Pore Size Distribution of a Tight Sandstone Reservoir and its Effect on Micro Pore-throat Structure: A Case Study of the Chang 7 Member of the Xin’anbian Block, Ordos Basin, China

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Abstract: Pore distribution and micro pore-throat structure characteristics are significant for tight oil reservoir evaluation, but their relationship remains unclear. This paper selects the tight sandstone reservoir of the Chang 7 member of the Xin’anbian Block in the Ordos Basin as the research object and analyzes the pore size distribution and micro pore-throat structure using field emission scanning electron microscopy (FE-SEM), high-pressure mercury injection (HPMI), high-pressure mercury injection, and nuclear magnetic resonance (NMR) analyses. The study finds that: (1) Based on the pore size distribution, the tight sandstone reservoir is characterized by three main patterns with different peak amplitudes. The former peak corresponds to the nanopore scale, and the latter peak corresponds to the micropore scale. Then, the tight sandstone reservoir is categorized into three types: type 1 reservoir contains more nanopores with a nanopore-to-micropore volume ratio of 82:18; type 2 reservoir has a nanopore-to-micropore volume ratio of 47:53; and type 3 reservoir contains more micropores with a nanopore-to-micropore volume ratio of 35:65. (2) Affected by the pore size distribution, the throat radius distributions of different reservoir types are notably offset. The type 1 reservoir throat radius distribution curve is weakly unimodal, with a relatively dispersed distribution and peak ranging from 0.01 μm to 0.025 μm. The type 2 reservoir’s throat radius distribution curve is single-peeked with a wide distribution range and peak from 0.1 μm to 0.25 μm. The type 3 reservoir’s throat radius distribution curve is single-peeked with a relatively narrow distribution and peak from 0.1 μm to 0.25 μm. With increasing micropore volume, pore-throat structure characteristics gradually improve. (3) The correlation between micropore permeability and porosity exceeds that of nanopores, indicating that the development of micropores notably influences the seepage capacity. In the type 1 reservoir, only the mean radius and effective porosity have suitable correlations with the nanopore and micropore porosities. The pore-throat structure parameters of the type 2 and 3 reservoirs have reasonable correlations with the nanopore and micropore porosities, indicating that the development of these types of reservoirs is affected by the pore size distribution. This study is of great significance for evaluating lacustrine tight sandstone reservoirs in China. The research results can provide guidance for evaluating tight sandstone reservoirs in other regions based on pore size distribution.

Key words: tight sandstone reservoir, pore size distribution, pore-throat structure, Ordos Basin, Chang 7 member

1 Introduction

At present, tight oil has become a popular topic in the field of petroleum geology. With the successful exploration and development of Bakken tight oil in the Williston Basin Eagle Ford tight oil in South Texas and Barnett tight oil in the Fort Worth Basin in north-central Texas, tight oil has become a strategic target after shale gas in North America (Hill et al., 2007; Mille et al., 2008; Mullen, 2010). China has also gradually strengthened the exploration and development of tight oil and gas. With the continuous deepening of shale gas exploration and development, China has made a major breakthrough in the Sichuan Basin and its surrounding marine shale strata (Guo and Zhang, 2014; Jin et al., 2016; Li et al., 2016b), becoming the country that then successfully realized shale gas commercial exploitation after North America. China's tight oil resources are also widely distributed; they are mainly concentrated in the Ordos Basin, Sichuan Basin, Songliao Basin, Tuha Basin and Junggar Basin, with good prospects for exploration and development (Zou et al. 2009, 2012; Jia et al., 2012a, 2012b; Kuang et al., 2012; Huang et al., 2013; Yang et al., 2013; Liang et al., 2014).
According to previous research results, the oil and gas accumulation and distribution in tight sandstone reservoirs are significantly different from those in conventional sandstone reservoirs (Zhu et al., 2008; Qiao et al., 2015; Wu et al., 2016; Lin, 2016; Zhou et al., 2016; Yang et al., 2017; Zhong et al., 2017). In tight sandstone reservoirs, oil and gas are mainly concentrated and distributed in micro/nano pore-throat systems. Compared with the milli/micro pore-throat network systems of conventional sandstone reservoirs, micro/nano pore-throat networks have a more complex structure, smaller pore radius, more diverse connectivity and stronger heterogeneity (Sun et al., 2007; Loucks et al., 2009). The mechanism of oil and gas filling, migration and aggregation is quite different from that of conventional macroporous systems (Zhao et al., 2012; Ning et al., 2015; Xue et al., 2015; Chen and Zhang, 2016; Ali et al., 2017).

