Title: A Field Case of CO_2 Storage and EOR

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Abstract

Carbon dioxide (CO_2) emissions have become a major environmental concern due to their potential negative impact on the Earth's climate. It is hoped that the vast majority of CO_2 emissions from industry can be captured and gradually immobilised by various trapping mechanisms. A well selected, designed, and managed geological storage site can in theory retain CO_2 for millions of years. At the same time, injection of CO_2 for improved recovery has proven to be beneficial in a number of petroleum projects. Nevertheless, the large volume of CO_2 being emitted requires the development of methods that provide for its sequestration, capture, transport and storage, in addition to that which is used in improved oil recovery methods. The CO_2 trapping mechanisms must be properly understood and modelled in order to optimize each particular application.

Hydrocarbon phase behaviour must be accurately described when there is a need to account for mass transfer between phases in a porous medium. The overly simplified black-oil formulation, although appropriate for waterflooding, cannot be used to adequately represent complex phase behavior such as that in miscible displacement processes. As a result, compositional simulation has gradually evolved to provide accurate representation of the mass balance in the isothermal modelling of hydrocarbon recovery processes.

In this paper, a field case using compositional simulation of CO_2 injection for enhanced recovery is presented. The incremental oil and the amount of injected CO_2 stored in the reservoir are quantified.

Due to the high cost of CO_2 capture, if a project scenario does not indicate economic viability, an alternative option is to inject flue gas directly without CO_2 capture plant. A new scenario for flue gas injection is simulated to compare with CO_2 injection. An economic analysis of incremental oil produced with CO_2 injection and flue gas injection into abandoned petroleum reservoirs has also been performed considering an optimistic, a moderate and a pessimistic economical scenario.

The results suggests that the slower the CO_2 injection, the higher the incremental oil production. The CO_2 injected on the formation top sweeps and pushes the oil down, and part of this oil is produced by the production wells completed near the original oil water contact. When the injectors operate at a high rate, the producer hasn't enough time to produce all the swept oil. Part of this non-produced oil is pushed under the water contact and stays trapped, as irreducible oil.

The conclusion reached is that both the injection of pure CO_2 and the injection of flue gas lead to incremental oil recovery due to oil swelling and reduced liquid viscosity, but while flue gas injection may lead to lower economic cost, CO_2 injection provides more efficient displacement and storage volume benefits. The effect of oil swelling and reduced liquid viscosity is more pronounced in CO_2 than in flue gas due to its solubility in water, of course the flue gas has low CO_2 concentration and thus a low storage volume of CO_2 is expected using this method.

Introduction

There are two main purposes for injecting CO_2 into oil and gas reservoirs: 1. To enhance oil production in a non-miscible displacement simply by displacing the oil, or, in a miscible displacement, by dissolving the CO_2 into the oil, thereby swelling the oil, reducing its viscosity, and enhancing production and 2. To store the CO_2 in abandoned oil and gas reservoirs, taking advantage of the cap-rock of these reservoirs, which are proven to hold buoyant fluids, since they have confined buoyant oil and gas on a geological time-scale.

This modelling uses GEM - a compositional numerical simulator from CMG, which contains thermodynamically consistent means to accurately describe the phases and compositions present within the porous interconnected net works using a continuum approach for representing reservoir rocks.

The chosen field case is an oil reservoir located in the northeast of Brazil operated by Petrobras. A nearby gas-fired thermoelectric power generation plant is able to supply all of the required CO_2, in addition to other similar reservoirs that could be used to maximize profit.

The reservoir considered is sandstone at 1100 metres depth that has a dome-shaped structure and a bottom aquifer. It has 25% average porosity and 1500 mD average absolute permeability. The geologic model is represented by a grid with dimension 47x50x7. The oil, characterised by five pseudo-components, has a gas-oil ratio of 20.2 m^3/m^3 and a total volume of 2.927 $\times 10^6$ STD m^3. Fifty-nine wells have been drilled to drain the reservoir, all of them pumped and with the annular space open to the atmosphere. The produced gas is not measured and has insignificant economic value.

The aim was to build a compositional numerical model using engineering and geological data. Then small adjustments were made in the aquifer capacity, the horizontal and vertical transmissibility multiplier, and the relative permeability curve to get a match between the observed production curves and the simulated curves. The idea was to inject CO_2 in an abandoned oil field, so the CO_2 injection was started about one year after the abandonment. Four wells were selected to inject CO_2 and the CO_2 injection was executed in six different schemes in an attempt to find a more profitable way of storing CO_2 while improving the incremental oil recovery. A total amount of 1.17×10^9 standard cubic meters (scm) of CO_2 was injected in the model, which is the amount the reservoir can safely hold.

CO_2 Characteristics

Carbon dioxide (CO_2) has become a major environmental concern due to its potential negative impact on Earth's climate due to its greenhouse gas effect. Anthropogenic emissions are thought to be the cause of accumulation of CO_2 in the atmosphere, and unless an aggressive program to reduce CO_2 emissions is implemented, the carbon dioxide concentration in the atmosphere will continue to grow. At the same time, injection of CO_2 for improved recovery purposes has proven beneficial to a number of petroleum projects. Nevertheless, the amount of CO_2 available requires the development of methods that provide for its capture, transport, sequestration and storage, in addition to that which is used for improved oil recovery. The CO_2 trapping mechanisms must be properly understood and modelled in order to take proper advantage of these mechanisms in each application.

Figure 1 presents the CO_2 pressure-temperature phase diagram. The triple point occurs at 5.11 atm and -56.4 °C, where the three phases – gas, liquid and solid – can coexist simultaneously in thermodynamic equilibrium. At one atmosphere and for temperatures below -78.5 °C, CO_2 condenses into a solid, known as 'dry ice'.

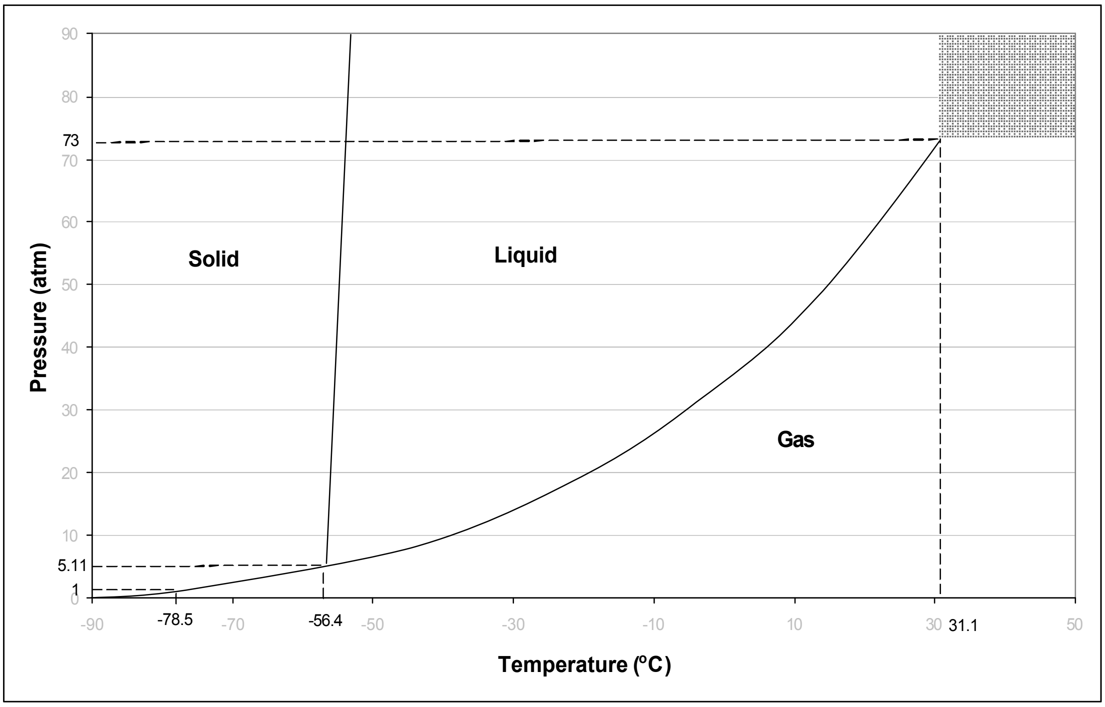


Figure 1 - CO_2 Pressure -Temperature Phase Diagram

Its liquid phase only occurs at pressures above 5.11 atm. For temperatures above 31.1 °C and pressures above 73 atm, CO_2 behaves like a supercritical fluid; it expands to fill its recipient like a gas, but with a density like a liquid.

