Journal of Petroleum Science and Engineering 119 (2014) 139–148

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

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

Percolation modeling of relative permeability hysteresis

V.V. Kadet, A.M. Galechyan [1]

Department of Petroleum and Underground Hydromechanics, Gubkin Russian State University of Oil and Gas, 65 Leninsky Prospekt, Moscow 119991, Russian Federation

ARTICLE INFO

Article history:
Received 29 November 2013
Accepted 2 May 2014
Available online 14 May 2014

Keywords:
relative permeability
drainage
imbibition
hysteresis
percolation theory

ABSTRACT

The phenomenon of relative permeability hysteresis is observed during the process of developing an oil field by methods where the flow direction changes and the displacement of oil by water is changed into the displacement of water by oil and vice versa. This paper represents a model of relative permeability hysteresis for drainage and imbibition based on percolation theory. The phenomenon of active oil components' adsorption on the rock-forming minerals is chosen for the main mechanism of hysteresis origin. In the process of drainage, this causes surface hydrophobization of initially hydrophilic rock which leads to each phase relative permeability change. To describe this phenomenon a percolation model for media with microheterogeneous wettability is used. The received numerical solution is represented as relative permeability curves and is qualitatively confirmed by the experimental data. The behavior of relative permeability hysteresis is observed and analyzed for different differential radius distribution curves, capillary network coordination numbers, saturation models and hydrophobization degrees. Further, the introduced methodology can be put into practice for relative permeability calculation considering hysteresis in any porous media to reduce the time spent.

1. Introduction

During the process of developing an oil field using such methods as cycling waterflooding and changing the flow direction the displacement of oil by water is changed into the displacement of water by oil and vice versa. Such a change in flow character depends on relative permeability as a function of water saturation. This phenomenon is called relative permeability hysteresis in drainage and imbibition.

In different scientific articles, drainage and imbibition are explained differently. In this article in accordance with the introduced experimental methodology (Dernaika et al., 2012) drainage is given as displacement of the wetting phase by the nonwetting phase under the pressure gradient. As for imbibition it is presented as displacement of the nonwetting phase by the wetting phase also under the pressure gradient. Therefore, for a hydrophilic (water-wet) sample, drainage is the displacement of water by oil, and imbibition is the displacement of oil by water. In the case of a hydrophobic rock (which is oil-wet), the displacement of water by oil is imbibition and the displacement of oil by water is drainage.

Processes of fluid flow in porous media can be mathematically described by percolation theory which was introduced by Broadbent and Hammersley (1957). There are a significant number of scientific papers in this area. The first percolation approach for relative permeability calculation was introduced by Heiba et al. (1982). This approach was used by many authors including Dixit et al. (1998) and Phirani et al. (2009). Dixit used this method to calculate relative permeability considering hysteresis for different coordination numbers and fractions of oil-wet pores in the network. Phirani compared this method with correlation functions for relative permeability in the case of hydrate formation. However, there was no ultimate analytical expression for relative permeability in their works. Kadet and Selyakov (1987) obtained an analytical solution based on r-chain hierarchy. It was used by some authors (Salomao, 1997).

The represented percolation model of relative permeability hysteresis employs analytical expressions for media with microheterogeneous wettability obtained by Selyakov and Kadet (1996) based on an approach introduced by Kadet and Selyakov (1987). This model allows one to describe the hysteresis phenomenon and to explain the mechanism of its origin.

The novelty of this paper is in using the percolation approach to calculate relative permeability hysteresis for any type of reservoir rock and to demonstrate the tendencies of hysteresis changing for different reservoir and wetting properties. It is important to notice that analytical expressions for relative permeabilities allow one to

E-mail addresses: kadet.v@gubkin.ru (V.V. Kadet), matvey0508@yandex.ru (A.M. Galechyan).
[1] Tel.: +7 9152310568.

http://dx.doi.org/10.1016/j.petrol.2014.05.001
0920-4105/

understand the nature and physics of relative permeability hysteresis which has not been investigated till recently.

2. Experimental research of relative permeability hysteresis

The presence of relative permeability hysteresis was noted in quite a few experimental articles (Wei and Lile, 1993; Braun and Holland, 1995; Spiteri et al., 2005, Chang et al., 2009; Dernaika et al., 2012; Parvazdavani et al., 2012). The most obvious results were introduced by Dernaika et al. (2012), where the following experimental methodology was used. Ten core samples (their numbers: 113, 114, 9, 15, 22, 72, 4, 6, 138, and 139) covering five reservoir rock types (RRTs) were selected based on whole core analysis. Samples 113 and 114 were formed by RRT 1; samples 9 and 15 by RRT 2; samples 22 and 72 by RRT 3; samples 4 and 6 by RRT 4; and samples 138 and 139 by RRT 5. Samples 113 and 114 were dolomite-rich and the other samples were calcite-rich. Samples 113 and 114 had differential radius distribution 1 (Distr. 1); samples 9, 15, 22, 72, 4, and 6 Distr. 2; and samples 138 and 139 Distr. 3. Every sample was totally imbibed by wetting fluid (water).

