Analysis of the Static and Dynamic Imbibition Effect of Surfactants and the Relative Mechanism in Low-Permeability Reservoirs

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ABSTRACT: Establishing an effective displacement system for conventional water flooding development in low-permeability reservoirs is difficult, with generally low liquid and oil production and a worse water flooding effect. Imbibition oil recovery technology has received increasing attention from oil development workers because of its simple operation, low cost, and good oil increase effect. To explore the method and mechanism to further improve the effect of imbibition oil recovery, we study the imbibition and oil recovery effect and its influencing factors in a low-permeability reservoir in the Dagang Oilfield based on evaluation indexes of the adhesion work reduction factor, ratio of capillary force to gravity $N_{C/G}^{-1}$, regression analysis of the recovery rate of imbibition, proportional relationship with spontaneous imbibition, and dynamic imbibition effect in crack rocks. Results show that the interfacial tension of the surfactant on the imbibition process has a dual effect. The selection of the surfactant for fractured tight reservoirs should not excessively pursue ultralow interfacial tension, and it should consider the surface wettability environment favorable for imbibition to ensure that a sufficient driving force can be provided. In the initial imbibition stage, the capillary force is large, the velocity of water imbibition in pores is fast, and the oil recovery rate is high; the holding time of the imbibition process is important to imbibition recovery. With the increase in imbibition time, the capillary force weakens, and the imbibition speed decreases to zero. With the increase in injection volume, reservoir pressure, pressure holding time, and imbibition cycles, the oil recovery increases, but the amplification of oil recovery decreases. From the technical and economic viewpoints, the optimal slug size, throughput cycle, and pressure holding time of the target reservoir are recommended as follows: 0.5 PV, three 3 rounds, and greater than 96 h, respectively.

1. INTRODUCTION

In recent years, with the rapid growth of global oil demand, the proportion of low-permeability oilfield reserves in proven recoverable reserves has been increasing day by day, but low-cost and efficient exploitation of such reservoirs have gradually become a problem of increasing concern for petroleum scientists and technicians.1–5 To meet the development needs of similar reservoirs, petroleum scientists and technologists have put forward forward measures to improve the development effect, such as cyclic water injection,6,7 acid fracturing8–9 and imbibition oil recovery,10,11 based on the geological characteristics and water drive mechanism of low-permeability oilfields. Among them, imbibition oil recovery technology has received considerable attention because of its simple operation, low cost, and good oil increase effect.12–15 Since the 1950s, many studies have been performed on the mechanism and the law of imbibition and displacement of wetted phase fluids through capillary force in porous media. Aronofsky et al. first derived the equation of the percolation and displacement index.16 Rapoport proposed the percolation and displacement index,17 Gharam and Richardson18 and Mannon and Chilingar19 performed percolation experiments using triangle and square models. Mattax and Kyte20 and Parsons and Chaney21 carried out bottom water rising and imbibition experiments, and the relationship curve between the recovery factor and dimensionless time was obtained. Ifly et al.22 completed the submergence imbibition experiments by the weighing method and capillary method, consistent with the bottom water rising test results. At present, Dagang Oilfield has 412 million tons of proven geological reserves in a low-permeability reservoir of which 163 million tons have been put into development. This accounts for 39.6% of the total low-permeability geological reserve in which 249 million tons have not been put into...
development, accounting for 60.4% of the total low-permeability geological reserves. The deep low-permeability reservoir is one of the main development areas of the Dagang Oilfield, which has clear low-permeability characteristics. However, there are many problems in the development process, such as poor water flooding effect, difficult water injection, and rapid decrease of oil production. Therefore, in response to the development requirements of the low-permeability fractured reservoirs in the Dagang Oilfield, this study considers the adhesion reduction factor and the ratio of capillary force to gravity as the evaluation indicators to describe the change of the oil washing efficiency and capillary force of the surfactant during the imbibition process. Experimental studies on the effects of surfactant types, injection slug size, reservoir pressure, pressure holding time, and imbibition cycles on the imbibition effect and the related mechanism analysis were performed, providing a theoretical basis for imbibition recovery technology in low-permeability reservoirs.

