ANALYTICAL INTERPRETATION METHODS FOR DYNAMIC IMMISCIBLE CORE FLOODING AT CONSTANT DIFFERENTIAL PRESSURE

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ABSTRACT

Relative permeabilities are usually determined from unsteady state immiscible core flooding experiments under constant differential pressure or constant flow rate conditions. In the latter case, the classical fractional flow theory can be applied to interpret the results. Recently, a new analytical interpretation method was presented for core flooding experiments under constant differential pressure. This new interpretation method is based on an analytical solution published recently. The analytical nature improves the accuracy of the interpretation. It eliminates the need of using numerical differentiation, and therefore reduces the overall numerical error. Under constant differential pressure, the new theory determines the flow rate as a function of time, which is used to interpret core flooding experiments under constant differential pressure conditions. In this paper, we will first briefly review the interpretation method. Next, unsteady state core flooding experiments are conducted under constant differential pressure conditions; the results from different interpretations are compared and analyzed in terms of accuracy and efficiency.

INTRODUCTION

Core flooding experiments are essential to Special Core Analysis (SCAL). These experiments provide valuable information such as relative permeabilities and recovery factors. Interpretation of the experimental results is generally based on fractional flow theory of an immiscible fluid flow system. Combining Darcy's Law and a material balance equation for each phase, the general fractional flow model can be written as

$$\frac{\partial S_w}{\partial t} + \frac{u_T}{\emptyset}\frac{\partial F_w(S_w)}{\partial x} = -\frac{1}{\emptyset}\frac{\partial}{\partial x}\left[\frac{\lambda_w \lambda_o}{\lambda_T}\frac{dP_c(S_w)}{dS_w}\frac{\partial S_w}{\partial x}\right], \quad (1)$$

where S is the phase saturation; w means the water phase; P_c is capillary pressure; u_T is the total volumetric flux; the water fractional flow function is given by $F_w = \lambda_w/(\lambda_o + \lambda_w)$; where the water mobility is $\lambda_w = Kk_{rw}/\mu_w$ and the oil mobility $\lambda_o = Kk_{ro}/\mu_o$, $\lambda_T = \lambda_w + \lambda_o$. In analytical solutions to fractional flow theory, capillary pressure is ignored, i.e. the right hand side of Eq. (1) equals zero. The classical fractional flow theory by Buckley and Leverett [1] assumes that the total volumetric flux u_T is constant. A similar theory was recently presented by Johansen and James [2] assuming that the inlet and outlet pressures are constant rather than the flow rate. In the latter solution, the total flow rate is a function of time, which is determined analytically.

Johnson *et al*. [3] first presented an analytical method (JBN method) to determine relative permeabilities based on the fractional flow theory developed by Buckley and Leverett [1] and Welge [4]. This interpretation method is based on the assumption that the total flow rate is constant during the core flooding experiments. However, core flooding experiments are sometimes conducted under constant differential pressure conditions. One of the main inaccuracies using JBN method is from the numerical calculation of the differentiation of the cumulative water injection terms. Jones and Roszelle [5] provided a similar method to JBN method. In the Jones-Roszelle method, the "reciprocal relative mobility" at the outlet is determined by the intercepts of the tangent of the effective viscosity curves. Since the tangent is determined from the discrete effective viscosity data points, this introduces numerical instability and inaccuracy. Recently, Cao et al. [6] presented a new analytical interpretation method for core flooding experiments under constant differential pressure conditions. This method applied the novel solution to fraction flow theory under constant pressure boundaries by Johansen and James [2]). Contrary to the assumption of constant total flow rate, the total flow rate is a function of time under constant differential pressure conditions and it is determined analytically as part of the generalized solution. In the formulation by Cao et al. [6] pressure and saturation profile at each point in time are solved analytically, hence this new method eliminates numerical differentiation and provides stable and accurate results.

