Investigation on the Mechanisms of Spontaneous Imbibition at High Pressures for Tight Oil Recovery
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ABSTRACT: Water flooding is widely used for recovering crude oil from unconventional reservoirs due to its economic feasibility. At reservoir conditions, the injected water is usually imbibed into fractured rocks, so-called spontaneous imbibition, providing a considerable driving force for enhancing oil recovery. In this work, spontaneous imbibition on a rock surface is investigated at high-pressure conditions, and its influence on tight oil recovery is revealed from a pore-scale perspective. Specifically, three typical core samples are selected and characterized to obtain their pore-size distribution by applying the NMR technique. These core samples are then saturated with crude oil and are submerged in formation water, which is filled in a high-pressure vessel. Oil recovery efficiency as well as the imbibition rate is consequently calculated for specific pores during spontaneous imbibition. Test results indicate that oil recovery from spontaneous imbibition is different in different pores depending on the petrophysical properties of the tight cores. That is, the difference in imbibition efficiency between small and large pores decreases as permeability and porosity increase in the core samples. In addition, as for core samples #1 and #2, the imbibition rate usually reaches a maximum at the initial imbibition stage. However, as for core sample #3, the maximum imbibition rate is far delayed due to high capillarity. This work may reveal the fundamental mechanism of the influence of spontaneous imbibition on a rock surface at high-pressure conditions on tight oil recovery from a pore-scale perspective.

1 INTRODUCTION

Tight oil, as one kind of unconventional energy resource, is playing an increasingly important role in energy supply. Tight reservoirs have some unique characteristics, such as distinctive fluid-phase properties, heterogeneity, and extremely low permeability.1,2 Hydraulic fracturing is widely used for the initial tight reservoir development, which is then followed by water flooding or cyclic water injection for enhanced tight oil recovery.3,4 It has been found that the success of either water flooding or cyclic water injection methods strongly correlates with the efficiency of the matrix imbibition process.5 Spontaneous imbibition and forced imbibition are two different imbibition categories occurring during the matrix imbibition process, depending on whether the injected water is imbibed by capillary pressure alone or by other forces; it was found that spontaneous imbibition dominates the entire oil displacement process.5 Tight oil production from reservoirs highly depends on the spontaneous imbibition of tight rocks.6,7 After water flooding or cyclic water injection, more than 60% of the crude oil is still trapped in tight reservoirs.8 Capillary pressure between water and in situ crude oil is the main mechanism controlling oil production from fractured tight reservoirs.9 Thereby, it is important to understand the fundamental mechanisms of spontaneous imbibition for tight oil recovery.

Extensive studies, including either experimental or theoretical methods, have been applied to investigate the behavior of spontaneous imbibition in petroleum engineering.10 Zhou et al. explored the interrelationship of various factors, i.e., wettability, initial water saturation, aging time, and oil recovery, with spontaneous imbibition by conducting displacement tests. Imbibition rate strongly correlates with water wetness and aging time as well as the initial water saturation.11 The oil recovery is also strongly affected by spontaneous imbibition. By performing experimental tests, Babadagli measured the oil recovery from different rock types by the spontaneous imbibition of a surfactant solution. It was found that rock and oil types or the lowered interfacial tension by the addition of a surfactant into brine contribute to the final spontaneous
imbibition recovery in naturally fractured reservoirs.\textsuperscript{12} However, previous works had only focused on giving a qualitative description of the influence of spontaneous imbibition on oil recovery or some possible factors that may expose the effect on spontaneous imbibition. To understand the fundamental mechanisms behind spontaneous imbibition, Stukan et al. simulated spontaneous imbibition of fluids in nanopores with different roughnesses using coarse-grain molecular dynamics simulation. Their results show that the fluid flow due to spontaneous imbibition is a function of pore roughness and wettability.\textsuperscript{13} Our previous work showed that spontaneous imbibition correlates the physical properties of core samples, such as pore structure and stress sensitivity of pores in core samples.\textsuperscript{10} Pores in tight core samples generally show pore-size distribution, while understanding of the mechanisms of oil recovery from spontaneous imbibition based on a pore-scale perspective has scarcely been touched. In addition, previous works were mostly conducted at atmospheric pressure; imbibition behavior at high-pressure conditions has scarcely been performed due to the limitations of experimental apparatus.\textsuperscript{14,15}

