

Article

Study of Pore–Throat Structure in Tight Triassic Sandstone: A Case Study on the Late Triassic Yanchang Formation, Southwestern Ordos Basin, China

Hui Xiao ^{1,2,*}, Haonan Wang ^{1,2}, Yao Ning ^{1,2}, Xiaoli Ma ^{1,2} and Shuai Yin ^{1,2,*} 

¹ School of Earth Sciences and Engineering, Xi'an Shiyou University, Xi'an 710065, China; xahn_wang@163.com (H.W.); ningyao0916@yeah.net (Y.N.); 19156589748@163.com (X.M.)

² Shaanxi Key Laboratory of Petroleum Accumulation Geology, Xi'an Shiyou University, Xi'an 710065, China

* Correspondence: xiaohui@xsyu.edu.cn (H.X.); speedsys@163.com (S.Y.); Tel.: +86-18629294519 (H.X.); +86-13331190422 (S.Y.)

Abstract: In order to better understand pore–throat structure characteristics, the coupling relationship between micropore–throat structure and macro reservoir quality and influencing factors caused by authigenic minerals were studied. Petrographic analyses, scanning electron microscopy (SEM), pressure-controlled mercury injection (PMI), nuclear magnetic resonance (NMR), and X-ray diffraction (XRD) were performed on a suite of tight reservoir samples from the Chang 8 Member of the Upper Triassic Yanchang Formation in the southwestern Ordos Basin, China. The results show that the pore–throat sizes obtained with the combination of PMI and NMR methods varied from nano- to microscale, revealing pore–throat sizes ranging from 0.001 μm to 70 μm , and showing that pore–throats with a radius larger than 1.0 μm are rare. Larger pore–throats with good connectivity ($>r_{\text{apex}}$) account for a smaller part of the total pore volume, ranging from approximately 7.58% to 38.90% with an average of 22.77%, but account for more than 80% of contributions to permeability. The effective movable fluid porosity (φ_{emp}) measured by NMR, ranging from approximately 0.10% to 7.07% with an average of 2.56%, had a positive contribution to permeability. The contents of chlorite occurrence state, other than illite, are beneficial to pore–throat preservation. A new reservoir evaluation scheme of the Chang 8 reservoir is established. These research results provide a theoretical basis for the evaluation and development of tight sandstone oil and gas exploration.

Keywords: Yanchang Formation; microscopic pore–throat structure; movable fluid; authigenic minerals; tight sandstone



Citation: Xiao, H.; Wang, H.; Ning, Y.; Ma, X.; Yin, S. Study of Pore–Throat Structure in Tight Triassic Sandstone: A Case Study on the Late Triassic Yanchang Formation, Southwestern Ordos Basin, China. *Minerals* **2024**, *14*, 617. <https://doi.org/10.3390/min14060617>

Academic Editor: Thomas Gentzis

Received: 14 March 2024

Revised: 6 June 2024

Accepted: 11 June 2024

Published: 17 June 2024



Copyright: © 2024 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (<https://creativecommons.org/licenses/by/4.0/>).

1. Introduction

The pore–throat structure affects the occurrence and seepage characteristics of fluids in a reservoir, which in turn affects the quality of the reservoir. As non-traditional oil and gas resources, tight sandstone oil and gas have become a “hot spot” in the field of oil and gas development due to their huge resources [1,2]. Porosity and permeability, the important petrophysical parameters in conventional reservoir evaluation, also play a key role in the quality evaluation of tight sandstone reservoirs [3–5]. At the same time, the pore–throat structure of tight sandstone reservoirs cannot be ignored [6–8]. The microscopic pore–throat structure of a reservoir (including the type, shape, size and distribution, and connectivity of pores and throats) is one of the important factors affecting the hydrocarbon-bearing properties of tight sandstone reservoirs. It determines the petrophysical properties, as well as the heterogeneity and seepage characteristics of a reservoir, and therefore ultimately affects the migration and accumulation of oil, and the effective development of oilfields [9–15]. The tight sandstone oil and gas reserves in the Ordos Basin are abundant, with high exploration and development potential. However, there are issues such as ultra-low permeability, complex pore structures, micro–nano pore–throat systems, and an extremely low natural

productivity of single wells. Therefore, studying the influence of the pore structure of tight sandstone reservoirs on seepage characteristics is of great significance for improving reservoir development efficiency and recovery rates.

The Maling Oilfield is located in the southwest of the basin and is a large tight sandstone oilfield discovered in recent years in the Ordos Basin. Its structural units span across the Yishan Slope and the Tianhuan Syncline secondary structural units (Figure 1). The main production layer of Maling Oilfield is the Chang 8 oil layer group—the Upper Triassic Yanchang Formation (Figure 1). The Chang 8 reservoir in the study area is mainly controlled by western provenance, with the development of a shallow water delta sedimentary system. The tectonic deformation of the Chang 8 oil layer is gentle, and it has the characteristics of a gentle monocline structure. The compositional maturity and structural maturity are relatively low, with relatively low porosity and low permeability (with an average porosity of 10.3% and an average permeability of $0.71 \times 10^{-3} \mu\text{m}^2$). It has the characteristics of a complex pore–throat structure, strong heterogeneity, large oil saturation change, and low oil and gas recovery [16,17]. Previous studies of the pore–throat structure of the Chang 8 tight sandstone reservoir in the Maling Oilfield show that the throat is the main factor controlling the petrophysical properties of the Chang 8 reservoir. The lower the reservoir permeability, the smaller the throat radius and the more concentrated its distribution [16,17]. In general, the research on the coupling relationship between the microscopic pore–throat structure and the macroscopic petrophysical properties of the Chang 8 tight sandstone reservoir in the Maling Oilfield is unclear.

The Chang 8 reservoir in the Maling area of the Ordos Basin is a typical tight sandstone reservoir, and previous studies have extensively investigated its pore structure and the impact on the flow properties of the Chang 8 reservoir in this area [18–22]. Liu Hanlin et al. (2018) [17] found that the throat is the main controlling factor for the physical properties of tight sandstone reservoirs. As the permeability decreases, the throat radius decreases and the distribution becomes more concentrated, occupying a larger proportion of effective reservoir space. Ren Xiaoxia et al. (2015) [23] used experimental methods such as core and thin section observation, scanning electron microscopy, and high-pressure mercury intrusion to comprehensively characterize the micropore structure characteristics of the Chang 8 tight sandstone reservoir in the Maling area. The results showed that the reservoir was relatively dense as a whole, with a threshold permeability of $1 \times 10^{-3} \mu\text{m}^2$. Samples greater than $1 \times 10^{-3} \mu\text{m}^2$ had a higher proportion of nanoscale and submicron pore–throats (30% to 55%), while samples lower than $1 \times 10^{-3} \mu\text{m}^2$ had an increased proportion of micrometer pore–throats in the total pore–throats. The capillary flow model was applied to analyze the contribution of different-scale throats to permeability, pointing out that sub-micron-scale pore–throats in reservoirs play a dominant role in flow. In summary, previous researchers have conducted extensive research on the micropore–throat structure of tight sandstone, represented by the Chang 8 reservoir in the Maling area, and have achieved a certain understanding and recognition. However, many researchers have focused on the characteristics and influencing factors of pore structure, with less attention paid to the impact of pore–throat structure on storage and seepage.

In addition to the study of micropore structure, different scholars have applied a variety of techniques (such as casting thin sections, scanning electron microscopy, mercury intrusion, nuclear magnetic resonance, nitrogen adsorption, and CT scanning) to study the pore–throat structure of different types of tight sandstone reservoirs [6,18,24–26]. In the characterization of tight sandstone reservoirs, different methods have their own focuses, but each has its own limitations. Casting thin sections and scanning electron microscopy analysis can intuitively display the appearance and two-dimensional distribution characteristics of micropore–throat structures, and can obtain parameters such as pore–throat size, coordination number, and porosity calculation through image analysis. However, these methods have low accuracy and cannot provide quantitative parameters for pore–throat distribution characteristics. High-pressure mercury injection (HPMI) provides a wide range of pore–throat scales that can be measured, and a series of parameters reflecting pore–throat

size, pore–throat sorting, pore–throat connectivity, and seepage ability can be obtained to achieve the quantitative characterization of reservoir pore–throat characteristics. However, some larger pore–throats in the reservoir may be omitted [27]. Nuclear magnetic resonance (NMR) testing technology is based on determining the difference in fluid hydrogen nucleus relaxation rates in different diameter pores, and the transverse relaxation time T_2 is used as the research object. This has been widely used to determine the pore size and saturation of fluids with different occurrence states (free water and bound water) [25,28]. NMR technology cannot destroy the pore–throat structure of rock samples, and can characterize the distribution of the full range of pore sizes [18,29].

Li Aifen et al. (2015) [30] believe that the T_2 spectrum is controlled by the pore–throat radius. Comparing this method with the pore–throat radius distribution reflected by the mercury intrusion method, they believe that the mercury intrusion method has significant limitations and errors. The throat radius below the maximum mercury intrusion pressure cannot be characterized, while nuclear magnetic resonance can more comprehensively reflect the overall pore–throat and fluid flow characteristics. Gong Yanjie et al. (2016) [31] found that there are certain shortcomings and limitations in the T_2 spectrum conversion process, among which include the values of relaxation rate and structural factors. Therefore, NMR and HMPI can be combined for calibration [32] to ultimately determine the optimal relaxation rate and structural factors, and improve the accuracy of pore and throat analysis in tight reservoirs.

In order to finely characterize the micropore structure of the Chang 8 reservoir in the Maling area of the Ordos Basin and determine the impact of different-scale/range pore–throats on the reservoir's physical properties and fluid flow, a new reservoir evaluation scheme for the Chang 8 reservoir is established. These research results provide a theoretical basis for the evaluation and development of tight sandstone oil and gas exploration.

2. Geological Background

In the Late Triassic, the Ordos Basin was actually a quasi-cratonic non-equilibrium subsidence basin superimposed on the Paleozoic Great North China Basin. The basin morphology was influenced by the Indosinian movement and exhibited a NW–SE trending syncline with a wide eastern wing and a narrow western wing [33].

The study area is located in the northwestern part of the Qingcheng area in the southwestern part of the Ordos Basin (shown in the blue wireframe of Figure 1). This area is located between the Tianhuan depression and the north Shaanxi slope tectonic belt, and it is a western-leaning monoclinic which is high in the east and low in the west. The average slope of the formation is less than 1° , with low-amplitude nose-like uplifts only developing in local areas.

The basin is filled with sediments from the Upper Proterozoic to the Middle Jurassic, including the Early Paleozoic marine facies strata, the Late Paleozoic marine–continental transitional facies strata, and the Mesozoic continental petroleum-bearing strata. In the Upper Triassic Yanchang Formation in the Mesozoic, the Chang 10 to Chang 1 members were deposited from bottom to top (Figure 1). The Upper Triassic Yanchang Formation is a set of alluvial fan and delta–river–lake facies with a terrigenous clastic sedimentary system deposited in the process of continuous depression and stable settlement. Its lithology is mainly composed of fine sandstone, siltstone, and mudstone interbedded with oil shale [26]. Among them, the Chang 6 to Chang 8 members are important tight sandstone oil-bearing strata.

