

## Criteria for Intermediate Storage of Carbon Dioxide in Geological Formations

Semere Solomon\*, The Bellona Foundation  
October 2006

**Abstract:** The greenhouse gas (GHG) making the largest contribution to atmospheric emissions from human activities is carbon dioxide (CO<sub>2</sub>) and released dominantly by burning fossil fuels such as coal, oil, and natural gas. Increased emissions of GHG, causes global warming thus steps should be taken that aim in the stabilization of greenhouse gas concentrations in the atmosphere. Carbon dioxide capture and storage (CCS) is a good option and can contribute to reduce emissions of GHG provided it is implemented on a large scale. For continued and wide implementation of CCS on a large scale and long time span, intermediate storage of CO<sub>2</sub> in geological formations is deemed necessary. This paper investigates the criteria and possibilities of intermediate storage of CO<sub>2</sub> in geological formations aiming at large scale implementation of CCS for deep emission reduction. The main criteria are thus the depth of injection and density, CO<sub>2</sub> flow and transport processes, storage mechanisms, reservoir homogeneity, the presence of impurities, the type of the reservoirs and the duration of intermediate storage. Structural traps where no flow of formation water occur when combined with proper injection planning such as gas-phase injection favours intermediate storage in deep saline aquifers. Depleted oil and gas homogeneous reservoirs with high permeability forming structural traps (e.g. Anticlinal structures) are good candidates for intermediate CO<sub>2</sub> storage. Intermediate CO<sub>2</sub> storage in enhance oil recovery (EOR) operations are optimal due to economic gains, oil reservoirs should be relatively thin (less than 20 m), have high reservoir angle and homogenous formation with low vertical permeability in order to achieve effective removal of the oil. For horizontal reservoirs, the absence of natural water flow, major gas cap and major natural fractures are preferred. Depleted gas reservoirs can be potential candidates for intermediate storage of carbon dioxide due to similarity in storage characteristics as natural gases

### 1 Introduction

The greenhouse gas (GHG) making the largest contribution to atmospheric emissions from human activities is carbon dioxide (CO<sub>2</sub>). It is released by burning fossil fuels and biomass as a fuel; from the burning, for example, of forests during land clearance; and by certain industrial and resource extraction processes. Emissions of CO<sub>2</sub> due to fossil fuel burning are the dominant influence on the increasing trends in atmospheric CO<sub>2</sub> concentration because according to the International Energy Agency (IEA) 80 % of the

global energy consumption is based on coal, oil, and natural gas (IEA, 2005). Increased emissions of GHG, causes global warming thus steps should be taken that aim in the stabilization of greenhouse gas concentrations in the atmosphere.

Carbon dioxide capture and storage (CCS) is a good option and can contribute to reduce emissions of GHG provided it is implemented on a large scale. Several types of storage reservoir may provide storage capacities of this magnitude. In some cases, the injection of CO<sub>2</sub> into oil and gas fields could lead to the enhanced production of hydrocarbons, which would help to offset the cost due to the increased income from the increased fossil

---

\* Dr. Semere Solomon, Advisor at The Bellona Foundation, P.O.Box 2141 Grunerløkka, N-0505 Oslo, Norway.  
Contact e-mail: semere@bellona.no

fuels production. However, for continued and wide implementation of CCS on a large scale and long time span intermediate storage of CO<sub>2</sub> in geological formations is deemed necessary. Intermediate storage in this paper means the storage of CO<sub>2</sub> in geological media temporarily for limited span of time that can be reproduced for later use for example in large scale enhanced oil recover (EOR) operations in order to secure continued supply. This paper analyzes the criteria and possibilities of intermediate storage of CO<sub>2</sub> in geological formations aiming at large scale implementation of CCS for deep emission reduction.

## 2 Properties of CO<sub>2</sub>

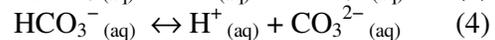
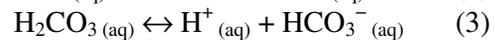
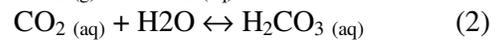
Carbon dioxide is a chemical compound of two elements, carbon and oxygen, in the ratio of one to two; its molecular formula is CO<sub>2</sub>. It is present in the atmosphere in small quantities (370 ppmv) and plays a vital role in the Earth's environment as a necessary ingredient in the life cycle of plants and animals. During photosynthesis plants assimilate CO<sub>2</sub> and release oxygen. Anthropogenic activities which cause the emission of CO<sub>2</sub> include the combustion of fossil fuels and other carbon containing materials, the fermentation of organic compounds such as sugar and the breathing of humans. Natural sources of CO<sub>2</sub>, including volcanic activity, dominate the Earth's carbon cycle. CO<sub>2</sub> gas has a slightly irritating odour, is colourless and is denser than air. At normal temperature and pressure, carbon dioxide is a gas.

The physical state of CO<sub>2</sub> varies with temperature and pressure as shown in Figure 1a – at low temperatures CO<sub>2</sub> is a solid; on warming, if the pressure is below 5.1 bar, the solid will sublime directly into the vapour state. At intermediate temperatures (between –56.5°C, the temperature of the triple point, and 31.1°C, the critical point), CO<sub>2</sub> may be turned from a vapour into a liquid by compressing it to

the corresponding liquefaction pressure (and removing the heat produced). At temperatures higher than 31.1°C (if the pressure is greater than 73.9 bar, the pressure at the critical point), CO<sub>2</sub> is said to be in a supercritical state where it behaves as a gas; indeed under high pressure, the density of the gas can be very large, approaching or even exceeding the density of liquid water (also see Figure 1b). This is an important aspect of CO<sub>2</sub>'s behaviour and is particularly relevant for its storage. Figure 1b shows the variation of the density of CO<sub>2</sub> as a function of temperature and pressure.