Recently, the contribution of spontaneous imbibition on oil recovery was determined from a pore-scale perspective. Based on the guidelines from the International Union of Pure and Applied Chemistry (IUPAC), the pore radii of macropores, mesopores, and micropores are defined as >50, 2−50, and <2 nm, respectively.\textsuperscript{16,17} Yang et al. investigated the effect of spontaneous imbibition on oil recovery from the pore-scale level. They observed that oil in the macropores is more readily recovered due to spontaneous imbibition, which accounts for the majority of oil recovery.\textsuperscript{18} Lai et al. studied fluid flow in oil–water–rock systems under the effect of spontaneous imbibition. They proposed that the pore structure of core samples significantly affects fluid flow in rock pores; it indicates that the effect of spontaneous imbibition on oil recovery varies in different pores.\textsuperscript{19} Even though the spontaneous imbibition effect on tight oil recovery has been explored at the pore-scale level, the influence of spontaneous imbibition on tight oil recovery at the pore level is still unclear.

Low-field nuclear magnetic resonance (NMR) is a commonly used technique in the petroleum industry. The basic use of the NMR technique is to explore the distribution of hydrogen-containing fluids in porous media.\textsuperscript{20−22} It should be noted that this technique can be applied to obtain some physical properties of core samples, such as porosity, pore-size distribution, and permeability.\textsuperscript{23} This technique has been widely used to reveal the distribution of reservoir fluid in porous media by obtaining the $T_2$ spectrum of the hydrogen-containing fluid-saturated porous media.\textsuperscript{24} The low-field NMR technique is also applied to monitor the process of spontaneous imbibition in tight cores.\textsuperscript{25} Using the NMR technique, spontaneous imbibition of distilled water was monitored in shale samples; it was found that micropores are the preferential pores during spontaneous imbibition in shale samples.\textsuperscript{26} However, the formation water generally contains various salts, while salinity may also play an important role in affecting the spontaneous imbibition process. Recently, Wang et al. used the NMR technique to investigate oil distribution in tight core samples under the influence of spontaneous imbibition. It was found that contribution from the micropores accounts for more than half of the total oil recovery.\textsuperscript{3} However, the measured $T_2$ spectrum was not converted into pore-size distributions; oil recovery due to spontaneous imbibition from specific pores cannot thus be determined.

In this work, three typical tight core samples are retrieved from the Ordos Basin. Pore-size distribution of these core samples is then characterized using mercury injection tests. Based on the measured pore-size distribution, distribution of the $T_2$ spectrum obtained from the NMR technique is then transformed into the specific pore-size distribution. Spontaneous imbibition is then performed at the reservoir temperature and pressure conditions. Oil recovery efficiency as well as the imbibition rate is calculated for specific pores in the spontaneous imbibition process. Imbibition rate is defined as the amount of fluids imbibed into core samples at a unit time. The saturated fluid is herein replaced by the imbibed foreign fluids. The influence of spontaneous imbibition on tight oil recovery as well as the imbibition rate is analyzed from a pore-scale perspective. As a comprehensive study on spontaneous imbibition in the oil industry, it may be the first time that oil recovery efficiency under the influence of spontaneous imbibition is thoroughly analyzed at high-pressure conditions as well as from the pore-scale perspective.

2. RESULTS AND DISCUSSION

2.1. $T_2$ Spectrum Distribution during Spontaneous Imbibition. In this experiment, we first saturate the three core samples with crude oil. The $T_2$ spectrum is then obtained for each core sample; the initial $T_2$ distribution reveals oil distribution in the pore systems.\textsuperscript{27} Figure 1 presents the measured initial $T_2$ distribution of the three oil-saturated samples. According to the $T_2$ signals, it can be inferred that oil mainly resides in the large pores in core sample #1; sample #1 has larger permeability and porosity than samples #2 and #3, which have a higher total volume of large pores. Unlike core sample #1, samples #2 and #3 have in situ oil mainly remaining in the small pores, indicated by the $T_2$ distribution in the small pore-size range. In addition, it is observed that the small pores dominate core sample #3 due to its extremely low permeability.

