

Article

Occurrence Mechanisms and Distribution Characteristics of Remaining Oil in Medium-to-High-Permeability Reservoirs

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Abstract

To address the scattered distribution of remaining oil and the difficulty of quantitatively characterizing its microscopic occurrence after long-term water flooding in medium-to-high-permeability sandstone reservoirs, this study investigated representative core samples from the Songnan Oil and Gas Block of Jilin Oilfield. High-pressure mercury intrusion, nuclear magnetic resonance (NMR) movable-fluid testing, cryogenic molding-based full-field map scanning, and three-dimensional (3D) reconstruction were used to characterize differences in pore structure, variations in movable fluid during water flooding, and the microscopic occurrence of remaining oil. The results show that: (1) The pore-throat systems of the sandstone reservoirs are highly heterogeneous and are dominated by medium-sized pore throats, with widely developed micropore throats and locally enlarged pore throats. (2) During water flooding, the peak amplitudes of the NMR T2 spectra generally decrease, and the spectral distributions gradually change from bimodal to unimodal. Oil in well-connected pores is preferentially mobilized. After displacement, the remaining oil is still concentrated mainly in medium-sized pores, which constitute both the principal pore domain for oil mobilization and a key site of remaining-oil retention at the late stage. (3) The 2D image-analysis and 3D reconstruction results show that, after water flooding, the remaining oil occurs as locally enriched clusters, connected bodies, and dispersed residues. Across the four imaged samples, cluster-type remaining oil accounts for 54–80%, whereas the combined proportion of discontinuous forms—including multi-pore, columnar, droplet-like, and film-like oil—accounts for 20–46%. These proportional differences reflect variations in oil-phase connectivity and retention under the combined influence of water-flooding state and pore-network characteristics. The results support an integrated characterization approach combining NMR movable-fluid testing, cryogenic molding-based full-field map scanning, and 3D reconstruction, providing a new technical route for detailed identification of remaining oil at the high-water-content stage and for identifying potential targets for further oil recovery.

Keywords: medium-to-high-permeability reservoir; nuclear magnetic resonance; cryogenic molding; three-dimensional reconstruction

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1. Introduction

Medium-to-high-permeability reservoirs are commonly developed by water flooding to maintain reservoir pressure and sustain oil production. Water flooding is one of the most important methods for enhancing oil recovery [1]. During early development, well-developed pore networks and favorable connectivity allow relatively stable flow channels to form, resulting in high displacement efficiency and strong production performance. As water flooding proceeds, however, the internal flow paths are progressively reorganized. Owing to pore-structure heterogeneity, injected water preferentially migrates through high-permeability channels, gradually establishing dominant flow paths [2,3]. This preferential flow intensifies channeling, reduces the swept volume, and leaves low-permeability zones poorly mobilized. Previous studies have shown that relative-permeability evolution and multiphase-flow behavior significantly control water-flooding efficiency [4]. Reservoir heterogeneity also affects the swept volume and the distribution of injected-fluid flow paths and is therefore a major cause of declining displacement efficiency and remaining-oil retention [5].

When development reaches high- and ultrahigh-water-content stages, the oil–water distribution within the reservoir becomes increasingly complex. Remaining oil shifts from a macroscopically continuous distribution to a microscopically dispersed state, with pore-scale, pore-throat-scale, and adsorbed-phase remnants coexisting. Consequently, conventional production-performance analysis and core experiments cannot readily characterize its actual spatial distribution [6].

From the perspective of microscopic flow mechanisms, the formation and occurrence of remaining oil are governed mainly by pore-structure heterogeneity, capillary forces, wettability, and multiphase-flow pathways. Through fluid-displacement experiments, Saffman and Taylor (1958) [2] identified interfacial instability and viscous fingering during displacement of a more viscous fluid by a less viscous fluid, establishing a classical theoretical basis for understanding the development of preferential flow paths during water flooding. Ran (2016) [7] showed that pore-scale disorder strongly affects immiscible-displacement patterns and can induce transitions between stable displacement and unstable fingering. Such disorder promotes fluid trapping at low flow rates and viscous fingering at high flow rates, thereby jointly controlling displacement and sweep efficiencies. Borgman et al. (2019) [8] studied granular porous media with spatially correlated heterogeneity and found that microstructural heterogeneity enhances preferential invasion and nonuniform displacement, thereby affecting retention of the displaced phase. At the pore scale, Krummel et al. (2013) [9] used confocal microscopy to directly observe two-phase flow in 3D porous media and found that the wetting phase can snap off the nonwetting oil phase during displacement, forming disconnected oil clusters. Datta et al. (2014) [6] further showed that remobilization of trapped nonwetting-oil clusters depends on the balance between the viscous force exerted by the wetting phase and the capillary force that traps the oil at the pore scale. Although these studies have improved understanding of the multiscale occurrence of remaining oil during water flooding, differences in its spatial distribution and mobility under contrasting pore-structure conditions have not been systematically quantified. Further investigation integrating NMR with multiscale imaging is therefore required.

In recent years, advances in NMR and multiscale pore-imaging techniques have provided powerful tools for quantitatively characterizing the microscopic occurrence of remaining oil. NMR measurements based on T_2 relaxation-time distributions can non-destructively identify fluid occurrence in pores and distinguish movable from bound fluids. The method is founded on the coupled effects of surface relaxation and fluid diffusion [10–12]. NMR signals have also been widely used to characterize reservoir-fluid distributions and pore-scale fluid changes during displacement, thereby revealing oil–

water distributions and the evolution of movable fluids [13,14]. In parallel, advances in X-ray microcomputed tomography (micro-CT) have accelerated digital-rock reconstruction, enabling 3D visualization and quantitative characterization of complex pore systems and detailed analysis of pore connectivity, pore-size distributions, and fluid occurrence [15–18].

However, existing studies commonly employ NMR or imaging techniques independently. NMR can quantify fluid redistribution among different pore-size classes but cannot directly resolve the morphology and connectivity of remaining oil, whereas cryogenic imaging and 3D reconstruction provide spatial and topological information but cannot independently quantify pore-size-dependent oil mobilization. Therefore, the contribution of this study does not lie in proposing a new measurement technique or a universal pore-classification scheme. Instead, it establishes a cross-scale interpretive framework that jointly evaluates pore-size-dependent oil mobilization and the spatial occurrence of remaining oil. The framework reveals the dual role of medium-sized pores as both the principal domain of oil mobilization and the main site of remaining-oil retention, and quantitatively characterizes the change from connected cluster-type oil to discontinuous forms under the tested water-content conditions. By linking pore-throat structure, fluid mobility, and remaining-oil morphology, this study provides a new physical interpretation of the increasing recovery difficulty at the high-water-content stage and a basis for differentiating potential targets for further oil recovery.

2. Geological Overview and Experimental Samples

2.1. General Geological Setting

The study area lies within the Songnan Oil and Gas Block of PetroChina Jilin Oilfield Company, with the Fuyu and Honggang Saertu oilfields serving as representative fields. The principal targets are the Fuyang and Saertu oil layers, which contain typical medium-to-high-permeability sandstone reservoirs. The Songliao Basin is a major continental petroliferous basin in northeastern China. Its reservoirs consist mainly of channel sand bodies and fine-grained delta-front sandstones, which provide favorable conditions for hydrocarbon accumulation [19]. The Qingshankou–Putaoehua/Saertu petroleum system is one of the basin’s principal petroleum systems, and the Saertu Oil Layer and associated sandstone reservoirs are important development targets [20,21]. The Fuyang Oil Layer is closely associated with sand bodies in the fourth member of the Quantou Formation. Studies have shown that the Quantou–Nenjiang stratigraphic interval in the southern Songliao Basin contains extensively developed fluvial and shallow-water deltaic depositional systems. Variations in sand-body distribution, connectivity, and sedimentary microfacies strongly control reservoir heterogeneity [22,23]. The study block has long been developed by water flooding and has now entered the late high- to ultrahigh-water-content stage. At the macroscopic scale, the remaining oil is broadly dispersed but locally enriched.

As water flooding continues, the internal fluid distribution is progressively reorganized. Preferential flow channels develop, and high-permeability layers experience early water breakthrough and subsequently dominate fluid migration. In contrast, medium- and low-permeability zones are swept less effectively, promoting remaining-oil enrichment at the pore and pore-throat scales. Previous studies have shown that, at the high-water-content stage, vertical and lateral reservoir heterogeneity further aggravates uneven sweep, resulting in an increasingly complex remaining-oil distribution characterized by overall dispersion and local enrichment [24,25]. The reservoir rocks in the study block are predominantly sandstone and contain relatively well-developed but unevenly distributed pore networks. Variations in pore-throat configurations produce marked differences in displacement behavior among layers. Pore-throat connectivity,

pore-size combinations, and microscopic heterogeneity are important controls on oil-phase occurrence, fluid mobilization, and remaining-oil retention [26]. These geological characteristics provide the basis for examining whether variations in sand-body distribution and connectivity are reflected in the pore-throat structure, fluid mobilization, and remaining-oil occurrence of the experimental core samples.

The experimental core samples were obtained from cored wells in the representative fields described above and cover a range of petrophysical properties and water-flooding conditions. These samples were used to examine pore-scale fluid mobilization and remaining-oil occurrence within the geological context described above. The results should be interpreted in relation to the tested samples and should not be taken as a spatial characterization of remaining oil across the entire study area.

