Extracting Capillary Pressure and Global Mobility from Spontaneous Imbibition Data in Oil-Water-Rock Systems
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Abstract
An approach was developed to extract the imbibition capillary pressure and the global mobility data from spontaneous water imbibition tests in oil-water-rock systems. Capillary pressure and global mobility data were calculated using this method with the experimental data of countercurrent spontaneous water imbibition tests in different rocks and at different interfacial tensions. The calculated capillary pressures were consistent with the change in interfacial tension. The oil-water-rock systems with greater interfacial tensions had greater capillary pressures. However, the oil-water-rock systems with greater capillary pressure may not have greater imbibition rate. The calculated values of the global mobility and the imbibition index explain why the oil recovery or the imbibition rate in systems with high interfacial tension was smaller than that in systems with low interfacial tension, which has been considered a paradoxical result for many years.

Introduction
Capillary pressure is of fundamental significance in reservoir engineering. Capillary pressure data are measured often using porous-plate, centrifuge, and mercury injection techniques. These methods can suffer limitations in one or other aspects. Spontaneous imbibition in porous media is a process dominated by the effect of capillary pressure. It would be useful if capillary pressure data could be extracted from spontaneous imbibition tests, because such tests are relatively simple, fast, and economical. Also, spontaneous imbibition tests are more representative of the fluid flow that happens in fractured reservoirs compared to the frequently used methods such as porous-plate, centrifuge, and mercury injection approaches. However, it has been a challenge for a long time to extract capillary pressure from spontaneous imbibition tests.

Handy1 reported a method to determine the effective capillary pressure in porous media from imbibition data. A linear relationship was proposed. That is, the square of the volume of imbibed water is proportional to the imbibition time:

\[ N_{wt}^2 = A^2 \frac{2P_c k_w \phi S_{swf} t}{\mu_w} \]  (1)

where \( A \) and \( N_{wt} \) are the cross-section area of the core and the volume of water imbibed into the core respectively; \( \phi \) is the porosity, \( \mu_w \) is the viscosity of water and \( t \) is the imbibition time; \( S_{swf} \) is the water saturation behind the imbibition front. \( k_w \) is the effective permeability of water phase at a water saturation of \( S_{swf} \). Similarly; \( P_c \) is the capillary pressure at \( S_{swf} \).

It can be seen from Eq. 1 that capillary pressure can not be calculated independently from spontaneous water imbibition data if the effective water permeability is not determined using a different method. Eq. 1 has other limitations, as we discussed in a previous paper2.

Recently, we developed a method to extract capillary pressure and end-point relative permeability simultaneously from spontaneous water imbibition data in gas-liquid-rock systems3-4. However, there have been few studies on doing this in oil-water-rock systems. In gas-liquid-rock systems, the gas phase mobility could be assumed to be infinite in comparison to the liquid phase mobility. Oil-water-rock systems are more complicated because one cannot make a similar assumption. Note that capillary pressure may be extracted from spontaneous water imbibition data in oil-water-rock systems if oil-water relative permeabilities are available according to our previous paper5.

In this study, a method was developed to infer the imbibition capillary pressure and the global mobility data from spontaneous water imbibition experiments in oil-saturated rock without knowing oil and water relative permeabilities. Using this approach, capillary pressure and global mobility data were calculated with the experimental data of countercurrent spontaneous water imbibition tests in Berea.
sandstone and Indiana limestone at different interfacial tensions. The approach developed in oil-water-rock systems can be reduced to the gas-water-rock cases, in which the capillary pressure calculated from spontaneous imbibition data was consistent with that measured using a different method: an X-ray CT technique.

**Mathematics**

In a previous paper, we developed a general scaling approach for spontaneous imbibition in almost all fluid-fluid-rock systems. A theoretical relationship between the normalized oil recovery and the dimensionless time was also established, which is expressed as follows:

\[ (1 - R^*) e^{R^*} = e^{-t_d} \]  

where \( R^* \) is the normalized recovery by spontaneous imbibition and defined as follows:

\[ R^* = cR \]  

here \( R \) is the recovery in the units of pore volume.