The Chang 8 member of the Maling Oilfield is mainly a delta front sedimentary system. Its microfacies include underwater distributary channels, diversion bays, and river channel flanks, while alluvial fans are occasionally seen [34].

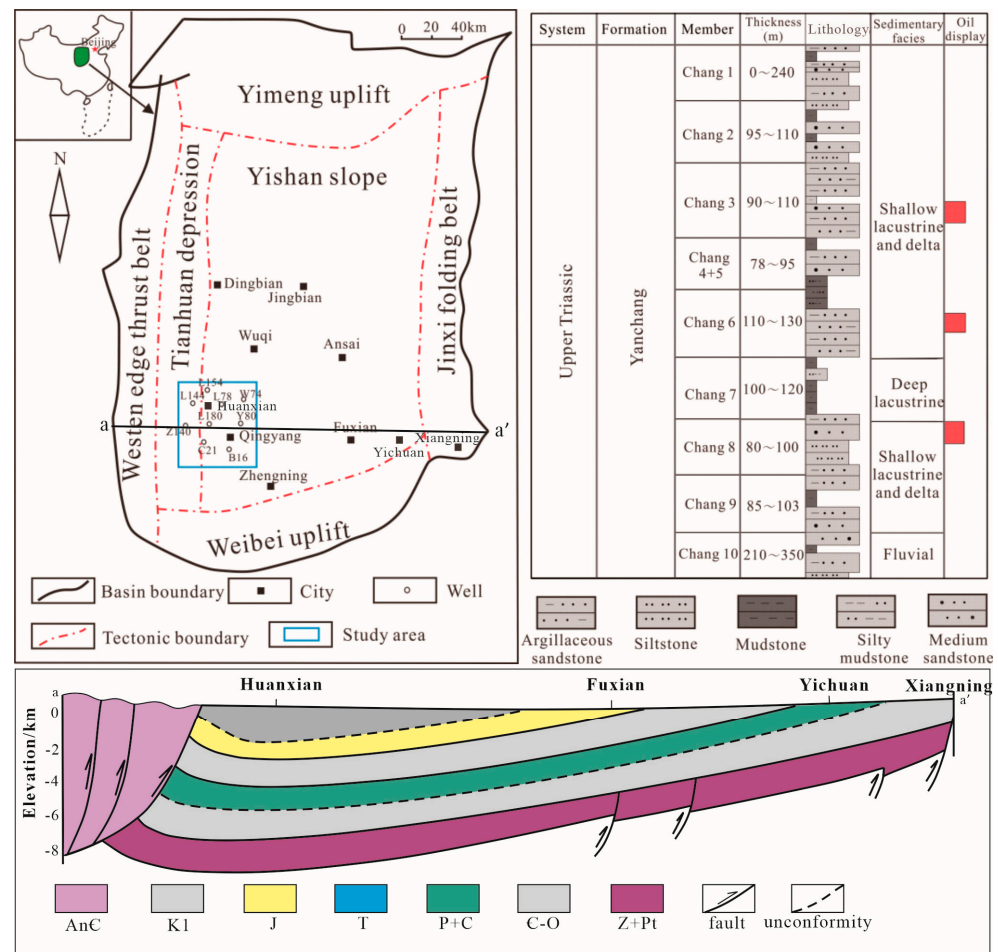


Figure 1. Location of the Maling Oilfield and stratigraphic column of the Yanchang Formation and regional stratigraphic cross-section in the Ordos Basin, China (modified from [35]). Explanation of stratigraphic symbols: AnC: Pre-Cambrian; K1: Early Cretaceous; J: Jurassic; T: Triassic; P + C: Carboniferous Permian; C-O: Cambrian–Ordovician; Z + Pt: Proterozoic.

3. Materials and Methods

The principle of sample selection for HPMT and NMR measurements covers well cores with different oil-bearing grades, including oil immersion, oil stains, and oil spots from relatively high oil-bearing grades to low grades. A total of 15 rock samples in the Maling area were collected in this study from 9 exploration wells (wells C21, L78, L144, L154, L180, Y80, B16, W74, and Z140) in the Chang 8 member in the Yanchang Formation. The depth of the samples was from 1867.4 m to 2297.4 m. In addition to the two experiments mentioned above, parallel samples of sandstone from the same location were selected for casting thin sections, scanning electron microscope testing, X-ray diffraction, and the analysis of physical properties.

The conventional petrophysical property analysis and X-ray diffraction of the cores were conducted at the Collaborative Innovation Center of Unconventional Oil and Gas Exploration and Development at Xi'an Shiyou University. A helium porosity method and a nitrogen permeability method were used for the petrophysical property analysis. The instruments used for porosity and permeability were ULTRAPORE-200A and ULTRAPERMTM 200, respectively, and the core dimensions were 2.5×2.5 cm. The instrument used for X diffraction was the D8 Focus. X-ray diffraction analyses were completed using bulk sample powders on an X'Pert Pro DY2198 at the State Key Laboratory of Geological Process and Mineral Resources in the China University of Geosciences. The samples were

ground into powders smaller than 200 meshes (75 microns in diameter). XRD patterns were recorded by a Rigaku D/max-rA diffractometer with Cu K α radiation.

Casting thin sections was undertaken at the School of Earth Sciences and Resources at China University of Geosciences (Beijing, China). The polarizing microscope used was an Olympus BH2. The scanning electron microscope instrument was Quant200, and the working voltage HV was 20 kV.

The conventional petrophysical property analysis and X-ray diffraction of the cores were conducted at the Collaborative Innovation Center of Unconventional Oil and Gas Exploration and Development at Xi'an Shiyou University. A helium porosity method and a nitrogen permeability method were used for the petrophysical property analysis. The instruments used for the porosity and permeability assessments were ULTRAPORE-200A and ULTRAPERMTM 200, respectively, and the core dimensions were 2.5×2.5 cm. The instrument used for X-ray diffraction was the D8 Focus. X-ray diffraction analyses were completed using bulk sample powders on an X'Pert Pro DY2198 at the State Key Laboratory of Geological Process and Mineral Resources in the China University of Geosciences. The samples were ground into powders smaller than 200 meshes (75 microns in diameter). XRD patterns were recorded by a Rigaku D/max-rA diffractometer with Cu K α radiation.

Casting thin sections was undertaken at the School of Earth Sciences and Resources at China University of Geosciences (Beijing). The polarizing microscope used was an Olympus BH2. The scanning electron microscope instrument was Quant200, and the working voltage HV was 20 kV.

The high-pressure mercury intrusion (HPMI) experiment was completed at the Collaborative Innovation Center for Unconventional Oil and Gas Exploration and Development at Xi'an Shiyou University. The experimental instrument was the American Mike Auto Pore IV9520 mercury intrusion meter. The highest mercury intrusion pressure was 200 MPa, and the minimum pore-throat radius was $0.0037 \mu\text{m}$ (3.7 nm). Meanwhile, the relationship between the mercury intrusion pressure P and the throat radius r was calculated according to the Washburn formula (1921) [36], $P_c = 2\sigma\cos\theta/rc$. The interfacial tension σ of the mercury intrusion experiment in this study was 480 dyn/cm, and the wetting angle θ was 140° .

The r_{apex} value was proposed by Pittman (1992) [19], and is the pore radius corresponding to Swanson's parameter. The value indicates whether the pore-throat of the rock sample has poor connectivity or good connectivity [11,19,20,37]. Swanson's parameter is the maximum value of mercury saturation in relation to the mercury pressure ratio (S_{Hg}/P_c) [20]. If the mercury saturation is plotted on the abscissa and S_{Hg}/P_c is plotted on the ordinate (Figure 2), the pore-throat radius at the vertex of S_{Hg}/P_c (maximum) is r_{apex} and the mercury saturation is SHg_{apex} [12].

Nuclear magnetic resonance (NMR) measurement is a rapid, non-destructive experimental method for studying rock pore-throat structure, porosity, permeability, fluidity, and pore size distribution [37]. The experiment was completed at the Collaborative Innovation Center for Unconventional Oil and Gas Exploration and Development at Xi'an Shiyou University. The instrument used a MARAN DRX2 nuclear magnetic resonance instrument with a waiting time of 3000 ms, an echo time of 300 μs , a number of echoes of 1024, a number of scans of 64, and a gain of 50. First, the samples were placed in simulated formation water at a saturation concentration of 50,000 mg/L for 24 h, and the transverse relaxation time T_2 distribution was measured. Then, the samples were centrifuged at 300 psi (about 2 MPa) for 3 h, and the T_2 distribution after centrifugation was measured. Finally, the ratio of the cumulative amount of nuclear magnetic signals in the two experiments to the nuclear magnetic cumulative signal in the saturated state was calculated. This ratio is also known as free water saturation.

NMR measurements are based on the inverse relationship between [7,17] reservoir pore size and hydrogen nuclear relaxation rate [38]. The T_2 spectrum does not only reflect the proportion of fluids with different relaxation times, but can also reflect the distribution of rock pore radius [7,17]. The pore size distribution (PSD) can be determined by transforming the transverse relaxation time T_2 . As an indirect measurement method,

the key to achieving the quantitative evaluation of reservoir pore structure through NMR technology is to accurately determine the conversion system between nuclear magnetic resonance relaxation time T_2 and pore–throat radius (r) [39].

$$T_2 = C \cdot r$$

C is the conversion coefficient in $\mu\text{m}/\text{ms}$; r is the pore radius.

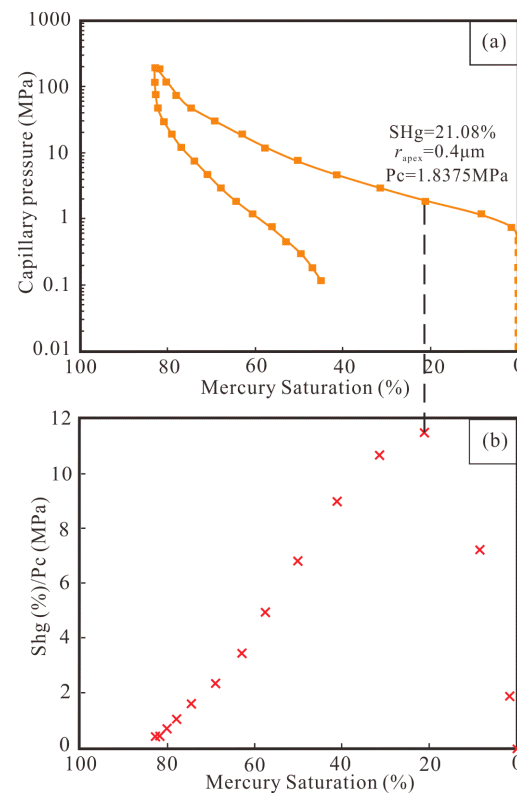


Figure 2. (a,b) Mercury intrusion curve and calculation of r_{apex} . Sample collected from well L154, 2281.6 m.