CO_2 Storage Sites

The ocean is the most remarkable and largest natural sink for CO_2 (Bachu, 2000). The normal pressure and temperature in seawater at depths greater than 800 metres make the density of CO_2 greater than that of the seawater, so that CO_2 sinks to the bottom. However, any use of the ocean as an artificial sink for CO_2 could have a substantial environmental impact. The possible effects of any artificial increase in acidity in the ocean ecosystem are not well understood, but it is known that CO_2 produces plumes or hydrates on the ocean bed. Besides, the cost of transporting CO_2 from land to offshore locations can be economically prohibitive, in addition to the possibility of offshore disposal being unacceptable from an environmental point of view (Bachu, 2000).

It is hoped that the vast majority of CO_2 emissions from industry can be gradually immobilised by various trapping mechanisms. A well selected, designed, and managed geological storage site can theoretically retain CO_2 for millions of years. Geological storage can therefore be more secure over very long timeframes (IPCC, 2005). Proposals for Carbon Capture and Storage (CCS) have been extensively investigated for geological storage of CO_2. Thus, CO_2 can be injected principally into oil and gas reservoirs, deep coal seams , or deep saline formations. Geological storage of CO_2 is ongoing in industry-scale projects with one Mt (million tons) CO_2 per year or more.

The Weyburn project (IEA-GHG, 2004) started in 2000 in Southeastern Saskatchewan, Canada. The CO_2 is used for Enhanced Oil Recovery (EOR) and is also stored, with an injection rate about 1.5 Mt per year. It comes from the Great Plains Coal gasification Plant in North Dakota, which produces methane from coal. With a purity of 96%, the CO_2 is compressed to about 2200 psi, in a supercritical condition, and fed into a 330-kilometre pipeline (Brown et al., 2001).

The In Salah gas project, in Algeria, comprises eight gas fields in the central Saharan region (Riddiford et al., 2004). After separation from the natural gas, the CO_2 is injected back into the subsurface at a rate about 1.3 Mt per year.

The first commercial CO_2 storage project is the Sleipner project, in Norway (Backlid et al., 1996; Kongsjorden et al., 1997; Solomon, 2007). Located in the middle of the North Sea, approximately 200 kilometres from land, this project stores CO_2 in the Utsira formation, above the Sleipner natural gas field. The natural gas from the field contains approximately 9% CO_2. It is separated from the natural gas at the surface and is then injected into the Utsira formation, rather than being emitted into the atmosphere. The Sleipner project has been injecting about 1 Mt of CO_2 per year in this way since 1996 (Solomon, 2007). Figure 2 (from Solomon, 2007) shows the storage project schematically.

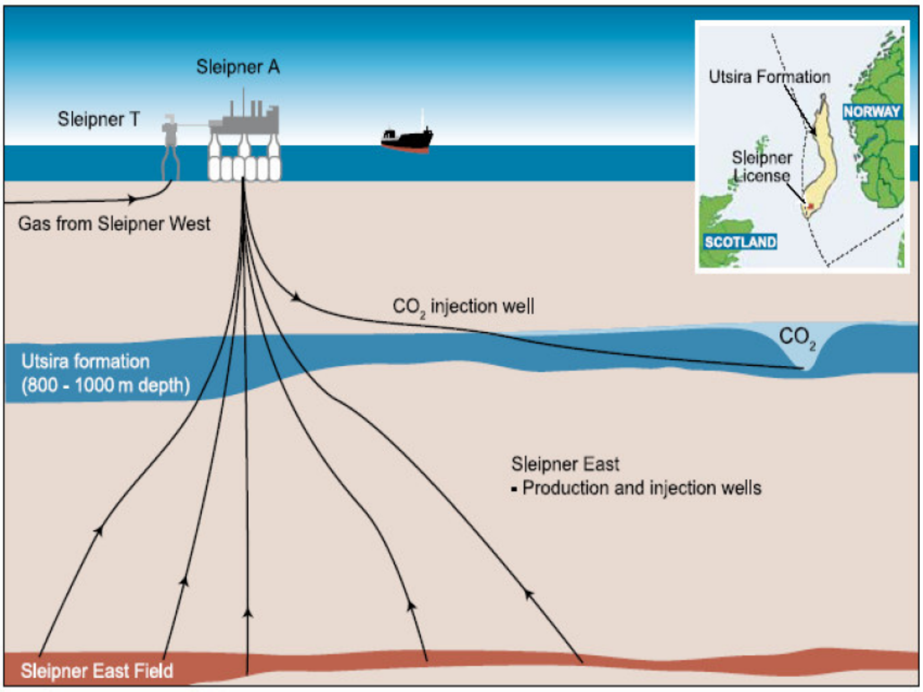


Figure 2 - Illustration of Sleipner CO_2 Storage Project in Utsira Formation. Picture from Solomon (2007)

In addition to the CCS projects currently in place, approximately 30 Mt CO_2 is injected annually for EOR, mostly in Texas, where EOR commenced in the early 1970s (IPCC, 2005).

Economic Aspects of Carbon Capture and Storage

Carbon dioxide capture and storage (CCS) requires three processes: capture, transport, and storage of carbon dioxide.

CO_2 Capture

The purpose of carbon dioxide capture is to produce a concentrated stream of CO_2 at high pressure that can readily be transported to a storage site (IPCC, 2005). The most obvious places to capture CO_2 are large industrial sources such as power plants, cement plants, and oil and gas refineries (Holloway, 2008). There are essentially three ways to capture CO_2 (Holloway, 2008).

Post-Combustion. In this process, the CO_2 is separated from the flue gas (gas produced by combustion of the primary fuel). This process normally uses a solvent to capture the CO_2 present in the flue gas, whose main constituent is nitrogen.

Pre-Combustion. The primary fuel passes through a reactor with a stream of oxygen or air producing a mixture consisting mainly of carbon monoxide and hydrogen. In a second reactor, the carbon monoxide reacts with steam, producing CO_2 and more hydrogen.

Oxy Fuel Combustion. This process uses oxygen instead of air for combustion of the primary fuel. The resulting flue gas is mainly water vapour and CO_2 in high concentration (about 80% in volume). The water is easily removed by cooling and compressing the gas stream.

Many of the technologies for CO_2 capture require removal of air pollutants such as SO_x, NO_x, heavy metals, and fine particulates before the CO_2 enters the capture unit. Alternatively, they may be removed simultaneously with the CO_2 capture process (Mathieu, 2008 - Chapter 10). Flue gas from combustion processes normally contains less than 0.5 vol% sulphur dioxide. Most combustion gases that contain SO_2 also contain a small amount of SO_3 or its reaction product with water (sulphuric acid). The SO_x is of considerable importance because of its highly corrosive nature and its critical role in air pollution problems (Kohl and Nielsen., 1997 - Chapter 7). NO_x denotes nitric oxide NO and nitrogen dioxide NO_2. NO is converted into NO_2 in the atmosphere in the presence of light. NO_2, in excessive concentration in the air, has a direct effect on health and is a precursor of acid rain. Fossil fuel combustion also produces small amounts of nitrous oxide N_2O (Kohl and Nielsen, 1997 – Page 867).

The energy penalty associated with CO_2 capture and compression at power plants varies between 9% and 34%, depending on the type of power plant and capture process (Holloway, 2008). The cost of a carbon dioxide capture process from power plants, including compression for pipeline transport, is of the order of US\$ 18.0 - US\$ 72.0 per ton of CO_2 avoided (Holloway, 2008; Berger et al., 2004; David and Herzog, 2001; and Doctor et al., 2001). A power plant equipped with a CCS (Carbon Capture and Storage) system needs roughly 10-40% more energy than a plant with equivalent output without CCS (IPCC, 2005). Considering that a plant with CCS produces 20% more CO_2 compared with an equivalent plant without CCS, the cost is of the order of US\$ 15.0 - US\$ 60.0 per ton of CO_2 captured. Improvements to commercial technologies can reduce the current CO_2 capture cost by at least 20-30% over approximately the next 10 years, provided R&D efforts are sustained (IPCC, 2005).

CO_2 Transport

Unless plants are located directly above a geological storage site, the CO_2 captured must be transported from the capture point to the storage site. Pipelines are the most common method for transporting CO_2 (IPCC, 2005). Drying is sometimes necessary to prevent corrosion and the formation of CO_2 hydrates. Sulphur reduction may also be required (Holloway, 2008).

Pipeline transport of CO_2 through populated areas requires detailed route selection, over-pressure protection, and leak detection, together with other design factors (IPCC, 2005). The CO_2 transport cost for onshore sites depends on the distance, the quantity transported, whether the area is heavily congested, and whether there are mountains, large rivers, or frozen ground on the route. Any additional costs for recompression for longer pipelines are counted as part of transport cost (IPCC, 2005).

For a nominal distance of 250 kilometres, the typical cost is 1 -8 US$/ton CO_2 (IPCC, 2005). For 500 kilometres, assuming the necessity of an infrastructure, costs are estimated at US$7.82/ton of CO_2 (Holloway, 2008).

CO_2 Geological Storage

Regions with sedimentary basins that are potentially suitable for CO_2 storage exist around the globe, both onshore and offshore (IPCC, 2005).

