INTRODUCTION

With the increasing demand for energy and constant decrease of conventional oil and gas production, unconventional oil and gas have gradually become the new leader in global petroleum exploration and development.1-3 Tight oil plays an important role in the global energy industry, with enormous development potential, although substantially more difficult.4 The fine-grained nature, low porosity and permeability, greater compaction, smaller pore throats with the development of corrosion holes and micro fractures all increase the anisotropy of the reservoirs, increasing the level of difficulty of development. This special micro pore structure leads to a difference in oil-water seepage mechanisms in a tight sandstone reservoir compared to a conventional reservoir.1-3,5 Furthermore, the characteristics of the micro pore structure of a reservoir directly affects the reserves and distribution of residual oil. Therefore, accurate characterization of types and space for tight oil in pore throats has great significance for creating a scientific evaluation and the effective development of the reservoir.6
This characterization of tight oil reservoirs was started during the Second International Technical Seminar of Reservoir Characterization in 1989.\textsuperscript{7} During the same period, several Chinese scholars have studied the anisotropy of micro pores, including the distribution of pore throats, pore types and clay matrix, and summarized the research results and methods for determining the pore structure of tight reservoirs.\textsuperscript{8,9} With the improvement and development of experimental methods, research of microscopic pore structures in reservoirs has gradually transitioned from basic physical analysis to advanced experimental tests and methods. There are three frequently used methods for characterizing the microscopic pore structure in a low permeability, tight reservoir:\textsuperscript{10-13} (a) two-dimensional (2D) image observation, including optical microscopy and field emission scanning electron microscopy (FESEM), which provides qualitative and semiquantitative descriptions of the pore structure according to the 2D images; (b) three-dimensional (3D) volume reconstruction, including micro CT-scans, nano CT-scans, and focused ion beam field emission scanning electron microscopy, which provide 3D descriptions and evaluation of the pore structure and connectivity; (c) quantitative volume evaluation, including low-temperature gas adsorption, high-pressure mercury injection (HPMI), rate-controlled mercury injection, and nuclear magnetic resonance (NMR), which provide a quantitative evaluation of the pore structure and reservoir space. However, each technique has advantages and disadvantages. For example, 2D image observations can visually display the pore structure in a 2D plane, but unable to make 3D observations and quantitative analyses of the pore throat distribution.\textsuperscript{14} The magnification factors of SEM and optical microscopy are not high enough to observe micro and nano pores in a tight reservoir. Limited by the observation region, the focused ion beam FESEM and CT scan cannot characterize fractures, and are very expensive analyses.\textsuperscript{15-17} HPMI and rate-controlled mercury injection can qualitatively and semiquantitatively determine the pore structure and space of a reservoir, but cannot characterize the connectivity of the pore structure in 2D and 3D structures. Moreover, high-pressure mercury injection experiments require drying of the samples, which alters the porosity, permeability, and fabric of samples with high clay contents.\textsuperscript{18,20}

Ideal results cannot be achieved by a single technological method because of the lithology of tight oil reservoirs, diversity, and heterogeneity of rock pores and the limitation of experimental methods.\textsuperscript{21,22} Although there has been much research characterizing the pore structure of tight oil reservoirs, the contribution of different pore throat types toward the reservoir accumulation capacity and producing degree has been ignored for the most part.\textsuperscript{23} Therefore, using the Chang 6 reservoir in the Huagang area, Ordos Basin as an example, the differences of pore structure, micro seepage, and water-drive producing features for cores with various permeabilities are compared in this paper, and the influence of pore structure on seepage and water-drive producing mechanism is thus analyzed. This can further deepen the understanding of micro geological characteristics within a tight oil reservoir, provide a theoretical basis to reasonably explain inconsistencies that occur throughout production, and offer a theoretical guidance during development. Details of the experiment, including samples and conditions, setup and procedures, are given in appendix A1, A2 and A3.