In this paper, the new interpretation method for unsteady state core flooding experiments under constant pressure boundaries is first briefly reviewed. Then, it is applied to determine relative permeabilities from the core flooding experiments. The main purpose of this paper is to verify the accuracy of the new interpretation method and compare it to the JBN and Jones-Roszelle interpretation methods. Two cases are presented in this paper: Case 1: high viscosity oil in a low permeability core; and Case 2: low viscosity oil in a high permeability core. In both cases, the core flooding experiments are conducted under constant pressure condition and interpreted by the new method and JBN and Jones-Roszelle methods. The results show that the new method is more accurate and stable as a consequence of eliminating numerical differentiation.

METHODOLOGY

The core flooding experiments used two sandstone cores, synthetic oil, filtered crude oil (from Hibernia oil field offshore Newfoundland, Canada), and brine. The experiments were performed at room temperature. The schematic of the core flooding experiment is shown in Fig. 1.

The pressure differential on the core was held constant by running the Quizix 20K pump at constant pressure delivery mode for the inlet and using a back pressure regulator (BPR) at the outlet. A calibrated density meter was connected to the outlet of the core holder to monitor the density change in real time in order to determine the fraction of each producing phase.

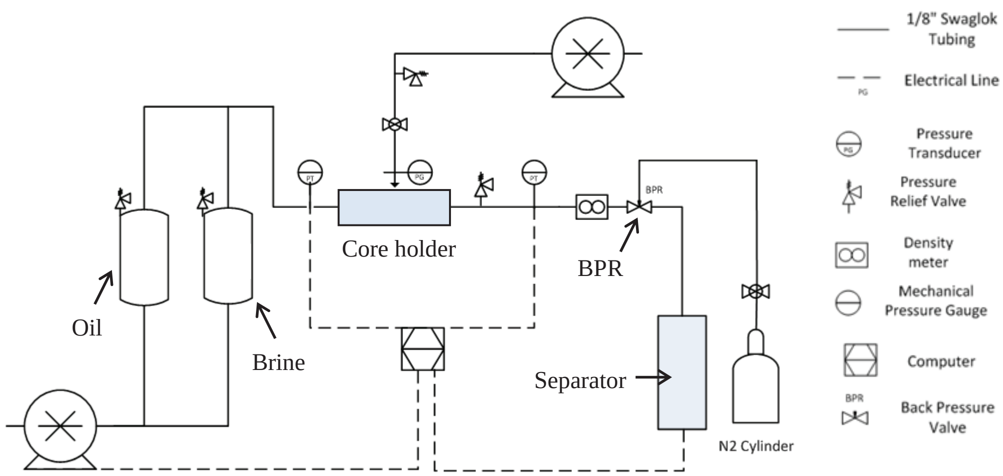

Fig. 1 Schematic of the core flooding experiment

The interpretation methodology for core flooding experiments under constant differential pressure conditions was presented by Cao et al. [6]. During the core flooding experiments, differential pressure, total fluid density at the outlet and cumulative production were recorded in time. Basic information of the core dimension and fluid properties (viscosity and density) are shown in Table 1. The methodology involves determining the pressure and saturation profiles analytically along the core length at the time of water breakthrough analytically using the method in Johansen and James [2]. The saturation profile is calculated when each saturation point arrives at outlet. In this process, the total flow rate as a function of time can also be determined analytically and injection accumulation is easily integrated. The new method for relative permeability calculation in this paper can be summarized in the steps described below with the detailed procedures and equations described by Cao et al. [6].

1. Calculate the saturation at the outlet at selected times post water breakthrough: calculate the water fractional flow function for each saturation point.
2. Determine the saturation and pressure profiles along the length of the core at the time of water breakthrough analytically using Johansen and James [2].
3. Calculate the spatial pressure derivative (pressure gradient) throughout the core.
4. Calculate the relative permeability.
5. Calculate the absolute permeability with brine when the single phase flow is steady state. End points of the relative permeability curves are determined by continuing the steady state two phase flow until connate water and residual oil saturation is reached.

RESULTS

In both cases (Case 1: high viscosity oil and low permeability core; and Case 2: low viscosity oil and high permeability core), the core flooding experimental results are interpreted using the JBN method, the Jones-Roszelle method and the new method. The experimental data is shown in Table 1. The lack of data regularity in both cases stems from the fact that the core floods are performed under unsteady state conditions.

