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Security of storage in carbon dioxide enhanced oil recovery

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Abstract

The Pembina Cardium CO_2 Monitoring Pilot was used as a test site to determine the relative roles of trapping mechanisms. Two methods to assess this distribution are presented. A geochemical approach using empirical data from the site was used to determine the phase distribution of CO_2 at a number of production wells that were sampled monthly during a two-year CO_2 injection pilot. In addition, a simplified reservoir simulation was performed. Results indicate that significant amounts of CO_2 are stored in the oil phase thus reducing the amount of CO_2 available as a buoyant free phase and hence increasing storage security.

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Keywords: CO_2 Enhanced Oil Recovery, CO_2 Storage Security, CCS, CO_2 solubility, trapping mechanisms

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1. Introduction

Preliminary studies from Carbon Dioxide Enhanced Oil Recovery (CO_2-EOR) in Canada have suggested that, in CO_2-EOR settings, solubility trapping takes place within both aqueous and hydrocarbon phases. As such it is postulated that CO_2-EOR may provide a greater quantity of securely stored CO_2 than a purely non-EOR storage operation. This study's principal objective was to quantify how much solubility trapping takes place within both aqueous and hydrocarbon phases in CO_2-EOR settings.

1.1. Trapping mechanisms

The fate of CO_2 is an important consideration when injecting CO_2 into the geological subsurface. CO_2 can be trapped structurally and stratigraphically, by residual trapping, solubility trapping, and by mineral trapping [1]. Although in a well selected storage complex a combination of each of these trapping mechanisms should lead to extremely high confidence in storage security, certain geological risks will always exist [2]. What is known, however, is that the highest geological storage risks exist when CO_2 is in free phase and is reliant on structural and stratigraphic trapping and on well integrity. Increased security of CO_2 storage will be achieved if the primary storage mechanism changes from structural and stratigraphic trapping to solubility trapping in the time frame of injection operations and thereafter.

1.2. Pembina Cardium CO_2 Monitoring Pilot

The Pembina Cardium CO_2 Monitoring Pilot (PCCMP) was used as a test site to determine the relative roles of trapping mechanisms. The PCCMP site is located near the town of Drayton Valley, west of Edmonton, (Fig. 1) in the Pembina Field. The Pembina oilfield is the largest individual and one of the oldest onshore oilfields in Canada [3]. The pilot consists of two five-spot injection patterns, with two of the production wells being shared by the two injector wells. This results in a configuration with two CO_2 injectors surrounded by six producers (Fig. 1). These wells are located in the middle of the Pembina field in an area that has been water flooded since 1962 [4]. CO_2 injection started in 2005 with approximately 75,000 tons of truck delivered liquid CO_2 being injected between March 2005 and March 2008. Between March 2005 and March 2007 CO_2 was continuously injected through the two injection wells. After this period the pilot switched to Water Alternating Gas (WAG) injection with injected CO_2 being periodically alternated with water injection [5]. A detailed description of the geology of the field can be found in Dashtgard et al. [4], Hitchon [5], Krause et al. [6], and Plint et al. [7].