## 2  |  PORE STRUCTURE CHARACTERIZATION USING NMR

Based on the principle of mercury injection, the size of throat and the volume distribution of pores connected can be obtained by capillary pressure curve, while the NMR\textsuperscript{24,25} T\textsubscript{2} spectrum of a sample 100% saturated with water can evaluate the pore sizes and corresponding pore volume distribution.\textsuperscript{24,25}

According to the basic principle of nuclear magnetic resonance, the T\textsubscript{2} time in a single pore can be expressed as:\textsuperscript{26}

\[
\frac{1}{T_{2}} = \frac{1}{T_{2\text{bulk}}} + \frac{1}{T_{2\text{surface}}} + \frac{1}{T_{2\text{diffusion}}}
\]  \hspace{1cm} (1)

In equation (1):

\[
\frac{1}{T_{2\text{surface}}} = \frac{\rho_{s}}{V} \cdot \frac{1}{T_{2\text{diffusion}}} = \frac{D(\gamma G T_{k})^{2}}{12}
\]  \hspace{1cm} (2)

For a water-wet rock, the value of T\textsubscript{2\text{bulk}} can be ignored. The T\textsubscript{2\text{diffusion}} can also be ignored according to established experimental methodology (G and $T_{k}$ are small).\textsuperscript{26}

Therefore, the T\textsubscript{2} in the single pore is proportional to the surface-to-volume ratio of the pore, which is a measure of the size of the pore. Thus, the observed T\textsubscript{2} distribution of all the pores in the rock represents the pore-size distribution. Li et al. considered the throat radius, and T\textsubscript{2} satisfies the equation of $r_{s} = CT_{2}^{1/n}$.\textsuperscript{27,28} The method by Li et al.\textsuperscript{27} was used in this paper, and the T\textsubscript{2} relaxation time by NMR was converted into a pore throat radius.

## 3  |  RESULTS AND DISCUSSIONS

### 3.1  |  Micro pore structure

Considering the complexity and specificity of pore structures in a tight reservoir, ideal results cannot be achieved by a single method. Multiple methods, including quantitative evaluation of minerals by scanning electron microscopy (QEMSCAN), optical microscope, FESEM, CT scan, focus ion beam scanning electron microscopy (FIB-SEM), and
Ren et al. were combined to perform qualitative and quantitative descriptions of the pore structure of the Chang 6 tight sandstone reservoir.

FIGURE 1 Thin section of the Chang 6 reservoir in Huaqing area (Yuan 414-2, Yuan 414-4)

HPMI were combined to perform qualitative and quantitative descriptions of the pore structure of the Chang 6 tight sandstone reservoir.

FIGURE 2 Mineral analysis results of QEMSCAN. (A) Mineral distribution of M51-20. (B) Mineral distribution of M51-02. (C) Mineral distribution of M51-23. (D) Mineral quantitative result statistics of M51-20. (E) Mineral quantitative result statistics of M51-02. (F) Mineral quantitative result statistics of M51-23

3.1.1 Lithological characteristics
The reservoir lithological characteristics, including clastic mineral composition, clastic sorting, rounding, arrangement mode, interstitial material, etc., are the main influences on reservoir diagenesis, pore structure, and reservoir physical properties. Thin section identification of the Chang 6 reservoir (Figure 1) shows that the reservoir lithology is mainly gray-black, gray and dark gray sandstone or siltstone, dark gray and gray-black mudstone or silty mudstone, and pelitic siltstone. The main rock type is lithic quartz sandstone. The grains are mostly subangular (92.67%), followed by angular-subangular (4.76%), showing a poor overall degree of rounding. The sandstone is fine- to ultra-fine-grained,
with occasional medium- and coarse-grained intervals, with the main distribution range of particle sizes of 0.09 mm to 0.22 mm, and a maximum particle size 0.06 mm to 1.1 mm. The sandstone is moderately sorted, consisting mostly of clastic particles. It consists of a relatively high abundance of interstitial materials (average of 15.60%), and their types are diversified, mainly authigenic clay minerals (illite and chlorite) and carbonate cement (calcite and dolomite), with lower contents of siliceous cement. The samples consist mainly of pore cementation, followed by dilated-porous cementation, diaphragm-porous cementation and porous-diaphragm cementation in select samples.