2. EXPERIMENTAL CONDITIONS

2.1. Experimental Materials.

2.1.1. Surfactant. The surfactant includes the agent PO-FASD (referred to as "PO-FASD", effective content 35%) provided by CNOOC Oilfield Services Company and BHS-01A (referred to as "BHS", effective content 40%) and a nanometer displacement agent (referred to as "PQJ", effective content 100%) provided by the Dagang Oilfield Branch Company.

2.1.2. Oil and Water Samples. The experimental water is simulated injected water, and its ion composition is shown in Table 1. The experimental oil is taken from the well head in the Dagang Oilfield, and the viscosity of degassed crude oil is 23.8 mPa·s at 75 °C.

2.1.3. Core. Artificial cores were used in the experiment, which were made of quartz sand cemented with epoxy resin with a pore structure and permeability similar to those of cores found in the Dagang reservoir. Cores with different permeabilities can be made by changing the grain size of quartz sand and the consumption of epoxy resin. The core used in the static imbibition experiment is an artificial columnar core, with a core geometric size of Φ 2.5 cm × 5 cm and a permeability $K = 5 \times 10^{-3} \mu$m². The core is used in the dynamic imbibition experiment (see Figure 1). The geometric dimensions, height × width × length, are 4.5 cm × 4.5 cm × 30 cm, respectively.

2.2. Instruments and Equipment. The experimental equipment mainly includes an advection pump, a pressure sensor, a core holder, a hand pump, and an intermediate container. With the exception of the advection pump and hand pump, other parts are placed in the incubator of an experimental temperature of 75 °C. The diagram of the experiment is shown in Figure 2.

2.3. Experimental Methods.

2.3.1. Making Method of Water-Wet Artificial Core. The wettability of the target reservoir rock is water-wet; thus, the artificial core must have similar wettability. At present, the wettability of the quartz sand epoxy resin-cemented core is weakly lipophilic; therefore, the epoxy resin needs to be modified to be water-wet. In this study, propylene glycol methyl ether was used as the solvent, and a certain proportion of epoxy resin and modifier polyethylene glycol were stirred evenly at 60 °C. Then, the temperature was raised to 80 °C, ammonium persulfate was added into the catalyst, and the reaction was carried out for 6 h under stirring conditions, yielding the water-wet epoxy resin after vacuum distillation. Then, according to the predetermined mass ratio (water-wet epoxy: common epoxy: curing agent phenolic amine = 0.8:5:1), the water-wet epoxy resin, common epoxy resin, curing agent phenolic amine, quartz sand, and clay are
mixed and stirred evenly. This mixture is then placed in the metal mold for pressurization and then placed in a constant temperature box at 45 °C for 12 h to obtain the artificial water-wet core.

2.3.2. Steps of Imbibition Experiment. 2.3.2.1. Static Imbibition Experiment. (1) The core was dried, weighed, and saturated with formation water, the wet weight was weighed, and the pore volume was calculated.

(2) Complete oil flooding (the core was saturated with oil) in the core holder at the temperature of the reservoir was performed, and it was left to stand for 24 h to calculate the oil saturation.

(3) Simulated injection water was used to prepare a surfactant, and the surfactant solution for 2–3 h was evacuated to eliminate the adverse effects of dissolved gas on the core imbibition and oil production.

(4) The oil slick on the surface of the core was wiped off, and the core was put into an imbibition bottle for testing imbibition oil recovery (see Figure 3).

(5) The amount of oil discharged from the core in different time periods was recorded, and the imbibition oil recovery was calculated.

2.3.2.2. Dynamic Imbibition Experiment. In the actual reservoir, the imbibition phenomenon not only happens during the shut-in period but also happens when the surfactant flows along the microcracks during the injection process. In this manuscript, the imbibition process during the injection is called dynamic imbibition. However, it is difficult to separate the imbibition process from the displacement process during the injection, and the total oil recovery from imbibition and displacement is called the dynamic imbibition oil recovery.

