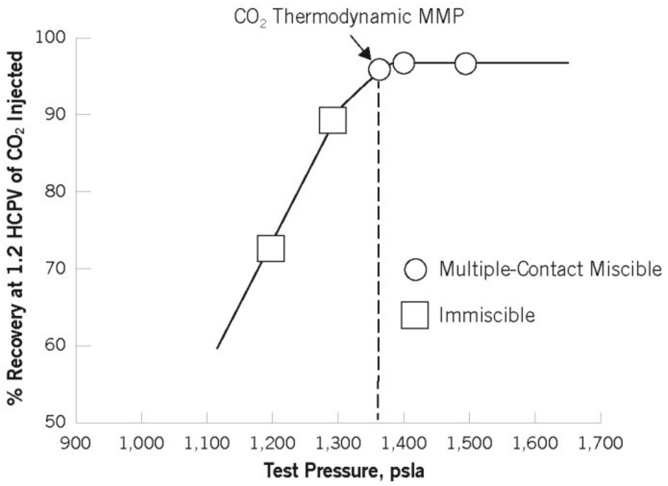

Figure 2: Miscible and immiscible zones during experimental oil recovery as a function of CO_2 (reservoir) pressure. HCPV = hydrocarbon pore volume. Shelton and Yarborough (1977).

One of the aims of CO_2 EOR is to have a relatively smooth front of CO_2 'sweeping' oil not previously recovered into the producing wells. The density of supercritical CO_2 is slightly less than water and oil so injected CO_2 will tend to be buoyant in the reservoir providing the potential to sweep higher and potentially unswept portions of the reservoir, but also with the possibility of over-riding and thereby bypassing the oil. Variations in physical characteristics of the reservoir such as porosity and permeability play a critical role in influencing the effectiveness of the distribution of the injected CO_2.

Porosity is the void spaces between grains or minerals, and permeability is a measure of the ability of a rock to allow fluids to flow through it. Small scale heterogeneities effectively disperse the CO_2 and expand the contact region between CO_2 and oil, whereas larger scale heterogeneities may channel the injected CO_2 thereby reducing reservoir sweep (often referred to as viscous fingering). The affinity of mineral surfaces for water or other fluids is known as wettability and this also influences the movement of water, oil and CO_2 within the reservoir. For example, if the reservoir rock is water-wet, this indicates a thin film of water is present on all mineral surfaces and oil does not touch the surfaces (Melzer 2012). Moreover, each fluid may have a different permeability within the reservoir depending on fluid proportions (saturation) and compositions.

Determining the relative permeability of CO_2, oil and water is an important parameter for modeling the long-term performance of the flood. The influences of the reservoir heterogeneities, relative permeability and wettability all must be considered in the design of the CO_2 flood, which in turn encompasses well placement, CO_2 injection rates, water injection rates, and reservoir pressure management.

1.3 Recovery Methods and Processes

There are several strategies for injecting CO_2 and recovering oil in CO_2 EOR operations. Most straightforward is to inject CO_2 into a single well over a finite time, leave the CO_2 in the reservoir for days, weeks or even months (soak period), and then produce reservoir fluids using the same well. This is called cyclic stimulation or the 'huff n puff' method (Figure 3) and is generally used only in small fields or in a pilot test to establish suitability or potential for CO_2 EOR. More usually, fields targeted for CO_2 EOR are relatively large involving tens to hundreds of existing wells and which have already undergone a secondary process for oil recovery (Edwards et al., 2002). Often the wells are configured in patterns; a single injector well surrounded by several producing wells, or several injector wells surrounding a central producer. The style of the patterns can be highly variable depending on reservoir and operator preference and may include both horizontal wells and vertical wells. The operator may need to drill new wells and decommission others to prepare the field for the flood and several years may be needed to implement the required changes to the existing field infrastructure. Usual facility upgrades include gas separation facilities such as recompression and dehydration, the drilling of new wells, upgrading existing valves and fittings, installing additional pipelining and gathering system.