2.2. Core Characteristics

As shown in Table 1, four representative core samples from wells Jian 28, Honghua 2, and Honghua 9 were selected for NMR movable-fluid testing: S161-6, S44-1, S74-1, and S92-2. Their porosities range from 12.33% to 21.96%, and their permeabilities range from 16.04×10^{-3} to $201.67 \times 10^{-3} \mu\text{m}^2$. Collectively, the samples cover a range of porosity–permeability combinations typical of medium-to-high-permeability sandstone reservoirs and reflect the petrophysical variability and heterogeneity of the study area. S92-2 and S161-6 have relatively high porosity and permeability and represent reservoirs with favorable connectivity and strong fluid-transport capacity. S74-1 has the lowest permeability and represents a comparatively restricted pore-throat system. S44-1 has intermediate properties and represents a reservoir with moderate flow capacity. This sample set facilitates comparison of how pore-structure variations affect movable-fluid occurrence, remaining-oil retention, and water-flooding efficiency.

Cryogenic molding-based full-field map scanning and 3D reconstruction were performed on separate core samples selected from representative reservoir intervals. Because cryogenic molding and sectioning are destructive, repeated imaging of the same core at successive water-flooding stages was not feasible. The imaging samples therefore represent different combinations of water-content state and petrophysical characteristics.

Table 1. Basic experimental parameters.

Well No.	Core No.	Depth (m)	Length (cm)	Porosity (%)	Gas Permeability ($\times 10^{-3} \mu\text{m}^2$)
Jian 28	S161-6	445.1–445.3	6.02	20.08	120.72
Honghua 2	S44-1	1185.6–1185.8	6.85	17.34	90.83
Honghua 9	S74-1	1196.4–1196.6	6.82	12.33	16.04
Honghua 9	S92-2	1202.09–1202.33	6.25	21.96	201.67

3. Experimental Methods

3.1. NMR Testing and Pore-Scale Classification

Nuclear magnetic resonance (NMR) measurements were performed using a MacroMR12-150H-I large-bore NMR imaging and analysis system (Suzhou Niumag Analytical Instrument Co., Ltd., Suzhou, China) to characterize movable fluids in cores from medium-to-high-permeability sandstone reservoirs. The NMR T_2 spectrum tracks fluid distribution and remaining-oil mobilization across different pore-size classes during water flooding and is particularly suitable for assessing the effects of wettability, pore-throat heterogeneity, and displacement rate on the microscopic distribution of remaining oil [27,28]. The NMR system was equipped with a high-temperature and high-pressure online displacement module to monitor fluid distributions during water flooding. Tests were performed at 32 and 55 °C to represent differences in reservoir-fluid occurrence

associated with burial depth and formation temperature. Temperature affects relaxation by changing crude-oil viscosity and molecular mobility. Compared with 32 °C, the lower oil viscosity at 55 °C generally results in a shift toward longer relaxation times. Therefore, changes in the NMR spectra during water flooding were compared under the same temperature condition to avoid interpreting temperature-induced relaxation shifts as changes in oil content. During water flooding, NMR T_2 measurements were acquired in the initial oil-saturated state, at core-specific intermediate outlet-water-content stages, and at the ultimate water-content stage. The intermediate outlet water contents were 36% and 82% for S44-1; 38%, 80%, and 94% for S74-1; 45%, 86%, and 95% for S92-2; and 22%, 70%, and 96% for S161-6. High-pressure mercury intrusion measurements were performed using an AutoPore V 9600 automated mercury porosimeter (Micromeritics Instrument Corporation, Norcross, GA, USA) to characterize the pore-throat structure of the core samples.

After oil extraction, the cores were dried at 105 °C for 12 h, cooled, and measured for mass and length. They were then evacuated for 8 h and saturated with simulated formation water at a pressure of 15 MPa for at least 8 h. Porosity was subsequently measured, and the cores were held at a constant temperature for 1 day. The simulated formation water was of the sodium bicarbonate type. Crude oils from the study area were used, each with a viscosity of 22 mPa·s at its corresponding test temperature. Following NMR measurements in the water-saturated state, the cores were treated with a manganese chloride solution to suppress the water-phase signal. Crude oil was subsequently injected at a constant volumetric flow rate of 0.1 mL/min, corresponding to an estimated Darcy velocity of approximately 3.4×10^{-6} m/s based on a nominal core diameter of 25 mm, until no further water production was observed at the outlet. The initial oil saturation was calculated as the ratio of the cumulative volume of displaced water to the pore volume, and the initial water saturation was determined using $S_{wi} = 1 - S_{oi}$. The cores were then aged at the corresponding reservoir temperature for 12 days before the initial NMR T_2 spectra were acquired as the baseline for subsequent water-flooding analysis.

Under fast-diffusion conditions and when surface relaxation dominates, the NMR transverse relaxation time can be expressed as:

$$\frac{1}{T_2} = \rho_2 \frac{S}{V} \quad (1)$$

where ρ_2 is the transverse surface relaxivity and S/V is the pore surface-to-volume ratio. For a given pore geometry, S/V is inversely related to pore size. However, because NMR primarily responds to the pore-body surface-to-volume ratio, whereas mercury intrusion characterizes the entry radius of pore throats, a universal conversion between T_2 and pore-throat radius cannot be assumed. Therefore, a sample-specific empirical relationship was adopted:

$$r_t = CT_2 \quad (2)$$

where r_t is the effective pore-throat radius (μm), T_2 is the relaxation time (ms), and C is the sample-specific conversion coefficient ($\mu\text{m}/\text{ms}$). The water-saturated NMR T_2 distribution and the mercury-intrusion pore-throat-radius distribution were normalized, and the T_2 and r_t values at the same cumulative distribution frequencies were paired. The coefficient C was then obtained by fitting the paired data with a linear relationship passing through the origin. For core S44-1, which was continuously monitored during water flooding, the calibrated relationship was $r_t = 0.05482T_2$. Based on this sample-specific calibration, 1, 10, 100, and 1000 ms were selected as the T_2 boundaries for micropores, small pores, medium pores, large pores, and ultralarge pores, respectively. The corresponding ranges are summarized in Table 2.

Table 2. Operational pore-throat intervals based on NMR T_2 relaxation time.

Pore-Size Class	T_2 Range (ms)	Corresponding Pore-Throat Radius, r (μm)
Micropores	$T_2 < 1$	$r < 0.0548$
Small pores	$1 \leq T_2 < 10$	$0.0548 \leq r < 0.5482$
Medium pores	$10 \leq T_2 < 100$	$0.5482 \leq r < 5.4817$
Large pores	$100 \leq T_2 < 1000$	$5.4817 \leq r < 54.8171$
Ultralarge pores	$T_2 \geq 1000$	$r \geq 54.8171$

According to the calibrated pore-size criteria, the short-peak in the bimodal spectra mainly represents oil in micropores and small pores, whereas the medium- to long-peak mainly represents oil in medium and large pores. Because peak height can also be affected by peak width, oil mobilization was quantified from the change in the integrated NMR signal, expressed as oil saturation, within each T_2 interval rather than from peak height alone. For each pore class, the mobilization ratio was calculated as the difference between the initial oil saturation and the oil saturation at a given displacement stage, divided by the initial oil saturation and multiplied by 100%. Oil mobilized during water flooding was quantified from the reduction in the integrated oil-phase NMR signal. Oil retained at each measurement stage, including the final stage, is referred to as remaining oil.

3.2. Cryogenic Full-Field Imaging, Image Segmentation, and 3D Reconstruction

Cryogenic molding-based full-field map scanning, image processing, and three-dimensional (3D) reconstruction were used to characterize the microscopic occurrence of remaining oil in medium-to-high-permeability sandstone reservoirs across multiple scales. Image-analysis methods are widely used to quantify oil-phase distributions after water flooding; for example, CT imaging and image processing can visualize remaining oil in naturally water-wet sandstones during water flooding, and parameters such as shape factor, contact ratio, and Euler number can be used to quantitatively classify remaining-oil occurrence [29]. Micro-CT can also characterize the cluster-size distribution and spatial connectivity of the nonwetting phase during drainage and imbibition, providing a methodological basis for the 3D reconstruction of remaining oil [30].

During sample preparation, the cores were rapidly frozen with liquid nitrogen at different displacement stages. Rapid freezing immobilized the pore fluids at specified water contents and preserved the original oil–water configuration as closely as possible. The samples corresponded to typical water-content stages in the displacement experiments—approximately 50%, 80%, 90%, and 95%—allowing comparison of remaining-oil occurrence across different displacement stages. The frozen cores were progressively ground and sectioned under low-temperature conditions and then scanned over the full field of view using a confocal laser scanning microscope. High-resolution two-dimensional images of the pore structure and remaining-oil distribution were obtained by stitching multiple adjacent fields of view. Two-dimensional images of the pore structure and remaining-oil distribution were obtained by stitching multiple adjacent fields of view. Because spatial-calibration information was unavailable in the exported images, these images were used primarily to compare the relative spatial distributions and morphological characteristics of remaining oil.

The acquired images were subjected to background correction, noise reduction, and grayscale enhancement. Threshold segmentation and morphological processing were subsequently performed to distinguish the pore space, mineral matrix, and oil phase. Connected-component analysis was used to identify spatially continuous oil bodies, while geometric and topological descriptors were employed to characterize their morphological features.