In Eq. 2, \( t_d \) is the dimensionless time and determined theoretically as follows:

\[ t_d = c^3 \frac{kk^*_{re} P^*_{cw} S_{nf} - S_{wi} - t}{\mu^* c e L_a^2} \]  

where \( P^*_{cw} \) is the capillary pressure at \( S_{nf} \), \( k^*_{re} \) is the relative permeability pseudofunction associated with \( k^*_{nw} \) (the nonwetting-phase relative permeability at \( S_{nf} \)) and \( k^*_{rw} \) (the wetting-phase relative permeability at \( S_{nf} \)), \( S_{nf} \) is the initial wetting-phase (water in this study) saturation in the core sample, \( \mu^* \) is the effective viscosity of the nonwetting (oil in this study) and the wetting phases, and \( L_a \) the characteristic length. \( c \) is a parameter associated with the ratio of the gravity force to the capillary force, which is expressed as follows:

\[ c = \frac{b_0}{a_0} \]  

where \( a_0 \) and \( b_0 \) are two constants associated with capillary and gravity forces respectively. The two parameters determine the linear correlation between the imbibition rate and the reciprocal of the recovery by spontaneous imbibition in fluid-fluid-rock systems:

\[ q_w = a_0 \left( \frac{1}{R} - b_0 \right) \]  

Eq. 6 is similar to the linear model developed by Li and Horne for gas-liquid-rock systems but the expressions for the two constants here, \( a_0 \) and \( b_0 \), have different physical significance and are more complicated:

\[ a_0 = \frac{AM^*_{e}(S_{nf} - S_{wi})}{L} \]  

\[ b_0 = AM^*_{e} \Delta \rho g \]  

where \( \Delta \rho \) is the density difference between the wetting phase and the nonwetting phase (=\( \rho_w - \rho_{nw} \)). \( L \) is the length of the core sample. \( M^*_{e} \) is the global mobility of the two phases. For cocurrent spontaneous imbibition, the global mobility is calculated as follows:

\[ M^*_{e} = M^*_{nw} M^*_{cw} / M^*_{nw} \]  

where \( M^*_{nw} \) and \( M^*_{cw} \) are the wetting and nonwetting phase mobilities at \( S_{nf} \).

For countercurrent spontaneous imbibition, the expression of the global mobility is represented as follows:

\[ M^*_{e} = M^*_{nw} M^*_{cw} / M^*_{nw} + M^*_{cw} \]  

According to Eqs. 7 and 8, both capillary pressure (\( P^*_{cw} \)) and global mobility (\( M^*_{e} \)) can be calculated from spontaneous imbibition data. Unlike in gas-liquid-rock systems, relative permeability of each phase in oil-water-rock systems may not be inferred independently from spontaneous imbibition data. However, if the relative permeability of one phase is known, the relative permeability of other phase can be inferred using the calculated global mobility. Note that the water phase relative permeability at \( S_{nf} \) may be measured at the end of spontaneous water imbibition tests in the cocurrent imbibition cases if the experiments are conducted in a coreholder.

The procedure to calculate capillary pressure and the global mobility from the experimental data of spontaneous imbibition is described briefly in the following. The calculated imbibition rate is first plotted vs. the reciprocal of the recovery
(the amount of the wetting phase imbibed into the core in terms of pore volume). According to Eq. 6, a straight line is expected from which the values of the two constants, \(a_0\) and \(b_0\), could be obtained from a linear regression analysis. The capillary pressure, \(P_c^*\), at \(S_{wf}\) and the global mobility, \(M'_c\), could be then calculated using the following equations once the values of \(a_0\) and \(b_0\) are available:

\[
P_c^* = \frac{1}{S_{wf} - S_{wi}} \frac{a_0}{b_0} \Delta \rho g L \tag{11}
\]

\[
M'_c = \frac{b_0}{A \Delta \rho g} \tag{12}
\]

Eqs. 11 and 12 can be reduced to the models that we developed previously in gas-liquid-rock systems\(^2\). As stated previously, the gas phase mobility may be assumed to be infinite in comparison to the liquid phase mobility. In this case, \(M'_c\) is equal to \(M'_w\) according to Eq. 9. Using this, the general models proposed in this article (Eqs. 11 and 12) reduce to the models (Eqs. 19 and 20 in Ref. 2) for gas-liquid-rock systems.