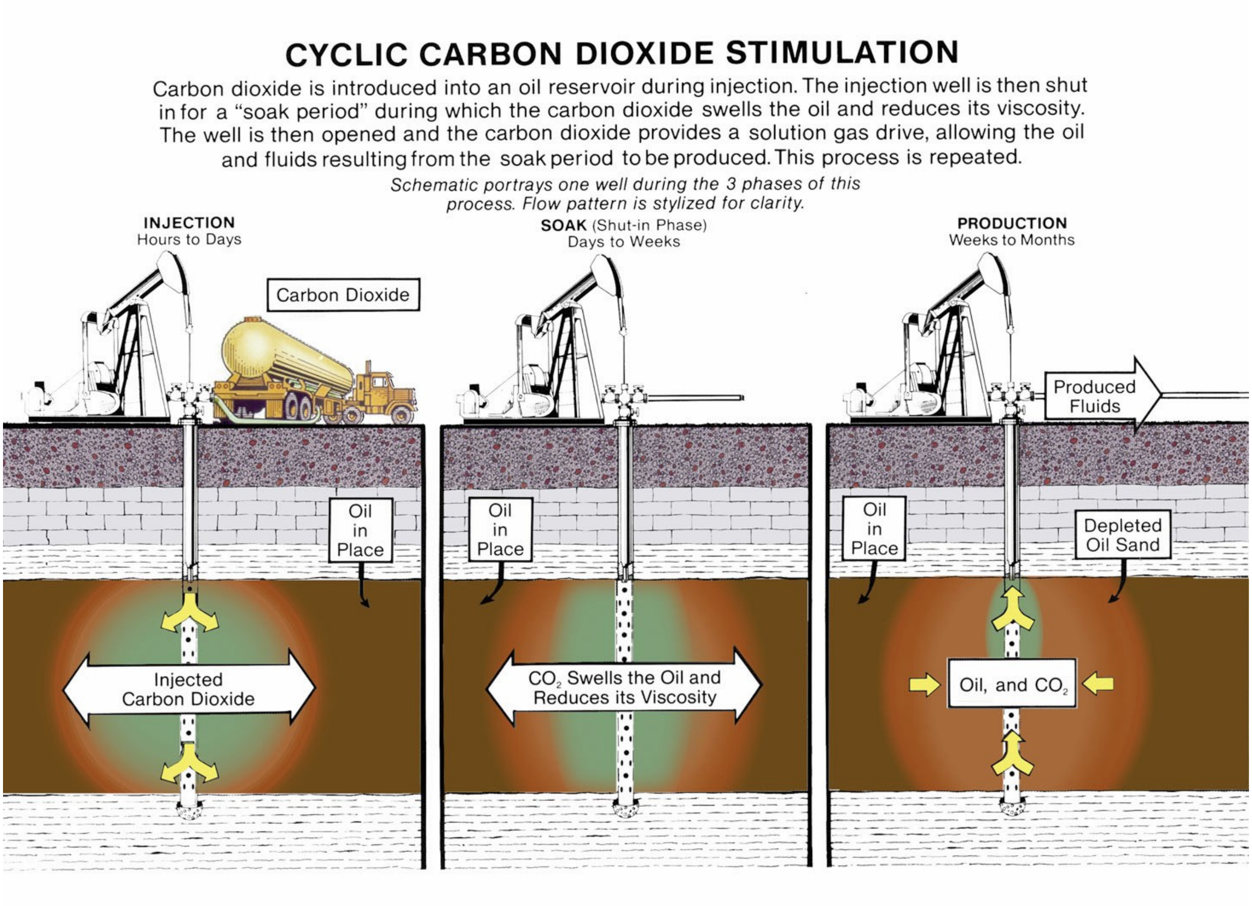

Figure 3. Diagram of cyclic CO_2 EOR recovery methods. The CO_2 is injected into the reservoir and allowed to 'soak' to enable the CO_2 to mix with the oil and then produced. This cycle can be repeated. US Department of Energy, NETL.