To display the distribution of different minerals more visually, QEMSCAN analysis was used on three core samples from different depths, with a scanning area of 5 mm and scanning resolution of 2 μm. The three samples have fairly similar mineral distributions (Figure 2). Quartz and albite constitute the rock matrix, illite and dolomite fill the pores as cement, and small amounts of chlorite has developed around the pores. Quartz content ranges from 56% to 59%, potash feldspar ranges 3.5%-4.6%, and albite ranges 10%-14%. The variation in calcite content varies 10-fold across the samples (0.26%-2.6%), and the content of dolomite is greater than calcite (5%-6%). Pyrite and siderite are much lower in the samples, less than 3% total. Illite is the most abundant clay mineral (8%-11%), followed by chlorite (1.2%-2%).

3.1.2 | Types of reservoir space

Pore types
The Chang 6 reservoir pores are complex. The average facial porosity is low, only 3.32%, where the intergranular pores are 1.53%, and pores formed by dissolution of feldspar and rock debris comprise 1.17%, and 0.23%, respectively (Figure 3). A small amount of intercrystal pores, micro fractures, and other types of pores have also developed within the samples, and the degree of development of micro fractures can extensively enhance the seepage capacity of the reservoir. The combination of reservoir pore types are mainly dissolved pores-intergranular pores, followed by intergranular pores-dissolved pores and intergranular pores.

Pore throat types
The pore throat is the narrow passage connecting pores, and the size and shape of the pore throats determine the seepage capacity of rock. Stress sensitivity is not the same for different types of throats. Necking throats have a stronger stress sensitivity, followed by laminated or curved lamellar throat types, and the pore itself can be a throat in reservoirs when they are tube-shaped. These tube-shaped pores have the weakest stress sensitivity. The contact relationships among the particles in Chang 6 reservoir are mainly line contact and point-line contact, followed by concavo-convex contact and suture line contact (Figure 2 and 3). The types of throats are mainly laminated throats, followed by punctual throats and tube-shaped throats.

3.1.3 | Structural characteristics of pore throats

Figure 4 and Table 1 are the capillary pressure curves and the pore throat parameters of the samples from Chang 6 reservoir HPMI. The displacement pressure was 0.338–14.498 MPa, with an average value of 2.751 MPa. There was only one
sample with a displacement pressure greater than 10 MPa, while there were five with displacement pressures less than 1 MPa, and four samples less than 1 MPa. The median capillary pressure was distributed in the range of 1.214-233.075 MPa, with an average value of 36.152 MPa. The median radius was distributed in the range of 0.003-0.606 μm, with an average value of 0.141 μm. The coefficient of homogeneity was between 0.208 and 0.662, with an average value of 0.612. The maximum mercury injection saturation was 50.21%–92.07%, with an average value of 76.03%. The mercury ejection efficiency varied from 6.07% to 27.17%, with an average value of 20.07%. Generally, the displacement pressure and its differential were large, the pore throat radius was small, the differences of pore structure was great, and the efficiency of mercury ejection was low.

Based on the above analysis, the pore throat structure of the Chang 6 is poor, with small pores, fine throats, and fine pores with miniscule throat develop. There is a large degree of heterogeneity in the pore throat size and shape across the samples, demonstrating clear anisotropy.

![Capillary pressure curves of high-pressure mercury injection](image)