Based on the HPMI and NMR measurements, this study used mercury intrusion pore–throat radius data and nuclear magnetic resonance T_2 spectra to accumulate from the right boundary (maximum pore) to the left, and determined the pore–throat radius conversion coefficient (C) of the nuclear magnetic resonance T_2 spectrum of the tight sandstone using longitudinal interpolation and the least squares method. The specific method process is as follows: (1) Select the same core sample for the nuclear magnetic resonance T_2 spectrum and mercury intrusion testing, and obtain the cumulative curve of the T_2 spectrum. Similarly, the mercury injection pore–throat radius data are accumulated sequentially from right to left to obtain the accumulated curve of the pore–throat radii. (2) Select comparable intervals between two types of curves to ensure consistency between the T_2 spectra and the mercury intrusion pore–throat radii. (3) From the above two types of cumulative curves, two columns of data are obtained using the interpolation method with equal spacing along the vertical axis. Based on the principle of maximum similarity, the error between the two columns of data is calculated using the least squares method proposed by previous researchers [40,41], and the optimal conversion coefficient C value between the T_2 value and the pore–throat radius is determined.

Nuclear magnetic resonance (NMR) is also a very effective measurement method for the study of fluid parameters in tight sandstone reservoirs [42]. It can quantitatively evaluate the bound water and free water in the pores (Figure 3a), and therefore can reflect the mobility of the fluids in the pores and the connectivity between the pores [43]. The

bound water and free water saturation were determined by the difference in the amount of nuclear magnetic signals of the transverse relaxation time T_2 of the samples before and after centrifugation. The exact determination of the T_2 cutoff value is important for determining the bound water and free water volumes [17]. As shown in Figure 3b, the cumulative curve of the nuclear magnetic signals after centrifugation and water saturation shows the T_2 spectrum, and the horizontal projection line of the centrifugal cumulative curve is drawn. The intersection of the horizontal projection line and the cumulative curve of saturated water is the T_2 cutoff value.

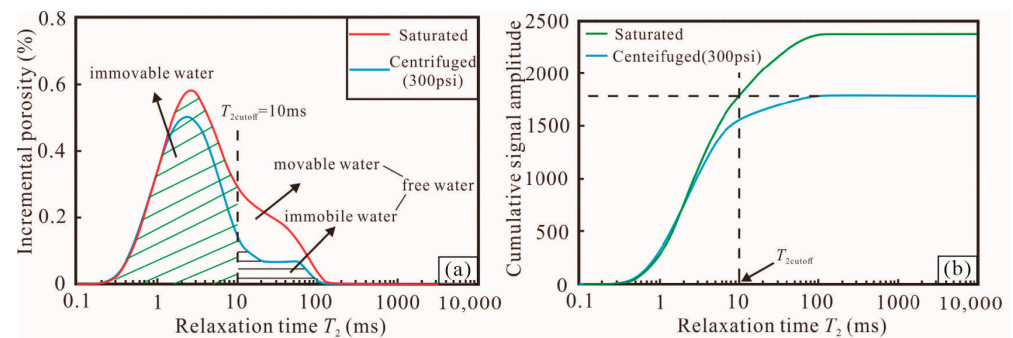


Figure 3. (a,b) $T_{2\text{cutoff}}$ based on the NMR test for the tight sandstone sample collected from well Z140, 2224 m.

4. Results

The lithology of the Chang 8 formation in the Maling area mainly includes medium sandstone, fine sandstone, siltstone, and mudstone. Through observing the cores of 15 core wells and identifying more than 120 cast thin sections in the study area, it was found that the volume content of the clastic components in the Chang 8 reservoir in the Maling area accounts for 83.36% of the total rock, and mainly includes quartz and feldspar. The average content of quartz is 30.46%, the average content of feldspar is 31.29%, and the content of rock debris is relatively low, with an average of 21.61%. The content of metamorphic rock debris is the highest, with an average of 11.34%. Igneous rock debris comes second, with an average content of 8.58%. Sedimentary rock fragments comprise the lowest proportion, accounting for an average of only 1.74%. The main rock types in the study area are lithic feldspar sandstone and feldspar lithic sandstone, with a high content of interstitial material (average greater than 10%), reflecting a low maturity in the rock composition. Impurities and cementitious materials are the two main types of interstitial materials, with significant differences in content. They mainly comprise calcite (average content of 6.21%), ferrocalcite (average content of 5.05%), chlorite (average content of 5.35%), siderite (average content of 4.51%), and hydromica (average content of 3.55%). The above data show that the reservoir interstitial materials are mainly calcium cementitious materials, followed by clay cementitious materials.

4.1. Types of Pore Geometry Forms

By observing the casting thin sections and scanning electron micrographs of the samples, we found that the Chang 8 reservoir in the study area has mainly developed intergranular pores (IEPs), intragranular dissolution pores (SPs), and clay-related pores (CRPs) (Figure 4). Microscopic observations revealed that the primary intergranular pores were mainly developed between mineral particles and were mostly surrounded by clay films (Figure 4a,b,e). Residual intergranular pores are the residual pores after pores have been filled with autogenous or secondary siliceous cement (Figure 4a,c), clay cement (Figure 4c–e), or calcareous cement (mainly calcite) (Figure 5b,e). Through the automatic statistical analysis of the images and the observation of the thin sections (with a count of 200 points per slice), the pore size of the micropores in the tight sandstone is less than 10 μm ,

and the diameter of the micro throat is less than 1 μm . According to Nelson (2009) [44], the intergranular pores of the target layer belong to the micropore category.

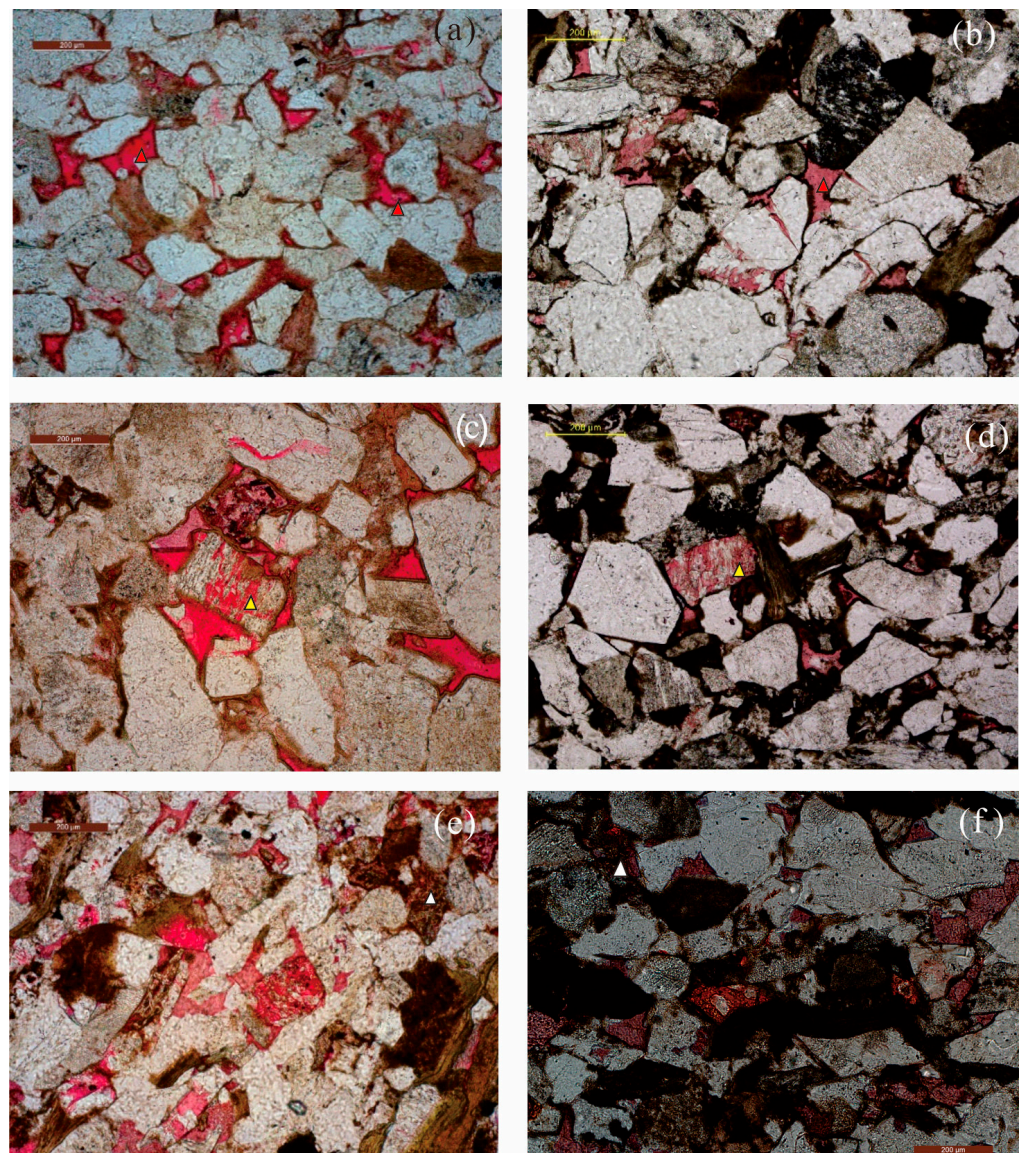


Figure 4. Pore throat types based on casting thin section observations. Red arrows represent intergranular pores; yellow arrows represent dissolution pores; white arrows represent clay-related pores, blue arrows represent throats. (a) B16 well, 2055.6 m, $\varphi = 9.32\%$, $k = 0.1921$ mD, the primary intergranular pores are developed, and the feldspar was partially dissolved to form intragranular pores; (b) L154 well, 2274 m, $\varphi = 11.07\%$, $k = 0.8439$ mD, mainly developed intergranular pores and clay-related pores and a few feldspar dissolution pores; (c) L180 well, 2150.1 m, $\varphi = 9.37\%$, $k = 0.4201$ mD, feldspar dissolution pore; (d) Y80 well, 2002.11 m, $\varphi = 14.28\%$, $k = 5.7313$ mD, intergranular pore; (e) C21 well, 2131 m, $\varphi = 9.43\%$, $k = 0.5597$ mD, primary intergranular pores are developed; (f) L154 well, 2281.6 m, $\varphi = 9.56\%$, $k = 0.3329$ mD, dissolution intragranular pores and a small amount of clay pores.

