Local capillary trapping in carbon sequestration: Parametric study and implications for leakage assessment

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ABSTRACT

Local capillary trapping (LCT) is the trapping of CO_2 by local capillary barriers. It occurs during buoyancy-driven migration of bulk phase CO_2 within a saline aquifer exhibiting spatially varying properties (permeability and capillary entry pressure). The benefit of LCT, in the context of CO_2 sequestration, is that local capillary trapped CO_2 is not susceptible to leakage through failed seals. However, it is unclear how the petrophsyical/geological properties and flow dynamics influence LCT. Thus, the objective of this work is to evaluate the degree to which potential local capillary traps are filled and quantify the extent of immobilization persisting after loss of seal integrity. This paper presents a systematic and thorough study of the influential parameters of LCT. Fine-scale capillary pressure fields are generated by using geostatistical permeability realizations and applying the Leverett j-function. Multiple factors are examined, including injection rate, anisotropy, formation dip, aquifer types, residual gas saturation, and capillary hysteresis. Leakage representative of wellbore failure is simulated, and LCT after leakage is evaluated and compared to other trapping mechanisms. The results show that local capillary traps in the near-well region can be fully filled during injection. Moreover, they remain filled after post-injection buoyancy-driven flow ends. The filling efficiency of local capillary traps increases with the decrease in gravity number (ratio of buoyant force over viscous force). As a result, maximizing LCT in carbon sequestration in porous reservoirs may be achievable with the implementation of appropriate injection strategies.

1. Introduction

CO_2 sequestration in saline aquifers has been widely accepted as the promising and easily accessible way to reduce carbon emissions and global warming in this century (Bachu, 2008). In order for CO_2 to be stored in a manner that is secure and environmentally acceptable, it is essential to understand the behavior and migration of CO_2 in geologic formations under the effects of complicated interplaying forces (namely buoyancy, capillary pressure, and viscous force), geologic characteristics, and operating conditions.

Typically, CO_2 can be trapped by the following mechanisms: stratigraphic/structural trapping (Gupta, 2011), dissolution trapping (Burton and Bryant, 2009), residual trapping (Pentland et al., 2008) and mineral trapping (Pruess et al., 2003). Among these mechanisms, dissolution, residual and mineral trapping are considered as the safest way of immobilizing CO_2 in storage media. The remaining CO_2 (as free gas), mostly in the stratigraphic and structural traps, is potentially mobile and most likely to escape from the storage media should leakage occur.

Recently, a new trapping mechanism – local capillary trapping (LCT) – was proposed when considering the intrinsic heterogeneous

capillary pressure of a given storage formation (Saadatpoor et al., 2010). LCT is a form of trapping where CO_2 accumulates behind capillary barriers. It occurs during buoyancy-driven migration of bulk phase CO_2 within a saline aquifer exhibiting spatially varying properties (permeability and capillary entry pressure). Its benefit, applied specially to CO_2 sequestration, is that saturation of stored CO_2 is larger than residual phase saturation (Saadatpoor et al., 2010). In addition, in case of leakage, CO_2 in LCT does not escape from the storage formation even if seal systems are compromised (Saadatpoor et al., 2010).

LCT is analogous to other well-known phenomena in the context of multiphase flow through porous media. It is equivalent to the large-scale "fill and spill" process used in charging hydrocarbon reservoirs (Siddiqui and Lake, 1997). Additionally, it is analogous to pooling of non-aqueous phase liquid spilled onto soils (Van Valkenburg and Annable, 2002). Several mechanisms would create local capillary traps, such as grain size variation (e.g., fining upward sequence), changes in depositional environments over time, and non-uniform/uneven diagenetic alteration.

A number of studies (Saadatpoor et al., 2010; ; Trevisan et al., 2017a; Li and Benson, 2015) have been conducted to investigate the impact of LCT or capillary heterogeneity on CO_2 movement and

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saturation distribution. Generally, these studies originate from two different research considerations; theoretically, under the buoyancy-dominated flow of CO_2 in saline aquifers, buoyant force is comparable to capillary pressure, thus, capillary heterogeneity essentially influences CO_2 movement. Experimentally, researchers found that it is difficult to replicate two-dimensional (2D) and three-dimensional (3D) CO_2 saturation profiles within cores when adopting a single capillary pressure curve for history matching. However, when appropriate scaling laws for capillary pressure are incorporated, the saturation profiles or fields can be better reproduced (Krause et al., 2011; Shi et al., 2011; Kong et al., 2014; Wei et al., 2014). Apart from LCT in cores, LCT has been studied in 2D bench-scale experiments when considering only buoyant flow (Li and Benson, 2015; Sun, 2014) and when incorporating injection-period (Trevisan et al., 2017b). It is shown that CO_2 buoyant flow is greatly disrupted in the event of even slight heterogeneities, i.e., when the grain size becomes fine, half of the size is enough to temporarily hinder buoyant flow (Sun, 2014). All the above results provide important qualitative and quantitative insights on the role of capillary heterogeneity on CO_2 flow and distribution in storage aquifers.