Consecutive two-dimensional images were registered using their structural features and reconstructed layer by layer through spatial alignment and interpolation. Remaining oil was described using five morphological categories: film-like, droplet-like, columnar, multi-pore, and cluster-type oil. These categories distinguish oil attached to pore surfaces, isolated within individual pores or throats, and distributed across multiple connected pores. The geometric and topological descriptors associated with this classification framework are defined in Equations (3)–(5), and the classification criteria are summarized in Table 3 [31].

$$S = \frac{A^3}{36\pi V^2} \quad (3)$$

$$C = \frac{A_{or}}{A_o} \quad (4)$$

$$E = 1 - N_c + N_l \quad (5)$$

In Equations (3)–(5), S is the shape factor, A is the surface area of the oil phase, and V is the volume of the oil phase; C is the contact ratio, A_{or} is the contact area between the oil phase and the rock, and A_o is the surface area of the oil phase; E is the Euler number, N_c is the number of connected components, and N_l is the number of closed loops.

The shape factor and oil–rock contact ratio are dimensionless descriptors. For the shape factor defined as $S = A^3/(36\pi V^2)$, uniform scaling of all three spatial axes changes the surface area and volume by the second and third powers of the scale factor, respectively, leaving S unchanged. Likewise, the contact ratio, $C = A_{or}/A_o$, is invariant under uniform scaling because both areas change by the same factor. The Euler characteristic describes the topology of the segmented oil phase rather than its physical dimensions. These properties distinguish the descriptors from absolute volumes and surface areas, which require spatial calibration. Nevertheless, their reliable application requires preservation of the relative spacing along all three axes, appropriate phase segmentation, and a clearly defined connectivity convention. Missing spatial-calibration and reconstruction metadata therefore limit the verification of the geometric descriptors and the reproducibility of the quantitative classification.

Table 3. Quantitative criteria for classifying remaining-oil occurrence types.

Occurrence Type	Typical Shape	Geometric Criterion	Shape Factor (S)	Contact Ratio (C)	Euler Number (E)
Film-like		Thickness < one-third of the pore-throat diameter	>2	<0.4	>0
Droplet-like		No. of pores/throats ≤ 1	≤2	=0	>0
Columnar		No. of pores/throats ≤ 1	>2	≥0.4	>0
Multi-pore		No. of connected pores > 1	>2	≥0.4	>−1
Cluster		Number of connected pores > 5	>2	≥0.4	≤−1

4. Pore Structure and Movable-Fluid Occurrence Characteristics

4.1. Pore Structure Characteristics

High-pressure mercury intrusion data from four representative sandstone cores were compared to characterize pore structure. As shown in Figure 1, the mercury intrusion–withdrawal curves differ among the cores, although all exhibit multiscale pore-throat systems, indicating pronounced reservoir heterogeneity.

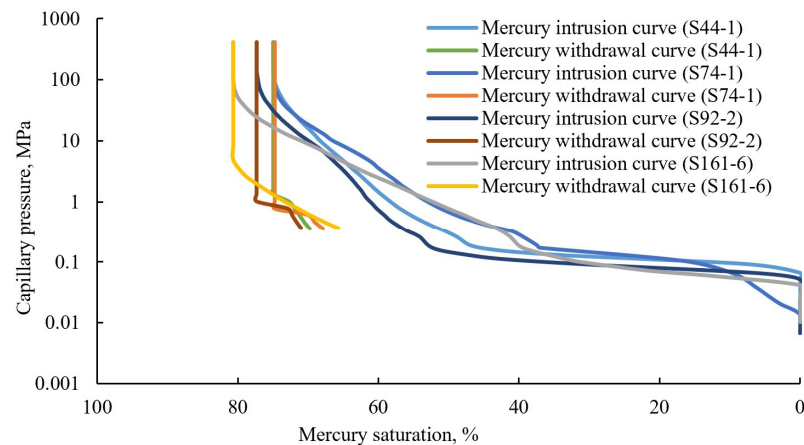


Figure 1. Mercury intrusion–withdrawal curves of the core samples.

As shown in Table 4, marked differences occur among the cores in maximum mercury saturation, mercury withdrawal efficiency, and pore-throat radius distribution. Maximum mercury saturation ranges from 74.76% to 80.66%, and mercury withdrawal efficiency ranges from 6.93% to 18.60%, reflecting variations in pore connectivity and fluid-withdrawal capacity. S161-6 has the highest maximum mercury saturation (80.66%) and mercury withdrawal efficiency (18.60%), indicating relatively favorable pore-throat connectivity. S92-2 has the highest permeability ($201.67 \times 10^{-3} \mu\text{m}^2$) and a median pore-throat radius of $4.859 \mu\text{m}$, reflecting relatively large effective flow paths and strong fluid-transport capacity. By contrast, S74-1 has the lowest permeability ($16.04 \times 10^{-3} \mu\text{m}^2$) and a median radius of only $1.067 \mu\text{m}$, indicating smaller pore throats and greater flow resistance.

Table 4. Pore-throat characteristics of the core samples.

Well No.	Core No.	Displacement Pressure (MPa)	Median Pressure (MPa)	Maximum Pore-Throat Radius (μm)	Median Radius (μm)	Sorting Coefficient	Maximum Mercury Saturation (%)	Mercury Withdrawal Efficiency (%)
Jian 28	S161-6	0.04	0.770	18.375	0.955	3.19	80.66	18.60
Honghua 2	S44-1	0.07	0.304	10.500	2.418	3.01	74.94	6.93
Honghua 9	S74-1	0.04	0.689	18.375	1.067	3.25	74.76	9.18
Honghua 9	S92-2	0.05	0.151	14.700	4.859	2.99	77.33	8.21

The four imaging samples can be divided into two approximate permeability groups. S179-4 and S129-2 are low-permeability samples, with permeabilities of 6.42×10^{-3} and $6.52 \times 10^{-3} \mu\text{m}^2$, respectively, whereas S60-4 and S90-3 have substantially higher permeabilities of 144.64×10^{-3} and $170.29 \times 10^{-3} \mu\text{m}^2$, respectively. Comparisons within each permeability group reduce, but do not eliminate, the influence of permeability. In contrast, comparisons across all four samples combine differences in water content with differences in intrinsic pore structure

and flow capacity. Accordingly, the following imaging results are interpreted as associations between water-content state and remaining-oil morphology, rather than as evidence that the observed morphological differences were caused solely by the progression of water flooding.

Comparison of the cumulative NMR T_2 distributions with the mercury-intrusion pore-throat distributions shows that the two measurements are generally consistent, particularly in the medium- and large-pore ranges. However, the agreement decreases in the micropore range. This discrepancy arises because NMR T_2 relaxation is mainly controlled by the pore-body surface-to-volume ratio and surface relaxivity, whereas mercury intrusion primarily reflects the sizes of pore throats that control mercury entry. Consequently, pores connected by narrow throats may produce relatively long T_2 signals but correspond to smaller mercury-intrusion radii, and a complete one-to-one correspondence between the two measurements is not expected.

The pore-throat systems of the sandstone reservoirs are dominated by medium-sized pore throats, with widely developed micropore throats and locally enlarged pore throats, resulting in pronounced multiscale heterogeneity. This pore-scale heterogeneity is consistent with the spatial variation in the distribution and connectivity of fluvial-channel and delta-front sand bodies in the study area. At the core scale, such geological variations are expressed as differences in permeability, pore-throat radius, and pore-network connectivity. Across the four cores, pore-throat size generally decreases, and the distribution narrows as permeability declines, reflecting progressive deterioration in reservoir connectivity and fluid-transport capacity. These differences in pore structure and flow capacity provide the basis for the subsequent variations in oil mobilization and remaining-oil retention during water flooding.

As shown in Figures 2–5, sample-specific linear relationships passing through the origin were obtained between T_2 relaxation time and pore-throat radius. The conversion coefficients for S44-1, S74-1, S92-2, and S161-6 were 0.05482, 0.07422, 0.10719, and 0.076 $\mu\text{m}/\text{ms}$, respectively, with corresponding R^2 values of 0.7909, 0.9272, 0.9458, and 0.9457. S92-2 exhibited the largest conversion coefficient, consistent with its relatively large median pore-throat radius and high permeability. The lower R^2 value of S44-1 indicates a greater mismatch between pore-body-sensitive NMR responses and pore-throat-sensitive mercury-intrusion results, which may reflect stronger pore-body–throat differentiation and variations in surface-relaxation behavior. By contrast, the higher R^2 values of S74-1, S92-2, and S161-6 indicate a more consistent correspondence between their T_2 distributions and pore-throat-radius distributions. These differences demonstrate that the T_2 -to-pore-throat-radius conversion is sample-dependent. Accordingly, the sample-specific fitted relationships were used in the subsequent pore-size analysis, because applying a single conversion coefficient to all cores would introduce additional uncertainty.