**Results and Discussion**

The proposed approach in this article (represented by Eqs. 11 and 12) is general. The approach can be applied to most liquid-liquid-rock systems as well as gas-liquid-rock systems in which Eqs. 11 and 12 can be reduced. In a previous paper\(^2\), we proved the validity of the simplified forms of Eqs. 11 and 12 in gas-water-rock systems by conducting water imbibition into an air-saturated glass-bead pack. The core sample was positioned vertically and the water saturation profile was measured by an X-ray CT technique. We demonstrated that the capillary pressure calculated from the spontaneous imbibition data using the simplified forms of Eqs. 11 and 12 was close to that measured using a different method (an X-ray CT technique). The results in our previous paper\(^2\) also provide evidence of the validity of the general approach proposed in this study (represented by Eqs. 11 and 12). Only the results of capillary pressure calculated from spontaneous imbibition data in oil-water-rock systems are discussed in this section.

To demonstrate the application of the models in oil-water-rock systems, the experimental data of spontaneous water imbibition (with equilibrated fluids) by Schechter et al.\(^7\) were used. Schechter et al.\(^7\) conducted spontaneous water imbibition in rocks with different permeability. The results in rocks with permeability ranging from 15 to 500 md were used in this study. In each core sample, experiments were conducted at three different interfacial tensions (IFT) ranging from 0.10 to 38.01 mN/m. Gravity may play an important role in cases of low interfacial tensions and high permeability. Therefore gravity may not be neglected. According to Eq. 8, \(b_0\) is equal to zero if gravity is negligible. If so, Eq. 6 can be reduced to the form that we discussed in another paper\(^5\). In this case, however, capillary pressure and global mobility may not be inferred independently from spontaneous imbibition data if oil and water relative permeabilities are not available.

The experimental data\(^3\) of spontaneous water imbibition conducted at three different interfacial tensions in three core samples with different permeabilities are depicted in Figs. 1, 2, and 3. The permeability ranged from 15 to about 500 md and the interfacial tension ranged from 0.10 to 38.1 mN/m.

Fig. 1 shows the oil recovery in the units of OOIP (oil originally in place) in three different core samples in which spontaneous water imbibition tests were conducted at the same interfacial tension, 38.1 mN/m. The oil recovery in the two Berea sandstone samples increases with permeability. However the oil recovery by spontaneous water imbibition in the Indiana limestone with a much lower permeability (15 md) is greater than that in Berea sandstone samples with high permeabilities (100 and 500 md). This phenomenon is not consistent with the frequently used scaling rule, which will be explained later.

Fig. 2 shows the oil recovery by spontaneous water imbibition at an interfacial tension of 1.07 mN/m. The oil recovery in this case increases with permeability for all the three core samples. It can be seen from Figs. 1 and 2 that the effect of permeability on oil recovery by spontaneous water imbibition is different at different interfacial tensions.

The oil recovery by spontaneous water imbibition at a low interfacial tension of 0.10 mN/m is shown in Fig. 3. In this case, the oil recovery in the Indiana limestone sample is smaller than that in Berea sandstone samples with high permeabilities. However, the oil recovery in the two Berea samples increases with the decrease in permeability at later time of spontaneous water imbibition. This may be interpreted using the values of the global mobility and will be discussed in detail later.

The relationships between the imbibition rate and the reciprocal of the oil recovery by spontaneous water imbibition are shown in Figs. 4, 5, and 6. The solid lines in these figures are the linear fits to the experimental data. The fits are good in most cases for oil-water-rock systems with different permeabilities and interfacial tensions.