Foreign scholars have previously recognized the uniqueness and importance of the microscopic pore structure of tight sandstone reservoirs and have made many beneficial attempts to explore and quantitatively characterize the microscopic pore structure of tight oil reservoirs at different scales (Law and Curtis, 2002; Sun et al., 2007; Josh et al., 2012). Chinese scholars have also observed that nanosized pores developed in the microscopic pore structure of unconventional tight sandstone reservoirs are the main part of the connected reservoir space in tight sandstone reservoirs, and the pore diameter is usually less than 1,000 nm (Zou et al., 2011, 2015a, 2015b; Liu et al., 2016). Studies on pore development characteristics and micro pore-throat structure characteristics of tight sandstone reservoirs are of great significance for tight oil reservoir evaluation. However, current studies mainly focus on the characterization of the micro pore-throat structure of reservoirs and the relationship between micro pore-throat structures and macroscopic properties of reservoirs (such as the permeability) (Nabawy et al., 2009; Nelson, 2009; Camp, 2011; Clarkson et al., 2012); quantitative analysis has not been performed on the relationship between the pores and throats, the two elements that constitute the micro pore-throat system of a tight sandstone reservoir.

In this paper, a tight sandstone reservoir of the Chang 7 member in the Xin’anbian area of the Ordos Basin is selected as the research object. Through the application of field emission scanning electron microscopy (FE-SEM), high-pressure mercury injection (HPMI), nuclear magnetic resonance (NMR) analyses and other data, qualitative and quantitative characterizations of tight sandstone reservoirs were performed, and the pore size distribution characteristics and relationships between the micro structure parameters of pore-throats were studied to provide a reference for tight sandstone reservoir evaluation.

2 Geological Settings

The Ordos Basin, the second largest basin in China, is located in the western region of the North China Platform (Fig. 1) and belongs to the craton marginal depression basin, with an area of approximately $32 \times 10^3$ km$^2$. The basement of the Ordos Basin is metamorphic rock from the Archean to Proterozoic. The sedimentary covers of the Paleozoic, Mesozoic and Cenozoic are developed on the basement, and there are several sets of oil-bearing combinations of early Paleozoic, late Paleozoic and Mesozoic age, which contain rich potential oil and gas resources.

According to the present structural morphological characteristics of the basin, the Ordos Basin can be divided into six secondary structural units, namely, the Western Thrust Belt, Tianhuan Depression, Yimeng Uplift, Weibei Uplift, Jinxu Fault-fold Belt, and Yishan Slope. The Xin’anbian area of the research area is located in the western part of the Yishan Slope of the secondary structural unit, and the administrative region is subordinate to Wuqi County and Dingbian County of Shaanxi Province (Fig. 1) (Li et al., 2016a, 2019).

During the development of the Chang 7 member, the lake was in the expansion stage, which was the peak stage of lake development, and the water depth and expansion range reached their maxima. At the beginning of sedimentation of the Chang 7 member of the Yanchang Formation, the water body was at its deepest, and the semideep lacustrine mudstone was primarily deposited. The Chang 7 member is an important set of hydrocarbon source rocks of the Yanchang Formation. By the middle and late sedimentary period of the Chang 7 member, the sedimentary facies zone gradually evolved into a sedimentary system dominated by delta front subfacies, in
which a distributary channel sand body was primarily developed as the main reservoir sand body in the study area (Yao J L et al., 2013; Yao Y T et al., 2015).

3 Samples and Methods

To define the characteristics of the tight sandstone reservoir pore size distribution and its influence on the micro pore-throat structure, we carried out a large amount of research. NMR and high-resolution FE-SEM analysis provide a suitable consistency in the testing range of tight sandstone reservoir pores. Therefore, we have explored a set of methods for quantitatively characterizing the pore size distribution of tight sandstone reservoirs.

3.1 Principle of the method for converting the aperture distribution by NMR $T_2$ spectra

According to atomic physics, the NMR method is a physical process in which nuclei interact with an external magnetic field. In petroleum exploration and development research, the most commonly used nuclei are the abundant hydrogen nuclei in oil and water. On the basis of the oil or water saturation of a rock sample, the abundant hydrogen nuclei in oil or water will experience a nuclear magnetic moment, which will result in energy level splitting under the action of an external static magnetic field. Meanwhile, if there is an external resonance frequency (RF) field with a specific frequency, the nuclear magnetic moment will result in an absorption transition and generate NMR.

Based on appropriate detection and receiving coils, the NMR phenomenon can be observed, and the NMR signal (namely, the magnetization vector) can be detected. The intensity of the NMR signal is often proportional to the number of hydrogen nuclei contained in the test sample (He et al., 2005; Wang et al., 2010).

An extremely important physical quantity is involved in NMR research, namely, the relaxation, which is the process of the magnetization vector returning to the equilibrium state after deviating from it after the NMR signal is generated under excitation of the external RF field. The relaxation in the NMR signal can be divided into $T_1$ relaxation (longitudinal relaxation) and $T_2$ relaxation (transverse relaxation) according to different mechanisms (Fan et al., 2017).

The rate of relaxation can be expressed by the time of relaxation. Although both the $T_1$ and $T_2$ relaxation times can reflect the physical properties and fluid characteristics of rocks, it is time consuming to measure the $T_1$ relaxation time; therefore, modern NMR research usually involves measuring the $T_2$ relaxation time. The duration of the relaxation time depends on the strength of the force exerted by the liquid molecules on the solid surface.

