Dynamic capillarity during displacement process in fractured tight reservoirs with multiple fluid viscosities

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Abstract
Dynamic capillarity commonly exists for multiphase flow in porous media, during which fluid viscosity varies and has strong influence. Displacement experiments are conducted on water-wet, fractured tight rock at in situ pressure and temperature of an oil reservoir via a specially designed apparatus to investigate the effects of fluid viscosity on the dynamic capillarity. The dynamic effect in the matrix is examined through the measurement and calculation of capillary pressure, the dynamic coefficient, and the fluid flow behavior. The results show that with a higher oil viscosity: (a) both the steady and the dynamic capillary pressures reverse their directions more quickly and behave as larger resistances in the matrix; (b) the difference between the steady and the dynamic capillary pressures becomes around 5%-19% more significant; (c) water saturation changes more slowly corresponding to the lower water relative permeability, while oil relative permeability quickly becomes lower than that during the basic displacement process; and (d) the dynamic coefficient becomes 2-3 times higher, and the dynamic contact angle becomes 10%-25% larger, showing a more variable interface. A contact angle advancement coefficient is proposed to identify the significance of contact angle advancement and the competition between capillary pressure and viscous force. The findings of this study can help for better understanding of multiphase flow in tight reservoirs and enhancing oil recovery.

Keywords
capillary pressure, dynamic capillarity, fractured tight rock, multiphase flow, viscosity

1 INTRODUCTION
Capillary pressure is an important property that can affect multiphase flow during various physical and chemical process such as petroleum recovery and CO₂ storage.¹⁻⁴ During the fluid flow process, fluid viscosity varies caused by the mixing of different kinds of fluids, which can have strong influence on the dynamic capillarity and fluid flow.⁵,⁶ The dynamic capillarity means a dynamic effect on the capillary pressure; that is, \( P_c - S_w \) relationship not only depends on the fluid saturation, but also the time derivative of saturation \( \partial S_w / \partial t \). The fluid flow behavior is correspondingly affected by the dynamic capillarity.⁷ Figure 1 depicts the difference between the transient displacement process and the steady displacement process caused by the dynamic effect.⁸

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Several equations have been proposed to quantitatively demonstrate the dynamic effect on the \( P_c - S_w \) relationship,\(^9\)\(^{-11}\) and a widely used equation has been proposed by Hassanizadeh and Gray as follows\(^{12,13}\):

\[
P_c^d = P_{nw} - P_w = P_c - \tau \left( \frac{\partial S_w}{\partial t} \right) \tag{1}
\]

where \( P_c^d \) represents the dynamic capillary pressure, MPa, dependent on flow dynamics; \( P_c^d \) is the steady capillary pressure at equilibrium conditions, MPa, an intrinsic property of the porous medium-fluid system; \( \partial S_w / \partial t \) is the time derivative of the wetting fluid phase saturation, s; \( \tau \) is the dynamic coefficient, Pa·s; and \( P_w \) and \( P_{nw} \) denote the wetting and nonwetting phase pressure, respectively, MPa.

The dynamic effect is measured directly by the dynamic coefficient, \( \tau \). A large dynamic coefficient means that the disturbed equilibrium needs a long necessary time period to re-establish equilibrium through the change of fluid saturation.\(^{14}\) During the equilibrium displacement process, the capillary pressure is steady, while during the transient displacement process the capillary pressure is dynamic. If the disturbance in the system fades away within a short time period, the dynamic coefficient is nearly 0 and the difference between the dynamic capillary pressure and the steady capillary pressures can be neglected. In such cases, the steady capillary pressure can be applied to describe a transient fluid flow system, regardless of the dynamic capillary pressure. Such simplification helps to reduce the measurement difficulty because it is much more difficult to measure the dynamic capillary pressures than the steady ones. However, this replacement of the dynamic capillary pressures by the steady ones is unrealistic in most cases.\(^{15,16}\) Reasons are given as follows:

The dynamic effect depends on the fluid and material properties. The dynamic effect is stronger in a lower permeability porous media, as well as in a more heterogeneous porous media.\(^{17}\) Therefore, the dynamic effect is considerable in the fractured tight porous media, corresponding to the tight pore structure and the increased heterogeneity induced by the fractures.\(^{18-23}\) Such strong dynamic effect can cause noticeable difference between the steady and the dynamic capillary pressures, and consequently the considerably different fluid flow behavior between the transient and the steady fluid flow systems. Therefore, the dynamic capillary pressure and the dynamic relative permeability are supposed to describe the displacement process in these fractured tight porous media.