CO_2 storage in hydrocarbon reservoirs or deep saline formations is expected to take place at depths below 800 metres, where the pressure and temperatures usually result in CO_2 being in a liquid or supercritical state. Under these conditions, the density of CO_2 ranges from 50 -80% of water density (IPCC, 2005). The result is buoyancy that tends to move the CO_2 upward.

CO_2 Geological Storage Mechanisms

Geological storage, encompassing EOR in petroleum fields and injection into saline formations and in abandoned oil and gas fields, is the only process able to provide a remarkable abatement of CO_2 at a level considered nowadays as economically feasible under specific conditions (IPCC, 2005).

CO_2 can be stored in a formation through four main mechanisms:

1. **Structural trapping** : trapping of CO_2 due to the structure of geological formations;
2. **Solubility trapping** : dissolving CO_2 in saline water surrounding the geological formation;
3. **Residual gas trapping** : immobilising CO_2 as a residual gas saturation along a water migration path; and
4. **Mineral trapping** : chemically reacting CO_2 with formation water and rock to form a carbonate mineral.

To evaluate these trapping mechanisms and their effects when storing CO_2, the use of a numerical simulator tool, especially with compositional capabilities, is indispensable.

Structural Trapping

Structural trapping, known by some as hydrodynamic trapping, is one of the less secure trapping mechanisms due to leakage hazards. Potential leakages for CO_2 injected into a saline formation may occur when (IPCC, 2005): A- CO_2 gas pressure exceeds capillary pressure and passes through siltstone; B - Free CO_2 leaks into upper aquifer up fault; C - CO2 escapes through a gap in cap rock into higher aquifer; D - Injected CO_2 migrates up dip, increases reservoir pressure and permeability of the fault; E - CO_2 escapes via poorly plugged old abandoned wells; F- Natural flow dissolves the CO_2 at CO_2/water interface and transports it out of closure; G- Dissolved CO_2 escapes to atmosphere or ocean.

In a case of a CO_2 leakage, the excess local concentration of CO_2 can lead to acidification of ground-water, and elevated CO_2 in soils that can kill plants (Duong and Keith, 2003).

Geomechanics plays a relevant role in structural trapping. The best choice is to use aquifers with a suitable impermeable cap rock and sealing faults. During the injection, however, there is a chance that geomechanical deformations modify the cap rock with regard to permeability, thus transforming the sealing faults into conductive paths.

Solubility Trapping

CO_2 dissolution in a saline aquifer is one of the most important mechanisms in CO_2 storage. The parameters typically used to evaluate the solubility are pressure, temperature and salinity, as carbon dioxide solubility increases with pressure and decreases with temperature and water salinity. It is necessary to identify with reasonable accuracy the solubility of CO_2 in saline aquifers in order to improve the storage calculations.

Residual Gas Trapping

In a water-wet medium with a capillary dominant flow regime, snap-off is the main trapping mechanism at the pore scale. Capillary trapping of the non-wetting phase occurs during the process of imbibition when the gas saturation is decreasing, and the water saturation (wetting phase) increases as it invades the pore space (Juanes et al., 2006).

Considering aspects such as the time required to trap, long-term trapping security, and CO_2 volume capacity to trapping, residual gas trapping as well as solubility trapping are recognised as the most efficient CO_2 trapping mechanisms (Nghiem et al. 2009; Kumar et al. 2005; Ennis-King and Paterson 2002; and Obi and Blunt 2006).

The model proposed by Land (1968) is commonly used to represent the gas relative permeability hysteresis. The Land model uses a coefficient C defined by:

$$C = \frac{1}{S^*_{gt,\max}} - \frac{1}{S^*_{g,\max}} \tag{1}$$

where $S^*_{gt,\max} = S_{gt,\max}/(1-S_{OR})$ and $S^*_{g,\max} = S_{g,\max}/(1-S_{OR})$. The effective residual gas saturation $S^*_{gt} = S_{gt}/(1-S_{OR})$ for a given $S^*_g = S_g/(1-S_{OR})$ is:

$$S^*_{gt} = \frac{S^*_g}{1+CS^*_g} \tag{2}$$

Land used Equation (2) to obtain the equation for the saturation of mobile gas during the imbibition cycle, Equation (3):

$$S^*_{gF} = \frac{1}{2}\left[S^*_g - S^*_{gt,\max} + \sqrt{\left(S^*_g - S^*_{gt,\max}\right)^2 + \frac{4}{C}\left(S^*_g - S^*_{gt,\max}\right)}\right] \tag{3}$$

It is possible to use the Carlson (1981) model to determine the relative permeability for gas during imbibition from the primary drainage curve, as described by Qi et al. (2007).

$$K_{rg}^{imbibition}(S_g) = K_{rg}^{primary\ drainage}(S_{gF}) \tag{2.65}$$

Figure 3 depicts the gas relative permeability hysteresis for Land's model.

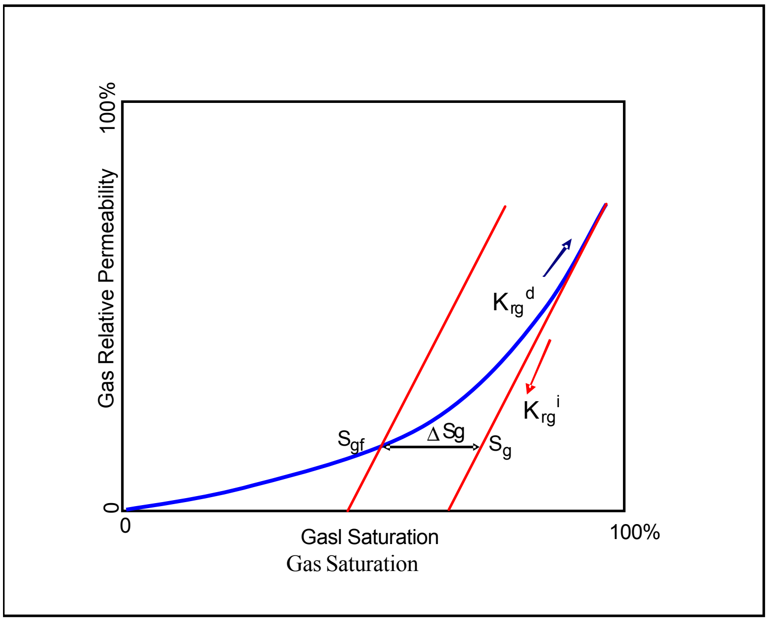


Figure 3 - Land's Model for Gas Relative Permeability Hysteresis

Mineral Trapping

The chemic al reaction of CO_2 with rock results in a process of mineralisation of the CO_2. Mineral carbon dioxide is probably the safest form of CO_2 storage. However, the mineralisation process takes hundreds or thousands of years (IPCC, 2005). The carbon dioxide dis solves in the aqueous-phase and reacts with water to produce carbonic acid, Equation (4). This is a critical reaction because it is CO_2 dissolved in water, not the molecular form that is reactive toward the aquifer rock (Rosenbauer et al., 2005).

$$CO_2 + H_2O \leftrightarrow H_2CO_3 \tag{4}$$

In the absence of any other fluid and rock iteraction, this CO_2 in a dissolved form, results in an acid solution of pH 3.4 due to the dissociation of carbonic acid, Equation (5):

$$H_2CO_3 \leftrightarrow H^+ + HCO_3^- \tag{5}$$

This separation of carbonic acid into reactive hydrogen ion and bicarbonate potentially initiates a complex set of reactions (Rosenbauer et al., 2005). The chemical rea ctions occur between components in the aqueous phase and between mineral and aqueous components (Nghiem et al., 2004).

The chemical reactions that occur following CO_2 injection into an aquifer are of two types (Gunter et al., 1993; Thibeau et al., 2007):

- In carbonate aquifers, the carbonate dissolves and releases HCO_3^- into formation water together with calcium and magnesium.
- In siliciclastic aquifers, the pH decreases due to the CO_2 injection and leads to the dissolution of basic alu minosilicate minerals.

The chemical reactions in the subsurface may occur between components present in the aqueous-phase, or between components present in mineral rock, and components in the aqueous-phase. The latter is the dissolution or precipitation chemical reaction, depending on how the components in the mineral rock react with the aqueous -phase.

If the component in the rock passes to the aqueous -phase after the reaction, it is a dissolution reaction; and if the component, in the aqueous -phase, adsorbs in the rock after the reaction, it is a precipitation. The dissolution or precipitation chemical reactions are rate-dependent reactions and their velocities of reaction are slow relative to the aqueous -phase reaction.

Field Case Description

The selection of the field case took into account that the reservoir has to be at depth of at least at 800 metres. Storage of CO_2 in a shallow reservoir is not practical because relatively small masses of CO_2 occupy a relatively large volume of pore space (Holloway, 2008 – Chapter 4).

