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A simulation study on CO_2 sequestration in saline aquifers: Trapping mechanisms and risk of CO_2 leakage

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Abstract. Carbon dioxide (CO_2) is one of the main greenhouse gases that its high concentration in the atmosphere has caused the global warming issue. Sequestering CO_2 in a suitable geological subsurface formation can be a feasible method to reduce the CO_2 concentration in the atmosphere. CO_2 sequestration in saline aquifers can store a significant volume of CO_2 underground for thousand years. However, injecting CO_2 into such formations does not guarantee a safe storage because CO_2 could leak back to surface or contaminate the formation water. Hence, a proper evaluation of the sequestration site is required. In this study, a case study regarding CO_2 sequestration in saline aquifers was conducted using CMG-GEM compositional simulator to study the effects of aquifer permeability, injection pressure and well trajectory on CO_2 trapping mechanisms during sequestration process. A field-scale model with one injector well in which CO_2 was injected into the aquifer for ten years and simulated for hundred years was studied. The results showed that, CO_2 solubility trapping is the dominant mechanism with less risk of leakage when the aquifer has a good vertical permeability and the injection pressure is not high regardless of the well trajectory.

1. Introduction

Carbon dioxide (CO_2) as a main greenhouse gas, has a significant effect on the global climate change due to its high concentrations in atmosphere. One of the vital solutions to global warming is the geological storage of CO_2. Furthermore, CO_2 can be stored through enhanced oil recovery process by injecting CO_2 in oil reservoirs to improve the oil recovery [1-5]. The process of long storage of CO_2 in the earth's subsurface, known as CO_2 sequestration, can occur in various types of reservoirs such as: depleted oil and gas reservoirs, saline aquifers, and coal seams. The deep saline aquifers have the largest capacity of storage among all other geological formations considered for CO_2 storage [6]. CO_2 is usually injected in deep saline aquifers at supercritical state due to the high pressure and temperature of the aquifers. Indeed, supercritical CO_2 has a higher capability to be dissolved in saline water compared to gaseous CO_2. Additionally, supercritical CO_2 occupies less space and prevents the hydrate formation in pipelines that may occur if gaseous CO_2 is injected [7]. After CO_2 is injected in saline

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aquifer, the less dense supercritical CO_2 overlay the formation brine, and escape vertically to the top of aquifer through buoyancy effects until it is trapped by a cap rock. Hence, the storage sites must have impermeable cap rocks to avoid free CO_2 from escaping to the atmosphere [8]. Four storage mechanisms are responsible for keeping CO_2 underground; structural trapping, dissolution trapping, mineral trapping, and capillary trapping [9]. In structural trapping, the upward migration of CO_2 is controlled by impermeable cap rocks that act as barrier to prevent the leak of gas to the surface. When the aquifer brine is overlaid by the CO_2 plume, CO_2 starts to dissolve into the aquifer water (brine). This process is called dissolution trapping. The dissolution of CO_2 into water (brine) causes an increase in the water density that results in convective forces due density difference. The density driven natural convection accelerates the dissolution process and causes more gas to be dissolved in a shorter time period [10]. Additionally, the chemical reactions between the formation rock, CO_2 and saline water causes the storage of CO_2 in the form of solid mineral phase. This process is called mineral trapping. CO_2 can be also stored in aquifers by the effect of residual trapping where CO_2 bubbles are trapped in formation by capillary forces [11]. It was found that the main risk considered for the CO_2 sequestration process is the leakage of the free CO_2 gas to the surface through natural fractures or even though the drilled wells that has been used for CO_2 injection. Some previous studies investigated the factors affecting CO_2 sequestration process in deep saline aquifers [8, 12-15]. However, CO_2 sequestration process still needs more investigation to set the criteria for selecting the best candidate sites for storing CO_2 with avoiding leakage to the atmosphere. In this study, a numerical simulation was performed to evaluate the feasibility of CO_2 storage in deep saline aquifers under various operating conditions. A sensitivity analysis was conducted to understand the effect of injection strategy (pressure), vertical and horizontal permeability variation, and well trajectory on CO_2 sequestration process using CMG-GEM compositional simulator.