(1) The fractured core was dried, weighed, and saturated with water under vacuum, the wet weight was weighed, and the pore volume was calculated.

(2) A silica gel spacer was added to the core fracture. It was placed into the holder and saturated with oil at the reservoir temperature; then, the core was aged for 24 h, removed from the holder, and soaked in experimental oil to calculate the oil saturation.

(3) A surfactant solution was prepared and evacuated for 2–3 h to eliminate the adverse effects of gas on oil production.

(4) The silica gel spacer was removed, and the core surface and two end faces was sealed with Teflon tape to ensure that the core only has the two sides of the crack exposed. Then, the core was placed into the holder, and the ring pressure to the formation pressure was pressed, water flooding was performed to a water cut of 95%. Then, the surfactant was injected according to the size of the design slug, and the valves at the inlet and outlet of the holder were closed. After the pressure holding time, subsequent water flooding was performed to a water cut of 95% (see Figure 4).

(5) The amount of oil discharged at different times was recorded, and the oil recovery was calculated.

2.4. Experiment Principle. 2.4.1. Adhesion Work Reduction Factor. In the process of capillary drive, it is necessary to overcome the adhesion work to separate the crude oil adsorbed on the pore surface of the rock. Therefore, the smaller the adhesion work is, the higher the oil washing efficiency is. The addition of a surfactant not only can reduce the interfacial tension of oil and water but also improve the contact angle of water in order to reduce the adhesion work. The reduction can be expressed by the reduction factor $E$ of adhesion work:

$$E = \frac{W_s}{W_w} = E_w \times E_\theta = \frac{\sigma_w}{\sigma_s} \times \frac{1 - \cos \theta_w}{1 - \cos \theta_s}$$

In the formula, $W_s$ is the adhesion work of oil on the rock surface in the water–oil–rock system; $W_w$ is the adhesion work of oil on the rock surface in the water–oil–rock system; $\sigma_w$ is the interfacial tension between oil and water; $\sigma_s$ is the interfacial tension between the surfactant solution and oil; $\theta_w$ is the contact angle of water on the rock surface; $\theta_s$ is the contact angle of water on the surfactant solution.
angle of the surfactant solution on the rock surface; $E_r$ is the interfacial tension factor; and $E_w$ is the wetting factor.  

### 2.4.2. Ratio of Capillary Force to Gravity $N_{ff}^{-1}$

The process of imbibition is affected by the capillary force and gravity. Low-permeability reservoirs mainly depend on the capillary force for imbibition and displacement. However, when the displacement force changes, the imbibition process will also change accordingly. To clarify the relative importance of the capillary force and gravity in the process of imbibition, Li et al. modified the capillary force gravity ratio $N_{ff}^{-1}$ proposed by Schechter on the basis of fully considering the double effects of the imbibition agent on reducing the interfacial tension and improving wettability:

\[
N_{ff}^{-1} = C \frac{2 \cos \theta \sqrt{\phi \rho}}{K \Delta \sigma g H} \tag{2}
\]

In the formula, $\sigma$ is the oil-water interfacial tension, mN/m; $\theta$ is the contact angle, °; $\phi$ is the porosity of the porous media; $K$ is the permeability of the porous media, $10^{-3}$ m$^2$/s; $\Delta \rho$ is the density difference of oil and water, g/cm$^3$; $g$ is the acceleration due to gravity, cm/s$^2$; $H$ is the height of the porous media, cm; $C$ is the constant related to the geometric size of the porous media (for a cylindrical core, $C$ is 0.4); and $N_{ff}^{-1}$ is the ratio value of capillary force and gravity. When $N_{ff}^{-1} \geq 5$, the capillary force dominates the imbibition process and reverse imbibition occurs; when $0.2 \leq N_{ff}^{-1} < 5$, the capillary force and gravity simultaneously act; when $N_{ff}^{-1} < 0.2$, gravity dominates the imbibition process, and forward imbibition occurs.

