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Current minireview

Recent advances in spontaneous imbibition with different boundary conditions

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Abstract:
Spontaneous imbibition plays an important role in many practical processes, such as oil recovery, hydrology, and environmental engineering. The past few years have witnessed a rapid development in the mechanism analysis and industry applications of spontaneous imbibition. In this paper, we focus on boundary conditions of spontaneous imbibition, which has important effects on the imbibition rate and efficiency. Various boundary conditions are first generated using different capillary model and introduced focusing on the fundamental physical mechanisms. Then, the studies of spontaneous imbibition in core scale are reviewed. The feature is discussed and the relative permeability for co- and counter-current imbibition is analyzed. The scaling of imbibition data with different boundary conditions is also presented by combination of experimental and numerical methods. An analytical model to describe spontaneous imbibition is provided at the end.

1. Introduction

Spontaneous imbibition is a very important mechanism of oil recovery from naturally fractured reservoirs and unconventional reservoirs (Lai et al., 2016; Teklu et al., 2017). When water is injected into reservoirs, it preferentially goes through the fracture system. Oil recovery from matrix system is mainly driven by spontaneous imbibition action. The pattern of matrix blocks connected to oil and water is called boundary condition. Due to the complexity of fractures and matrix, boundary conditions can vary a lot and it is difficult to proposed a generalized model. However, according to the pattern of spontaneous imbibition, all boundary conditions can be divided into two categories, i.e., all open faces covered by water (Fig. 1a) (Xu et al., 2018) and part of open faces covered by water (Fig. 1b) (Harimi et al., 2019; Zhang et al., 2019). For the first boundary condition, oil could only be produced by counter-current imbibition (Rangel-German and Kovscek, 2006a; Mason et al., 2012). For the second boundary, oil is produced by combination of counter- and co-current imbibition (Khan et al., 2018). Oil production by counter-current imbibition must overcome capillary back pressure, which is not needed for co-current imbibition.

In this paper, a review on oil recovery by spontaneous imbibition with different boundary conditions is provided. The mini-review mainly includes the fundamental mechanism and core scale studies of spontaneous imbibition with different boundary conditions. In addition, scaling of imbibition data and analytical model of imbibition are discussed as well.

2. Capillary model of spontaneous imbibition with different boundary conditions

Capillary model is a very simple model to study the fundamental mechanisms of spontaneous imbibition. Washburn (1921) developed the first model in which one end of the tube is connected to water and the other is connected to gas. Using this model, it can be described that water will be imbibed into the tube and gas is expelled. This is the simplest model for co-current imbibition. If the tube is fully immersed in water, spontaneous imbibition would not occur because the capillary pressure between the two sides of tube is the same. The capillary pressure in different side of tube must be different when the counter-current occurs (Unsal et al., 2007a; Meng et al., 2017a). Since the structure of porous media is complex,

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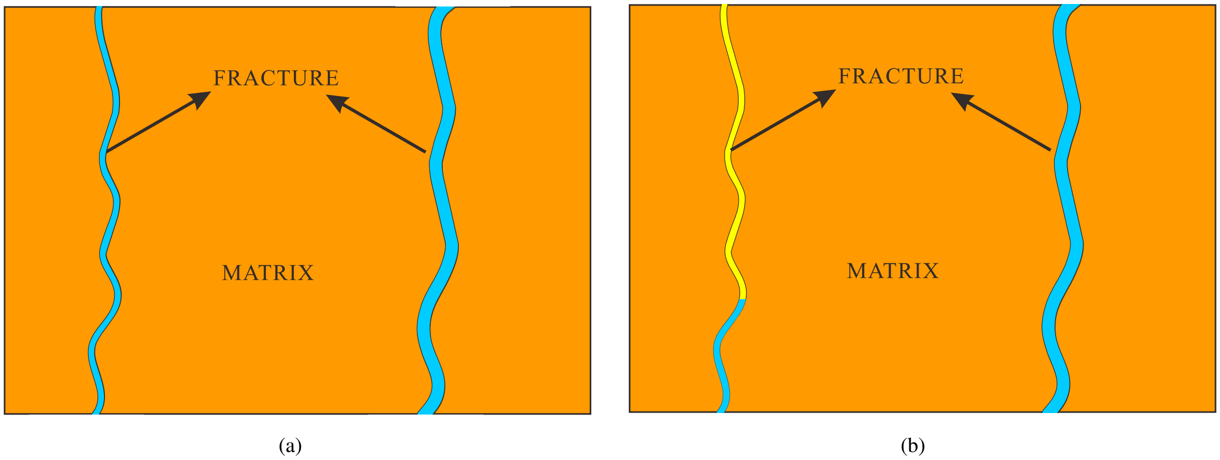