For pure material samples (such as pure water), the environment around each hydrogen nucleus and its interaction are the same. Through the diffusion surface relaxation model of NMR, the nuclear relaxation in a single pore can be expressed by the relaxation time. At this time, $T_2$ can be expressed as:

$$\frac{1}{T_2} = \frac{1}{T_{2B}} + \rho_s \frac{S}{V} + \gamma^2 G^2 D \tau^2/3$$  \hspace{1cm} (1)

For the porous medium of a reservoir rock sample, the process is much more complex (Yao et al., 2010). Reservoir rock has a very complex mineral composition and pore structure, and fluid flow in a porous medium is influenced by parameters such as segmentation resulting from numerous surrounding interfaces and the shape and size of heterogeneous pore-throats, while the nucleus and solid surface properties of paramagnetic impurities and probabilities of contact, among others, influence nucleus relaxation (Yao et al., 2012; Xiao et al., 2013). Therefore, each occurrence of nucleus relaxation enhances the probability range. In a rock fluid system, the nucleus relaxation cannot be expressed by a single relaxation time and will be described by a distribution (Ping et al., 2013; Zhang et al., 2017).

Different fluid systems have different $T_2$ distributions due to their petrophysical properties, so their physical properties can be determined by obtaining their $T_2$ distributions.

For rock porous media with different pore sizes, the total relaxation can be expressed by the superposition of a single pore relaxation,

$$S(t) = \sum_i A_i \exp\left(-t/T_{2i}\right)$$  \hspace{1cm} (2)

where $S(t)$ is the total NMR signal strength, $A_i$ is the relaxation time, and $T_{2i}$ is the proportion of components, that is, the percentage of pore volume with a pore radius corresponding to $T_{2i}$, in the total pore volume.

The first term on the right side of equation (1) is the bulk relaxation term, the size of which depends on the nature of the saturated fluid. The volume relaxation $T_{2B}$ refers to attenuation of the fluid itself when it occurs in larger pores (which is considered to be independent of the pore space), also known as free relaxation. Similar to the pore size of heterogeneous rock, the pore space is not subject to restriction, so the volume relaxation and pore surface have no clear correlation but are related to the whole test system, such as test system conditions of the temperature, the wettability of rock, and the fluid viscosity; the volume relaxation is one of the main parameters or properties of the fluid in pores.

In the application of NMR, the relaxation strength of the rock surface is much greater than that of the fluid, so the relaxation effect of the fluid can generally be neglected.

The third term on the right side of equation (1) is the diffusion relaxation term. According to the experimental measurement technique of NMR diffusion, the diffusion relaxation term can be removed. After removing the first and third terms on the right side of the equation, equation (1) can be simplified as

$$\frac{1}{T_2} = \rho_s \frac{S}{V}$$  \hspace{1cm} (3)

In the equation, $\rho_s$ is the surface relaxation strength, and its magnitude is controlled by mineral composition and pore surface properties. $S/V$ is the specific surface of a single pore and is inversely proportional to the pore radius (Xiao et al., 2013). It can be observed that the more complex the pore structure is, the smaller the pore will be, the larger the specific surface area will be, the stronger the influence of pore surface interaction will be, and the shorter the $T_2$ time will be.
According to equation (3), the observed relaxation time $T_2$ is related to the specific surface of the porous medium. If the pore structure is simplified as spherical and columnar pores, the relationship between the pore surface and pore radius changes to $\frac{S}{V} = \frac{F_s}{n}$, then,

$$T_2 = \frac{r_s}{\rho_s F_s}$$

(4)

where $F_s$ is the shape factor of the pores (for spherical pores, $F_s = 3$; for columnar pores, $F_s = 2$), dimensionless, and $r_s$ is the aperture in $\mu$m.

However, in the actual formation, the pore structure is complex, and the $T_2$ distribution has a power function relationship with the pore radius as follows:

$$T_2 = \frac{r^n}{\rho_s F_s}$$

(5)

where $n$ is the power exponent and is dimensionless.

Because of the current equipment, $\rho_s$ and $F_s$ are not actually measured in the method, and the $T_2$ distribution of the NMR method cannot be inverted with the aperture distribution curve using equation (5) (Li et al., 2015).

If $C = (\rho_s F_s)^\frac{1}{n}$, then

$$r_s = C T_2^n$$

(6)

Therefore, as long as the values of $C$ and $n$ are obtained, the $T_2$ distribution curve of rocks with 100% saturated water can be converted into the pore size distribution curve.

3.2 FE-SEM large-area high-resolution two-dimensional mosaic imaging technology

FE-SEM has a very high resolution, but practice shows that a higher resolution of the characterization technology is not always better. The resolution and characterization scale form a pair of contradictory parameters. The higher the resolution is, the smaller the characterization scale is (Zhu et al., 2016). The pore-throat size of tight sandstone reservoirs is smaller and more heterogeneous than that of conventional reservoirs. Therefore, when studying the pore structure of tight sandstone reservoirs, the representativeness of the resolution and characterization scale must be considered. To solve this contradiction, image mosaic technology is introduced.