### 2.4.3. Relation Equation of Imbibition Displacement Index

The Aronofsky model can be used to quantitatively describe the experimental results, namely:

\[
r = r_{max}(1 - e^{-\lambda t}) \tag{3}
\]

In the equation, $r = r_{max}$ as $t \to \infty$; $r$ is the recovery rate of imbibition at time $t$; and $\lambda$ is the empirical constant, dimensionless. The results show that $\lambda$ reflects the change in the imbibition rate. The larger the $\lambda$ is, the faster the imbibition attenuation is and the shorter the imbibition termination time is.

### 2.4.4. Equal Proportion Relationship of Spontaneous Imbibition

There are four types of equations for calculating the recovery rate of capillary force imbibition, namely, the diffusion equation, equal proportion equation, experience equation, and material balance equation. Considering the viscosity of wetting and non-wetting phases, permeability and porosity of the matrix rock, and contact angle and surface tension, Feng and Liao established the equation of equal proportion:

### 3. RESULTS AND DISCUSSION

#### 3.1. Static Imbibition Effect

Under the conditions of different types and concentrations of surfactants, the experimental results of core imbibition recovery are shown in Table 2.

| Surfactant Types   | Permeability $K_f$ ($10^{-3}$ m$^2$/s) | Interfacial Tension (mN/m) | Contact Angle (°) | Porosity (%) | $N_{ff}^{-1}$ | Adhesion Work Reduction Factor | Imbibition Oil Recovery (%) |
|--------------------|----------------------------------------|-----------------------------|-------------------|--------------|---------------|-----------------------------|----------------------------|
| Pure water solution| 5.1                                    | 29.3600                     | 56.79             | 18.10        | 1295.965      | 1.00000                     | 2.85                       |
| 0.05% PO-FASD      | 4.8                                    | 0.7800                      | 20.42             | 17.97        | 59.267        | 0.01300                     | 8.36                       |
| 0.10% PO-FASD      | 5.1                                    | 0.5410                      | 17.16             | 18.07        | 40.800        | 0.00639                     | 11.80                      |
| 0.20% PO-FASD      | 4.9                                    | 0.4170                      | 16.45             | 17.95        | 32.097        | 0.00453                     | 17.65                      |
| 0.30% PO-FASD      | 5.2                                    | 0.2930                      | 13.91             | 18.19        | 22.305        | 0.00228                     | 13.99                      |
| 0.30% BHS          | 5.0                                    | 0.0073                      | 21.13             | 17.53        | 0.535         | 0.00013                     | 12.95                      |
| 0.30% PQJ          | 5.0                                    | 1.2200                      | 15.93             | 17.79        | 92.790        | 0.01242                     | 9.86                       |

In the formula, $t_0$ is the dimensionless time; $t$ is the time, h; $K$ is the gas permeability, $10^{-3}$ m$^2$/s; $\phi$ is the porosity,%; $\mu_w$ is the water viscosity, mPa·s; $\mu_{ow}$ is the non-wetting phase viscosity, mPa·s; and $L_s$ is the characteristic length of a laboratory core or reservoir block, which represents the ratio of the volume of the matrix block to its percolation surface area, m.

## Table 2. Imbibition Oil Recovery

| Surfactant Types   | Permeability $K_f$ ($10^{-3}$ m$^2$/s) | Interfacial Tension (mN/m) | Contact Angle (°) | Porosity (%) | $N_{ff}^{-1}$ | Adhesion Work Reduction Factor | Imbibition Oil Recovery (%) |
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| 0.30% BHS          | 5.0                                    | 0.0073                      | 21.13             | 17.53        | 0.535         | 0.00013                     | 12.95                      |
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In the formula, $t_0$ is the dimensionless time; $t$ is the time, h; $K$ is the gas permeability, $10^{-3}$ m$^2$/s; $\phi$ is the porosity,%; $\mu_w$ is the water viscosity, mPa·s; $\mu_{ow}$ is the non-wetting phase viscosity, mPa·s; and $L_s$ is the characteristic length of a laboratory core or reservoir block, which represents the ratio of the volume of the matrix block to its percolation surface area, m.
higher, and the flow resistance of oil is still big, so the imbibition effect is still influenced. Therefore, it is clearly seen that the reduction in the interfacial tension by the surfactant has a dual effect on the imbibition process. To improve the imbibition effect, ultralow interfacial tension should not be excessively used; rather, focus should be placed on forming a favorable wetting environment to provide sufficient driving force.