The chosen field case is an oil reservoir from Petrobras located in the northeast of Brazil. A nearby thermoelectric generation power gas plant can supply all the CO_2, and other reservoirs with some similarities could be used to maximise the profit. The sandstone reservoir has a dome-shaped structure and a bottom aquifer. The reservoir is about 1100 metre deep. It has 25% average porosity and 1500 mD average absolute permeability.

A compositional numerical model was built using reservoir engineering and geological data. Then small adjustments were made in the aquifer capacity, the horizontal and vertical transmissibilities multiplier, and the relative permeabilities curve to get a match between the observed production curves and the simulated curves.

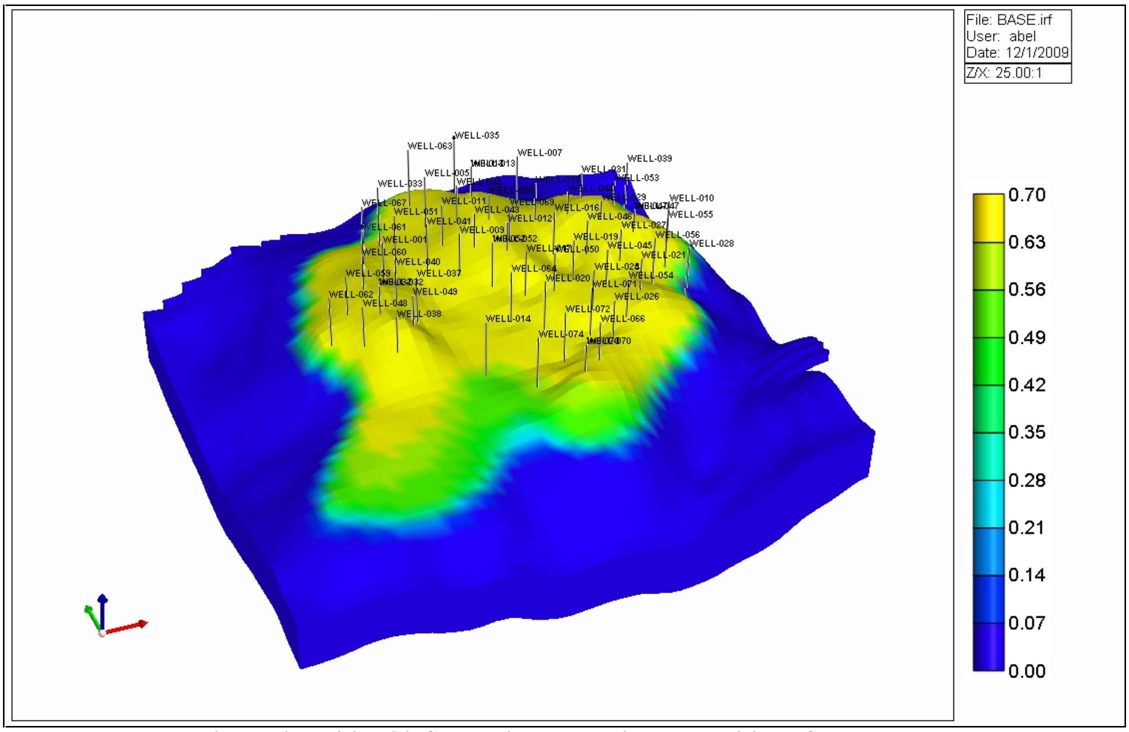


Figure 4 - Initial Oil Saturation Map with the Position of the Wells

There is a bottom analytical aquifer and the water salinity is 1000 ppm of NaCl. Figure 4 shows the reservoir shape, the initial oil saturation, and the placement of each well draining the reservoir.

The geologic model was represented by a grid with dimension 47x50x7. The oil, characterised by five pseudo-components, has a gas-oil ratio 20.2 m^3/m^3 and a total volume of 2.927×10^6 STD m^3. Fifty-nine wells have been drilled to drain the reservoir, all of them pumped and with the annular space open to the atmosphere. The produced gas was not measured and had insignificant economic value.

History Match

The oil, gas, and water production of each well must be matched with the production history. The model assumes that all the wells produce with specified liquid production (oil plus water). The history match occurs when the simulated oil, gas, and water production, in addition to the pressure behaviour, of all wells match what is observed historically in the field.

The gas production is directly proportional to the oil production curve due to the pressure maintenance being kept above the saturation pressure. So reaching a match with oil production warrants a match with gas production.

Figure 5 illustrates the match between the simulated model and the observed history of oil and water production rates and Figure 6 represents the match between the simulated model results and the historical cumulative oil and water production.

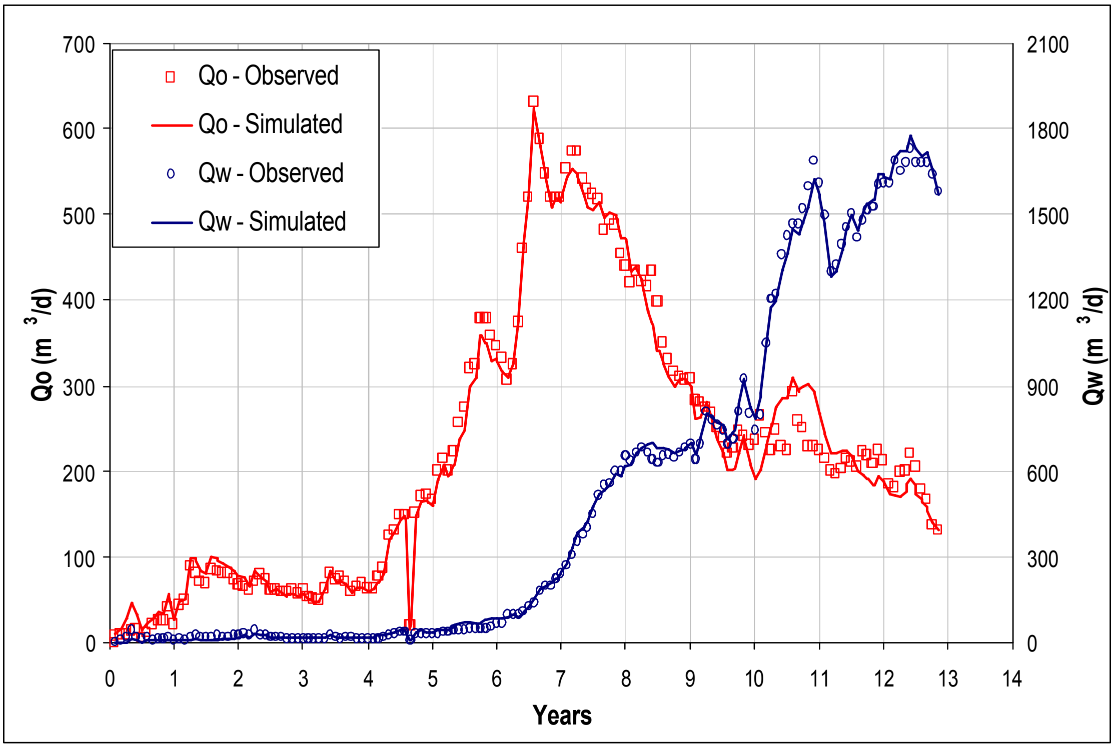


Figure 5 - History Match between Simulated and Observed Oil and Water Production Rates

The average pressure in the reservoir is maintained due to fluid injection and water encroachment from the aquifer and the evaluation tests in the field have confirmed the simulated data. Figure 7 demonstrates the aquifer influence on pressure maintenance of the reservoir.

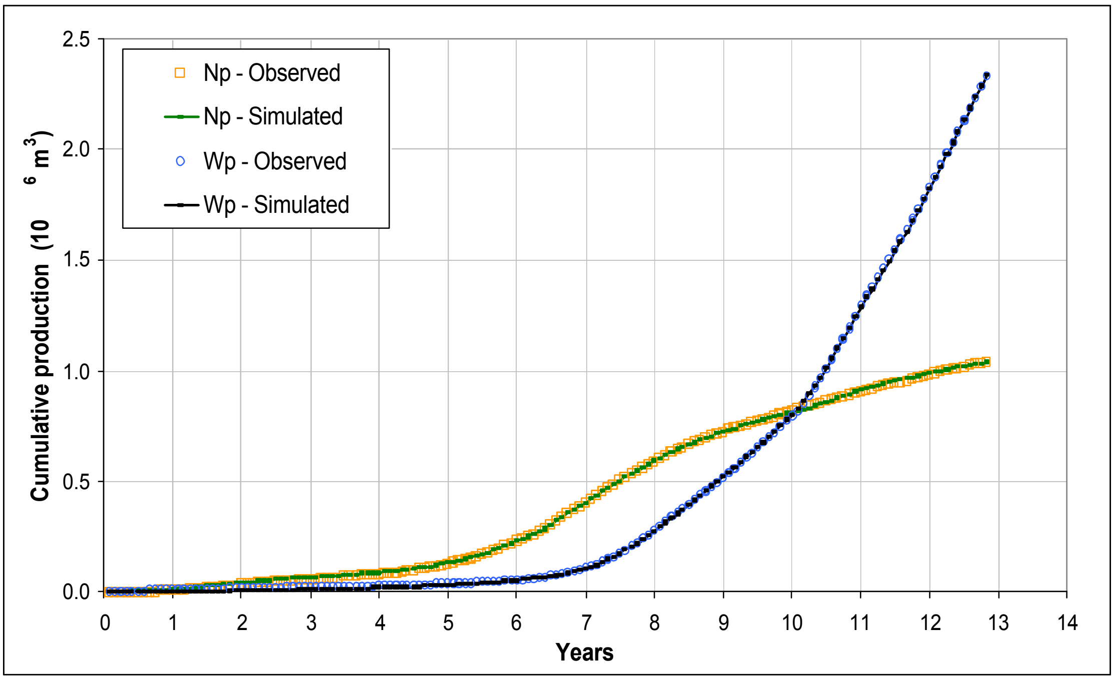


Figure 6 - History Match between Simulated and Observed Cumulative Oil and Water Productions