As mentioned above, fluid viscosity varies during various fluid flow process. Fluid viscosity influences significantly in the magnitude of dynamic effects.\(^{24}\) Recent theoretical and experimental studies have investigated the relationship between the dynamic coefficient and the fluid viscosity, but some results are conflicting.\(^{25,26}\) Stauffer\(^{25}\) proposed the early empirical relationship indicating that the value of \( \tau \) increases with the increase in water viscosity. Further, Dahle et al.\(^{24}\) Gielen et al.\(^{27}\) and Joekar-Niasar et al.\(^{25}\) found that the value of \( \tau \) increased with the increase in the viscosity ratio through their pore-network modeling, while Das et al.\(^{15}\) found the opposite trend by testing the variation of the dynamic coefficient in a series of drainage experiments at the core scale through numerical simulations.

Joekar-Niasar and Hassanizadeh\(^{28}\) illustrated that the value of \( \tau \) increased with the increase in the effective viscosity by the dynamic pore-network modeling. They defined the effective viscosity \( \mu_{\text{eff}} \) as follows:

\[
\mu_{\text{eff}} = \mu_n S_n + \mu_w S_w \tag{2}
\]

where \( S_n \) and \( S_w \) represent the dimensionless saturation of the nonwetting phase and the wetting phase, respectively, dimensionless; \( \mu_n \) and \( \mu_w \) represent the viscosity of the nonwetting phase and the wetting phase, respectively, Pa·s. This trend is verified by the primary drainage experiments of Goel and O’Carroll.\(^{29}\)

Although the aforementioned literatures have discussed the effects of fluid properties on the dynamic capillarity, limited experimental results can be found regarding the effects of fluid viscosity on the dynamic effect and the consequent fluid flow behaviors during the displacement process in fractured tight porous media, where the induced fractures considerably affect the capillary pressure and the

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**FIGURE 1** Difference between the transient and the steady displacement processes caused by the dynamic effect (revised from Li et al\(^{8}\)). (A) Water-wet rock at high flow rate or oil-wet; (B) Water-wet rock at low flow rate.

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**Key points**

- Effects of fluid viscosity on the dynamic capillarity are clarified specifically for fractured tight reservoirs.
- A contact angle advancement coefficient is proposed to identify the significance of contact angle advancement and forces competition.
- Fluid flow behaviors are detailed and analyzed to explore the role of dynamic capillarity.
fluid flow behavior. Therefore, this issue is particularly investigated in this work through displacement tests on water-wet fractured tight cores. Specially designed apparatus is employed to determine the dynamic capillary pressure during the displacement processes in fractured tight rock samples. Experimental procedures and methodologies, aimed at the displacement processes under the in situ conditions of a fractured tight oil reservoir, are employed to determine the time derivative of water saturation, relative permeability, and the dynamic contact angle in the fractured tight rock samples.

Contact angle is vital for a precise prediction of capillarity-dominated fluid flow in porous media. Such contact angle has been explored by numerous experimental and theoretical studies. There are several theoretical contact angle models at multiscale levels, such as the hydrodynamic model at the macroscopic level, the molecular kinetic theory at the microscopic level, and the combined model at the mesoscopic level. However, most of these models are complex regarding the engineering application. If these models can be integrated to describe the displacement process in a simple way, the application of these models can be more accessible in engineering propose. Thus, in this work a contact angle advancement coefficient is proposed through the combination of the microscopic and the macroscopic contact angle models. Such contact angle advancement coefficient is simple, useful, and accessible to identify the competition between the dynamic capillary pressure and the viscous force, and the significance of the contact angle advancement.