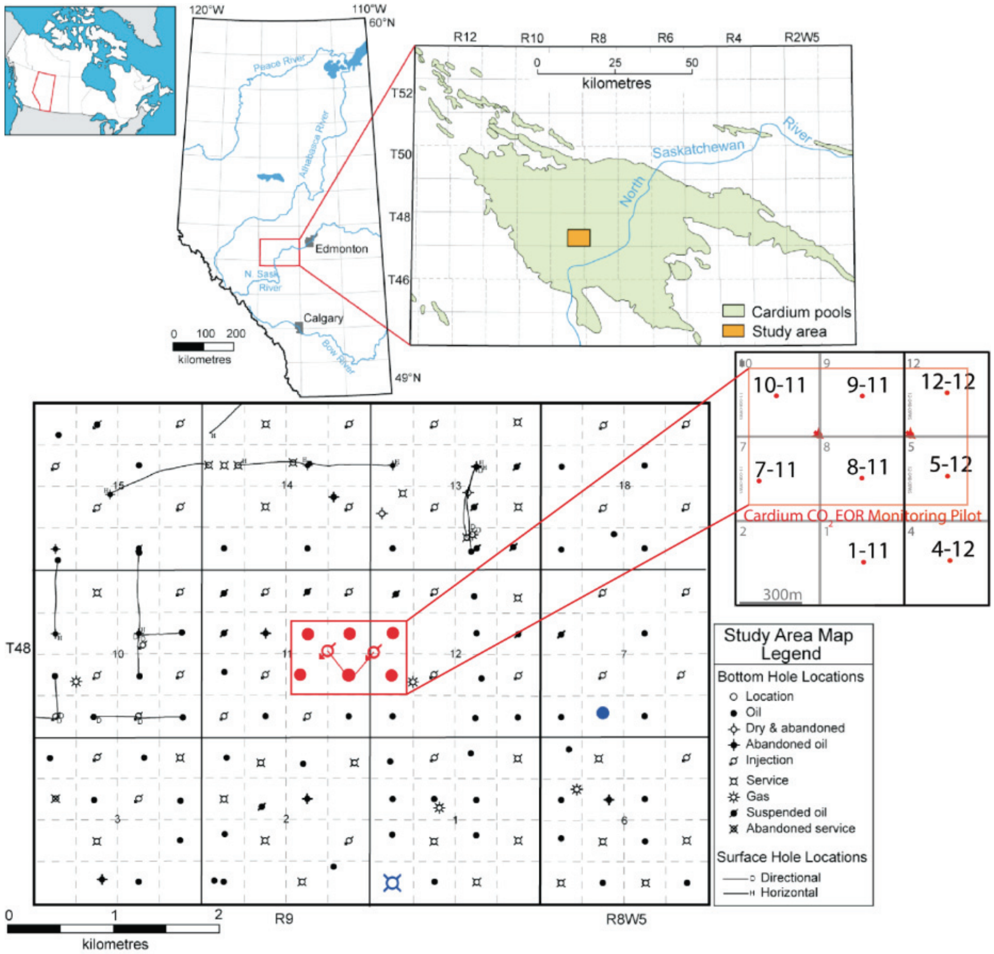

Figure 1. Location Map of the PCCMP in the Cardium pool, Pembina Field, adapted from Dashtgard et al. [4]. The lower map illustrates the location of all wells within the study area. Wells 10-11, 9-11, 7-11 and 8-11 are production wells in the classic 5 spot pattern with a CO_2 injector in the middle. Using wells 9-11 and 8-11wells 12-12 and 5-12 form a second 5 spot pattern with another CO_2 injector in the middle. Wells 1-11 and 4-12 are also production wells which sit further to the south.

1.3 Solubility of CO_2 at Pembina reservoir temperatures and pressures

The solubility of CO_2 in oil is controlled predominantly by reservoir pressure, temperature and to a smaller extent the oil API gravity [8,9,10,11]. Generally, solubility increases with pressure and oil API gravity (i.e. higher in lighter oils) but decreases with temperature. The solubility of CO_2 in aqueous fluids is primarily dependent on temperature, pressure and much like the solubility of CO_2 in oil, the solubility of CO_2 in brine decreases with temperature but increases rapidly with increasing pressures up to the saturation pressure [12].

CO_2 solubility in brine at pressures and temperatures nearest to those at Pembina field reservoir conditions of 50°C and 190 bar (19MPa) and 0.085M NaCl, a solubility of 2.3 mole % CO_2 (1.25 mol/L) is predicted [12].

The solubility of CO_2 in oil at Pembina reservoir temperatures and pressures is predicted to be 0.67 mole fraction. If the molecular weight and density of the oil is known this solubility can be converted to molality (mol L-1). The Pembina oil has a molecular weight of 191g mol-1 and a density of 0.8338 kg L-1 [5]. Therefore, at equilibrium saturation 0.67 mole fraction equates to 8.5 mol L-1 of oil. Therefore the solubility of CO_2 in oil at Pembina reservoir conditions is approximately seven times greater than in brine.