Figure 1a presents the $T_2$ distribution of core sample #1 at different spontaneous imbibition scenarios when the pressure is 15.0 MPa. According to the measured $T_2$ spectrum, pores in this core sample can be classified as two types, i.e., small pores (0.01−0.36 μm) and large pores (4.20−336.00 μm). As the spontaneous imbibition goes on, $T_2$ signals in both pores are reduced, suggesting that oil is driven out from the core sample. In the initial imbibition stage (0−5 h), the $T_2$ spectrum in large pores is reduced more significantly than that in small pores. It indicates that as for core sample #1, in situ oil in the large pores is more readily displaced out by the imbibed water at the initial imbibition stage. When imbibition is in 96−144 h, the $T_2$ spectrum is slightly changed as the imbibition time increases. As more formation water is imbibed in cores, oil at the pore center is readily replaced by intruding water, while the in situ oil near the pore surface is left behind due to the strong surface attraction. However, as for imbibition at room pressures, the imbibed water readily flows around the pore surface, leading to viscous fingering.\textsuperscript{28}

As shown in Figure 1a, it is found that a small proportion of oil resides in the medium pores with the pore radius in the range of 0.96−4.20 μm, in addition to the small and large pores. We observe that oil residing in the medium pores can be displaced by the imbibed formation water in the initial imbibition stage, i.e., 0−12 h, while spontaneous imbibition
stops, and no oil is displaced after 96 h of imbibition. Compared to the small pores, it seems that more oil is replaced by the imbibed formation water in the large pores. In the first place, the large pores have a larger total pore volume than the small pores, resulting in more oil storage in the large pores. In addition, due to the relatively small capillarity and more favorable heterogeneity in the large pores, formation water is more readily imbibed into the large pores.

Figure 1b presents the measured $T_2$ signals of sample #2 at various spontaneous imbibition stages when the pressure is 15.0 MPa. We divide pores in the tight core sample #2 into small pores and large pores with the pore size falling into $0.01 - 0.38$ and $0.38 - 78.00$ μm, respectively. Similar to sample #1, the measured $T_2$ signals decrease with the increasing imbibition time. In addition, it has a more obvious decrease in the initial imbibition stage, i.e., 0–5 h, in small and large pores. It indicates that oil is more readily displaced by the imbibed formation water at the beginning of spontaneous imbibition. As imbibition progresses further, $T_2$ signals are less decreased, suggesting that imbibition becomes weaker and less oil is driven out from core sample #2.

Figure 1c presents the measured $T_2$ signals of sample #3 at various spontaneous imbibition stages when pressure is 15.0 MPa. Similarly, we divide the pores in core sample #3 into small pores and large pores with the pore sizes falling into $0.01 - 4.80$ and $4.80 - 108.00$ μm, respectively. According to the $T_2$ spectrum distribution, more oil is stored in the small pores due to the relatively large volume of small pores. In addition, sample #3 has the smallest permeability and porosity among the three typical cores, which is dominated by small pores. Unlike core samples #1 and #2, there is almost no decrease in the $T_2$ spectrum in the initial imbibition stage, suggesting that spontaneous imbibition hardly occurs at the beginning of soaking. As spontaneous imbibition progresses further, water is imbibed into core samples and the stored oil starts getting replaced, resulting in a decrease in the $T_2$ spectrum. After the primary oil recovery stage, most of the oil remains in oil reservoirs. In this work, we can observe that spontaneous imbibition of formation water can replace part of the residual oil from the tight core samples; however, a considerable amount of oil is still left, which is hard to be recovered. For this case, more advanced recovering methods, such as CO$_2$ flooding and cosolvent-assisted imbibition methods, should be implemented for improved oil recovery.29–31

2.2. Oil Recovery from the Pore Scale. Figures 2–4 present oil recovery in the small and large pores at various spontaneous imbibition stages for the three tight samples. As imbibition progresses, oil recovery increases in both kinds of pores. In addition, large pores show higher oil recovery at all imbibition stages than the small pores for samples #1 and #2. Moreover, oil recovery in both pores is smaller in sample #2 than that in sample #1. It is noted that core sample #1 possesses larger permeability and porosity than core sample #2, which is favorable to spontaneous imbibition. In addition, the difference in oil recovery between both pores is more obvious for sample #1, which is followed by core samples #2 and #3. Oil recovery due to spontaneous imbibition varies in different pores, highly depending on the petrophysical properties of the tight cores; specifically, the difference in imbibition efficiency between the small and large pores decreases when permeability and porosity of core samples become large. Table 1 presents oil recovery in both kinds of pores at various spontaneous imbibition stages.

