Sensitivity Analyses and Value Qualification of CO_2 Storage in the Fractured Saline Aquifer

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Abstract. The objective of this research is to study effects of injection strategies, solubility factor, and aquifer parameters on the feasibility of storing CO_2 in the naturally fractured aquifer by running compositional numerical simulator. Factors with direct relevance to CO_2 trapping estimations: injection rates, well configurations, permeability anisotropy, fracture locations, fracture permeability, and fracture spacing were investigated using dual-permeability models in compositional reservoir simulator (CMG-GEM). A 30-point experimental design, aimed at evaluating the effect of solubility and aquifer parameters such as depth, porosity, and permeability on CO_2 storage, was conducted in various heterogeneous reservoir models. Results show that when horizontal producers are down-dip, the combined influence of buoyancy and heterogeneity can delay CO_2 breakthrough. Sub-seismic geological features such as fracture locations, fracture spacing, fracture permeability, and shale layers are demonstrated to have impact on CO_2 sequestration. Results are seen to be far more sensitive to thin shale layers than to variations in the vertical to horizontal permeability ratios. The result of the 30-point design shows that variability in trapping efficiency was explained primarily by depth, then permeability, and finally porosity.

Introduction

Over the past decade, the international scientific and engineering communities have investigated the feasibility of CO_2 disposal in deep saline formations to reduce CO_2 emissions into the atmosphere. Case studies have shown that fractures occur in nearly all geological settings and play a major role in hydrocarbon migration as well as entrapment. At Weyburn, In Salah, Snøhvit, and Spraberry CO_2 storage sites, fractures have already been described. It is likely that many future storage sites will exhibit fractures. This type of geology is a challenge for both characterization efforts and CO_2 flow simulations.

Despite limited research on CO_2 trapping in naturally fractured aquifers, previous attempts to predict CO_2 trapping behavior and mechanisms appear to be hampered by several limitations: (1) Most previous models did not explicitly couple all CO_2 trapping mechanisms simultaneously and neglected pointing out the dominant trapping form for long-term storage in fractured aquifers. (2) Previous studies simplified the hysteresis effect as relative permeability hysteresis only, and neglected capillary pressure hysteresis. (3) Previous studies are mostly concerned with homogeneous porous media, and the effect of heterogeneity and anisotropy on the CO_2 transfer in fractured aquifers is not fully understood, while real fractured aquifers are anisotropic and heterogeneous. In this study, we discuss the effects of fracture-matrix flow on long-term trapping of CO_2 in a naturally fractured aquifer to investigate how the presence of fractures affects the dynamics of the CO_2 plume in the long-term. We consider all CO_2 trapping mechanisms simultaneously, except for mineralization, during a 200-year CO_2 storage period in a fractured aquifer. The case study presented here illustrates how natural fractures could affect immobilization of carbon dioxide by structural trapping, residual trapping, and dissolution into brine in the post-injection period. For residual trapping, hysteresis effects include both relative permeability and capillary pressure hysteresis. The effect of aquifer properties and injection strategies are also investigated. Results of our simulations show the increase of trapping by compensating buoyancy effects to some extent resulted from optimizing injection strategies, and the significant effects of sub-seismic geological features such as fracture locations, fracture permeability and spacing, and shale layers with regard to the amount of CO_2 stored within the modeling region.

Aquifer Model Descriptions

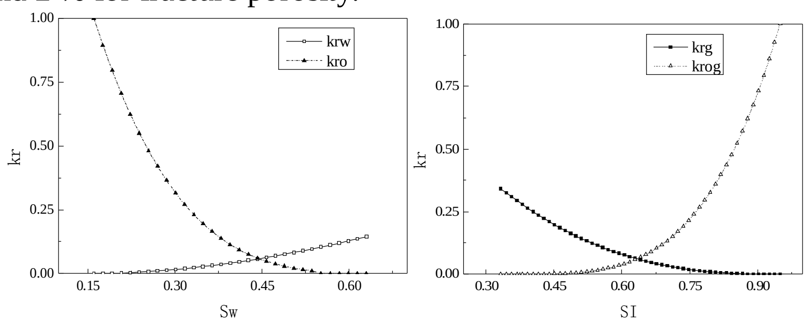
In this study, a compositional simulation model was built using CMG-GEM module (Version 2012, Computer Modelling Group Limited, Canada), an equation-of-state compositional simulator, various petrophysical properties of the aquifer rock, fluid and rock-fluid properties, and well constraints were entered to define the simulation model. A full list of aquifer properties is in Table 1.

Table 1. Details of reservoir simulation modeling.

