Advances in Water Resources 96 (2016) 251–265

Contents lists available at ScienceDirect

Advances in Water Resources

journal homepage: www.elsevier.com/locate/advwatres

# A new unsteady-state method of determining two-phase relative permeability illustrated by $CO_2$-brine primary drainage in berea sandstone

Xiongyu Chen*, David A. DiCarlo

*The University of Texas at Austin, Austin, TX 78712, United States*

ARTICLE INFO

*Article history:*
Received 20 April 2016
Revised 28 July 2016
Accepted 30 July 2016
Available online 1 August 2016

*Keywords:*
Relative permeability
Unsteady-state method
Local phase flux
Fractional flow theory
$CO_2$-brine system
Primary drainage

ABSTRACT

This study presents a new unsteady-state method for measuring two-phase relative permeability by obtaining local values of the three key parameters (saturation, pressure drop, and phase flux) versus time during a displacement. These three parameters can be substituted to two-phase Darcy Buckingham equation to directly determine relative permeability. To obtain the first two, we use a medical X-ray Computed Tomography (CT) scanner to monitor saturation in time and space, and six differential pressure transducers to measure the overall pressure drop and the pressure drops of five individual sections (divided by four pressure taps on the core) continuously. At each scanning time, the local phase flux is obtained by spatially integrating the saturation profile and converting this to the flux using a fractional flow framework. One advantage of this local method over most previous methods is that the capillary end effect is experimentally avoided; this improvement is crucial for experiments using low viscosity fluids such as supercritical and gas phases. To illustrate the new method, we conduct five $CO_2$-brine primary drainage experiments in a 60.8 cm long and 116 mD Berea sandstone core at 20 °C and 1500 psi. In return, we obtain hundreds of unsteady-state $CO_2$ and brine relative permeability data points that are consistent with steady-state relative permeability data from the same experiments. Due to the large amount of relative permeability data obtained by the new unsteady-state method, the uncertainties of the exponents in the Corey-type fits decrease by up to 90% compared with the steady-state method.



## 1. Introduction

Relative permeability in porous media is simply a *measure* of the reduction of permeability to a certain phase when that phase is not at complete saturation. It is used in the Darcy Buckingham equation as:

$$Q_i = \frac{k_{ri} K A}{\mu_i} \cdot \frac{\Delta P^i}{L} \tag{1}$$

where $i$ is the subscript for the phase, $Q_i$ is the phase $i$ volumetric flow rate, $k_{ri}$ is the phase $i$ relative permeability, $K$ is the permeability, $A$ is the cross section area, $\Delta P^i$ is the phase $i$ pressure drop, $\mu_i$ is the phase $i$ viscosity and $L$ is the length of porous media. Typically, the relative permeability is assumed to be a function of the phase saturation ($S_i$). To measure relative permeability, one needs to have *local* measurements of saturation, flow rate and pressure drop of phase $i$. In terms of corefloods, obtaining *global* (core integrated) measurements of $S_i$, $Q_i$, and $\Delta P^i$ are typically straightforward; unfortunately the global values can vary significantly from the local values, which is primarily due to saturation variations in the core, caused by end effects and temporal changes in the core. The key to any relative permeability measurement method is designing the method to obtain local values of the three quantities. Here, we first review how these quantities are obtained in both steady and unsteady methods, which are the two categories of relative permeability determination methods. Second, we give an overview of the new method.

During steady-state methods, equilibrated two phase fluids are injected into a core until the measured overall pressure drop and the overall saturation do not change with time (Oak et al., 1990; Oak, 1990, 1991; Dria et al., 1993; Bennion and Bachu, 2005; Bachu and Bennion, 2007; Bennion and Bachu, 2008; Bennion and Bachu, 2006; Al-Abri et al., 2009, 2012; Perrin et al., 2009; Lee et al., 2009; Krevor et al., 2012; Akbarabadi and Piri, 2013; Bachu, 2013; Chen et al., 2014; Akhlaghinia et al., 2014; Farokhpoor et al., 2014; Ruprecht et al., 2014; Akbarabadi and Piri, 2015; Reynolds and Krevor, 2015; Manceau et al., 2015; Al-Menhali et al., 2015). The phase flow rates, the saturation, and the pressure drop are constants along the core when steady state is reached. Thus, for

* Corresponding author.
*E-mail address:* haplobasalt@gmail.com (X. Chen).

http://dx.doi.org/10.1016/j.advwatres.2016.07.018
0309-1708/

steady-state methods, the global measurements are equivalent to the local measurements and the relative permeability equation can be used directly. Potentially there are some complicating capillary effects that occur at the inlet and outlet of the core; these effects can be remedied by measuring pressure drops and saturations in the center of the core (Chen et al., 2014, 2016). This simple equivalence between global and local values makes steady-state methods the gold-standard of relative permeability measurements. Since at each steady state only two data points are obtained (the relative permeability of each phase), the process must be repeated for each flux ratio to obtain a full relative permeability curve. This makes the steady-state methods very time consuming (in addition, steady state is achieved very slowly at the end points) and expensive.