Image mosaic technology combines several overlapping images (which can be obtained at different times, from different perspectives or through different sensors) into a large seamless high-resolution image. When SEM is used to obtain images with a wide field of view, the larger the field of view is, the lower the resolution will be. Therefore, to obtain a panoramic image with an ultrawide field of view without reducing the image resolution, image mosaic technology has been proposed and developed. At present, image mosaic technology has become the focus of research in computer graphics. The technology has been widely used in space exploration, remote sensing image processing, video compression and transmission, medical image analysis, superresolution reconstruction, virtual reality technology and other fields.

In this paper, an FIB-SEM double-beam scanning electron microscope (model Helios NanoLab650, Thermo Scientific, USA) is used to observe pores and throats that are as small as 5–10 nm. The supporting MAPS 1.0 software can obtain continuous images. Image mosaic technology can effectively solve the contradiction between the size and resolution of SEM samples and is more suitable for sandstone with large mineral particles, specifically for tight sandstone reservoirs with strong heterogeneity.

It is necessary to understand the macroscopic characteristics when describing the micro pore-throat structure of tight sandstone reservoirs. If only the local pore structure is characterized, the characterization cannot truly and comprehensively reflect the pore structure characteristics of the sample. Generally, the smaller the field of view is, the higher the resolution, the stronger the homogeneity and the poorer the corresponding representativeness. Different types of samples are affected by the mineral composition and pore size, and the representative scale also has certain differences. Generally, the representative scale should be 10 times larger than the grain size and pore size of rock samples. Through observation and analysis, the pore size of the study area was observed to be between 50 nm and 100 $\mu$m, and the size of the large view area of tight sandstones should be greater than 1 mm.

In this paper, the analysis area was finally divided into 625 grids (25 by 25) through the analysis of multiple scale view domains. High-resolution SEM analysis was performed on each grid with a horizontal range of 50 $\mu$m, thereby identifying the smallest pores of 58 nm and basically observing all available pores. After implementing the image mosaic technology, the horizontal range of the whole region was determined as 1.19 mm, which also exceeded the lower limit of the size of the large view area of tight sandstones and could effectively represent the pore development and distribution characteristics of the reservoir.

3.3 Image processing, pore recognition and statistical techniques

After obtaining effective images of the pore development characteristics of standard reservoirs, the issue becomes how to extract the area fraction and pore size distribution of the different sizes and types of pores from the two-dimensional images.

Since the obtained image is a grayscale image and quantitatively represents the pore structure parameters, an appropriate segmentation algorithm should be selected to extract the pores from the grayscale image. Threshold segmentation is the most commonly used method for pore segmentation and assumes that the gray values of the pixels between the pores and skeletons in gray images are different. Threshold segmentation is mainly composed of two steps. The first step is to determine a reasonable threshold, which is also the core step. Otherwise, the number and size of extracted pores will be too small or too large.
Based on the professional image processing software JMicrovision© and the green mud holes in the crystal images, as shown in Fig. 2 as an example, through manual adjustment of the segmentation threshold and visual observation of the pore extraction process, it was observed that the gray value of the pore area was mainly distributed in the interval [0,60]. That is, when the segmentation threshold was approximately 60, the segmentation of all pores could be effectively realized, as shown in Fig. 2.

After the image was divided into pores, binarization images of the pores could be obtained. Based on the binarization images, software could be used to quantitatively count the size, number, plane porosity and other parameters of organic matter pores to achieve a combination of qualitative description and quantitative evaluation of the pores.

According to the above method, four parallel samples with different burial depths and different porosities in the same sandstone member of the same well were selected and prepared for pore identification statistics and NMR analysis, respectively. In addition, 22 other samples were selected for NMR testing. The porosity and permeability of all the samples were measured by the gas method. Meanwhile, HPMI analysis was carried out on 23 samples.

4 Results

4.1 Quantitative characterization of the pore size

The pore identification results are shown in Table 1. The table shows that the minimum pore radius was 58 nm, while the maximum pore radius notably increased with increasing porosity. The maximum pore radius of the H221-31 sample was only 6.7 μm, and the maximum pore radius of the H221-35 sample could reach 41.4 μm. There was a good positive correlation between the value of the plane porosity and the number of pores of different samples and the porosity (Fig. 3). With the increase in porosity, the number of pores and plane porosity value increased, indicating that the statistical results could represent pore size distribution characteristics of the samples.