In the case of a water-wet sample initially saturated with water it was displaced by oil under the pressure gradient up to the maximal oil saturation for drainage. Then oil was displaced by water under the pressure gradient up to the maximal water saturation for imbibition.

The received experimental data are represented in the article mentioned above.

3. Mathematical models of drainage and imbibition

3.1. Model of porous media

The regular network of capillaries (primitive cubic, body-centered cubic or face-centered cubic) is taken as a model of porous media. The capillaries are considered to have circular cross sections. The capillary network has the model density of capillary radius distribution – lognormal function, which is qualitatively close to a real differential radius distribution curve:

$$f(r)=\left(\sqrt{2\pi}\sigma_d r\right)^{-1}\exp\left(-\frac{(\ln(r)-\mu)^2}{2\sigma_d^2}\right),$$

where $\sigma_d=0.25$, $\mu=2$ for the model distribution shown in Figs. 3–5 (which was used for illustration); $\sigma_d=0.5$, $\mu=0.9$ for Distr. 1; $\sigma_d=0.25$, $\mu=-0.1$ for Distr. 2; and $\sigma_d=0.3$, $\mu=-1$ for Distr. 3 (Fig. 1).

The fluid flow in a single capillary is Poiseuille. According to R. Lenormand's classification, a piston-type motion is represented in the model (Lenormand et al., 1983). The connection of phases is illustrated further in Fig. 2.

Water saturation S can be considered to be proportional to the number of water saturated capillaries if the sizes of the pores do not differ significantly (Model I) or to the volume of the water saturated capillaries (Model II). According to Model I water saturation is the area of the zone of capillaries occupied by water in the $f(r)$ plot.

The mechanism of hysteresis origin is caused by the following phenomenon. In the process of drainage, surface hydrophobization occurs in hydrophilic rock as a result of active oil components' adsorption on the rock-forming minerals (Yusupova et al., 1997; Drozdov and Drozdov, 2012).

Models of drainage and imbibition are considered further.

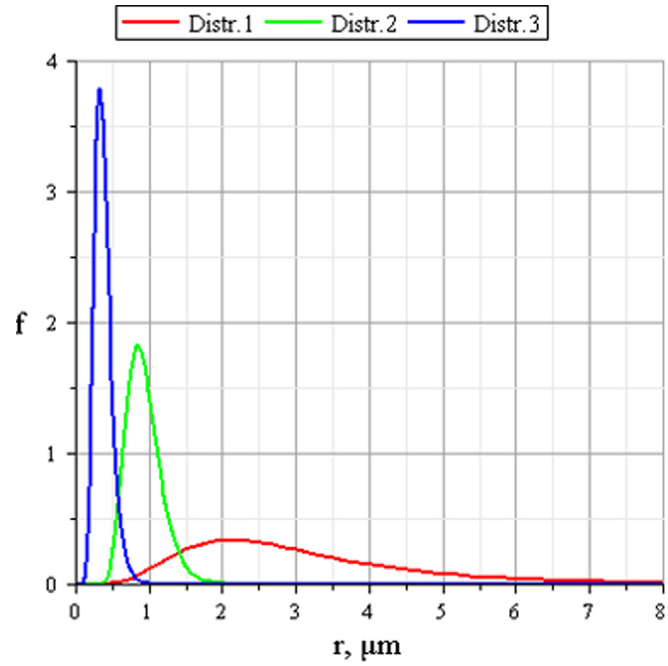

Fig. 1. Differential radius distribution curves.

3.2. Drainage model

In a water-wet sample oil first of all flows into large pores because of small hydrodynamic resistance while in small pores water is kept by capillary forces that prevent oil flow through them. Thereby oil is contained in capillaries with a radius more than r_k and water is in capillaries with a radius less than r_k, where r_k is the minimal radius of a capillary from which the displacement of the wetting phase (water) occurs having set pressure difference in liquids Δp. It is determined by the Young–Laplace equation (Landau and Lifshitz, 1987):

$$r_k=\frac{2\chi\cos\theta}{\Delta p},$$

where χ is the interfacial tension factor and θ is the wetting angle.

According to this, the density of radius distribution function for capillaries occupied by oil is equivalent to

$$f_o(r)=\begin{cases}0, & r<r_k,\\ f(r), & r\geq r_k.\end{cases} \tag{1}$$

Then the analytical expression for oil relative permeability $k_o(r_k)$ (Selyakov and Kadet, 1996) can be written as

$$k_o(r_k)=K_0^{-1}\int_{r_k}^{r_c}\frac{\left[\int_{r_1}^{r_c}f(r)dr\right]^{\nu}f(r_1)}{\frac{8}{\pi}\int_{r_1}^{\infty}(f(r)/r^4)dr\left[\int_{r_1}^{\infty}f(r)dr\right]^{-1}}dr_1. \tag{2}$$

Here K_0 is the absolute permeability of the sample, ν is the radius correlation index and r_c is determined by the relation

$$\int_{r_c}^{\infty}f(r)dr=P_c^b=\frac{D}{z(D-1)}, \tag{3}$$

where P_c^b is the percolation threshold, D is the dimensionality of network ($D=3$), and z is the coordination number ($z=6$ for primitive cubic network; $z=8$ for body-centered cubic network; and $z=12$ for face-centered cubic network).