This paper is organized as follows. First, we present the experimental materials, apparatus, procedures, and methodologies to show how the experimental tests are conducted and how the results are calculated in Section 2. Thereafter, we discuss the effect of fluid viscosity on the dynamic capillary pressure and thus on the flow paths during the displacement process in the fractured tight porous media in Section 3.1. After that, we analyze the effect of fluid viscosity on the dynamic effect directly from the dynamic coefficient and find the functional relationship between the fluid viscosity and the dynamic effect in Section 3.2. Fluid flow behavior is explored to show the effect of fluid viscosity on the change of fluid saturation, fluid flow characters, and the moving fluid-fluid interfaces in Section 3.3. We define a contact angle advancement coefficient through the combination of the molecular kinetic theory and the hydrodynamic model to identify the impact of dynamic capillary pressure and the significance of contact angle advancement in Section 3.4. Finally, conclusions are summarized in Section 4.

2 | MATERIAL AND METHODS

2.1 | Materials

The experimental rock samples selected in this work are tight sandstone cores collected from a tight oil formation through sealed coring. The average formation pressure is 14.5 MPa, and the temperature is 60°C. Pendant-drop method is employed to measure the wettability of the rock samples under 60°C (Figure 2), which shows that the contact angle ranges from 36.6° to 41.1° with the average contact angle of 39.0°. It can be easily known that the rock is water-wet, and the wettability shows small difference.

The rock samples were cleaned by pressuring methanol and toluene to remove the nonaqueous phase liquid and brine. Then, they were dried in an oven for 3 days and vacuumed to remove any air. Permeability and porosity of the rock samples were both measured under the in situ effective stress in the formation. Fractures were then generated in the laboratory. Three fractured rock samples were used for the displacement tests. Properties of the rock samples are listed in Table 1. Typical rock samples fractured in the laboratory are shown in Figure 3.

Viscosity of the formation oil was measured to be 1.13 mPa·s at the formation temperature under atmospheric pressure. Based on the properties of the formation oil, two kinds of formulated oil with different viscosities were adopted as the nonwetting phase in the experiments. One kind of the formulated oil (basic oil) is the diluted formation oil (formation oil: diesel oil = 1:3), which is particularly prepared for the basic displacement experiments. On the one

| Rock sample | \( K_{aw} \) (µm²) | Porosity (%) | Length (cm) | Diameter (cm) |
|-------------|---------------------|--------------|-------------|---------------|
| #1          | 0.171               | 9.5          | 4.11        | 3.88          |
| #2          | 0.237               | 10.3         | 4.17        | 3.83          |
| #3          | 0.329               | 10.0         | 4.16        | 3.79          |
hand, the viscosity of the formulated oil is smaller than the formation oil at the room temperature so that the original oil saturation can be achieved at the room temperature by vacuuming and pressuring the rock samples with the formulated oil. On the other, the viscosity of the formulated oil is close to the formation oil at the formation temperature so the displacement process in the laboratory is similar to that in the formation. The other kind of the formulated oil (viscous oil) was formulated by adding some heavy oil to the basic oil. As such, the impact of different oil viscosities on the dynamic capillarity can be investigated.

Total salinity of the formation brine is 41.04 g/L, density is 1.017 g/cm³, electrical resistivity is 0.102 Ω·m, and viscosity is 0.488 mPa·s at the formation temperature.

2.2 | Apparatus

Special apparatus (see Figures 4 and 5) designed to measure the dynamic capillary pressure of tight porous media was employed to examine the dynamic effect during the displacement process in the fractured tight column samples. Two important parts of the apparatus are the modified pressure transducers (PTs) and the LCR meter (type TH2810D), respectively. As for the pressure transducers, semipermeable plates and probes are fixed in them, with the probes in contact with the rock sample sides. The semipermeable plates (ceramic, 1500 psi) are durable enough to bear the high imposed pressure, which fits the displacement process in the tight rock samples where the high injection pressure is applied. The pressure transducers allow single-phase fluid flows from the rock surface, through the plates and finally to the pressure-sensitive sensor, thus measuring single-phase pressure. The selectivity of the semipermeable plates was demonstrated by single-phase flow and then the outflow blockage, which shows no signal changes of the sensors (permeable for the other phase). The LCR meter measures the electrical resistivity of the column segment between two probes, which ensures stable measured data for tight porous media. The calculated accuracy of the phase saturation is 1%.