To facilitate the calculations, the $T_2$ spectrum and pore size distribution were converted into a cumulative distribution curve, and a series of $T_2$ values and corresponding pore size values with the same cumulative content were selected (Fig. 4); the values were substituted into equation (6) to obtain C and $n$ values through regression iteration to realize the transformation of the $T_2$ spectrum into a pore size distribution. Based on this

<table>
<thead>
<tr>
<th>Samples</th>
<th>Depth (m)</th>
<th>Porosity (%)</th>
<th>Number of pores</th>
<th>Minimum pore radius (nm)</th>
<th>Maximum pore radius (nm)</th>
<th>Plane porosity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>H221-31</td>
<td>2201.2</td>
<td>2.52</td>
<td>170672</td>
<td>58</td>
<td>6749</td>
<td>0.97</td>
</tr>
<tr>
<td>H221-43</td>
<td>2206.32</td>
<td>4.86</td>
<td>202278</td>
<td>58</td>
<td>13882</td>
<td>1.88</td>
</tr>
<tr>
<td>H221-36</td>
<td>2204</td>
<td>6.56</td>
<td>298703</td>
<td>58</td>
<td>30728</td>
<td>4.71</td>
</tr>
<tr>
<td>H221-35</td>
<td>2203.7</td>
<td>8.58</td>
<td>351021</td>
<td>58</td>
<td>41415</td>
<td>4.06</td>
</tr>
</tbody>
</table>
method, the values of C and n were determined as 181 and 0.8248, respectively, for the tight sandstone reservoirs in the Chang 7 member of the study area.

4.2 Pore size distribution characteristics and classification of the reservoirs

Based on the conversion equation, the $T_2$ NMR spectra of 26 samples in the study area were converted to obtain the corresponding pore size distributions. The results indicated that the pore size distribution pattern of the tight sandstone reservoir in the Chang 7 member of the study area was primarily bimodal, and the peaks were slightly different. The converted pore size distribution curve exhibited distinct peaks and valleys at approximately 1 μm. With this boundary, the whole distribution could be divided into nanopores and micropores.

Based on the pore size distribution, the tight sandstone reservoir was characterized by three main patterns with different amplitudes of the former peaks and latter peaks. The former peak corresponded to the scale of the nanopores, and the latter peak corresponded to the scale of the micropores. Then, the tight sandstone reservoir was divided into three types: the type 1 reservoir contained more nanopores and fewer micropores, the type 2 reservoir contained similar amounts of nanopores and micropores, and the type 3 reservoir contained fewer nanopores and more micropores (Fig. 5).

From the physical property experiment, the porosity and permeability of the Chang 7 sandstone samples could be obtained. The porosity was in the range of 3.68%–10.57% with an average of 6.84%, and the permeability was in the range of $0.009 \times 10^{-3}$–$0.212 \times 10^{-3}$ μm$^2$ with an average of $0.067 \times 10^{-3}$ μm$^2$ (Tables 2–4). The different types of reservoirs had different ranges of porosity and permeability.

The porosity of the type 1 reservoir was in the range of 2.52%–11.44% with an average of 7.05%, and the permeability was in the range of $0.003 \times 10^{-3}$–$0.062 \times 10^{-3}$ μm$^2$ with an average of $0.025 \times 10^{-3}$ μm$^2$ (Table 2). Among them, the proportion of nanopores was 73% to 93%, and the volume ratio of nanopores and micropores was 18:82 on average. The porosity of the nanopores was

![Fig. 4. Comparison diagram of the cumulative $T_2$ and pore size distribution of the H221-36 sample.](image)

![Fig. 5. Pore size distribution patterns of the different types of reservoirs. (a) type 1, H221-43; (b) type 2, H221-35; (c) type 3, J114-02.](image)

<table>
<thead>
<tr>
<th>Table 2 Pore size distribution characteristics of the type 1 reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Samples</td>
</tr>
<tr>
<td>H221-31</td>
</tr>
<tr>
<td>H221-43</td>
</tr>
<tr>
<td>H295-17</td>
</tr>
<tr>
<td>J111-05</td>
</tr>
<tr>
<td>A244-10-2</td>
</tr>
<tr>
<td>H295-13</td>
</tr>
<tr>
<td>H295-15</td>
</tr>
<tr>
<td>H295-21</td>
</tr>
<tr>
<td>J68-10</td>
</tr>
<tr>
<td>A255-5-1</td>
</tr>
<tr>
<td>Average</td>
</tr>
</tbody>
</table>
Table 3 Pore size distribution characteristics of the type 2 reservoir

<table>
<thead>
<tr>
<th>Samples</th>
<th>Porosity (%)</th>
<th>Permeability ($\times10^{-3}$ μm$^2$)</th>
<th>Nanopore proportion (%)</th>
<th>Micropore proportion (%)</th>
<th>Porosity of nanopores (%)</th>
<th>Porosity of micropores (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>H221-35</td>
<td>8.58</td>
<td>0.143</td>
<td>45</td>
<td>55</td>
<td>3.86</td>
<td>4.72</td>
</tr>
<tr>
<td>H221-36</td>
<td>6.56</td>
<td>0.078</td>
<td>47</td>
<td>53</td>
<td>3.07</td>
<td>3.49</td>
</tr>
<tr>
<td>J45-20</td>
<td>7.28</td>
<td>0.034</td>
<td>45</td>
<td>55</td>
<td>3.25</td>
<td>4.03</td>
</tr>
<tr>
<td>A236-14-3</td>
<td>6.90</td>
<td>0.019</td>
<td>43</td>
<td>57</td>
<td>2.93</td>
<td>3.97</td>
</tr>
<tr>
<td>A244-10-3</td>
<td>6.42</td>
<td>0.070</td>
<td>55</td>
<td>45</td>
<td>3.52</td>
<td>2.90</td>
</tr>
<tr>
<td>A244-10-4</td>
<td>6.54</td>
<td>0.167</td>
<td>46</td>
<td>54</td>
<td>3.01</td>
<td>3.53</td>
</tr>
<tr>
<td>A263-13-2</td>
<td>9.83</td>
<td>0.186</td>
<td>51</td>
<td>49</td>
<td>4.99</td>
<td>4.84</td>
</tr>
<tr>
<td>A263-13-4</td>
<td>10.57</td>
<td>0.212</td>
<td>46</td>
<td>54</td>
<td>4.88</td>
<td>5.69</td>
</tr>
<tr>
<td>Average</td>
<td>7.84</td>
<td>0.113</td>
<td>47</td>
<td>53</td>
<td>3.69</td>
<td>4.15</td>
</tr>
</tbody>
</table>

