

OPTIMIZATION OF CO₂ INJECTION FOR SEQUESTRATION / ENHANCED OIL RECOVERY AND CURRENT STATUS IN CANADA

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Abstract: In today's industrialized world, the generation (and emission) of greenhouse gases (GHG) is likely to continue. The reduction of greenhouse gas emissions through public outreach programs is one approach to mitigate this problem however, in practice, it has not yet been received well by the public due to economic costs. Therefore, permanent storage of these gases in underground reservoirs is believed to be one of the most suitable solutions for the mitigation of greenhouse gases. Sequestration of GHG is not cheap, however, and thus the injection of greenhouse gases into oil or gas reservoirs to enhance production may offset some of these associated costs. The use of CO₂ for purely EOR purposes versus injection of CO₂ primarily for sequestration are technically two different problems. Proper design practices and technology need to be developed and applied in order to inject CO₂ into oil reservoirs not only for the purpose of tertiary oil recovery but also for permanent sequestration. In conventional CO₂ injection projects the main purpose is to increase the amount of oil produced per amount of CO₂ injected. In contrast optimization of CO₂ injection for sequestration purposes requires "maximum oil production with the highest amount of CO₂ storage". Breakthrough time is a critical parameter in this exercise as recycling CO₂ is undesirable due to economic and environmental constraints. This paper summarizes on-going research into the conditions that will maximize oil recovery while maximizing the underground sequestration of CO₂. Results obtained from numerical modeling of the injection process are discussed. Current efforts on CO₂ injection in Canada are also presented.

Key words: CO₂ sequestration, enhanced oil recovery, optimisation, miscible/immiscible CO₂ injection, flue gas injection, numerical modeling

1. INTRODUCTION

One of the most suitable means for geological CO₂ sequestration is in enhanced oil recovery (EOR) operations, which lower the cost of CO₂ disposal by recovering incremental oil (Fanchi, 2001; Jessen et al., 2001; Brush et al., 2002). According to the U.S. DOE, 2,000 scf of CO₂ are stored per barrel of currently produced oil, with targets set for an eventual 10,000 scf per barrel of oil (<http://www.netl.doe.gov/coalpower/sequestration>).

CO₂ injection for EOR is a proven technology and many applications are in progress all around world. Note, however, that the sequestration of CO₂, while enhancing oil production in partly depleted reservoirs, is technically a different problem. Detailed analyses of the process are needed as early breakthrough of CO₂ is not desired.

This paper focuses on the determination of optimal conditions that maximize both oil recovery and underground CO₂ sequestration. This was investigated by using a numerical model and considering different injection schemes, such as miscible and immiscible CO₂ and flue gas. Evaluations were done for breakthrough times.

2. STATUS IN CANADA

Depleted or nearly depleted oil reservoirs are good candidates for CO₂ storage as they offset some of the costs of sequestration by producing additional oil recovery. This is of particular importance in Alberta, Canada, as many oil reservoirs here are nearing depletion and the needed infrastructure is already in place. A recent study has shown that 4,470 oil reservoirs out of 8,637 in Alberta have passed the screening criteria for CO₂ injection (Shaw and Bachu, 2002). Preliminary calculations show that up to 558×10^6 m³ of additional oil could be recovered while sequestering 1,118 Mt of CO₂. Injecting CO₂ into oil reservoirs, however, should be done in a controlled way to improve oil recovery (Rojas et al., 1991, Babadagli, 2003-a and b).

Existing, proven oil reserves in Canada (~ 6.5 billion barrels) are diminishing. On the other hand, Alberta owns the largest oil sands reserves in the world and they are expected to provide approximately half of Canada's crude oil production by 2005. For both cases, enhanced oil recovery (EOR) applications are inevitable, but still more effort is needed for the development of technology which can recover the great amount of oil left in the depleted pools and oil sands.