A fundamental consideration in production design is whether the CO_2 flood will be miscible or immiscible as determined by reservoir pressure and which can be influenced by operating parameters (Stalkup 1983). An immiscible flood is basically a drive process; the injected CO_2 effectively pushes the oil towards the production well but this process also suffers from the large viscosity contrast between the injected CO_2 and the reservoir oil. Whereas a miscible CO_2 flood does entail some component of 'push', its strength is in the resulting decreases in oil viscosity and density (oil swelling) that results in a more efficient sweep of oil.

Figure 4 illustrates idealised behaviour in a miscible flood showing the development of compositional zones within the reservoir along the path of oil displacement by the injected CO_2.

Figure 4: Illustration of the zones that develop in miscible CO_2 flooding.

The CO_2 being more buoyant and less viscous than oil, however, may potentially channel or finger through the upper reservoir thereby bypassing oil and breaking through at a producing well. To reduce the chance of early breakthrough and improve sweep, operators will often inject alternating slugs of water and CO_2 in what is known as a WAG (Water Alternating Gas) process (Figure 5). Water has a viscosity more similar to the dominant reservoir fluids (brine and oil) than CO_2, and can provide a more uniform sweep. Water is also heavier than oil so that it may tend toward the lower portion of the reservoir complementing the less dense CO_2 that may rise to the upper portion of the reservoir. Most current CO_2 floods implement some form of WAG within their operations. A version of this strategy is to simultaneously but separately inject water and CO_2 (SS-WAG) shown in Figure 6 as deployed at the Weyburn Field in Saskatchewan, Canada (Monea and Wilson, 2004).

In this example vertical wells are used to inject water lower in the sequence to provide pressure support and maintain a more efficient sweep by the CO_2 that is injected using horizontal injection wells in the upper part of the reservoir. Alternatively, some operators implement continuous CO_2 injection without using water. Continuous CO_2 injection is suitable for gravity driven processes where the CO_2 is injected at the top of the reservoir and pushes reservoir fluids downward to a deeper production well (or, where injected below the production well, quickly moves upward and overrides). Continuous injection can also be used in thinner reservoirs where the effect of CO_2 over-riding oil because of lower density is minimal. Continuous CO_2 injection may also be used in more conventional settings and also uses the most CO_2 of all EOR methods; a significant aspect of alternating water injection with CO_2 is that water, when available, is much less expensive than CO_2.

In practice, a combination of recovery processes can be used within a single reservoir and the design and operation of the recovery process is rarely static. If CO_2 breakthrough occurs at a production well, or reservoir monitoring suggests that the sweep is missing a portion of the zone, additional wells may be drilled. Production and monitoring data and reservoir simulation results may suggest turning wells off or back on, and perhaps switching injectors to producers or visa-versa. In a large field such as the Weyburn Field at various times WAG, SS-WAG and continuous injection patterns have all been in operation simultaneously (Monea and Wilson, 2004).

