

Supercritical CO₂ and brine displacement in geological carbon sequestration: Micromodel and pore network simulation studies



Shuang Cindy Cao^a, Sheng Dai^b, Jongwon Jung^{a,*}

^a Department of Civil and Environmental Engineering, Louisiana State University, Baton Rouge, LA 70820, USA

^b School of Civil and Environmental Engineering, Georgia Institute of Technology, Atlanta, GA 30332, USA

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ABSTRACT

The competence of geological carbon sequestration to a large extent relies on the short-term injection efficiency and the long-term capillary trapping and geological stability. This study uses a high-pressure micromodel and pore network simulation to investigate pore-scale displacement phenomena during the injection of supercritical carbon dioxide (scCO₂) into brine-saturated reservoirs. Results show that the brine displacement can be enhanced by increasing the scCO₂ injection rate, but hindered by brine salinity which alters the interfacial contact properties and displacement patterns. The scCO₂–brine displacement ratio increases with the capillary number N_c , increasing which by adding viscosifiers or surfactants would enhance the overall scCO₂ injection efficiency in microscopic flows. Results also suggest that better injection efficiency and capillary trapping capacity can be achieved in reservoirs with more widely-distributed pore sizes. It is not evident that mutual solubility and upscaling using the Leverett- J function readily allow to expand the injection efficiency results of microscopic flows to reservoirs; yet, the effects of salinity and pore size distribution on the scCO₂–brine displacement process remain pertinent in both microscopic and macroscopic flows through porous media.

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1. Introduction

Carbon-producing fossil fuels will continue to be the dominant energy resources for decades (Tsouris et al., 2010; Xie and Economides, 2009). Thus, more carbon dioxide (CO₂) is anticipated to be discharged into atmosphere due to the continued increase in global energy demand. As a prospective method to alleviate CO₂ emission into the atmosphere, geological carbon sequestration (GCS) is desired to store a large amount of CO₂ in places like deep saline aquifers, depleted oil or gas reservoirs, and deep ocean sediments (Benson and Surlles, 2006; Li et al., 2009; White et al., 2005). Among these potential sites, deep saline aquifers are possibly the most promising due to their large capacity for CO₂ storage (IPCC, 2005).

The prediction of CO₂ flow and CO₂–brine displacement in deep saline aquifers largely relies on the relation between capillary pressure (P_c) and water saturation (S_w) under reservoir conditions (Akbarabadi and Piri, 2013; Bachu et al., 2007; Bennion and Bachu, 2008; Benson and Cole, 2008). This P_c – S_w relationship is usually termed as capillary pressure curve or water retention curve.

The two most popular models to describe the capillary pressure curve are:

Brooks–Corey model (Brooks and Corey, 1964):

$$P_c = P_0 \left(\frac{S_w - S_r}{1 - S_r} \right)^m, \quad (1)$$

van Genuchten model (van Genuchten, 1980):

$$P_c = P_0 \left[\left(\frac{S_w - S_r}{1 - S_r} \right)^{-1/m} - 1 \right]^{1-1/m}, \quad (2)$$

where P_0 is a reference capillarity which reflects the entry pressure value; S_r is the residual water saturation; and m is a fitting parameter that captures the sensitivity of the capillarity change in response to saturation change.

The capillary pressure curves for CO₂ and brine at reservoir pressure and temperature conditions have been measured in the laboratory (Krevor et al., 2011; Pentland et al., 2011; Pini et al., 2012; Plug and Bruining, 2007; Tokunaga et al., 2013). The capillary pressure P_c is often determined by measuring the contact angle and the interfacial tension at various pressure–temperature conditions relevant to GCS (Bikkina, 2011; Chiquet et al., 2007; Dickson et al., 2006; Jung and Wan, 2012; Kim et al., 2012; Chalbaud et al., 2009; Aggelopoulos et al., 2010; Bachu and Bennion, 2009;

* Corresponding author.

E-mail address: jjung@lsu.edu (J. Jung).

Shah et al., 2008; Duchateau and Broseta, 2012). However, both mineral wettability (Bikkina, 2011; Chiquet et al., 2007; Dickson et al., 2006; Jung and Wan, 2012) and interfacial tension (Chiquet et al., 2007; Chalbaud et al., 2009; Bachu and Bennion, 2009) are subjected to change during CO₂ injection, leading to alternations in the capillary pressure curve and CO₂–brine displacement patterns.

The capillary pressure curves are important in characterizing both drainage and imbibition processes, as the brine drained by injected CO₂ will eventually be imbibed back into the saline aquifers (Bachu et al., 2007; Bennion and Bachu, 2008; Benson and Cole, 2008). The capillary pressure curves during these two processes have been experimentally determined using distilled water and gaseous or liquid CO₂ (Plug and Bruining, 2007) and more recently using water and scCO₂ (Pentland et al., 2011; Pini et al., 2012; Tokunaga et al., 2013; Perrin and Benson, 2010; Iglauder et al., 2011). However, obtained capillary pressure curves have not been able to cover a broad range of pressure, temperature, and chemical conditions relevant to GCS, and even show discrepancies among each other. The drainage and imbibition processes have not only different capillary pressure curves but also hysteresis in relative permeability that governs the efficiencies of CO₂ injection and capillary trapping (Juanes et al., 2006).