**Figure 1.** $T_2$ distribution of the three oil-saturated core samples. (a) $T_2$ signals of sample #1 at various spontaneous imbibition stages at 15.0 MPa. (b) $T_2$ signals of sample #2 at various spontaneous imbibition stages at 15.0 MPa. (c) $T_2$ signals of sample #3 at various spontaneous imbibition stages at 15.0 MPa.
Figure 5 presents the total oil recovery of the three typical core samples at different spontaneous imbibition scenarios. As for core sample #1, in the initial stage of spontaneous imbibition (0−5 h), a large amount of the saturated oil is displaced by the imbibed formation water, as much as 24.93% of the total stored oil, contributing to the largest oil recovery in the entire imbibition process. As imbibition progresses further, oil replacement becomes slow and the oil recovery is about 59.94%. As for core sample #3, oil recovery is only about 3.37%, which reaches the maximum when the imbibition time is about 96 h with the oil recovery of 44.11%; it is much smaller than those of core samples #1 and #2. Interestingly, small pores possess smaller oil recovery than large pores at the beginning, while it becomes higher as imbibition progresses. In a word, core sample #1 has the highest oil recovery due to spontaneous imbibition, followed by core samples #2 and #3. Core sample #1 has the highest permeability and porosity among the three core samples, which favors spontaneous imbibition and enhances tight oil recovery.

2.3. Imbibition Rate in Different Pores. The imbibition rate is different in different spontaneous imbibition scenarios. In this work, the imbibition rate ($R_i$) is calculated as

$$R_i = \frac{(E_{i+1} - E_i)}{(T_{i+1} - T_i)} \times 100 \%$$

(1)

where $E_{i+1}$ and $E_i$ represent oil recovery due to spontaneous imbibition in the $(i + 1)$th and $i$th spontaneous imbibition scenarios, respectively. $T_{i+1}$ and $T_i$ represent the imbibition times in the $(i + 1)$th and $i$th spontaneous imbibition scenarios, respectively.

Figure 6 presents the imbibition rates in the small and large pores in various spontaneous imbibition stages for the three samples at 15.0 MPa. Generally, the imbibition rate is much higher in the large pores than that in the small pores. As for core samples #1 and #2, the imbibition rate reaches the

| core sample | 24 h | 48 h | 72 h | 96 h | 120 h | 144 h | 168 h | average |
|-------------|------|------|------|------|-------|-------|-------|---------|
| #1          | 16.70| 16.00| 14.70| 15.47| 15.01 | 14.41 | 15.38 |         |
| #2          | 5.45 | 3.13 | 3.45 | 4.30 | 2.03  | 4.44  | 4.16  | 3.85    |
| #3          | 1.93 | −0.89| −1.06| −2.16| 0.00  | 2.15  | −0.01 |         |
maximum in both pores in the initial imbibition stage (i.e., 0–20 h). However, as for core sample #3, the imbibition rate is always kept at a small value due to the low permeability and the maximum imbibition rate is far delayed. The imbibition rate depends on the petrophysical properties; high permeability and porosity favor spontaneous imbibition, while it is hindered in the tight cores. In addition, compared to the imbibition at lower pressures or without pressure conditions, the imbibition rate may be much smaller at higher pressure conditions due to the larger capillary pressure at the high-pressure conditions. Furthermore, capillary pressure correlates the interfacial tension and wettability since the imbibition phenomenon is mainly controlled by capillarity. That is to say, interfacial tension and wettability are affected by reservoir pressures, which, on the contrary, play key roles in changing the capillarity. Specifically, size of the pore throat is reduced because of the stress from overburden formation. The detailed imbibition rates in both pores have been summarized in Table 2. Here, it should be noted that the small and large pores are defined by different pore-size ranges for the three core samples. In this work, the pore-size range determined for the small and large pores is selected based on the measured T2 spectrum range, as shown in Figure 1a–c.

### 3. EXPERIMENTAL SECTION

#### 3.1. Materials

Crude oil used was dehydrated, which has viscosity and density of 2.1 mPa·s and 810 kg/m³, respectively, at the reservoir conditions of 353.15 K and 15.0 MPa. Three natural core samples are retrieved from Chang 6 and 8 formations in the depth range of 1780–2310 m from the Changqing oilfield of China. The petrophysical properties of the three samples are shown in Table 3. The formation water containing CaCl2 has a salinity of $3.0 \times 10^4$ mg/L.