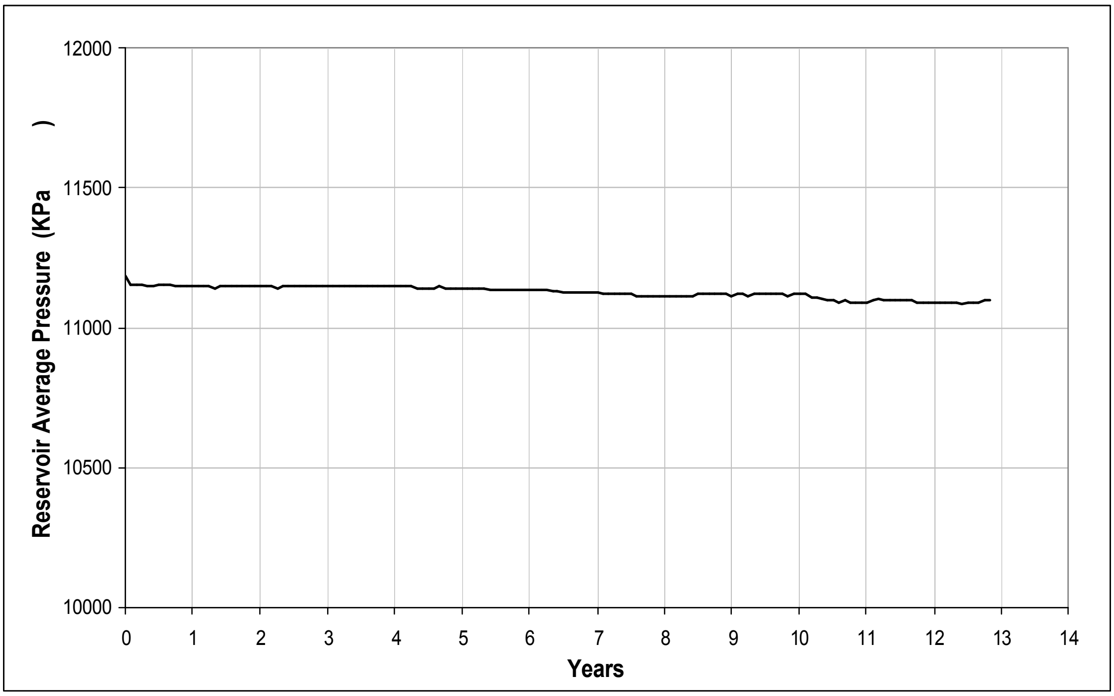


Figure 7 - Simulated Pressure Behaviour

Production Forecast

The following step is to extrapolate the production, considering that each well reaches its economic production limit with 98% watercut and a minimum of 1 m^3/d of oil production.

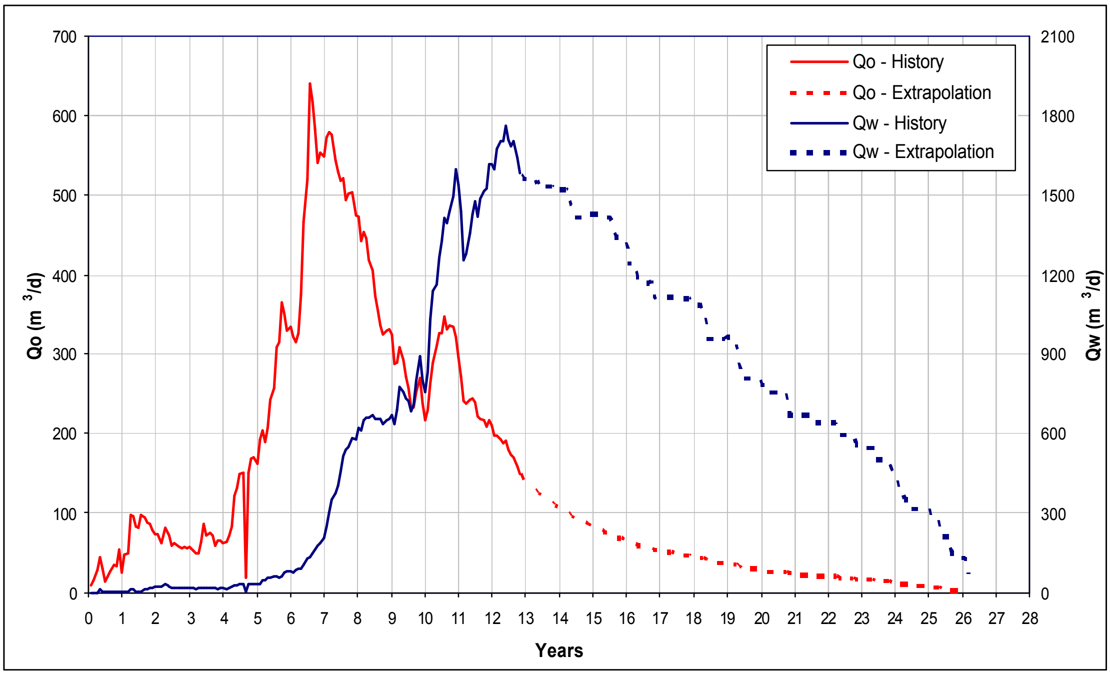


Figure 8 - Production Extrapolation up to the Abandonment Point

Figure 8 presents the production behaviour, including a simulation of historical product ion and the extrapolation of production up to the time of abandonment. During the extrapolation the total fluid rate is not maintained due to abandon of wells that reaches its economic production limit with a water cut above 98% or an oil production below 1 m^3/d.

The idea is to inject CO_2 in an abandoned oil field, so the CO_2 injection starts about one year after the abandonment.

CO_2 Enhanced Oil Recovery

Figure 9 exhibits the oil saturation map at the abandonment with the location of the four CO_2 injector wells.

The CO_2 injection is executed in six different schemes in an attempt to find the most profitable way of storing CO_2 while improving the incremental oil recovery. A total amount of 1.17×10^9 standard cubic metres (scm) of CO_2 is injected, which is the amount the reservoir can hold without exceeding the safety margins.

Thirty-two production wells are recompleted in order to produce near the original Water -oil contact. The 6 injection schemes are as foll ows:

A – $5x10^3$ STD m^3/d per well for 160 years
B – $10x10^3$ STD m^3/d per well for 80 years
C – $25x10^3$ STD m^3/d per well for 32 years
D – $50x10^3$ STD m^3/d per well for 16 years
E – $100x10^3$ STD m^3/d per well for 8 years
F – $200x10^3$ STD m^3/d per well for 4 year s