In an aqueous solution CO<sub>2</sub> forms carbonic acid, which is too unstable to be easily isolated. The solubility of CO<sub>2</sub> in water decreases with increasing temperature and increases with increasing pressure. The solubility of CO<sub>2</sub> in water also decreases with increasing water salinity.

The dissolution of CO<sub>2</sub> in water (this may be seawater, or the saline water in geological formations) involves a number of chemical reactions between gaseous and dissolved carbon dioxide (CO<sub>2</sub>), carbonic acid (H<sub>2</sub>CO<sub>3</sub>), bicarbonate ions (HCO<sub>3</sub><sup>-</sup>) and carbonate ions (CO<sub>3</sub><sup>2-</sup>) which can be represented as follows:



Addition of CO<sub>2</sub> to water initially leads to an increase in the amount of dissolved CO<sub>2</sub> (1). The dissolved CO<sub>2</sub> reacts with water to form carbonic acid (2). Carbonic acid dissociates to form bicarbonate ions (3), which can further dissociate into carbonate ions (4). The net effect of dissolving *anthropogenic* CO<sub>2</sub> in water is the removal of carbonate ions and production of bicarbonate ions, with a lowering in *pH*.

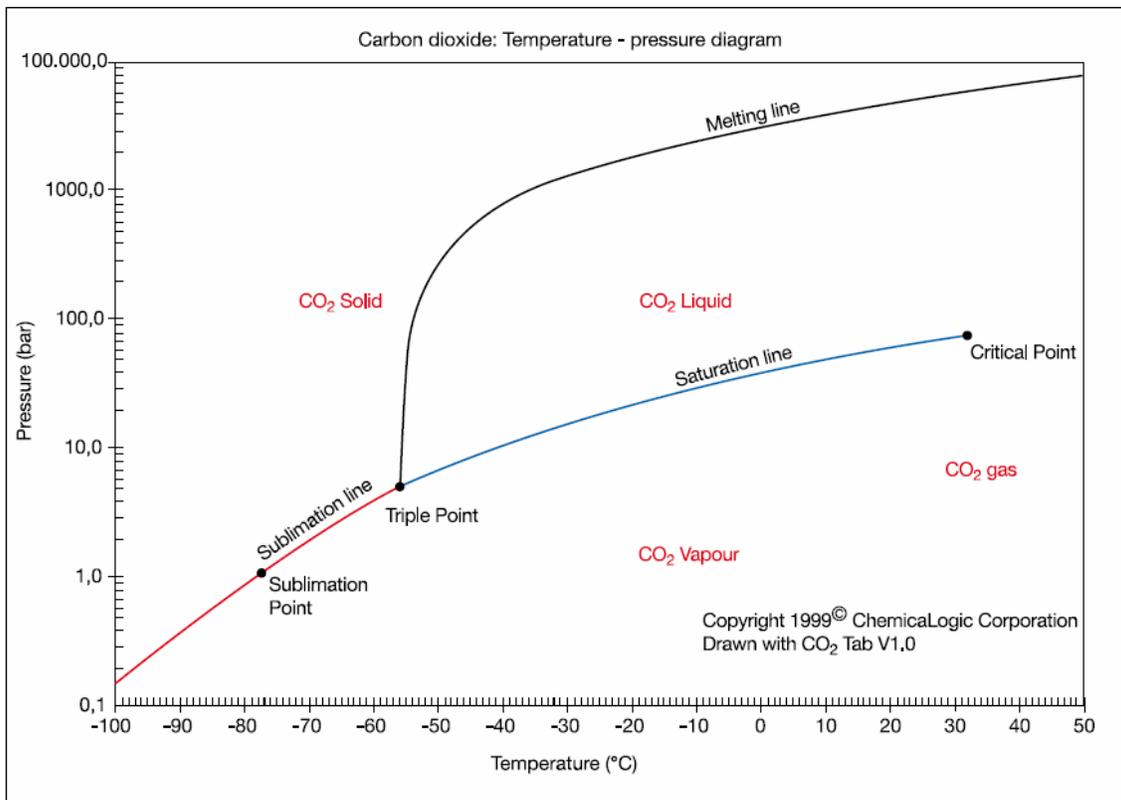


Figure 1a: Phase diagram for CO<sub>2</sub>.