Fig. 4 shows the effect of rock permeability on the relationship between the imbibition rate and the reciprocal of oil recovery. The interfacial tension in this case was 38.1 mN/m. The reason to use a semilog coordination was because of the great difference among the imbibition rates in rocks with different permeabilities. The relationships between the recovery rate (equal to imbibition rate) and the reciprocal of the oil recovery by spontaneous water imbibition are linear, as foreseen by Eq. 6. The effect of permeability on the oil recovery rate is different in different rocks. The recovery rate in Berea increases with permeability. However the recovery rate in the 15 md Indiana limestone is greater than that in Berea sandstone samples with higher permeabilities (100 and 500 md) at the early period of spontaneous imbibition.

The effect of rock permeability on the relationship between the imbibition rate and the reciprocal of oil recovery
at an interfacial tension of 1.07 mN/m is shown in Fig. 5. In this case, the recovery rate increases with permeability in both Berea and the 15 md Indiana limestone. However, the effect of permeability on the recovery rate in Berea is less significant than in the case in which the interfacial tension was 38.1 mN/m. Note that the recovery rate in the 15 md Indiana limestone becomes smaller than that in Berea sandstone samples with higher permeabilities (100 and 500 md) at 1.07 mN/m. Compared the results in Fig. 5 to those in Fig. 4, it can be seen that the effect of rock permeability on the relationship between the imbibition rate and the reciprocal of oil recovery is different at different interfacial tensions.

The further decrease in interfacial tension had significant effect on the oil recovery rate. The results are shown in Fig. 6. In this case, the Berea sandstone sample with a permeability of 100 md had the maximum oil recovery rate. The fit between the linear model and the experimental data in Berea with a permeability of 500 md is not as good as those in other rock samples. The reason might be the large time intervals between data points.

The values of \( a_0 \) and \( b_0 \) were calculated according to the linear relationships between the imbibition rate and the reciprocal of oil recovery shown in Figs. 4, 5, and 6. The imbibition capillary pressures at a water saturation of \( S_{wf} \) in rocks with different permeabilities and at different interfacial tensions were then inferred using Eq. 11 with these values. The results are shown in Fig. 7. The calculated imbibition capillary pressure increases with interfacial tension in the three core samples (both Berea and Indiana limestone).

Also shown in Fig. 7 are the relationships between the imbibition capillary pressure and the permeability. The imbibition capillary pressure may increase or decrease with permeability, dependent on the interfacial tension. For example, the imbibition capillary pressure increases with decrease in permeability at 38.1 mN/m but increases with increase in permeability at 0.10 mN/m for the two Berea sandstone core samples. The Indiana limestone core sample with a low permeability of 15 md had a smaller imbibition capillary pressure than the Berea sandstone with a high permeability of 100 md at 38.1 mN/m. Note that the imbibition capillary pressures shown in Fig. 7 have different values of \( S_{wf} \).

Comparing the results in Fig. 7 to those shown in Figs. 1, 2, and 3, it may not be possible to conclude that the greater the imbibition capillary pressure, the faster the oil recovery rate. Actually one may explain this according to Eq. 6. It is not only the capillary pressure but also the global mobility that govern the oil recovery rate by spontaneous water imbibition. The capillary pressure may vary in a different way from the global mobility. For example, the global mobility may decrease but the capillary pressure may increase with the increase in interfacial tension, as we will show later.

According to Eq. 11, \( S_{wf} \) influences the magnitude of the imbibition capillary pressure. The values of \( S_{wf} \) may be different in different rock samples at different interfacial tensions, as shown in Fig. 8. It can be seen that \( S_{wf} \) increases with permeability but decreases with interfacial tension in the cases studied. In a previous paper\(^3\), we observed that \( S_{wf} \) could increase or decrease with increase in permeability in gas-water-rock systems. Wettability of fluid-rock systems is another important parameter that determines the values of \( S_{wf} \).

