Research Article

Influence of Pore Throat Structure and the Multiphases Fluid Seepage on Mobility of Tight Oil Reservoir

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Mobility is the main factor restricting the production of tight oil. In order to explore the influence of pore throat structure and fluid seepage on the mobility, six tight sandstone samples are selected by high-pressure mercury intrusion, nuclear magnetic resonance, water driving oil experiments, and oil-water relative permeability experiments to discuss the influence of pore structure and multiphases on the mobility of tight oil. The results indicate that with the increase in effective porosity, more oil and water are exchanged, and the mobility of the oil phase is enhanced. The large pore is positively correlated with the mobility of tight oil while the relationship between the mobility of small pore and effective porosity remains unclear. Particularly, the mobility of the tight oil is determined by the matching relationship between the pore throat radius and the sorting of the tight reservoir. Specifically, the smaller the two-phase copermiation zone, the greater the bound water saturation; the greater the slope of the oil phase permeability curve, the less the space for the two phases to flow together; the more the oil blocked by water in the reservoir, the worse the phase mobility. The mobility of tight oil can be divided into four categories by pore throat radius, pore throat sorting coefficient, and bound water saturation.

1. Introduction

Since the small pore throat and large pore throat radius ratio in the tight reservoir [1–5] and the capillary force of crude oil in the flow process are large, the mobility and seepage capacity are poor. There is no natural energy in production. Therefore, fracturing or water flooding technology is commonly used to obtain industrial production. In the development of tight oil reservoir, the oil-water two phases strongly interfere with each other, leading to a decrease in the seepage capacity, poor mobility of oil phase, and significant difference in production per well [6–9]. For the same reservoir, the temperature, pressure, and fluid viscosity are similar; thus, the root cause of this phenomenon is the difference in pore throat structure and oil-water two-phase seepage. At present, some scholars have discussed the influence of pore throat structure on permeability [10–15]. However, permeability only reflects the overall seepage capacity of rock, but not effectively reflect the mobility of tight oil under the background of complex pore-throat structure [13, 16, 17].

The meaning of mobility can be understood from two perspectives. First, it refers to the part of the tight oil flowing out of the pore throat space during the macroproduction. Second, it indicates the microexperimental conditions, and it can be assumed that the percentage of oil can be displaced in the process of water flooding in the original oil when the oil is full of the reservoir. The current research on fluid mobility focused on two aspects. The first is to use NMR and centrifugal experiment to investigate the characteristics of fluid saturation of tight reservoirs [18–21]. The advantage of the NMR experiment is that it is nondestructive to the sample and can obtain all the pore throat information of the sample [22–25]. However, the fluid mobility calculated by NMR and centrifugal experiments is completely affected...
by centrifugal force, and the NMR can simulate the gas-water two phases. Moreover, this experiment cannot effectively reflect the mobility of the oil phase under the condition of oil-water coexistence since tight oil always exists with water in the formation. The second aspect is to use displacement experiments to evaluate tight mobility [26, 27]. The disadvantage of this experiment is that it cannot reflect the tight mobility in different pore throat intervals. Aiming at the above shortcomings, the influence of pore throat structure and oil-water seepage on tight oil mobility is explored in this paper using high-pressure mercury injection, NMR, displacement experiment, and oil-water relative permeability. The mercury injection test is widely used to quantitatively characterize the pore throat structure of tight reservoirs because the mercury injection pressure is high enough to identify nanoscale pore and obtain many parameter information of sample in pore throat [15, 28–31]. The combination of NMR and displacement experiment can not only simulate oil-water two phases but also observe the mobility of tight oil in different pore throat intervals. Generally, the oil-water relative permeability experiment is used to describe the change of the permeability of each phase with the change in the fluid saturation of each phase when the multiphase fluid flows in porous media [32–35]. The characteristics of the phase permeability curve usually focus on two curves, three regions, and four characteristic points. Specifically, the two curves mainly indicate the relative permeability curves of the oil phase and the water phase; the three areas refer to the oil phase flow area, the oil-water multiphase fluid flow area, and the water phase flow area; the four characteristic points suggest the bound water saturation point, water phase permeability point of residual oil saturation, residual oil saturation point, and oil-water permeability equal point. How do these curve characteristics affect the mobility of tight oil? There is little research on it. In this paper, six samples of tight sandstone of Yanchang formation in Ordos basin were selected for high-pressure mercury intrusion, NMR test, displacement experiment, and oil-water relative permeability to clarify the influence of pore throat structure and oil-water seepage characteristic on the tight mobility of the purpose.