Fig. 1. Illustration of spontaneous imbibition boundary conditions (a) all face of matrix system is covered by water (b) part of face of matrix system is covered by water.

more tube models were developed. The multiple tube models could be divided into two categories, i.e., independent tube model and interacting tube model. Since there is interaction between the fluids flowing in porous media, interacting model is a more reasonable model to simulate spontaneous imbibition in porous media. The interacting tube model were firstly proposed by Dong et al. (1998) and it has been developed by many researchers (Wang and Dong, 2011; Ashraf et al., 2018). The interacting tube model could be used to simulate both co- and counter-current imbibition. If one end of the interacting model is connected to the wetting phase and the other end is closed, counter-current imbibition will occur. Wetting phase will be imbibed from the smaller tube and non-wetting phase will be expelled from the larger tube because capillary pressure in the smaller tube will be larger than that in the larger tube. Non-wetting phase must overcome the capillary pressure in the larger tube and this is the fundamental mechanism of capillary back pressure for counter-current imbibition (Unsal et al., 2007b; Unsal et al., 2009). If one end of the interacting model is connected to wetting phase and the other end is connected to non-wetting phase, co-current spontaneous imbibition will occur. For interacting tube, the menisci in the smaller tube advances faster than that in the larger tube (Fig. 2). This phenomenon is consistent with the results from the visual experiments in porous media (Rangel-German and Kovscek, 2006b).

The topology of porous media is tortuous. Therefore, simulated results of linear capillary model may be not accurate for spontaneous imbibition (Li et al., 2018; Wang and Zhao, 2019). Cai and Yu (2011) reported that the tortuosity is an important factor affecting on fluid flow features such as permeability and flow resistance in porous media. He proposed a fractal model considering the tortuosity of capillary and it is shown that the time exponent of LW equation is not equal to 0.5 in some cases which is consistent with the experimental results (Hu et al., 2012; Gao and Hu, 2016). On the basis of this work, Cai et al. (2014) proposed a more generalized model by considering the different sizes and pore shapes (Fig. 3). Tests results show that the generalized model can be used

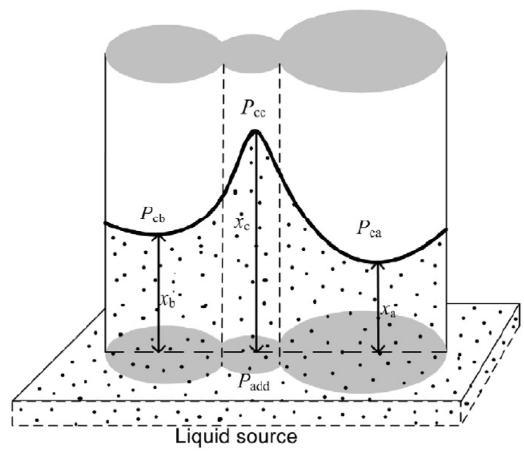

Fig. 2. Interacting tube model for co-current imbibition (Unsal et al., 2007b).

to characterize spontaneous imbibition behavior with different pore structure.

