Lattice Boltzmann Simulation of capillary pressure curves in a rock sample

Felipe F. Munarin · José S. Andrade Jr. · Francisco Nepomuceno Filho · Hans J. Herrmann

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Abstract Two-phase flow of water-oil and oil-gas through a porous medium is simulated by the multi-component Boltzmann Method to determine capillary pressure curves in a heterogeneous three-dimensional pore network obtained from microphotography images of a reservoir rock. The accuracy of the model is validated by simulations of equilibrium contact angle and dynamic capillary intrusion. The simulation results show good agreement with the analytical calculation of dynamic capillary intrusion. Experimentally obtained capillary pressure curves of a hydrocarbon reservoir from the literature are consistent with our simulated capillary pressure curves. The effect of density ratio between the fluids and contact angle on the shape of the capillary pressure curve is investigated. Hysteresis is observed in all studied cases, becoming more apparent with large density differences. The density ratio is found to influence the pressure required to remove fluids from porous media and the volume of residual fluids trapped in it. The results are useful for the study of the capillary pressure curves of a reservoir and confirm that the multi-component Lattice Boltzmann method can quantitatively determine the capillary pressure.
pressure curve for oil-water and oil-gas flow in a realistic three-dimensional rock sample.

Keywords Lattice Boltzmann Method · Capillary Pressure · Multiphase Flow · Wettability · Density ratio

1 Introduction

Multiphase flow in oil reservoirs is a challenging fluid mechanics problem due to the complicated properties of reservoir fluids and the heterogeneous geometry of the porous medium (Gerritsen and Durlofsky, 2005). Especially from a pore scale point of view, understanding the dynamics is not only very important, but also difficult due to a large number of factors that influence flows, e. g., fluid density and viscosity, surface tension, surface wettability, pore geometry and heterogeneity. Precise determination of reservoir rock properties is a difficult and expensive process, which involves performing laboratory experiments on rock cores that are specially cut during the well drilling. The cores should be carefully selected to provide an accurate representation of the larger sections of reservoir rock.

In reservoir engineering, capillary pressure and relative permeability curves play a considerable role. Therefore, these curves must be generated accurately. However, capillary pressure measurements at the lab-scale are time consuming and expensive. Several core samples must be taken from different depths of the reservoir in order to make the traditional core analysis for the petrophysical and flow dynamical characterization of a hydrocarbon reservoir. However, it is not guaranteed that the available samples will be extracted from the entire lithological and petrophysical spectrum of the formation. Therefore, in heterogeneous formations, the capillary pressure curve obtained from the experiments can not be considered universal. Thus, it is still challenging to model and predict the capillary pressure curve (Ahrenholz et al., 2008; Olafuyi et al., 2008; Angeles et al., 2010).

Capillary pressure data should be generated by a model that contains rock and fluid properties. Advanced simulation tools combining computational fluid dynamics (CFD) and pore scale modeling techniques appear as a powerful approach to analyzing multiphase flow (Blunt et al., 2013). Conventional CFD methods require a highly refined grid and huge computational resources to capture underlying flow physics in porous media. On the other hand, less conventional techniques such as the Lattice Boltzmann method (LBM) offer a very attractive alternative and have been used quite often in recent years. Based on a mesoscopic approach, LBM efficiently uses computational resources to capture physical phenomena at the microscopic scale and translates them into macroscopic parameters (Succi, 2001). LBM uses microscopic models and mesoscopic kinetic equations to track the evolution of the particle distribution function (He and Luo, 1997). From the momentum integrations of the particle distribution function, macroscopic variables are obtained. LBM is capable of handling complicated geometries and adapted for efficient parallel programming. Because it does not require any discretization technique, LBM does not generate truncation errors. Several multiphase LBM models have been proposed in the literature (Haihu et al., 2013). The Lattice Boltzmann method has been used by several researchers to simulate Special Core Analysis (SCAL) tests and some other phenomena related to fluid-solid interactions in petroleum.
engineering because of its intrinsic simplicity and accuracy (Schaap et al., 2007; Ramstad et al., 2012).