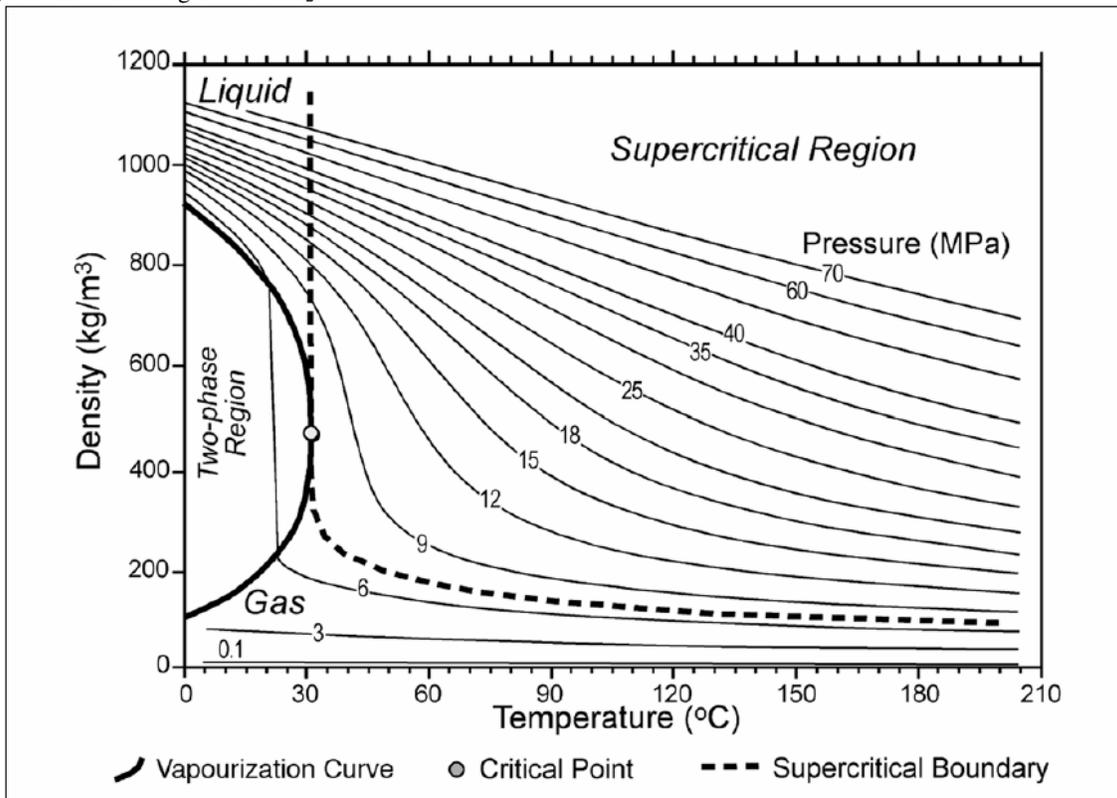


Figure 1b: Variation of CO<sub>2</sub> density as a function of temperature and pressure (Bachu, 2003).

### 3 Geological formations

Geological storage of CO<sub>2</sub> can be undertaken in a variety of geological settings in sedimentary basins. Within these basins, oil fields, depleted gas fields, deep coal seams and saline formations are all possible storage formations (Figure 2). Subsurface geological storage is possible both onshore and offshore, with offshore sites accessed through pipelines from the shore or from offshore platforms. In addition to storage in sedimentary formations, some other geological formations which may serve as storage sites include caverns, basalt and organic-rich shales.

Figure 2 shows various options for storing CO<sub>2</sub> in geological formations. In this study the possibilities of using two storage sites namely, oil and gas fields and saline formations for intermediate storage of CO<sub>2</sub> will be assessed. In the case oil and gas fields, intermediate storage in depleted oil and gas fields as well as enhanced oil and gas recoveries are assessed. It is important to note that the storage requirements for storing CO<sub>2</sub> in geological formations are equally significant when using these sites for intermediate storage. These include: (1) Adequate porosity and thickness (for storage capacity) and permeability (for

injectivity), (2) a satisfactory sealing caprock or confining unit and (3) a sufficiently stable geological environment to avoid compromising the integrity of the storage site. The difference is that intermediate storage is meant for short term storage which can be reproduced when the need arises.

### 4 Criteria for Intermediate Storage

Reproducing CO<sub>2</sub> back from a reservoir thus to a large extent depends upon several factors which need to be considered. It is assumed that storage sites are well characterized so that extensively faulted and fractured sedimentary basins or parts thereof, are avoided and the presence of wells penetrating the subsurface that can create potential CO<sub>2</sub> leakage pathways are well identified at the storage site. Besides injection of CO<sub>2</sub> into formations are well controlled so that exceeding pressures that can damage the caprock are avoided. The criteria for intermediate storage are highlighted in this section.

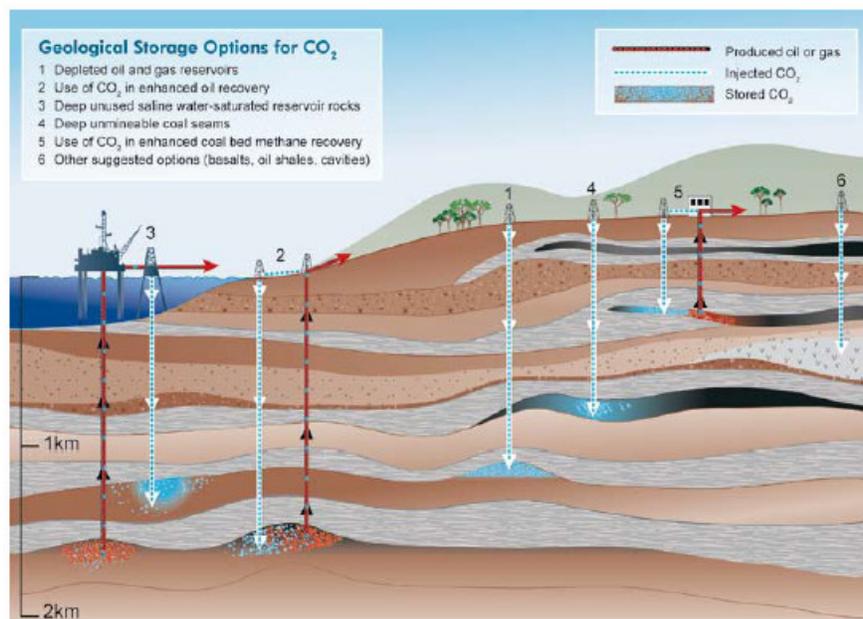
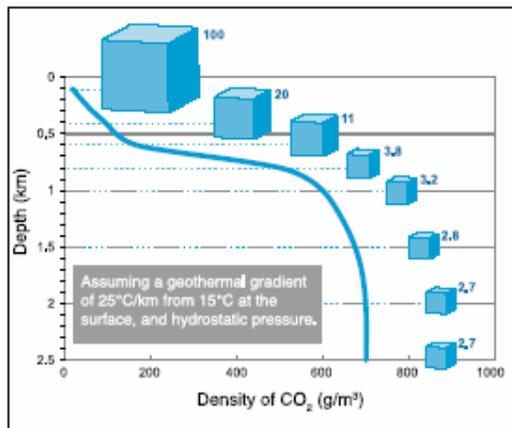


Figure 2: Options for storing CO<sub>2</sub> in deep underground geological formations (after Cook 1999, source IPCC 2005).