Table 4 Pore size distribution characteristics of the type 3 reservoir

<table>
<thead>
<tr>
<th>Samples</th>
<th>Porosity (%)</th>
<th>Permeability ($\times10^{-3}$ μm$^2$)</th>
<th>Nanopore proportion (%)</th>
<th>Micropore proportion (%)</th>
<th>Porosity of nanopores (%)</th>
<th>Porosity of micropores (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>J88-04</td>
<td>8.39</td>
<td>0.072</td>
<td>33</td>
<td>67</td>
<td>2.74</td>
<td>5.64</td>
</tr>
<tr>
<td>J114-02</td>
<td>6.93</td>
<td>0.115</td>
<td>30</td>
<td>70</td>
<td>2.08</td>
<td>4.85</td>
</tr>
<tr>
<td>J46-06</td>
<td>6.05</td>
<td>0.064</td>
<td>30</td>
<td>70</td>
<td>1.81</td>
<td>4.24</td>
</tr>
<tr>
<td>A236-14-1</td>
<td>9.33</td>
<td>0.082</td>
<td>36</td>
<td>64</td>
<td>3.33</td>
<td>6.00</td>
</tr>
<tr>
<td>A236-14-2</td>
<td>5.51</td>
<td>0.015</td>
<td>40</td>
<td>60</td>
<td>2.19</td>
<td>3.32</td>
</tr>
<tr>
<td>A244-10-1</td>
<td>5.24</td>
<td>0.026</td>
<td>34</td>
<td>66</td>
<td>1.80</td>
<td>3.44</td>
</tr>
<tr>
<td>A263-13-1</td>
<td>8.95</td>
<td>0.162</td>
<td>39</td>
<td>61</td>
<td>3.46</td>
<td>5.49</td>
</tr>
<tr>
<td>A263-13-3</td>
<td>6.55</td>
<td>0.058</td>
<td>37</td>
<td>63</td>
<td>2.41</td>
<td>4.14</td>
</tr>
<tr>
<td>Average</td>
<td>7.12</td>
<td>0.074</td>
<td>35</td>
<td>65</td>
<td>2.48</td>
<td>4.64</td>
</tr>
</tbody>
</table>

Between 1.97% and 9.04%, with an average of 5.76%, whereas the porosity of the micropores was between 0.45% and 2.40%, with an average of 1.29% (Table 2).

The porosity of the type 2 reservoir was in the range of 6.42%–10.57% with an average of 7.84%, and the permeability was in the range of 0.019×10$^{-3}$–0.212×10$^{-3}$ μm$^2$ with an average of 0.114×10$^{-3}$ μm$^2$ (Table 3). The distribution of micropores was similar to that of the nanopores, and the ratio of nanopores to micropores was 47.53 on average. The porosity of nanopores was 2.93% to 4.99%, with an average of 3.69%, and the porosity of micropores was 2.90% to 5.69%, with an average of 4.15% (Table 3).

The porosity of the type 3 reservoir was within the range of 5.24%–9.33% with an average of 7.12%, and the permeability was in the range of 0.015×10$^{-3}$–0.162×10$^{-3}$ μm$^2$ with an average of 0.074×10$^{-3}$ μm$^2$ (Table 4). The volume ratio of nanopores to micropores was 35.65 on average. The porosity of nanopores was between 1.81% and 3.46%, with an average of 2.48%, and the porosity of micropores was between 3.32% and 6.00%, with an average of 4.64% (Table 4).

As seen from the relationship diagram of the porosity and permeability of the different types of reservoirs (Fig. 6), the physical properties of tight sandstone reservoirs in the Chang 7 member of the study area as a whole exhibited a certain positive correlation, but the correlation was not profound. Additionally, notably positive linear correlations between the porosity and permeability could be observed in all three types of reservoirs (Fig. 6).

Two groups of samples with similar porosity values were selected for comparative analysis (Table 5). Under the condition of roughly the same porosity, with the change in pore distribution morphology, the volume proportion of micropores in the reservoir increased, and the permeability increased correspondingly. These results indicated that the pore size distribution had a significant controlling effect on the variation in the porosity and permeability.