To speed up the measurement process, unsteady-state methods have been developed, particularly in determining oil-brine relative permeabilities (Buckley and Leverett, 1942; Welge, 1952; Johnson et al., 1959; Jones and Roszelle, 1978; Hagoort, 1980; Toth et al., 1998, 2002). Many of these unsteady-state methods obtain the local saturations and phase flow rates from their global measurements by solving the continuity equation along with Darcy Buckingham equation either analytically or numerically. In the well-known JBN method (Johnson et al., 1959; Jones and Roszelle, 1978; Toth et al., 1998 , 2002), one phase is injected into a core saturated with another phase and the overall pressure drop and outlet flux (effluent) are measured versus time. Again, the global measurements of pressure drop, phase flow rate, and saturation (through mass conservation) are taken, but now there are large differences between the global and local values both in time and space. The local values are obtained by assuming a 1-dimensional Buckley Leverett (Buckley and Leverett, 1942; Welge, 1952) type displacement, and from mathematical inversions both the relative permeabilities and the saturation at the outlet are calculated. This procedure is time dependent, allowing many different saturations and relative permeabilities to be obtained from one displacement.

There are other unsteady-state methods; all use slightly different ways of obtaining local values of the three key quantities. Hagoort et al. (Hagoort, 1980) extended the JBN method to oil displacement by air in a centrifuge. The expression for oil relative permeability at the outlet is simplified from the original JBN expression to the oil production rate due to high mobility of air and low capillary pressure. DiCarlo et al. (2000a, b) and Kianinejad et al. (2014, 2015a, b, 2016a, b) conducted gravity drainage experiments and measured local saturations and fluxes in-situ using CT scanning. The local pressure gradient was taken to be the gravitational gradient, which was shown to be a good assumption for the center portion of the column.

The history matching method of obtaining unsteady-state relative permeability data has become a more popular method to obtain local values from measurements of overall pressure drop, effluent versus time, and, in some cases, in-situ saturation. The method presumes a relative permeability model (such as Corey model (Corey et al., 1956) and the LET model (Lomeland et al., 2012)) with prior fitting parameters and a capillary pressure curve (Leverett J function (Leverett, 1941)). Using the experimental boundary and initial conditions, the coupled Darcy Buckingham equation and continuity equation are numerically solved. This is compared to the experimental results, and the fitting parameters of the relative permeability model are adjusted to minimize the differences. Various simulators have been used/developed for this process, including (1) the commercial reservoir simulator ECLIPSE (Schembre and Kovscek, 2003), (2) specialized 1D coreflood simulators, such as open-source SCORES (Maas et al., 2011, 2016, Maas and Schulte, 1997), commercial software CYDAR™ and Sendra, and (3) Shell proprietary 2D reservoir simulator (designed by Regtien et al. (1995) and used by Berg et al. (2013) in two-phase displacements). Two examples of this are Schembre and Kovscek (2003) and Berg et al. (2013). Both did two-phase displacement experiments and measured saturation profiles, pressure drop, and effluent versus time and obtained a posterior relative permeability model that best matched simulated results with measurements. Other authors have reported similar history matched relative permeability models (Eydinov et al., 2007; Jennings et al., 1988, Yang and Watson, 1991; Kulkarni and Datta-Gupta, 1999). However, the history matching method only obtains the fitting parameters of a particular function instead of actual relative permeability data.

In this paper, we develop a new unsteady-state method that is based on steady-state experiments – two phases are simultaneously injected into the core at a certain water fractional flow (which is the water flux divided by the total flux), local saturation is measured non-destructively using CT scanning, and pressure drops are measured through pressure taps to avoid the capillary end effect. Unlike the steady-state method, here we obtain local measurements at all times at each new water fractional flow, and not just at steady state. Local saturations are found from repeated CT scans, local pressure gradients are found from multiple pressure taps with continuously recorded pressure drops, and local fluxes are found from saturation profile along the core versus time and a fractional flow analysis. From these local measurements, from each water fractional flow step, we obtain many points on a relative permeability curve rather than a single point obtained using the steady-state method. Compared with standard unsteady-state methods (e.g. JBN and history matching), we are able to avoid the capillary end effect by only using the upstream four sections of the core.

To demonstrate this new method, it is used to obtain $CO_2$-brine relative permeability. $CO_2$ relative permeability has been a key parameter in modeling multiphase flow scenarios such as enhanced oil recovery using $CO_2$ as an agent (Pope, 1980; Jessen et al., 2005; Kovscek and Cakici, 2005), and $CO_2$ geological storage in deep saline aquifers (Kumar et al., 2005; Juanes et al., 2006; Doughty, 2007; Gao et al., 2016). The method is detailed, and then the results are compared to steady-state data and to those obtained using another unsteady-state scheme.

## 2. Obtaining local flux from saturation data

Any unsteady-state method needs to obtain the local flux. This section gives two different approaches that use the measured saturation profiles with time to find the local flux during the unsteady portion of the flow, which is the part that occurs during each fractional flow step before steady state is reached. Note, each drainage experiment consists of a few fractional flow steps, during which two phase fluids are injected at a fixed fractional flow.

Firstly, we introduce a new procedure that uses the fractional flow theory (Buckley-Leverett solution) (Buckley and Leverett, 1942) and integrates the water fractional flow derivative on the spatial saturation difference. Secondly, we use a previously published solution that integrates the temporal saturation difference on space (DiCarlo et al., 2000b, a; Kianinejad et al., 2014, 2015).

Both approaches have the same initial condition and boundary condition. The initial condition is that the core starts with the uniform saturation achieved at the earlier fractional flow step:

$$S_w(x, t = 0) = S_w(x, \text{steady state of previous fractional flow step}) \quad (2)$$

In Eq. (2), $S_w$ is the water saturation, $t$ is the time from the onset of a new imposed fractional flow, and $x$ is the distance from the inlet of core (unit: cm). The boundary condition is the application of a new fractional flow:

$$f_w(x = 0, t > 0) = f_w(\text{imposed at the pumps}, t > 0) \quad (3)$$