Attitude of the center of the two LCR meter probes and the pressure transducers is the same, so the measured water/oil pressure and water/oil saturation match each other. The water saturation and the capillary pressure are measured at the middle part of the core samples to avoid the capillary pressure discontinuity at the outflow face of the domain.

2.3 | Experimental procedures

The experimental procedures were conducted through the described setup above as follows:

1. Establish the original fluid saturations. Since the rock is tight, the establishment of the original water and oil saturation is special. The core samples were cleaned, dried, and rolled on a permeable porous sheet which was saturated with water. The roll of the core samples enables water to be imbibed from the permeable porous sheet to the core samples, and this process was stopped until the original water saturation was achieved. The core samples were vacuumed for 4 hours to enable the water in the sample to distribute evenly. Then, the core samples were pressured with the oil for 24 hours under the average formation pressure 14.5 MPa.
2. Prepare the experimental rig. The semipermeable plates and fluid were firstly vacuumed. The semipermeable plates were immersed in the fluid (oil-wet plates in the formulated oil and water-wet plates in the brine), then vacuumed again, and fixed in the pressure transducers. The PTs probes and the LCR meter probes pierced through the core holder and contact the core surface. Seal tests were conducted to show there was no leakage in the experimental rig.
3. Establish the in situ condition. The confining pressure was slowly increased to make the effective stress close to the in situ formation condition, 25.5 MPa. The back pressure was set to be 2.5 MPa. Temperature was raised to 60°C.
4. Conduct transient displacement tests. For the transient displacement process, the injection pressure gradually increased until it was stable at 5 MPa. The local oil pressure \( P_{oj} \), local water pressure \( P_{wj} \), the local water saturation \( S_{wj} \), and total oil outflow \( V_{oi} \) were recorded at every 5 seconds.
5. Conduct steady displacement tests. For the steady experimental test, the injection pressure increased at a minimum value of 0.1 MPa, equilibrium flow (oil outflow is close to 0, and the electrical resistivity of the core sample is stable) reached at each step before the injection pressure further
increased. Similar to the transient displacement tests, the $P_{op}$, $P_{w}$, $S_{w}$, and $V_{oi}$ were recorded at every 5 seconds. The capillary end effects are eliminated since the pressure difference of the displacement tests is high enough and the back pressure is set to be 2.5 MPa. In addition, the phase pressure and the water saturation were measured at the sides rather than the end of the core samples, which prevents the capillary end effects from affecting the measured data.

2.4 | Experimental methodologies

Considering the effects of the response characteristics of the sensors, the in situ single-phase pressure is corrected according to Hou et al. The in situ water saturation at each time $t_n$ is calculated using the method proposed by Li et al., which is more accurate for tight porous media than Archie’s formula. The in situ time derivation of water saturation ($\frac{dS_w}{dt}$) can be calculated as:

$$\frac{dS_w}{dt} = \frac{S_{n+1} - S_n}{t_{n+1} - t_n} \tag{3}$$

where $S_{n+1}$ is the water saturation at time $t_{n+1}$, and $S_n$ is the water saturation at time $t_n$.

The average capillary pressure and the average water saturation of the whole core sample at each time $t_n$ are calculated using the same way presented in our previous work.

The thickness of the boundary layer is suggested to be associated with the pore radius of porous media, the displacement gradient, and the fluid viscosity. In this work, the

FIGURE 4 Experimental apparatus to examine the dynamic effect during the displacement tests for the fractured tight rock samples

FIGURE 5 Cross-sectional view of the core holder (left) and the semipermeable plates (right)

- Oil-wet semi-permeable plates
- Rubbersleeve
- PTs
- Water-wet semi-permeable plates
- Core
- Liquid collector
- LCR meter probes
- Back pressure valve
- Pressure transducer
- Inflow
- Outflow
- Pump
- Data logger
- Oven
- Water container
- Oil container
- Pressure transducers with semipermeable plates
- Pressure transducer
- $N_2$
following empirical model proposed by Cao et al.\textsuperscript{41} is employed to estimate the boundary layer thickness:

\[
    h = \begin{cases} 
    r \cdot 0.25763 e^{-0.261 r (\nabla p)^{0.419} \mu}, & |\nabla p| < 1 \text{ MPa/m} \\
    r \cdot 0.25763 e^{-0.261 r} \mu, & |\nabla p| > 1 \text{ MPa/m} 
\end{cases}
\]