Nekoeian et al. (2018) presented a quantitative study of a water-oil biphasic flow in a homogeneous porous medium to generate capillary pressure curves. In addition, they proposed a new approach relating pore media permeability and capillary data using the Purcell equation. Ansarinasab and Jamialahmadi (2016) simulated a two-phase flow of gas and oil through a porous medium using the Lattice Boltzmann free energy model. They generated capillary pressure curves in a two-dimensional porous medium instead of a three-dimensional one. These studies were important because the trend of experimental capillary curves was reproduced, however, a detailed study of capillary pressure curves under the conditions of an oil reservoir is still required. Ahrenholz et al. (2008) studied with the Lattice Boltzmann model the flow of two-phase flow through three dimensional artificial porous media as function of their porosity. Schaap et al. (2007) and Bijeljic et al. (2013) analyzed fluid flow in a porous medium obtained from X-ray computed microtomography (CMT) which yield 3-D images of the pore geometry of a rock. However, further studies using the geometry of a natural porous medium are still needed.

Capillary pressure is driven by the wettability of the porous medium which is determined by its mineral composition. In addition, the saturation history becomes important in the calculation of multiphase flow through a rock due to the wettability changes driven by the flow of oil and brine. Thus, porous media exposed to both brines and oils have varying wettability. Buckley and Liu (1998) studied the process involved in crude oil/brine/solid interaction including interactions between the polar functional groups in the oil and polar surface sites on the mineral, surface precipitation, acid/base reactions, and ion binding. Once the mineral surface of porous media is in contact with a fluid, the fluid-mineral surface chemistry controls the alteration in wettability (Landry et al., 2014). The measurement of the contact angle at the pore scale within natural porous media, where individual pores exhibit mineral heterogeneity, is very difficult to obtain. Robin et al. (1995) imaged the distribution of oil and water phases in a reservoir of sandstone and carbonate before and after wettability alteration using cryogenic scanning electron microscopy. They showed evidence of mineral wettability alteration within individual pores. Although these images confirm the assumptions of bulk studies, they do not provide much insight into the 3-D pore geometry.

The focus of our paper is to further elucidate the relationship between different wet states and capillary pressure curves for fluids with different densities. We use the parallelized Shan-Chen model to generate capillary pressure curves by simulating immiscible oil-water and oil-gas displacement in a three-dimensional porous medium. After the validation of the LBM code by the Laplace and Washburn laws, we present a detailed study of the influence of the capillary pressure as function of the saturation history for a biphasic fluid with specific interfacial tension and viscosity. We use the properties of oil and saline water (brine) and gas to represent the actual fluid used in the oil recovery. Our main focus is to analyse the influence of the solid wettability on the capillary pressure curves for small (oil-water) and large (oil-gas) fluid density ratios. Our study is performed in a porous medium obtained from the CMT image of a natural rock. The results presented here confirm that the LBM model can capture the capillary phenomena in porous media adequately for several types of wet rocks.
2 Numerical Method

2.1 Principles of the Lattice Boltzmann Method

The Boltzmann Lattice Method is a mesoscopic method based on discrete velocities which provides numerical solutions for macroscopic hydrodynamics. The fluid is composed of particles which can collide and propagate under certain rules that conserve mass and momentum. The fluid lives on the nodes of a cubic grid and can flow in the direction of discrete velocities. A distribution function \( f_i(x) = f(x, t) \) is used to describe the amount of fluid flowing from node \( x \) in the discrete direction \( i \) with velocity one. The density is given by:

\[
\rho(x, t) = \sum_i f_i(x, t), \\
\rho u(x, t) = \sum_i e_i f_i(x, t),
\]

where \( u(x, t) \) is the macroscopic velocity of \( f_i(x, t) \). We use the D3Q19 lattice model (Qian et al., 1992) which is composed of 19 velocities on a cubic 3D lattice. This model is widely used in 3D LBM simulations. The lattice velocity matrix is written as:

\[
e = e \begin{bmatrix}
0 & 1 & -1 & 0 & 0 & 0 & 1 & -1 & 1 & -1 & 1 & -1 & 1 & -1 & 0 & 0 \\
0 & 0 & 0 & 1 & -1 & 0 & 0 & 1 & -1 & 1 & 0 & 0 & 1 & -1 \\
0 & 0 & 0 & 0 & 1 & -1 & 0 & 1 & -1 & 1 & 0 & 0 & 0 & 1 & -1 \\
0 & 0 & 0 & 0 & 0 & 1 & -1 & 0 & 0 & 1 & -1 & 1 & -1 & 0 & 0 & 1 & -1 & 1
\end{bmatrix}
\]

where \( e = \Delta x / \Delta t \) is the local lattice speed, \( \Delta x \) the lattice spacing, \( \Delta t \) the discrete time step, the prefactor \( e \) is related to the speed of sound by \( c_s = e \sqrt{3} \).

The evolution of the distribution functions is described by the discrete lattice Boltzmann equation:

\[
f_i(x, t) - f_i(x + e_i \Delta t, t + \Delta t) = \frac{\Delta t}{\tau} \left[ f_i(x, t) - f_i^{eq}(x, t) \right],
\]

where \( \tau \) is the relaxation parameter, and \( f_i^{eq} \) the equilibrium distribution function given by the Maxwell-Boltzmann distribution. In the D3Q19 model the equilibrium distribution function \( f_i^{eq} \) can be expanded in Hermite polynomials as

\[
f_i^{eq}(x, t) = w_i \rho \left[ 1 + \frac{e_i \cdot u^{eq}}{c_s^2} + \frac{(e_i \cdot u^{eq})^2}{2c_s^4} - \frac{u^{eq^2}}{2c_s^2} \right],
\]

where the weight coefficients for the D3Q19 model are

\[
w_i = \begin{cases} 
1/3 & i=0 \\
1/18 & i=2,3,...7 \\
1/36 & i=8,9,...19.
\end{cases}
\]

To incorporate an external force \( F_{ext} \), we use Guo’s force term (Guo et al., 2002) where momentum is added to the macroscopic velocity \( u \) in the following way,
\[ \rho u(x, t) = \sum_i e_i f_i(x, t) + \frac{\Delta t}{2} F_{\text{ext}}. \]  

(6)

The Lattice Boltzmann method can be divided in three steps. First, the particle distribution function is streamed to neighboring nodes. Secondly, properties such as density and velocity are determined from this new arrangement, including an external force if necessary. Finally, the collision procedure is applied. There are three different types of nodes: fluid, solid surface, and solid nodes. The fluid distribution function is calculated on fluid nodes. The bounce-back procedure is applied to fluids on the solid surface nodes, that is, the solid nodes reflect particle densities with the opposite moment, producing a non-slip condition halfway between the fluid and the bounce-back node. There is no fluid in the solid nodes.

2.2 Shan-Chen Multicomponent Lattice Boltzmann model

The Shan Chen model (SC) (Shan and Chen, 1993, 1994) is known for its inherent simplicity and for being one of the least demanding computationally LBM multiphase models capable of simulating high density and high viscosity fluids (Sukop and Thorne, 2007). The concept of the Shan Chen model is to model two immiscible fluids using an inter-particle potential, where each fluid phase has its own particle distribution function \( f_\alpha(x, t) \), where \( \alpha \) is the index of each component. The same concept is used to model the interaction force between the fluid and solid surface. The former is comprised of cohesion and adhesion forces. The interaction force term between fluid components \( F^{\text{int}}_\alpha \) is defined as,

\[ F^{\text{int}}_\alpha(x, t) = -G_c \bar{\psi}_\alpha(x, t) \sum_i w_i \bar{\psi}_\alpha(x + e_i \Delta t, t) e_i, \]  

