Percolation Characteristics and Fluid Movability Analysis in Tight Sandstone Oil Reservoirs

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ABSTRACT: The development of tight oil has started relatively late, and the flow mechanisms and fluid movability are still research spotlights. The goal of this paper is to investigate the percolation characteristics and fluid movability of the Chang 6 tight sandstone oil layer in the Upper Triassic Yanchang Formation, Ordos Basin, China. Results show that (1) at low flow velocity, the percolation curve of flow velocity vs pressure gradient is a concave-up nonlinear curve and does not pass through the origin. It is more difficult for oil flow than water flow in cores with similar permeability due to rock wettability and fluid apparent mobility. The application of back pressure makes the nonlinear stage eliminated and the percolation character improved. (2) Two-phase flow tests reveal that oil-phase permeability decreases faster in samples with lower permeability, and the coexistent flow region of oil and water is relatively narrow. The contribution of oil recovery mainly happens at the early stage. The permeability at the isotonic point reduces with the decrease of sample permeability. (3) Flow during water flooding can be roughly divided into four stages according to the injection pressure and flow change. The injection pressure experiences stages of increasing to a peak, then decreasing, and finally becoming stable, accompanied by an increase of oil production until water breaks through. (4) The pore throats of the target reservoir mainly range from 0.001 to 10 µm, and the bound water mainly distributes in pores less than 0.2 µm. The irreducible water saturation is 30–35%, and the movable fluid saturation is 65–70%, mainly distributed in pores at 0.2–10.0 µm with a maximum of 2.0 µm. The results will supplement the existing knowledge of percolation characters and fluid movability in tight sandstone oil reservoirs.

1. INTRODUCTION

Tight sandstone oil resources are distributed worldwide with huge exploitation potential, mainly distributed in North America, Latin America, Russia, and some regions in Asia. They are among the promising resources for future oil and gas exploration. In China, tight sandstone oil resources are common in the Ordos Basin, Sichuan Basin, Junggar Basin, and so on. Tight sandstone reservoirs are characterized by low permeability, low porosity, and strong capillary force. Actually, a tight reservoir is a relatively indistinct concept, which has not been strictly and precisely defined internationally yet. The U.S. Federal Energy Management Committees refer to fields with permeability less than 100 mD as low-permeability fields and reservoirs with permeability less than 0.1 mD as tight reservoirs. For different research objects, Chinese scholars put forward various classification schemes. The common recognition is that reservoirs with a permeability of 100–10 mD can be regarded as low-permeability reservoirs, reservoirs with a permeability of 10–1 mD are extra-low-permeability reservoirs, reservoirs with a permeability of 1–0.1 mD are ultra-low-permeability reservoirs, and reservoirs with permeability less than 0.1 mD are referred to as tight reservoirs. Zhou et al. defined tight oil reservoirs as unconventional oil reservoirs with the ground permeability less than 1.0 mD, the in situ permeability less than 0.1 mD, and the porosity less than 10%.4

The seepage characteristics and fluid movability of tight sandstone reservoirs are significantly different from those in conventional reservoirs as complex pore structures. The development of clay minerals makes the reservoir permeability reduced, and compaction and cementation make reservoirs densified, while later dissolution and metasomatism make petrophysical performance improved. Fluid movability is usually characterized by the movable fluid volume and saturation, which directly affects oil recovery. Low-field nuclear magnetic resonance (NMR) is usually used for fluid movability analysis. Zhou et al. revealed that fluid content in tight reservoirs is very low and mainly distributes in small pores, and

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the fluid availability is poor. As tight reservoirs have large pore-throat ratios, the capillary pressure is remarkable. Capillarity plays an important role in multiphase systems, and it affects the fluid distribution and the overall behavior of the system, especially in tight reservoirs.