(4)

where \( h \) represents the boundary layer thickness, \( \mu \); \( r \) stands for the pore radius, \( \mu \); \( \nabla p \) denotes the displacement pressure gradient, \( \text{MPa/m} \); and \( \mu \) represents the fluid viscosity, \( \text{mPa} \cdot \text{s} \). Such boundary layer narrows the effective fluid flow radius, which can be defined as:

\[
r_e = r - h
\]

(5)

Therefore, the dynamic contact angle \( \theta_d \) can be calculated by:

\[
    \theta_d = \arccos \left( \frac{10^3 r_e p_c}{2 \sigma} \right)
\]

(6)

where \( p_c \) is the measured capillary pressure, \( \text{MPa} \); and \( \sigma \) is the interfacial tension, \( \text{mN/m} \).

The capillary pressure is integrated into the calculation of oil/water relative permeabilities at each time \( t \); thus, the models are obtained as follows:

\[
f_o(S_w) = \frac{d \bar{V}_o(t)}{d \bar{V}(t)}
\]

(7)

\[
K_{ro} = f_o(S_w) \frac{d[1/\bar{V}(t)]}{d[1/\bar{V}(t)]}
\]

(8)

\[
K_{rw} = K_{ro} \frac{\mu_w (1 - f_o(S_w))}{\mu_o f_o(S_w)}
\]

(9)

\[
I = \frac{Q(t)}{Q_o} \frac{\Delta p_{ini} - p_{cini}}{\Delta p(t) - p_c(t)}
\]

(10)

where \( f_o(S_w) \) represents the fraction of oil phase in the oil-water mixture; \( \bar{V}_o(t) \) and \( \bar{V}(t) \) represent the cumulative oil and liquid production, respectively, \( \text{PV} \); \( K_{ro} \) and \( K_{rw} \) stand for the relative permeability of oil and water, respectively; \( Q_o \) is the initial flow rate, \( \text{cm}^3/\text{s} \); \( I \) is the relative injectivity, the ratio of the intake capacity of the porous rock at time \( t \) to that at the initiation of the displacement; \( Q(t) \) is the flow rate at time \( t \), \( \text{cm}^3/\text{s} \); \( \Delta p(t) \) denotes the displacement pressure difference at time \( t \), \( \text{MPa} \), in this work \( \Delta p(t) = \Delta p_o \) and \( \Delta p_{ini}) \) \( P_{ini} \) and \( p_c(t) \) denote the initial displacement pressure difference, the initial capillary pressure, and the capillary pressure at time \( t \), respectively, \( \text{MPa} \).

3  RESULTS AND DISCUSSION

The oil production and the resistance of the fluid flow are mainly form the matrix, which is strongly affected by the dynamic capillarity. The dynamic effect in fractures can be neglected due to the high permeability and low capillary pressure of fractures.\textsuperscript{44} Thus, we only consider the dynamic capillary pressure, the dynamic coefficient, and the dynamic contact angle in the matrix in this work. The time derivative of water saturation and the relative permeability are measured for the whole core sample.

3.1  Dynamic capillary pressure-saturation imbibition curves

The dynamic effect is directly expressed by the capillary pressure. For fractured rocks, the average capillary pressures rather than the capillary pressures of one location are investigated, thus avoiding the measurement errors caused by fractures and representing the capillary pressure for the whole matrix. Figure 6 shows the typical average capillary pressure curves with the different oil viscosities during the displacement process in the fractured tight rocks. Different observations can be found from the experimental data and the curves.