(7)

where \( \alpha \) and \( \bar{\alpha} \) denote the different fluid components. \( G_c \) is the parameter controlling the strength of the interparticle force \( F^{\text{int}}_\alpha(x, t) \) which determines whether the interaction is attractive or repulsive. In our study, \( G_c = 1.8 \) for all simulations which imposes a repulsive iteration between fluids with an interfacial tension of \( \sigma = 0.1 \). In our calculation only nearest-neighbor nodes are considered. \( \psi_\alpha \) is the effective number density of component \( \alpha \) and we will consider here \( \psi_\alpha = \rho_\alpha \). The adhesion force between each component and solid surfaces is imposed adding an adsorption coefficient, \( G_{\text{ads}, \alpha} \) on bounce-back nodes, giving a force:

\[ F^{\text{ads}}_\alpha(x, t) = -G_{\text{ads}, \alpha} \psi_\alpha(x, t) \sum_i w_i s(x + e_i \Delta t, t) e_i. \]  

(8)

The Boolean function denoted by \( s(x + e_i \Delta t, t) \) indicates the existence of a bounce-back node. In this equation, \( G_{\text{ads}, \alpha} \) is the adhesion parameter of the component \( \alpha \) which characterizes the surface wettability of each fluid. Negative values of \( G_{\text{ads}, \alpha} \) are used for wetting fluids and positive values for the nonwetting fluids, with \( G_{\text{ads}, w} = -G_{\text{ads}, w} \) (Huang et al., 2007).

The equation of state describes the relationship between pressure, density and temperature. The SC model is particularly powerful when the components are immiscible. For sufficiently large \( G_c \), when demixing occurs and interfaces between components appear, surface tension is an emergent feature of the SC model, which influences the displacement of a wet by a non-wet fluid inside a porous medium. In order to assess this influence, we will study the capillary pressure for different
Fig. 1 Pressure difference between inner and outer fluid as function of the inverse bubble radius. Data from LBM simulations and equation 10 are presented. Visualization of the red bubble and half volume of the blue fluid in three dimensions is shown inside.

saturations of oil/water and therefore calculate the pressure of a multicomponent fluid system by,

\[ p = c^2 \sum_{\alpha} \rho^\alpha + c^2 \frac{\Delta t^2}{2} \sum_{\alpha, \pi} G_{c\psi}^\alpha \psi^\pi. \]  \hspace{1cm} (9)

3 Validation of the Shan-Chen Model

In the following, we present two simulations in order to validate the LBM model. We study the relation between surface tension and pressure in each component through the Laplace law, and the injection of a wetting fluid into a capillary tube in order to calculate the fluid penetrating length.

3.1 Laplace’s Law

For the first validation, we simulate a bubble of fluid-1 immersed in another fluid-2. We compare this simulation with Laplace’s law which states that the surface tension \( \sigma \) is related to the bubble radius \( R \) and the pressure difference between the inside and the outside of the bubble \( \Delta p \) as follows

\[ \Delta p = \frac{2\sigma}{R}. \]  \hspace{1cm} (10)

For the measurement of the bubble radius, a simple criterion was suggested in Huang et al. (2007) and used here, which implies that a lattice node is considered occupied by fluid-1 if the density of fluid-1 at this node is higher than half of the maximum value of the fluid-1 density, which is observed at the center of the
bubble. Equation 10 implies that in equilibrium the mean curvature of the interface between the two fluid phases is constant.

We immerse a 3D bubble with a fixed radius of 25 lattice units of fluid-1 in a periodic cubic box filled with fluid-2. The size of the cubic box is 100 x 100 x 100 lattice units. The initial density for fluid-1 equals 1 inside the bubble and 0 everywhere else, while the initial density for fluid-2 equals 0 inside the bubble and 1 everywhere else. Periodic boundary conditions are applied to all walls of the cubic box and both fluid viscosities are set equal to unity. The relaxation times for the two fluids are set to one. Fig. 1 presents the relation between the reciprocal of the measured bubble radius (1/R) and the measured pressure difference (ΔP). The figure shows that the pressure difference is directly proportional to (1/R), as expected from Laplace’s law.