Case 1. High viscosity oil and low permeability core

In Case 1, a viscous crude oil (32 cP) and a tight sandstone (10 mD) core were used. As shown in Fig. 2, the relative permeability results calculated from different methods are compared. It is shown in Fig. 2. that the water relative permeability results from the new method have a good agreement with most of the data points with the results from Jones-Roszelle method, where oil relative permeability results are perfectly matched in the water saturation range from 0.68 to 0.80. Water relative permeability results from JBN methods shows minor deviation from the new method in the water saturation ranged from 0.20 to 0.58. The results from both the JBN and Jones-Roszelle methods show a non-monotonic derivative variation deviating from the new method curve ranged from water saturation of 0.55 to 0.75, while the results from the new method gives a smooth relative permeability curve.

Table 1 Experimental data

Parameter	Symbols	Case 1 Value	Case 2 Value
Oil viscosity (cP)	μ_o	32.0	3.0
Brine viscosity (cP)	μ_w	1.0	1.0
Core sample length (cm)	L	30.48	30.48
Core cross-section area (cm^2)	A	10.01	10.01
Core sample porosity	ϕ	0.24	0.24
Absolute oil permeability (mD)	K	10	876
Connate water saturation	S_{wc}	0.35	0.29
Differential Pressure (psi)	ΔP	243.0	1.0

Case 2 Low viscosity oil in a high permeability core

The comparison of the results of Case 2 using a low viscosity oil (3 cP) in a high permeability core (876 mD) from the three methods is shown in Fig. 3. It is shown that the relative permeability curve obtained from the new method still shows a smooth continuous curve. Similar to Case 1, the results from both the JBN and Jones-Roszelle methods show a non-monotonic derivative variation deviating from the new method curve in the water saturation range of 0.45 to 0.55, where the non-monotonic derivative variation is more significant compared to Case 1. During the calculation using the Jones-Roszelle method, the effective viscosity calculated for Case 2 is scattered as shown in Fig. 4 which makes it difficult to calculate the tangents on the curve numerically and leads the instability of the relative permeability curve. It is relatively easier to calculate the tangents for the smooth effective viscosity curve in Case 1 compared with Case 2 as shown in Fig. 4, but the calculation of the tangents using discrete points numerically still introduces errors.