Based on the automatic statistical analysis of the images and the observation of 15 thin sections (with a count of 200 points per slice), the connection types of different types of pore–throats are shown in Figure 6. This allows us to better understand the connection between the pores and throats. Previous studies suggest that pore–throat connectivity becomes weaker as the pore–throat ratio increases [45]. As shown in Figure 6a,d, the large

intergranular pores are mostly connected by narrow throats, and thus the connectivity between the pores and throats is relatively poor. The dissolution pores are mostly beaded or weakly connected closed pores, or open intragranular pores. As shown in Figure 6b,e, these have poor connectivity. The clay pores include clay intercrystalline pores and intragranular dendritic pores (Figure 6e,f). Clay pores in tight sandstones also provide important reservoir space and the necessary seepage channels [24].

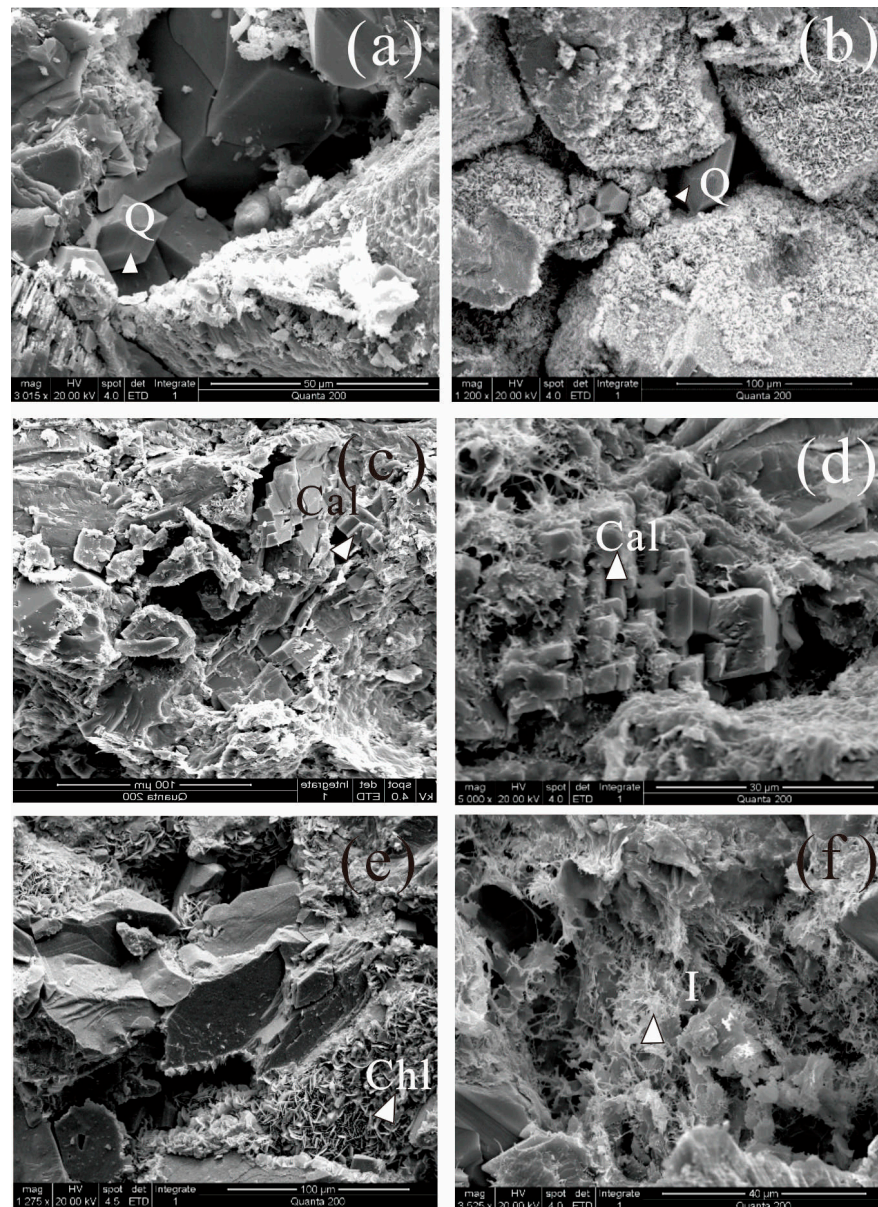


Figure 5. Pore–throat types of the tight sandstone samples of the target layer based on scanning electron microscopy. I—illite, F—feldspar, M—mica, Cal—calcite, Q—quartz, Chl—chlorite. (a) B16 well, 2055.4 m, $\phi = 9.32\%$, $k = 0.1921$ mD, filamentous illite intercrystalline pore. (b) B16 well, 2055.4 m, $\phi = 9.32\%$, $k = 0.1921$ mD, dissolution intragranular pore and residual intergranular pore. (c) C21 well, 2131.1 m, $\phi = 10.05\%$, $k = 0.6651$ mD. The throats are developed, and the pore–throats are well connected. The throats have bay-shaped and curve-shaped structures. (d) W74 well, 1867.4 m, $\phi = 10.51\%$, $k = 0.2791$ mD, dissolution intergranular pores and intragranular pores. (e) Y80 well, 2002.1 m, $\phi = 14.28\%$, $k = 5.7313$ mD. The throats and intergranular pores are developed. The chlorite film fills the surface of the particles, and a large number of clay pores also developed. (f) Y80 well, 2017.2 m, $\phi = 8.89\%$, $k = 0.1024$ mD. Illite filling in dissolution pores.

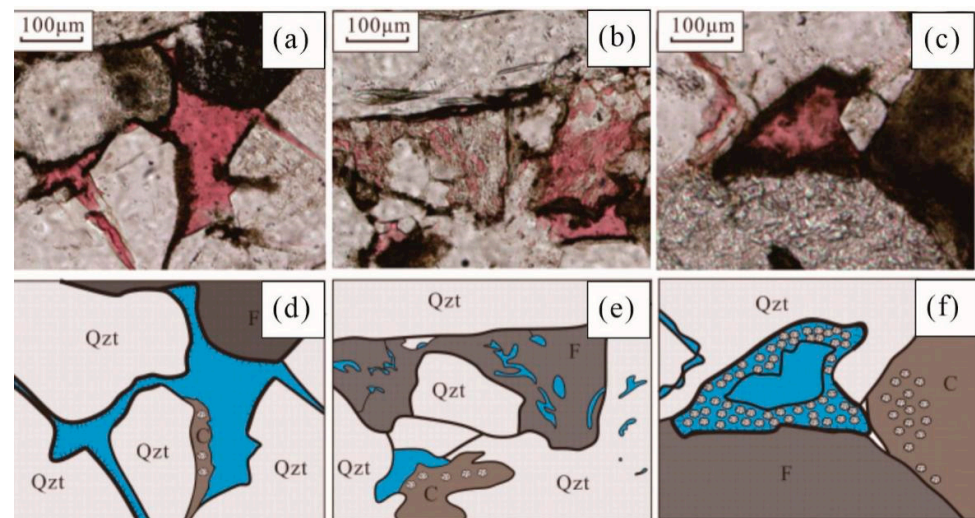


Figure 6. Pore and throat connection type. (a–d) Image of casting thin section, L144 well, 2240.9 m. (a,e) Microscopic observations and patterns of the casting thin sections of the intergranular pores and throats, respectively; (b,e) observation results and patterns of the casting thin sections of the intragranular dissolution pores; (c,f) observation results and patterns of the casting thin sections of the clay pores. Qzt—quartz particle; F—feldspar particle; C—clay. Blue filling is the pore and throat.

4.2. Type and Content of Clay Minerals

The X-ray diffraction analysis of 15 samples showed that (Table 1) the main clay minerals in the target layer were illite (0.668% to 5.998%, with an average of 2.928%), chlorite (0.773% to 5.306%, with an average of 3.344%), or illite/smectite mixed layers (0.533% to 2.487%, with an average of 1.283%), while kaolinite was not developed.

Table 1. Petrophysical properties and X-ray diffraction analysis results of the 15 samples collected from the target layer.

Well	Depth (m)	Porosity (%)	Permeability (mD)	Clay Content (%)	Chlorite Content (%)	Illite Content (%)	I/S Content (%)	Calcite Cement Content (%)	Silica Cement Content (%)
C21	2131.0	9.43	0.5596	7.89	4.9028	1.7736	1.2134	1.45	2.42
C21	2131.1	10.05	0.6738	5.05	3.1513	1.5354	0.4105	0.81	1.97
L78	2203.1	9.12	0.0997	6.92	4.0668	1.3978	1.4552	0.94	0.33
L144	2240.9	10.71	0.1881	8.15	4.0391	2.2925	1.8182	0.75	1.09
L144	2242.0	10.38	0.1544	8.78	4.8931	2.6331	1.2537	1.03	1.55
L144	2297.4	5.06	0.0241	6.51	1.8852	3.9528	0.6718	6.33	2.80
L154	2274.0	11.07	0.8438	7.18	4.9532	1.8258	0.3996	2.79	1.69
L154	2281.6	9.56	0.3329	9.06	5.3064	2.3057	1.4477	1.17	1.43
L180	2150.1	9.37	0.4201	10.37	4.3948	4.2568	1.7183	0.85	2.36
Y80	2002.11	14.28	5.7313	5.83	4.6284	0.6681	0.5334	0.98	0.42
Y80	2017.2	8.89	0.1024	7.85	1.6673	4.6055	1.5771	3.54	0.32
B16	2055.4	9.32	0.1921	4.52	0.8307	3.0017	0.6874	6.72	0.31
W74	1867.4	10.51	0.2827	9.45	3.2121	4.2676	1.9703	5.40	1.72
W74	1881.6	8.89	0.1068	5.22	0.7731	3.7296	0.7172	6.36	1.80
Z140	2224.0	9.11	0.1250	11.37	2.8857	5.9976	2.4866	4.55	0.38

Notes: The porosity and permeability data are from core analyses; I/S—illite/smectite mixed layer.

4.3. Quantitative Characterization of Pore–Throat Structure

Figure 7 shows the distribution of the pore–throat radii obtained for the five tight sandstone samples by high-pressure mercury intrusion and the pore–throat radius distribution converted by nuclear magnetic measurements. The pore–throat radii obtained by

high-pressure mercury intrusion were between $0.0037\ \mu\text{m}$ and $4\ \mu\text{m}$ (Figure 7a), and the pore–throat radii obtained by nuclear magnetic measurement were between $0.001\ \mu\text{m}$ and $70\ \mu\text{m}$ (Figure 7b). The nuclear magnetic tests had a larger pore–throat radius distribution range than the high-pressure mercury tests, and also identified bimodal and unimodal types. The first reason for this is that high-pressure mercury intrusion is limited by the maximum pressure, and mercury saturation cannot reach 100% [37], which results in the micropores in the rock sample not being measured, so the pore size range is smaller than in the nuclear magnetic tests. Second, the pore–throats in the high-pressure mercury intrusion tests were assumed to be cylindrical pore–throats, and the pores and throats could not be distinguished. Therefore, the pore–throat distribution range calculated by this method is smaller than in the nuclear magnetic tests. This understanding is consistent with previous research into the pore size distribution characteristics of the tight sandstone in the Longdong area of the Ordos Basin [17].