Present studies reveal that the flow of fluid in low-permeability reservoirs is nonlinear and deviates from Darcy’s law at low velocity, also known as pre-Darcy flow. Actually, the fluid flow in tight reservoirs is strongly affected by the interface effect. When fluid percolates underground, there will form a thin liquid layer on the surface of the rock due to the interaction between solid and liquid molecules. The thin liquid layer is usually named the boundary layer and can produce additional resistance to percolation. The smaller the pore throat radius involved in seepage, the stronger the impairing effect. As a result, the boundary layer fluid needs larger displacing pressure to overcome the flow resistance, and the seepage at a low flow rate may fail to follow Darcy’s law in low-permeability reservoirs. In fact, in the early 1960s, some studies have indicated that the relationship of percolation velocity vs pressure gradient is nonlinear, and the fluid needs to overcome a threshold pressure gradient (TPG) to flow underground. This phenomenon was proven in low-permeability sandstone reservoirs. In fact, whenever there is a pressure gradient, there is flow. It is difficult to obtain the real TPG value as it is affected by many factors. Instead, it is suggested to use the term “pseudo-threshold pressure gradient” to describe the initial nonlinear stage. Zeng et al. revealed that the pseudo-threshold pressure gradient declines with the increase of sandstone permeability, especially for tight reservoirs. Dou et al. pointed out that factors affecting the pseudo-threshold pressure gradient include capillary pressure, physicochemical action of fluid with reservoir rock, structural characteristics of the porous material, and the stress sensitivity. Tight reservoirs usually develop with fine pore throats along with low reservoir pressure, causing fluid to lose flow ability, and additional pressure needs to be supplied to ensure flow. The greater the permeability, the smaller the pseudo-threshold pressure gradient, and vice versa. In order to eliminate the effect of the TPG on seepage, early water injection or advanced water flooding is commonly implemented to keep the reservoir pressure at a certain value.

Although percolation and fluid movability have long been research spotlights, most of these studies focus on factors or percolation characteristics in low-permeability reservoirs from a single viewpoint. There are still uncertainties and problems that need to be solved. It is of significance to carry out in-depth research on the seepage characters and fluid movability in tight reservoirs for rational development. Based on experiments, we first determined the percolation of tight sandstone from single-phase flow and two-phase flow, then studied the characters of water flooding, and finally discussed the pore radius distribution and water movability of tight sandstone based on the T$_1$ spectrum obtained by low-field NMR.

2. RESULTS AND DISCUSSION

2.1. Single-Phase Flow. 2.1.1. Single Water Flow. Figure 1 shows the relationship of flow velocity vs the pressure gradient for sample 1, sample 2, and sample 3 fully saturated with water. The outlet end of the core holder is the atmosphere. It shows that the percolation curve of velocity vs pressure gradient is a concave-up nonlinear curve at low pressure, and the curve does not pass through the origin. When the pressure increases to a certain value, linear correlation of the velocity vs pressure gradient occurs, and the trend line intersects with the pressure gradient in the abscissa. With the increase of the pressure difference, water permeability increases slowly to basically stability. At the end of the experiment, water permeabilities of sample 1, sample 2, and sample 3 are 0.0034, 0.0060, and 0.0064 mD, respectively. The pressure gradients at which fluid outflows at the outlet are 4.53, 1.64, and 0.17 MPa/m for sample 1, sample 2, and sample 3, respectively. The lower the permeability is, the greater the starting pressure gradient and the smaller the curvature radius of the concave-up curve section.

2.1.2. Single Oil Flow. Figure 2 shows the relationship of the flow velocity vs the pressure gradient for sample 4, sample 5, and sample 6 fully saturated with oil. Oil percolation is a little different from water percolation. Compared with sample 4 and sample 5, the percolation in sample 6 presents a more obvious nonlinear stage under the experimental conditions. The possible reason may be related to rock wettability and structures. Most of the natural outcrop samples are water wetting and water-film boundary layer that is easy to form compared to the oil-film boundary layer. So, there may be no obvious nonlinear correlation for oil flow, especially for sample 4 and sample 5. However, the oil viscosity is higher than water viscosity, making oil flow much more difficult than water flow. The pseudo-threshold pressure gradient decreases with the increase of fluid apparent mobility, which is determined by permeability and viscosity. So, the pseudo-threshold pressure gradient for oil is much bigger than that of water despite the core permeability being similar. Figure 3 shows the correlation of apparent mobility and the pressure gradient at which fluid outflows at the outlet. At the end of the experiment, the final
oil permeabilities are 0.0045, 0.0050, and 0.0053 mD, and the corresponding pressure gradients at which fluid outflows at the outlet are 15.60, 14.20, and 6.15 MPa/m for sample 4, sample 5, and sample 6, respectively.