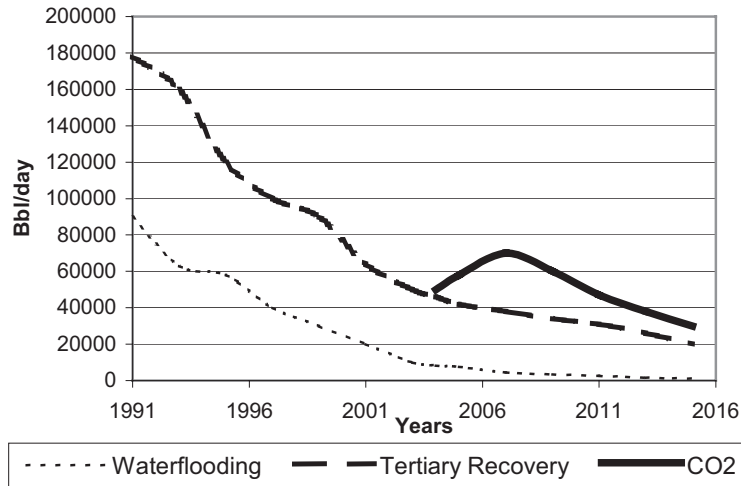


Figure 1. Enhanced oil production in Canada as of 2001. The values beyond 2001 are forecast. Source: www.ptac.org, CAPP, ADOE, and AEUB.

The current status and prospect of Canadian secondary-tertiary oil recovery are shown in Figure 1 in comparison with potential CO₂ applications.

More than half of the existing oil pools in Alberta have shown a potential for CO₂ recovery (Shaw and Bachu, 2002), however a well known problem is CO₂ capture and transportation from different sources. Having oil and gas reservoirs near dependable CO₂ sources makes sequestration applicable in this region. The total amount of anthropogenically-produced CO₂ in Canada was 277 Mt/year in 1997. The prospect in 2010 is 333 Mt/year and the great percentage of this comes from power plants, as shown in Figure 2. Applications in the eastern part of Canada are also under consideration (Shafeen et al., 2004).

Emission of impure CO₂ other than flue gas also exists in Alberta. Acid gas has been produced in Zama (80% CO₂ – 20 % H₂S) and disposal of this gas has been a concern (Davison et al., 1999). It has also been noted that acid gas is an effective enhanced oil recovery agent as it reduces the minimum miscibility pressure of CO₂ as opposed to N₂. There is no doubt that storing H₂S with CO₂ in underground reservoirs will double the benefit for the environment (Trivedi et al., 2005).

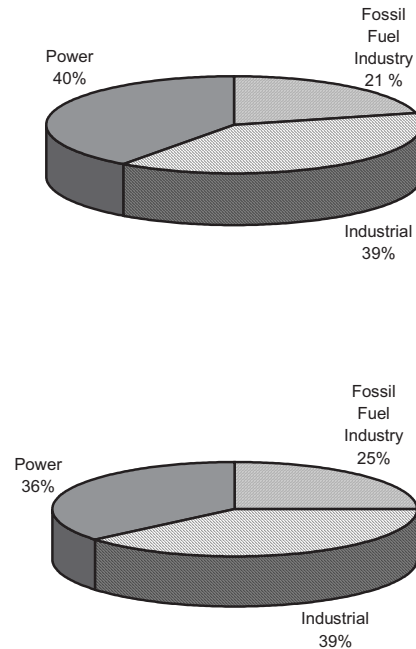


Figure 2. CO₂ emissions in Canada (source: www.nrcan.gc.ca/es/etb/cetc/combustion/co2network).

Early breakthrough is a serious problem in naturally fractured reservoirs since the fractures serve as a high permeability pathway which results in the faster movement of injected fluids (Beliveau et al., 1993 and Babadagli, 2003-a and b). Beliveau et al. (1993) observed that water injected into a fractured carbonate reservoir (Midale, Canada) yielded very early breakthrough (order of hours) whereas CO₂ breakthrough took a month. This indicates the viability of EOR (due to diffusive matrix-fracture interaction) during the sequestration of CO₂. Oil recovery and sequestration potential should be identified in such weakly-water-wet fractured systems, and the Weyburn field in Canada is a good example of this type of reservoir.