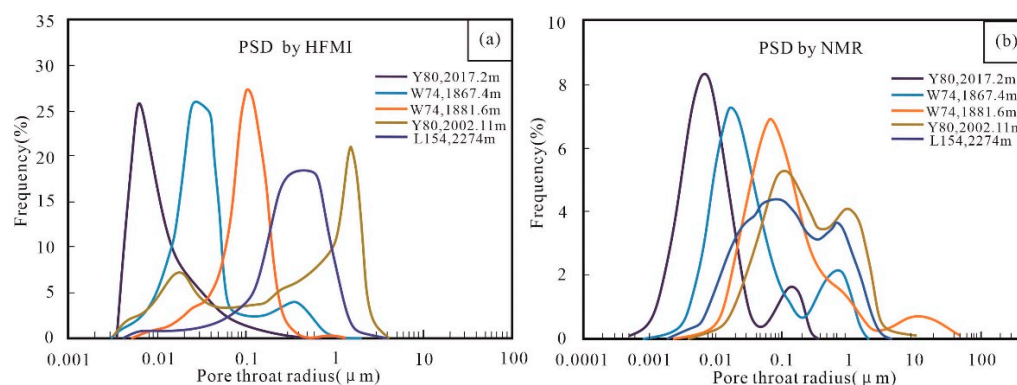


Figure 7. (a,b) Typical distribution of pore radius by HMPI and NMR tests for the tight sandstone samples in study area.

4.4. Movable Fluids

The T_2 cutoff values of the 15 samples were distributed between 3.4 and 10 ms, with an average value of 5.75 ms (Table 2). The bound water saturation of the 15 samples was distributed between 37.29% and 93.55%, with an average value of 64.91%; the movable water saturation was distributed between 2.02% and 49.52%, with an average value of 24.53%. The ratio of the movable fluid to the total porosity of a rock sample is the movable fluid porosity (or effective movable porosity). According to our calculations, the effective movable porosity of the 15 rock samples ranged from 0.102% to 7.071%, with an average value of 2.564%. The characteristics of high bound water saturation value and a large range of variation are consistent with the overall understanding of the complex pore structure of the tight sandstone reservoir in the Chang 8 section of the region by previous researchers [42].

Table 2. High-pressure mercury and nuclear magnetic resonance parameters.

Well	Depth (m)	POR (%)	PERM (md)	HPMI						NMR						
				P_d (MPa)	$SHg_{\max}$ (%)	r_{50} (μm)	r_{apex} (μm)	MRE (%)	Por_{apex} (%)	FWS(%)		$T_{2\text{cutoff}}$ (ms)	C ($\mu\text{m/ms}$)	φ_{emp} (%)	BWS (%)	
										MW	IW					
C21	2131.0	9.43	0.5524	0.7727	78.66	0.2985	0.40	30.734	3.60	38.09	12.93	8.7	0.0250	3.59	48.98	
C21	2131.1	10.05	0.6651	1.1657	83.77	0.1079	0.42	46.281	2.26	43.02	15.02	6.6	0.0030	4.32	41.96	
L78	2203.1	9.12	0.0985	0.7109	52.05	0.0228	0.63	11.046	1.67	12.66	6.36	5.1	0.0330	1.15	80.98	
L144	2240.9	10.71	0.1857	1.5653	61.55	0.0279	0.41	43.059	1.31	18.70	11.31	3.4	0.0330	2.00	69.99	
L144	2242.0	10.38	0.1524	2.0132	70.13	0.0735	0.25	34.2807	2.71	15.14	9.71	6.1	0.0300	1.57	75.15	
L144	2297.4	5.06	0.0238	4.6499	55.79	0.0083	0.20	31.968	0.38	2.02	4.42	6.7	0.0100	0.10	93.55	

Table 2. Cont.

Well	Depth (m)	POR (%)	PERM (md)	HPMI						NMR					
				P_d (MPa)	SHg_{max} (%)	r_{50} (μm)	r_{apex} (μm)	MRE (%)	Por_{apex} (%)	FWS(%)		$T_{2cutoff}$ (ms)	C (μm/ms)	ϕ_{emp} (%)	BWS (%)
										MW	IW				
L154	2274.0	11.07	0.8329	0.7509	78.45	0.3562	0.49	56.61	4.31	44.74	14.64	8.4	0.0083	4.95	40.62
L154	2281.6	9.56	0.3286	1.2223	80.19	0.1013	0.40	45.7673	2.02	27.68	6.61	7.2	0.0120	2.64	65.71
L180	2150.1	9.37	0.4147	1.4517	70.52	0.0815	0.25	45.188	2.76	26.95	16.75	3.2	0.0350	2.52	56.30
Y80	2002.11	14.28	5.6568	0.3371	86.00	0.3311	1.60	27.796	3.37	49.52	13.19	2.5	0.0460	7.07	37.29
Y80	2017.2	8.89	0.1011	22.038	64.64	0.0084	0.03	4.0490	1.20	13.91	11.67	3.6	0.0034	1.24	74.42
B16	2055.4	9.32	0.1896	3.0390	84.74	0.0313	0.06	41.204	1.89	16.12	9.84	3.7	0.0110	1.50	74.04
W74	1867.4	10.51	0.2791	3.8077	84.01	0.0349	0.06	28.788	1.75	29.85	8.61	3.2	0.0100	3.14	61.55
W74	1881.6	8.89	0.1055	3.3851	69.60	0.0987	0.13	27.796	3.22	15.01	7.45	7.9	0.0340	1.33	77.54
Z140	2224.0	9.11	0.1234	3.8737	74.44	0.0167	0.06	10.8630	1.88	14.49	9.95	10	0.0039	1.32	75.56

Notes: POR—porosity (%); PERM—permeability (mD); P_d —displacement pressure (MPa); SHg_{max} —the maximum value of mercury saturation (%); r_{50} —median radius (μm); r_{apex} —pore radius corresponding to Swanson's parameter (μm); MRE—mercury removal efficiency (%); Por_{apex} —the ratio of large pore-throats ($>r_{apex}$) to porosity(%); FWS: free water saturation (%); MW: movable water (%); IW: immovable water (%); $T_{2cutoff}$ — T_2 cutoff value (ms); C—conversion coefficient, μm/m; ϕ_{emp} —effective movable porosity; BWS: bound water saturation (%).

5. Discussion

5.1. Relationship between Microscopic Pore–Throat Structure and Reservoir Quality

Oil and gas migration in reservoirs is mainly affected by the distribution of pore–throats, and the contribution of different pore–throats to the petrophysical properties of reservoirs differs [46]. The new r_{apex} value can be used as a pore–throat boundary to discuss the contribution of different pore–throat sizes to reservoir properties. Compared to traditional pore structure evaluation parameters, this parameter can more comprehensively evaluate the contribution of different pore size ranges to permeability [47]. The contribution of pore–throat size to reservoir quality was analyzed based on mercury intrusion parameters. Figure 8a shows a rock sample with good reservoir quality. The sample was collected from 2002.11 m in well Y80. The large pore–throat volume ($>r_{apex} = 1.6 \mu m$) accounts for 23.66% of the total pore–throat volume, and its contribution to the permeability is 92.85%. The small pore–throat volume ($<r_{apex} = 1.6 \mu m$) accounts for 76.34% of the total pore–throat volume, but its contribution to the permeability is very small, accounting for only 7.15%. Sample L144 collected from 2297.4 m has a small porosity and permeability (Figure 8d). Its large pore–throat volume ($>r_{apex} = 0.204 \mu m$) accounts for 7.58% of the total pore–throat volume, and its permeability contribution rate is 95.3%, while its small pore–throats account for 95.42%, and its permeability contribution rate only accounts for 4.7%.

Through statistical analysis of the 15 samples (Table 2), it was found that the Chang 8 reservoir has mainly developed small pore–throats ($<r_{apex}$), which account for more than 60% of the total pore–throats, but their contribution to permeability is less than 20%. Large pore–throats ($>r_{apex}$) accounted for 7.58% to 38.9% of the total pore–throats, with an average value of 22.77%, and their contribution to permeability was over 80%.

The ratio of large pore–throats ($>r_{apex}$) to porosity was defined as “ Por_{apex} ”. This parameter reflects the space occupied by the large and well-connected pore–throats in the rock samples. Figure 9 shows the relationship between Por_{apex} and the porosity and permeability of the rock samples. Compared to traditional pore structure evaluation parameters, this parameter can link the connectivity of pore channels with the permeability characteristics of the reservoir, thus providing a more comprehensive evaluation of the quality of tight reservoirs [43]. Por_{apex} had a positive correlation with the petrophysical parameters in this study. This indicates that the petrophysical properties of the rock sample increase with the proportion of large pore–throats ($>r_{apex}$). However, the correlation coefficient with porosity ($R^2 = 0.3408$) is smaller than the correlation coefficient with permeability ($R^2 = 0.4829$), indicating that Por_{apex} has a greater influence on permeability than porosity. These results are consistent with the conclusions stated in the previous

paragraph of this paper. Large pore-throats ($>r_{\text{apex}}$) contribute more to permeability than porosity. However, we found that both R^2 values were lower than 0.5, indicating that the influencing factors of permeability are various. The pore-throat structures represented by Por_{apex} are also affected by factors such as mineral composition and diagenesis.