3. Core scale of spontaneous imbibition with different boundary conditions

The most widely used boundary conditions for core experiments of spontaneous imbibition is all faces open connected to water (AFO) because it is the most convenient way to conduct (Javaheri et al., 2018; Yang et al., 2018; You et al., 2018). However, it is also very difficult to solve due the high complexity caused by flow patterns. Recently, linear spontaneous imbibition has become the focus of more and more researchers. The boundary conditions can be divided into two categories according to the direction of fluid flow. If open faces are in contact with water, the direction of water and oil flow is opposite (Fig. 4a). For this boundary condition, oil can only be produced by counter-current imbibition. In addition, oil production is linear with square root of imbibition time for conventional core (Hamidpour et al., 2015). However, more studies show that the time exponent for linear correlation

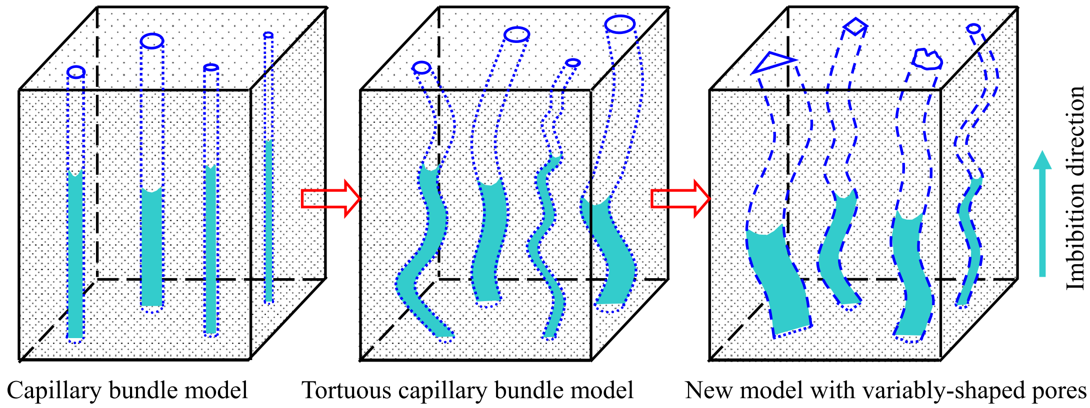

Fig. 3. Evolution of tube model (a) capillary bundle model (b) tortuous capillary bundle model (3) capillary model with variably-shaped pores (Cai et al., 2014).