2. Methods

Two methods were used to determine the relative of trapping mechanisms. Firstly a geochemical method using empirical production data from the project. was used to determine the phase distribution of CO_2 (dissolved or free phase) at a number of production wells during the two-year CO_2 injection pilot at the Pembina field. Secondly a reservoir modelling approach was used to also estimate the phase distribution of CO_2 in the reservoir over the 2 year injection period. This would allow for the comparison of results between the two methods.

2.1 Geochemical method

Using the calculated equilibrium solubility coefficients (section 1.3), the partitioning of CO_2 that is dissolved in the oil, brine or present as a free phase gas can be estimated for the first two years of CO_2 injection at the PCCMP. To do this, the relative volumes of brine, oil and CO_2 in the reservoir must also be known. At the Pembina field monthly production volumes of gas, oil and brine are available and are here used as a proxy for the relative reservoir saturations. As observed in Figure 2 significant volumes of CO_2 were produced at wells 7-11, 8-11, 9-11 and 12-12. Using this production data the relative mole % of CO_2 dissolved in the oil, brine and as a free phase gas was calculated for the same 2 year injection period.

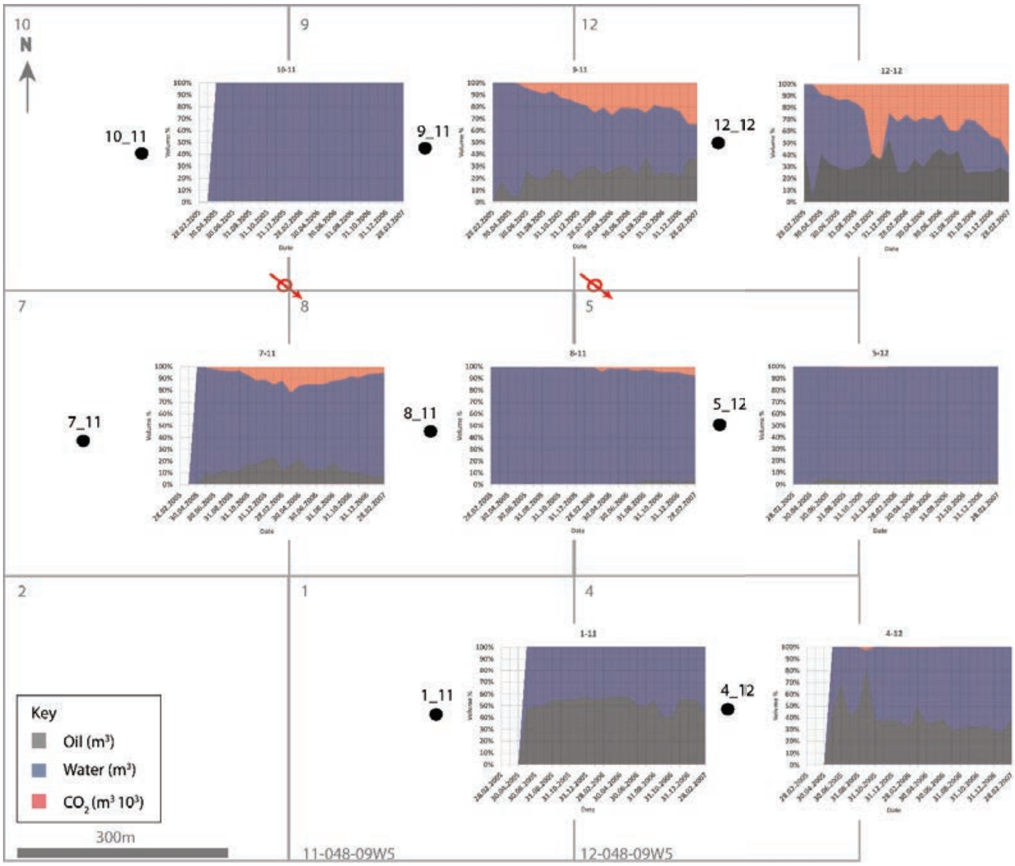

Figure 2. Produced fluids over the two year injection interval at each of the sampled wells. Production data from Alberta Innovates. [13,14,15].