**FIGURE 4** Capillary pressure curves of high-pressure mercury injection

| TABLE 1 | Pore throat parameters of high-pressure mercury injection |
|---------|------------------------------------------------------|
| Core    | $k_g$ $10^{-3} \mu m^2$ | $\phi$ | $P_T$ | $r_{max}$ | $P_{50}$ | $r_{50}$ | $r_a$ | $\alpha$ | Efficiency of mercury ejection | $S_{Hgmax}$ |
|---------|-------------------------|-------|-------|------------|----------|---------|-------|---------|--------------------------|-------------|
| L78-03  | 0.637                   | 12.441| 0.978 | 0.752      | 8.114    | 0.091   | 0.223 | 0.293   | 27                       | 83.76       |
| L78-04  | 0.266                   | 10.868| 1.996 | 0.369      | 8.937    | 0.082   | 0.301 | 0.662   | 19.87                    | 77.91       |
| M51-02  | 0.746                   | 14.064| 0.505 | 1.458      | 3.447    | 0.213   | 0.459 | 0.314   | 22.97                    | 79.09       |
| M51-03  | 1.116                   | 13.784| 0.338 | 2.178      | 1.214    | 0.606   | 0.721 | 0.326   | 21.52                    | 92.07       |
| M51-10  | 0.015                   | 3.367 | 14.498| 0.051      | 233.075  | 0.003   | 0.013 | 0.26    | 12.95                    | 50.21       |
| M51-20  | 0.067                   | 14.190| 2.619 | 0.281      | 62.003   | 0.012   | 0.081 | 0.284   | 21.08                    | 51.84       |
| M51-23  | 0.236                   | 13.234| 0.8   | 0.92       | 4.278    | 0.172   | 0.238 | 0.254   | 21.23                    | 86.94       |
| S127-06 | 0.325                   | 14.855| 0.792 | 0.928      | 5.55     | 0.133   | 0.275 | 0.291   | 27.17                    | 77.17       |
| S127-10 | 0.035                   | 7.766 | 3.292 | 0.223      | 21.481   | 0.034   | 0.048 | 0.208   | 6.07                     | 82.97       |
| S127-12 | 0.435                   | 11.929| 1.688 | 0.436      | 13.418   | 0.055   | 0.122 | 0.274   | 20.92                    | 78.37       |

![Distribution diagram for rock physical properties of the Chang 6 reservoir](image)

**FIGURE 5** Distribution diagram for rock physical properties of the Chang 6 reservoir
3.2 Physical characteristics

The reservoir porosity across 143 cores of the Chang 6 reservoir ranged from 0.14% to 17.40%, with an average of 7.84%. Permeability ranged 0.007-1.116 × 10⁻³ μm², with an average of 0.151 × 10⁻³ μm², and the main distribution ranges of porosity and permeability were 6.0%-12.0% and 0.1%-0.5 × 10⁻³ μm² (Figure 5).

Porosity and permeability varied widely across the samples of the Chang 6 reservoir. The porosity and permeability were mostly less than 15% and 1 × 10⁻³ μm². Permeability in these samples is generally positively associated with porosity (Figure 6), although samples with similar porosity did have varied permeability values. The difference can be up to 10-fold, due to the existence of micro fractures in certain samples. In comparison, samples with similar porosity did have relatively similar permeabilities. This difference shows that the pore structures of the Chang 6 reservoir in the Huaqing area is complex and diversified.

3.3 Influence of pore structure on seepage parameters

3.3.1 Influence on permeability

Pore throats can be divided into nano pores (less than 0.1 μm), sub-micro pores (0.1-1 μm), and micro pores (larger than 1 μm) based on their sizes and according to the classification of pore throats in petroleum geology. Different sized pores within the Chang 6 reservoir samples that have different permeabilities account for different proportions of the total pore throats, and the contribution to permeability is different (Figure 7). The proportion of nano pores to the total pore volume decreased with the increase of permeability, while the proportion of sub-micro pores linearly increased; when core permeability was low (less than 1 × 10⁻³ μm²), micro pores were almost nonexistent, and when permeability was over 1 × 10⁻³ μm², only a few micro pores were distributed within the sample (less than 5%).

Based on the Hagen-Poiseuille equation, the contribution of the throat with radius \( r_i \) to permeability of the formation can be calculated as follows:

\[
\Delta K_i = \frac{r_i^2 \alpha_i}{\sum r_i^2 \alpha_i} \times 100\%
\]

where \( \Delta K_i \) is the contribution of the throat with radius \( r_i \) to permeability (%); \( r_i \) is the throat radius (μm); \( \alpha_i \) is normalized distribution frequency of throat with radius \( r_i \) (%).

When permeability was less than 0.1 × 10⁻³ μm², nano pores accounted for the highest proportion of the total pores, and were the main contributor in seepage. When permeability ranged from 0.1 × 10⁻³ μm² to 0.5 × 10⁻³ μm², nano pores were still the most widely distributed. However, micro pores were the main path of seepage.

The capillary model shows that rock permeability is proportional to the quadratic value of the average pore throat radius. Therefore, for the two types of pores in these samples with little difference in the distribution frequency, the contribution of sub-micro pores to permeability is much higher than that of nano pores. For samples with permeability greater than 0.5 × 10⁻³ μm², sub-micro pores account for the highest proportion, and play the leading role in seepage.