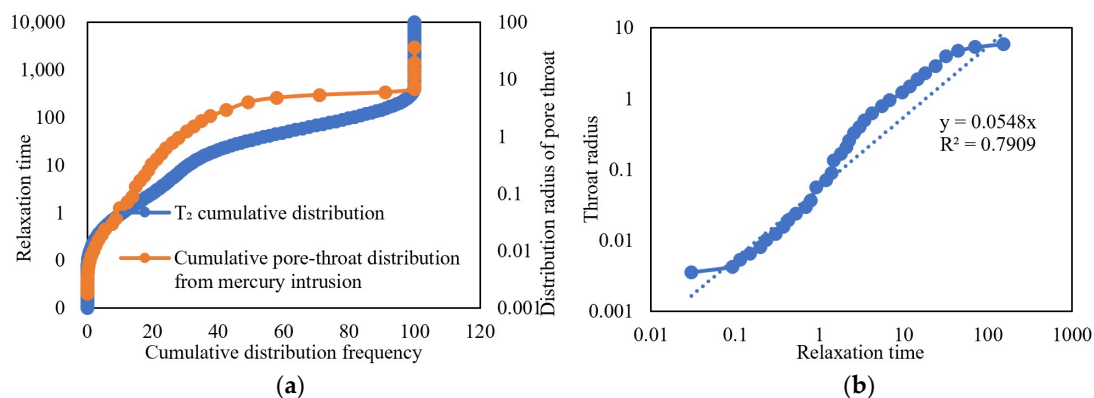


Figure 2. Relationship between NMR T_2 and pore-throat structure for core S44-1. (a) Comparison of the T_2 and cumulative mercury-intrusion pore-throat distributions, (b) Relationship between T_2 and pore-throat radius. The dashed line in panel (b) represents the linear fit.

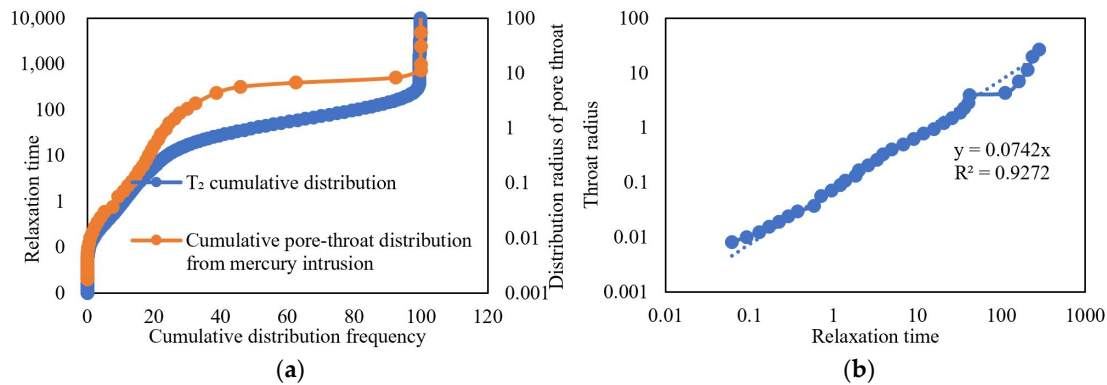


Figure 3. Relationship between NMR T₂ and pore-throat structure for core S74-1. (a) Comparison of the T₂ and cumulative mercury-intrusion pore-throat distributions; (b) Relationship between T₂ and pore-throat radius. The dashed line in panel (b) represents the linear fit.

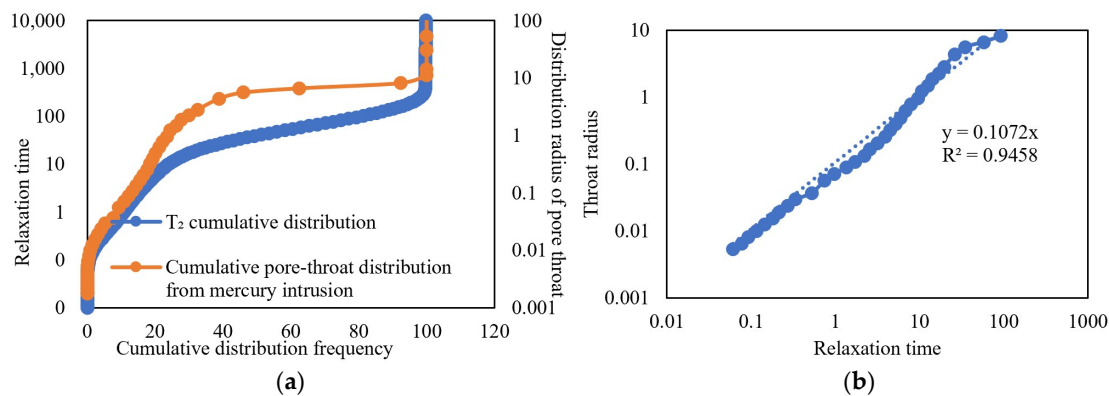


Figure 4. Relationship between NMR T₂ and pore-throat structure for core S92-2. (a) Comparison of the T₂ and cumulative mercury-intrusion pore-throat distributions, (b) Relationship between T₂ and pore-throat radius. The dashed line in panel (b) represents the linear fit.

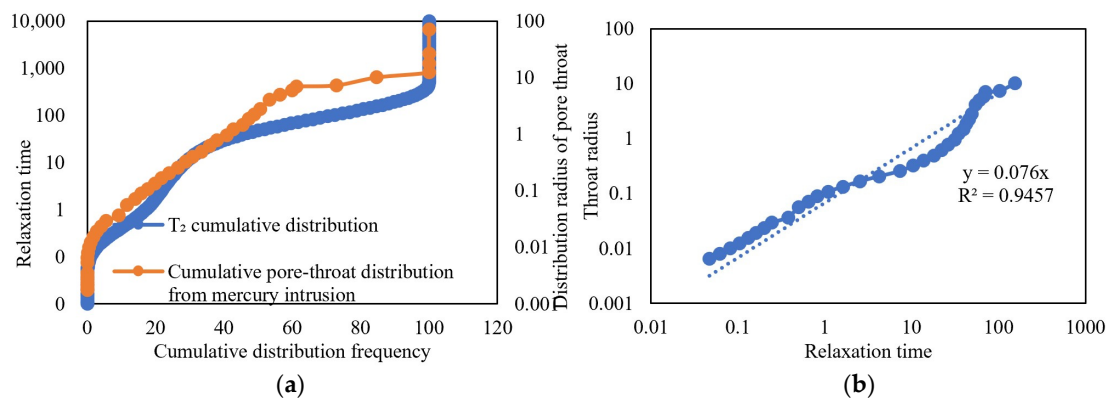


Figure 5. Relationship between NMR T₂ and pore-throat structure for core S161-6. (a) Comparison of the T₂ and cumulative mercury-intrusion pore-throat distributions, (b) Relationship between T₂ and pore-throat radius. The dashed line in panel (b) represents the linear fit.

4.2. Initial Fluid-Occurrence Characteristics

Based on the NMR T_2 measurements, the initial fluid-occurrence characteristics of the four representative cores were analyzed. As shown in Figure 6, all cores exhibit multimodal T_2 distributions, but peak configurations and principal peak positions differ markedly. In high-permeability cores, the T_2 distributions shift toward longer relaxation times, and the proportion of medium- to long-relaxation-time components increases, indicating well-developed medium and large pores and a high movable-fluid fraction. In low-permeability cores, the distributions are concentrated mainly at short relaxation times and are dominated by micropores and small pores.

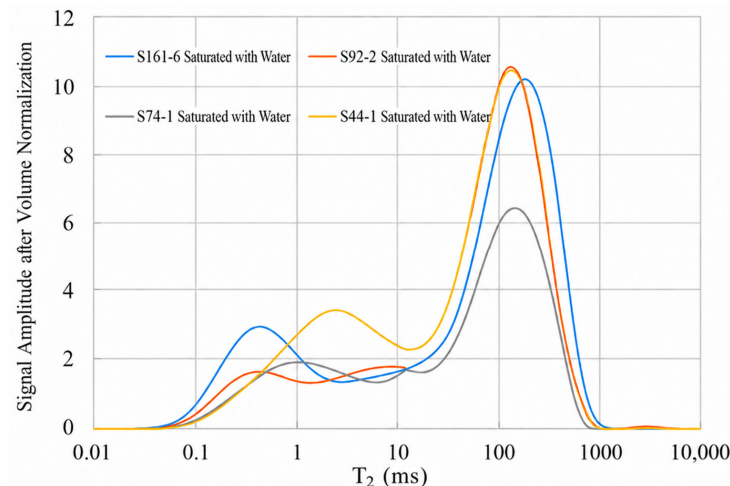


Figure 6. NMR T_2 spectra of the core samples after initial water saturation.

4.3. Variation in Movable Fluid During Water Flooding

Core S44-1 was selected for continuous NMR monitoring because its porosity and permeability are intermediate among the four samples, representing moderate reservoir quality. NMR measurements were conducted from the initial state to the end of water flooding. The resulting T_2 spectra were used to track fluid redistribution and retention across different pore-size classes.

(1) Oil-saturated state

In the oil-saturated state, the pore space is essentially filled with oil. As shown in Figure 7a, the NMR T_2 spectrum exhibits a clear bimodal distribution, indicating that oil occupies pores across a range of sizes. The principal peak occurs in the medium- to long-relaxation-time range, suggesting that medium-sized pores constitute the main oil-bearing domain.

As shown in Figure 7b, medium pores have the highest oil saturation (36.43%), followed by micropores (16.65%) and small pores (13.20%). Oil saturation in large pores is 7.91%, whereas no oil is detected in ultralarge pores. Thus, oil in the saturated core occurs predominantly in medium pores, with appreciable proportions also present in micropores and small pores and a relatively small proportion in large pores.

