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Investigating The Impact Of Relative Permeability Curves On Cold CO2 Injection

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Summary

Different injection methods have been already proposed by different researchers to improve the solubility of CO2 in the formation brine. In this study an injection technique is presented to cool down (liquefy) the supercritical CO2 in the wellbore by the use of a downhole cooler equipment. CO2 with a higher temperature enters the cooling equipment and exits the equipment with a lower temperature at the down-stream in a same injection pressure. The colder (liquid) CO2 has a higher solubility in brine, higher density and viscosity which increases the security of CO2 storage. With this method the supercritical CO2 is cooled down to a liquid phase to increase the solubility at the wellbore and thus it eliminated the risk of phase change or pressure and rate fluctuation in liquid CO2 injection from the surface. To simulate this technique two cases have been considered by changing the relative permeability curves. The results show that using the combination of CO2STORE and THERMAL options shows a higher dissolution compared with only inserting the relative permeability curves corresponding the injection condition.

Introduction

The concentration of CO_2 in the atmosphere has increased up to 45% since the industrial revolution. Carbon capture and storage (CCS), that comprises of the separation of CO_2 from the gaseous exhaust of power plants and other heavy industries and safe and secure long-term storage in geological formations is considered as the most applicable method for mitigation of CO_2 concentration in the atmosphere (Jiang 2011). In long-term, several trapping mechanisms are active in the aquifer which are categorised as: structural trapping, residual trapping, solubility trapping and mineral trapping. Since the leakage from the storage sites can create harmful environmental defects, the security of long-term storage is of a great importance (Celia *et al*. 2011). In this regard, researchers have proposed different engineering techniques (Vilarrasa *et al*. 2013; Shariatipour *et al*. 2016) in order to improve the solubility of CO_2 in the formation brine. When CO_2 is dissolved in brine the density of the formation brine increases by 1% which leads the dissolved CO_2 to sink in the reservoir and prevent upwards migration of free CO_2 phase towards the cap rock. Vilarrasa *et al*. (2013) investigated liquid CO_2 injection from the surface and they analyse the evolution and thermo-hydro-mechanical response of the formation and cap rock. The higher density of CO_2 causes less CO_2 to migrate upwards towards the top seal and increases the storage security. Additionally, the denser brine causes convective flow and accelerate the dissolution of CO_2 in brine within the reservoir. Moreover, another effect of cold CO_2 injection is creation of thermal stress which results in fracturing the near wellbore formation (Oldenburg 2007) and increase in injectivity. The cold CO_2 injection method, however, has some technical challenges such as the phase change in the tubing. Therefore, this paper aims to present a new technique to accelerate the CO_2 solubility in brine by reducing its temperature downhole while minimising the challenges associated with the cold (liquid) CO_2 injection method from surface.

Methodology

The main focus of this work is to present a method to maximize CO_2 solubility in brine in downhole conditions where the injected CO_2 first contacts the formation brine. The idea comes from the well-known rule that the solubility of CO_2 in brine increases with decrease in temperature. Thus, our proposed idea is to install a tool that can make a decrease in the temperature of the injected CO_2 in the wellbore where the CO_2 contacts with brine (Fig. 1). The temperature decrease in a section of the wellbore can be created by the utilization of a tool that uses external energy of a colder fluid or to cool down the injected CO_2. A throttling valve can be installed in the wellbore to decrease the pressure and consequently the temperature decreases based on the Joule-Thomson effect in an isenthalpic process. The advantage of this method is that when the temperature decreases, the most possible amount of CO_2 corresponding that pressure could be dissolved in the formation brine (theoretically). It minimizes the amount of free gas entered the formation. Since dissolved CO_2 in brine has a higher density than the *in-situ* brine it will sink in the storage formation. Cold CO_2 injection in the liquid phase from the surface is a method which has been proposed to be energetically an efficient injection method (Silva *et al*. 2011). However, it is more desirable that CO_2 is injected in a supercritical condition to prevent from problems created by phase change in the length of the tubing in deep formations (Nimtz *et al*. 2010). Thus, with this new technique we can ensure that CO_2 is converted to liquid (in case of high temperature decrease) only in the wellbore while it is in the supercritical phase in the tubing preventing from any phase change problems in the tubing. Usually the normal temperature to ensure that CO_2 is in the supercritical phase at the surface is 40 ˚C in different cases and non-isothermal calculations of temperature profile of CO_2 flow in the injection well showed that with this wellhead temperature CO_2 will reach the formation at a temperature close to 50 ˚C for a potential aquifer located at the depth of 1500 m with the injection rate of 1 Mt/year. Analytical calculations show that assuming a temperature of 50 ˚C and a pressure of 150 bars, a 30 ˚C decrease in temperature results in near 20 % increase in CO_2 solubility in brine in the same pressure.