3. OBJECTIVES AND METHODOLOGY

The objective of this study is to test numerous different injection schemes and to determine the conditions which yield the highest oil recovery while

storing the maximum amount of CO₂. To achieve this, the compositional option of a commercial reservoir simulator (CMG) was used. Runs were performed for different injection schemes and comparisons were made for the amount of oil produced against the amount of CO₂ stored at breakthrough time.

4. MODELING CO₂ SEQUESTRATION DURING ENHANCED OIL RECOVERY

4.1 Numerical Model

A hypothetical reservoir was considered by adapting CO₂ injection data from the Wasson field (Hsu et al., 1997). The model consists of 7x7x3 grids. The injector was located at the centre and four producers were in the four corner grids representing a typical 5-spot injection pattern.

Twelve components (C1-C29, CO₂, NO₂) were considered. Other reservoir, rock and fluid properties used as simulator variables are given in Table 1. Relative permeabilities for oil, gas and water phases were obtained from Hsu et al. (1997).

Table 1. Reservoir, rock and fluid properties used as simulator variables.

Properties	
Depth	5200 ft.
Average porosity	12%
Permeability	5 md
Net thickness	460 ft
Reservoir temperature	110 °F
Oil gravity	33 API
Min. miscibility press.	1300 psi

Reported minimum miscibility pressure (MMP) values for Wasson crude oil range from 1250 to 1400. For pressures less than 0.9 times the MMP the displacement is treated as immiscible, while for pressures equal to or greater than the MMP the displacement is assumed miscible. Note that the runs were performed after a long water-flooding period.

4.2 Results

Evaluations were performed using cumulative oil recovery vs. cumulative CO₂ storage plots and cumulative oil recovery-cumulative CO₂ storage vs. time plots. Examples of these graphs for pressures less than the

MMP are shown in Figures 3 and 4. Increasing pressure yielded higher oil recovery and CO₂ storage (Fig. 3). Obviously the breakthrough time of CO₂ is critical and it is expected that the earlier breakthrough time will be obtained with increasing pressure. Note that this plot is not sufficient to decide whether an optimum pressure (or conditions) exists.

Another performance indicator was considered to be the plot of cumulative oil vs. CO₂ stored to explain the efficiency of the process (Fig. 4). For any given oil recovery, higher storage was obtained with increasing pressure. For any given amount of CO₂ storage, cumulative oil produced increased with decreasing pressure. Thus any decision should be made on what the final expectation or economic limitations are. If the purpose of injection is CO₂ sequestration, one should pay attention to the latter. If oil recovery is the primary concern, however, lower pressure would be more suitable for the application. In other words, the weighing factor is a critical issue in this decision. Kavscek and Cakici (2004) proposed an objective function ($f = wN_p + (1-w)V_{CO_2}$) and analysed the CO₂ injection cases where the storage (V_{CO_2}) and the recovery (N_p) are equally important ($w=0.5$).

The above process was repeated for other injection scenarios and the cumulative oil recoveries were compared to the CO₂ storage at breakthrough time. The results are shown in Figures 5 through 8. The immiscible case, which occurs under the MMP (1500 psi), was considered first. Both oil recovery and CO₂ storage showed a similar trend (Fig. 5). The lowest recovery and storage occurs at a pressure of 1300 psi, but both parameters increase with increasing pressure when the pressure is above the MMP. The continuation of this trend can be found in Figure 6, where recovery and storage continue to increase with increasing pressure. Obviously the highest pressure yielded the best solution at breakthrough. One can conclude that miscible injection is desirable for storage and recovery if the required pressure is practically applicable.

Another case considered was the injection of flue gas rather than pure CO₂. Flue gas injection is a proven enhanced oil recovery technique (Iijima, 1998 and Dong and Huang, 2002). It is practical and economical to store CO₂ in this form as the purification of CO₂ generated in power plants is costly. The results for the flue gas injection case are illustrated in Figure 7, where the trend is similar to the miscible case. Note that maximum storage with maximum recovery was obtained for the highest pressure (2500 psi). The amount of storage below this pressure is significantly lower even though the recovery did not change significantly. Thus injection pressure would be selected based on the primary purpose, i.e., storage or additional oil recovery.