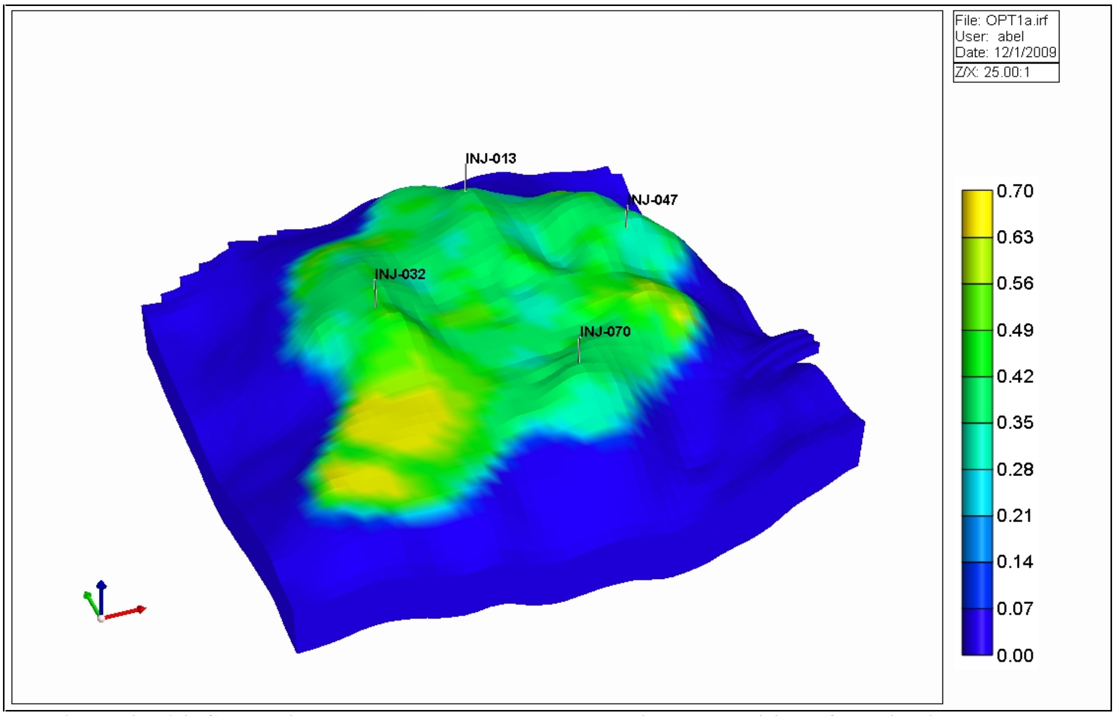


Figure 9 - Oil Saturation Map at the Abandonment with the Position of the 4 Injectors Wells

Figure 10 shows a reservoir section with the gas saturation at the end of the CO_2 injection , scheme C , and Figure 11 shows the incremental oil production for each CO_2 injection scheme.

Figure 11 suggests that the slower the CO_2 injection, the higher the incremental oil production. The CO_2 injected on the formation top sweeps and pushes the oil down, and part of this oil is produced by the production wells completed near the original oil water contact.

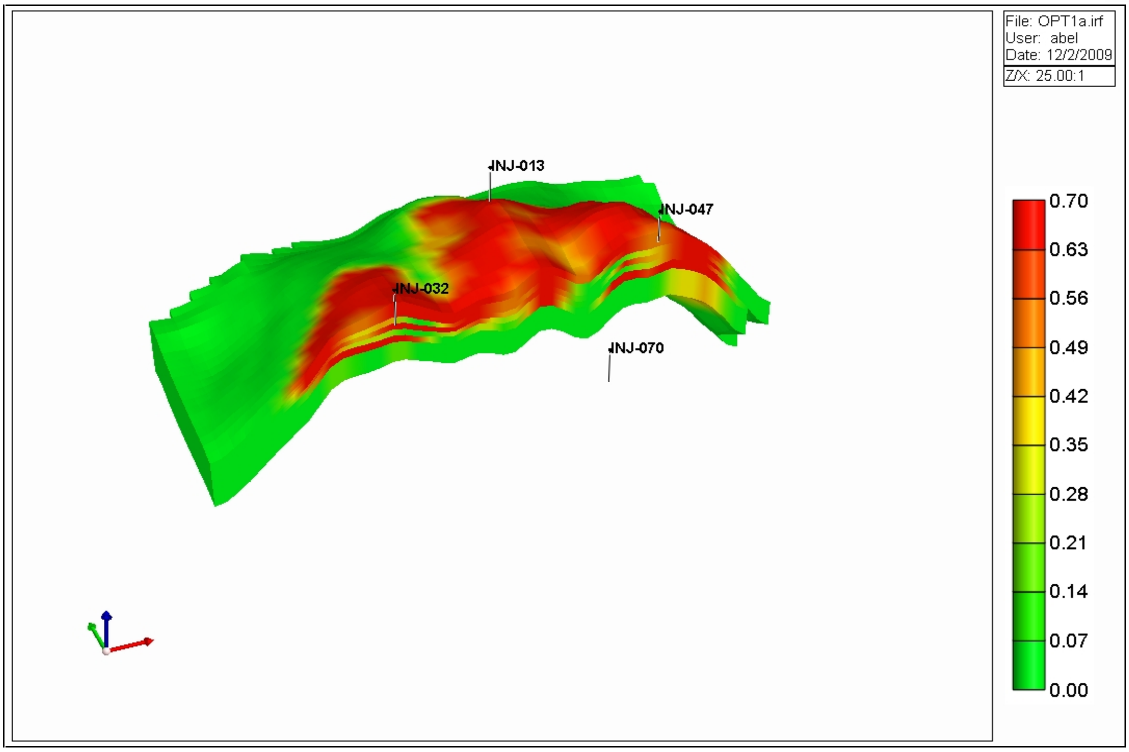


Figure 10 - Gas Saturation at the End of the CO2 Injection

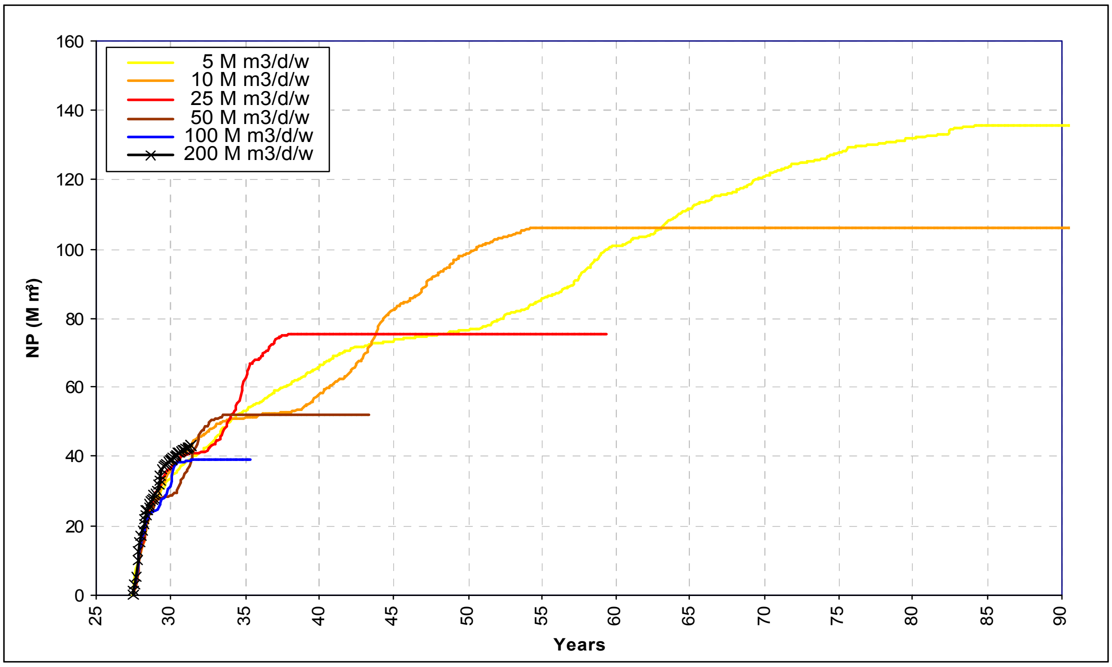


Figure 11 - Incremental Oil Production for the Six Injection Schemes

When the injectors operate at a high rate, the producer hasn't enough time to produce all the swept oil. Part of this non-produced oil is pushed under the water contact and stays trapped, as irreducible oil. After CO_2 breakthrough in the production well, the well must be shut in. Each producer well has the gas production monitored, and when it reaches 1000 STD m^3/d, it is automatically shut in. When the injectors operate at a low rate, the producer has time to collect more of the available incremental oil, but the production rate is small and spreads over a long time period.

The economics of oil production favour an early recovery. The revenue from production is used to cover various costs such as interest in borrowed money, lifting cost, equipment rental etc. To compute this economic influence, considering that the oil has a direct monetary value, an interest rate of 10% per year is added to the incremental oil production. The incremental oil production loses more significance for late production than for early production.

Figure 12 indicates the incremental oil production updated at 10% interest rate. That is the equivalent of the oil volume in present value. The CO_2 injection scheme referring to 25,000 standard cubic metres per day per well presented the best present value for an interest rate of 10% per year.