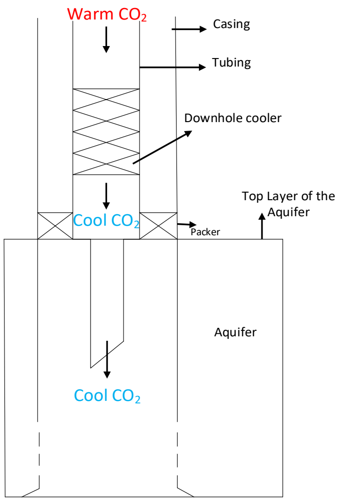

***Figure 1** Schematic of the downhole cooler equipment and process.*

Numerical Simulation

The three dimensional reservoir simulation model was created by the Eclipse 300 through the CO2STORE option combined with the THERMAL option. Input data and the thickness of the formation were adopted from the work by (Heinemann *et al*. 2012). The porosity and horizontal permeability in the homogeneous case is 0.18 and 250 mD, respectively and with a K_v/K_h ratio of 0.1. For the heterogeneous case, the heterogeneity data was generated based on the same mean as the homogeneous model (Standard Deviation = 200). To simulate the impact of cold CO_2 injection on CO_2 solubility in brine and storage security, two cases are considered to be compared with CO_2 injection at supercritical conditions. 1) A model is built with the pressure and temperature equal to geostatic and geothermal conditions, respectively. Then, CO_2 is injected with the lowest possible temperature (here, 20 ˚C) to the formation while the relative permeability curves are those of supercritical CO_2 injection. 2) The initial temperature of the reservoir is considered to be 20 ˚C and the corresponding relative permeability curves to this temperature and geostatic pressure (Liu *et al*. 2010) are input to the model and the CO_2 injection is run.

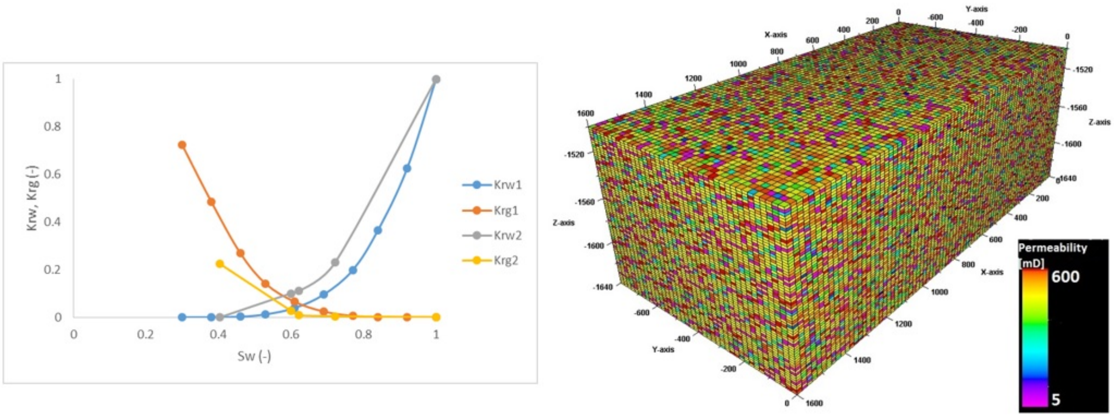

***Figure 2** Horizontal permeability of the model and the relative permeability curves used in this study.*

Results and Discussion

Fig. 3 shows the amount of dissolved CO_2 in brine in both homogeneous and heterogeneous models with and without applying the cooling method for the first case for the depth of 1500 m. As can be seen in the left side figures, because CO_2 in the supercritical conditions is less dense and less viscose it moves upwards. However, in the right side figures CO_2 were injected with a lower temperature in the liquid phase and consequently with higher density and viscosity (up to 34% and 71%, respectively). Thus, in the same duration more CO_2 has been dissolved in the brine in the lower part of the aquifer and no gravity override has happened.

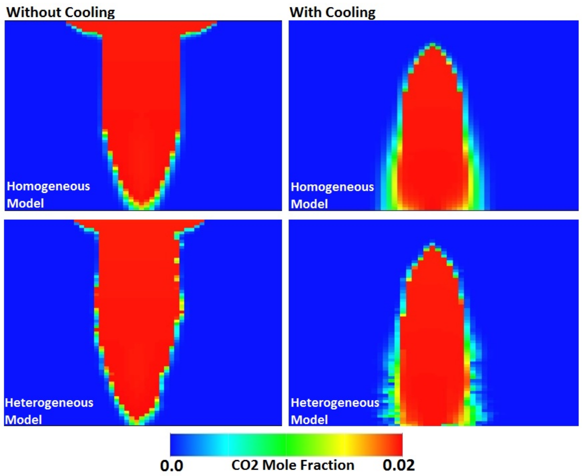

Figure 3 *Dissolved CO_2 in the aquifer brine after 20 years. Left hand figures show standard CO_2 injection method and right hand side figures show the proposed method (cold CO_2 injection method using downhole cooler).*

Using the new technique the pressure build up in the formation is less than the base case (Case 1) because more CO_2 is dissolved in the formation brine and less stays in the free gas phase (Fig. 4). Furthermore, cold and denser CO_2 occupies a lower capacity of the reservoir rock and less brine will be displaced. Additionally, Injecting CO_2 with THERMAL option shows a better result than just applying the low temperature relative permeability curves.