2. Regional Background and Test Methods

2.1. Regional Background. The Ordos basin is a multicycle superimposed basin with six tectonic units (Figure 1) [36–38]. Influenced by the Indochinese movement, the late Triassic in Ordos basin changed from marine facies to continental facies. Chang7 is a typical continental lake deposit and reaches the peak of the lake basin in the Triassic system. The thickness of Zhangjiatan shale at the bottom of Chang7 is more than 30 m. This is the main source rock of Yanchang formation [39–41]. The Chang7 member exhibits strong heterogeneity and frequent sand and mud alternations. The total thickness of Chang7 is between 80 and 120 m, and Chang7 can be divided into three small layers: Chang71, Chang72, and Chang73 (Figure 2). Chang71 and Chang72 are mainly composed of mudstone, fine sandstone, silty sandstone, and muddy siltstone while Chang73 is mainly composed of shale. In this paper, six samples were selected from the tight sandstone of Chang71 and Chang72 in the southwest of Ordos basin, with the porosity of 6.91%-10.71% and permeability of 0.020-0.210 mD.

2.2. Test Methods

2.2.1. High Pressure Mercury Injection (HPMI). The HPMI technology is often used to study the pore throat structure of tight reservoirs due to its high pressure and ability to identify small pore throats. The principle of the HPMI experiment is that mercury can enter a smaller pore throat as the pressure increases. Therefore, the pore throat radius can be calculated according to the equation [42, 43]. The maximum pressure used in this paper is 400 MPa.

2.2.2. NMR and Water Driving Oil Tests. The principle of NMR is that the hydrogen nuclei in the fluid will be polarized by the magnetic field when the hydrogen-containing fluid is in a uniform magnetic field. At this time, the application of a certain frequency of the RF field could produce nuclear magnetic resonance. Besides, a signal whose amplitude decays with time can be received when the added RF field is removed. We usually use $T_2$ to reflect pore throat information. The bound fluid exhibits a shorter $T_2$ relaxation time while the movable water exhibits a larger $T_2$ relaxation time on the NMR. Therefore, the pore size can be determined according to $T_2$ spectrum [18].

In this study, the NMR test and water driving oil experiment were combined to obtain the $T_2$ spectrum of saturated oil state, bound water-saturated oil state, and the end of water flooding oil state of the sample. The formation of oil and water viscosity is simulated at room temperature with the simulated oil viscosity of 1.92 mPa.s and water viscosity of 0.465 mPa.s. The experimental process refers to the People’s Republic of China Petroleum and Natural Gas Industry Standard “Core Analysis Method” (SY/T5336-2006) and the experimental method agreed in “Measurement Method of Relative Permeability of Two-phase Fluid in Rock” (SY/T5345-2007). The specific experimental methods and steps are described as follows.

1. Standard core washing oil and drying
2. Measuring porosity and permeability
3. Vacuum and pressurize saturated kerosene, and measure samples to measure $T_2$ spectrum
4. Dry core and vacuum pressurize heavy water with saturation salinity of 20000 mg/L (shielded water signal)
5. Put the core into the displacement process, and use kerosene to displace the saturated water core, in order to establish the saturated oil bound water state (displacement multiple is about 10PV) and measure the NMR $T_2$ spectrum of the saturated oil bound water state core
6. Conduct water flooding oil of the core until no oil is produced (displacement multiple of 10PV), and measure the $T_2$ spectrum with NMR of the core
(7) Process and analyze experimental data