2. Aquifer model

In order to evaluate the performance of CO_2 sequestration and investigate the sensitivity of different parameters, a numerical simulation model (CMG-GEM) was used to create a 3D cartesian aquifer model. The model parameters are shown in Table 1. The model was created with 20250 grids and one injection well was located at the middle of the aquifer and CO_2 injection was conducted at a constant bottom-hole pressure. It should be noted that, a sensitivity analysis on grid block dimensions was conducted on three different sizes of grid blocks while it was found that 45x45x10 resulted in the lowest numerical dispersion error (<1%).

Table 1. Aquifer properties used to create the model

Parameter	Value
Aquifer depth, ft	3937
Thickness, ft	16.4
Grid dimension	45x45x10
Rock compressibility, psi^{-1}	4.5x10^{-6}
Initial reservoir pressure, psi	1711
Aquifer salinity, ppm	10,000
Average permeability, mD	100
Average porosity	0.18

CMG-Winprop was used to obtain aquifer fluid properties. Peng-Robinson Equation of State [16] was used to estimate supercritical CO_2 ($scCO_2$) properties. Henry's law [17] was used to model CO_2 solubility in brine. Injection of supercritical CO_2 was carried out for 10 years continuously. Then, the injector well was shut in and simulation continued for 100 years to monitor the sequestration process of CO_2.

3. Results and discussion

3.1 Base case simulation

In the base case, CO_2 was injected into the aquifer at controlled bottom-hole pressure of 4100 psi. However, the CO_2 injection rate for 10 years was kept constant at 3150 Mft^3/day for 10 years. The average horizontal and vertical permeability are equal to 100 mD. The reference pressure and temperature are equal to 1711 psi and 122°F, respectively. The simulation results of the base case are shown in Fig. 1.

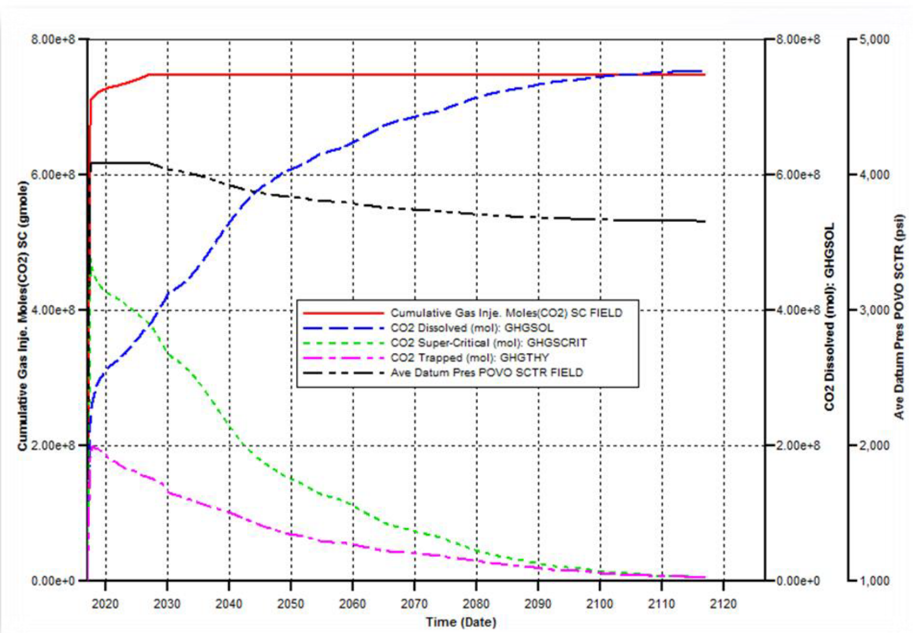

Fig. 1. CO_2 injection history and trapping for the base case.