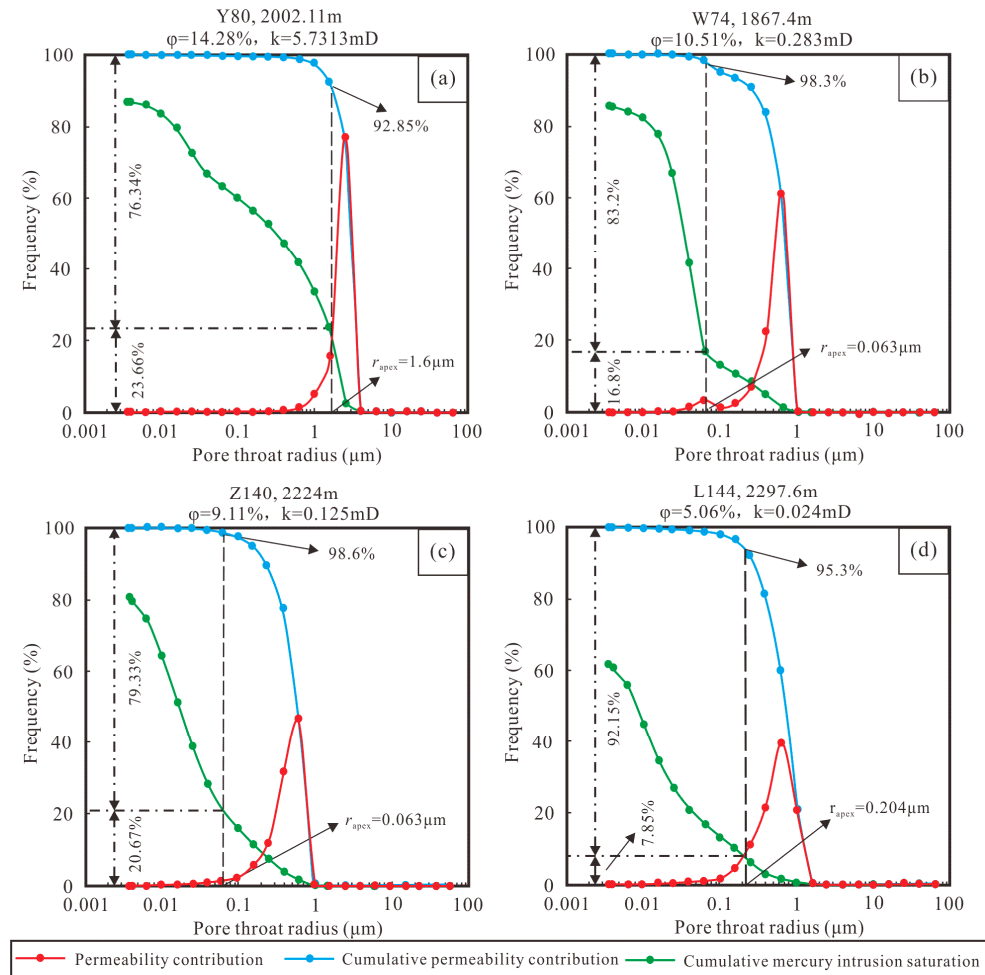


Figure 8. (a–d) Relationship between pore-throat size and macroscopic petrophysical properties.

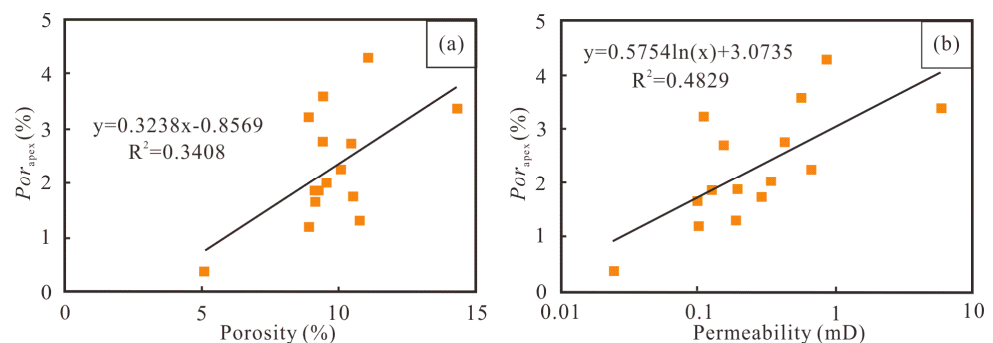


Figure 9. (a,b) Relationship between Por_{apex} and porosity and permeability.

5.2. Effect of Mineral Components on Microscopic Pore–Throat Structure and Movable Fluids

Figure 10 shows the correlation analysis between chlorite content and pore-throat structure parameters (r_{apex} and ϕ_{emp}). Chlorite has a positive correlation with r_{apex} and ϕ_{emp} . The correlation coefficient R^2 values are 0.5858 and 0.1902, respectively (Figure 10a,b), which indicate that the increase in chlorite content is beneficial to the pore-throat structures

and the movable fluids. The chlorite generally adheres to the surface of the mineral particles to form a chlorite film, which inhibits compaction and preserves the intergranular pores [20].

On the contrary, clay has a negative correlation with r_{apex} and φ_{emp} , and the correlation coefficient R^2 values are 0.5388 and 0.3387, respectively (Figure 10c,d). In addition to chlorite, the types of clay minerals in the study area also include illite and illite/montmorillonite mixed layers. Among them, illite is mainly found in filamentous form in intergranular pores and dissolution intergranular pores [46,48,49]. With the increase in clay mineral content, a large amount of non-chlorite fills the pores, causing a decrease in reservoir properties.

Figure 10 shows the correlation analysis between clay content and pore–throat structure parameters (r_{apex} and φ_{emp}). Chlorite has a positive correlation with r_{apex} and φ_{emp} . The correlation coefficient R^2 values are 0.5858 and 0.1902, respectively (Figure 10a,b), which indicate that the increase in chlorite content is beneficial to the pore–throat structures and the movable fluids. The chlorite generally adheres to the surface of the mineral particles to form a chlorite film, which inhibits compaction and preserves the intergranular pores [20]. On the contrary, illite has a negative correlation with r_{apex} and φ_{emp} , and the correlation coefficient R^2 values are 0.5388 and 0.3387, respectively (Figure 10c,d). The illite generally fills the pores and the throats, resulting in the poor connectivity of the pore–throats (Figure 5a). In addition, Figure 10e,f shows a negative correlation between total clay content and r_{apex} and φ_{emp} . This indicates that the clay has an adverse effect on the pore–throat structures and the movable fluids. Clay can fill or block pores and throats, resulting in narrow pore–throats and affecting reservoir storage space and seepage capacity [50,51].

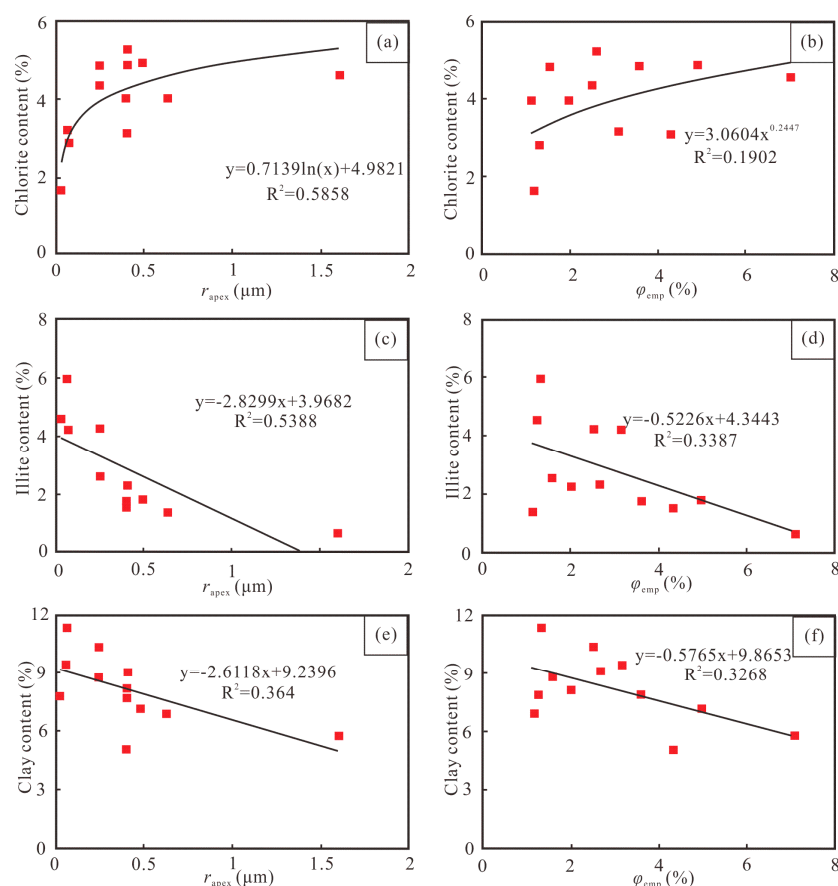


Figure 10. Relationship between clay minerals, r_{apex} (a,c,e), and φ_{emp} (b,d,f).

5.3. Classification and Evaluation of Pore–Throat Structures

According to casting thin sections, SEM observations, high-pressure mercury intrusion, and nuclear magnetic resonance test parameters, the pore–throat structures of the studied reservoirs were classified into three categories. In addition to the reservoir’s basic petrophysical parameters, such as *porosity*, *permeability*, r_{50} , and clay mineral content, new reservoir quality parameters, like k/φ , Por_{apex} , and φ_{emp} (%), were also taken into account [21,22], and the results are shown in Table 3.

Table 3. Classification of pore–throat structures with various parameters of Chang 8 reservoir in Maling Oilfield, Ordos Basin.

Pore Structure	Type I	Type II	Type III
Porosity (%)	>9	8–11	<8
φ_{emp} (%)	>2.5	1–2.5	<1
Por_{apex} (%)	>2.2	0.5–2.2	<0.5
k (mD)	>0.5	0.1–0.5	<0.1
r_{50} (μm)	>0.08	0.02–0.08	<0.02
k/φ	>0.05	0.01–0.05	<0.01
Clay mineral and content	Clay content (5%–8%), mainly chlorite, accounting for greater than 50%; Carbonate cement (<2%).	Clay content (4%–11%), with illite accounting for more than 50%; Carbonate cement (2%–6%).	Illite accounting for more than 60%; carbonate cement (>6%).

The type I pore–throat structure (Figure 11a,d) has a larger mineral particle size and a small thickness of clay film attached to the surface of the particles. The pores of type I are mainly intergranular pores, and a small number of dissolution pores are developed. The content of clay is not high, ranging from 5% to 8%, with an average value of 7.26%. The clay component is dominated by chlorite, which accounts for more than 50% of the total clay minerals. The chlorite adheres to the surface of the granule in the leaf-shaped form, and the thickness of the film is small; thus, it has a limited effect on the obstruction of the pore–throats. The mercury intrusion curve shows that the inlet pressure was low. When the pressure reached 200 MPa, the final mercury saturation was high (>80%), indicating that the pore–throats were well connected. The r_{50} is greater than 0.08 μm , and the volume of the large and well-connected pore–throats ($>r_{apex}$) accounts for more than 2.2%. The nuclear magnetic resonance analysis showed that the T_2 spectrum developed left and right fronts, and the area of the right peak was large. This indicates that the proportion of large pores in the rock sample is high ($\varphi_{emp} > 2.5\%$), and the permeability is greater than 0.5 mD. In summary, the pore–throat connectivity of type I reservoirs is good, the micropores (clay pores) and macropores (intergranular pores) are well developed, and the reservoir quality is good ($k/\varphi > 0.05$).

When the pressure was continuously reduced (mercury withdrawal), reaching 0 MPa, about 50% of the mercury of type II was retained in the rock samples, and the amount of mercury withdrawal was 10% to 20%. This indicated that the connectivity of the pore–throats of type II was poor, and the volume of the large and well-connected pore–throats ($>r_{apex}$) accounted for 0.5% to 2.2%. The T_2 spectrum of the NMR tests was dominated by the left front (<10 ms), and the right peak was small (Figure 11b,e), indicating that the rock samples from the type II reservoir mainly comprised small pores, and the macropores were poorly developed. φ_{emp} was distributed in the range of 1% to 2.5%, permeability was distributed in the range of 0.1 mD to 0.5 mD, and the reservoir quality parameter (k/φ) was distributed in the range of 0.01 to 0.05. These parameter values are all lower than that of type I.