Parameters	Values
Total number of host grids in simulation model	30×30×8
Model dimension (m)	1000×1000×20
Irreducible water saturation	0.15
Transition between imbibition and drainage	0.07
Average aquifer vertical permeability (mD)	15
Average aquifer horizontal permeability (mD)	35
Average matrix porosity (%)	12
Depth of aquifer top (m)	1500
Aquifer temperature (°C)	65
Initial pore pressure at aquifer top (MPa)	14.5
Fracture spacing (m)	10
Fracture permeability (mD)	200

Given the presence of natural fractures in the aquifer, the aquifer appears to behave as a dual-permeability medium. The matrix porosity represents the major storage for water and gas, while the fracture system provides the main fluids flow paths (Ouenes et al., 2010; Vogel et al., 2000). Therefore, fracture parameters, such as fracture porosity, permeability, and spacing are incorporated with the dual-permeability mode that allows for accurate modeling of the matrix-fracture transfer in the fractured aquifer system.

Since a fraction of the injected CO_2 is certainly dissolved into the water phase, thus in order to model the CO_2 solubility, a fluid model was generated using the WinProp package of CMG suite to enable CO_2 to dissolve into the water phase, and it was then imported to the main model. The main parameters of the double porosity media were set as 200 mD for the fracture permeability, 10 m for fracture spacing, and 2 % for fracture porosity.



(a)Water/Oil systems. (b) Gas/Oil systems

Fig.1. Relative permeability curves for the matrix system.

The matrix relative permeability curves incorporated in the simulation model are shown in Figure 1. Since no data was available for fracture relative permeability curves, a linear distribution was chosen for fluid flow in the fracture system. In order to evaluate the effect of hysteresis on gas trapping, hysteresis effects induced by relative permeability and capillary pressure is accounted for in the model.

CO_2 is injected from upper grid cells. The producers are completed in the bottom layer of the formation, down-dip of the aquifer far away from CO2 injectors. The maximum bottom-hole pressure for injectors is 30% higher than the initial reservoir pressure, and the minimum bottom-hole pressure for producers is 2.5 MPa lower than the initial reservoir pressure. The entire formation is initially filled with brine. There is no CO_2 assumed to be dissolved in the initial aquifer water.

In this paper, storage prediction cases are run for another 200 years after the prescribed 50-year period injection to examine the long-term trend of leakage outside the modeling region and gas trapping in the modeling region. No attempt is made here at modeling CO_2 trapping via mineralization/precipitation in 200-year lengths of time in order to simplify the model, since mineral dissolution is negligible within this time period.

Methodologies

Determination of Injection Strategies and Fracture Properties

In CO_2 injection process, the CO_2 injection rate, well configurations, fracture permeability and spacing, fractures locations, and reservoir heterogeneity influence CO_2 storage performance significantly. A big CO_2 injection rate results in early gas breakthrough and high producing gas ratios. Moreover, the bottom hole injection pressure may exceed the formation fracturing pressure at high CO_2 injection rates. While a small CO_2 slug size may not compensate the cost of the storage plan and makes on-site operations complex. It is required to achieve an optimal injection rate to maximize the CO_2 storage in the hypothesized formation. An appropriate well configuration is conductive to the control of early gas breakthrough and pressure build-up. Fractures in the low-permeability field enhance CO_2 storage and injectivity. Moreover, fractures could alleviate pressure buildup caused by CO_2 injection in the formation if they locate far away from the CO_2 plume. However, an extensive dense of fractures or inappropriate completions of CO_2 injectors lead to the preferential pathways for CO_2 flow and may therefore reduce the storage capacity of the storage formation. Therefore, optimization study was conducted to achieve the optimal combination of these injection strategies and fracture properties.

Table 2. Injection strategies, fracture properties, and heterogeneity study and their levels of uncertainty.

No.	Analyzed Parameters	Values					
1	Injection Rate (%PV)	0.5	1	1.5	2	2.5	3
2	Well Configuration	Bottom VPro.	Bottom HPro.		Upper VPro.,	Upper HPro.	
3	Frac. Spacing (m)	10		20		40	
No.	Analyzed Parameters	Values					
4	Frac. Perm (mD)	100	200		400	800	
5	Frac. Location	Located up-dip from injectors			Located down-dip of injectors		
6	Kv/Kh	0.1	0.15		0.2	0.4	
7	Presence of shale layer	With shale layers			Without shale layers		

Table 2 shows the seven parameters discussed in the study. In order to evaluate CO_2 storage performance, the evaluating indices was defined as the trapping efficiency, which refers to the percentage of the total trapped gas of the cumulative gas injected.