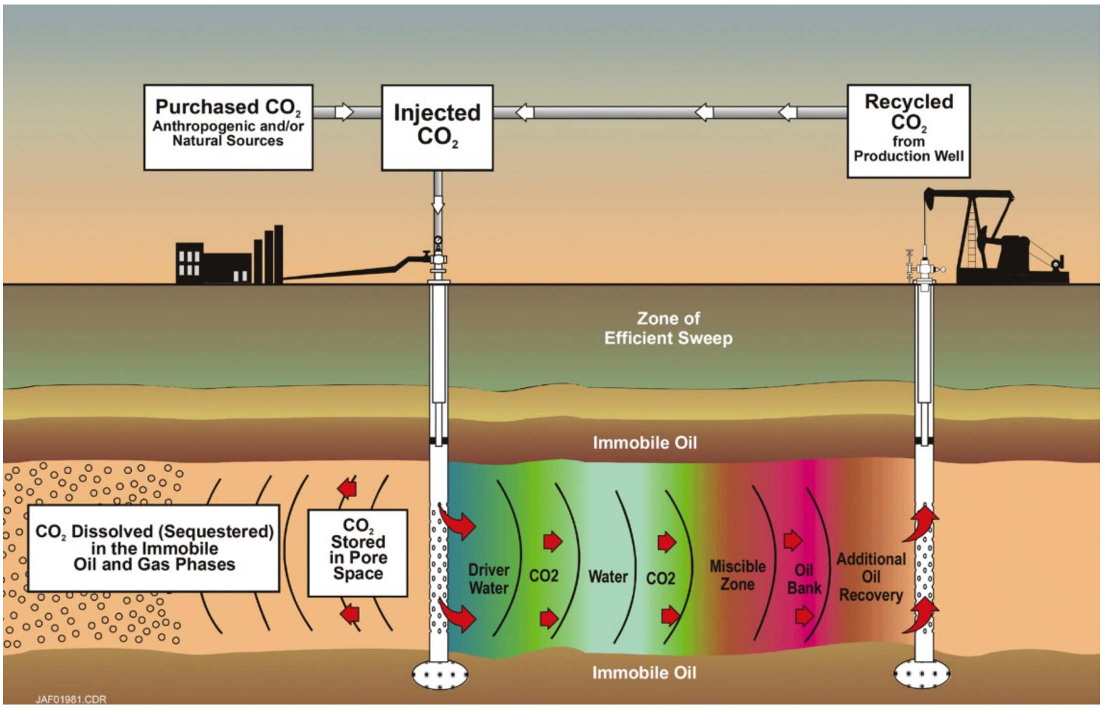

Figure 5: Depiction of CO_2 EOR WAG operations with the various miscible zones identified. Figure from Advanced Resources International and Melzer Consulting (2010).

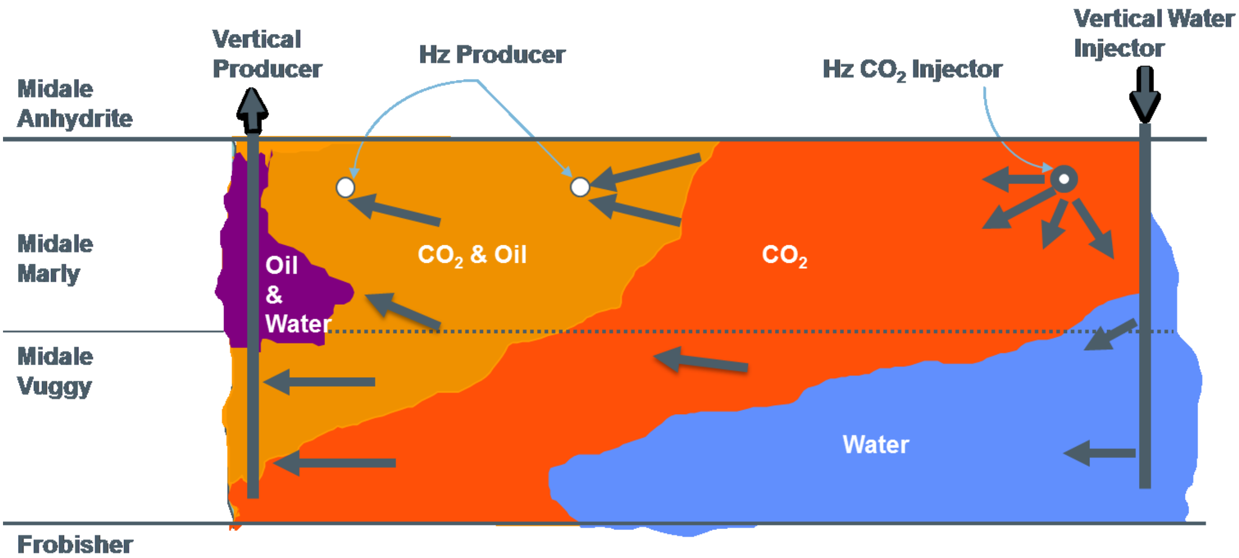

Figure 6: Simultaneous but separate WAG as deployed at the Weyburn Field in Saskatchewan, Canada. CO_2 is injected into the upper reservoir zone using a horizontal well and water is injected simultaneously into the lower reservoir zone using a vertical well. Production wells are both horizontal and vertical in this instance. (Wilson and Monea, 2004).