Because the micro pore-throat structure of the reservoir was a key factor controlling the percolation of the reservoir, to clarify the cause of this difference in permeability, the micro pore-throat structure of the tight sandstone reservoir in the study area was analyzed in detail in this paper.

4.3 Characteristics of the micro pore-throat structure

The characteristics of the pore-throat structure and pore size distribution of the tight sandstone samples in the Chang 7 member could be obtained from HPMI experiments (Torabi et al., 2013). The pore-throat structure of the Chang 7 tight sandstone reservoir was heterogeneous, and the pore size distribution varied over a wide range.

The type 1 reservoir exhibited high mercury injection pressures, high median pressures, wide spans of the maximum mercury injection saturation and residual mercury saturation, and large variations in the mercury withdrawal efficiency, indicating a high degree of heterogeneity (Fig. 7a).

The mercury injection pressure of the type 2 reservoir was also high, with a small increase in the median pressure, a narrower span of the maximum and residual mercury saturation, and a low mercury removal efficiency.

Table 5 Comparison of the physical properties and nanopore volume ratio of the samples with similar porosity values

<table>
<thead>
<tr>
<th>Type of reservoir</th>
<th>Samples</th>
<th>Porosity (%)</th>
<th>Permeability ($\times10^{-3}$ μm$^2$)</th>
<th>Ratio</th>
<th>Sample</th>
<th>Porosity (%)</th>
<th>Permeability ($\times10^{-3}$ μm$^2$)</th>
<th>Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type 1</td>
<td>A244-10-2</td>
<td>6.82</td>
<td>0.013</td>
<td>93.7</td>
<td>J68-10</td>
<td>8.63</td>
<td>0.013</td>
<td>87.13</td>
</tr>
<tr>
<td>Type 2</td>
<td>H221-36</td>
<td>6.56</td>
<td>0.078</td>
<td>47.53</td>
<td>H221-35</td>
<td>8.58</td>
<td>0.143</td>
<td>45.55</td>
</tr>
<tr>
<td>Type 3</td>
<td>J114-02</td>
<td>6.93</td>
<td>0.115</td>
<td>30.70</td>
<td>A263-13</td>
<td>8.95</td>
<td>0.162</td>
<td>39.61</td>
</tr>
</tbody>
</table>
in general (Fig. 7b).

The mercury injection pressure of the type 3 reservoir was relatively low, and the median pressure was also low. Both the maximum mercury injection saturation and residual mercury saturation span were large, and mercury withdrawal efficiency was low; the latter indicated a high degree of heterogeneity (Fig. 7c).

The throat radius distribution curve of the type 1 reservoir exhibited a weak single peak, and the peak value was within the range of 0.01 μm to 0.025 μm (Fig. 8a). The throat radius was smaller than 0.5 μm, and the distribution was relatively uniform. The main body was distributed within the range of 0.005 μm to 0.25 μm, which accounted for 80.98% of the pore volume, while the proportion of the pore volume represented by a throat with a radius smaller than 0.0025 μm was only 17.91%.

The throat radius distribution curve of the type 2 reservoir (Fig. 8b) presented a single peak with a distinct peak value; the distribution was primarily within the range of 0.1 μm to 0.25 μm. The overall throat radius was smaller than 2 μm, the distribution span was wide, the main body was distributed in the range of 0.05 μm to 0.5 μm, which accounted for 54.93% of the pore volume, and the radius was smaller than 0.0025 μm.

The throat radius distribution curve of the type 3 reservoir (Fig. 8c) was unimodal with a peak value of 0.1 μm to 0.25 μm. The overall throat radius was smaller than 1 μm, and the distribution was relatively narrow. The main body was distributed in the range of 0.05 μm to 0.5 μm, accounting for 68.21% of the pore volume, while the proportion of throats with a radius smaller than 0.0025 μm was 15.09%.

Influenced by the pore size distribution, the micro pore-throat structures of the different types of reservoirs exhibited different characteristics. The entry pressure is the point on the capillary pressure curve at which the mercury initially enters the pore-throats of the rock, and it corresponds to the maximum throat radius. The entry pressure of the type 1 reservoir was, on average, 6.05 MPa, which was the highest value and more than 3 times larger than those of the type 2 and type 3 reservoirs (1.84 and 1.95 MPa, respectively). The corresponding maximum throat radius of the type 1 reservoir was 0.224 μm, which was significantly smaller than those of the type 2 and type 3 reservoirs (0.917 μm and 0.491 μm, respectively) (Table 6).

The median pressure corresponds to the capillary pressure at a 50% mercury saturation and to the median radius. The median pressure of the type 1 reservoir was 43.44 MPa on average, which was significantly higher than those of the type 2 and type 3 reservoirs (8.16 MPa and 6.18 MPa, respectively). The corresponding median radius was 0.026 μm, which was much smaller than those of the type 2 and type 3 reservoirs (0.129 μm and 0.140
The mainstream throat radius refers to the weighted average of the throat radius intervals and injected mercury volumes based on the HPMI results in which the contribution of calculated permeability reaches 95%. A large mainstream throat radius indicates a good permeability of the reservoir. The mainstream throat radius of the type 1 reservoir was, on average, 0.108 μm, which was approximately half of those of the type 2 and type 3 reservoirs (0.259 μm and 0.223 μm, respectively). These differences reflected the better permeability developed in the type 2 and type 3 reservoirs compared to that in the type 1 reservoir.