However, most of the researchers in this field did not explore how LCT influences CO_2 leakage, which is a significant concern in geologic carbon sequestration (Tao, 2012). Additionally, previous work (Saadatpoor et al., 2010; Saadatpoor, 2012) indicates that 10–50% of local capillary traps get filled during the buoyancy-driven drainage process. However, the previous work (Saadatpoor et al., 2010) assumed a limiting-case initial distribution of CO_2 in the storage formation. It remains to be determined whether more realistic distributions of saturation for buoyancy-driven CO_2 migration, namely the distribution of CO_2 at the end of injection, affect the extent of LCT. In addition, it is valuable to examine the effect of both fluid/rock properties (e.g., residual phase saturation) and operating parameters (e.g., injection rates) on LCT.

In this paper, a systematic numerical assessment of LCT is conducted to evaluate the fraction of potential local capillary traps filled as a function of primary controls while including both the injection and leakage periods. A series of two-dimensional synthetic domains are built and these domains are representative of typical storage formations. Different factors are examined, including injection parameters and reservoir static properties. Particularly, a wide range of buoyancy numbers (i.e., ratio between buoyant force and viscous force) are considered. At the end of post-injection, a leak conduit is introduced along a wellbore to evaluate the effect of LCT on storage security. The understanding thus obtained here will provide insights into post-injection leakage behaviors while the injection period is simulated realistically.

2. Approach

The simulator used in the study, CMG-GEM (2012), is a multi-dimensional and equation-of-state compositional simulator. It can simulate all the important mechanisms controlling CO_2 sequestration into saline aquifers.

2.1. Reservoir properties

A series of 2D models are generated, and they are vertically oriented since LCT occurs during buoyant flow. Fig. 1a shows the based model with the properties detailed in Table 1. Permeability fields (Fig. 1b) are generated using a fast Fourier transform technique (Jennings et al., 2000). The advantages of the method are speed and global conditioning, and it can be applied in any number of dimensions. Porosity is correlated with permeability by Eq. (1) (Holtz, 2002). In Eq. (1), the unit of permeability is mD. The initial reservoir pressure is 2265.6 psi (15.62 MPa) with a constant reservoir temperature of 140 °F (60 °C). The settings of other parameters are the same as Saadatpoor et al.

(2010).

$$\phi = \left(\frac{k}{7E + 7}\right)^{1/9.61} \tag{1}$$

Capillary entry pressure fields (Fig. 1c) are generated using the Leverett j-function [Leverett (1941), Eq. (2)]. In Eq. (2), p_c is capillary pressure, $\sigma_{g/w}$ is the interfacial tension between CO_2 and brine water, θ is contact angle, k is permeability, φ is porosity. The detailed procedures of generating capillary entry pressure field have been elaborated in (Saadatpoor et al., 2010). Table 1 summarizes the properties of the base geologic model.

$$J(S_w) = \frac{p_c(S_w)}{\sigma_{g/w}\cos\theta}\sqrt{\frac{k}{\phi}} \tag{2}$$

In this model (Fig. 1), the pore volume of cells in the right boundary is adjusted to mimic different types of aquifers (i.e., an open aquifer and a closed aquifer). This is realized by using the keyword VOLMOD in CMG-GEM (2012). The magnitude of VOLMOD is chosen based on the magnitude of injected CO_2 volume. An extremely large VOLMOD (1.0E + 7) is assigned to the right boundary cells to mimic an open boundary condition. This boundary is convenient because it prevents pressure buildup during injection. Alternatively, a small (1E + 4) VOLMOD is used to mimic a closed aquifer system, which enables us to study the effect of pressure buildup on LCT.

The above base storage model is varied in terms of permeability anisotropy, dip angle, and heterogeneity. Permeability fields are set to be anisotropic by considering the vertical component of permeability to be a tenth, hundredth, and thousandth of the horizontal component. Three formation dip angles (0, 5 and 25°) are examined; they represent horizontal, moderately-deviated, and highly-deviated formations, respectively. Different horizontal auto-correlation lengths and standard deviations of permeability are also considered. Table 3 summarizes the settings of these parameters.

Following the storage model, a leakage model is built (Fig. 2). The leakage conduit has a permeability of 10 Darcy (9.87×10^{-12} m²) and width of 2 ft (0.609 m). The lower formation in Fig. 2 is the same as the storage domain in Fig. 1. The properties of the upper formation is the same as described in Saadatpoor et al. (2010), and the main difference is the right boundary settings; previous work (Saadatpoor et al., 2010) employs a closed boundary (VOLMOD = 1), but here an open boundary condition is created through using a large VOLMOD (1E + 7).

2.2. Components and rock-fluid properties

Component properties are the same as those in previous work (Saadatpoor, 2012; Kumar et al., 2005) with CO_2 dissolution in brine considered. Figs. 3 and 4 show the relative permeability curves and the capillary pressure curves, respectively. They are consistent with each other. The capillary pressure curves in Fig. 4 are assigned to the simulation cells with the arithmetic mean of permeability. The corresponding capillary pressure curves for other cells are scaled using Leverett j-function with the detailed procedures described in Saadatpoor et al. (2010). The hysteresis in both the relative permeability and capillary pressure curves are considered. The above settings mean that dissolution and residual trapping are modeled in simulations. However, our main interest is on LCT. Mineral trapping is not considered.

2.3. Injection and leakage simulation schemes

A buoyancy number is introduced to describe the influence of buoyancy on CO_2 migration; the number is a dimensionless ratio of buoyancy to viscous force that drives CO_2 migration. Several definitions of the buoyancy number are possible. Here, the buoyancy number (N_{gr}) is defined in following form (Shook et al., 1992):