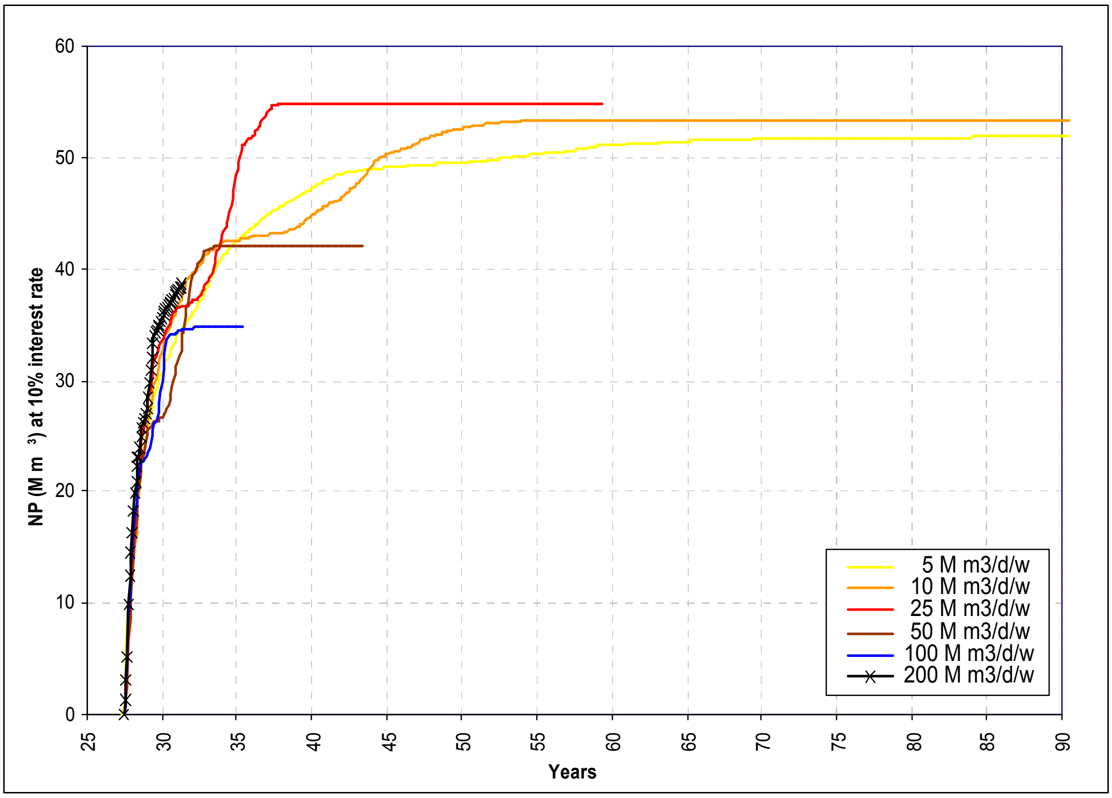


Figure 12 - Incremental Oil Production Discounted at 10% Interest Rate

Table 1 shows the results observed for each CO_2 injection scheme. After the time observed in the column "Production Time of Incremental Oil", there is no more additional oil production and the injection rate could increase up to the available CO_2 rate. Other oil reservoirs can be used to optimise the injection of CO_2 available.

Table 1 - Results of CO_2 Injection Schemes

Injection Rate scm/d/well	Injection Time years	Production Time of Incremental Oil years	Incremental NP 10^3 scm	Incremental Recovery % OOIP	Discounted NP by 10%/year 10^3 scm
5,000	160	56.87	135.38	4.63	51.83
10,000	80	26.76	105.76	3.61	53.31
25,000	32	10.67	75.85	2.59	54.87
50,000	16	6.16	53.22	1.82	42.04
100,000	8	4.25	40.83	1.39	34.71
200,000	4	4.08	44.30	1.51	38.72

Figure 13 presents the incremental oil production observed for a CO_2 injection of 25,000 S TD m^3 per day per injector well. For this injection scheme, the total CO_2 injected is 1.1688x10 ^{9} m^3. A volume of 0.00649x10 ^{9} m^3 is produced back, and a total volume of 1.1623x10 ^{9} m^3 remains in the reservoir. From the CO_2 that remains in the reservoir 56.21% is str ucturally trapped, 32.50% residual gas trapped, and 11.29% solubility trapped after 32 years of injection.

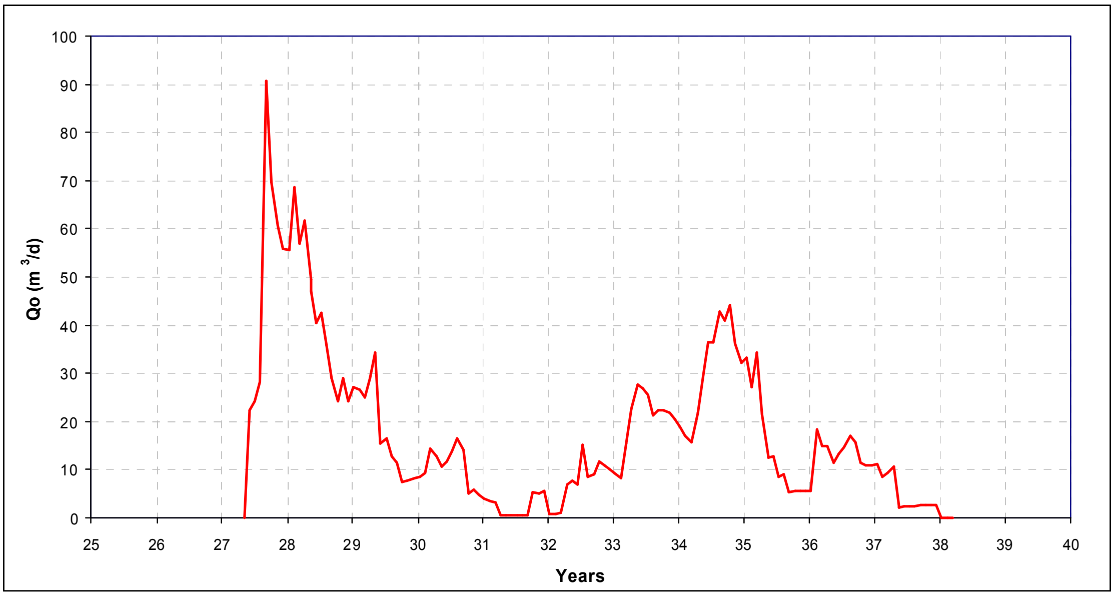


Figure 13 - Incremental Oil Production for a CO_2 Injection of 25,000 STD m^3/d per Well

Some producing wells, close to the injectors , provide a qui ck oil production response to the CO_2 injection, but the CO_2 reach es these wells increasing the gas production and shutting in . Other wells, far from the injectors, have a late oil production response giving this bimodal behavio ur in Figure 13.

Although the miscibility is not reached, t he solubility of the CO_2 with the oil makes the oil swells and reduces its viscosity, enhancing oil production as an EOR process. The original oil viscosity is 2.2 cP; with the CO_2 injection, the new viscosity ranges from 1.3-1.5 cP.

Economic Aspects of CO_2 Enhanced Oil Recovery

The cost of CO_2 storage in the abandoned oil reservoir, involves the recompletion of 32 wells , necessary to locate the production interval near the water -oil contact and also the conversion cost of four wells from producers to injectors. Each well workover in the field costs about US$ 30,000. A total of US$ 1,080,000 is spent on CO_2 storage and EOR operation.

The overall capture and transportation cost of CO_2 can be used for more than one storage site; hence, these costs are calculated per tonne of CO_2.[1]

As an example, in order to evaluate the CO_2 storage and EOR in an abandoned oil reservoir, three different scenarios are considered. In all these cases the power plant is operated with natural gas in a location less than 100 kilometres from the injection site, and the CO_2 is delivered for injection at an appropriate pressure:

Optimistic Scenario - A cost of US$ 15.00 per ton of CO_2 captured and US$ 1.00 per ton of CO_2 transported, with a total cost of US$ 16.00 per ton of CO_2 captured and transported, ready to inject. This represents about US$ 2876.64 per day for injection.

Moderate Scenario - A cost of US$ 38.00 per ton of CO_2 captured and US$ 4.00 per ton of CO_2 transported, with a total cost of US$ 42.00 per ton of CO_2 captured and transported, ready to inject. This represents about US$ 7551.18 per day for injection.

Pessimistic Scenario - A cost of US$ 60.00 per ton of CO_2 captured and US$8 per ton of CO_2 transported, with a total cost of US$ 68.00 per ton of CO_2 captured and transported, ready to inject. This represents about US$ 12,225.72 per day for injection.

Table 2 presents the net cash flow for the three scenarios, considering a cumulative oil production of 54,870 m^3 using a discount rate of 10% per year. The local production cost is US$ 40.00 per bbl, with the oil price at US$ 100.00 per bbl resulting in an income of US$ 60.00 per bbl of incremental oil.

Table 2 - Economic Analysis of CO_2 Storage and EOR for Different Scenarios

SCENARIOS	CO_2 Injection Cost			Workover Investment	Income (Oil Price - Cost)	Net Cash Flow
	per Day	total after 32 years	Present Value at 10%/year			
	US$	10^3 US$	10^3 US$	10^3 US$	10^3 US$	10^3 US$
Optimistic	2,876.64	33,599.16	10,493.25	2,520.00	20,700.94	7,687.69
Moderate	7,551.18	88,197.78	27,544.79	2,520.00	20,707.94	-9,356.85
Pessimistic	12,225.72	142,796.41	44,596.32	2,520.00	20,707.94	-26,408.38

As indicated above CO_2 capture process requires a huge investment. If a project scenario does not indicate an economically viable scenario, an alternative option is to inject the flue gas directly without the capture plant.