2.2.3. Oil-Water Relative Permeability Test. Relative permeability can measure the ability of the rock to pass single-phase fluids when multiphase fluids coexist. This experiment in the paper simulated oil-water two phases, and its principle is that the distribution of two-phase saturation in porous media in the process of oil-water two-phase displacement is a function of distance and time, according to the record date and use of the JBN method to obtain oil-water relative permeability [37]. Thus, the oil-water relative permeability curve can be obtained. The sample size of this experiment is 2.5 cm × 6 cm, the viscosity of simulated formation water is 0.465 mPa.s, and the viscosity of the oil is 1.92 mPa.s, which are close to the actual formation values. The steps of this experiment are described as follows.

(1) Core preparation and wash oil
(2) Measure absolute permeability of the core at 100% saturated water
(3) Oil driving water makes the core in a saturated oily water state
(4) Water driving oil and obtain relative permeability data

3. Result

3.1. Pore Throat Structure Characterization by HPMI. The characteristics of the mercury injection curve of the six samples are exhibited in Figure 3. The mercury saturation distribution of the six samples ranges from 73.9% to 96.64%, the main throat radius ranges from 0.056 to 0.46 μm, and the average pore throat radius ranges from 0.042 to 0.29 μm (Table 1). As illustrated in Figure 4, the permeability is mainly contributed by macropore throat, the permeability of Z2 and Z3 samples is mainly contributed by 0.3-0.6 μm pore throat, the permeability of Z5 and Z6 samples is mainly contributed by 0.1-0.4 μm pore throat, and the permeability of Z1 and Z4 samples is mainly contributed by 0.04-0.1 μm pore throat. The difference in percolation capacity between different samples is mainly determined by the distribution range of pore throat radius. According to the statistics of the pore throat sorting coefficient of a different sample, Z2 and Z3 samples have the worst sorting while Z4 and Z5 samples have the best sorting. This mercury injection experiment is aimed at obtaining the pore throat 1.

3.2. NMR and Displacement Tests to Characterize the Mobility. Tight oil mobility in this paper refers to the percentage of oil that can be displaced in the process of water flooding in the original oil. NMR and water driving oil experiment were combined to explore the mobility of the tight oil under the condition of oil and water coexistence. The specific experimental steps have been introduced in “Test methods.” The three curves in Figure 5 represent the $T_2$ spectrum of the saturated oil state, the bound water-saturated oil state, and the end of water flooding oil state, respectively. Predecessors have lots of research that the $T_2$ spectrum is proportional to the pore throat radius, less than 10 ms corresponds to the intercrystalline pores (small pores) of clay minerals, and 10-100 ms corresponds to the dissolution pores and smaller intergranular pores (mesopores) while $T_2$ more than 100 ms corresponds to large dissolution pores and intergranular pores (large pores) [44]. The sample interval was divided
into less than 10 ms, 10-100 ms, and more than 100 ms by $T_2$ spectrum.

The corresponding oil saturations under different conditions at different intervals were calculated, respectively (Table 2). The oil saturation in different $T_2$ intervals for the six samples under oil saturation condition is illustrated in Figure 6. Among them, Z2 and Z3 have the highest oil saturation in the interval greater than 100 ms, indicating that the two samples have the largest proportion of large pore throats. This is consistent with high-pressure mercury intrusion experiment. Besides, the oil saturation of different $T_2$ intervals under the bound water-saturated oil state is presented.
Figure 3: Characteristics of mercury injection curves of sample in Chang 7 reservoir.