For sample 6, the pressure for linear flow beginning above was 2.55 MPa (pressure gradient was 71.30 MPa/m), shown as the dotted line in Figure 4. In order to analyze in depth the percolation characteristic, a test was carried out in sample 6 with a back pressure of 3.0 MPa applied at the outlet. Outflow occurs when pressure is greater than the back pressure. Results in Figure 4 show that the nonlinear correlation is eliminated, and the relationship curve moves to the left when the back pressure is applied. The corresponding pressure gradient at which fluid outflows at the outlet decreases from 71.30 to 2.75 MPa/m, indicating that it is important to establish a pressure system early to improve the flow character in tight reservoirs.

The final oil permeability with back pressure is 0.0050 mD, which is equivalent to that without back pressure. Results reveal that back pressure is important for early percolation and makes time for linear flow to shorten, reflecting the significance of maintaining pressure during oil production of these tight reservoirs.

**2.2. Two-Phase Flow Characters.** Figures 5 and 6 show oil/water relative permeability and oil recovery curves, respectively. Figure 5 shows that the coexistent flow region of oil and water is narrow for sample 130-3, and the saturation at the isotonic point is slightly less than 50% indicating that the sample is partially oil-wet. Oil permeability decreases by 84% when water saturation increased from initial saturation to isotonic saturation. The final water relative permeability is about 0.2, and water saturation is 55% with a residual oil saturation of 45%. The production curve in Figure 6 indicates that oil recovery increases rapidly to 20% with the increase of the injection amount before the injection volume less than 0.5PV. Water cut also increases rapidly to more than 90%. Continuing to increase water injection, oil recovery increases slowly, accompanied by early water breakthrough. These phenomena imply that oil-wet is not conducive to oil displacing. There may exist dominant channels such as large pore throats causing strong heterogeneity for sample 130-3. During water injection, water flows along the dominant channels and breaks through, making oil trapped and later water injection invalid.

Compared with sample 130-3, sample 130-7 exhibits a relatively wider two-phase coexistent flow region. The saturation at the isotonic point is more than 50%, indicating that the sample is hydrophilic. With the increase of water saturation, oil permeability drops sharply as well. When water saturation increases to the isotonic point, oil-phase permeability drops by 95%. When water saturation reaches 74%, there is no more oil flowing out. Oil recovery increases gradually to stability with the increase of injected volume. Though the permeability is less than that of sample 130-3, the final oil recovery of sample 130-7 has reached 57%, implying that weaker heterogeneity and water-wet benefit water flooding.

The heterogeneity of the micropore structure is key to water flooding. If the core permeability is high but pore connectivity is poor, water enters the dominant capillaries (larger pore throats) first and breaks through in advance, which will lead to water bypassing small pores and low oil displacement efficiency.

**2.3. Water Flooding Characters.** Figure 7 shows the inlet pressure and displacement liquid volume varying with time during water injection in sample J9. It can be divided into four stages: no outflow, pure oil flow, oil and water co-flow, and pure water flow. At the beginning, inlet pressure increases fast, and no liquid flows out. When inlet pressure reaches 3.5 MPa (pressure gradient is 60.0 MPa/m, line A), oil first flows out. So, under the experimental conditions, the pressure at which fluid begins to flow out for sample J9 is 3.5 MPa. When inlet
pressure reaches 5.0 MPa (pressure gradient is 85.0 MPa/m, line B), water begins to flow out along with oil, and the injection pressure continues to rise to a peak of 5.30 MPa when the pressure gradient is 89.4 MPa/m as seepage resistance continues to increase. Then the injection pressure begins to decline, and the two phases still coexist but with more water and less oil. It can be speculated that the seepage resistance also begins to decline from the peak. Pure water flow emerges when pressure drops to 3.6 MPa (pressure gradient is 62.2 MPa/m, line C), but the seepage resistance still declines. The cumulative oil production is 1.21 mL, and oil recovery is 58.2%. A ladder-like continuous descent in the injection pressure can be seen in Figure 7, indicating that fluid struggles to overcome different capillary resistances and percolates in some capillaries until flow is stable.

Figure 8 shows the inlet pressure and displacement volume varying with time in the process of water injection for sample J10. Similar to J9, it can also be divided into four stages, but inlet pressure increases slowly, and the peak is much higher than that of J9. When the pressure rises to 11.3 MPa (line A), the oil phase first flows out. When inlet pressure reaches 14.2 MPa (line B), water flows out along with oil. When the injection pressure reaches a peak of 19.6 MPa, it begins to drop, and the two phases still coexist but with more water and less oil. When the pressure drops to 19.2 MPa (line C), pure water starts to flow, and the pressure continues to decrease to become steady, indicating that seepage resistance still exists, and water struggles to overcome capillary resistance and percolates in some capillaries until flow is stable. The cumulative oil displacement is 0.38 mL with an oil recovery of 27.9%.