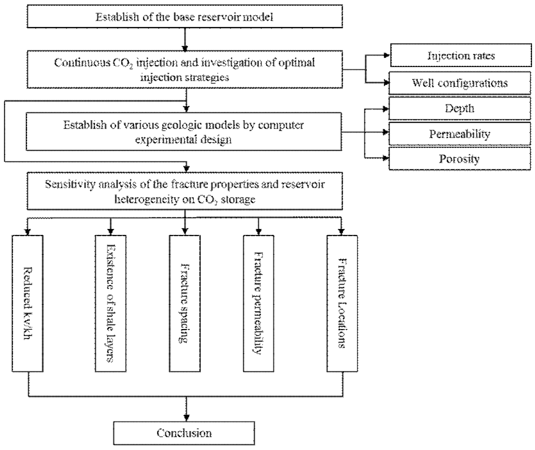


Fig.2. Flowchart of the research procedure.

The flowchart of the research procedure was provided in Figure 2. In order to achieve the objective of this study, a three-task plan was acted out. During the first task, a sensitivity analysis of the injection strategies, injection rates and well configurations, was conducted. Next, series of planned simulation runs were conducted on the model to analysis the impact of fracture properties and reservoir heterogeneity on CO_2 storage performance. In the tests of the second part, the CO_2 injection rate and the well configuration were set to be the optimal values.

Results and Discussion

Sensitivity Analysis of Injection Strategies

A range of injection rates from 0.5% PV/year to 3% PV/year scenarios were run on the compositional aquifer model to test the effect of injection rates on CO_2 storage efficiency. As anticipated, injection rates affect trapping efficiency and CO_2 distribution (Figure 3). Too high an injection rate increases leakage, thus reducing trapped gas in the model. Results show that trapping efficiency decreases with the increase in injection rates, from 0.5% PV/year to 1.5% PV/year, followed by a sharper decreasing trend after the injection rate reaches 1.5% PV/year, which was selected as the injection rate for the remaining simulations.

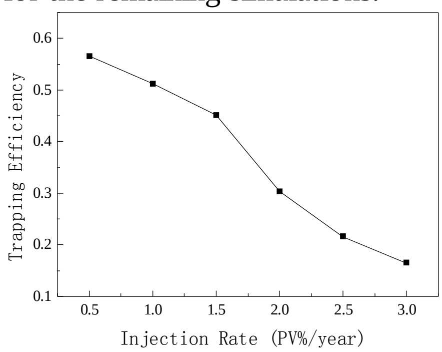


Fig.3. Sensitivity analyses on injection rates.

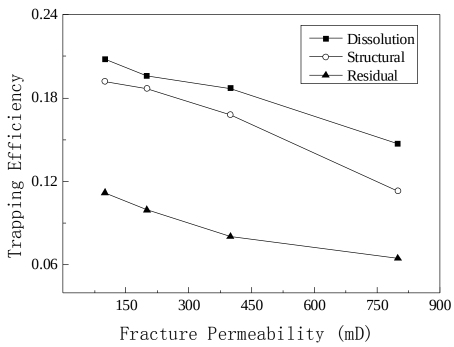


Fig. 4. Sensitivity studies on fracture permeability.

A few well configurations were tested: vertical producers and horizontal producers for the continuous CO_2 slug injection scheme in four different models as mentioned earlier. In the first case, vertical injectors at the up-dip of the formation and vertical producers at the down-dip of the formation are completed. The second case is the same as the first case except that producers are horizontal wells. In the third case, vertical producers at the up-dip of the formation are simulated. The difference between the third and fourth case is that producers are horizontal wells in the fourth case. Trapped gas for the four scenarios is shown in Table 3.

Table 3. Sensitivity studies on well configurations.

No.	Case Name	Trapping Efficiency (%)
1	bottom layer vertical producers + upper layer injectors	44.1
2	bottom layer horizontal producers +upper layer injectors	48.2
3	upper layer vertical producers + bottom layer injectors	41.5
4	upper layer horizontal producers + bottom layer injectors	42.0

Results indicate that when producers are completed down-dip of the aquifer, the combined influence of buoyancy and heterogeneity can delay CO_2 breakthrough. In addition, horizontal production wells completed at the bottom of the aquifer are conducive to store a larger amount of CO_2 by allowing CO_2 to be steadily ramped up, increasing the contact opportunities between CO_2 and brine, promoting the dissolution (trapping) of CO_2 in the saline aquifer. Therefore, the selected well configuration is vertical injectors at the up-dip of the formation, with horizontal producers completed in the bottom layer of the formation, far away from injectors.