3.2. Analysis of the Imbibition Process. The experimental data was substituted into Feng and Liao’s proportional equation, and the relationship curve between the core imbibition oil recovery and the dimensionless time was calculated, as shown in Figure 5.

![Figure 5. Relation between imbibition oil recovery and dimensionless time.](image)

It can be seen from Figure 5 that the capillary force is large at the initial stage of imbibition, the water is drawn into the core faster, and the recovery factor is greatly increased. As time advances, the capillary force weakens, and the imbibition rate becomes increasingly slower, and continually, water enters the core pores until the end of the imbibition at which time the recovery rate tends to be constant. In the early stage of imbibition oil recovery, the 0.30% PO-FASD imbibition agent solution has the highest imbibition oil recovery efficiency. However, in the middle and late stages, the imbibition oil recovery of 0.20% PO-FASD is the highest.

The Aronofsky model was used to quantitatively describe the experimental results (see Figure 6).

![Figure 6. Regression analysis of imbibition recovery factor. 0.05% trend line equation: \( y = e^{-0.129t} \), \( R^2 = 0.9823 \); 0.10% trend line equation: \( y = e^{-0.097t} \), \( R^2 = 0.9969 \); 0.20% trend line equation: \( y = e^{-0.072t} \), \( R^2 = 0.9918 \).](image)

It can be seen from Figure 6 that as the imbibition time \( t \) increases, \( y = 1 - r/r_{max} \) tends to be \( y = 0 \), and \( r \) approaches \( r_{max} \). That is, with the process of imbibition and oil recovery, the recovery approaches the limit of imbibition oil recovery. It can be seen from the trend line equation that the fitted \( \lambda \) value from large to small corresponds to surfactant concentrations of 0.05, 0.10, 0.30, and 0.20%. Larger \( \lambda \) values correspond to faster attenuation rates of imbibition. It can be deduced from this that the 0.20% PO-FASD imbibition agent solution has the best imbibition effect as the effective imbibition time is long and the imbibition attenuation rate is slow. This further demonstrates that the imbibition effect needs a proper interfacial tension and not a lower interfacial tension. When the interfacial tension is below a certain range, the capillary force of the core insufficiently promotes an effective flow of oil. At this time, the imbibition effect will deteriorate, the imbibition attenuation rate will increase, and the effective time of imbibition and imbibition oil recovery will decrease. Therefore, under the condition of ensuring improved wettability, interfacial tension should be maintained within a reasonable range to ensure sufficient driving force. In summary, this study recommends the 0.20% PO-FASD solution for subsequent experimental research.

3.3. Effect of Dynamic Imbibition Oil Recovery and Its Influencing Factors. 3.3.1. Effect of Injection Volume. Under the conditions of a reservoir pressure of 20 MPa and pressure holding time of 48 h, the experimental data of the effect of surfactant injection volume on the dynamic imbibition oil recovery are shown in Table 3. The relationship between oil recovery and PV under different injection volumes is shown in Figure 7.

![Figure 7. Relationship between oil recovery and PV under different injection volumes.](image)

| Injection Volume (PV) | Recovery (%) | 0.05% | 0.10% | 0.20% | 0.30% |
|-----------------------|-------------|-------|-------|-------|-------|
| 0.05PV                | 22.22       | 22.42 | 22.26 | 22.10 | 22.47 |
| 0.10PV                | 22.22       | 22.26 | 22.10 | 22.47 | 22.10 |
| 0.20PV                | 22.22       | 22.26 | 22.10 | 22.47 | 22.10 |
| 0.30PV                | 22.22       | 22.26 | 22.10 | 22.47 | 22.10 |
| 0.50PV                | 22.22       | 22.26 | 22.10 | 22.47 | 22.10 |
| 0.70PV                | 22.22       | 22.26 | 22.10 | 22.47 | 22.10 |
It can be seen from Table 3 and Figure 7 that as the injection volume of the surfactant increases, the dynamic imbibition and displacement effect get better. When the slug size is 0.5 PV, the increase in the efficiency of imbibition and displacement oil recovery efficiency reaches the highest recovery of 16.61%. Above the injection volume of 0.5 PV, although the injection volume of the imbibition fluid continues to increase, the increase in the final oil recovery does not significantly change because the increase of the area influenced by imbibition and displacement becomes slowly. Therefore, when designing an imbibition construction parameter, the appropriate injection volume of surfactant should be selected to ensure the best technical and economic benefits.