The analysis above shows that (a) at the initial stage of water injection, injection pressure increases continuously, and water spreads to displace oil; oil production increases quickly. (b) Injection pressure reaches the peak at which the number of capillaries involved in seepage may be the largest, and then the production rate increases very slowly as water gradually breaks through some capillaries. (c) With the displacement of oil, water dominates in capillaries, and the recovery gradually becomes stable. The injection pressure gradually decreases as well. (d) Continuous water flow first occurs in pore throats with low flow resistance and also breaks through earlier than others, then flow resistance becomes lower and lower, and finally, the injection pressure becomes stable. The residual oil is bypassed, and consequent injection becomes invalid.

The above percolation tests indicate that as capillaries have different displacement pressures, when the applied pressure is higher than the capillary displacement pressure, fluid will participate in seepage. The back-pressure experiment shows the importance of maintaining pressure in tight sandstone reservoirs. When back pressure is applied, capillaries involved in seepage will increase. Maintaining a certain pressure at the outlet can decrease the effect of stress and make more capillaries involved in flow. The number of capillaries participating in flow increases with back pressure, as shown in Figure 9. As the flow resistance is smaller in larger capillaries, it is easier to break through for the displacing phase. Zhang et al. pointed out that large capillary pressure caused by strong heterogeneity makes small pores and throats unable to involve in seepage during water flooding. As a result, the effective cross-sectional area of seepage decreases, and the flow resistance increases. 8

2.4. Fluid Distribution and Mobility by NMR. Figure 10 shows the $T_2$ spectra by NMR for sample J9 at different water saturations. The saturation was established by capillary imbibition and vacuumizing. Figure 10 shows that when the sample is fully saturated by water, the $T_2$ spectra ranges from 0.03 to 500 ms, and the cutoff value is 9.3 ms, which is smaller than that in conventional low-permeability reservoirs. When water saturation increases from 20 to 30%, there is one peak at the left, but when the area below the curve becomes larger, the peak shifts to the right. It can be speculated that there is mainly bound water under the capillary suction force. Increasing water saturation to 35%, there is no change in the left peak, while a small peak appears at the right, indicating that fluid distribution has changed, and fluid becomes movable. When water saturation is close to 100%, it presents bimodal characteristics on the $T_2$ spectra. The left peak basically overlaps with that when water saturation is 30 or 35%. The porosity measured by NMR is 10.2%, which is consistent with the premeasured porosity (10.6%), indicating that the sample is almost fully saturated by water. Results also imply that the irreducible water saturation is 30–35%, and movable fluid saturation is 65–70%, which is also consistent with the irreducible water saturation (32.0%) and oil saturation (68.0%) established in Section 4.3.3.

Figure 11 presents the distribution of pore throat radii under the corresponding $T_2$ values at different water saturations. The pore throats mainly range between 0.001 and 10 μm, and the bound water mainly distributes in pores less than 0.2 μm. The movable fluid mainly distributes in pore throats ranging 0.2–10.0 μm with a maximum of 2.0 μm. In water flooding tests, oil
recovery for J9 is 58.2%; about 10% of the oil (0.87 mL) is not displaced. This residual oil is likely to be attached on the rock surface in the form of an oil film or in the form of droplets entrapped in pores. An additional technique may be needed for higher oil recovery.

3. CONCLUSIONS

Tight sandstone oil resources are distributed worldwide with huge exploitation potential. It is usually characterized by low porosity and low permeability, narrow pore throat size, high displacement pressure, great seepage resistance, and poor fluid movability. In this paper, seepage characteristics and fluid movability of the Chang 6 tight sandstone oil layer, Triassic Yanchang Formation, Ordos Basin, China, were experimentally analyzed. The main conclusions are as follows:

(1) It is nonlinear flow with a threshold pressure gradient during single-phase flow. The percolation curve of velocity vs pressure gradient is a concave-up nonlinear curve at low pressure, and the curve does not pass through the origin. It is more difficult for oil flow than water flow in cores with similar permeability due to rock wettability and fluid apparent mobility. The application of back pressure makes time for linear flow to shorten and improves the percolation.