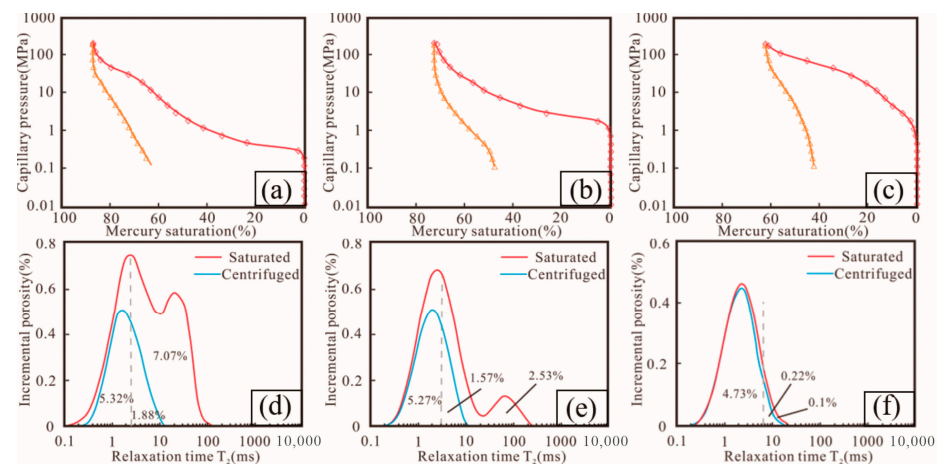


Figure 11. (a–f) Classification of pore–throat structures divided by capillary pressure curve and NMR T_2 .

In the type III reservoir, almost no intergranular pores were observed under the thin sections or via scanning electron microscopy, and only the intragranular dissolution pores were developed after the feldspar and rock debris were dissolved. These particles had the characteristic of directional alignment. Calcareous cementation in this type of reservoir was well developed, and most cement was pore-type filling (content > 6%). The X-ray diffraction clay analysis showed that the type III reservoir mainly developed illite, which accounted for 60% of the total amount of clay minerals. The content of chlorite was low, and the chlorite ring (or film) was not developed. It can be seen from the mercury intrusion curve that the inlet pressure of the samples was high, the maximum pore–throat radius was small, and the maximum mercury saturation was less than 60% (200 MPa). The above parameters are the lowest among the three types of reservoirs, and the r_{50} is less than $0.02 \mu\text{m}$. Moreover, the mercury withdrawal is only 10%, and the pore–throat connectivity is poor ($Por_{\text{apex}} < 0.5\%$). Meanwhile, the T_2 spectrum of the NMR tests had a unimodal type, the transverse relaxation time T_2 of the main peak was less than 10 ms, and there were no pores with a relaxation time greater than 100 ms ($\phi_{\text{emp}} < 1\%$) (Figure 11c,f). The rock permeability was less than 0.1 mD and the reservoir quality parameter (k/ϕ) was less than 0.01. All these parameters reflect that the quality of the type III reservoir was the worst.

6. Conclusions

- (1) The pore types of the tight sandstone reservoirs in the target layer include intergranular pores, intragranular pores, and clay-related pores. The larger intergranular pores are mostly connected by narrow throats, while the clay pores comprise mostly dendritic pores. The main clay minerals in the target layer are illite, chlorite, and illite/smectite mixed layers, while kaolinite is not developed.
- (2) The results of the high-pressure mercury intrusion (HPMI) and nuclear magnetic resonance (NMR) tests showed that the pore–throat distribution of the tight sandstone in the target layer was wide, ranging from $0.001 \mu\text{m}$ to $70 \mu\text{m}$. The r_{apex} is positively correlated with porosity and permeability, and its correlation coefficient with permeability is large. The reservoir mainly developed small pore–throats ($< r_{\text{apex}}$), which accounted for more than 60% of the total pore–throats, but the contribution to permeability was less than 20%. Large pore–throats ($> r_{\text{apex}}$) accounted for 7.58% to 38.9% of the total pore–throats, with an average value of 22.77%, and the contribution to permeability was over 80%.
- (3) The effective movable fluid porosity (EMP) can reflect the proportion of large pore–throats with good connectivity and the seepage capacity of the Chang 8 reservoir. The minimum, maximum, and average values of the EMP of the rock samples were 0.102%, 7.07%, and 2.56%, respectively. This indicates that the studied sandstone reservoir has

a large difference in seepage capacity, and the reservoir heterogeneity is strong. The correlation between EMP and permeability is as high as 0.9832, indicating that the pore-throat scale reflected by EMP is an important contributor to permeability.

- (4) Chlorite is positively correlated with r_{apex} and EMP, reflecting that chlorite is beneficial to the development of pore-throats; however, illite is not conducive to the development of pore-throats. Chlorite adheres to the surface of the mineral particles to form a chlorite film, which inhibits compaction and preserves the intergranular pores, while illite fills the pores and the throats, resulting in the poor connectivity of the pore-throats.
- (5) According to parameters such as EMP, Por_{apex} , porosity, and permeability, combined with X-ray diffraction, casting thin sections, and SEM observations, the pore-throat structures of the studied reservoirs were classified into three categories. Different types have different pore-throat structures and connectivity. Type I is dominated by intergranular pores and chlorite is developed, while carbonate cement is not developed; there are less intergranular pores in type II and III, or they are not developed, and illite content is more developed than type I. Carbonate cement is also developed, so its pore-throat structure is worse than type I.

Future work will focus on the study of the influence of pore-throat structure on oil and gas injection. We will focus on three aspects—pore-throat distribution and size, pore-throat type and relative content, and pore-throat connectivity—and analyze the influence mechanisms of pore-throat structural parameters on oil and gas filling. The next step is to determine the lower limit of oil and gas filling for whole throats. Using high-pressure mercury injection and nuclear magnetic resonance experiments to calculate the thickness of bound water film in tight sandstone, we will consider the differences between experimental and real formation conditions and determine the lower limit of oil and gas injection in pore-throats.

Author Contributions: H.X. is responsible for the idea and writing of this paper, and H.W., Y.N., and X.M. are responsible for the experiments. S.Y. is responsible for academic and legal responsibilities for this paper. All authors have read and agreed to the published version of the manuscript.

Funding: This paper is supported by the National Natural Science Key Fund Project of China (No. 41630312).

Data Availability Statement: The original contributions presented in the study are included in the article. Further inquiries can be directed to the corresponding authors.

Conflicts of Interest: All authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

References

- Han, C.; Han, M.; Jiang, Z.; Han, Z.; Li, H.; Song, Z.; Zhong, W.; Liu, K.; Wang, C. Source analysis of quartz from the Upper Ordovician and Lower Silurian black shale and its effects on shale gas reservoir in the southern Sichuan Basin and its periphery, China. *Geol. J.* **2019**, *54*, 438–449. [[CrossRef](#)]
- Zou, C.; Zhu, R.; Liu, K.; Su, L.; Bai, B.; Zhang, X.; Yuan, X.; Wang, J. Tight gas sandstone reservoirs in China: Characteristics and recognition criteria. *Pet. Sci. Eng.* **2012**, *88*, 82–91. [[CrossRef](#)]
- Ali, A.M.; Kwaya, M.Y.; Mijinyawa, A. Quartz dissolution in a single phase-high pH Berea sandstone via alkaline injection. *Energy Geosci.* **2021**, *2*, 181–188. [[CrossRef](#)]
- Anovitz, L.M.; Cole, D.R. Characterization and Analysis of Porosity and Pore Structures. *Rev. Mineral. Geochem.* **2015**, *80*, 61–164. [[CrossRef](#)]
- Ma, L.; Song, M.; Wang, Y.; Wang, Y.; Wang, H. Exploration progress of the Paleogene in Jiyang Depression, Bohai Bay Basin. *Energy Geosci.* **2022**, *4*, 42–50. [[CrossRef](#)]
- Xi, K.; Cao, Y.; Haile, B.G.; Zhu, R.; Jahren, J.; Bjørlykke, K.; Zhang, X.; Hellevang, H. How does the pore-throat size control the reservoir quality and oiliness of tight sandstones? The case of the Lower Cretaceous Quantou Formation in the southern Songliao Basin, China. *Mar. Pet. Geol.* **2016**, *76*, 1–15. [[CrossRef](#)]
- Li, J.; Zhang, P.; Zhou, Z. Quantitative characterization on dynamic methane flow in Chinese marine shales: An experimental study. *Unconv. Resour.* **2022**, *4*, 44–53. [[CrossRef](#)]