Table 1: Pore throat structure parameters of sample.

| Sample | Gas porosity/% | Gas permeability/mD | $P_d$/MPa | $r_t$/$\mu$m | $r_m$/$\mu$m | $S_{\text{Hg}}$/% | $S_c$ |
|--------|----------------|---------------------|------------|---------------|---------------|-----------------|------|
| Z1     | 6.91           | 0.020               | 6.00       | 0.042         | 0.056         | 73.90           | 1.25 |
| Z2     | 9.83           | 0.186               | 0.90       | 0.25          | 0.43          | 94.34           | 2.10 |
| Z3     | 10.57          | 0.210               | 0.63       | 0.29          | 0.46          | 96.64           | 2.26 |
| Z4     | 8.83           | 0.030               | 5.10       | 0.056         | 0.079         | 79.49           | 0.89 |
| Z5     | 10.15          | 0.045               | 1.30       | 0.093         | 0.18          | 88.03           | 1.08 |
| Z6     | 10.70          | 0.073               | 1.00       | 0.13          | 0.21          | 90.00           | 1.18 |

$P_d$: displaced pressure; $r_t$: mean throat radius; $r_m$: mainstream throat radius; $S_{\text{Hg}}$: maximum mercury saturation; $S_c$: sorting coefficient of throat.

Figure 4: The relationship between permeability contribution and throat radius.
in Figure 7. It can be observed that Z4 and Z5 have the highest oil saturation in the bound water state, 66.79% and 63.11%, respectively, while Z1 and Z6 only are 55.25% and 59.19% of oil saturation, respectively. The remaining oil saturation in different $T_2$ intervals at the end of waterflooding is exhibited in Figure 8, and the highest remaining oil saturation of the Z1 sample is 34.09%. The oil phase mobility in different $T_2$ intervals is shown in Figure 9, indicating that the mobility of large pores for the same sample is stronger than that of small pores. Among them, the Z4 and Z5 samples have the strongest mobility of the oil phase, and the Z1 sample has the lowest mobility. To sum up, the mobility of samples with good physical properties is not necessarily strong. What causes this phenomenon? It will be explained in the discussion part. Besides, the mobility of the saturated oil $T_2$ spectrum with a single peak (Z4, Z5, and Z6) is stronger than that of the double-peak sample (Z1, Z2, and Z3).

3.3. Oil-Water Relative Permeability. The oil-water relative permeability experiment was conducted on six tight
Table 2: NMR test parameters of sample.

| Sample | $\phi_e$ (%) | Sample | Oil saturation in different pore intervals of saturated oil state (%) | Oil saturation in different pore intervals of bound water-saturated oil state (%) | Residual oil saturation in different pore intervals of water driving oil (%) | Recovery ratio (%) |
|--------|-------------|--------|-------------------------------------------------|------------------------------------------|-------------------------------------------------|-------------------|
|        |             |        | <10 ms | 10-100 ms | >100 ms | <10 ms | 10-100 ms | >100 ms | <10 ms | 10-100 ms | >100 ms | <10 ms | 10-100 ms | >100 ms | <10 ms | 10-100 ms | >100 ms |
| Z1     | 4.05        | Z1     | 45.10  | 39.78     | 15.20   | 12.06  | 28.14     | 15.05   | 10.10  | 17.02     | 6.97    | 35.34 |
| Z2     | 5.92        | Z2     | 41.99  | 34.98     | 23.03   | 19.61  | 26.01     | 14.72   | 16.96  | 9.61      | 0.99    | 54.33 |
| Z3     | 6.90        | Z3     | 46.66  | 30.01     | 23.33   | 25.11  | 22.61     | 12.79   | 20.42  | 8.43      | 1.53    | 49.80 |
| Z4     | 5.93        | Z4     | 47.45  | 41.78     | 10.77   | 26.60  | 30.82     | 9.37    | 14.86  | 10.37     | 0.01    | 62.20 |
| Z5     | 7.03        | Z5     | 47.19  | 41.12     | 11.69   | 21.90  | 31.26     | 9.94    | 13.57  | 9.18      | 0.90    | 63.96 |
| Z6     | 7.35        | Z6     | 45.63  | 40.65     | 13.72   | 24.92  | 26.70     | 7.57    | 15.96  | 7.99      | 0.00    | 59.53 |

Figure 6: Oil saturation in different $T_2$ intervals under saturated oil state.