To estimate partitioning, the equilibrium solubilities of 8.5 mol/L in oil and 1.25 mol/L in brine were multiplied by the number of liters of brine and oil produced at monthly intervals. This provided an estimate of the volume of CO_2 that would be needed to saturate both the brine and the oil. The volume of CO_2 in the system was calculated by multiplying the produced gas volume by the CO_2 concentration (mole %). When the volume of CO_2 in the system was in excess of the volume needed to saturate the brine and the oil, it was assumed that free phase CO_2 was present. When the volume in the system was less than the saturation volume it was assumed that both the brine and oil phase would be under-saturated with respect to CO_2. An assumption was made that the ratio of partitioning of CO_2 in brine and oil would remain constant in both under-saturated and saturated conditions. However this ratio was adjusted to represent the relative volumes of oil and brine by multiplying the saturated mole fractions by the fraction change in volume relative to a 1:1 oil water ratio. This leads to the solubility molalities (moles /L) in oil and brine remaining constant but the total number of moles in oil in relation to that in brine being different compared to that if the oil:water ratio was 1:1.

2.2 Reservoir modelling

A simple box compositional reservoir simulation model of the PCCM was developed to test results derived from the empirical site data. The primary purpose of the model developed here was not to match any project specific injection and production history, but rather to use it as a test-bed to investigate various CO_2 injection scenarios with a model having some of the salient features of the pilot project. In particular, the question posed was the differentiation between the proportions of CO_2 that is dissolved in water and CO_2 dissolved in oil, as well as CO_2 in the mobile and residual in the free gas phase, under various injection scenarios, such as could be reasonably envisaged for such a site.

The model was developed using CMG GEM compositional reservoir simulation software [16]. The model was constructed with a 21 × 21 × 15 grid with 20 m × 20 m cells in the areal plane. The solubility of CO_2 (and the other hydrocarbon components) dissolved in water was calculated using Henry's Law with Harvey's correlation used for CO_2, which makes the constant a function of pressure, temperature and salinity [17]. For the simulations reported here the water salinity was taken to be zero.

3. Results

Table 1 shows the phase distribution of the CO_2 at the end of the two-year injection interval. On average across all wells 74% of the CO_2 remains as a free phase with 14% and 12% dissolved into the oil and brine phase respectively. However the range of values vary from 55-91% for CO_2 in a free phase and from 8-84% and 1-100% for CO_2 in oil and brine respectively at individual wells. Thus one must be careful to not over interpret any one well in isolation of considering the production volumes.

Table 1. Mole % CO_2 in each reservoir fluid phase for each sampled well at the end of the two year CO_2 injection interval.

Well	moles CO_2 in brine	as %	moles CO_2 in oil	as %	moles CO_2 free phase	as %	SUM (moles)
12_12	13163	1	156060	8	1694668	91	1863891
7_11	100100	50	61880	31	37633	19	199613
8_11	411950	34	126140	10	663962	55	1202052
9_11	30100	2	264180	21	935451	76	1229731
1_11	33	16	180	84	0	0	213
10_11	379	100	0	0	0	0	379
4_12	50	20	206	80	0	0	256
5_12	138	79	38	21	0	0	176
TOTAL	555913		608684		3331713		4496310
% Total		12		14		74	100

