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Effect of the drawdown pressure on the relative permeability in tight gas: A theoretical and experimental study

S.Y. Mo, S.L. He, G. Lei*, S.H. Gai, Z.K. Liu

Key Laboratory for Petroleum Engineering of the Ministry of Education, China University of Petroleum, Beijing 102249, China

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ABSTRACT

The relative permeability in tight gas is important for the gas production industry. It is reported that the drawdown pressure may affect the immobile water saturation and thus significantly influence the gas-water relative permeability. Precisely predicting the behavior of the relative permeability under different drawdown pressures is thus critically important. The goals of this paper include theoretically and experimentally investigating the effect of the drawdown pressure on the relative permeability. A novel predictive model for the gas-water relative permeability based on fractal theory has been derived, and the corresponding gas flooding tests have been conducted. The predictions of the relative permeability by the proposed model have been validated by comparing them with the experiments conducted. Both the theoretical and experimental results show that the driving pressure has a significant effect on the relative permeability. The predicted and experimental results demonstrate that a lower immobile water saturation produces a wider two-phase region, and a higher gas-water relative permeability corresponds to a higher drawdown pressure. The proposed relative permeability is expressed as a function of the drawdown pressure and other structural parameters (i.e., the pore fractal dimension D_f and the tortuosity fractal dimension D_T). The effects of the structural parameters on the relative permeability are also discussed.

1. Introduction

The relative permeability is an essential parameter to characterize the behavior of a multi-phase fluid flow and is significant when evaluating the performance of a multi-phase flow. As a result, the relative permeability has been investigated extensively in the studies of oil/gas reservoir engineering using the relative permeability (Bear, 1972; Adler and Brenner, 1988; Berkowitz, 2002; Lian et al., 2012; Xu et al., 2013).

Experimentation is a common method to study the relative permeability (Honarpour and Mahmood, 1988; Abaci et al., 1992; Chen et al., 2000; Schembre and Kovscek, 2003; Lian et al., 2012). Additionally, many studies have investigated numerical simulations (Xu and Wu, 2002; Bryant and Blunt, 1992; Hao and Cheng 2010; Sheng et al., 2011). Burdine (1953) investigated the relative permeability curve using pore size distribution data. Corey (1954) presented an exponential expression for the relative permeability using exponential coefficients that were empirically determined. Johnson et al. (1959) calculated a two-phase relative permeability with their theoretical sound method using the data from a displacement test. Schembre and Kovscek (2003) conducted spontaneous imbibition experiments to study the relative permeability, where they obtained the saturation profiles using an X-ray CT scanner. Xu and Wu (2002) used the Lattice Boltzmann Method (LBM) to predict the relative permeability. Using pore network modeling, Bryant and Blunt (1992) proposed a method to calculate the relative permeability in granular porous media that formed from a dense random packing of equal spheres. Hao and Cheng (2010) used the multi-phase LBM to simulate a two-phase flow in a packing sphere bed and obtained the relative permeability from the simulation.

It should be noted that both experiments and numerical simulations usually produce results expressed as correlations. To better understand the relative permeability, an analytical model is should be developed; however, it is difficult to find an analytical expression for the relative permeability due to the typically disordered and complex structure of porous media.

Based on fractal theory, Yu et al. (2003) proposed an analytical

* Corresponding author.
E-mail addresses: 2012312028@student.cup.edu.cn, Leigang5000@126.com (G. Lei).

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expression for the relative permeability using a capillary bundle model, where a single capillary tube was supposed to be partially filled with wetting and non-wetting phase fluids. Extending Yu's relative permeability model (2003), Liu et al. (2007) presented another model that considered the capillary pressure effect. However, these two models did not consider the immobile wetting phase (i.e., water) saturation. Based on fractal theory, Xu et al. (2013) determined the relative permeability via the Monte Carlo technique and the capillary model; however, the model still neglected the effect of the immobile water saturation on the relative permeability. An analytical model of the relative permeability that better approximated real conditions should consider the immobile water saturation.