1.4 Response, Recycle and Incidental Storage

An example of reservoir response to a large-scale CO_2 flood is shown in the production graph of the Weyburn Field in Figure 7. CO_2 injection commenced in October 2000 and ten years later oil production had increased to daily volumes not recovered since the 1970s with 20,000 barrels of oil/day incremental production, or two-thirds of the total field production, due to the CO_2 EOR process. At the onset of a CO_2-flood only a subset of the total patterns within a large oil field may receive CO_2 and with time the flood is rolled-out in stages more broadly across the field. CO_2-floods are long-lived operations spanning decades; parts of a large field subjected to early CO_2 injection may be suspended once production drops prior to other areas even being started to be flooded. Operators will continually monitor injection rates, production volumes and downhole pressures to tweak operating parameters and adjust recovery strategies. Some operations may also include surveillance wells, repeat seismic surveys and other monitoring techniques (such as saturation logging or fluid sampling) within their program to assess CO_2 distribution and field performance.

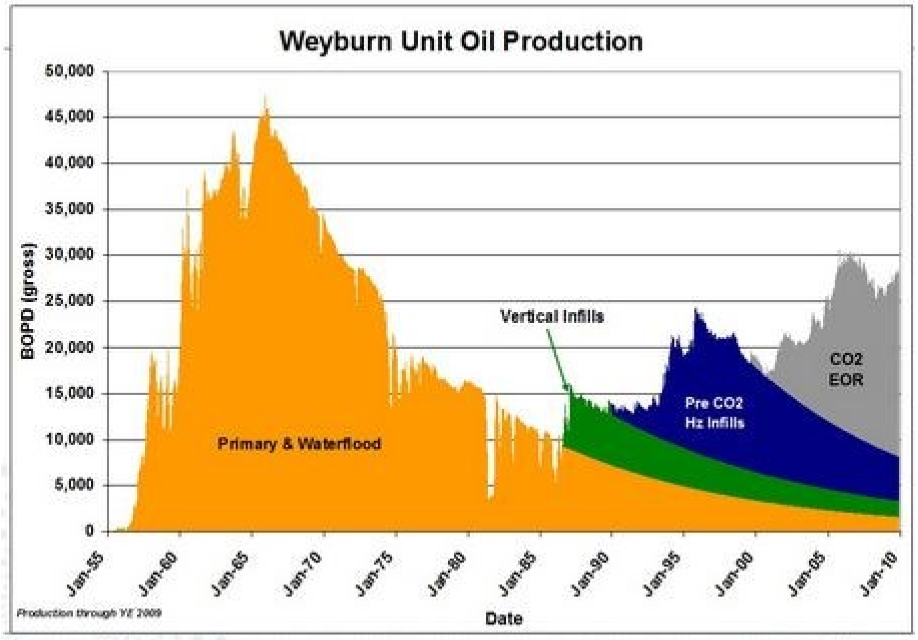

Figure 7: Production history over 55 years at the Weyburn Unit, Saskatchewan, Canada, showing stages from Primary production, Secondary water-flooding, infill drilling (both vertical and then more dominantly horizontal wells) and implementation of Tertiary CO_2 EOR. (Hitchon, 2012)