3.3.2 Influence on nonlinear seepage characteristics

The minimum threshold pressure gradient of oil \( (S_{wc}) \) negatively correlated with the maximum throat radius (Figure 8), which agrees with the power function. When the maximum throat radius was less than 0.5 μm, the minimum threshold pressure gradient of oil \( (S_{wc}) \) rapidly increased as the throat radius decreased.

Figure 9 shows the flow velocity-differential pressure curve of oil \( (S_{wc}) \) for samples with different permeabilities and the throat radius distribution of the corresponding sample at various depths in well M51. When the displacement pressure gradient was low, there was nonlinear section in the velocity-differential pressure curve, where the flow rates did not linearly increase with the increase of the pressure gradient. Moreover, a lower permeability corresponds to a longer nonlinear segment. It is worth noting in Figure 9B that the throat distribution moved toward the left with a decrease in permeability, indicating that smaller pore throats become more abundant in samples with lower permeabilities.

Huang Yanzhang proposed a new concept of boundary fluid\(^3\) to explain the phenomenon of flow characteristics deviating from Darcy’s linear law, and show a nonlinear flow pattern in a low permeability reservoir. A boundary fluid
borders the pore wall to form a boundary layer with a much higher viscosity and shear stress compared to the center fluid. It is unable to flow when the displacement pressure gradient is low, and can only be driven under a considerable pressure gradient.

The samples used in the experiment were all oil-wet or slightly oil-wet, and bound water was in the center of the pore, while oil was against the pore walls. Water is immobile under the state of bound water saturation, and the oil phase can flow if the drive pressure gradient overcomes the resistance provided from the maximum radius throat. The corresponding displacement pressure gradient is the true (minimum) threshold pressure gradient.\(^3\)\(^4\)\(^3\)\(^6\)

The properties of porous flow fluid are based on the properties of the bulk fluid, boundary fluid, porous medium, and pressure gradient.\(^3\)\(^3\)\(^7\)\(^3\)\(^8\) According to the relationship between the effective thickness of the boundary layer and the displacement pressure gradient and capillary radius,\(^3\)\(^7\) an increase of displacement pressure corresponds to a reduction in the boundary layer thickness; the fluid in the larger pore throats will begin to flow. As the number of throats participating in flowing increases, a bending section occurs in the flow velocity-pressure differential curve; when the displacement pressure increases to a certain extent, the thickness of the boundary layer will ultimately cease to decrease with the increase of displacement pressure. The pores in the samples that can flow all participate in allowing fluid to pass through the sample, and the samples have a linear relationship between flow velocity and pressure gradient. For the same pressure gradient, the boundary layer of the fluid in smaller pore throats is thicker, which creates the pressure needed for the increased fluid flow through all pores. This in turn also lengthens the corresponding nonlinear section of the relationship.\(^3\)\(^9\)\(^4\)\(^0\)

### 3.4 Influence of pore structure on water-drive producing mechanism

Because the oil used in the displacement experiment does not contain hydrogen, all resonance signals detected during experiments were from the water. By analyzing the change of the water distribution at different states of rock samples, the distribution characteristics of oil and water in pores and throats of different sizes in the states of bound water and residual oil can be determined. Using sample L78-03 as an example (Figure 10), the water distribution curve in the state of saturated water represents the pore distribution of the core, and the water distribution curve in the state of irreducible water represents the distribution of bound fluid in pores after oil displacement. The sections between the two curves in the state of saturated water and irreducible water is the movable oil, between the two curves in the state of residual oil and irreducible water is the movable fluid, and between the two curves in the state of saturated water and residual oil is the residual oil.

According to the size difference, pores were classified as nano pore, sub-micro pore, and micro pore.\(^4\)\(^1\) Table 2 shows
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the statistics of the experimental parameters in the state of saturated oil and the final state of displacement. The saturated oil state of a sample is when the sample was under the condition of irreducible water, which reflects the initial oil distribution. The residual oil state of a sample was the end of the water drive.

The porosity and permeability of sample M51-10 were extremely low, and nano pores occupy over 90% of the total pores. The fluid in the core was difficult to move under laboratory conditions, so the following discussion does not include this core data.