3.2 Wettability

The wettability of the solid surface is represented by the contact angle between two fluids in contact with a solid surface. This angle θ is defined as the angle between the solid surface and the interface between the two fluids. The validation is carried out using a cubic domain of size 50 x 50 x 50. The initial condition is a liquid droplet with radius R = 12 lattice units sitting close to the bottom wall (1 lattice unit of distance). The bounceback boundary condition is imposed on the wall located at the bottom boundary in the y-direction while periodic boundary conditions are used in the x and z direction. We run the simulations until the droplet shape does not change anymore, i.e., reaches an equilibrium state.

The contact angle can be computed using Young’s equation for the interfacial tension between the two fluids and between each fluid and the surface tension. Huang et al. (2007) proposed a direct application of Young’s equation. The authors use the cohesion and adhesion strength parameters of the Shan-Chen model instead of the interfacial tension as follows

$$\cos\theta_w = \frac{G_{ads,nw} - G_{ads,w}}{G_c \rho_w - \rho_{nw}},$$  (11)

where ρ_w is the density of the wetting fluid and ρ_{nw} the dissolved density of the nonwetting fluid in the wetting fluid. In Fig. 2 we present the equilibrium shape for four different contact angles between two fluids with the same characteristics of the previous section, i.e., the initial density for fluid-1 equals 1 inside the bubble and 0 everywhere else, while the initial density for fluid-2 equals 0 inside the bubble and 1 everywhere else and both fluid viscosities are set to unity. We see that the use of Eq. 11 is an efficient way to impose a wettability interaction between fluid and solid.

3.3 Capillarity

Capillary intrusion, which originated from the pioneering work of Washburn (1921), is often used to assess whether a multiphase model is able to simulate moving
contact lines. If the fluid viscosity, gravity, and inertial effects are neglected, the position of the interface inside a capillary can be expressed as:

\[ l = \sqrt{\frac{r \sigma \cos \theta}{2 \eta t}} \]  

(12)

where \( \sigma \) is the surface tension between liquids, \( \theta \) the static contact angle, \( \eta \) the liquid viscosity, \( r \) the channel radius and \( t \) the time. Our system consists of a 30 x 30 x 112 lattice domain with periodic boundary conditions in the z direction (see Fig. 3 a)). The wall of the tube is non-slip and oil-wet. At the beginning of the simulation the channel is completely saturated with water and we place an oil container at one end of the channel. Fig. 3 a) illustrates the oil intrusion inside the channel. Half of the box, in the x-direction, has been made transparent to allow viewing inside. The initial density ratio between water and oil was fixed as \( \gamma = \rho_w / \rho_{ow} = 1.55 \) while we impose the same viscosity for both fluids. The interaction between solid and oil dominates and therefore the water is displaced by oil. The oil intrusion length as a function of simulation time is shown in Fig. 3(b). We can observe that the comparison between the simulation and the analytical prediction of Eq. 12 shows a good agreement.
4 Capillary pressure for two phase flow in three dimensional porous media

Fluid displacement is a frequent and one of the most important experiments performed on porous media, and more specifically for petroleum reservoirs. In this study, the sample is a Castlegate sandstone (CGS) and its CMT image was acquired on a cylindrical core of 2 mm diameter and length 3 mm with an Xradia Versa micro-CT scanner. Reconstruction and image analysis were performed by voxilon software (https://voxaya.com/voxilon/), resulting in images of around $1000^3$ pixels from which a central rectangular parallelepiped section connected to an inlet section and an outlet section were taken for our study. Our simulation domain was obtained defining each pixel of the CMT image as a node. This process ensures that we are using a resolution large enough to capture the fluid-fluid and fluid-solid interfacial areas. Fig. 4 a) and b) show the CMT image of the core sam-
Fig. 4 a) and b) present the x-y and y-z cross-section of the core sample, respectively. c) Presents the discrete 3D solid medium used to calculate the capillary pressure.

During the simulation, the porous medium is first fully saturated with wet fluid and thereafter a pressure drop is applied between the inlet and outlet sides to push a non-wetting fluid into the core sample. The non-wetting fluid invasion increases as a result of an increase of the difference of applied pressure which is known as primary drainage. The capillary pressure curve is obtained plotting the saturation of wetting fluid ($S_w$) against the capillary pressure ($P_c = P_{nw} - P_w$).