#### 4.1 Depth of injection and density

The depth of CO<sub>2</sub> injection and density of CO<sub>2</sub> are important parameters to consider for intermediate storage of carbon dioxide. The two parameters are interrelated and both depend on the temperature and pressure conditions in the subsurface. To geologically store CO<sub>2</sub>, it must first be compressed, usually to a dense fluid state known as ‘supercritical’. Supercritical means at a temperature and pressure above the critical temperature and pressure of carbon dioxide (31.1°C and greater than 73.9 bar, Fig. 1a). The critical point represents the highest temperature and pressure at which the substance can exist as a vapour and liquid in equilibrium. Depending on the rate that temperature increases with depth (the geothermal gradient), the density of CO<sub>2</sub> will increase with depth, until at about 800 m or greater, the injected CO<sub>2</sub> will be in a dense supercritical state (Figure 3).

The efficiency of CO<sub>2</sub> storage in geological media, defined as the amount of CO<sub>2</sub> stored per unit volume (Brennan and Burruss, 2003), increases with increasing CO<sub>2</sub> density. Storage safety also increases with increasing density, because buoyancy, which drives upward migration, is stronger for a lighter fluid. Density increases significantly with depth while CO<sub>2</sub> is in gaseous phase, increases only slightly or levels off after passing from the gaseous phase into the dense phase and may even decrease with a further increase in depth, depending on the temperature gradient (Ennis-King and Paterson, 2001; Bachu, 2003).



‘Cold’ sedimentary basins, characterized by low temperature gradients, are more favourable for CO<sub>2</sub> storage (Bachu, 2003) because CO<sub>2</sub> attains higher density at shallower depths (700–1000 m) than in ‘warm’ sedimentary basins, characterized by high temperature gradients where dense-fluid conditions are reached at greater depths (1000–1500 m). The depth of the storage formation (leading to increased drilling and compression costs for deeper formations) may also influence the selection of storage sites. Storage in reservoirs at depths less than approximately 800 m may be technically and economically feasible, but the low storage capacity of shallow reservoirs, where CO<sub>2</sub> may be in the gas phase, could be problematic.

#### 4.2 CO<sub>2</sub> flow and transport processes

Once injected into the formation, the primary flow and transport mechanisms that control the spread of CO<sub>2</sub> include:

- Fluid flow (migration) in response to pressure gradients created by the injection process;
- Fluid flow in response to natural hydraulic gradients;
- Buoyancy caused by the density differences between CO<sub>2</sub> and the formation fluids;
- Diffusion;
- Dispersion and fingering caused by formation heterogeneities and mobility contrast between CO<sub>2</sub> and formation fluid;
- Dissolution into the formation fluid;
- Mineralization;
- Pore space (relative permeability) trapping;
- Adsorption of CO<sub>2</sub> onto organic material.

**Figure 3:** Variation of CO<sub>2</sub> density with depth, assuming hydrostatic pressure and a geothermal gradient of 25°C km<sup>-1</sup> from 15°C at the surface (based on the density data of Angus *et al.*, 1973). Carbon dioxide density increases rapidly at approximately 800 m depth, when the CO<sub>2</sub> reaches a supercritical state. Cubes represent the relative volume occupied by the CO<sub>2</sub> and down to 800 m, this volume can be seen to dramatically decrease with depth. At depths below 1.5 km, the density and specific volume become nearly constant.

The rate of fluid flow depends on the number and properties of the fluid phases present in the formation. When two or more fluids mix in any proportion, they are referred to as miscible fluids. If they do not mix, they are referred to as immiscible. The presence of several different phases may decrease the permeability and slow the rate of migration.

As CO<sub>2</sub> migrates through the formation, some of it will dissolve into the formation water and some of it is retained in the pore space by capillary forces, commonly referred to as 'residual CO<sub>2</sub> trapping', which may immobilize significant amounts of CO<sub>2</sub> (Obdam *et al.*, 2003; Kumar *et al.*, 2005). Water saturated with CO<sub>2</sub> is slightly denser (approximately 1%) than the original formation water, depending on salinity (Enick and Klara, 1990; Bachu and Adams, 2003). With high vertical permeability, this may lead to free convection, replacing the CO<sub>2</sub>-saturated water from the plume vicinity with unsaturated water, producing faster rates of CO<sub>2</sub> dissolution (Lindeberg and Wessel-Berg, 1997; Ennis-King and Paterson, 2003). Unlike in pure water the solubility of CO<sub>2</sub> in brine decreases with increasing pressure, decreasing temperature and increasing salinity.