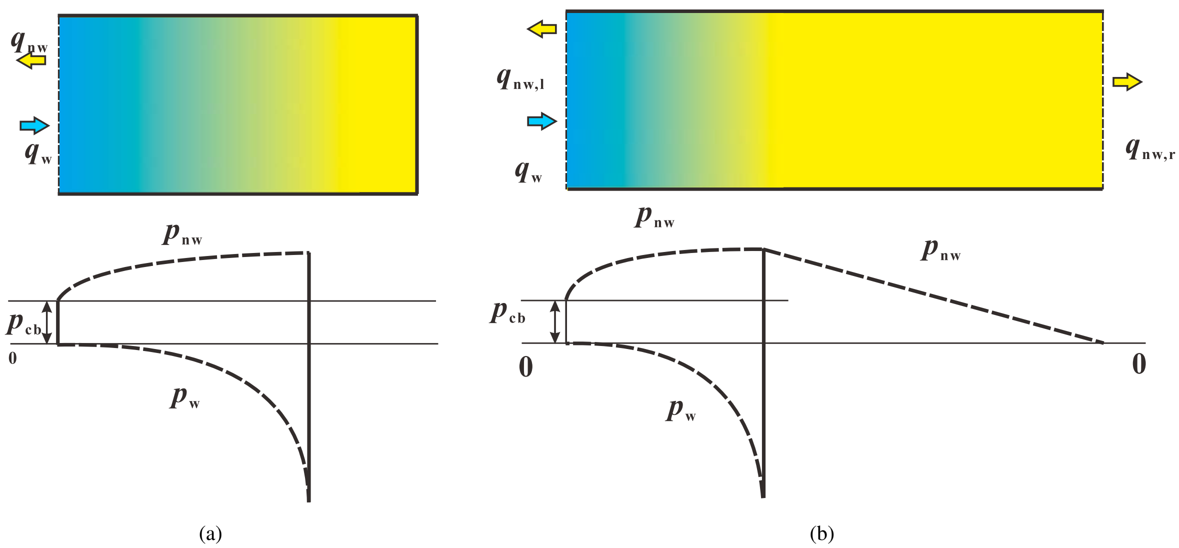

Fig. 4. Schematic illustration of fluid flow distribution and pressure profiles in the core with (a) OEO boundary condition (b) TEO-OW boundary condition (Meng, 2017).

are less than 0.5 and for unconventional reservoirs, a linear correlation is sometimes not applicable, especially for tight core and shale (Cai and Yu, 2011; Gao and Hu, 2016; Cheng et al., 2018; Lyu et al., 2019). If one end face is in contact with water and the other face is in contact with oil (TEO-OW), oil will be produced by combination of co- and counter-current imbibition (Fig. 4b). At the initial stage of TEO-OW imbibition, the pressure in oil at the imbibition front is higher than the capillary back pressure. Thus, oil can be produced from the left end of core. With the advancing of imbibition front, oil pressure in the imbibition front decreases and when the oil pressure in the imbibition front is lower than the capillary pressure, oil can only be produced by co-current imbibition. Since it does not need to overcome capillary back pressure for oil production by co-current imbibition, it may a more efficient way for oil production.

Evaluation of capillary pressure and relative permeability is another important work for spontaneous imbibition with different boundary conditions. It is difficult to directly measure the relative permeability for spontaneous imbibition by experiments, especially counter-current imbibition (Li et al., 2018). Generally, relative permeability of spontaneous imbibition is estimated by fitting the theoretical results with experimental results (Haugen et al., 2015; Alyafei and Blunt, 2018). Bourblaux (1990) reported that both oil and water relative permeabilities for counter-current imbibition are lower than that for co-current imbibition. Haugen et al. (2014), Meng et al. (2015) and Meng et al. (2017b) estimated the average relative permeability to water and capillary pressure through the piston-like displacement. It is interesting to find that the curve of average relative permeability to water saturation is very similar to the shape of relative permeability curve (Fig. 5). However, this is the average relative permeability and there are still experimental results needed to verify if it is suitable to be used. Another problem to obtain relative permeability by fitting the theoretical results with the experimental results

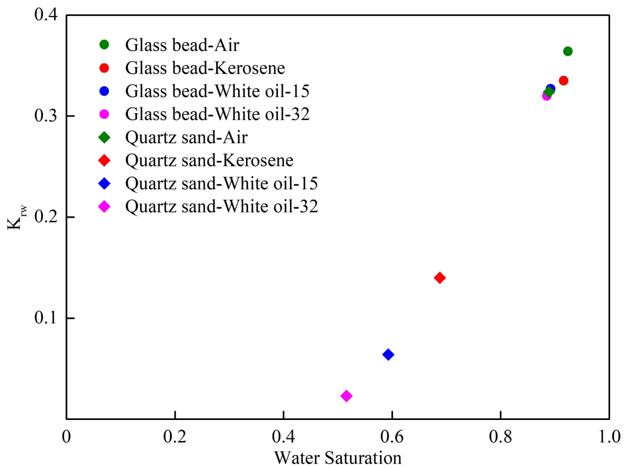

Fig. 5. Average relative permeabilities versus average water saturation (Meng et al., 2015).

is that the solution is not unique. The good fitting results could be obtained by adjusting the oil and water relative permeability curves and end-point but the shape of relative permeability cannot be determined uniquely in that way. It is still an important work in the future.