To discuss the degree of oil displacement by water in a pore section and distinguish the oil displacement efficiency, the sectional oil displacement efficiency is defined as the ratio of producing oil saturation ($\Delta S_{oi}$) of a pore section to the initial oil saturation in this section ($S_{oi}$) (equation 4):

$$R_{ni} = \frac{\Delta S_{oi}}{S_{oi}}$$

where $\Delta S_{oi}$ is the changing value of oil saturation in a pore section $i$, that is, the reduction of the oil saturation from the state of saturated oil (irreducible water $S_{wc}$) to the final state of the water drive (residual oil $S_{or}$). $S_{oi}$ is the initial oil saturation in pore section $i$.

This value can quantitatively describe the complexity of the water drive for saturated oil in different sized pores. For the total pores, the sectional displacement efficiency is the displacement efficiency of the sample.

3.4.1 | Initial oil saturation

Oil displaces water to the state of saturated oil (irreducible water state $S_{wc}$), which simulates the process of hydrocarbon accumulation in a formation. The permeability of the experimental samples ranged from $0.015 \times 10^{-3} \mu m^2$ to $1.116 \times 10^{-3} \mu m^2$, with an average of $0.388 \times 10^{-3} \mu m^2$. The distribution of oil saturation in the nano pores ranged from 19.51% to 56.67%, with an average of 39.91%; in sub-micro pores, saturation ranged between 12.94% and 31.31%, with an average of 24.38%; saturation in micro pores ranged between 3.39% and 27.81%, with an average of 12.29%; saturation in total pores varied between 65.56% and 86.14%, with an average of 76.58%. The oil saturation in total, sub-micro, and micro pores were all positively correlated with the permeability. However, the initial oil saturation in nano pores decreased with the increase of permeability (Figure 11). This indicate that hydrocarbon accumulations are selective and heterogeneous, and oil is preferentially charged into the larger pores (micro and sub-micro pores).

When permeability was lower than $1.0 \times 10^{-3} \mu m^2$, oil mainly was found in nano pores; when permeability was greater than $1.0 \times 10^{-3} \mu m^2$, oil mainly was found in sub-micro pores. Because the permeability of the research area is essentially below $1.0 \times 10^{-3} \mu m^2$, the nano pores of the Chang 6 reservoir is mainly enriched in oil.
3.4.2 Producing oil saturation

The relationship between producing oil saturation and permeability is shown in Figure 12. Producing oil saturation in nano pores ranged between 4.62% and 28.22%, with an average of 17.39%; producing oil saturation in sub-micro pores ranged between 6.36% and 22.62%, with an average of 17.05%; producing oil saturation in micro pores ranged between 3.67% and 27.47%, with an average of 11.86%; producing oil saturation across all the pores ranged between 24.44% and 58.93%, with an average of 46.30%. With an increase in permeability, the producing oil saturation in the total pores and pores larger than sub-micro sized increased, while the producing oil saturation in nano pores decreased. Generally, with the increase of permeability, the main producing oil would first come from nano pores ($k_g < 0.4 \times 10^{-3} \text{ μm}^2$), followed by...
sub-micro pores ($k_g \approx 0.4 \times 10^{-3} \mu m^2$–$1.0 \times 10^{-3} \mu m^2$), and then micro pores ($k_g > 1.0 \times 10^{-3} \mu m^2$) pores. Therefore, the direction of water flooding should be adjusted to the pore throats with a larger size as permeability increases.

3.4.3 Displacement efficiency

The relationship between the oil displacement efficiency and permeability has shown in Figure 13. The sectional oil displacement efficiency in the nano pores ranged 23.68%-55.26%, with an average of 41.33%; sub-micro pores ranged between 34.75% and 97.61%, with an average of 69.72%; micro pores ranged between 10.76% and 87.77%, with an average of 44.54%; total pores ranged between 37.27% and 69.25%, with an average of 59.77%.