### 4.3 Storage mechanisms

The storage mechanisms, while they are effective way of securing permanent storage of CO<sub>2</sub> in geological formations they have an influence when a site is considered for intermediate storage. The storage mechanism known as physical trapping of CO<sub>2</sub> below low-permeability seals (caprocks), such as very-low-permeability shale or salt beds, is the principal means to store CO<sub>2</sub> in geological formations. Sedimentary basins have such closed, physically bound traps or structures, which are occupied mainly by saline water, oil and gas. Structural traps include those formed by folded or fractured rocks. Stratigraphic traps are formed by changes in rock type caused by variation in the setting where the rocks were deposited. Both of these types of traps are suitable for intermediate storage of CO<sub>2</sub>, although, care must be taken not to exceed the allowable overpressure to avoid fracturing the caprock or re-activating faults.

Hydrodynamic trapping can occur in saline formations that do not have a closed trap, but where fluids migrate very slowly over long distances. When CO<sub>2</sub> is injected into a formation, it displaces saline formation water and then migrates buoyantly upwards, because it is less dense than the water. When it reaches the top of the formation, it continues to migrate as a separate phase until it is trapped as residual CO<sub>2</sub> saturation or in local structural or stratigraphic traps within the sealing formation. In the short term this may not affect intermediate storage, but in the longer term significant quantities of CO<sub>2</sub> dissolve in the formation water and then migrate with the groundwater.

Carbon dioxide in the subsurface can undergo a sequence of geochemical interactions with the rock and formation water that will further increase storage capacity and effectiveness, a mechanism known as Geochemical trapping. First, when CO<sub>2</sub> dissolves in formation water, a process commonly called solubility trapping occurs. With solubility trapping once CO<sub>2</sub> is dissolved, it no longer exists as a separate phase, thereby eliminating the buoyant forces that drive it upwards. This mechanism while very important for permanent storage of CO<sub>2</sub>, it makes intermediate storage unviable. Mineral trapping is believed to be comparatively slow, potentially taking thousands of years or longer so it will not have an immediate effect on the intermediate storage of CO<sub>2</sub>.

### 4.4 Reservoir heterogeneity

Reservoir heterogeneity also affects CO<sub>2</sub> storage efficiency and hence intermediate storage. The density difference between the lighter CO<sub>2</sub> and the reservoir oil and/or saline water leads to movement of the CO<sub>2</sub> along the top of the reservoir, particularly if the reservoir is relatively homogeneous and has high permeability it is well suited for intermediate storage of CO<sub>2</sub>. This negatively affects the CO<sub>2</sub> storage and oil recovery. Consequently, reservoir heterogeneity may have a positive effect, slowing down the rise of CO<sub>2</sub> to the top of the reservoir and forcing it to spread laterally, giving more complete invasion of the formation and greater storage potential

(Bondor, 1992; Kavscek, 2002; Flett *et al.*, 2005). This, however, is not suitable for intermediate storage purposes.

#### 4.5 The presence of impurities

The presence of impurities (e.g., SO<sub>x</sub>, NO<sub>x</sub>, H<sub>2</sub>S) in the CO<sub>2</sub> gas stream affects the engineering processes of capture, transport and injection, as well as the trapping mechanisms and capacity for CO<sub>2</sub> storage in geological media. Gas impurities in the CO<sub>2</sub> stream affect the compressibility of the injected CO<sub>2</sub> (and hence the total volume to be stored) and reduce the capacity for storage in free phase, because of the storage space taken by these gases.

## 5 Intermediate storage

### 5.1 Saline Aquifers

Saline formations are deep sedimentary rocks saturated with formation waters or brines containing high concentrations of dissolved salts. These formations are widespread and contain enormous quantities of water, but are unsuitable for agriculture or human consumption. At depths below about 800–1000 m, CO<sub>2</sub> has a liquid-like density that provides the potential for efficient utilization of underground storage space in the pores of sedimentary rocks. When CO<sub>2</sub> is injected into a deep saline formation in a liquid or liquid-like supercritical dense phase, it is immiscible in water. Because supercritical CO<sub>2</sub> is much less viscous (flows more easily) than water and oil (by an order of magnitude or more), migration is controlled by the contrast in mobility of CO<sub>2</sub> and the *in situ* formation fluids (Celia *et al.*, 2005; Nordbotten *et al.*, 2005a). Thus due to this comparatively high mobility of CO<sub>2</sub>, only some of the oil or water will be displaced, leading to an average saturation of CO<sub>2</sub> in the range of 30–60%.

The magnitude of the buoyancy forces that drive vertical flow depends on the type of fluid in the formation. In saline formations, the comparatively large density difference (30–50%) between CO<sub>2</sub> and formation water creates strong buoyancy forces that drive CO<sub>2</sub> upwards. The upward migration of the buoyant plume of injected CO<sub>2</sub>, however, may not be evenly

distributed. This is because the presence of a lower permeability layer acts as a barrier and causes the CO<sub>2</sub> to migrate laterally, filling any stratigraphic or structural trap it encounters. This creates a condition where part of the injected CO<sub>2</sub> to become dissolved in the formation water due to solubility trapping coupled with delayed upward migration. Besides solubility trapping eliminates the buoyant forces that drive it upwards. Also free convection replaces the CO<sub>2</sub>-saturated water from the plume vicinity with unsaturated water, producing faster rates of CO<sub>2</sub> dissolution. For example in the case of the Utsira Formation up to 18% of the CO<sub>2</sub> injected can be dissolved in the formation water in the life time of the project (Best Practice Manual, 2004). Roughly about 1% of the injected CO<sub>2</sub> can be dissolved in the formation water annually. In systems with slowly flowing water, reservoir-scale numerical simulations show that, over tens of years, a significant amount, up to 30% of the injected CO<sub>2</sub>, will dissolve in formation water (Doughty *et al.*, 2001). Once CO<sub>2</sub> is dissolved in the formation fluid, it migrates along with the regional groundwater flow and thus will not be available for retrieval or reproduction.