#### 3.2. Experimental Procedures

Before the experiment, the core samples were washed with octane to eliminate the remaining oil left in samples. These cleaned samples were then placed in an oven at 423.15 K and vacuumed for 12 h. Figure 7 shows the schematic for conducting spontaneous imbibition in the tight cores at high-pressure conditions using the LFNMR technique. The NMR setup, regarded as the key apparatus, was used for analyzing oil distribution in the core samples by obtaining $T_2$ signals of the oil-saturated samples. As shown in Figure 7, the core samples are loaded in a high-pressure vessel. In such a vessel, these samples were first saturated with formation water, which was injected at 0.05 mL/min until there was $T_2$ variation between two NMR scans. Mn²⁺ solution was then introduced into the water-saturated samples at 0.05 mL/min until injecting the Mn²⁺ solution for 3–4 PVs. Next, tight oil was introduced into the samples to build the initial oil saturation at 0.02 mL/min until no water was produced. To obtain oil distribution in core samples, the LFNMR scan was applied to obtain the $T_2$ spectrum of the oil-saturated samples. The core samples were held in a nonmagnetic core holder, which can withstand pressures as high as 20.0 MPa and temperatures up to 373.15 K. In addition, compare to the spontaneous imbibition at lower pressures, the pressure in the core samples is controlled slightly higher than the pressure in the core samples to ensure that fluids can be imbibed from one side of the core sample.

As shown in Figure 7, the oil-saturated core sample emerges into formation water containing Mn²⁺ with a mass concentration of 30 000 mg/L for conducting spontaneous imbibition at the reservoir pressure of 15.0 MPa; due to the imbibition effect, oil saturated in the cores is consequently replaced. For given time intervals, i.e., 0, 5, 12, 24, 48, 72, 96, 120, and 144 h (or 168 h), the shale core samples are scanned to obtain the $T_2$ spectrum for different imbibition scenarios. The $T_2$ spectrum measured is transferred into pore-size distribution, which is then analyzed to discuss the influence of spontaneous imbibition on tight oil recovery as well as the imbibition rate from the pore-scale perspective. It is noted that each scan is performed on the same sample.

### Table 2. Imbibition Rate in Both Kinds of Pores

| core sample      | imbibition rate, %/h |
|------------------|-----------------------|
|                  | 5 h       | 12 h      | 24 h     | 48 h     | 72 h     | 96 h     | 120 h    | 144 h    | 168 h    |
| #1 small pores   | 0.01–0.36 μm |           |           |           |           |           |           |           |           |
|                  | 0.032      | 0.093     | 0.063    | 0.15     | 0.28     | 0.23     | 0.07     | 0.10     |           |
|                  | large pores 4.2–336.0 μm | |           |           |           |           |           |           |           |
|                  | 0.992      | 1.220     | 0.740    | 0.12     | 0.23     | 0.26     | 0.05     | 0.07     |           |
| #2 small pores   | 0.01–0.38 μm |           |           |           |           |           |           |           |           |
|                  | 2.840      | 1.200     | 0.280    | 0.30     | 0.08     | 0.18     | 0.43     | 0.00     | 0.03     |
|                  | large pores 0.38–78.00 μm | |           |           |           |           |           |           |           |
|                  | 3.740      | 0.780     | 0.600    | 0.20     | 0.10     | 0.21     | 0.34     | 0.10     | 0.02     |
| #3 small pores   | 0.01–4.80 μm |           |           |           |           |           |           |           |           |
|                  | 0.270      | 0.250     | 0.700    | 0.27     | 0.35     | 0.61     | 0.10     | 0.02     |           |
|                  | large pores 4.80–108.00 μm | |           |           |           |           |           |           |           |
|                  | 1.020      | 0.130     | 0.700    | 0.15     | 0.35     | 0.56     | 0.19     | 0.11     |           |
tested twice to confirm the accuracy of the measurement. It should be noted that the uncertainties for measuring the system temperature and pressure are ±1.0 K and ±0.1 MPa, respectively.