The first point is that the capillary pressure in tight rocks is very high compared with that in the high to medium permeability (\( \geq 1 \mu \text{m}^2 \)) rocks measured by the previous studies,\textsuperscript{20,45} which is a feature of tight rock from its micro/nanopores. Both the steady and the dynamic capillary pressures reverse their directions at the early stage of the displacement process. This indicates a contact angle advancement from the originally water-wet condition before the displacement to oil-wet condition during the displacement process, and that the role of the capillary pressure changes from a driven force to a capillary trapping force (resistance).\textsuperscript{46} The second point is that both the steady and the dynamic capillary pressures reverse more quickly and behave as a larger resistance during the displacement process caused by the higher oil viscosity. In addition, the difference between the steady and the dynamic capillary pressure becomes more significant (around 5%-19% more notable) with the viscous oil. It demonstrates that the dynamic effect in capillary pressure is stronger with a higher oil viscosity.

The dynamic effect can be attributed to the fact that the water-oil interfaces tend to change positions at the pore scale; thus, the fluid system reaches an equilibrium between the dynamic capillary pressure and the viscous forces.\textsuperscript{47-49} If the oil viscosity changes, the viscous forces would change accordingly, and the water-oil interfaces will move to a new equilibrium position, with the capillary pressure varying at this new equilibrium position. In turn, the dynamic capillary pressure affects the stability of the displacement front, which
influences the formation of preferential flow paths and leads to early breakthrough of the displacing liquid. Additionally, a higher oil viscosity enlarges the time for a fluid interface to rearrange and the free energy to minimize.\textsuperscript{50}

\subsection{3.2 Dynamic coefficient}

The dynamic coefficient is a direct measurement of the dynamic effect. The dynamic coefficient varies over several orders of magnitude in different porous media and is generally higher in less permeable rocks.\textsuperscript{51} In this work (typical results see Figure 7), although fractured, the rock samples show higher dynamic coefficient compared with the results of previous studies where the relative permeabilities of the tested porous media are higher.\textsuperscript{52} Moreover, the dynamic coefficient becomes 2-3 times higher with the viscous oil, which verifies that the dynamic effect causes a more pronounced gap between the dynamic and the steady capillary pressures with a higher oil viscosity in the fractured capillary pressures. Note that the dynamic effect is extremely sensitive to experimental measurements, which may contribute to the higher dynamic coefficients with viscous oil system.\textsuperscript{5}

The fluid properties affect the stability of fluid-fluid interfaces and consequently the dynamic coefficient. At a given saturation for drainage, a lower value of $\tau$ indicates a more stable front,\textsuperscript{15} which can explain the results of this work. As the permeability of the porous rocks decreases, or the oil viscosity increases, the stability of the fluid front decreases, and thus, the dynamic coefficient is higher for the tight rocks and higher for a higher oil viscosity. Moreover, the stability of the fluid-fluid interface is strongly influenced by the fluid/fluid/solid contact line friction, which is a contributing factor of the dynamic effect.\textsuperscript{53} As the oil viscosity increases, the fluid/fluid/solid contact line friction increases,\textsuperscript{29} and thus, the dynamic effect becomes more significant.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure6.png}
\caption{Typical dynamic capillary pressure-saturation imbibition curves during the displacement tests in the fractured core samples with different oil viscosities (for core #1: (A) capillary pressure with the basic oil, (B) capillary pressure with the viscous oil, (C) steady capillary pressure, and (D) dynamic capillary pressure)}
\end{figure}
The experimental data are well correlated according to the power-law relationship of Civan\(^6\) as shown in Equation (15), and the best estimates of the power-law parameters are given in Table 2.

\[
\tau = \frac{\mu_e^b}{(S_w - S_{wi})^a}
\]  

(11)

Based on the power-law relationship, the relationship between the oil viscosities and the dynamic coefficient was examined. Contrary to the previous researches, the dynamic coefficient in this work is found to be proportional to another parameter, \(\mu_{ew}\), defined as the effective relative viscosity particularly in this work.

\[
\mu_{ew} = (\mu_o S_o + \mu_w S_w) / \mu_w
\]  

(12)

The dynamic coefficient is normalized by the effective relative viscosity, as plotted in Figure 8, to better represent the relationship between the dynamic coefficient and the fluid viscosity.

### 3.3 Fluid flow behavior

The dynamic effect can be reflected by the fluid flow behavior. In this work, the variation rates of the water saturation and the relative permeability are investigated to explore the characteristics of the dynamic effect with the different oil viscosities during the displacement process in the fractured rock samples.