8. Thota, S.T.; Islam, M.A.; Shalaby, M.R. Reservoir quality evaluation using sedimentological and petrophysical characterization of deep-water turbidites: A case study of Tariki Sandstone Member, Taranaki Basin, New Zealand. *Energy Geosci.* **2022**, *4*, 13–32. [\[CrossRef\]](#)
9. Anovitz, L.M.; Cole, D.R.; Rother, G.; Allard, L.F.; Jackson, A.J.; Littrell, K.C. Diagenetic changes in macro- to nano-scale porosity in the St. Peter Sandstone: An (ultra) small angle neutron scattering and backscattered electron imaging analysis. *Geochim. Cosmochim. Acta* **2013**, *102*, 280–305. [\[CrossRef\]](#)
10. Zuo, J.P.; Yu, M.L.; Hu, S.Y.; Song, H.Q.; Wei, X.; Shi, Y.; Zuo, S.H. Experimental investigation on fracture mode of different thick rock strata. *J. Min. Strat. Control Eng.* **2019**, *1*, 88–96.
11. Lai, J.; Wang, G.; Cai, C.; Fan, Z.; Wang, S.; Chen, J.; Luo, G. Diagenesis and reservoir quality in tight gas sandstones: The fourth member of the Upper Triassic Xujiahe Formation, Central Sichuan Basin, Southwest China. *Geol. J.* **2018**, *53*, 629–646. [\[CrossRef\]](#)
12. Lai, J.; Wang, G.; Fan, Z.; Wang, Z.; Chen, J.X.; Zhou, Z.; Wang, S.; Xiao, C.-W. Fracture detection in oil-based drilling mud using a combination of borehole image and sonic logs. *Mar. Pet. Geol.* **2017**, *84*, 195–214. [\[CrossRef\]](#)
13. Zhu, W.C.; Niu, L.L.; Li, S.H.; Li, S. Creep-impact test of rock: Status-of-the-art and prospec. *J. Min. Strat. Control Eng.* **2019**, *2*, 77–87.
14. Yin, S.; Han, C.; Wu, Z.; Li, Q. Developmental characteristics, influencing factors and prediction of fractures for a tight gas sandstone in a gentle structural area of the Ordos Basin, China. *Nat. Gas Sci.* **2019**, *72*, 103032. [\[CrossRef\]](#)
15. Yin, S.; Tian, T.; Wu, Z. Developmental characteristics and distribution law of fractures in a tight sandstone reservoir in a low-amplitude tectonic zone, eastern Ordos Basin, China. *Geol. J.* **2019**, *55*, 1546–1562. [\[CrossRef\]](#)
16. Fang, T.; Zhang, L.; Liu, N.; Zhang, L.; Wang, W.; Yu, L.; Li, C.; Lei, Y. Quantitative characterization of pore structure of the Carboniferous–Permian tight sandstone gas reservoirs in eastern Linqing depression by using NMR technique. *Pet. Res.* **2018**, *38*, 902–915. [\[CrossRef\]](#)
17. Liu, H.; Yang, Y.; Wang, F.; Deng, X.; Liu, Y.; Nan, J.-x.; Wang, J.G.; Zhang, H. Micro pore and throat characteristics and origin of tight sandstone reservoirs: A case study of the Triassic Chang 6 and Chang 8 members in Longdong area, Ordos Basin, NW China. *Pet. Explor. Dev.* **2018**, *45*, 239–250. [\[CrossRef\]](#)
18. Gao, H.; Li, H. Determination of movable fluid percentage and movable fluid porosity in ultra-low permeability sandstone using nuclear magnetic resonance (NMR) technique. *Pet. Sci. Eng.* **2015**, *133*, 258–267. [\[CrossRef\]](#)
19. Pittman, E.D. Relationship of porosity and permeability to various parameters derived from mercury injection-capillary pressure curves for sandstone. *AAPG Bull.* **1992**, *76*, 191–198.
20. Swanson, B.F. A Simple Correlation Between Permeabilities and Mercury Capillary Pressures. *Pet. Technol.* **1981**, *33*, 2498–2504. [\[CrossRef\]](#)
21. Yao, Y.; Liu, D. Comparison of low-field NMR and mercury intrusion porosimetry in characterizing pore size distributions of coals. *Fuel* **2012**, *95*, 152–158. [\[CrossRef\]](#)
22. Zhang, L.; Lu, S.; Xiao, D.; Li, B. Pore structure characteristics of tight sandstones in the northern Songliao Basin, China. *Mar. Pet. Geol.* **2017**, *88*, 170–180. [\[CrossRef\]](#)
23. Ren, X.; Li, A.; Wang, Y.; Wu, S.; Wang, G. Pore structure of tight sand reservoir and its influence on percolation—Taking the Chang 8 reservoir in Maling oilfield in Ordos Basin as an example. *Oil Gas Geol.* **2015**, *36*, 774–779.
24. Lai, J.; Wang, G.; Wang, Z.; Chen, J.X.; Pang, X.; Wang, S.; Zhou, Z.; He, Z.; Qin, Z.; Fan, X. A review on pore structure characterization in tight sandstones. *Earth-Sci. Rev.* **2018**, *177*, 436–457. [\[CrossRef\]](#)
25. Schmitt, M.; Fernandes, C.P.; Wolf, F.G.; Neto, J.A.B.d.C.; Rahner, C.P.; Santos, V.S.S.d. Characterization of Brazilian tight gas sandstones relating permeability and Angstrom-to micron-scale pore structures. *Nat. Gas Sci. Eng.* **2015**, *27*, 785–807. [\[CrossRef\]](#)
26. Yin, S.; Lv, D.; Ding, W. New Method for Assessing Microfracture Stress Sensitivity in Tight Sandstone Reservoirs Based on Acoustic Experiments. *Int. J. Geomech.* **2018**, *18*, 1–16. [\[CrossRef\]](#)
27. Lai, J.; Wang, G.; Wang, S.; Cao, J.; Li, M.; Pang, X.; Zhou, Z.; Fan, X.; Dai, Q.; Yang, L.; et al. Review of diagenetic facies in tight sandstones: Diagenesis, diagenetic minerals, and prediction via well logs. *Earth-Sci. Rev.* **2018**, *185*, 234–258. [\[CrossRef\]](#)
28. Lai, J.; Wang, G.; Wang, S.; Cao, J.; Li, M.; Pang, X.; Han, C.; Fan, X.; Yang, L.; He, Z.; et al. A review on the applications of image logs in structural analysis and sedimentary characterization. *Mar. Pet. Geol.* **2018**, *95*, 139–166. [\[CrossRef\]](#)
29. Kaikai, Z.; Pengfei, J.; Yanjun, F.; Xiaodong, S.; Lixing, C.; Jianwei, Z. Investigation of the characteristics of hydraulic fracture initiation by using maximum tangential stress criterion. *Min. Strat. Control Eng.* **2021**, *2*, 14–22.
30. Li, A.F.; Ren, X.X.; Wang, G.J.; Wang, Y.Z.; Jiang, K.L. Characterization of pore structure in low permeability reservoirs using a nuclear magnetic resonance method. *J. China Univ. Petroleum* **2015**, *39*, 92–98.
31. Gong, Y.; Liu, S.; Zhao, M.; Xie, H.; Liu, K. Characterization of micro pore throat radius distribution in tight oil reservoirs by NMR and high pressure mercury injection. *Pet. Geol. Exp.* **2016**, *38*, 389–394.
32. Gao, H.; Zhugeng, B.L.; Wang, X.Y. Differences and origin of micro-pore throat characteristics for tight sandstone reservoir of Yanchang Formation, Ordos Basin. *Oil Gas Geol.* **2019**, *40*, 302–312.
33. Chen, Y.Z.; Fu, J.H.; Yang, G.Y.; Xiao, A.C.; Sun, L.Y.; Xu, B.; Bao, H.P.; Mao, L.G. Researches on basin property of Ordos block during Mesoproterozoic Changcheng Period. *Acta Petrol. Sin.* **2016**, *32*, 856–864.
34. Yang, Y.; Zhang, P.; Zhang, Z. Chang 8 oil formation in Xifeng Oilfield, Ordos Basin Sedimentary characteristics and sequence evolution of braided river deltas. *Geol. Sci. Technol. Inf.* **2005**, *24*, 45–48.

35. Shen, J.; Zhang, J.; Ge, Y.; Du, K.; Jiang, Z.; Wang, L. Deepwater Sedimentary Characteristics and Evolution of Members 7-8 of Yanchang Formation in the Ordos Basin. *Sci. Technol. Eng.* **2023**, *23*, 4135–4148.
36. Washburn, E.W. The Dynamics of Capillary Flow. *Phys. Rev. Ser.* **1921**, *17*, 273–283. [[CrossRef](#)]
37. Aliakbardoost, E.; Rahimpour-Bonab, H. Effects of pore geometry and rock properties on water saturation of a carbonate reservoir. *Pet. Sci. Eng.* **2013**, *112*, 296–309. [[CrossRef](#)]
38. Ren, D.Z.; Sun, W.; Dong, F.; Hang, H.; Qu, X.F. Characteristics of Movable Fluids in the Chang 8_1 Reservoir, Yanchang Formation in Huaqing Oilfield, Ordos Basin and the Influencing Factors. *Geol. Explor.* **2015**, *51*, 797–804.
39. Kenyon, W.E. Nuclear magnetic resonance as a petrophysical measurement. *Int. J. Radiat. Appl. Instrum. Part E Nucl. Geophys.* **1992**, *6*, 153–171.
40. He, Y.; Mao, Z.; Xiao, L. A new method to obtain capillary pressure curve using NMR T_2 distribution. *J. Jilin Univ. Earth Sci. Ed.* **2005**, *35*, 177–181.
41. Liu, T.; Zhao, T.; Li, G. An improved method to evaluate pore size distribution of tight sandstone reservoir using NMR. *Well Logging Technol.* **2012**, *36*, 119–123.
42. Liu, X.; Wang, J.; Ge, L.; Hu, F.; Li, C.; Li, X.; Yu, J.; Xu, H.; Lu, S.; Xue, Q. Pore-scale characterization of tight sandstone in Yanchang Formation Ordos Basin China using micro-CT and SEM imaging from nm- to cm-scale. *Fuel* **2017**, *209*, 254–264. [[CrossRef](#)]
43. Yang, W.; Liu, G.; Liu, X.; Feng, Y.; Cheng, D. The accumulation mechanism and accumulation models of oil in low permeability reservoir of Yanchang Formation in Longdong Area, Ordos Basin. *Earth Sci. Front.* **2013**, *20*, 132–139.
44. Nelson, P.H. Pore-throat sizes in sandstones, tight sandstones, and shales. *AAPG Bull.* **2009**, *93*, 329–340. [[CrossRef](#)]
45. Yang, Y.; Liu, X.; Sun, R. A new method for the calculation of secondary porosity originating from the dissolution of feldspars in deeply buried formations and its application: A case study of the Chang 81 Formation in Longdong area, Ordos Basin. *Pet. Geol. Exp.* **2016**, *38*, 395–401.
46. Kassi, A.M.; Grigsby, J.D.; Khan, A.S.; Kasi, A. Sandstone petrology and geochemistry of the Oligocene–Early Miocene Panjgur Formation, Makran accretionary wedge, southwest Pakistan: Implications for provenance, weathering and tectonic setting. *Asian Earth Sci.* **2015**, *105*, 192–207. [[CrossRef](#)]
47. Lai, J.; Wang, G.; Cao, J.; Xiao, C.-w.; Wang, S.; Pang, X.; Dai, Q.; He, Z.; Fan, X.; Yang, L.; et al. Investigation of pore structure and petrophysical property in tight sandstones. *Mar. Geol.* **2018**, *91*, 179–189. [[CrossRef](#)]
48. Wang, Z.; Zhang, K.; Cheng, Y.; Wu, Q. Identification and evaluation of fault-fracture reservoirs in buried hills of the Lower Paleozoic, Chengdao area, China. *Energy Geosci.* **2023**, *4*, 100183. [[CrossRef](#)]
49. Tong, K.; He, J.; Dong, S.; Sun, F.; Chen, P.; Tong, Y. Fracture characterization of Asmari Formation carbonate reservoirs in G Oilfield, Zagros Basin, Middle East. *Energy Geosci.* **2023**, *4*, 2023. [[CrossRef](#)]
50. Ajdukiewicz, J.M.; Larese, R.E. How clay grain coats inhibit quartz cement and preserve porosity in deeply buried sandstones: Observations and experiments. *AAPG Bull.* **2012**, *96*, 2091–2119. [[CrossRef](#)]
51. Bate, B.B.; Boboye, O.A.; Fozao, K.F.; Ndip, E.A.; Anene, N.O. Petrophysical characterization and 3D seismic interpretation of reservoirs in the Baris Field, onshore Niger Delta Basin, Nigeria. *Energy Geosci.* **2023**, *4*, 103–116. [[CrossRef](#)]

Disclaimer/Publisher’s Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.