In order to be used in the LBM simulation the images are divided into pore and solid voxels. Fig. 4 c) presents the 3D solid network which was build from the CMT images of the core presented in Fig. 4 a) and b). The image resolution in Fig. 4 c) is 0.13 x 0.13 x 0.52 mm$^3$. We used the solid medium of Fig. 4 c) in our Lattice Boltzmann simulation. The pore voxels become our fluid nodes, and the solid voxels that are in contact with pore voxels become bounce-back nodes, all other solid voxels being ignored (Fig. 4 c)). The porosity of the porous medium is 0.27 and we consider that the porous medium is water wetting when invaded by oil and oil wetting when invaded by gas. We use the density ratio $\gamma = \rho_w/\rho_{nw} = 1.55$ (water-oil) and 9 (oil-gas) making sure that the global sum of the lattice density of both fluids, $\rho = \rho_w + \rho_{nw}$, is set to unity in order to impute a constant interfacial tension between both fluids. We also set the relaxation as $\tau = 1$ which imposes the same viscosity for both fluids.

In order to calculate the capillary pressure curves, we conduct a single step simulation starting the porous medium from a fully wetted saturated medium (drainage) or from a non-wetting saturated medium (imbibition). The objective of each simulation was to reach an equilibrium state at which there is no more change in wetting saturation ($S_w$). From these simulations, drainage and imbibition curves
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Fig. 5 The drainage steady state in the porous medium system for different pressure drops for contact angle $\theta = 20^\circ$. Oil and water are represented by red and blue colors, respectively. $S_w$ is the obtained wetting fluid saturation.

are obtained. This procedure is similar to the standard method for determining $P_c|\delta S_w$ curves in the laboratory employing constant pressure at the inlet and outlet of the sample following Schaap et al. (2007). In the LB simulations we assume that equilibrium is reached when the change in saturation over time becomes negligible.

Fig. 5 shows the distribution of the fluids during drainage for water-oil and different pressure drops. We observe that the oil presents a preferential flow direction. In addition, we see in Fig. 5 that there are some places of the porous medium that trap oil even for large saturation of water. The same is also observed for small saturations of water in Fig. 5 f). This behavior shows that the geometry of the porous medium plays a significant influence on the residual oil and therefore on the capillary pressure curves as well. We can see from Fig. 5 c), d) and e) that the oil intrusion does not behave like a sweeping front, but rather like a finger invasion. This behavior is due to the small contact angle making the interaction between water and solid strong enough to induce oil to enter in the middle of the pore channel.

In Fig. 6, we present the capillary pressure curves for different contact angles as function of water saturation for drainage and imbibition and density ratio $\gamma = 1.55$. We can observe a difference between the drainage and imbibition curves, i.e. hysteresis. During drainage, when the oil is invading the porous medium oil can remove all water (as seen in Fig. 6 for low $S_w$). On the other hand, during imbibition, in which water is invading the porous medium by removing oil, Fig. 6 shows that it is impossible to remove all oil and therefore a residual oil in the water with a saturation around $S_w \approx 0.9$. This is because the oil cannot slip on the surface towards the outlet because the solid is water wetting and therefore the oil is trapped at some points inside the pore.

Fig. 6 also shows that, in general, the contact angle does not influence the imbibition curves. During drainage, we observe that when the contact angle of the wetting phase (water) increases the capillary pressure decreases. However, the opposite behavior is observed for low water saturations (see the inset of Fig. 6). This interesting behavior is due to the interaction between each fluid with the
Fig. 6 Drainage and imbibition capillary pressure curves for different contact angles for density ratio $\gamma = 1.55$. The inset enlarges the region of low water saturations.

solid. At large water saturation, fluids with large contact angle are more attracted to the solid and therefore more difficult to remove from the porous medium. On the other hand, it is more likely that a fluid with a low contact angle will remain in contact with the porous surface and therefore become more difficult to remove with a low saturation. All these results agree very well with experimental studies which measured the capillary pressure curves for oil and brine for different rocks, i. e., different contact angles (Wang and Tokunaga, 2015).