Figure 7: Oil saturation in different $T_2$ intervals with saturated oil bound water state.
sandstone samples. The bound water saturation of the six samples was distributed in 30.77%-41.37%, the residual oil saturation was distributed in 32.92%-41.9%, and the oil-water multiphase fluid flow area was distributed in 23.11%-31.54%, and the oil-water permeability equal point was distributed in 0.036-0.135 (Table 3). The Z1 sample has the smallest oil-water multiphase fluid flow area and the highest bound water saturation while the Z5 sample has the largest oil-water multiphase fluid flow area. The Z3 sample has the highest oil-water permeability equal point. There were significant differences in the oil-water relative permeability curves between those samples, and how these differences affected the mobility of tight oil is illustrated in Figure 10.

In this paper, two parameters were introduced to study the influence on the mobility of tight oil reservoirs. The first parameter is effective porosity $\varphi_e$, which reflects the real space occupied by the oil phase under the condition of oil-water two-phase coexistence. It is calculated by the total porosity

\[
\varphi_e = \frac{S_w + S_o}{1 - S_w}
\]

\[
\text{Table 3: Experimental parameters of oil-water relative permeability.}
\]

| Sample | $S_w$ (%) | $S_o$ (%) | Oil-water multiphase fluid flow area (%) | $K_o$ | Oil-water permeability equal point |
|--------|-----------|-----------|------------------------------------------|-------|-----------------------------------|
| Z1     | 41.37     | 33.52     | 23.11                                    | 0.039 | 0.053                             |
| Z2     | 39.76     | 32.92     | 27.32                                    | 0.0348| 0.126                             |
| Z3     | 34.73     | 33.61     | 29.66                                    | 0.042 | 0.135                             |
| Z4     | 32.80     | 39.00     | 28.2                                     | 0.0315| 0.036                             |
| Z5     | 30.77     | 37.69     | 31.54                                    | 0.0312| 0.100                             |
| Z6     | 31.30     | 41.9      | 26.8                                     | 0.033 | 0.085                             |

$S_w$: bound water saturation, %; $S_o$: residual oil saturation, %; $K_o$: slope of oil phase curve.
of the sample and bound water saturation (formula (1)). The second parameter is $K_o$, which represents the slope of the oil phase permeability curve and reflects the change of oil phase permeability with the increase of water saturation. Particularly, the higher the slope is, the faster the oil phase permeability decreases as the same water saturation increases.

\[
\phi_e = \frac{100 - \phi_{sw}}{100} \cdot \phi
\]

where $\phi_e$ is the effective porosity (%), $\phi$ is the total porosity (%), and $\phi_{sw}$ is the bound water saturation (%).

### 4. Discussion

#### 4.1. Effects of Physical Properties on the Mobility of Tight Oil

4.1.1. Porosity and Effective Porosity. Figure 11 illustrates that the recovery rate of the large pore is higher than small pore. From one perspective, it is difficult for water to enter the small pore when water flooding oil due to the large capillary

\[Z_1\]

\[Z_2\]

\[Z_3\]

\[Z_4\]

\[Z_5\]

\[Z_6\]
force of small pore. Therefore, the recovery rate of the small pore is low. From another perspective, the connectivity of those large pores is better than that of the small pore (Figures 12). Thus, the oil with small pore is difficult to be swept, contributing to one of the main reasons for the recovery rate of the small pore being usually lower than that of the large pore. As revealed from analysis, effective porosity can better characterize the mobility of tight oil than porosity (Figure 11) because the physical meaning of effective porosity is the volume of pores occupied by oil phase under the condition of oil-water coexistence, demonstrating that the real storage space where oil and water can be exchanged. Therefore, more oil and water can be exchanged with the increase of effective porosity, contributing to enhancing the mobility of the oil phase.