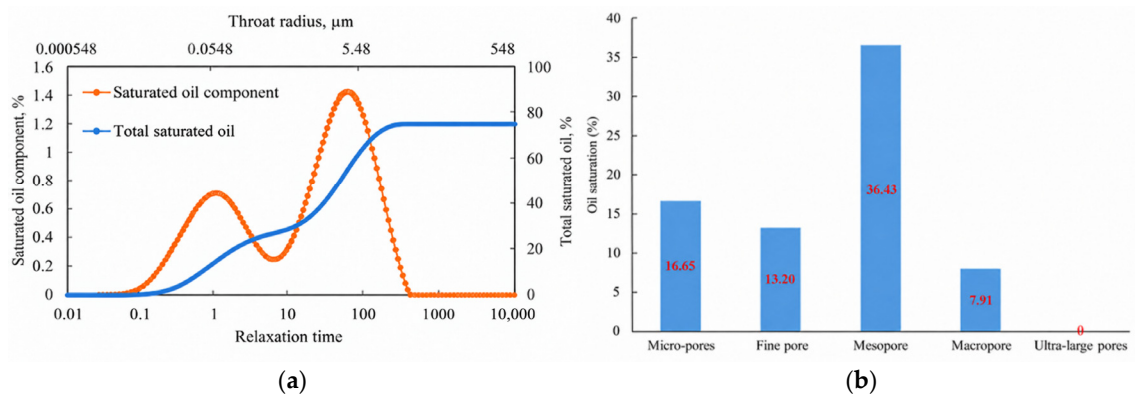


Figure 7. Oil-saturation results: (a) NMR T₂ spectrum in the oil-saturated state; (b) oil saturation across pore-throat radii.

(2) Outlet water content of 36%

As shown in Figure 8, when the outlet water content reached 36%, the T₂ distribution differed markedly from that in the oil-saturated state. The spectrum contracted toward the medium- to short-relaxation-time range, and the principal peak amplitude decreased, indicating that water flooding preferentially displaced mobilized oil from well-connected pores.

Medium pores remained the principal oil-bearing domain, with an oil saturation of 30.85%. Oil saturations in small pores and micropores were 13.18% and 8.85%, respectively, indicating that substantial oil remained trapped in smaller pores. Oil saturation in large pores decreased to 6.83%.

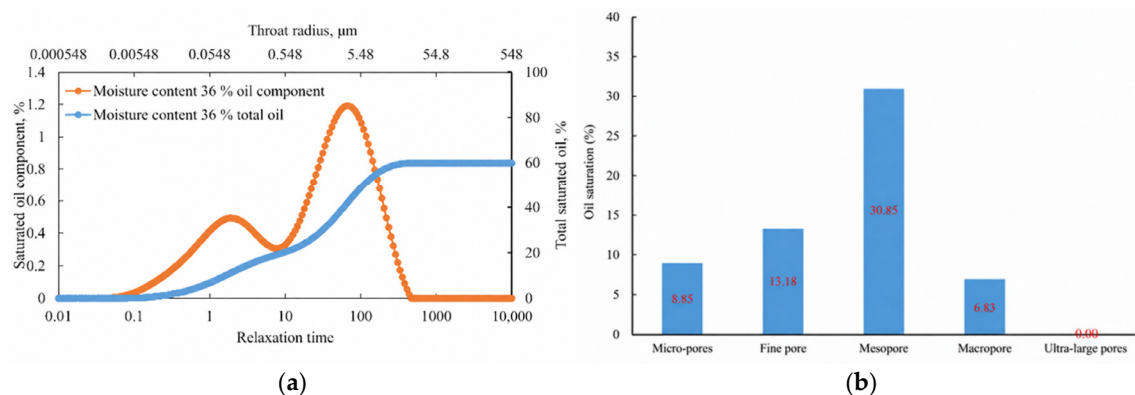


Figure 8. Results at 36% outlet water content: (a) NMR T₂ spectrum; (b) oil saturation across pore-throat radii.

(3) Outlet water content of 82%

When the outlet water content increased to 82%, oil mobilization within the core increased further. As shown in Figure 9a, the NMR T₂ peak amplitude decreased relative to that at 36% water content, and the overall spectrum contracted, indicating a continued reduction in the amount of remaining oil. The spectrum was still dominated by the medium-relaxation-time range, but its peak area was substantially smaller, indicating continued mobilization of oil from medium-sized pores.

As shown in Figure 9b, medium pores remained the principal site of remaining oil, with an oil saturation of 23.14%. Oil saturation decreased to 7.96% in small pores, 4.86% in large pores, and 1.98% in micropores. Although oil saturation decreased in every pore-size class relative to the preceding stage, it remained highest in medium pores. Water

flooding therefore exerted an increasingly strong displacement effect on oil in medium-sized pores.

(4) Ultimate water-content stage

At the ultimate water-content stage, the remaining-oil content decreased further, and the remaining-oil distribution became more localized. As shown in Figure 10a, the NMR T_2 peak amplitude and overall spectral width continued to decrease. As water flooding approached completion, oil in well-connected pores had been largely displaced, and the core entered a stage dominated by remaining-oil retention. The remaining oil was concentrated mainly in pore spaces subject to strong pore-throat constraints.

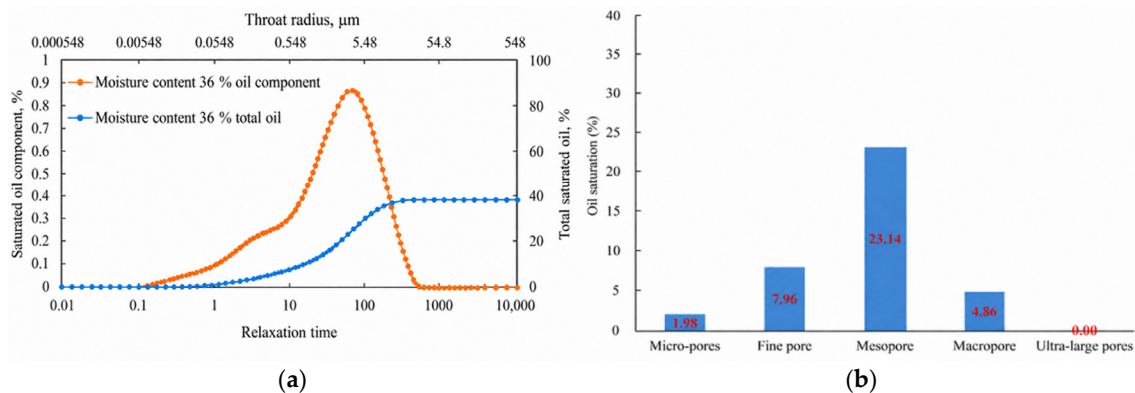


Figure 9. Results at 82% outlet water content: (a) NMR T_2 spectrum; (b) oil saturation across pore-throat radii.

As shown in Figure 10b, medium pores remained the principal site of remaining oil, with an oil saturation of 13.86%. Oil saturation was 4.10% in small pores, 2.61% in large pores, and approximately 1.10% in micropores. Saturation in every pore-size class had declined to a low level, with the largest decreases occurring in large and medium pores, indicating that most mobilized oil had been produced during water flooding.

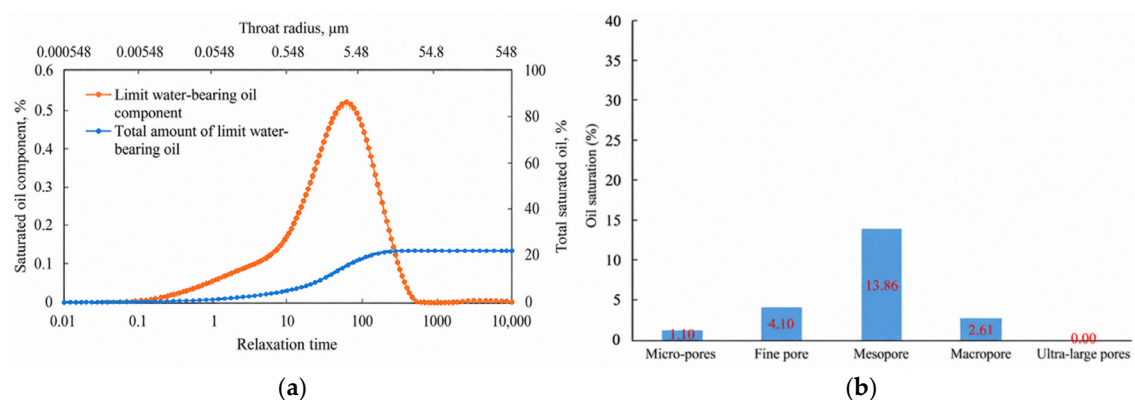


Figure 10. Results at the ultimate water-content stage: (a) NMR T_2 spectrum; (b) oil saturation across pore-throat radii.

Quantitative comparison of Figures 7–10 shows that the total oil saturation of S44-1 decreased from 74.19% in the initial oil-saturated state to 59.71%, 37.94%, and 21.67% at outlet water contents of 36%, 82%, and the ultimate stage, respectively. The corresponding cumulative oil-mobilization ratios were 19.5%, 48.9%, and 70.8%. From the initial oil-saturated state to the ultimate water-content stage, oil saturation decreased by 15.55

percentage points in micropores, 9.10 percentage points in small pores, 22.57 percentage points in medium pores, and 5.30 percentage points in large pores. Medium pores therefore showed the largest absolute reduction in oil saturation and contributed most to the total amount of mobilized oil. Nevertheless, their final oil saturation remained the highest at 13.86%, indicating that medium pores were both the principal domain of oil mobilization and the main site of remaining-oil retention.