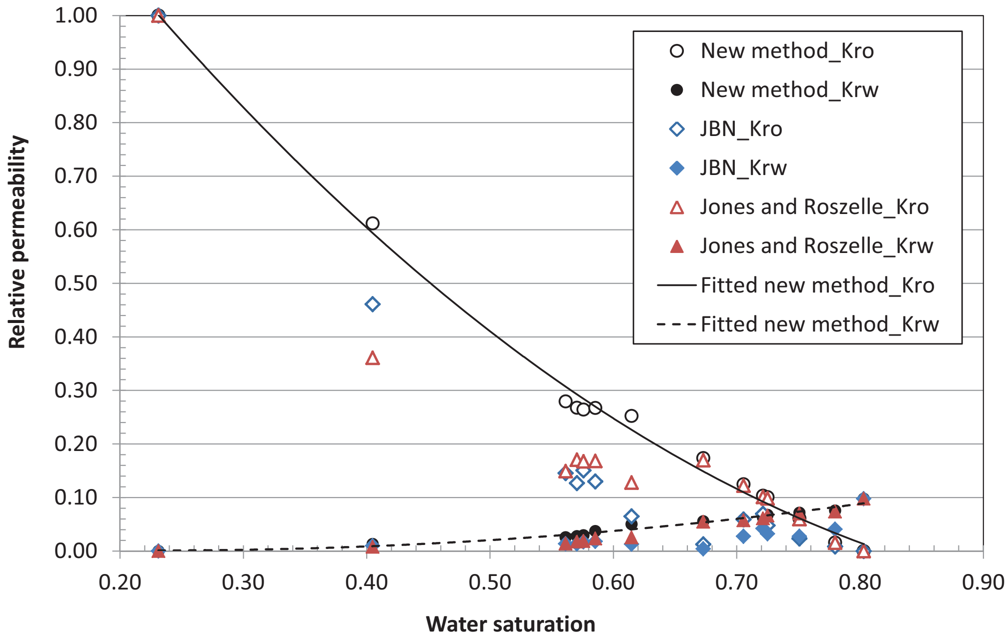

Fig. 2 Relative permeability for Case 1: 32 cP oil and 10 mD rock

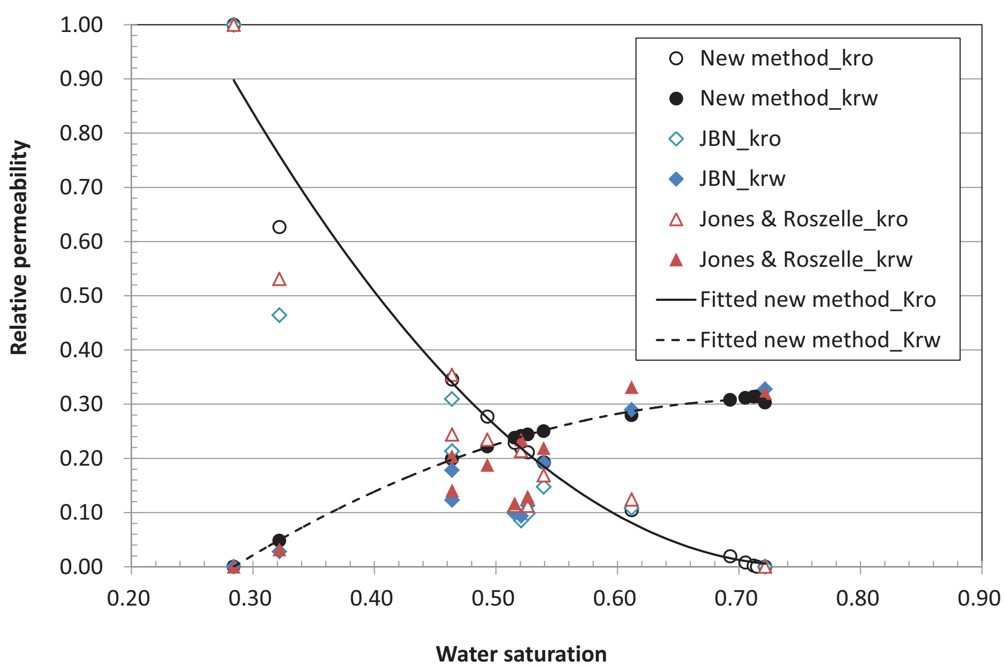

Fig. 3 Relative permeability for Case 2: 3.0 cP oil and 876 mD rock

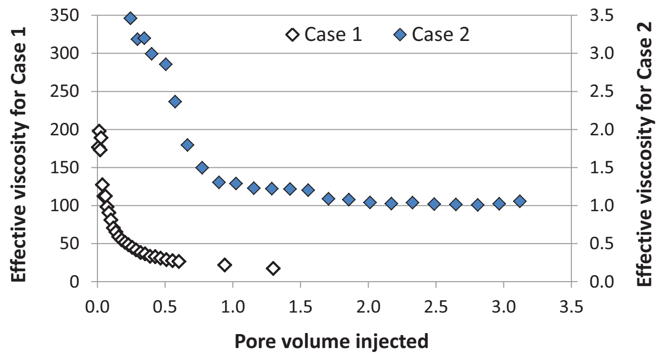

Fig. 4 Effective viscosity for the Jones-Roszelle method

CONCLUSIONS

As discussed in the comparison of the results using different methods, both JBN and Jones-Roszelle methods give instable relative permeability results shown as non-monotonic derivative variation on the curves due to numerical differentiation. By eliminating the numerical differentiation calculation, relative permeability results from the new method yield smooth curves for both cases. We show that the new method provides a robust and stable methodology to interpret unsteady state core flooding data for determining relative permeability. The superiority of the new method is that the numerical differentiation is eliminated and the overall numerical errors are reduced.

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