4.1.2. Permeability. There is an incompatibility between permeability and mobility (recovery rate) in tight sandstone reservoirs. It can be revealed that there is a complex relationship between permeability and tight oil mobility. Besides, there is a positive correlation between permeability and tight oil mobility when permeability is less than $0.05 \times 10^{-3} \, \mu m^2$. The mobility tended to decrease with the increase in permeability (Figure 13(a)) when the permeability is more than $0.05 \times 10^{-3} \, \mu m^2$. It is verified that the heterogeneity of pore throat structure has a key control on mobility. As revealed from the high-pressure mercury injection experiment, the lower the permeability of the reservoir, the higher the required displacement pressure (Figure 3(b)). Therefore, development costs are high, even though some reservoirs with low permeability have high mobility. However, some reservoirs with high permeability exhibit low mobility. This also reflects that although tight sandstone reservoirs are difficult to be developed, they have preferable development potential and the development effect may be better compared to low-permeability and medium-high permeability reservoirs. Therefore, conventional physical property parameters cannot effectively reflect the mobility of tight oil.

4.2. Effects of Pore Throat Structure on the Mobility of Tight Oil

4.2.1. Pore Throat Radius. The relationship between the average pore throat radius and the mobility is segmented.
Figure 12: The distribution of pores at different scales.

Figure 13: The relationship between recovery ratio, displaced pressure, and permeability.
The reasons are that the pore throat radius reflects the overall average value of the pore throat, and the average pore throat radius has an excellent positive correlation with permeability. Why there is an incompatibility between permeability and mobility has been discussed in Section 4.1? Regarding tight reservoirs, the existence of large pore throats will form a dominant channel during water injection development, even though large pore throat radius has strong seepage ability, making the oil phase in small pore throats difficult to be swept. Therefore, the influence of the average pore throat radius on the mobility of tight oil is super complicated. After comparing the Z1 and Z4 samples, the pore throat radius of the two samples is the same while the Z4 sample exhibits excellent pore throat sorting; thus, the mobility of Z4 is more than that of Z1. This indicates that the mobility of tight oil is affected by multiple parameters.

4.2.2. Pore Throat Sorting. The pore throat sorting of tight reservoir restricts the mobility of oil phase while it does not determine the mobility of oil phase, which is directly reflected in the segmental correlation between pore throat sorting coefficient and mobility (Figure 14(b)). Generally, the mobility of tight oil decreases as the pore throat sorting coefficient increases. This is because the poor pore throat sorting of samples has a single seepage channel in the process of water flooding, resulting in the small swept area and the low mobility of the oil phase. However, samples with good pore throat sorting have a large swept area, making the oil-water distribution relatively uniform. Consequently, the viscous resistance is reduced, and the capillary force self-absorption of the micropores makes water to enter the smaller pores to displace the oil in the process of water driving oil. Therefore, a relatively uniform displacement path is easily formed under a higher driving pressure, and the mobility of oil is better. After comparing Figures 14(a) and 14(b), the pore throat sorting coefficient and the average pore throat axis exhibit a complementary relationship. Therefore, tight oil reservoirs with strong seepage capacity may not have high oil phase mobility, inspiring us. Moreover, the mobility of the oil phase of the reservoir with low permeability is not necessarily poor. The matching relationship between pore throat radius and pore throat sorting determines the mobility of the oil phase.
In order to prove the above problems, multiple regression analysis is used in this paper to newly define the parameter $\omega$ (Equation (2)), which comprehensively reflects the pore throat radius and pore throat sorting. It is revealed that the mobility has a very high correlation with the parameter $\omega$ (Figure 14(c)), and the correlation between of mobility in different $T_2$ intervals and $\omega$ is also excellent (Figure 14(d)).

$$\omega = 270 \cdot rt - 51 \cdot Sc + 90.8$$  \hspace{1cm} (2)
As demonstrated by the NMR experiment, the pore throat sorting has an effect on mobility. The $T_2$ spectrum of Z1, Z2, and Z3 is bimodal in saturated oil condition while Z4, Z5, and Z6 are unimodal. Besides, the distribution characteristics of the $T_2$ spectrum reflect the characteristics of pore throats. The relatively concentrated $T_2$ spectrum peak of the single-peak sample indicates that the pore throat is well-sorted; the relatively scattered $T_2$ spectrum peak value of the bimodal sample suggests that the pore throat sorting is poor [24]. The mobility of the $T_2$ spectrum of the single-peak sample is significantly higher than that of the double-peak sample (Figure 14(b)). Thus, the influence of pore throat sorting on oil phase mobility is significant.