Operators try to be as efficient with the use of CO_2 as possible as it is one of the more expensive components of the project. Recovery efficiencies can be expressed by the number of tonnes CO_2 injected to recover a cubic metre of oil (or some equivalent form of utilisation factor such as mcf/bbl). As the oil is brought toward the surface within the production well, the pressure decreases and the once miscible CO_2 begins to unmix with the oil. At surface the CO_2 can be separated, collected, dehydrated, compressed and re-injected into the reservoir. This recycling reduces the need to purchase additional CO_2 and effectively establishes a closed-loop use of CO_2. It also avoids emitting this CO_2 to atmosphere. There can be small-scale losses of CO_2 to atmosphere during surface equipment maintenance or power outages, and also in some circumstances such as during well workovers (general well maintenance) when, for a restricted period, the volume of recycle is more than can be injected and some recycle CO_2 may be emitted or vented.

A major influence on recovery efficiencies is the retention of CO_2 within the reservoir. A large portion of a given volume of CO_2 injected into a reservoir, generally considered to be 30 to 40 per cent but variable for different reservoirs, will not return to the surface with oil as it gets trapped at the end of pore channels or stuck on mineral surfaces. This 'loss' of CO_2 to the oil production cycle is actually a form of geologic storage as the CO_2 will be contained within the reservoir indefinitely and is an unavoidable mechanism associated with CO_2 EOR that is sometimes referred to as incidental storage. Moreover, as the 60 per cent or so of the injected CO_2 that does come out with oil is captured and re-injected, a similar proportion of the CO_2 from this cycle of injection will be stored incidentally.

As the recycled CO_2 is re-injected in numerous cycles, more of it will be progressively retained by incidental storage so that through this process essentially all the purchased CO_2 will eventually reside within the geologic reservoir. Melzer (2012) provides a clear discussion of this mechanism and indicates that almost all of the purchased CO_2 for a CO_2 EOR project will eventually be securely trapped in the subsurface and that loses are very minor and mainly related to surface activities as mentioned above.

During the course of the CO_2 EOR operation the amount of CO_2 purchased will remain somewhat constant to partially offset that lost through incidental storage and also maintain expansion of the flood. Because of the growing cumulative injection of purchased CO_2, the amount of recycled CO_2 will correspondingly increase so that the daily rate of total CO_2 injected (recycled plus newly purchased) will also increase during the initial to mid-stages of the flood. At some point, the amount of recycle may surpass that of the fresh CO_2 and eventually the flood will begin to taper off purchase of new CO_2 and rely increasingly on recycled CO_2 (Figure 8).

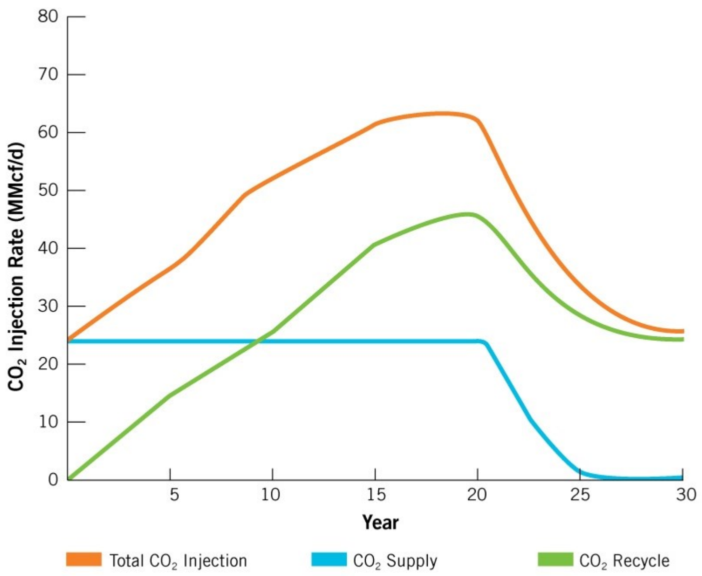

Figure 8. Stylised forecast injection rates for an oil field based on cumulative CO_2 retention. CO_2 supply from a capture source may remain constant, but total injection increases as CO_2 recycle increases. Eventually purchase of CO_2 is reduced and only recycle is used in the latter stages of the flood.