This may make the effect of permeability on \( S_{wf} \) more complicated.

The values of the global mobility, defined in Eq. 9 (for cocurrent) or Eq. 10 (for countercurrent), in rocks with different permeabilities and at different interfacial tensions were calculated using Eq. 12 with the values of \( b_0 \). These values were calculated according to the linear relationships between the imbibition rate and the reciprocal of oil recovery shown in Figs. 4, 5, and 6. The inferred data of the global mobility are shown in Fig. 9. One can see that the global mobility may increase or decrease with the increase in interfacial tension, which depends on the rock permeability and the range of interfacial tension. The global mobility increases with interfacial tension in the 15 md Indiana limestone core sample but decreases with the increase in interfacial tension in the 100 md Berea sandstone. The relationship between global mobility and interfacial tension is more complicated in the 500 md Berea sandstone. The global mobility first increases with interfacial tension and then decreases with the increase in interfacial tension.

Fig. 10 shows the effect of interfacial tension on the parameter \( a_0 \), which is referred to as the imbibition index because it is the value of \( a_0 \) that determines the oil recovery rate by spontaneous water imbibition. The imbibition index has a similar relationship with interfacial tension as the global mobility. However, the imbibition index is more consistent with the oil recovery rate than the global mobility. That is, the greater the imbibition index, the greater the oil recovery rate, as foreseen by Eq. 6. The phenomenon could also be observed by comparing the values of the imbibition index shown in Fig. 10 to the data of oil recovery rate in Figs. 1, 2, and 3.

In the following section, the paradoxical results of the relationships between oil recovery rate, permeability, and interfacial tension are discussed and explained using the calculated values of the imbibition index.

In a specific rock sample, the oil recovery rate may increase or decrease with the increase in interfacial tension. Cuic\(\text{ et al.}\)\(^8\) observed that oil recovery rate by spontaneous water imbibition increased with interfacial tension, which is consistent with the frequently used scaling dimensionless time defined as follows\(9^{10}\):

\[
t_D = \sqrt{\frac{k}{\phi \mu_m a_0^2 \sigma t}}
\]

(13)

where \( t_D \) is the dimensionless time, \( \sigma \) is the interfacial tension between the wetting and nonwetting phases, and \( \mu_m \) is the geometric mean of the viscosities of the two phases\(9\) or the viscosity of the water phase\(10\).

Schechter\(\text{ et al.}\)\(^7\) reported that oil recovery rate decreased with the increase in interfacial tension, as shown in Fig. 11.
The experimental phenomenon demonstrated in Fig. 11 is not consistent with Eq. 13. On the other hand, the Indiana limestone core sample with a low permeability (15 md) had a greater oil recovery rate than the Berea sandstone core samples with high permeabilities (100 and 500 md). The results shown in Fig. 1 are neither consistent with the frequently used scaling rule (see Eq. 13). However these experimental observations may not differ from that implied by the dimensionless time defined in Eq. 4.

As we already stated, not only the capillary pressure but also the global mobility governs the oil recovery rate by spontaneous water imbibition according to Eq. 6. The imbibition index includes the combined effects of the capillary pressure and the global mobility. It is also known that the process of spontaneous water imbibition is a two-phase flow. Therefore it is reasonable to characterize and scale up a multiphase flow using multiphase properties such as relative permeability (related to global mobility) instead of single-phase flow property such as permeability. Similarly, it is reasonable to use capillary pressure instead of only interfacial tension because capillary pressure includes the combined effects of interfacial tension and wettability, which is more general. It is certain that wettability influences spontaneous water imbibition significantly. All these considerations are included in the dimensionless time defined in Eq. 4 but not the traditional dimensionless time defined in Eq. 13.

Based on the discussion here, it may be seen that the dimensionless time defined by Eq. 4 is more universal and may be more representative of the true mechanisms that govern spontaneous imbibition. The fact that almost all the spontaneous water imbibition results in different rocks with different permeabilities and at different interfacial tensions could be scaled using the dimensionless time defined by Eq. 4 provides evidence of the validity of the analysis. Note that the same spontaneous water imbibition results could not be scaled using the traditional dimensionless time defined by Eq. 13.