4. Scaling of spontaneous imbibition data with different boundary conditions

In order to compensate for counter-current imbibition data with different boundary conditions, Zhang et al. (1996) and Ma et al. (1997) defined a factor called characteristic length as follows:

$$L_{\mathrm{C,MMZ}} = \sqrt{\frac{V_b}{\sum_{i=1}^{n} \frac{A_i}{l_{Ai}}}} \tag{1}$$

where V_b is bulk volume of matrix, A_i is the area open to imbibition at i_{th} direction l_{Ai} is the distance from the open face to the no-flow boundary condition. Ma et al. (1997) characteristic length has been verified by many experiments conducted by cylindrical cores with different boundary conditions (Fischer, 2008; Mason et al., 2010). It is noticed that Ma et al. characteristic length is a constant and it could not change the shape of imbibition recovery curve (Abbasi et al., 2018). However, the shape of imbibition recovery curve may not be similar for different boundary condition, especially for cores with different geometrical shapes (Mirzaei-Paiaman et al., 2017; Jing et al., 2019). Accordingly, Meng et al. (2019b) proposed a novel characteristic length function which is a function of imbibition time as follows:

$$L_{\mathrm{C,Mod1}}^2 = \left(1 - \frac{t}{t_{\mathrm{end}}}\right) L_{\mathrm{C,Theo}}^2 + \frac{t}{t_{\mathrm{end}}} L_{\mathrm{C,MMZ}}^2 \tag{2}$$

where tend t_{end} the time when oil production by imbibition is about to stop.

$$L_{\mathrm{C,Theo}} = \frac{V_b}{\sum_{i=1}^{n} A_i} \tag{3}$$

The shape of imbibition curves could be changed using the Meng et al. (2019a) characteristic length. Both numerical and experimental results show that scaling results could be improved using Meng et al. characteristic length (Fig. 6).

There are relatively few studies focusing on scaling of imbibition data for partially water-covered boundary condition. Generally, Ma et el. (1997) characteristic length is used to compensate for length of the core in 1D co-current imbibition experiments (Pooladi-Darvish and Firoozabadi, 2000; Mirzaei-Paiaman and Masihi, 2014). The characteristic length is defined as the distance from the water-covered face to the oil-covered face. Numerical and experimental showed that Ma et