#### 3.3.1 Time derivative of water saturation

Figure 9 displays the time derivative of water saturation \(\partial S_w / \partial t\), which shows the variation rate of the water saturation in the rock samples. Water saturation increases more slowly with the viscous oil, which means that the injected water transports more slowly in the rocks with the higher oil viscosity, and thus, the displaced oil transports more slowly. Although the saturation varies more slowly for the displacement process with the viscous oil, the dynamic effect is much stronger, and the steady capillary pressure is higher, so the dynamic capillary pressure is higher and the difference between the steady and the dynamic capillary pressures is more significant. It can be concluded that both the viscous forces

### Table 2

| Rock sample | Oil     | \(a\)  | \(b\)  | \(R^2\)  |
|-------------|---------|--------|--------|----------|
| #1 Basic    | -0.3962 | 25.759 | 0.966  |
| #1 Viscous  | -0.4606 | 27.214 | 0.9609 |
| #2 Basic    | -0.2745 | 25.02  | 0.9433 |
| #2 Viscous  | -0.3214 | 25.94  | 0.9322 |
| #3 Basic    | -0.1485 | 24.146 | 0.9211 |
| #3 Viscous  | -0.1987 | 26.734 | 0.9544 |

### Figure 7

Typical dynamic coefficient during the displacement process in the fractured porous rocks samples with different oil viscosities.

### Figure 8

The typical normalized dynamic coefficient during the displacement process in fractured tight porous rock samples with different oil viscosities.

### Figure 9

Typical time derivative of water saturation during the displacement tests in the fractured tight porous rocks samples with different oil viscosities.
and the dynamic capillary pressures, acting as resistances, were strengthened with a higher oil viscosity.

### 3.3.2 Relative permeability

Typical relative permeability during the steady and the transient displacement processes in the fractured tight rocks is illustrated in Figure 10. Oil relative permeability, for the displacement process with the viscous oil, is higher and then quickly becomes lower than the one for the displacement process with the basic oil. This may be related to the slightly higher capillary pressure with the viscous oil, which is very temporarily a driving force at the very early stage of the displacement processes and then very quickly becomes a resistance. Water relative permeability, for the displacement process with the viscous oil, is always lower than that of the displacement process with the basic oil. This may be resulted from the higher viscous forces with the viscous oil.

Relative permeability responds to the change of capillary pressure\(^9,11\) and also reflects the stability of the displacement front. The quick decrease in the oil relative permeability demonstrates the more nonuniform front during the displacement process with the viscous oil. The water relative permeability illustrates that water flows more difficultly and moves more slowly with the higher oil viscosity. In view of these conditions, the preferential flow paths form more easily, and the displacing liquid breaks the front at a smaller water saturation with the higher oil viscosity, which is unfavorable for the production in tight oil reservoirs.

### 3.3.3 Dynamic contact angle

Moving fluid-fluid interfaces can generate more pronounced dynamic effects, which causes the variation in dynamic contact angle\(^54,55\). This dynamic contact angle is velocity dependent during the displacement process and is quite different from its equilibrium value\(^54,56\). There are two typical models to describe the relationship between the moving velocity and the dynamic contact angle: the hydrodynamic model and the molecular kinetic theory. These two models were combined by Shikhmurzaev’s model\(^57,58\). Whether the viscosity dissipates in the hydrodynamic model, or the energy dissipates during the interfacial creation and destruction process in the molecular kinetic theory, the viscosity of fluid acts as a vital role, although the hydrodynamic model is based on the Navier-Stokes equations\(^33\).

The minimal pore radius allowing fluid flow is proposed to be approximately 20 nm\(^59\). The contact angles of these pores were calculated through Equation (6) to explore the characteristics of the dynamic contact in this study. As the typical results shown in Figure 11, the dynamic contact angle in the 20 nm pore of the rock samples is 10%-25% larger for the displacement process with the viscous oil. The dynamic contact angle, similar to the relative permeability, reflects the stability of the fluid-fluid interface\(^60,61\). Therefore, it can be concluded that the higher oil viscosity causes a more variable interface from the characteristics of the dynamic contact angle in this study.