4. LFNMR TECHNIQUE

Based on the LFNMR technique, a hydrogen-containing fluid can be detected in porous media when an oscillating magnetic field is imposed on certain atoms.35,36 The tight core used in this work belongs to one kind of porous media; \( T_2 \) signals of crude oil in such porous media are generally influenced by bulk relaxation, surface relaxation, and diffusion relaxation.37,38 The total \( T_2 \) spectrum can be expressed as39,40

\[
\frac{1}{T_2} = \frac{1}{T_S} + \frac{1}{T_D} + \frac{1}{T_B}
\]

where \( T_S \) is the surface relaxation time, ms; \( T_D \) is the diffusion relaxation time, ms; and \( T_B \) is the bulk relaxation time, ms.

In tight cores, the diffusion relaxation time and the bulk relaxation time are neglected, and the total relaxation time mainly depends on the relaxation from the rock surface. The surface relaxation is related to the rock-surface area. Thereby, the surface relaxation of tight rocks is given by41,42

\[
\frac{1}{T_S} = \rho_S \frac{S}{V}
\]

where \( \rho \) represents the relaxation rate, \( \mu \text{m}/\text{ms} \); \( s \) represents the specific surface area of the tight core sample; and \( S/V \) represents the specific surface area, 1/\( \mu \text{m}. \) It should be noted that \( S/V \) correlates with the pore radius.41,42

\[
s = \frac{V}{S} = \frac{F_S}{r}
\]

where \( F_S \) is the pore shape factor and \( r \) represents the pore radius, \( \mu \text{m}. \) Thereby, the total \( T_2 \) spectrum is given as43

\[
T_2 = \frac{1}{\rho F_S}
\]

Then,

\[
r = CT_2
\]

where \( C (= \rho F_S) \) is the coefficient factor. In this study, we convert the measured \( T_2 \) spectrum into pore-size distribution by comparing it with the directly measured data in Table 4.

| core sample | #1 | #2 | #3 |
|-------------|----|----|----|
| conversion coefficient C | 0.93 | 1.20 | 1.21 |

5. CONCLUSIONS

In this work, three tight cores were collected and then characterized to obtain the pore-size distribution using mercury injection tests. The LFNMR technique was applied to measure the \( T_2 \) spectrum of the samples after saturating oil, which was then transformed into specific pore-size distribution based on the characterization results. The \( T_2 \) variation due to the spontaneous imbibition at reservoir pressure was then analyzed to discuss the influence of spontaneous imbibition on oil recovery in tight core samples from a pore-scale perspective. The detailed conclusions can be drawn as follows.

- As for the tight core samples with relatively high permeability, \( \text{in situ} \) oil in the large pores is more readily driven out by the imbibed water than that in the small pores in the initial imbibition stage. As more formation water is imbibed, oil at the pore center is readily replaced by the intruding water, while the \( \text{in situ} \) oil near the pore surface is left behind due to the strong surface attraction.

- As for the tight core samples with extremely low permeability, spontaneous imbibition hardly occurs at the beginning. As spontaneous imbibition progresses, formation water is imbibed and the stored oil starts getting replaced, resulting in a decrease in the \( T_2 \) spectrum.

- Small pores possess smaller oil recovery at all imbibition stages than the large pores; however, as for the low-permeability cores, oil recovery was first lower than that in the large pores at the beginning, while oil recovery increased at the final imbibition stage. Oil recovery due to spontaneous imbibition varies in different pores, which highly depends on the petrophysical properties. Specifically, the difference in the imbibition efficiency...
between both pores decreases as permeability and porosity become higher.

As for core samples #1 and #2, the maximum imbibition rate occurs at the beginning of spontaneous imbibition. The imbibition rate depends on the petrophysical properties. High permeability and porosity favor the occurrence of spontaneous imbibition, while it is highly hindered in extremely tight cores.

This study proposes to use the LFNMR to reveal the effect of spontaneous imbibition on oil recovery at high-pressure conditions from a pore-scale perspective. It may reveal the recovering mechanism of crude oil due to spontaneous imbibition. Based on this study, it is found that the fundamental petrophysical properties of the tight core affect tight oil recovery. Next, it is recommended to study how minerals contained in core samples affect spontaneous imbibition. In addition, imbibition may also accompany water flooding or cyclic water injection processes and such imbibition is categorized as forced imbibition. Besides the conventional water flooding or cyclic water injection, forced imbibition also contributes to oil recovery. In future works, the influence of forced imbibition on crude oil recovery should be investigated.

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**Notes**

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