(5) Layer-resolved T_2 spectra and NMR images

Layer-resolved T_2 spectra reveal spatial variations in fluid mobilization along the core. In Figure 11, Δ denotes the relative axial position along the core, ranging from -40 to 40 mm, and each colored curve represents the T_2 spectrum at the corresponding axial position. In the oil-saturated state, all measured axial positions display strong signals, with their principal peaks located mainly in the medium- to long-relaxation-time range. Variations in peak height and position among these axial positions indicate heterogeneity in both pore structure and oil distribution. As the outlet water content increased to 36% and then 82%, the T_2 amplitudes at all measured axial positions decreased, and the long-relaxation-time components diminished markedly, indicating continued oil mobilization from well-connected pores. At the ultimate water-content stage, the spectra contracted further, although signals remained in the medium-relaxation-time range, indicating that the remaining oil was concentrated mainly in medium-sized pores.

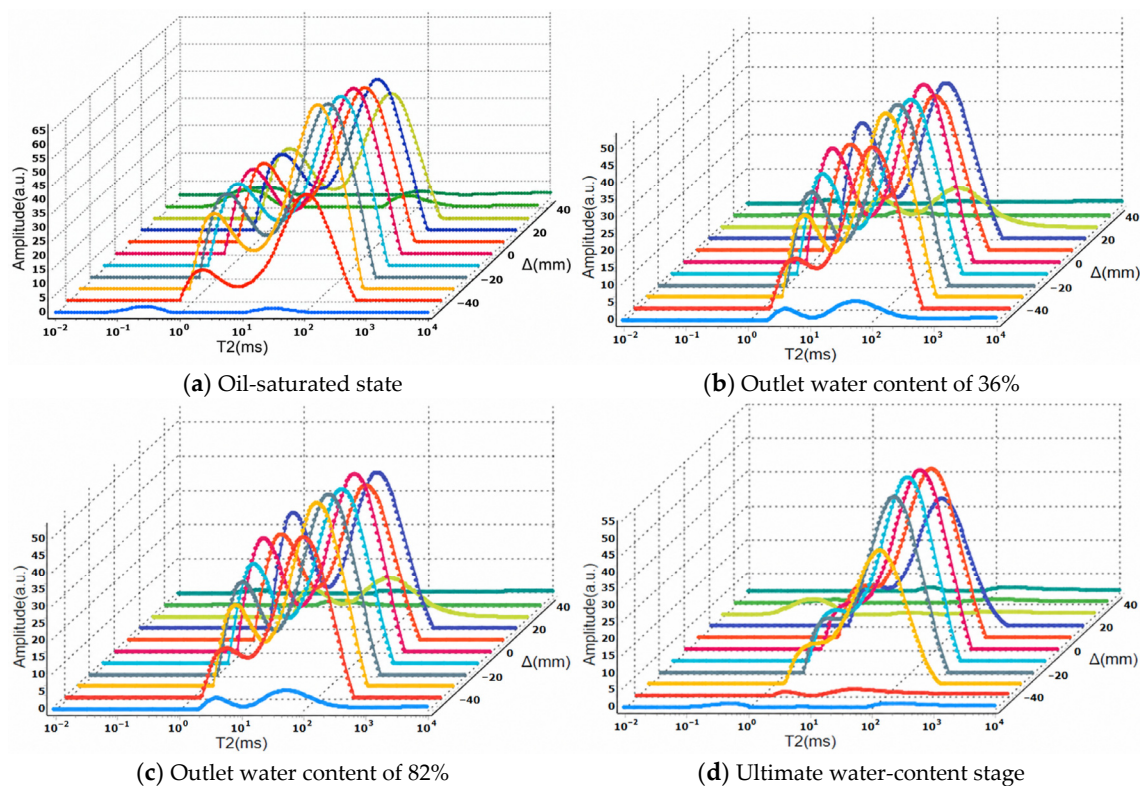


Figure 11. Layer-resolved NMR T_2 spectra at different displacement stages. The curves of different colors represent the NMR T_2 spectra at different axial positions (Δ) along the core.

The layer-resolved NMR images are consistent with the corresponding T_2 spectra. As shown in Figures 12–15, the signals in all layers are relatively continuous in the oil-saturated state. As the outlet water content increases, the high-signal regions progressively weaken, and spatial contrasts become more pronounced. At the ultimate

water-content stage, residual signals remain within the core, demonstrating that some oil persists after conventional water flooding.

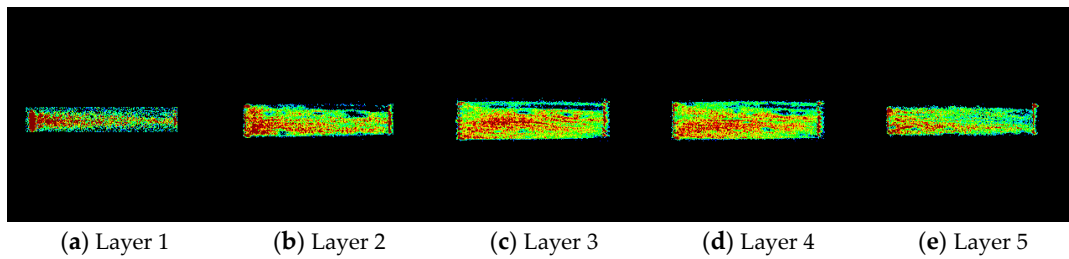


Figure 12. Layer-resolved NMR images in the oil-saturated state.

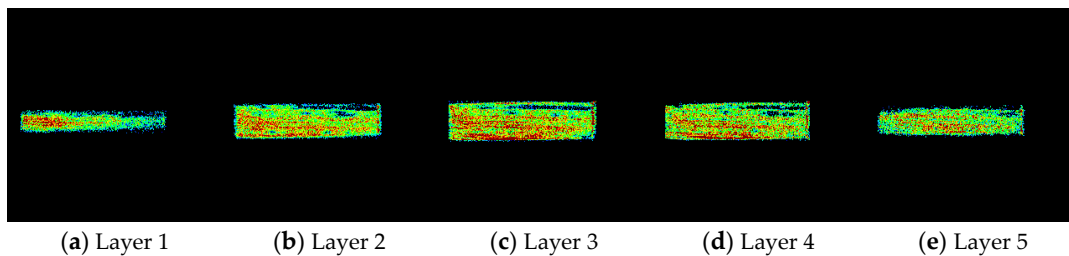


Figure 13. Layer-resolved NMR images at 36% outlet water content.

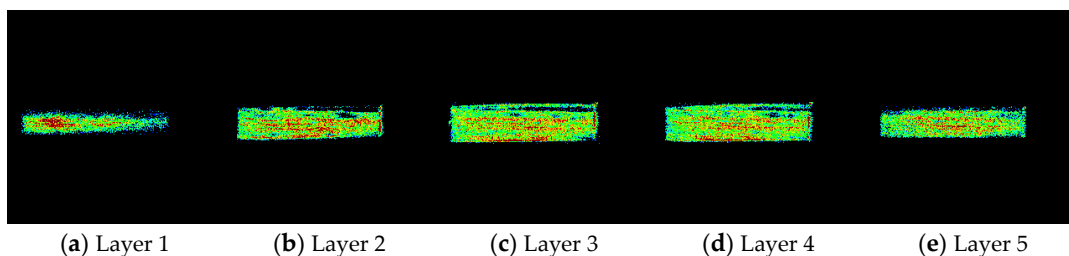


Figure 14. Layer-resolved NMR images at 82% outlet water content.

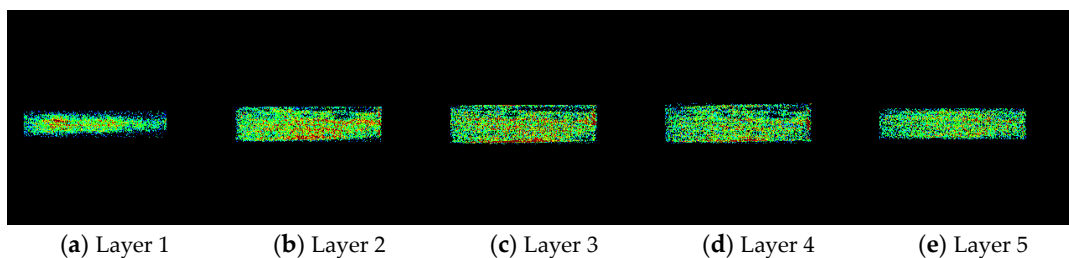


Figure 15. Layer-resolved NMR images at the ultimate water-content stage.

(6) Comparison of T_2 spectra during water flooding among cores

As shown in Figure 16, all four cores exhibited clearly bimodal T_2 distributions in the oil-saturated state. As water flooding progressed, both peaks decreased to varying degrees, indicating changes in oil content in both small and medium pores. By the late displacement stage, the spectra had gradually changed from bimodal to unimodal distributions, and the remaining-oil signals had become more concentrated.

The four cores showed similar spectral evolution: with continued displacement, the overall T_2 amplitudes decreased, the bimodal structure weakened, and a residual unimodal signal ultimately remained. Together with the pore-size-specific oil-saturation results, these observations indicate that, after water flooding, the remaining oil is

concentrated mainly in medium-sized pores. These pores constitute both the principal domain of oil mobilization during water flooding and a key site of remaining-oil retention after displacement.