There was an increase in bottom-hole pressure during the period of injection followed by a gradual decline in pressure after shutting in the well. CO_2 solubility trapping (GHGSOL curve on the plot) gradually increased, while residual (GHGTHY curve on the plot) and structural (GHGSCRIT curve on the plot) trapping decreased with time. Furthermore, Fig. 1 shows that a reduction in free CO_2 concentration by structural trapping has occurred as more CO_2 is dissolved in brine. This high increase in the CO_2 dissolution, will increase the brine density, and hence cause the CO_2 fingers to migrate downward towards the bottom of the aquifer known as natural convection. The density driven natural convection is a result of density difference between fresh and CO_2 saturated brine. It accelerates the dissolution process by moving low CO_2 concentration and fresh brine from the bottom to top to be contacted with the CO_2 gas at the top of the aquifer. This phenomenon is well discussed in the literature [12]. The results obtained from this base case were used as benchmark for the sensitivity analysis presented in the next sections. To do so, design of experiment (DOE) was used to select the sensitive parameters that were later investigated in the sensitivity analysis. The selected sensitive parameters were: the aquifer permeability in horizontal and vertical directions (K_h and K_v), injection strategy (injection pressure) and well's trajectory (horizontal or vertical well).

3.2 Effect of permeability variation in vertical and horizontal directions

Fig. 2 shows the trapped CO_2 mole percentage by 3 different trapping mechanisms for different cases of vertical and horizontal permeability values.

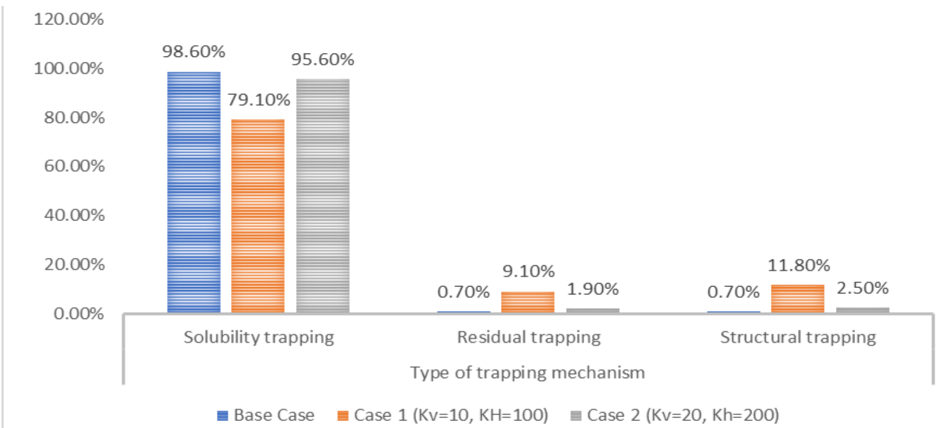

Fig. 2. Mole % of CO_2 trapped by 3 trapping mechanisms for different permeability cases.

Fig. 2 shows that solubility trapping is much dependent on vertical permeability value for the cases with proper horizontal permeabilities. Furthermore, it can be found that a low vertical permeability aquifer has the highest amount of residual and structural trapped CO_2. It should be noted that structural trapping has the highest risk of CO_2 leakage towards the upper layers and the surface. So, the storage site should have a good vertical permeability to reduce the risk of structural trapping.

3.3 Effect of well trajectory

The effect of well trajectory in addition to the vertical permeability effect is investigated in this section. Fig. 3 shows that a horizontal well with low vertical permeability (10 mD) has the lowest solubility trapping at the end of the simulation period. However, the residual and structural trapping is high compared to the vertical and horizontal wells of 100 mD vertical permeability. Although one can observe from Fig. 3 that the solubility trapping is similar for the high permeability horizontal and vertical wells. It should be noted that the effect of horizontal well should be more pronounced for low permeable aquifers. However, in this study only high permeable aquifers were considered.