Some scholars have addressed the effect of pressures on the relative permeability. Reports of effects of the overburden pressure and the pore pressure on the relative permeability are published in the literature; however, reports about the effect of the drawdown pressure are rare (Wilson, 1956; Ali et al., 1987; Oldakowaski, 1994; Al-Quraishi and Khairy, 2005; Khan, 2009). This lack of research may be a result of the fact that the effect of the drawdown pressure seems insignificant for oil development; however, for gas development, particularly with tight gas, which usually contains a high water saturation, an improper drawdown pressure will induce unexpected water production, thus significantly affecting gas production. Thus, the effect of the drawdown pressure cannot be ignored. Guo et al. (2006) conducted a number of gas-water flooding experiments to study how the immobile water saturation varies with the drawdown pressure and flow rate and found that the water saturation can be reduced below the immobile water saturation as the flow rate increases. This finding indicates that the immobile water depends on the drawdown pressure. He and Hua (1998) presented a novel model to study the thickness of the liquid film in reservoirs. Based on their research, it was determined that immobile water exists in a reservoir primarily in the form of a liquid film whose thickness is related to the drawdown pressure. Li and He (2005) investigated the effects of the capillary radius, the drawdown pressure and the fluid viscosity on the thickness of the liquid film using many flooding tests. The above scholars focused on the immobile water but did not study the relative permeability in any detail. Gao et al. (2013) found that the drawdown pressure gradient significantly affected the gas-water relative permeability; the relative permeability curve was found to move to the right as the drawdown pressure gradient increased; however, the authors simply stated this phenomenon and had no comments on its mechanism.

In this paper, we attempted to establish a novel theoretical model for the gas-water relative permeability based on fractal theory. In this model, the immobile water and the effect of the drawdown pressure are considered. We also conducted corresponding flooding experiments on tight-gas sandstones to study the effect of the drawdown pressure.

2. Relative permeability models

As stated in many documents, the fractal feature of interspaces in real porous media typically spans scales from nanometers to micrometers (Zheng et al., 2013). Therefore, it is certain that the fractal feature is present in the pore size distribution of porous media (Zheng et al., 2013). Based on the fractal theory, the analytical equations used in this study must satisfy the following assumptions:

- The flow paths in a porous sample can be represented by a bundle of tortuous capillaries with variable cross-sectional areas, and the size and length distributions of the capillaries obey the statistically fractal scaling law (Yu et al., 2002; Zheng et al., 2013; Xu et al., 2013).
- Water is the wetting phase fluid, and gas is the non-wetting phase fluid. The capillaries with radii $r \geqq r_c$ act as the channels for the gas, and the capillaries whose radii $r \leqq r_c$ act as the channels for the water; r_c is a critical value (Xu et al., 2013).
- Part of the water phase called the immobile water (or residual water) adheres to the capillary.
- Both the gas and water are Newtonian fluids, and the flow is laminar and steady state (Xu et al., 2013).
- No phase transformation occurs in either the gas or the water.

The water saturation S_w and the immobile water saturation S_{wr} on the cross section of the capillary channel can be calculated using Eq. (1) and Eq. (2), respectively. The detailed derivation of the water saturation and the immobile water saturation is given in the Appendix:

$$S_w = \frac{N\int_{r_{min}}^{r_c} r^2 Lfdr + N\int_{r_c}^{r_{max}} \left[r^2 - (r-\delta)^2\right] Lfdr}{N\int_{r_{min}}^{r_{max}} r^2 Lfdr} \tag{1}$$

$$S_{wr} = \frac{N\int_{r_{min}}^{r_{max}} \left[r^2 - (r-\delta)^2\right] Lfdr}{N\int_{r_{min}}^{r_{max}} r^2 Lfdr} \tag{2}$$

where N is the number of pores, L is the real length of the capillary, f is the probability density function of the pore size distribution in the fractal porous media, and δ is the thickness of the immobile water film. The detailed expressions of these parameters are given in Appendix.

Based on the Hagen–Poiseulle equation and Darcy's extended law (Xu et al., 2013), the water phase relative permeability, K_{rw}, and the gas phase relative permeability, K_{rg}, can be written as Eq. (3a) and Eq. (3b), respectively. The detailed mathematical derivation of the relative permeability is given in the Appendix:

$$K_{rw} = S_w \frac{\int_{r_{min}}^{r_c} \frac{(r-\delta)^4}{L} fdr}{\int_{r_{min}}^{r_{max}} \frac{(r-\delta)^4}{L} fdr} \tag{3a}$$

$$K_{rg} = (1-S_w) \frac{\int_{r_c}^{r_{max}} \frac{(r-\delta)^4}{L} fdr}{\int_{r_{min}}^{r_{max}} \frac{(r-\delta)^4}{L} fdr} \tag{3b}$$

3. Experimental works

3.1. Samples and fluids

The samples used in the experiments of this study were drilled from the eastern Sulige gas field. The samples are low permeable sandstones with a permeability below 0.1 mD and a porosity below 10%. The basic properties of the samples are listed in Table 1. The experimental liquid was simulated formation water with a viscosity of 0.869 mPa▪s and a density of 1.028 g/ml. The experimental gas was high-purity nitrogen whose viscosity depended on the experimental pressure and should be looked up.