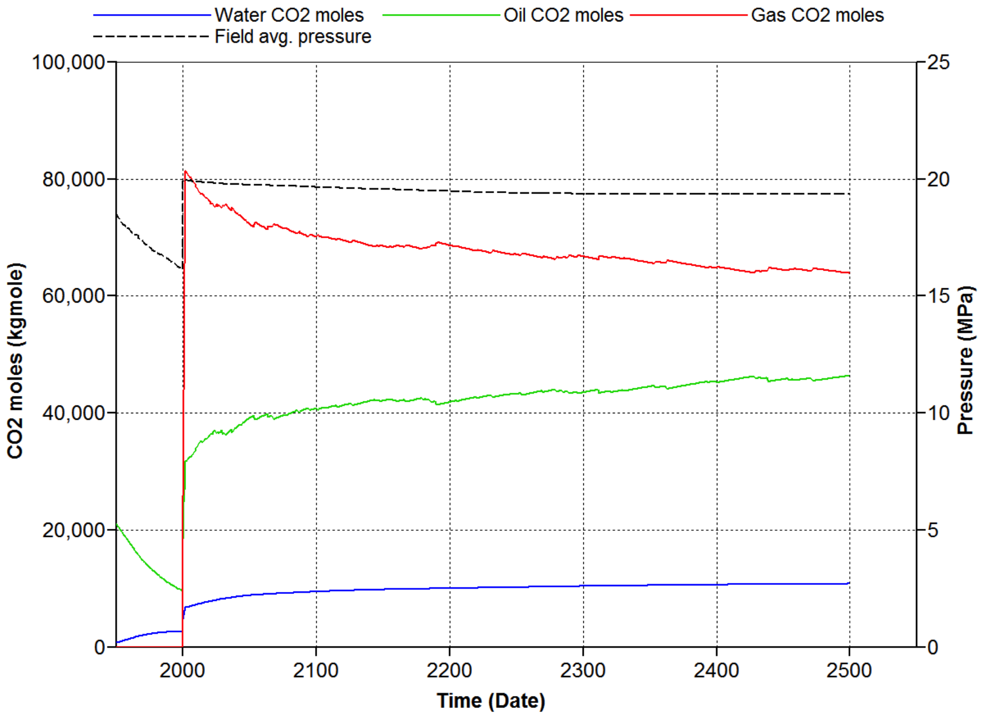

Figure 3. Initial simulation results showing the partitioning of CO_2 moles in the water, oil and gas phases and the average field pressure during water-flooding, CO_2 injection and subsequent equilibration stages.

Simulation results are shown in Figure 3. At time 2002, the final post CO_2 injection, CO_2 distributions were 68% in the free (gas) phase, 26% in the oil phase and 6 % in the water phase. This compares to an average of 74% in free phase, 14% in the oil phase and 12% in the water phase at the wells sampled during the operations (See table 1) which is considered a good fit given the uncertainty in the oil:water ratio at the start of CO_2 injection.

4. Discussion and Conclusions

Using a number of different correlations equilibrium solubility constants were calculated to be 8.5 mol/L for CO_2 in oil and 1.25 mol/L for CO_2 in brine at the PCCMP. Thus the presence of oil provides an additional sink for CO_2 that, dependent on conditions and relative oil:water saturations may have significantly higher CO_2 solubility than in saline aquifers alone. Using an empirical method based on production data and the solubility coefficients noted above it was found that 74% of the CO_2 remains as a free phase with 14% and 12% dissolved into the oil and brine phase respectively (on average across all wells). A previous assessment, which used an isotopic approach to estimate reservoir pore space saturations, gave similar partitioning results at the individual wells at the end of 2 years [18]. This study improves on this by accounting for pore-space away from wells and through comparison with a reservoir simulator.

The initial reservoir simulation modelling presented in this study also closely matches the average CO_2 distribution and relative trapping contributions derived from the geochemical approach. A slightly higher fraction of CO_2 dissolves in the oil and slightly lower fraction dissolves in the water when comparing the reservoir model to the average values of the geochemical data. However, the numbers thus calculated are well within the ranges of the geochemical data giving additional confidence in the empirical data method and the representativeness of the reservoir model itself.

We therefore conclude that security of storage can be greater in EOR settings where an oil phase permits additional solubility trapping and therefore less structural/stratigraphic trapping. However, it is noted that in EOR settings there may be more wells and therefore potential leakage pathways for CO_2 to migrate form than in virgin saline aquifer settings. Nonetheless these potential migration pathways should be well known and can be easily instrumented to ensure the security of the storage site.

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