In addition, the dynamic contact angle advancement in the 20 nm pores increases with the displacement; that is, dynamic contact angle advancement occurs continually during the displacement process. This indicates that a high contact line friction exists in the pores which slows down the velocity of the interface\(^32\). Therefore, the injected water essentially flows mainly into larger pores, hindered not only by the dynamic capillary pressure but also the contact line friction, and a sharp front forms at the initiation of the water drainage process. Later the forced imbibition overcomes these hindering forces and develops the diffusion zone.

### 3.4 Contact angle advancement coefficient

The molecular kinetic theory and the hydrodynamic model are the typical models to describe the dynamic contact angle during the dynamic wetting process, such as the transient...
capillary flow in this work. In the hydrodynamic model, the difference between the dynamic and the equilibrium contact angles can be reduced to\textsuperscript{35}:

\[
\theta_d^3 = \theta_s^3 + 9CaH \quad \text{(13)}
\]

\[
H = \ln \frac{L_m}{L_a} \quad \text{(14)}
\]

where \(\theta_d\) and \(\theta_s\) are dynamic and equilibrium contact angles, respectively. \(\circ\). \(L_m\) and \(L_a\) are appropriate macroscopic and microscopic length scales, respectively, m. \(Ca\) is the dimensionless capillary number.

In the molecular kinetic theory, the relationship between the dynamic and the equilibrium contact angels can be expressed as\textsuperscript{36}:

\[
\nu = \frac{\sigma}{\xi} (\cos \theta_s - \cos \theta_d) \quad \text{(15)}
\]

where \(\xi\) is the frictional coefficient between liquid and solid surface at the three-phase contact line, characterizing the interactions between the solid and liquid molecules, Pa·s. It increases with the increase in the solid-liquid adhesion work. \(\sigma\) is the interfacial tension, mN/m.

Combining the hydrodynamic model and the molecular kinetic theory, a contact angle advancement coefficient \((Al, \text{Pa}^{-1} \cdot \text{s}^{-1})\) is obtained and defined as:

\[
Al = \frac{H}{\xi} = \frac{\theta_d^3 - \theta_s^3}{9\mu_w(\cos \theta_s - \cos \theta_d)} \quad \text{(16)}
\]

With the larger the \(Al\), the contact angle tends to be more hysteretic and the impact of the dynamic capillary pressure becomes greater, while the viscous force tends to be less influential.

**FIGURE 11** Typical dynamic contact angle during the displacement process in the fractured tight porous rock samples with different oil viscosities.

**FIGURE 12** Contact angle advancement coefficient in the fractured porous rocks samples with the different oil viscosities.

Figure 12 depicts the influence of oil viscosity on the contact angle advancement coefficient in the 20 nm radius pores in the tested fractured tight porous rocks. It can be seen that the contact angle advancement coefficient increases with the higher oil viscosity, which indicates that the contact angle tends to be more hysteretic, and the dynamic capillary has greater influence on the fluid flow.

**4 | SUMMARY AND CONCLUSIONS**

In this work, specially designed experiments are carried out to reveal the effect of fluid viscosity on the dynamic effect and thus the capillary pressure and the fluid flow behavior during the displacement process in fractured tight rocks. The contact angle models are integrated, and a contact angle advancement coefficient is proposed to describe the displacement process in a simple and useful way.

1. The dynamic effect of capillary pressure is stronger with a higher oil viscosity, which is directly expressed by the behavior of the steady/dynamic capillary, and reflected by the relative permeability of water/oil, the time derivative of water saturation, and the dynamic contact angle.

2. The dynamic capillary pressure affects the stability of the displacement front, so the preferential flow paths form earlier, and the displacing liquid breaks earlier with a higher oil viscosity.

3. The contact angle advancement coefficient increases as the oil viscosity becomes larger, which indicates that the contact angle tends to be more hysteretic, and the dynamic capillary pressure has greater influence on the fluid flow with a higher oil viscosity.

Note that the permeability of the rock samples in this work has not reached the minimum values of the tight rock, and we did not consider this critical case. In the future...
work, we will use more tight rock samples in our experiments to extend the application scope of our research.

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**SUPPORTING INFORMATION**

Additional supporting information may be found online in the Supporting Information section.

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