Moreover residual CO<sub>2</sub> trapping may immobilize significant amounts of CO<sub>2</sub>. Studies show that when the degree of trapping is high and CO<sub>2</sub> is injected at the bottom of a thick formation, all of the CO<sub>2</sub> may be trapped by this mechanism, even before it reaches the caprock at the top of the formation. While this effect is formation-specific, Holtz (2002) has demonstrated that residual CO<sub>2</sub> saturations may be as high as 15–25% for many typical storage formations. The combined effects of dissolution, solubility trapping and residual trapping thus do not favour the use of deep saline aquifers for intermediate storage. Proper injection planning such as gas-phase injection may reduce the dissolution of CO<sub>2</sub> in the formation water and thus facilitates intermediate storage in saline aquifers. If the injected CO<sub>2</sub> is contained in a closed structure (no flow of formation water), it will take much longer for CO<sub>2</sub> to completely dissolve because of reduced contact with unsaturated formation water and thus facilitating intermediate storage in deep saline aquifers. Moreover the presence

of gas impurities affects the rate and amount of CO<sub>2</sub> storage through dissolution and precipitation.

## 5.2 Oil and gas fields

### 5.2.1 Abandoned oil and gas fields

Depleted oil and gas reservoirs are good candidates for intermediate CO<sub>2</sub> storage. The depths below about 800–1000 m are ideal for CO<sub>2</sub> injection because CO<sub>2</sub> attains a liquid-like density that provides the potential for efficient storage in oil and gas fields. Depths up to 1500 m can be tolerated because the density and specific volume become nearly constant (Fig. 3). Carbon dioxide injected into an oil reservoir may be miscible or immiscible, depending on the oil composition and the pressure and temperature of the system. In oil reservoirs, the buoyant plume of injected CO<sub>2</sub> migrates upwards, but may not be evenly distributed due to reservoir heterogeneity. If the reservoir is relatively homogeneous and has high permeability, it provides ideal site for intermediate storage of CO<sub>2</sub>. Due to the comparatively high mobility of CO<sub>2</sub>, only some of the oil will be displaced, leading to an average saturation of CO<sub>2</sub> in the range of 30–60% in the reservoir. Depleted fields will not be adversely affected by CO<sub>2</sub> (having already contained hydrocarbons) and if hydrocarbon fields are still in production, a CO<sub>2</sub> storage scheme can be optimized to enhance oil (or gas) production.

### 5.2.2 Enhanced oil recovery

Various miscible agents, among them CO<sub>2</sub>, have been used for enhanced (tertiary) oil recovery or EOR, with an incremental oil recovery of 7–23% (average 13.2%) of the original oil in place (Martin and Taber, 1992; Moritis, 2003). Intermediate CO<sub>2</sub> storage in EOR operations should be viewed in light of the oil recovery process. For instance homogeneous oil reservoirs with high vertical permeability provides ideal site for intermediate storage of CO<sub>2</sub>. However, in the case of EOR scheme oil recovery is adversely affected by this high vertical permeability.

For enhanced CO<sub>2</sub> storage in EOR operations, oil reservoirs may need to meet

additional criteria (Klins, 1984; Taber *et al.*, 1997; Kovscek, 2002; Shaw and Bachu, 2002). Generally, reservoir depth must be more than 600 m. Injection of immiscible fluids must often suffice for heavy- to-medium-gravity oils. Miscible flooding is applicable to light, low-viscosity oils. For miscible floods, the reservoir pressure must be higher than the minimum miscibility pressure (10–15 MPa) needed for achieving miscibility between reservoir oil and CO<sub>2</sub>, depending on oil composition and gravity, reservoir temperature and CO<sub>2</sub> purity (Metcalf, 1982). To achieve effective removal of the oil, other preferred criteria for both types of flooding include relatively thin reservoirs (less than 20 m), high reservoir angle, homogenous formation and low vertical permeability. For horizontal reservoirs, the absence of natural water flow, major gas cap and major natural fractures are preferred. Therefore intermediate storage must be considered with regard to the requirements for effective oil recovery while storing CO<sub>2</sub> in the reservoir.

Oil displacement by CO<sub>2</sub> injection therefore relies on the phase behaviour of CO<sub>2</sub> and crude oil mixtures that are strongly dependent on reservoir temperature, pressure and crude oil composition. These mechanisms range from oil swelling and viscosity reduction for injection of immiscible fluids (at low pressures) to completely miscible displacement in high-pressure applications. In these applications, more than 50% and up to 67% of the injected CO<sub>2</sub> returns with the produced oil (Bondor, 1992) and is usually separated and re-injected into the reservoir to minimize operating costs. The remainder (37–50%) is trapped in the oil reservoir by various means, such as irreducible saturation and dissolution in reservoir oil that it is not produced and in pore space that is not connected to the flow path for the producing wells.

Also impurities can affect the oil recovery because they change the solubility of CO<sub>2</sub> in oil and the ability of CO<sub>2</sub> to vaporize oil components (Metcalf, 1982). Methane and nitrogen decrease oil recovery, whereas hydrogen sulphide, propane and heavier hydrocarbons have the opposite effect (Alston *et al.*, 1985; Sebastian *et al.*, 1985). The presence of SO<sub>x</sub> may improve oil recovery, whereas the presence of NO<sub>x</sub> can retard

miscibility and thus reduce oil recovery (Bryant and Lake, 2005) and  $O_2$  can react exothermally with oil in the reservoir.