An explanation of the paradoxical results shown in Fig. 1 is given in the following. Fig. 10 shows that the sequence of the values of the imbibition index at 38.1 mN/m is as follows: \( a_0 \) (15 md) > \( a_0 \) (500 md) > \( a_0 \) (100 md). This sequence is the same as that of the oil recovery shown in Fig. 1, as foreseen by Eq. 6. The similar phenomenon can be observed in the cases of 1.07 and 0.10 mN/m. This demonstrates that the calculated values of the imbibition index can explain why the imbibition rate in fluid-rock systems with a low permeability might be greater than that in fluid-rock systems with a high permeability.

In the case of Fig. 11, one can also use the calculated values of the imbibition index to explain why the oil recovery decreases with the increase in interfacial tension. The sequence of the values of the imbibition index in the Berea with a permeability of 100 md is as follows (see Fig. 10): \( a_0 \) (0.10 mN/m) > \( a_0 \) (1.07 mN/m) > \( a_0 \) (38.1 mN/m). According to Eq. 6, the oil recovery should have the same sequence, which is shown in Fig. 11.

Another question arises, that is, why the imbibition index decreases with the increase in interfacial tension. The imbibition index combines the effects of the capillary pressure and the global mobility which is associated with relative permeabilities of oil and water phases.

The increase in interfacial tension may result in a decrease in relative permeabilities. For example, Talash \(^1\) studied the effect of interfacial tension on oil-water relative permeabilities and observed experimentally that relative permeabilities of both oil and water phases decreased with the increase in interfacial tension. Amaefule and Handy \(^12\) reported similar results from displacement experiments in Berea sandstone. Amaefule and Handy \(^12\) found that interfacial tension influenced relative permeabilities significantly when interfacial tension was reduced to a specific value. The experimental data from Amaefule and Handy \(^12\) showed that oil and water relative permeabilities decreased with the increase in interfacial tension at a given water saturation.

In gas-oil-rock systems, Bardon and Longeron \(^13\) reported that both gas and oil relative permeabilities decreased with the increase in interfacial tension, especially for in low range of interfacial tension. Henderson et al. \(^14\) observed the similar relationship between relative permeability and interfacial tension in gas-condensate-rock systems. Li and Firoozabadi \(^15\) demonstrated theoretically that both the wetting and nonwetting phase relative permeabilities decrease with the increase in interfacial tension.

According to Eq. 10, the global mobility during the countercurrent spontaneous water imbibition may decrease as the relative permeabilities of the two phases decrease with the increase in interfacial tension. This is the case for the 100 md Berea sandstone sample shown in Fig. 9. Although the capillary pressure increases with interfacial tension (see Fig. 7), the calculated imbibition index decreases with the increase in interfacial tension for the 100 md Berea sandstone sample, as shown in Fig. 10. In this case, the oil recovery decreases with the increase in interfacial tension (see Fig. 11). The oil recovery by spontaneous imbibition may also increase with the interfacial tension, which depends on the comparison of the relative reduction of the global mobility to the increment of the capillary pressure as the interfacial tension increases.

The limitation of the approach proposed in this article is that the entire capillary pressure curve may not be extracted from spontaneous imbibition data. Instead, only the capillary pressure at a water saturation of \( S_{swf} \) can be extracted.

**Conclusions**

The following conclusions may be drawn according to our current study:

1. An approach was proposed to extract the imbibition capillary pressure and the global mobility from spontaneous imbibition data in oil-water-rock systems.
2. The calculated imbibition capillary pressure at \( S_{swf} \) increases with interfacial tension in the oil-water-rock systems with interfacial tension ranging from 0.10 to 38.1 mN/m.
3. The effect of permeability on the imbibition capillary pressure is different. The calculated imbibition capillary
pressure may increase or decrease with the increase in permeability, dependent on the interfacial tension.