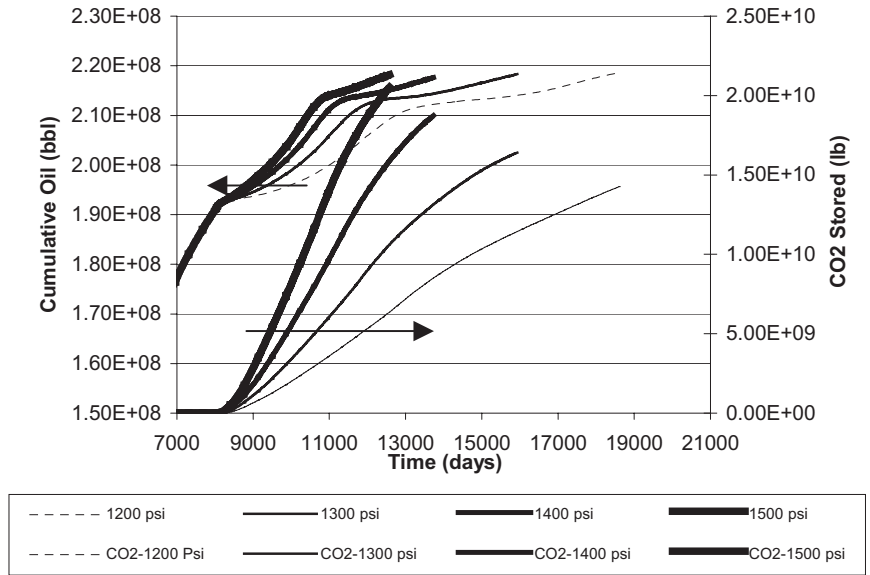


Figure 3. Cumulative oil and CO₂ stored against time for different injection pressures.

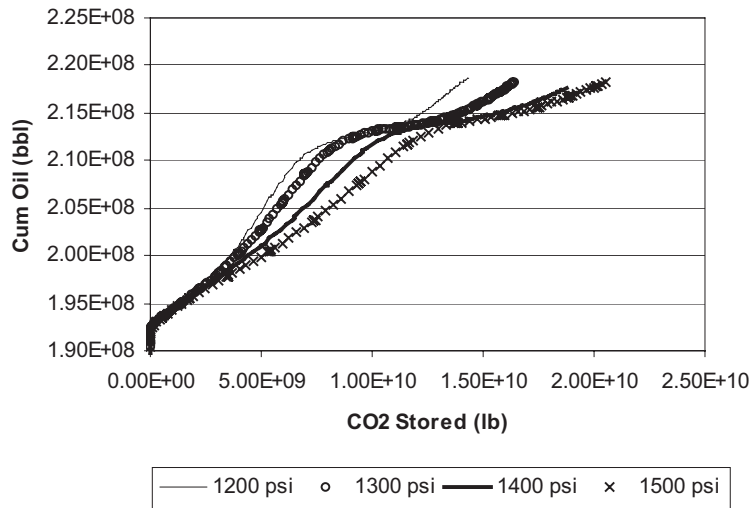


Figure 4. Cumulative oil against CO₂ stored at different injection pressures.

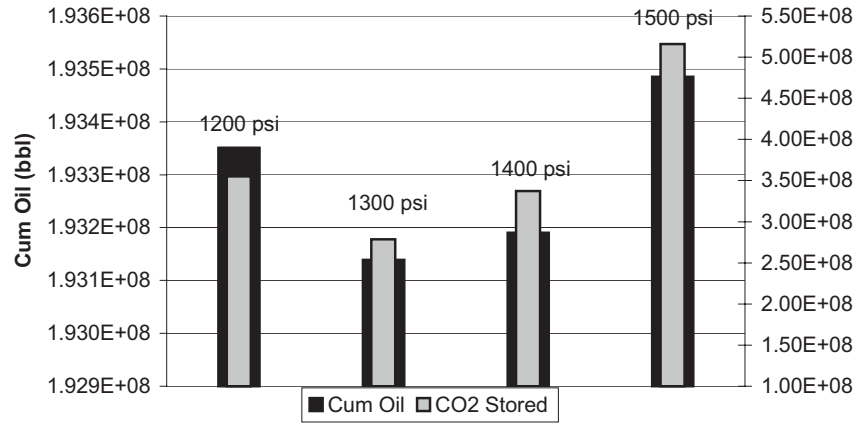


Figure 5. Comparison of cumulative oil recovery and CO₂ storage at breakthrough time for the immiscible case.