The analysis in Section 3.4.1 shows that the nano and sub-micro pores are the main type of pore developed in Chang 6 reservoir, with few micro pores throughout. The mere existence of micro pores intensifies the heterogeneity. The micro pores can easily form a preferential path during water displacement, thus reducing the degree of producing oil in small pores. Hence, with the increase of rock permeability, sectional oil displacement efficiency of all the pores, while the micro pores increase, that in nano pores decreases, and the sub-micro pores remain relatively constant. The overall permeability of the Chang 6 reservoir is less than $1.0 \times 10^{-3} \mu m^2$, and the sectional oil displacement efficiency of the sub-micro pores is always greater than that of nano pores and micro pores.

4 | CONCLUSION

Multiple methods have been combined to characterize the pore structure, and the influence of pore structure on seepage parameters was analyzed. NMR and displacement experiments were combined to obtain the distribution of oil and water in pores of different sizes at different saturation states.

1. The main rock type of the Chang 6 reservoir in the Huaqing area is a lithic quartz sandstone. The content of sandstone interstitial material is relatively high, and the types are diversified. The rock consists mainly of pore cementation, and the average facial porosity factor is low. The main pore types are intergranular pores and feldspar dissolved pores, and the combinational types of pores are mainly dissolved pores-intergranular pores. There are mostly laminated pore throats throughout the samples.

2. Micro pore throats are rarely found in the Chang 6 tight sandstones. The distribution of sub-micro pore throats approximately linearly increases with the increase of permeability, while the distribution of nano pore throats decreases. When permeability is less than $0.1 \times 10^{-3} \mu m^2$, the samples consist mainly of nano pores and are the main passageway for fluid flow. When the permeability ranges from $0.1 \times 10^{-3} \mu m^2$ to $0.5 \times 10^{-3} \mu m^2$, the samples generally still consists mainly of nano pores, while micro pores are the main seepage passageway for fluids. For samples with a permeability greater than $0.5 \times 10^{-3} \mu m^2$, sub-micro pores comprise most of the pore sizes, and act as the main flow channel.

3. The minimum threshold pressure gradient of oil ($S_{wc}$) negatively correlates with the maximum throat size as a power function. When the maximum throat radius is less than $0.5 \mu m$, the minimum starting pressure gradient of oil ($S_{wc}$) rapidly increases with the decrease of the throat radius.

4. Initial and producing oil saturation in sub-micro and micro pores are positively correlated with permeability, while that in nano pores are negatively correlated with permeability. With the increase of rock permeability, the sectional oil displacement efficiency of micro pore increases and the sectional oil displacement efficiency of nano pore decreases, while the sectional oil displacement efficiency of sub-micro pores is relatively steady at high values.

5. Nano pores are mainly enriched in oil in the Chang 6 reservoir in the Huaqing area, and with an increase of permeability, the main producing oil comes from the nano ($k_g < 0.4 \times 10^{-3} \mu m^2$), sub-micro ($k_g \approx 0.4 \times 10^{-3} \mu m^2$–$1.0 \times 10^{-3} \mu m^2$), and micro ($k_g > 1.0 \times 10^{-3} \mu m^2$) pores, respectively.

CONFLICT OF INTEREST

None declared.

NOMENCLATURE

- $k_g$ permeability measured with gas, $10^{-3} \mu m^2$
- $\phi$ porosity, %
- $p_T$ threshold mercury pressure, MPa
- $r_{max}$ the maximum capillary radius, μm
- $P_{50}$ median mercury injection pressure, MPa
- $r_{50}$ median capillary radius, μm
- $r_a$ average capillary radius, μm
- $\alpha$ uniformity coefficient, nondimensional
- $S_{Hgmax}$ the maximum mercury saturation, %
- $T_2$ transverse relaxation time of the pore fluid as measured by a CPMG sequence, ms
- $T_{2bulk}$ $T_2$ relaxation time of the pore fluid, ms
- $T_{2surface}$ $T_2$ relaxation time of the pore fluid resulting from surface relaxation, ms
- $T_{2diffusion}$ $T_2$ relaxation time of the pore fluid as induced by diffusion in the magnetic field gradient, ms
- $\rho_2$ $T_2$ surface relativity ($T_2$ relaxing strength of the grain surfaces) which varies with mineralogy, μm ms$^{-1}$
- $S/V$ ratio of pore surface to fluid volume, μm$^2$(μm$^3$)$^{-1}$
\( D \) molecular diffusion coefficient, \( \mu m^2 ms^{-1} \)