(2) In the relative permeability tests, oil permeability decreases faster in the sample with lower permeability, and the coexistent flow region of oil and water is relatively narrow. The main contribution of oil recovery mainly happens at the early stage. The permeability at isotonic saturation declines with the decrease of core permeability as well.

(3) The flow in tight sandstone samples can be roughly divided into four stages according to the injection pressure and liquid volume change. The injection pressure experienced increasing to a peak, then decreasing, and finally becoming stable, accompanied by the increase of oil production until water breaks through in some capillaries.

(4) The pore throats of the target reservoir mainly range 0.001–10 μm, and the bound water mainly distributes in pores less than 0.2 μm. The movable fluid mainly distributes in pore throats ranging 0.2–10.0 μm with a maximum of 2.0 μm. The irreducible water saturation is 30–35%, and the movable fluid saturation is 65–70%.

4. EXPERIMENTAL SECTION

4.1. Materials. All the samples are taken from the Chang 6 tight sandstone oil layer, Triassic Yanchang Formation in the Ordos Basin, China. The lithology of the reservoir is in the form of lithic feldspar sandstone. The main porosity of Chang 6 is in the range of 8–14% with an average of 10.68%, while the main permeability is in the range of 0.1–0.5 mD. The pore types are mainly intergranular pores, dissolution pores, and fractures. The pore throats are extremely fine, and capillary resistance is very strong. The displacement pressure ranges 0.18–7.33 MPa with an average of 1.59 MPa. The mid-value of throats is mainly between 0.01 and 0.69 μm with an average of 0.19 μm. The max mercury saturation by mercury injection is between 39.89 and 99.47% with an average of 84.25%, while the mercury withdrawal rate is 18.95–8.60% with an average of 30.73%. The aperture of microfractures mainly ranges 0.03–0.07 mm. Overall, the Chang 6 layer displays strong heterogeneity in pore-throat size, and the low-pressure reservoir has a pressure coefficient lower than 1. Present studies show that the Chang 6 reservoir is mixed wetting and...
apt to oil-wet with chlorite relatively developed and hardly with water-sensitive minerals.

The petrophysical properties of the samples are shown in Table 1. There are six natural outcrop samples for single-phase flow tests, two reservoir samples for multiphase flow tests, and two reservoir samples for water flooding tests.

Simulated formation water with salt about 30000 mg/L, prepared with potassium chloride (KCl) and distilled water, was used as the water phase. The viscosities were 0.47 mPa s at 60 °C and 1.01 mPa s at 20 °C. Kerosene was used as the oil phase with viscosities of 1.08 mPa s at 60 °C and 2.17 mPa s at 20 °C.

### 4.2. Apparatus

Figure 12 shows the flow chart of percolation tests. The experimental apparatus includes a constant flow pump, a special core holder, a back-pressure regulator, two intermediate containers for water and oil, a data measuring system, and several pressure sensors. Fluid in the container is displaced by a pump at a constant pressure. The outlet of the holder is connected to the back-pressure regulator. Back pressure is set according to the requirement. The setup is placed in an incubator.

The setup used for two-phase flow evaluation is shown in Figure 13. It includes an advection pump, liquid storage system, core holder, metering system, temperature controlling system, and data acquisition and processing control module.

In order to analyze the fluid mobility and distribution in tight sandstone oil reservoirs, nuclear magnetic resonance (NMR) is adopted. A full-diameter NMR analysis system (AniMR-150, Shanghai Niumag Electronic Technology Co., Ltd.) is used.

### 4.3. Procedures and Methodology

#### 4.3.1. Single-Phase Seepage

It is conducted using a setup shown in Figure 12. Core samples are first vacuumed and fully saturated with water or oil separately. The piston container is filled with the same fluid (water or oil). The back end of the holder is connected to a back-pressure device, so a certain back pressure can be set according to the requirement. The flow rate is recorded until the flow becomes stable. The displacement pressure difference is increased sequentially, and the corresponding flow rate is obtained serially. Permeability is finally calculated. The relationship of flow velocity vs pressure gradient is plotted to analyze the seepage characteristics. Sample 6 was selected to investigate the effect of back pressure on percolation. Experiments were conducted at 60 °C with a confining pressure of 10.0 MPa.