4. The calculated global mobility and the imbibition index may increase or decrease with the increase in permeability and interfacial tension.

5. The values of $S_w$ decrease with the increase in interfacial tension.

6. The imbibition index is representative of oil recovery rate, which implies that the greater the imbibition index, the greater the oil recovery rate.

**Nomenclature**

- $a_0$ = imbibition index, L³/t
- $A$ = cross-section area of the core, L²
- $b_0$ = coefficient associated with gravity, L³/t
- $c$ = ratio of the gravity to the capillary force
- $g$ = gravity constant, L/t²
- $k$ = absolute permeability, L²
- $k_e$ = effective permeability of the two phases (but considered as one phase), L²
- $k_e^*$ = effective permeability of the two phases at $S_w$, L²
- $k_{nw}$ = effective permeability of the nonwetting phase, L²
- $k^*$ = relative permeability pseudofunction of the two phases at $S_w$
- $k_w$ = effective permeability of the water or the wetting phase, L²
- $k_w^*$ = relative permeability of the water or the wetting phase at $S_w$
- $L$ = core length, L
- $L_e$ = characteristic length, L
- $M_e$ = global mobility of the two phases, mL/t
- $M_e^*$ = global mobility of the two phases at $S_w$, mL/t
- $M_{nw}$ = mobility of the nonwetting phase, mL/t
- $M_w$ = mobility of the water or the wetting phase, mL/t
- $M_w^*$ = mobility of the wetting phase at $S_w$, mL/t
- $N_{w}$ = volume of water (or the wetting phase) imbibed into the core, L³
- $P_c$ = capillary pressure, m/Lt²
- $P_c^*$ = capillary pressure at $S_w$, m/Lt²
- $q_w$ = imbibition rate of the wetting phase, L³/t
- $R$ = recovery by spontaneous imbibition in the units of pore volume
- $R^*$ = normalized oil (or the nonwetting phase) recovery
- $S_w$ = water saturation behind imbibition front
- $S_w^i$ = initial water (or the wetting phase) saturation
- $t$ = imbibition time, t
- $t_i$ = dimensionless time defined by Eq. 4
- $t_{i0}$ = dimensionless time defined by Eq. 13
- $V_p$ = pore volume of the core sample, L³
- $\mu_e$ = the effective viscosity of the two phases (but considered as one phase), m/Lt
- $\mu_w$ = viscosity of water, m/Lt
- $\mu_{nw}$ = the geometric mean of the wetting and nonwetting phase viscosities, m/Lt
- $\sigma$ = interfacial tension, m/L
- $\phi$ = porosity
- $\rho_{nw}$ = density of the nonwetting phases, m/L³
- $\rho_w$ = density of the wetting phases, m/L³
- $\Delta \rho$ = density difference between the wetting and nonwetting phases, m/L³

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**References**


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Fig. 1: Oil recovery by spontaneous water imbibition in different rocks at IFT=38.1 mN/m².

Fig. 2: Oil recovery by spontaneous water imbibition in different rocks at IFT=1.07 mN/m².

Fig. 3: Oil recovery by spontaneous water imbibition in different rocks at IFT=0.10 mN/m².

Fig. 4: Relationship between imbibition rate and the reciprocal of oil recovery in different rocks at IFT=38.1 mN/m.

Fig. 5: Relationship between imbibition rate and the reciprocal of oil recovery in different rocks at IFT=1.0 mN/m.
Fig. 6: Relationship between imbibition rate and the reciprocal of oil recovery in different rocks at IFT=0.10 mN/m.

Fig. 7: Capillary pressures calculated in different rocks at different interfacial tensions.

Fig. 8: Effect of interfacial tension on $S_w$ in different rocks with different permeability.

Fig. 9: Global mobilities calculated in different rocks at different interfacial tensions.

Fig. 10: Imbibition index calculated in different rocks at different interfacial tensions.

Fig. 11: Oil recovery by spontaneous water imbibition in a 100 md Berea sandstone core7.