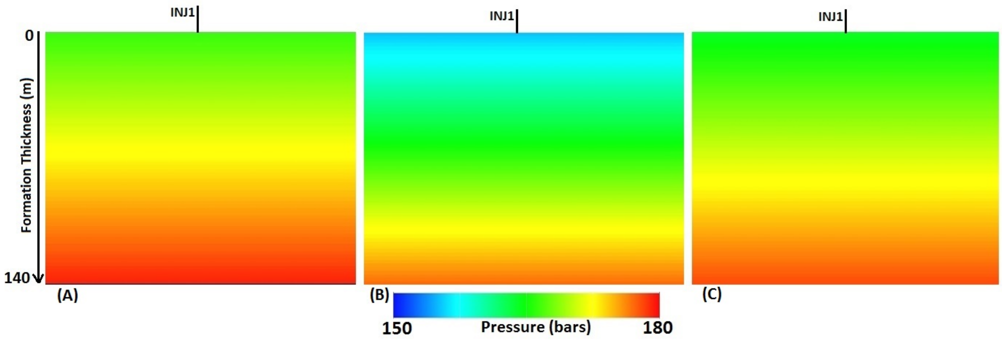

Figure 4 *Pressure build-up in the aquifer after 20 years for the depth of 1500 m. A) Without cooling system. B) Case 1. C) Case 2.*

CO_2 dissolution in the cases that CO_2 is injected with a low temperature by the use of THERMAL option is higher than the cases that low temperature relative permeability curves are applied in the model (Fig. 5).

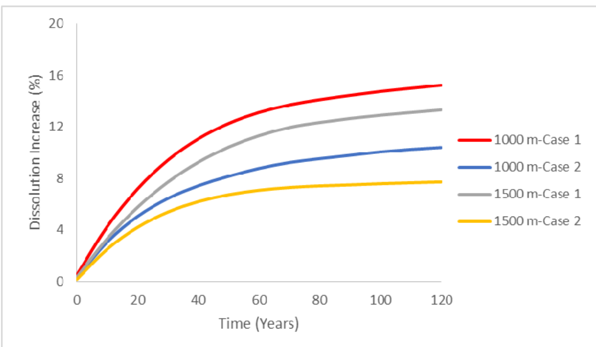

Figure 5 *The increase in CO_2 solubility in brine in different cases and depths.*

Fig. 6 indicates that the gas saturation in Case 1 is lower than Case 2 during and post injection periods. This means the dissolution is higher in Case 1 than Case 2 which can be attributed to the higher dissolution in lower temperatures. Although in Case 2, the relative permeability curves show more CO_2 wet condition which is expected a higher dissolution (Al-khdheeawi *et al.* 2017), the dissolution in Case 1 is higher due to the use of the THERMAL option.

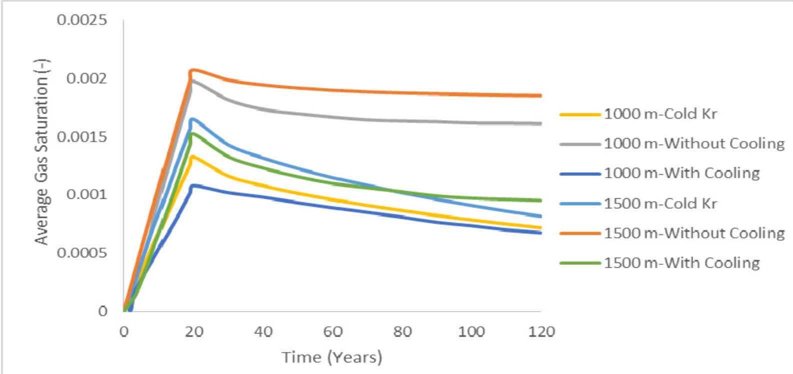

Figure 6 *Average CO_2 saturation in the aquifer for different cases.*

Conclusion

The results of this simulation study shows that by the use of downhole cooler equipment the amount of dissolved CO_2 in brine increases and the risk of phase change in the tubing decreases. Overall field pressure build-up will be less than that of supercritical CO_2 injection. Additionally, it is suggested that the appropriate relative permeability curves corresponding the injection and *in-situ* conditions have to be applied in simulating cold CO_2 injection.

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