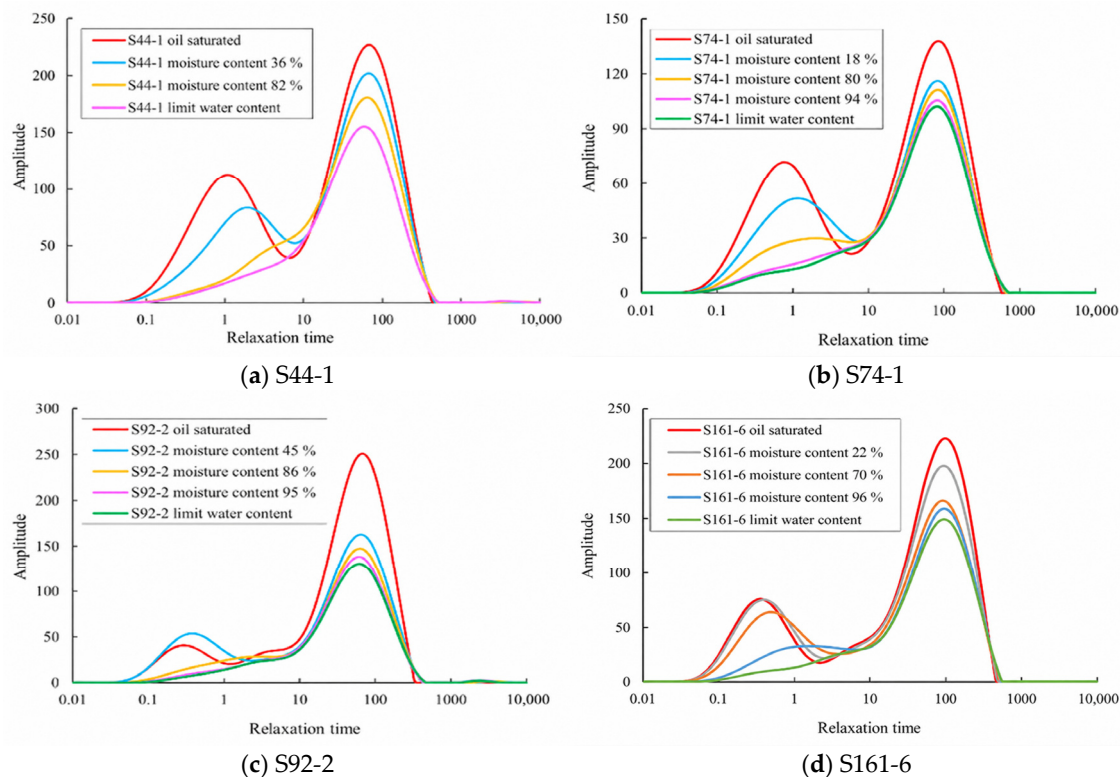


Figure 16. NMR T₂ spectra of the four cores at their respective outlet-water-content stages during water flooding.

5. Microscopic Occurrence Characteristics and Formation Mechanisms of Remaining Oil

5.1. Two-Dimensional Distribution of Remaining Oil

The microscopic occurrence of remaining oil was evaluated using four cryogenically preserved core samples prepared at different water contents. As shown in Table 5, samples S179-4, S129-2, S60-4, and S90-3 correspond to water contents of 50%, 70%, 90%, and 100%, respectively, and have permeabilities ranging from 6.42×10^{-3} to $170.29 \times 10^{-3} \mu\text{m}^2$.

Table 5. Samples used for full-field map scanning and 3D reconstruction.

Well No.	Sample ID	Permeability ($\times 10^{-3} \mu\text{m}^2$)	Preparation Condition
Honghua 9	S90-3	170.29	Water content: 100%
Honghua 2	S60-4	144.64	Water content: 90%
Jian 28	S129-2	6.52	Water content: 70%
Jian 28	S179-4	6.42	Water content: 50%

Cryogenic molding combined with full-field map scanning was used to identify and characterize oil-phase distributions in thin sections. As shown in Figure 17, red oil-phase signals are visible under all water-content conditions, showing that microscopic remaining oil persists throughout water flooding. In the samples at 100% and 90% water

content, the red regions are relatively prominent and include locally enriched, large, or patchy clusters. In the samples at 70% and 50% water content, the oil-phase signals are more dispersed and exhibit weaker local continuity.

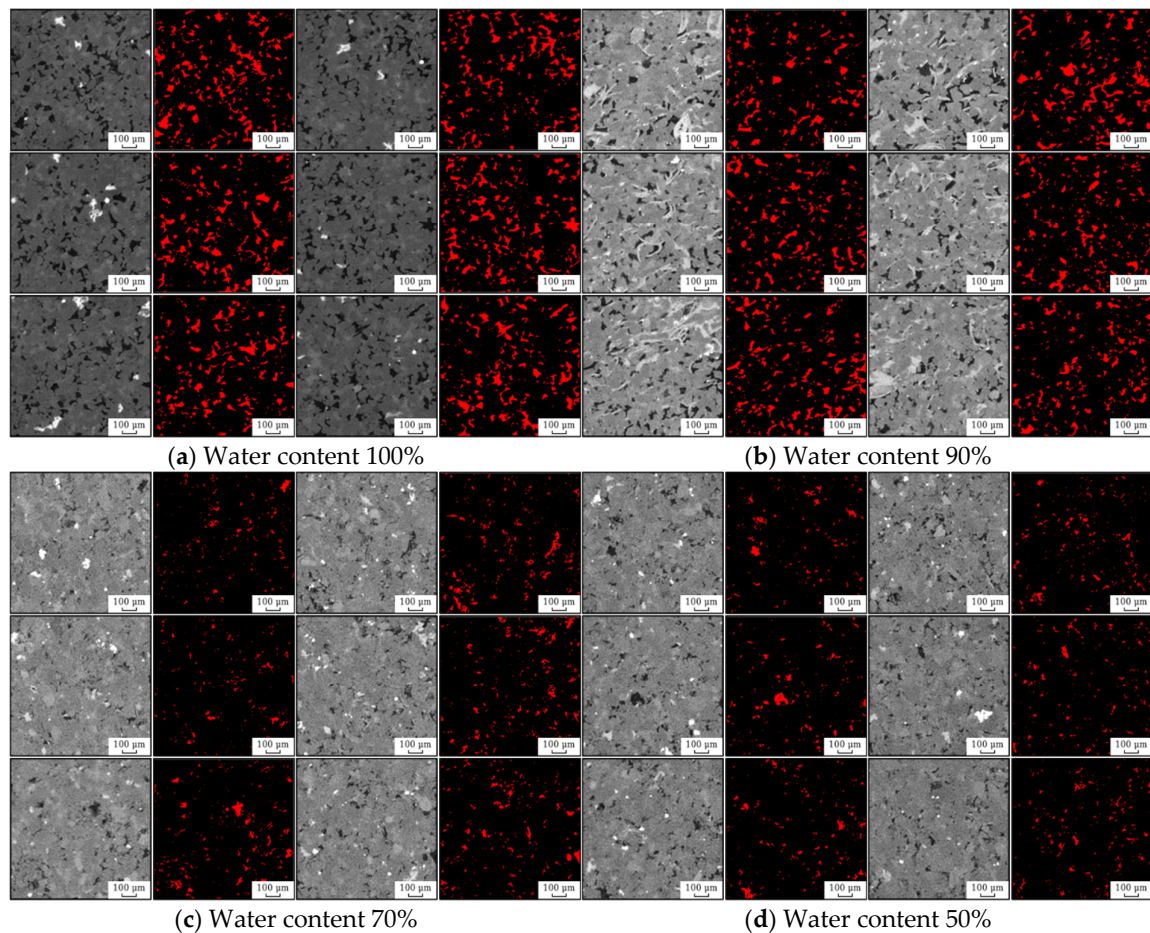


Figure 17. Full-field map-scanning images of cryogenically preserved samples at different water contents.

As shown in Figure 18, the extracted 2D remaining-oil maps further reveal differences in spatial distribution among the parallel samples. Remaining oil occurs as both locally enriched and dispersed bodies. Several enriched patches remain in the samples at 100% and 90% water content, whereas the samples at 70% and 50% water content show a more dispersed distribution composed of isolated spots and local clusters. These patterns reflect the influence of local pore structure and connectivity on oil-phase occurrence.

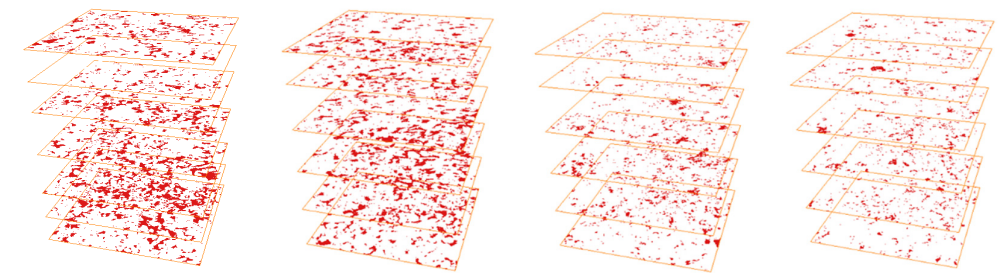
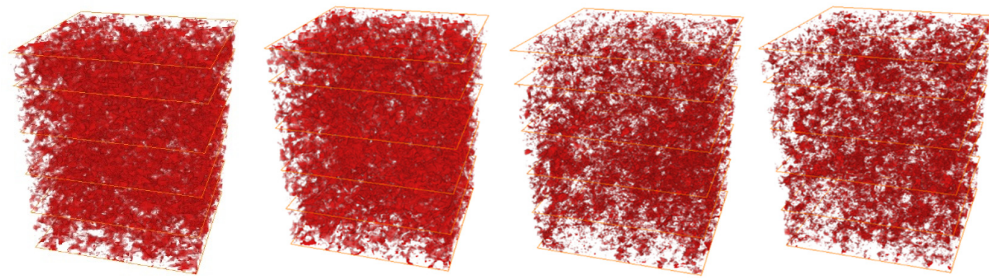


Figure 18. Two-dimensional distributions of remaining oil under different water-content conditions.