3.3.2. Effect of Reservoir Pressure. Under the conditions of a surfactant injection volume of 0.5 PV and pressure holding time of 48 h, the experimental data of the effect of reservoir pressure on the dynamic imbibition oil recovery are shown in Table 4. The relationship between oil recovery and PV under different reservoir pressures is shown in Figure 8.

Table 4. Recovery Experimental Results Influenced by Reservoir Pressure

| core number | permeability $K$ ($10^{-3}$ μm$^2$) | reservoir pressure (MPa) | water flooding recovery (%) | final recovery (%) | value added (%) |
|-------------|-------------------------------------|--------------------------|----------------------------|--------------------|-----------------|
| 2-6         | 5.1                                 | 5                        | 24.19                      | 30.81              | 6.62            |
| 2-7         | 5.2                                 | 10                       | 23.71                      | 32.66              | 8.95            |
| 2-8         | 5.1                                 | 15                       | 22.74                      | 34.84              | 12.10           |
| 2-4         | 4.9                                 | 20                       | 22.47                      | 39.08              | 16.61           |

Figure 8. Relationship between recovery and PV under different reservoir pressures.

It can be seen from Table 4 and Figure 8 that as the reservoir pressure increases, the imbibition oil recovery increases. The mechanism analysis shows that as the pressure of the reservoir increases, the capillary end effect gradually weakens, and the surfactant more easily enters the core pores through the fracture, continuing to penetrate deeper into the pores. This further improves the wettability of the core pore surface and decreases the interfacial tension between water and oil, thus promoting the imbibition process. Therefore, in the field construction design of imbibition technology, the pulse pressure injection method can be considered to improve the effect of imbibition oil production.

3.3.3. Effect of Pressure Holding Time. Under the conditions of a surfactant injection volume of 0.5 PV and reservoir pressure of 20 MPa, the experimental data of the effect of pressure holding time on the dynamic imbibition oil recovery are shown in Table 5. The relationship between oil recovery and PV under different pressure holding times is shown in Figure 9.

Table 5. Recovery Experimental Results Influenced by Pressure Holding Time

| core number | permeability $K$ ($10^{-3}$ μm$^2$) | pressure holding time (h) | water flooding recovery (%) | final recovery (%) | value added (%) |
|-------------|-------------------------------------|---------------------------|----------------------------|--------------------|-----------------|
| 2-9         | 5.1                                 | 24                        | 21.61                      | 35.48              | 13.87           |
| 2-4         | 4.9                                 | 48                        | 22.47                      | 39.08              | 16.61           |
| 2-10        | 4.8                                 | 72                        | 22.26                      | 40.00              | 17.74           |
| 2-11        | 5.2                                 | 96                        | 22.58                      | 41.29              | 18.71           |

Figure 9. Relationship between recovery and PV under different pressure holding times.

It can be seen from Table 5 and Figure 9 that with the increase in pressure holding time, the oil recovery of dynamic imbibition gradually increases, but the amplification of the oil recovery increase value decreases gradually. After a certain period of time, the oil—water replacement effect gradually weakens until it stops. When the pressure holding time is 96 h, the increase in the imbibition oil recovery can reach 18%. Therefore, a proper pressure holding time should be chosen to improve the technical and economic effect of imbibition technology.