### 5.2.3 Enhanced gas recovery

Although up to 95% of original gas in place can be produced,  $CO_2$  could potentially be injected into depleted gas reservoirs to enhance gas recovery by repressurizing the reservoir (van der Burgt *et al.*, 1992; Koide and Yamazaki, 2001; Oldenburg *et al.*, 2001). Enhanced gas recovery has so far been implemented only at pilot scale (Gaz de France K12B project, Netherlands) and some authors have suggested that  $CO_2$  injection might result in lower gas recovery factors, particularly for very heterogeneous fields (Clemens and Wit, 2002).

The criteria for depth of injection and hence the density can vary. If  $CO_2$  is injected into a gas reservoir, a single miscible fluid phase consisting of natural gas and  $CO_2$  is formed locally. Usually in natural gas reservoirs,  $CO_2$  is more viscous (flows less easily) than natural gas. Although  $CO_2$  injection for gas recovery appears to be economically unattractive, depleted gas reservoirs can be potential candidates for intermediate storage of carbon dioxide due to similarity in storage characteristics as natural gases.

## 6 Summary and Conclusions

Reproducing  $CO_2$  back from a reservoir depends very much up on the criteria such as the depth of injection and density,  $CO_2$  flow and transport processes, storage mechanisms, reservoir homogeneity, the presence of impurities, the type of the reservoirs and the duration of intermediate storage. At depths below about 800–1000 m where  $CO_2$  has a liquid-like density provides the potential for intermediate storage. Once  $CO_2$  is injected into the geological formations, the primary flow and transport mechanisms that control the spread of  $CO_2$  is governed by many processes (Section 4.2) that can affect intermediate storage in geological media. The rate of fluid flow depends on the number and properties of the fluid phases present in the formation and due to the comparatively high mobility of  $CO_2$  relative

to the in situ formation fluids, only some of the oil or water will be displaced, leading to an average saturation of  $CO_2$  in the range of 30–60%. Residual trapping with  $CO_2$  saturations as high as 50% can cause significant reduction in the amount of  $CO_2$  that can be reproduced and thus affects intermediate storage regard less the reservoir type. Storage mechanisms such as dissolution due to free convection and solubility trapping do not favour especially the use of deep saline aquifers for intermediate storage. In the absence of impurities homogeneous reservoirs with high permeability are ideal for intermediate storage over short period of time to reduce dissolution of the stored  $CO_2$ .

Finally, the type of reservoir is among the major criteria for selecting sites for intermediate storage of  $CO_2$ . Therefore, it is concluded that if the injected  $CO_2$  is contained in a closed structure (structural traps) where no flow of formation water occurs it will take much longer for  $CO_2$  to completely dissolve because of reduced contact with unsaturated formation water. In combination with proper injection planning such as gas-phase injection may reduce the dissolution of  $CO_2$  in the formation water and thus facilitating intermediate storage in deep saline aquifers. Depleted oil and gas homogeneous reservoirs with high permeability forming structural traps (e.g. Anticlinal structures) are good candidates for intermediate  $CO_2$  storage. Intermediate  $CO_2$  storage in EOR operations are optimal due to economic gains, oil reservoirs should be relatively thin (less than 20 m), have high reservoir angle and homogenous formation with low vertical permeability in order to achieve effective removal of the oil. For horizontal reservoirs, the absence of natural water flow, major gas cap and major natural fractures are preferred. Depleted gas reservoirs can be potential candidates for intermediate storage of carbon dioxide due to similarity in storage characteristics as natural gases.

## References:

Alston, R.B., G.P. Kokolis and C.F. James, 1985:  $CO_2$  minimum miscibility pressure: A correlation for impure  $CO_2$  streams and live oil systems. *Society of Petroleum Engineers Journal*, 25(2), 268–274.