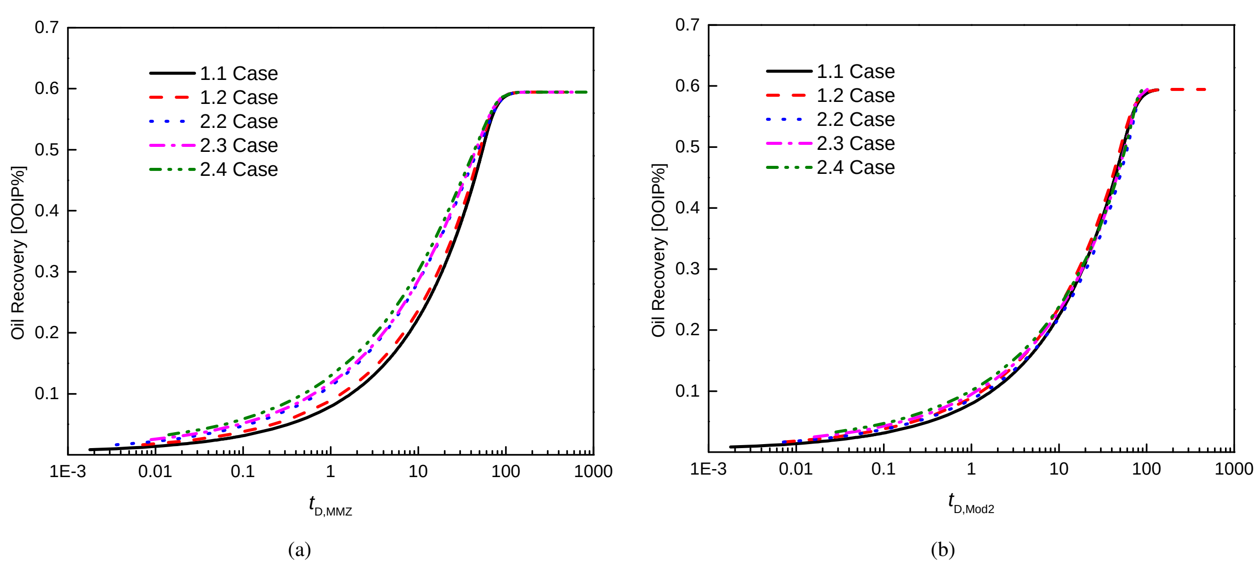

Fig. 6. Correlation of imbibition curves using (a) Ma et al. (1997) characteristic length (b) Meng et al. characteristic length to calculate dimensionless time (Meng et al., 2019b).

al. characteristic length is valid for 1D co-current imbibition. However, for 2D partially water-covered spontaneous imbibition, the pattern of fluid flow is very complex and the scaling results are not satisfactory using Ma et al. (1997) characteristic length (Standnes, 2004). Meng et al. (2019b) investigated features of spontaneous imbibition for 2D partially water-covered matrix blocks with different boundary conditions. It is reported that the most important two factors that affect the rate of imbibition are the area of water-covered face and the distance from the water face to oil face. Accordingly, three criteria were proposed for calculation of characteristic length. Numerical results showed that the close correlation is obtained in the early stage of imbibition process using the proposed criteria to calculate the characteristic length (Fig. 7).

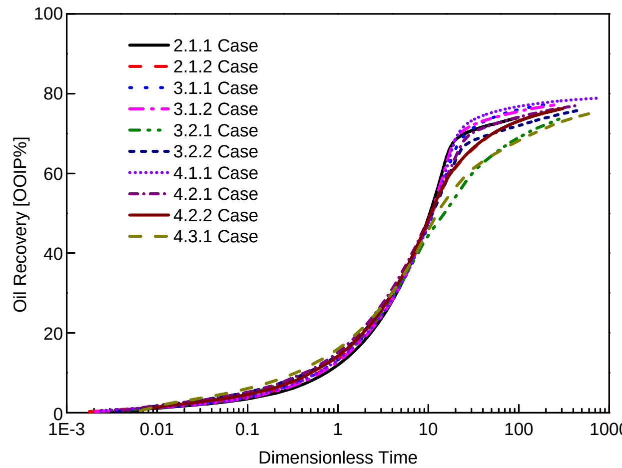

Fig. 7. Correlation of imbibition data for 2D partially water-covered matrix blocks using Meng et al. criteria to calculate characteristic length (Meng et al., 2019b).

5. Analytical models of spontaneous imbibition with different boundary conditions

The 1D linear counter-current imbibition can be described by a nonlinear diffusion equation as follows (Pooladi-Darvish and Firoozabadi, 2000; Li et al., 2003):

$$\frac{\partial}{\partial x}\left(D\left(S_{\mathrm{w}}\right)\frac{\partial S_{\mathrm{w}}}{\partial x}\right)=\frac{\partial S_{\mathrm{w}}}{\partial t} \tag{4}$$

where

$$D\left(S_{\mathrm{w}}\right)=\frac{k}{\phi}\frac{k_{\mathrm{ro}}}{\mu_{\mathrm{o}}}f\left(S_{\mathrm{w}}\right)\frac{dP_c}{dS_{\mathrm{w}}} \tag{5}$$

and

$$f\left(S_w\right)=\frac{1}{1+\frac{k_{ro}}{k_{rw}}\frac{\mu_{\mathrm{w}}}{\mu_{\mathrm{o}}}} \tag{6}$$

$D(S_w)$ is the diffusion function which is dependent on relative permeability and capillary pressure. This pressure can be expressed by a function of saturation (Fig. 8). S_w is the saturation of wetting phase, x is the distance, t is imbibition time, k is permeability, ϕ is porosity, k_{ro} is relative permeability to non-wetting phase, k_{rw} is relative permeability to wetting phase.