\( \gamma \) gyromagnetic ratio of a proton, \( rad·s^{-1}·T^{-1} \)

\( G \) field-strength gradient, Gauss \( cm^{-1} \)

\( T_E \) inter-echo spacing used in the CPMG sequence, ms

\( r_c \) pore radius, \( \mu m \)

\( C \) fit coefficient, nondimensional

\( n \) power exponent, nondimensional

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APPENDIX

A | EXPERIMENTAL SECTION

The experiment in this paper is composed of five parts: pore structure characterization, experimental test of oil (S_{wc}) minimum starting pressure gradient, flow velocity-differential pressure experiments, water-drive experiments, and NMR core analysis experiments.

A.1 | Samples and conditions

Core samples were from the Chang 6 reservoir of the Huaqing area, Ordos Basin. Permeability and porosity of the samples were measured with a YRD-CPerm200 Automated Permeameter and YRD-Smart-Por II Porosimeter based on the pressure decay and Boyle's Law method.

The temperature was set to 50°C for the oil-phase threshold pressure gradient tests, flow velocity-differential pressure curve tests of oil (S_{wc}), and water displacement experiments. The water used in the experiment was synthetic formation water with viscosity of 0.845 mPa·s (50°C). The oil used in the experiment was a customized synthetic oil without hydrogen (Substitute the H element in oil with F element and Cl element, and it cannot change the wettability of rock), which allowed for only the detection of the 1H signal in the water by NMR, rather than overlap between the water and oil within the pores. The oil had a viscosity of 2.454 mPa·s at 50°C. The viscosity ratio of oil and water at a temperature of 50°C was consistent with that of used in the Chang 6 reservoir, ensuring a similar flow of fluids through the samples.

A.2 | Experimental setup

Figure 14 illustrate the schematic diagram of the experimental setup for displacement. The experimental setup consist of a high pressure core holder, two high pressure containers for simulated oil and formation water respectively, a multiway valve, a micro pump, a fluid pump, an oil-water separator, and a data acquisition system for recording the pressure and temperature. The maximum experimental temperature and pressure of this experimental device are 180°C and 40 MPa, respectively. The water container has a piston used to separate the formation water and distilled water. The ISCO pump (100DX Teledyne Isco pump) can work at a constant pressure or constant flow mode, with the working pressure ranging from 0 psi to 10000 psi and the velocity ranging from 0.00001 to 60 mL min^{-1}. In the data acquisition system, a shunt wound pressure sensor group consisting of three pressure sensors is used to record the upstream pressure. These three pressure sensors have different spans, with the accuracy of ±0.05% of their full-scale span.

A.3 | Experimental procedure

The whole experimental process is shown in Figure 15, whereas the specific experimental procedure is as follows: (a) After the core was washed of oil and dried, the core was placed in the vacuum saturator having a vacuum of 10^{-3} Pa and then saturated with simulated formation water under 20 MPa (formation pressure). (b) The core with 100% saturated simulated formation water was placed in the NMR core analysis meter. The Carr- Purcell-Meiboom-Gill (CPMG) sequence was selected as the pulse sequence. The waiting time (TW), echo numbers, scanning times, echo spacing (TE) and other key parameters were 6000 ms, 8000, 256, and 0.2 ms.

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respectively. The main frequency (SF) of the magnetic pulse was 12 MHz. (c) The core was put into the core holder with annular pressure applied. It was displaced with simulated oil until the irreducible water saturation was established. (d) After 24 hours of aging, capillary equilibrium method and steady method were combined to measure the minimum starting pressure gradient and the flow velocity-differential pressure curve of oil \( (S_{wc}) \) at the same time. Then the core was taken out for NMR analysis. The test parameters were the same as listed in step 2. (e) The core was displaced by simulated formation water \((0.05 \text{ mL-min}^{-1})\) until the water ratio at the outlet reached 100%, then were taken out to perform the NMR analysis. The test parameters were the same as quoted in step 2. (f) The core that has finished the above experiments was washed, dried, and placed in a high-pressure mercury injection apparatus for the mercury injection experiment to obtain the capillary force curve.