1.5 Storage Capacity

Individual oil fields will have greater capacity to store CO_2 than results from an EOR operation. EOR operators will try to minimise use of CO_2 to minimize costs, but alternative operational scenarios can result in additional carbon storage. An extensive study was performed at the Weyburn Field to evaluate the merits of different strategies for storage and incremental oil production (Law, 2004). In this work the base-case scenario representing the operation as planned by the operator was simulated until the expected end of EOR in 2033. (Note the present operators have now expanded the extent and duration of the flood, but these simulation studies still serve to highlight storage potential).

Under this base-case scenario, over 23MT CO_2 would be stored from 2000–2033. By purchasing and injecting more CO_2 during operations (increasing the utilisation ratio), up to 30MT could be stored to year 2033 at end of commercial EOR operations. Scenarios were also evaluated for storage optimization post –EOR. By simply continuing to inject CO_2 until a pressure limit in the reservoir was reached and then systematically shutting in wells (stopping injection) an incremental storage of 6 to 7 MT CO_2 could be added to the above scenarios. As the Weyburn Field is a low permeability reservoir pressure limits would be reached within two to three years; more permeable reservoirs would take longer to reach a threshold pressure. Alternatively, by maintaining CO_2 injection post-EOR but with continued production of fluids from wells at gas to oil ratios much higher than would be typically produced (i.e. non-economic), an additional 30MT CO_2, or about double the base-case, can be stored without significant change to infrastructure (Wilson and Monea, 2004).

Storage potential in oil reservoirs can also be increased by targeting portions of the reservoir not usually accessed by EOR strategies. Near the base of reservoirs there is often a zone that is transitional between oil saturation and water saturation and is generally considered non-economic. This part of the reservoir is also called the residual oil zone (ROZ) and is gaining interest for increasing storage capacity and also for the possibility of recovering oil previously considered unrecoverable. Brine-filled formations also can occur beneath, adjacent or above oil reservoirs but with their use prevented from ownership or access rights, or lack of economic benefit. If these saline reservoirs are assessed to be appropriate for storage they can potentially be more easily accessed using the existing infrastructure associated with the CO_2 EOR operation. These situations are examples of stacked storage potential.

Storage estimates associated with CO_2 EOR in North America are over 20 billion metric tonnes CO_2 and by including ROZ potential this could increase by more than 50 per cent (Carpenter 2012). Globally Carpenter (2012) has suggested storage potential of several hundreds of billion tonnes. Although these numbers are very preliminary, they do indicate that there is significant storage potential associated with CO_2 EOR and that it can be important for future CCS development. Figure 9 indicates the potential mass of CO_2 stored in projects at various stages of advancement as determined during the Global CCS Institute's 2013 survey of Large-Scale Integrated CCS Projects (LSIPs). For the 65 LSIPs identified in the 2013 survey the storage potential associated with CO_2 EOR is much greater than for any form of geologic storage.

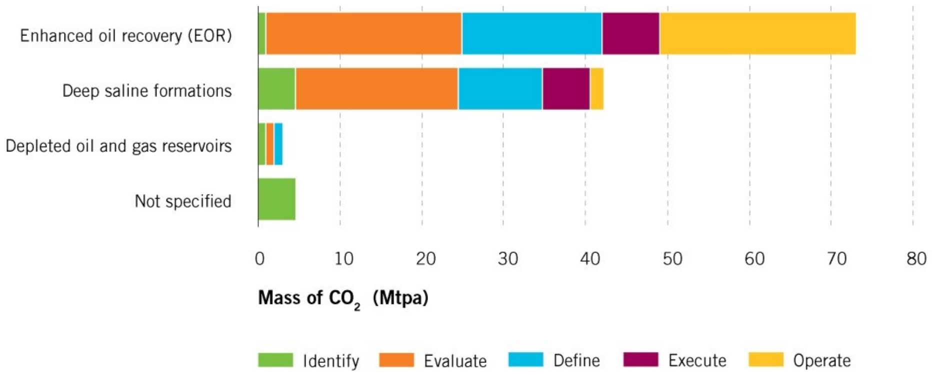

Figure 9. The potential mass of CO_2 that is being considered in different storage options in large-scale CCS projects. CO_2 EOR currently stores more CO_2 than any other method of geological sequestration. (Global CCS Institute, 2013)