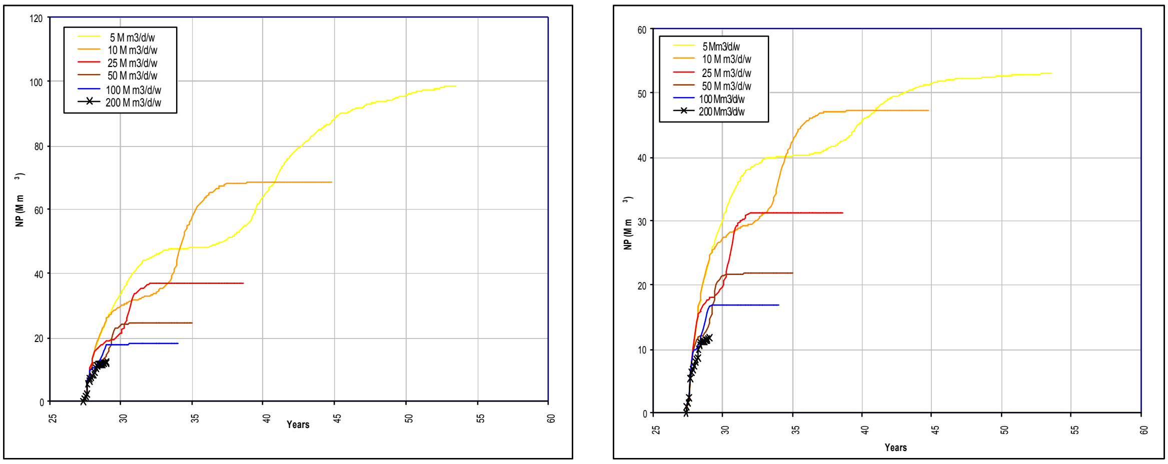
[1] 1 tonne CO_2 equals 1,000 kg CO_2, which is equivalent to 556.2 m^3 (1 atm and 25 °C). Therefore, CO_2 injection of 25,000 m^3/d per well equals to 100,000 m^3/d, which is equivalent to 179.79 tonnes of CO_2 per day.

Flue Gas Injection

CO_2 concentration in flue gas ranges from 3% to 15% (IPCC, 2005). The higher concentration is observed in coal-operated power plants, while plants operated on natural gas present the lowest concentration.

In order to compare the injection of flue gas with the injection of CO_2, the flue gas is considered as composed of 92% nitrogen (N_2) and 8% of CO_2. Because of the combustion, a certain amount of steam is formed; the flue gas must be dehydrated before transport and injection to avoid corrosion problems. Sulphur reduction may also be required.

Figure 14a shows the cumulative incremental oil produced for each scheme of injection and Figure 14b the equivalent present value of cumulative incremental oil with a discount rate of 10% per year. In contrast to CO_2 injection, the present value for cumulative oil has higher values for an injection rate of 10,000 STD m^3/d per well and 5000 STD m^3/d per well than for 25,000 STD m^3/d per well. But for the purposes of comparison with CO_2 injection, the economic evaluation is executed with a flue gas injection of 25,000 STD m^3/d per well.



a) NP of Incremental Oil **b) Discounted NP of Incremental Oil**

Figure 14 - Cumulative of Incremental Oil due to Flue Gas Injection

Table 3 presents the result for flue gas injection using the same schemes as for CO_2 injection. The results are smaller than for the corresponding CO_2 injections because of the large presence of Nitrogen (N_2) in flue gas. The N_2 does not have the same effect on oil as CO_2. For the flue gas injection of 25,000 STD m^3/d per well, a total flue gas volume of 1.1688×10^9 m^3 (0.0935×10^9 STD m^3 of CO_2) is injected. A total volume of 8.872×10^6 STD m^3 (0.6509×10^6 STD m^3 of CO_2) is produced back, and a total volume of 1.1599×10^9 m^3 (0.0929×10^9 STD m^3 of CO_2) remains stored in the reservoir. From the CO_2 that remains in the reservoir 83.30% is structurally trapped, 0.14% residual gas trapped, and 16.56% solubility trapped after 32 years of injection.

Table 3 - Results of Flue Gas Injection Schemes

Injection Rate scm/d/well	Injection Time years	Production Time years	Incremental NP 10^3 scm	Incremental Recovery % OOIP	Discounted NP by 10%/year 10^3 scm
5,000	160	25.59	98.49	3.36	52.92
10,000	80	11.67	68.49	2.34	47.27
25,000	32	5.67	36.74	1.26	31.35
50,000	16	4.58	24.43	0.83	21.8
100,000	8	3.75	18.23	0.62	16.9
200,000	4	1.66	12.31	0.42	11.66

Economic Aspects of Flue Gas Injection

Although there is no expensive separation process for flue gas, the compression is part of the capture process and must be accounted for with flue gas. The cost of compression from ambient to pipeline pressure (e.g. 2000 psi) is estimated at 6.00 - 8.00 US$/ton (Radosz et al., 2008). For the flue gas injection, the scenarios are as follows:

Optimistic Scenario - A cost of US$ 6.00 per ton of flue gas captured (compressed) and US$ 1.00 per ton of flue gas transported, with a total of US $ 7.00 per ton of flue gas captured and transported, ready to inject. This represent s about US$ 1258.53 per day for injection.

Moderate Scenario - A cost of US$ 7.00 per ton of flue gas captured (compressed) and US$ 4.00 per ton of flue gas transported, with a total of US$ 11.00 per ton of flue gas captured and transported, ready to inject. This represent s about US$ 1977.69 per day for injection.

Pessimistic Scenario - A cost of US$ 8.00 per ton of flue gas captured (compressed) and US$ 8.00 per ton of f lue gas transported, with a total of US$ 16.00 per ton of flue gas captured and transported, ready to inject. This represent s about US$ 2876.64 per day for injection.

Table 4 presents the net cash flow for the thr ee scenarios, considering a present value of cumulative oil production, using a discount rate of 10% per year, as 31,350 m ^{3}.

Table 4 - Economic Analysis of Flue Gas Storage and EOR for Different Scenarios

SCENARIOS	CO_2 Injection Cost			Workover Investment	Income (Oil Price - Cost)	Net Cash Flow
	per Day	total after 32 years	Present Value at 10%/year			
	US$	10^3 US$	10^3 US$	10^3 US$	10^3 US$	10^3 US$
Optimistic	1,258.53	14,699.63	4,590.80	2,520.00	11,831.00	4,720.20
Moderate	1,977.69	23,099.42	7,214.11	2,520.00	11,831.00	2,096.89
Pessimistic	2,876.64	33,599.16	10,493.25	2,520.00	11,831.00	-1,182.25

For this particular case, except for the optimistic case, the flue gas storage presents a better net cash flow than CO_2 storage and EOR due to the separation cost. The only income considered is the incremental oil; the volume of CO_2 stored when injecting CO_2 is 1.1623x10^9 STD m^3, which is much more than the volume of CO_2 stored when injecting flue gas 9.29x10^7 STD m^3.

Conclusion

CO_2 storage in abandoned oil field s has been analyzed along with Enhanced Oil Recovery (EOR) methods with CO_2. An economic analysis of incremental oi l produced with CO_2 injection and flue gas injection into abandoned petroleum reservoirs has also been performed , showing that both the injection of pure CO_2 and the injection of flue gas lead to incremental oil recovery due to oil swelling and reduced liquid viscosity, but while CO_2 injection provide s more efficient displacement and capture benefits , flue gas injection may be preferred due to its lower economic cost.

CO_2 Injection at a rate of 100,000 scm/d for 32 years, provides 75,850 m^3 of incremental oil representing an increment of 2.59% extra -recovery of oil obtained by EOR and a CO_2 storage volume of $1.162x10^9$ m^3 remaining in the reservoir, corresponding to 2.09 Mt. From this storage amount: 56.21 % is structural ly trapped, 32.50 % is residual gas t rapped and 11.29 % is solubility trapped.

By comparison , considering a flue gas injection rate of 100,000 scm/d for 32 years, results in 36,740 m^3 of incremental oil representing an increment of 1.26% extra -recovery of oil obtained by EOR and a CO_2 storag e volume of $9.29x10^7$ m^3 remaining in the reservoir, corresponding to 0.167 Mt. From this storage amount: 83.30 % is structurally trapped, 0.14 % is residual gas trapped and 1 6.56 % is solubility trapped.

For the particular case presented , except for the o ptimistic scenario, the flue gas storage present ed a better net cash flow than CO_2 storage and EOR due to the capture plant cost necessary to separate the CO_2.

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