In Fig. 7, we show the capillary pressure curves for different contact angles as function of the water saturation, for drainage and imbibition for the density ratio $\gamma = \rho_{\text{oil}}/\rho_{\text{gas}} = 9$. It is important to mention that, in this case, oil is the wetting fluid while the gas is non-wetting. First, we can observe that the results follow the general trend of capillary curves. However, the capillary pressures presented in the oil-gas system are about 50% higher than for the water-oil system (Fig. 6). This behaviour is due to the fact that the gas density is nine times lower than that of oil and therefore one needs a larger pressure difference to remove oil from the porous medium. We observe that the capillary curves depend strongly on contact angle, indicating that wettability of the solid influences more in systems with a large density difference. In addition, we observe that the hysteresis between drainage and imbibition is also more pronounced for oil-gas than for water-oil system presented in Fig. 6.

We can observe that the drainage and imbibition curves for $\theta = 80^\circ$ are very different from the other contact angles shown in Fig. 7. In addition to the small difference between drainage and imbibition curves for $\theta = 80^\circ$, they show almost linear behavior as function of the saturation. This behaviour indicates that there is little influence of the solid wettability on the flux of fluid inside the porous medium. Therefore, we can conclude from Figs. 6 and 7 that the fluid flow for low wettability is more influenced by fluid-solid interaction when the density ratio...
between non-wetting and wetting fluid is low. However, despite the small influence of wettability, at $\theta = 80^\circ$ still a residual gas is present during imbibition with higher oil saturation, which is larger for $\gamma = 9$ than $\gamma = 1.55$. These results underline the importance of the study of capillary curves in the oil-water reservoir.

The large difference between the densities of gas and oil also influences the residual oil which can be seen in Fig. 7. We can observe that, during drainage, the gas can remove less than 50% of the oil for contact angle $\theta = 20^\circ$ and $\theta = 50^\circ$. As observed for $\gamma = 1.55$, the pressure difference required to remove the oil for a specific saturation decreases with increasing contact angle. Also, during imbibition, the oil can not remove all the gas from the porous medium. It is important to note that the residual non-wetting fluid during imbibition is larger for a large ratio of fluid density. As already discussed for $\gamma = 1.55$, the fluid with low contact angle is more likely to remain in contact with the porous surface and therefore is more difficult to remove with a non-wetting fluid. As the gas has a density nine times lower than oil, more oil will be trapped in the porous medium.

5 Conclusion

Here the Shan-Chen two phase model is used to simulate drainage and imbibition of oil in water (brine) and oil in gas in a 3D porous medium acquired from CMT images of a reservoir rock. The usefulness and accuracy of this model is first validated by comparing simulations with the analytical solution obtained from Laplace’s law in order to test the model with respect to inter-particle forces. The surface forces are validated by simulating the injection of a non-wetting fluid into a capillary and comparing the capillary intrusion length with the Washburn law.
We present a systematic study of the influence of wettability on capillary pressure curves for different fluid density ratios. In general, the pressure required to remove a wetting fluid using a non-wetting fluid decreases with increasing contact angle. The influence of the wettability on drainage is more evident for large density ratios. The volume of residual wetting fluid during imbibition increases when the difference in the fluid densities is larger. In general, we observe that the geometry of the porous medium plays a significant influence on the residual non-wetting fluid and therefore on the capillary pressure curves. Thus, we can conclude that the shape of the capillary pressure curves is also influenced by the geometry of the porous medium.

Hysteresis between drainage and imbibition was observed in all cases. However, it was more pronounced for large ratios of fluid densities. Besides, we found that the pressure between the inlet and outlet necessary to drive drainage and imbibition is larger for large ratios of fluid densities. All these results agree qualitatively confirms that the parallel multicomponent LB model can well simulate the immiscible capillary pressure curves of oil-water and oil-gas flow in realistic three-dimensional pore structures.

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