1.6 Issues on Implementing Storage in conjunction with EOR

There are many challenges involving technical, business, legal and regulatory issues in the implementation or transition to storage as part of existing oil and gas operations. Technical challenges in the transition from CO_2 EOR to CCS include determining whether the reservoir is suitable for storage; establishing monitoring and accounting requirements for CCS; and considering operational issues associated with implementing or transitioning to storage.

In general, reservoirs suitable for CO_2 EOR are proven containers for retaining fluids as they have demonstrated sealing capabilities and relatively well-known storage capacities. Prior operational activities would also have identified injectivity characteristics as well as potentially defining numerous operational parameters including fracture gradients and pressure thresholds. Thus characterising the storage facility for an existing CO_2 EOR operation is generally more readily performed than for a greenfield saline formation storage project.

The goal of the monitoring requirements for geologic storage is to establish that the injected CO_2 remains in the target storage formation (or storage complex) and that none has migrated laterally or vertically out of this zone, potentially impacting other resources or the surface. The existence of numerous wells, pipelines, treatment and separation facilities and prior oil field activities in a CO_2 EOR operation makes it challenging to establish baselines for many monitoring parameters prior to the transition to a storage facility. In addition, where a large number of wells exist (abandoned, suspended and active) this may contribute to increased risk of potential leakage. In such instances, that risk must be assessed and mitigated as necessary through added monitoring or re-abandonment (reworking), as and if appropriate. This could be an expensive undertaking depending on the extent of mitigation. Finally, the CO_2 EOR operation or previous water injection or other field operations may have either modified portions of the reservoir or cap-rock through pressure cycling and final depressurisation.

An aspect often discussed regarding storage associated with CO_2 EOR is the monitoring requirement to account for the injected CO_2. While specific requirements may be established by individual jurisdictions or on a project basis, it is worth repeating that many current operations do conduct ongoing monitoring activities such as pressure monitoring, but also may use dedicated surveillance wells, repeat seismic surveys, geophysical logging and fluid sampling to provide data for maintaining or improving flood performance. The routine evaluation of gas/oil ratios from numerous production wells also provides much data regarding the distribution of CO_2 within the reservoir. What may evolve different to routine operations may be monitoring above the reservoir, including at surface.

From the specific standpoint of identifying operational considerations that can increase storage potential, options may include increasing purchase amounts of CO_2, decreasing WAG cycles and possibly injecting into deeper zones or less productive regions of the field (subject to appropriate incentives being in place aimed at maximization of storage potential). Aspects involving post-EOR activities may include continuing injection past economic oil recovery and development of a closure and post-closure operational plan (again subject to appropriate incentives being in place aimed at maximizing storage potential).

1.7 Summary

Injection of carbon dioxide into mature oil reservoirs is a proven effective method for improving oil production that can be applied to a variety of oil reservoirs in different geological settings. Retention of the injected carbon dioxide within the reservoir is an intrinsic part of the CO_2 EOR process, and effectively all CO_2 purchased for injection will ultimately remain stored within the oil field at the end of EOR operations. This storage aspect has driven interest in CO_2 EOR as a potential method of CCS that has a supportive business component.

The storage opportunities within CO_2 EOR floods are generally not maximised, although there are no over-riding technical impediments preventing using more of the pore space for storage. Transitional, or residual oil zones, and stacked reservoirs all pose significant opportunities to increase storage amounts well beyond that used strictly for EOR. While deploying monitoring equipment and determining suitable baselines may present challenges to some existing operations, technical solutions can be found to address most of these issues.

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