The overall effectiveness of the short-term CO₂ injection into brine-saturated reservoirs, without considering mineral dissolution and precipitation, is inherently governed by two dimensionless numbers (Lenormand et al., 1988; Lenormand, 1990):

Viscosity number:

$$N_m = \frac{\mu_{inv}}{\mu_{def}} \quad (3)$$

Capillary number:

$$N_c = \frac{\mu_{inv} v}{\sigma \cdot \cos \theta} \quad (4)$$

where, N_m is defined as the ratio of the injected fluid viscosity μ_{inv} and the defensed fluid viscosity μ_{def} ; N_c depicts the ratio of viscous force over capillary force and is associated with injected fluid velocity v_{inv} , injected fluid viscosity μ_{inv} , the contact angle on mineral surface θ , and the interfacial tension between injected- and defensed-fluids σ . These two dimensionless numbers govern three dominant regions with distinct displacement patterns

and efficiencies (Fig. 1a): capillary fingering, viscous fingering, and stable displacement (Lenormand et al., 1983; Daripa and Pasa, 2008; Buchgraber, 2008; Wang et al., 2012; Herring et al., 2014). When chemical reactions between CO₂ and reservoir minerals become prominent, such as during long-term storage, the flow patterns are affected by two additional dimensionless numbers (Fig. 1b): the Péclet number P_e and the Damköhler number D_a , which inherently capture the relative rates among advection, diffusion, and chemical reaction (Daccord et al., 1993; Golfier et al., 2002).

Overall, the key questions arising from various stages of the carbon sequestration process are different, i.e., injectivity, potentials of reservoir instability, and intense of seismic events during initial injection phase, as well as trapping, mineralization, brine imbibition, and caprock behaviors in long term (Gaus, 2010; Zoback and Gorelick, 2012a,b; Juanes et al., 2012). This study, however, explores the short-term injection of scCO₂ into saline aquifers with emphases on scCO₂–brine displacement patterns, the capillary pressure curve, and relative permeability. We utilize transparent engineered silica micromodels to directly visualize the scCO₂–brine displacement processes at pore-scale under conditions relevant to geological CO₂ sequestration. We also use 2D quasi-static pore network modeling of two immiscible fluids as a complementary approach to investigate the impacts of pore size statistics (which is difficult and costly to realize in experiments) and fluids properties on the brine drainage process. Note that we herein focus on scCO₂–brine displacement patterns and efficiencies in relatively short periods, during which mineral dissolution and chemical reactions between pore fluids and porous matrix become negligible; also, the scCO₂–brine are treated as immiscible since mutual solubility is important only at the scCO₂ flood front. Both experimental and numerical phenomena observed in this study will most likely not occur identically in the field due to their differences in scale and complexity among many other factors, e.g., the CO₂–brine displacement stability is heavily impacted by the length scale, gravitation, and capillarity (Berg and Ott, 2012; Kimbrel et al., 2015). However, this study does investigate two essential parameters, i.e., salinity and pore size distribution, which strongly affect the CO₂–brine displacement process in both microscopic and macroscopic flows yet have not attracted attention in previous studies.

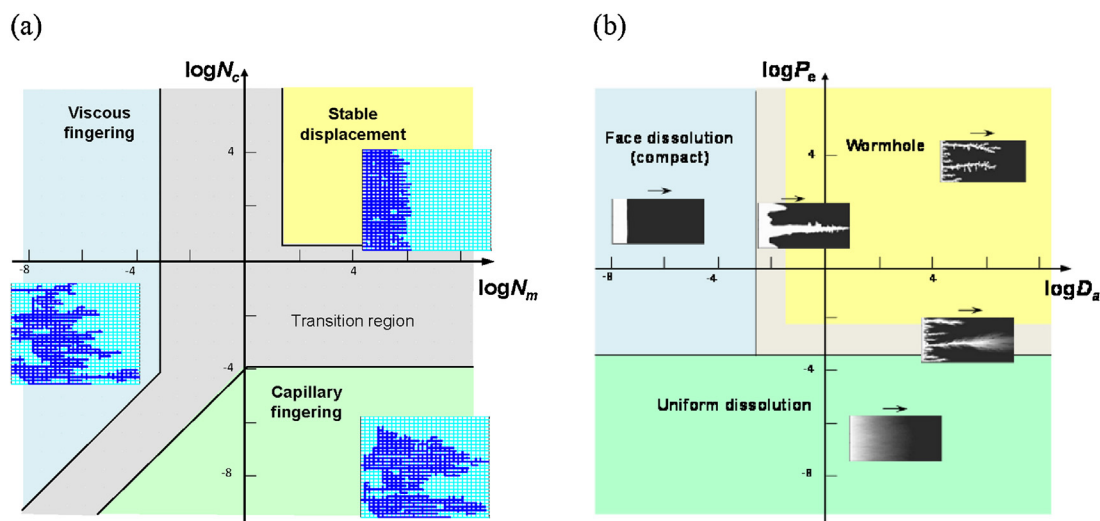


Fig. 1. Invading patterns of immiscible fluids in porous media. (a) The displacement pattern of non-reactive flow in porous media is governed by the viscosity number N_m and the capillary number N_c (Lenormand, 1990; Lenormand et al., 1988). (b) When the invading fluid is reactive with the porous matrix, the displacement pattern is inherently determined by the Péclet number P_e and the Damköhler number D_a (Daccord et al., 1993; Golfier et al., 2002).

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