4.3. Effects of Oil-Water Two-Phase Seepage on the Mobility of Tight Oil. In the section of the introduction, two curves, three regions, and four characteristic points of oil-water relative permeability curve were introduced. Research on the mobility of tight oil mainly focuses on whether the oil phase can be displaced by water. Therefore, the influence on the mobility of tight oil is discussed from the oil phase permeability curve, oil-water multiphase fluid flow area, bound water saturation, and oil-water permeability equal point.

4.3.1. Oil-Water Multiphase Fluid Flow Area. The oil-water multiphase fluid flow area indicates where the oil-water two phases flow together in the process of water driving oil. From a microscopic point of view, when the water phase exceeds a certain saturation, the water phase starts to flow and the water phase saturation increases while the oil phase saturation gradually decreases. The mobility and oil-water multiphase fluid flow area have a positive correlation (Figure 15(a)). This is because the physical meaning of the oil-water multiphase fluid flow area refers to the difference between the water saturation when the oil and water start to flow together and the corresponding water saturation at the end. Particularly, the smaller the oil-water multiphase fluid flow area, the less the space for the two phases to flow together, the greater the amount of oil inside the reservoir blocked by water, the lower the mobility of the oil phase. Corresponding to the macroproduction, it can be revealed that with the intrusion of water, the water saturation of the reservoir increases, the oil-water ratio decreases faster, the stable production time becomes shorter, and the oil phase mobility becomes worse.

4.3.2. Slope of Oil Phase Curve. The slope of the oil phase curve restricts the mobility of the reservoir. The recovery rate of the sample decreases as the slope of the oil phase curve increases (Figure 15(b)), indicating that the oil phase permeability decreases rapidly with the increase of water saturation.
while the flow capacity of oil phase decreases rapidly with the increase of water saturation; consequently, the mobility of oil phase deteriorates severely. The slope of the oil phase curve of Z1 and Z3 is 0.039 and 0.042, respectively, while the slope of the oil phase curve of Z4 and Z5 is 0.0315 and 0.0312, respectively. This indicates that the oil phase permeability of Z1 and Z3 decreases significantly, and the inside of the reservoir is dominated by water phase flow.

4.3.3. Bound Water Saturation. The mobility of tight oil becomes worse as the bound water content increases (Figure 15(c)). The higher the bound water saturation, the smaller the effective space for oil-water exchange during the displacement process, and the lower the sweep efficiency. The NMR and displacement experiments were conducted to demonstrate the relationship between bound water saturation and the recovery rate in different $T_2$ intervals of the sample (Figure 15(d)). Particularly, the larger the $T_2$, the larger the pores. As illustrated in Figure 15(d), the bound water saturation of the small pore is relatively high, and the mobility is worse because the water in the small pores is difficult to be displaced by the oil due to the big capillary force. Besides, the oil phase causes great resistance to the water because of the Jamin effect in the process of water driving oil given the high content of bound water in the small pore. Thus, the oil recovery rate in the small pores is low, and the mobility is poor. Figure 16 indicates that for the same sample, all the oil in the pores with $T_2$ spectrum greater than 100 ms was recovered while the recovery rate of $T_2$ spectrum in pores with 10-100 ms and $T_2$ spectrum less than 10 ms was only 70% and 35%, respectively, suggesting that the mobility of tight oil increases as the pores grow larger. In summary, the bound water content has an important influence on the mobility of tight oil.