- Angus, S., B. Armstrong and K.M. de Reuck, 1973:** International Thermodynamic Tables of the Fluid State Volume 3. Carbon Dioxide. IUPAC Division of Physical Chemistry, Pergamon Press, London, pp. 266–359.
- Bachu, S., 2003:** Screening and ranking of sedimentary basins for sequestration of CO<sub>2</sub> in geological media. *Environmental Geology*, **44**(3), 277–289.
- Bachu, S. and J.J. Adams, 2003:** Sequestration of CO<sub>2</sub> in geological media in response to climate change: Capacity of deep saline aquifers to sequester CO<sub>2</sub> in solution. *Energy Conversion and Management*, **44**(20), 3151–3175.
- Best Practice manual, 2004:** S. Holloway, A. Chadwick, E. Lindeberg, I. Czernichowski-Lauriol and R. Arts (eds.), Saline Aquifer CO<sub>2</sub> Storage Project (SACS), 53 pp.
- Brennan, S.T. and R.C. Burruss, 2003:** Specific Sequestration Volumes: A Useful Tool for CO<sub>2</sub> Storage Capacity Assessment. USGS OFR 03-0452 available at <http://pubs.usgs.gov/of/2003/of03-452/>.
- Bondor, P.L., 1992:** Applications of carbon dioxide in enhanced oil recovery. *Energy Conversion and Management*, **33**(5), 579–586.
- Bryant, S. and L. Lake, 2005:** Effect of impurities on subsurface CO<sub>2</sub> storage processes, Carbon Dioxide Capture for Storage in Deep Geologic Formations - Results from the CO<sub>2</sub> Capture Project, v. 2: Geologic Storage of Carbon Dioxide with Monitoring and Verification, S.M. Benson (ed.), Elsevier, London. pp. 983–998.
- Celia, M.A., S. Bachu, J.M. Nordbotten, S.E. Gasda and H.K. Dahle, 2005:** Quantitative estimation of CO<sub>2</sub> leakage from geological storage: Analytical models, numerical models and data needs. Proceedings of 7th International Conference on Greenhouse Gas Control Technologies. (GHGT-7), September 5–9, 2004, Vancouver, Canada, v.I, 663-672.
- Clemens, T. and K. Wit, 2002:** CO<sub>2</sub> enhanced gas recovery studied for an example gas reservoir, SPE 77348, presented at the SPE Annual Technical Meeting and Conference, San Antonio, Texas, 29 September - 2 October 2002.
- Doughty, C., K. Pruess, S.M. Benson, S.D. Hovorka, P.R. Knox and C.T. Green, 2001:** Capacity investigation of brine-bearing sands of the Frio Formation for geologic sequestration of CO<sub>2</sub>. Proceedings of First National Conference on Carbon Sequestration, 14–17 May 2001, Washington, D.C., United States Department of Energy, National Energy Technology Laboratory, CD-ROM USDOE/NETL-2001/1144, Paper P.32, 16 pp.
- Enick, R.M. and S.M. Klara, 1990:** CO<sub>2</sub> solubility in water and brine under reservoir conditions. *Chemical Engineering Communications*, **90**, 23–33.
- Ennis-King, J. and L. Paterson, 2001:** Reservoir engineering issues in the geological disposal of carbon dioxide. Proceedings of the 5<sup>th</sup> International Conference on Greenhouse Gas Control Technologies (GHGT-5), D. Williams, D. Durie, P. McMullan, C. Paulson and A. Smith (eds.), 13–16 August 2000, Cairns, Australia, CSIRO Publishing, Collingwood, Victoria, Australia, pp. 290–295.
- Ennis-King, J.P. and L. Paterson, 2003:** Role of convective mixing in the long-term storage of carbon dioxide in deep saline formations. Presented at Society of Petroleum Engineers Annual Technical Conference and Exhibition, Denver, Colorado, 5–8 October 2003, SPE paper no. 84344.
- Flett, M.A., R.M. Gurton and I.J. Taggart, 2005:** Heterogeneous saline formations: Long-term benefits for geo-sequestration of greenhouse gases. Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), September 5–9, 2004, Vancouver, Canada, v.I, 501-510.
- Holtz, M.H., 2002:** Residual gas saturation to aquifer influx: A calculation method for 3-D computer reservoir model construction. SPE Paper 75502, presented at the SPE Gas Technologies Symposium, Calgary, Alberta, Canada. April 2002.
- IEA, 2005:** World Energy Outlook 2004, OECD and International Energy Agency report, Paris, France.
- IPCC, 2005:** IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.
- Koide, H. and K. Yamazaki, 2001:** Subsurface CO<sub>2</sub> disposal with enhanced gas recovery and biogeochemical carbon recycling. *Environmental Geosciences*, **8**(3), 218–224.
- Kovscek, A.R., 2002:** Screening criteria for CO<sub>2</sub> storage in oil reservoirs. *Petroleum Science and Technology*, **20**(7–8), 841–866.
- Kumar, A., M.H. Noh, K. Sepehrnoori, G.A. Pope, S.L. Bryant and L.W. Lake, 2005:** Simulating CO<sub>2</sub> storage in deep saline aquifers, Carbon Dioxide Capture for Storage in Deep Geologic Formations - Results from the CO<sub>2</sub> Capture Project, v.2: Geologic Storage of Carbon Dioxide with Monitoring and Verification, S.M. Benson, (ed.), Elsevier, London. pp. 977–898.
- Lindeberg, E. and D. Wessel-Berg, 1997:** Vertical convection in an aquifer column under a gas cap of CO<sub>2</sub>. *Energy Conversion and Management*, **38**(Suppl.), S229–S234.

**Martin**, F.D. and J. J. Taber, 1992: Carbon dioxide flooding. *Journal of Petroleum Technology*, **44**(4), 396–400.

**Metcalf**, R.S., 1982: Effects of impurities on minimum miscibility pressures and minimum enrichment levels for CO<sub>2</sub> and rich gas displacements. *SPE Journal*, **22**(2), 219–225.

**Moritis**, G., 2003: CO<sub>2</sub> sequestration adds new dimension to oil, gas production. *Oil and Gas Journal*, **101**(9), 71–83.

**Nordbotten**, J.M., M.A. Celia and S. Bachu, 2005a: Injection and storage of CO<sub>2</sub> in deep saline aquifers: Analytical solution for CO<sub>2</sub> plume evolution during injection. *Transport in Porous Media*, **58**, 339–360, DOI 10.1007/s11242-004-0670-9.

**Oldenburg**, C.M., K. Pruess and S. M. Benson, 2001: Process modeling of CO<sub>2</sub> injection into natural gas reservoirs for carbon sequestration and enhanced gas recovery. *Energy and Fuels*, **15**, 293–298.

**Sebastian**, H.M., R.S. Wenger and T.A. Renner, 1985: Correlation of minimum miscibility pressure for impure CO<sub>2</sub> streams. *Journal of Petroleum Technology*, **37**(12), 2076–2082.

**Shaw**, J. C. and S. Bachu, 2002: Screening, evaluation and ranking of oil reserves suitable for CO<sub>2</sub> flood EOR and carbon dioxide sequestration. *Journal of Canadian Petroleum Technology*, **41**(9), 51–61.

**Taber**, J.J., F.D. Martin and R.S. Seright, 1997: EOR screening criteria revisited - part 1: introduction to screening criteria and enhanced recovery fields projects. *SPE Reservoir Engineering*, **12**(3), 189–198.

**van der Burgt**, M.J., J. Cattle and V.K. Boutkan, 1992: Carbon dioxide disposal from coal-based IGCC's in depleted gas fields. *Energy Conversion and Management*, **33**(5–8), 603–610.