#### 4.3.2. Two-Phase Seepage

Experiments were carried out according to the unsteady method in the industry standard SY/T5345-2007 "Test Method for Two-Phase Relative Permeability in Rock". The unsteady method for measuring oil/water relative permeability is based on Buckley–Leverett’s one-dimensional two-phase water flooding leading edge propulsion theory. It neglects the capillary force and gravity and assumes that the two immiscible fluids are incompressible, and oil/water saturation in any section is uniform. Samples are first saturated with water, then oil saturation is gradually established by oil displacing water, and finally, water is injected to displace...
4.3.3. Water Flooding Simulation. The flow chart is shown in Figure 12. Irreducible water saturation and oil saturation are first established according to the industry standard SY/T5345-2007 “Test Method for Two-Phase Relative Permeability in Rock” with results shown in Table 2. The pipeline is drained in 60 °C.

Table 2. Irreducible Water Saturation and Oil Saturation Established

| core # | porosity (%) | permeability (mD) | Swi (%) | So (%) | oil content (mL) |
|--------|--------------|------------------|---------|--------|-----------------|
| j9     | 10.68        | 0.303            | 32.0    | 68.0   | 2.080           |
| j10    | 10.98        | 0.172            | 30.8    | 69.2   | 1.363           |

The setup is shown in Figure 13. After water flooding simulation, the mechanism of nanoemulsion removal of water locking damage was studied. A study on the mechanism of nanoemulsion removal of water locking damage in tight sandstone reservoirs: A case study of Chang 7 of the Upper Triassic Yanchang Formation in Longdong area, Ordos Basin, was conducted. To establish the state of the bound water, the surface relaxation time is approximated by the general, NMR transverse relaxation time, determination of pore size by NMR relaxation time. In volume. Therefore, the constant injection speed is selected to flod the liquid distribution in the core sample for its time-saving property.37,38

Established according to the industry standard SY/T5345-2007, the target layer thickness is 18.0 m, the wellbore is about 16.5 mm in diameter, 40.0 m³ per day, the surface relaxation time is 40.0 m³ per day, the surface relaxation time is 20.0 m³, water injection speed is 0.08–0.15 mL/min calculated according to injection volume. Therefore, the constant injection speed is selected as 0.05 mL/min in case of sensitivity damage. Tests were conducted at 60 °C.

4.3.4. NMR Tests. NMR is usually used for the determination of pore size by NMR relaxation time. In general, NMR transverse relaxation time, T₂, is correlated with pore size and is commonly used to quantify the fluid distribution in the core sample for its time-saving property.37,38

Under fast diffusion conditions, the surface transverse relaxation time T₂a of the fluid in pores can be expressed as

\[
\frac{1}{T_{2a}} = \frac{1}{T_{2b}} + \rho_2 \frac{S}{V}
\]

(1)

where T₂b is the inherent relaxation time of fluid, ms; \( \rho_2 \) is a constant of surface relaxivity of the pore in which fluid is located, \( \mu m/ms \); S is the core surface area; V is the core volume; and S/V is the specific surface calculated using

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

(2)

where \( F_S \) is the pore shape factor and r is the pore radius, \( \mu m \).

For fluid with a long inherent relaxation time, such as water and light oil, the surface relaxation time T₂a can be approximated by

\[
\frac{1}{T_{2a}} \approx \rho_2 \frac{S}{V}
\]

(3)

Substituting eq 2 into eq 3, then

\[
T_{2a} = \frac{1}{\rho_2 F_S} \times r
\]

(4)

For a given sample, the surface relaxivity \( \rho_2 \) and the pore shape factor \( F_S \) can be approximated as constants. Therefore, the T₂ spectrum can reflect the pore size of the rock and the distribution. As can be seen from eq 4, the relaxation time is proportional to the pore radius. For low-permeability sandstone reservoirs, the correlation coefficient in eq 4 can be taken as a constant empirical value of 50. The relaxation time of the larger pore is longer than that of the smaller pore. Since the seepage resistance will increase as the pore size decreases, when the pore size reduces to a certain extent, the fluid will be subjected to large capillary resistance and becomes too hard to flow. The corresponding relaxation time on the T₂ spectrum is named the cutoff value of movable fluid, which divides fluid in pores into movable fluid and bound fluid. Since the state of the bound water depends on the capillary force, the bound fluid saturation can be obtained by capillary imbibition. In this paper, NMR experiments were performed on sample J9 in a series of water saturations established by capillary imbibition.

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**Notes**

The authors declare no competing financial interest.

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