5.2. Three-Dimensional Occurrence of Remaining Oil

Three-dimensional reconstruction further reveals the spatial distribution of remaining oil within the reconstructed sample volumes. As shown in Figure 19, the remaining oil exhibits heterogeneous spatial distributions under all water-content conditions. Local enrichment is most evident near the base of the reconstructed volumes, whereas the oil bodies in the other regions are relatively dispersed. In the samples at 100% and 90% water content, the remaining-oil signals are relatively densely distributed, whereas those in the samples at 70% and 50% water content appear more localized and dispersed.

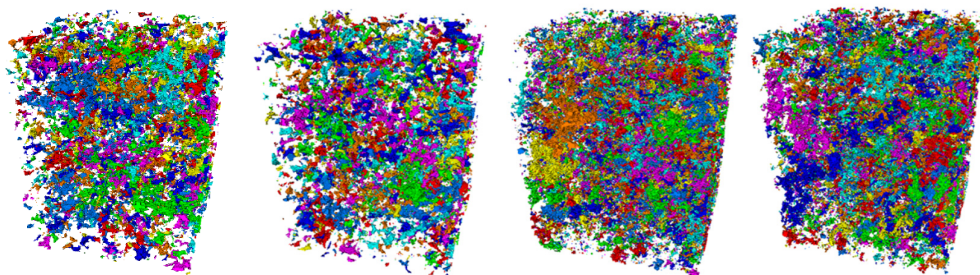


(a) Water content 100% (b) Water content 90% (c) Water content 70% (d) Water content 50%

Figure 19. Three-dimensional reconstructions of remaining oil under different water-content conditions.

5.3. Remaining-Oil Types and Changes in Their Proportions

Based on the 3D reconstructions, the occurrence types of remaining oil at different water contents were identified and quantified. Classification considered oil-phase morphology, connectivity, and contact with the rock framework. Remaining oil was divided into cluster-type, multi-pore, columnar, droplet-like, and film-like forms according to the criteria listed in Table 3. Figure 20 presents the segmented remaining-oil bodies under different water-content conditions. The different colors distinguish individual oil bodies identified by connected-component analysis and do not directly correspond to the five occurrence types. After water flooding, the oil phase comprises continuous bodies, locally connected bodies, and dispersed droplets. Cluster-type remaining oil represents the continuous phase, whereas the other four types represent discontinuous phases.



(a) Water content 100% (b) Water content 90% (c) Water content 70% (d) Water content 50%

Figure 20. Identification of remaining-oil types under different water-content conditions.

As shown in Figure 21, cluster-type remaining oil is the dominant morphology in all four samples, accounting for 54–80% of the total remaining oil. S179-4, with a water content of 50%, exhibits the highest proportion of cluster-type oil (80%), whereas S90-3, with a water content of 100%, exhibits the lowest proportion (54%). Correspondingly, the

combined proportion of discontinuous forms—including multi-pore, columnar, droplet-like, and film-like oil—ranges from 20% to 46%.

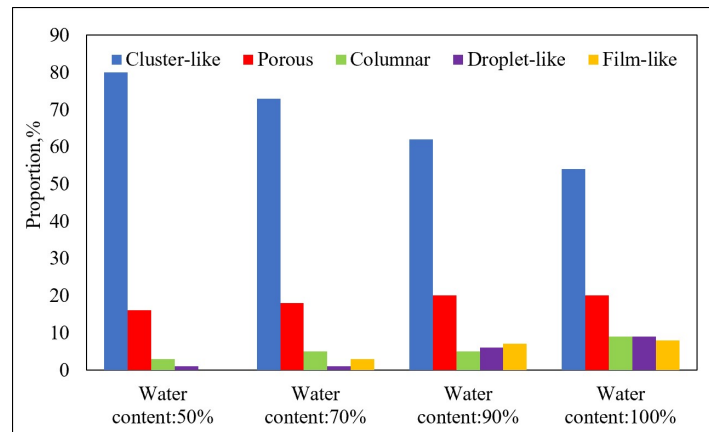


Figure 21. Proportions of remaining-oil types under different water-content conditions.

These proportional differences reflect the coupled influence of water-flooding state and pore-network characteristics. During water flooding, injected water tends to migrate preferentially through well-connected pores and throats, promoting the separation of locally connected oil bodies. Meanwhile, differences in permeability and pore-throat geometry influence preferential flow pathways and capillary trapping, leaving part of the oil in fine throats, pore corners, and on mineral surfaces as columnar, droplet-like, or film-like forms.

The relative proportions of cluster-type and discontinuous remaining oil therefore provide a morphological indication of oil-phase connectivity and local trapping intensity under different reservoir conditions. A higher proportion of cluster-type oil corresponds to greater local continuity of the remaining oil, whereas a higher proportion of discontinuous forms reflects stronger oil-phase segmentation and pore-throat confinement. Together with the stage-dependent NMR responses obtained from repeated measurements on the same core, these observations indicate that the mobilization of well-connected oil and the retention of pore-throat-constrained oil coexist during water flooding, thereby increasing the difficulty of further oil recovery.

These results also provide mechanistic indicators for qualitatively predicting subsequent flow behavior. Reservoir intervals dominated by well-connected medium-to-large pores and connected oil bodies are more likely to develop preferential water-flow paths, leading to earlier water breakthrough and relatively high initial oil mobilization. In contrast, a higher proportion of oil retained in small pores or as discontinuous columnar, droplet-like, and film-like bodies indicates stronger pore-throat confinement and capillary trapping, and therefore a weaker incremental response to continued water flooding. Accordingly, the combination of NMR-derived pore-size-specific oil saturation and image-derived remaining-oil connectivity can be used to distinguish flow behavior dominated by preferential channeling from that dominated by capillary-controlled retention. These predictions are qualitative and mechanism-based; quantitative forecasting requires further calibration against relative-permeability and field-production data.

5.4. Limitations

This study has several limitations. First, the spatial resolution of cryogenic full-field scanning restricts the identification of oil films, fine pore throats, and isolated oil bodies smaller than the effective imaging resolution; therefore, the volume and connectivity of some small remaining-oil bodies may be underestimated. Second, in micropores, strong surface-relaxation effects and the overlap of T_2 signals from different pore sizes introduce uncertainty into the conversion between T_2 relaxation time and pore-throat radius. Third, although consecutive slices were aligned before three-dimensional reconstruction, minor errors caused by section deformation, slice misalignment, and spatial interpolation may smooth oil-phase boundaries or alter the apparent connectivity of small oil bodies. Finally, the four imaged core samples differ in permeability and pore-network characteristics. Because cryogenic imaging is destructive and was performed on separate cores, the independent contribution of water content to the observed morphological differences could not be fully isolated. Future work should employ more closely matched parallel cores or nondestructive in situ imaging of the same core at successive displacement stages to further investigate the evolution of remaining-oil morphology.

6. Conclusions

- (1) Key findings. By integrating mercury-intrusion-calibrated NMR measurements with cryogenic full-field scanning and three-dimensional reconstruction, this study links pore-throat structure, pore-size-dependent oil mobilization, and remaining-oil morphology. The pore systems are strongly heterogeneous and dominated by medium-sized pores. For core S44-1, total oil saturation decreased from 74.19% to 21.67% during water flooding, with medium pores contributing the largest absolute reduction while retaining the highest final oil saturation. Across the four imaged samples, cluster-type remaining oil accounts for 54–80%, whereas discontinuous forms account for 20–46%. Their relative proportions characterize differences in oil-phase connectivity and local trapping under the combined influence of water-flooding state and pore-network characteristics. These observations are consistent with previous NMR and pore-scale CT studies showing that pore-structure heterogeneity promotes nonuniform displacement and oil-phase fragmentation, while the present study further establishes a cross-scale link between pore-size-dependent oil mobilization and three-dimensional remaining-oil morphology.
- (2) Implications for high-water-cut reservoirs. Development adjustment should focus on improving sweep efficiency rather than simply increasing water injection. Medium-pore regions containing relatively high remaining-oil saturation are important targets for further recovery. Locally connected cluster-type and multi-pore remaining oil may be preferentially mobilized through injection-profile adjustment and flow diversion, whereas dispersed columnar, droplet-like, and film-like oil may require measures that reduce capillary trapping or modify interfacial properties.
- (3) Future work. Further studies should expand the number and geological coverage of core samples, combine NMR with higher-resolution or in situ imaging, and systematically evaluate the effects of temperature, injection rate, and wettability. Establishing relationships between pore-scale characterization parameters and field production performance is also necessary for reservoir-scale application.

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Z.L. and J.Z.; funding acquisition, Z.L. and J.Z. All authors have read and agreed to the published version of the manuscript.

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