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Modeling rock-fluid interactions due to CO_2 injection into sandstone and carbonate aquifer considering salt precipitation and chemical reactions

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A B S T R A C T

Carbon dioxide is a greenhouse gas that has the most effect on the phenomenon of global warming. Saline aquifers have higher potential compared to other storage options to store carbon dioxide. Sandstone and carbonate aquifers have good reservoir characteristics and can be appropriate choices for CO_2 storage. The modeling of the process has been performed combining salt precipitation, solubility, region specification and pressure drop models to study the effect of CO_2 injection on gas saturation and pressure distribution profile, skin factor over time, the amount of salt precipitation, porosity and permeability. Sensitivity analysis has been done for temperature, pressure, permeability, porosity, salinity, critical gas saturation and CO_2 injection rate. In order to study chemical reactions, long time simulation of rock-fluid interaction in carbonate and sandstone aquifer is also performed.

The permeability reduction is in the range of 0.69–0.86 in all cases of salt precipitation simulation which is consistent with experimental results. The proposed salt precipitation model with an average relative deviation of about 5% for rock-fluid interaction parameters is able to predict the aquifer properties accurately during CO_2 gas injection. The advantage of the model presented in this study compared to Zeidouni's model (2009) is that the proposed model predicts the pressure distribution after injection and estimates mole fraction of components in equilibrium with higher accuracy. The results of this study are shown that CO_2 storage needs an aquifer with lower temperature, higher pressure and lower salinity compared to other options as the solubility trapping of carbon dioxide increases in this case. Permeability change does not influence on determining equilibrium regions and the only effect of the permeability is on the injectivity. Simulation of mineral reactions shows that chemical equilibrium is established after long time (more than 100 years) in sandstone aquifer and it is established in less than one day in carbonate aquifer. It should be noted that mineral trapping capacity of carbonate aquifer is less than sandstone aquifer in the CO_2 storage process.

1. Introduction

CO_2 is a greenhouse gas that has the most effect in the phenomenon of global warming. Human population growth and consequently increase in human activities have increased the concentration and rate of greenhouse gas changes in the atmosphere. If nothing is done to reduce the concentration of carbon dioxide in the atmosphere the mean global temperature increases by 4–6 °C within the next 50 years (Intergovernmental Panel on Climate Change, 2007). Depleted oil and gas reservoirs, saline aquifers and coal seams provide the possibility of CO_2 storage. Salinity of saline aquifers is more than salinity of sea water (35 g per liter), hence they are not used as a source of drinking water or other economic purposes. These formations are present in every continent and in most coastal areas and because of this abundance, the potential capacity of saline aquifers is higher than depleted oil and gas reservoirs to store carbon dioxide (Ofori and Engler, 2011). The role of saline aquifers in storage process and their storage capacity in North America are shown in Table 1 on a large scale (Nghiem et al., 2009). CO_2 can be trapped in a saline aquifer by dissolution in water. When CO_2 dissolves in water, water evaporation process happens and salt precipitation process occurs in the surrounding area of the injection wells (Zeidouni et al., 2009). Injection of

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Table 1
Carbon dioxide storage capacity in formations of North America (Nghiem et al., 2009).

Formation type	Storage capacity %
Saline aquifers	91.8–97.5
Unmineable coal seams	1.4–4.4
Matured Oil and gas reservoirs	1.1–3.8
Total Capacity	100

carbon dioxide into saline aquifer creates three flow regions (Zeidouni et al., 2009; Burton et al., 2008). These regions are separated by leading shock and trailing shock. There is a brine region at the downstream of leading shock that its salt has not precipitated and it is being displaced by injected CO_2. A two-phase equilibrium region is located behind the leading shock that includes dissolved CO_2 and brine (aqueous phase) and CO_2 gas and water vapor (gaseous phase). There is trailing evaporation shock between the equilibrium region and the dry-out region where salt has precipitated. These regions are shown in Fig. 1.

Numerical modeling of the rock-fluid interactions is in progress in the process of carbon dioxide storage and only a few studies have been done in this field. A few studies have addressed reactive transport modeling and most of them are still developing. Non-reactive transport modeling began in the early 90s so that Van Der Meer, 1993 simulated carbon dioxide trapping in a circular anticlinal stratigraphic trap (Van Der Meer, 1993). The most prominent studies that investigate the effects of various parameters on the rock-fluid interactions in the CO_2 storage process are shown in Table 2.

