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Comparison of Darcy's law and invasion percolation simulations with buoyancy-driven CO_2-brine multiphase flow in a heterogeneous sandstone core

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ABSTRACT

In CO_2 storage scenarios, CO_2 flow is dominated by gravity and capillary forces rather than viscous forces over much of the storage space. It is unclear what is the most efficient and effective method to model CO_2 flow under these conditions – standard continuum Darcy-based flow models or invasion percolation models. We perform experiments using high-pressure liquid CO_2 injection into a vertically-aligned heterogeneous Boise sandstone core (30 cm long, 7 cm diameter). Effluent measurements assure that the flow is gravity dominated, and the resulting invasion pattern is measured using X-ray computed tomography (CT). Before the flow experiment is performed, a porosity map of the core is obtained from the CT data and is used as an input to both an invasion percolation model and a Darcy-based flow model. Each simulation matched different features of the data, but neither produced a comprehensive match. The results highlight the strengths and weaknesses of each type of model. We suggest possibilities of integrating the techniques to improve predictions of buoyancy driven flow in heterogeneous media.

1. Introduction

The success of CO_2 geo-sequestration lies in the effective use of pore space and storage efficiency. Estimation of storage capacity requires a thorough understanding of the transport and trapping behavior of the injected CO_2 in the subsurface. In the near well-bore region, viscous forces dominate, and the supercritical CO_2 travels in a compact flow regime, invading most of the pore space. However, this viscous driving force weakens with distance so that away from the wells (tens to hundreds of meters away) the viscous pressure gradient is superseded by the buoyancy gradient due to the density difference between CO_2 and brine (Meckel and Bryant, 2014). This results in vertical flow of the CO_2 and further migration and redistribution depends on the interplay of buoyancy and capillary forces. Thus a large portion of the storage domain is likely to see buoyancy and capillary pressure dominated migration, and understanding of this flow process and how to simulate it are important for predicting storage efficiency.

Small scale geological heterogeneities have been known to affect immiscible displacement (Corbett et al., 1992) and their influence on CO_2 migration and trapping in capillary controlled flow regimes have been highlighted in many laboratory observations and numerical simulation studies (Krevor et al., 2011; Saadatpoor et al., 2010; Li and Benson, 2015; Gershenzon et al., 2015; Islam et al., 2016; Trevisan et al., 2015). Experimental studies of the effect of heterogeneity have mostly relied on horizontal core-flooding techniques (Shi et al., 2011; Pini et al., 2013; Wung, 2015).

The majority of modeling of CO_2 flow has been by carried out using full physics (Darcy law based) simulators. These simulators use finite difference or volume techniques for tracking CO_2 flow dynamically between blocks based on the porosity, permeability, and capillary pressure characteristics of each block. Multiphase flow is handled using phase relative permeabilities and capillary pressure curves. Darcy based simulators are also capable of coupling fluid transport with other physical and chemical processes which become important while modeling other CO_2 storage mechanisms like dissolution or mineralization. On paper, Darcy based simulators are capable of capturing

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the flow physics involved during capillary and buoyancy driven flows like in CO_2 migration, however inclusion of capillary pressure in the simulations introduces non-linearities making them computationally demanding. In addition to this, accounting for small scale heterogeneities necessitates the use of finer grid blocks in the reservoir model, which further increases computation cost and time. Conventionally in order to overcome these problems capillary pressure is neglected and coarse grid-blocks (meter to 10 s of meter sized) are employed. However, using grid blocks bigger than the length scales of the processes being captured, with averaged flow properties results in numerical dispersion (Ringrose et al., 1993; Doughty and Pruess, 2004). This shields the effects of fine scale geological heterogeneities and their effects on flow properties, ultimately resulting in inaccurate estimates of CO_2 plume shape, migration speeds and final capillary trapped capacity (Hovorka et al., 2004; Li and Benson, 2015; Saadatpoor et al., 2010).

In recent times, computationally robust invasion percolation (IP) schemes that are better capable of handling high resolution domains representing realistic heterogeneity have gained attention (Meckel et al., 2015). Invasion percolation is a quasi-static technique that was developed to model the slow immiscible displacement of one fluid by another fluid in a porous medium in the absence of viscous forces (Wilkinson and Willemsen, 1983; Wilkinson, 1984). The major advantage of IP arises from the fact that it is a reduced physics technique which neglects pressure driven flow and only considers the balance between capillary and buoyancy forces. IP models fluid invasion where the pore scale flow is represented as discrete jumps. The algorithms to compute the discrete jumps and the next position of the fluid are unlike those used by conventional full physics reservoir flow simulators where transport equations for each phase are coupled and solved for each time and spatial step. Instead the IP algorithm models the dynamic growth process in a time free series of steps where at each step the interface is advanced to the point of least resistance (smallest pore for example when oil is displaced by water). This makes the IP computational scheme highly efficient and fast compared to full physics simulators.