Sensitivity Analyses of Fracture Properties

Fracture permeability, has a significant effect on gas trapping in the system. Sensitivity analyses cases were run with 4, 2, and 0.5 times the fracture permeability values of the original case. Relative permeability, well control, and other parameters are the same as the original case. Results in Figure 4 show that, flow velocity in the higher fracture permeability cases leads to earlier gas breakthrough and therefore, the loss of injected gas from production wells early in the injection period. As a result, there is an overall decrease in gas trapping in the long term.

To evaluate the effect of fracture spacing on gas trapping in naturally fractured aquifers, two additional scenarios were generated with 2 and 4 times the original fracture spacing, respectively. As can be seen in Figure 5, the impact of fracture spacing on gas trapping is as important as that of fracture permeability, and its effect is apparent. It can be observed that cases with larger fracture spacing values make the gas trapping much higher than cases with smaller fracture spacing. Additionally, structural trapping is more important than the other two trapping mechanisms for cases with larger fracture spacing values.

Besides fracture permeability and spacing, fracture locations also impact CO_2 distribution and trapping efficiency in the long run. In this study, the influence of fracture locations is investigated.

In the base case, fractures are located in each layer, indicating that fractures locating in both down-dip and up-dip of the injectors. In the testing case, fractures were located only down-dip of the injector. Compared to the base case, the fractures could lead to much less leakage outside the modeling region and the increased trapping of CO_2 within the modeling region if they located down-dip of the injector (Table 4).

Table 4.Sensitivity studies on fracture locations- two scenarios are shown.

Case Name	Structural Trapping %	Dissolution Trapping %	Residual Trapping %	Total Trapping %
Base Case	16.3	19.2	12.4	47.9
Frac. down-dip inj.	23.0	20.2	16.3	59.5

The implication of the above is that injector locations have to be carefully selected taking into account geological uncertainties in order to mitigate risks of excessive leakage.

In the original simulation model, vertical to horizontal permeability ratio is 0.2. In this paper, sensitivity studies have been performed by reducing the vertical to horizontal permeability ratio

(Kv/Kh). It is found that reducing vertical permeability has impact on CO_2 distribution. Table 5 shows the CO_2 plume trapping with or without reducing vertical permeability.

In the reduced vertical permeability case, gas has a lower speed to reach the top of the model, and thus more gas could be trapped inside the model. The reason is assumed to be that the decreased vertical to horizontal ratio (Kv/Kh) reduces the buoyancy effect and gravity segregation, thus lowering the vertical gas movement velocity in the aquifer to some extent. Theoretically, the reduced vertical to horizontal permeability ratio induces the upward migration of the CO_2 saturation distribution to the horizontal direction. Therefore, the total volume gas trapping for the case that reduces vertical permeability by twice (Kv/Kh=0.1) is larger compared with the original model.

Table 5. Sensitivity studies on vertical to horizontal permeability ratios and presence of shale layers.

Case Name	Structural Trapping (%)	Dissolution Trapping (%)	Residual Trapping (%)	Total Trapping Efficiency (%)
Base Case-Kv/Kh=0.2	16.3	19.2	12.4	47.9
Kv/Kh=0.15	20.7	19.8	13.6	54.1
Kv/Kh=0.1	21.3	19.5	14.5	55.3
Kv/Kh=0.4	14.3	18.8	10.8	43.9
Presence of shale layer	21.5	18.3	19.8	59.6

The existence of these shale layers contribute to another important factor resulted in permeability anisotropy. Table 5 shows the CO_2 trapping developments with and without a shale layer above the injector perforation intervals. The results for the case with shale layers show a significant increase in the amount of gas trapped as super-critical, residual, and solubility gas.

Conclusions

The present study has demonstrated that:

(1) Horizontal producers with bottom-layer completions and vertical injectors completed in the upper-four layers are conducive to obtain larger amounts of CO_2 storage.

(2) It is observed that increase in injection rates enhances the trapping efficiency and causes more CO_2 to be stored when injection rates are less than 1.5% PV/year. However, injecting a larger CO_2 slug size does not considerably change the trapping efficiency when injection rates are higher than 1.5% PV/year.

(3) Sub-seismic geological features such as fracture permeability and spacing, fracture locations, and the presence of shale layers may have positive or negative effects with regard to the amount of CO2 stored within the modeling region. Fractures located up-dip from the injector may lead to more leakage while the opposite may happen in the presence of fractures located down-dip of the injector.

(4) Results also indicate that although reduced vertical to horizontal permeability ratios increase gas trapping to some extent, the existence of shale layers has more significant impact on gas trapping.

Acknowledgments

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