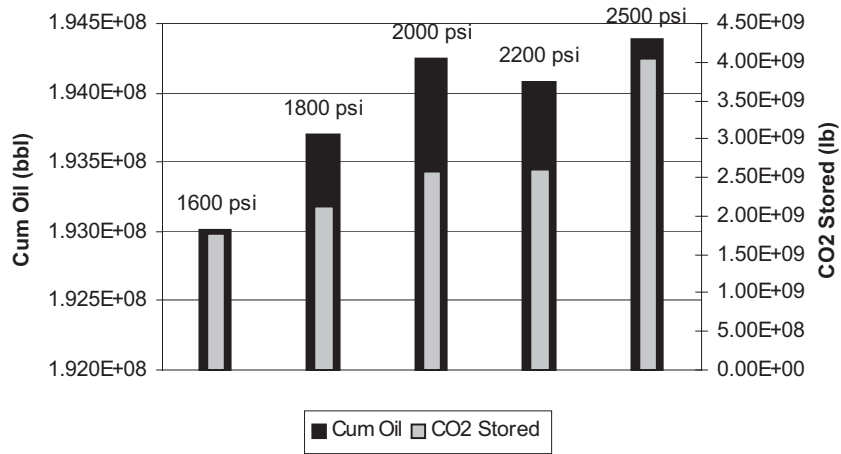


Figure 6. Comparison of cumulative oil recovery and CO₂ storage at breakthrough time for the miscible case.

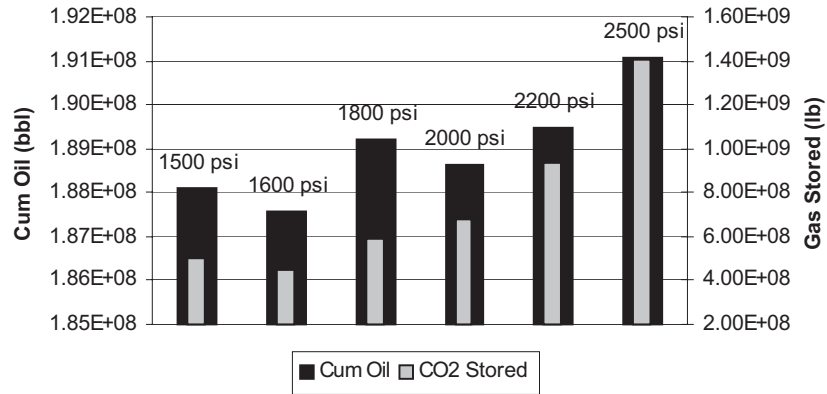


Figure 7. Comparison of cumulative oil recovery and CO₂ storage at breakthrough time for flue – gas injection.

5. CONCLUDING REMARKS

This paper reports the preliminary results of a numerical study on the optimization of CO₂ storage during enhanced oil recovery. It was observed that the immiscible and miscible cases exhibit different recovery/storage behavior. Although the miscible case showed better recovery performance and storage capacity with pressure increases, it is difficult to reach MMP due to technical difficulties and/or regulatory restrictions in many circumstances. One should select the injection pressure depending on the priorities, i.e., more additional oil or more CO₂ storage.

Identification of the causes of CO₂ entrapment is critical but it varies reservoir by reservoir. Answering what really causes CO₂ to get trapped in the reservoir needs special studies for any particular reservoir, with focus being given to the effects of pore types, fractures and chemical interactions with the reservoir rock. The need for investigations into the long-term behavior of injected and trapped gas are also obvious (Ennis-King and Paterson, 2003).

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