The equation of co-current imbibition should be added a convective term as follows:

$$\frac{\partial}{\partial x}\left(D\left(S_{\mathrm{w}}\right)\frac{\partial S_{\mathrm{w}}}{\partial x}-q_t f\left(S_{\mathrm{w}}\right)\right)=\frac{\partial S_{\mathrm{w}}}{\partial t} \tag{7}$$

where q_t is the total volume flux.

The solution of the capillary-driven flow is a hard problem due to the nonlinearity in the original flow equations (Ghosh et al., 2019). The main assumption for the spontaneous imbibition is that imbibition rate is inversely proportional to the square root of time (Andersen et al., 2019a; Andersen et al., 2019b) and Schmid et al. (2011) reported a semi-analytical solution for co- and counter-current imbibition by fully taking hydrodynamic dispersion for variable two-phase flow field into account. Nooruddin and Blunt (2016) reported a semi-analytical solutions for co-current imbibition with considering the counter-current flow of oil from the inlet face. They also present approximate solutions by use of a perturbative approach. Foley et al. (2017) investigated the impact of capillary back pressure by analytical solutions for 1D linear counter-current imbibition. It is reported that there existed an saturation value above which the change in capillary back pressure has a negligible effect on the function solutions.

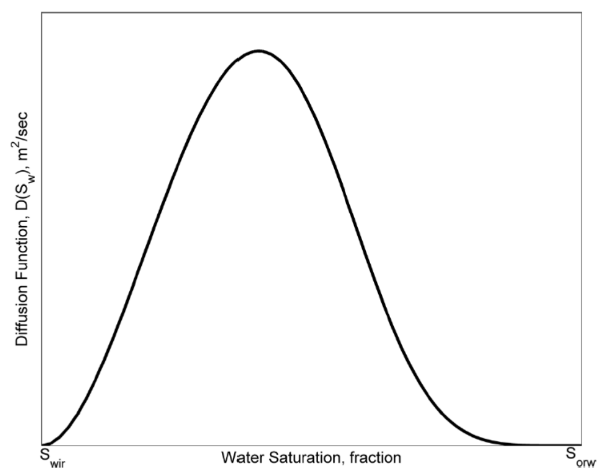

Fig. 8. Illustration of capillary diffusion function versus water saturation in strongly water-wet porous media (Nooruddin and Blunt, 2016).

6. Discussion and future work

The studies of spontaneous imbibition developed faster in the past few years. However, there remain still many problems to be solved. The interacting capillary model illustrated that wetting phase advances faster in the smaller tube. However, some experiments conducted in unconventional cores showed that wetting phase imbibed to the micro-fractures preferentially instead of matrix blocks, which is opposite to the estimations of interacting model. The capillary back pressure is another serious problem. To estimate the capillary back pressure and to evaluate its effect on spontaneous imbibition is an important work in the future. In addition, the relative permeability for co- and counter-current imbibition should be given more concentration even though this is a highly developed concerns. Scaling of imbibition data with more complex boundary conditions and how to associate the experimental model with the natural reservoirs are also needed to be investigated thoroughly. For the analytical model, the choice of boundary conditions is a key problem. The saturation at the open face also has a very important effect on the analytical solutions.

7. Conclusions

The boundary conditions have significant effect on oil recovery by spontaneous imbibition. The oil production is by counter-current imbibition when matrix block is fully immersed in water, while that is by combination of co- and counter-current imbibition. However, in this case co-current imbibition is dominated. It is not necessary to overcome capillary back pressure for co-current imbibition and it is considered as a more efficient way. The boundary condition will change the shape of imbibition curve and it is difficult to scale the curve by a constant. The characteristic length should be a function of imbibition time and the shape of imbibition curve could be changed by the modified characteristic length.

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Conflict of interest

The authors declare no competing interest.

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