4.3.4. Oil-Water Permeability Equal Point. The oil-water permeability equal point reflects the strength of the interference ability during the flow of oil and water. Specifically, the higher the relative permeability value of the oil-water permeability equal point, the smaller the degree of mutual interference between the oil and water phases in the reservoir. Besides, owing to the mutual interference of oil and water, the relative permeability of the oil-water permeability equal point is less than 1, and the oil-water permeability equal points of the six samples are less than 0.15, indicating that the oil and water two-phase interference of tight sandstone reservoirs is severe. The oil recover ratio and oil-water permeability equal point do not exhibit obvious correlation (Figure 15(e)), demonstrating that the oil-water permeability equal point value has no obvious influence on the mobility of tight oil. The previous studies have verified that the oil-water permeability equal point increases as the permeability increase [45]. The permeability and oil-water permeability equal point of the 6 samples also exhibited the same trend (Figure 15(f)). It has been discussed previously that a reservoir with low permeability is likely to have a higher recovery ratio compared to high permeability reservoir. Thus, the oil-water permeability equal point has no apparent relationship with the mobility of tight oil.

4.4. Comprehensive Evaluation of Tight Oil Mobility. The effects of physical properties, pore throat structure, and oil-water two-phase seepage on the mobility of tight oil are discussed. Through the previous discussion, five parameters that are most critical to the mobility of tight oil are selected: pore throat radius, pore throat sort coefficient, oil-water multiphase fluid flow area, bound water saturation, and slope of the oil-phase curve. Besides, the fitting equation (formula (1)) of tight oil mobility and five parameters was established by multivariate analysis method, and the correlation coefficient was 0.9856 (Figure 17). This indicates that the mobility of tight oil can be characterized by these five parameters. Generally, the micropore throat structure is the internal
cause, controlling the mobility of tight oil by influencing the reservoir physical property and the law of oil-water two-phase seepage. In this paper, the mobility of tight oil is divided into four categories (Figure 18) by considering pore throat radius, pore throat sorting coefficient, and bound water saturation. Particularly, the I category has large pore throat radius, good sorting, and low bound water content, as well as strongest mobility; thus, the oil phase can be displaced by water uniformly. The II category exhibits small pore throat radius and good sorting; then, the oil phase was displaced by water uniformly. However, the II category reservoir requires high displacement pressure. The III category has large pore throat radius, poor sorting, and high bound water content; it is easy to form the advantage channel. Consequently, the sweep efficiency is lower, and the mobility is poor compared to category II. The IV category has small pore throat radius, poor sorting, and higher bound water content; it not only needs the big displacement pressure but it is also easy to form the advantage channel. Therefore, its sweep area is smaller than that of the IV category, exhibiting the worst mobility.

\[
y = 3.694 * r_i - 0.787 * S_c + 2.541 * S_w + 2.459 * d + 0.433 * K_w - 0.425
\]  

(3)

The \( y \) is a comprehensive parameter of pore throat radius, pore throat sort coefficient, bound water saturation, oil-water multiphase fluid flow area, and slope of the oil phase curve.

5. Conclusion

The mobility of oil phase in a large pore is stronger than in small pores and effective porosity has a greater effect on tight oil mobility than porosity. This is due to the poor connectivity and the large capillary force of the small pores. Although it is difficult for tight reservoirs to be developed, it has good development potential, and the development effect may be better compared to low-permeability and medium-high permeability reservoirs.

The oil phase permeability curve slope and the bound water saturation affect the tight oil mobility under the coexistence of oil and water. The pore throat radius and sorting are important factors to control of oil phase permeability curve slope and bound water saturation. The larger pore throat radius and the better sorting of the reservoir, the lower the bound water saturation is, the oil phase permeability decreases slowly, and tight oil has strong mobility.

The pore throat radius, pore throat sorting coefficient, and bound water saturation are the internal factors that affect the mobility of tight oil. According to above three parameters, the tight oil mobility identification chart can be established, which can better describe the relationship between the three parameters and the mobility of tight oil.

Data Availability

The data can be found in manuscript.

Conflicts of Interest

The authors declare no competing financial interest.

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