3.3.4. Effect of Imbibition Cycles. Under the conditions of a surfactant injection volume of 0.5 PV, reservoir pressure of 20 MPa, and pressure holding time of 48 h, the experimental data of the effect of imbibition cycles on the dynamic imbibition oil recovery are shown in Table 6. The relationship between oil recovery and PV under different imbibition cycles is shown in Figure 10.

From Table 6 and Figure 10, it can be seen that with the increase of imbibition cycles, the imbibition oil recovery increases, but the amplification of the oil recovery increase value decreases gradually, indicating that the imbibition effect mainly occurs at the period of higher oil saturation, that is, the initial stage of imbibition. The mechanism analysis shows that during the development of fractured reservoirs, as the subsequent water flooding process continues, the oil saturation in the fractures and matrix systems gradually decreases, and the oil produced from imbibition in the fracture becomes a dispersed phase state, and the ability of oil to flow weakens. At the same time, the spontaneous imbibition process in the
matrix tends to stop. Thus, it is necessary to select a proper number of imbibition cycles.

4. CONCLUSIONS

1. The surfactant solution can effectively reduce the interfacial tension between water and oil and improve the wettability of the rock surface, thus improving the imbibition oil recovery. The adhesion work reduction factor and ratio of capillary force and gravity \( N_\delta^{-1} \) are obviously related to the interfacial tension between oil and water, and it is necessary to consider the dual effect of interfacial tension. There is no need to pursue an ultralow interfacial tension as a good balance between interfacial tension and wettability is good for imbibition.

2. In the initial imbibition stage, an imbibition phenomenon is obvious, and with the increase of imbibition time, the effect of the capillary force decreases, and the imbibition speed decreases until it reaches zero. Thus, choosing the type of surfactant can obtain a long time effectively utilizing the capillary force, which is important to imbibition.

3. With the increase in the injection volume, reservoir pressure, pressure holding time, and imbibition cycles, the oil recovery rate increases, but the amplification of the oil recovery increase value decreases. From the technical and economic points of view, it is recommended that the optimal injection volume, imbibition cycle, and pressure holding time of the target reservoir are 0.5PV, three rounds, and greater than 96 h, respectively.

Table 6. Recovery Experimental Results Influenced by Imbibition Cycles\(^a\)

| core number | permeability \( K (10^{-3} \, \mu m^2) \) | imbibition cycles(dimensionless) | water flooding | end of round | value added |
|-------------|--------------------------------|---------------------------------|----------------|-------------|-------------|
| 2-12        | 5.0                             | 1                               | 21.45          | 38.06       | 23.39       |
| 2           |                                 |                                 | 42.10          |             |             |
| 3           |                                 |                                 | 44.84          |             |             |

\(^a\)Note: the experimental process is water flooding to a water cut of 95% + 0.5PV imbibition agent + subsequent water flooding to a water cut of 95% + three cycles (every cycle has a pressure holding time of 48 h and then water flooding to a water cut of 95%).

Figure 10. Relationship between oil recovery and PV under different imbibition cycles.

The authors declare no competing financial interest.

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NOMENCLATURE

- \( K \): core permeability measured by gas, \( 10^{-3} \, \mu m^2 \)
- \( W_a \): adhesion work of the compound system of water/oil/rock, mN/m
- \( \sigma \): interfacial tension between oil and water, mN/m
- \( \sigma_o \): interfacial tension between oil and rock, mN/m
- \( \sigma_w \): interfacial tension between water and rock, mN/m
- \( \cos \theta \): contact angle
- \( E \): adhesion work reducing factor

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Notes
surfactant, mN/m; $\theta_s =$ contact angle of water on the surface of the rock; $\theta_i =$ contact angle of surfactant on the surface of the rock; $\sigma =$ interfacial tension between oil and imbibition solution, mN/m; $\theta =$ contact angle of the imbibition solution on the surface of the rock; $\phi =$ porosity of the rock; $\Delta \rho =$ density difference between oil and water, g/cm$^3$; $g =$ acceleration due to gravity, cm/s$^2$; $H =$ height of the rock, cm; $C =$ constant associated with the geometry size of the rock (C = 0.4 for a cylindrical rock); $N_B^{-1} =$ ratio between capillary force and gravity.

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