Invasion percolation has been successfully used to model capillary and buoyancy driven processes like secondary hydrocarbon migration (Sylta, 2004), DNAPL leak and transport during groundwater contamination (Glass et al., 2001) and more recently CO_2 migration (Hermanrud et al., 2010). IP has emerged as an alternative to conventional full physics computational techniques for simulating CO_2 migratory flows (Cavanagh and Haszeldine, 2014; Cavanagh et al., 2015), far field from the injection sites where gravity and capillary forces dominate as discussed in the previous sections. This is also the major shortcoming of IP, since only CO_2 flow far from the injection well or long after injection has ceased can be modeled. Pressure gradient driven viscous dominated flows close to the well or in faults or fractures cannot be captured by IP. Also other processes like reaction and dissolution cannot be coupled with fluid flow in this case. IP also lacks time dependence, thereby making determination of timescales involved during migration and trapping impossible.

Thus both techniques have their strengths: IP is computationally efficient and handles small grid sizes in large numbers easily whereas Darcy handles all flow regimes dynamically. Proper prediction of saturation will likely require a combination of the two techniques to model CO_2 migration through complex heterogeneous structures at various scales. By simulating the flow using two different computational schemes each with different capabilities we aim to validate and reconcile data from experiments and better understand the influence of heterogeneities on CO_2 flow path at the core scale.

In this paper, we present buoyancy-driven core flooding experiments to investigate the influence of cm-scale heterogeneities on CO_2 migration at reservoir conditions. For our experiments we use a Boise sandstone core which is characterized by high permeability (3800 mD) and porosity (35%) and visible cross bedding structures resulting in capillary heterogeneity. By choosing a high permeability core we circumvent the commonly faced problem while attempting buoyancy-driven core flooding: extremely low flow rates resulting in very high experimental runtimes. Using computer tomography imaging we visualize the multiphase flow of CO_2-Brine through the core. With flow patterns established from CT scans, we simulate flow through the core using both a conventional full physics simulator and an IP simulator and compare their performance. With recent reports comparing the two simulation techniques (Oldenburg et al., 2015), this study is instructive for understanding how the two compare with actual experiments.

2. Materials and methods

2.1. Experimental procedure

The flow experiment consists of high-pressure injection of CO_2 into the bottom of a vertically oriented, brine saturated sandstone at a low flow rate. The core flood is designed to replicate the conditions present in a saline aquifer far from a CO_2 injection well. In these far-field areas, viscous forces are negligible; a low flow rate of 0.82 mL/min ensures that buoyancy-driven flow dominates. The Appendix details how this flow rate was chosen.

The core used is a cross-bedded Boise sandstone. The dimensions and the petrophysical properties of the core are listed in Table 1. The core is secured within an aluminum Hassler-type core holder manufactured by Phoenix Instruments. The core was is confined under 2000 psia, which ensures that fluid flows entirely through the core.

Fig. 1 shows the experimental setup. The flow rate of is maintained by an ISCO pump (Model 260D). The pump injects DI water at 0.82 mL/min into 1.5 L accumulators that hold either brine or CO_2, which deliver the fluid into the core. The mass of liquid effluent from the core is recorded on a scale. Pressure transducers measure the pressure drop across the core over the course of the experiment.

Pressure within the core is maintained at 1500 psia by two back-pressure regulators (BPRs) in series. The BPRs are manufactured by Core Laboratories (Model BP 100-T-SS); the upstream BPR is set to 1500 psia and the downstream BPR is set to 950 psia. The series placement of two BPRs reduces CO_2 freezing at the core outlet and thus maintains a more accurate pressure level. The experiment was conducted at room temperature (23 °C). At these P and T conditions, pure CO_2 exists in a liquid phase. Other experimental parameters are given in Table 1.

Before securing the core into the coreholder, it is shrink-wrapped with Teflon, then wrapped with aluminum foil, then shrink-wrapped again with Teflon. The Teflon provides an impermeable barrier to water, and the aluminum prevents CO_2 diffusion from the core into the

Table 1
Input values for Darcy- and fractional flow equations.

Parameter	Symbol	Value SI
Permeability	k	3.75×10^{-12} m^2
Porosity	ϕ	30.8%
CO_2 Relative endpoint permeability	k_{org}	0.57 [dimensionless]
Water Relative endpoint permeability	k_{orw}	0.57 [dimensionless]
Area	A	0.0041 m^2
CO_2 Viscosity	μ	7.6×10^{-5} Pa s
Length core	L	0.305 m
CO_2 Density	ρ_{CO_2}	818 kg/m^3
Density Brine	ρ_{Brine}	1010 kg/m^3
Gravitational acceleration	g	9.81 m/s^2
CO_2 Corey coefficient	n_w	1.8 [dimensionless]
Water Corey coefficient	n_g	4.5 [dimensionless]
Residual CO_2 saturation	S_{rg}	0 [dimensionless]
Residual brine saturation	S_{rw}	0 [dimensionless]
Core inclination angle	α	90°