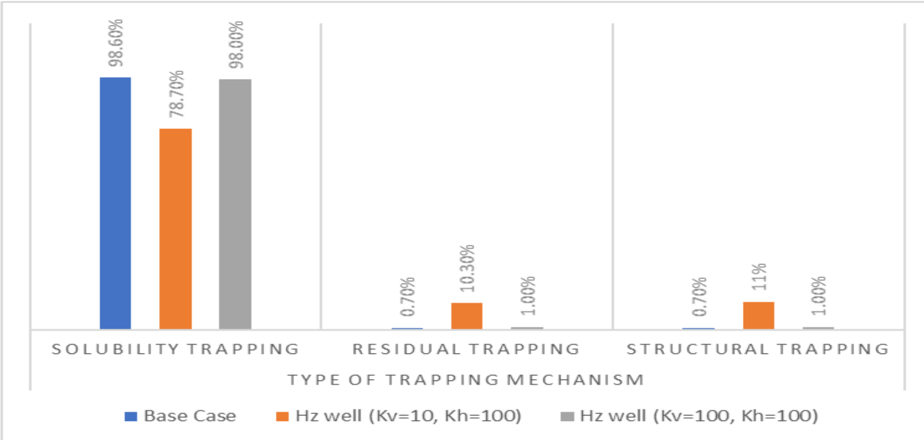

Fig. 3. Mole % of CO_2 trapped by 3 trapping mechanisms for different well trajectories.

3.4 Effect of injection bottom hole pressure

In this section the effect of injection bottom-hole pressure (P_w) on CO_2 trapping is investigated. Fig. 4 shows three cases of different P_w; 6000 psi, 4100 psi (the base case), and 3000 psi. High injection pressure of 6000 psi shows lower solubility trapping and higher structural trapping which has the risk of CO_2 leakage. It is clear that the high P_w increases the dissolution of CO_2 in the aquifer. However, the cumulative CO_2 injected is also much higher in the case of P_w=6000 psi as compared to the other 2 cases as the injection rate is also fixed at the rate of 3150 Mft^3/day. Moreover, it should be noted that, the high injection pressure might also cause fracture of the sealing rock. Therefore, a moderate injection pressure is recommended.

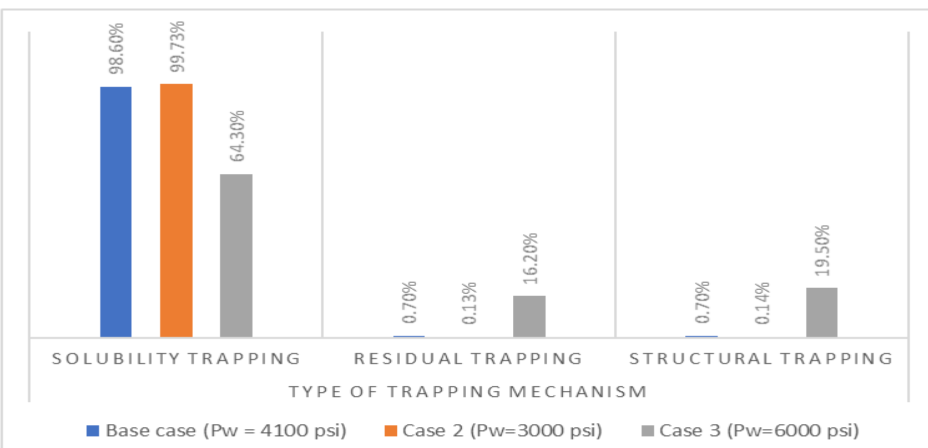

Fig 4. Mole % of CO_2 trapped by 3 trapping mechanisms at different injection bottom-hole pressures.

4. Conclusion

This study investigated the effect of aquifer vertical and horizontal permeabilities, well trajectory and injection pressure on CO_2 sequestration process in deep saline aquifers. Aquifers with high vertical permeability showed higher CO_2 solubility trapping and less CO_2

structural trapping. Therefore, its preferable to inject CO_2 into aquifers with high vertical permeability to reduce the risk of CO_2 leakage through structural trapping. Horizontal wells showed similar performance to vertical wells in terms of CO_2 trapping mechanisms provided the aquifer has a good vertical permeability. Regarding the effect of injection pressure, high injection pressure can increase the dissolution amount of CO_2 in aquifers, however on the other hand, will increase the cumulative gas injection causing more risk of structural trapping and also fracturing of the formation. Therefore, an average injection pressure is desirable.

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