Simulations of this paper are performed for two conditions: short time and long time. Estimates of parameters are important in deciding on possibility or impossibility of CO_2 storage in special reservoirs. Modeling rock-fluid interactions in the underground CO_2 capture and storage needs to predict the effects caused by carbon dioxide injection. This modeling is used for short time conditions. In this paper, modeling and simulation of salt precipitation parameters have been performed using MATLAB R2013a software to study the effects of CO_2 injection on the aquifer properties. Gas saturation and pressure distribution profile after injection, skin factor, amount of salt precipitation, porosity and permeability changes are studied. Sensitivity analysis has been done for temperature, pressure, permeability, porosity, salinity, critical gas saturation and CO_2 injection rate. Carbon dioxide injection into aquifer leads to chemical reactions with in-place minerals of aquifer. In order to study this process, long time simulation of rock-fluid interaction is also conducted in carbonate and sandstone aquifer.

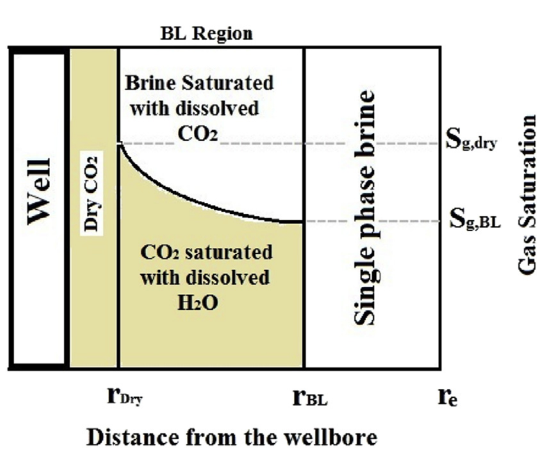

Fig. 1. Phase regions considered in the salt precipitation model (Gas Saturation vs. distance from wellbore).

2. Parametric modeling of salt precipitation caused by carbon dioxide injection into saline aquifer

Aquifers used to store carbon dioxide have good porosity and permeability to allow carbon dioxide to be injected into pores occupied by primary fluids. A reservoir can be divided into four categories based on capability of CO_2 geological storage (Shogenov et al., 2015):

1. 'Very appropriate' for CO_2 geological storage: having the highest permeability and high porosity (porosity in the range of 9–20% and permeability $\geq$300 md).
2. 'Appropriate' for CO_2 geological storage: having a permeability of 100–300 md, subdivided into 'good' and 'moderate' quality classes (porosity >18% and 9–18%, respectively).
3. 'Cautionary' for CO_2 geological storage: contains rocks with a permeability of 10–100 md and porosity of 7–23%.
4. 'Not appropriate' for CO_2 geological storage: composed of rocks with a permeability <10 md.

In addition, reservoirs have cap rock that prevents carbon dioxide leakage or escape. Due to high aquifer pressure and temperature carbon dioxide is usually in supercritical state which increases storage capacity. As it was mentioned previously, the effects of temperature, pressure as well as salinity of the aquifer have also been investigated on CO_2 storage capacity. The primary input parameters (reference case) are summarized in Table 3. Sensitivity analysis is performed on parameters: temperature, pressure, permeability, porosity, salinity, critical gas saturation and CO_2 injection rate. All of these parameters are related to aquifer except the last one that is a property of injected fluid. Table 4 shows the simulated performances. Geochemical reactions are not considered in these performances. In each of which only one parameter is changed relative to the reference case and other parameters have the reference values.

2.1. Description of model

Model dimensions are shown in Fig. 2. Simulated aquifer has a length of 400 m, a thickness of 100 m and a width of 100 m. Wells having constant pressure identical to initial aquifer pressure are assumed to be on the boundaries. Injection line is considered to be in the middle of aquifer. Fig. 3 shows relative permeability curves. Van Genuchten equations are used to determine brine relative permeability and Corey curve is used to determine gas relative permeability (Van Genuchten, 1980; Corey, 1954) (See Appendix A for details). This section describes four models including solubility model, salt precipitation model, region specification model and pressure drop model. CO_2 solubility and its effects on brine properties are modeled by solubility model. Salt precipitation models estimates the amount of precipitated salt, permeability and porosity changes and skin factor due to salt precipitation. It is required to estimate the saturations and coordinates of shocks to model salt precipitation which are obtained from region specification model. Finally, the coordinates of phase region obtained using region specification model and permeability change calculated by salt precipitation model are used to model pressure distribution.

2.1.1. Solubility model of carbon dioxide in brine

Solubility trapping is one of the mainly incentive trapping