The skewness reflects the asymmetry of the throat size distributions. The type 1 reservoirs had the smallest skewness with a low slanting degree, while the type 2 and type 3 reservoirs had degrees of skewness that were greater than 0, with large slanting degrees (Table 6). These results suggested that the type 2 and type 3 reservoirs possessed better storage and percolation capacities than those of the type 1 reservoirs.

The radius mean value represents the distribution characteristics of the overall pore-throat system. A larger mean value suggests a lower average value of the total pore-throat system. The capillary pressure curve tended to indicate morphology with a small slanting degree. Narrow throats dominated the entire pore-throat system. The radius mean value of the type 1 reservoir was 14.23 on average, which was significantly larger than those of the type 2 and type 3 reservoirs (12.69 and 12.17, respectively). These differences could explain why narrow throats were dominant in the pore-throat system of the type 1 reservoir.

The maximum mercury saturation is the volume percentage of mercury injected into pore-throats at the maximum pressure. The differences in the average values of the maximum mercury saturation among these three types of reservoirs were small. The maximum mercury saturation of the type 1 reservoir was slightly lower, with a value of 81.76%, compared to those of the type 2 and type 3 reservoirs (84.77% and 84.38%, respectively). The effective porosity refers to the ratio of pore volume to rock volumes obtained from the conversion of a mercury injection volume under the condition of maximum mercury injection pressure. The effective porosity represents the effectively connected pore volume. The effective porosities in the type 1, type 2 and type 3 reservoirs were 6.13%, 6.69%, and 5.73%, respectively, and showed little difference (Table 6).

5 Discussion
5.1 Relationship between the pore distribution, porosity and permeability

Nanopores and micropores together constitute the reservoir space of tight sandstone reservoirs. This paper analyzed the relationship between the presence of nanopores and micropores, total porosity and permeability.

The total porosity was weakly positively correlated with both the nanopore porosity and micropore porosity. However, the total porosity of each type of reservoir was positively correlated with both the nanopore and micropore porosities.

The relationship between the porosity and nanopore porosity presented a fan-like distribution, and the slope gradually increased from the type 1 to the type 2 to the type 3 reservoir (Fig. 9a, 10a). The distribution of the total porosity and micropores presented a positive linear relationship. The correlation between the total porosity and nanopores of the type 1 reservoir was more notable than that between the total porosity and micropores. The correlation coefficient of the relation between the total porosity and nanopores of the type 2 reservoir was similar to that of the relation between the total porosity and nanopores and micropores; the correlation between the total porosity and micropores of the type 3 reservoir was more notable than that between the total porosity and nanopores. The latter notably corresponded to the contribution of pores of different sizes.
Table 6 Parameters of the pore-throat structure obtained from HPMI experiments with the tight sandstone samples in the Chang 7 member

<table>
<thead>
<tr>
<th>Reservoir types</th>
<th>Samples</th>
<th>Wells</th>
<th>Depth (m)</th>
<th>Entry pressure (MPa)</th>
<th>Maximum pore-throat radius (μm)</th>
<th>Median pressure (MPa)</th>
<th>Median radius (μm)</th>
<th>Mainstream throat radius (μm)</th>
<th>Skewness</th>
<th>Radius mean value</th>
<th>Maximum mercury saturation (%)</th>
<th>Effective porosity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>#1 #2 #3 #4 #5 #6</td>
<td>H221-31 #2 H221-43 #2 H295-17 #5 A244-10-2 #2 H295-13 #7 H295-15 #8 H295-21 #9 686-10 #10 A255-5-1</td>
<td>2201.2 2206.32 2205.65 2202.97 2204.00 2207.16 2209.50 2228.00 2243.00</td>
<td>3.09 20.86 1.59 2.82 4.72 12.49 3.88 3.07 1.95</td>
<td>0.237 0.035 0.462 0.261 0.156 0.059 0.189 0.239 0.377</td>
<td>21.53 131.20 40.54 23.73 20.53 75.93 39.46 20.22 17.77</td>
<td>0.034 0.006 0.018 0.031 0.036 0.010 0.019 0.036 0.041</td>
<td>0.185 0.032 0.197 0.149 0.123 0.044 0.090 0.041 0.110</td>
<td>0.17 0.47 0.15 0.10 0.21 0.31 0.16 0.62 0.13</td>
<td>13.99 15.81 14.39 13.58 13.48 15.32 18.73 13.83 13.77</td>
<td>98.34 52.20 94.31 82.69 75.28 70.05 82.16 80.79 100.00</td>
<td>2.48 2.53 6.43 7.94 6.31 3.85 9.40 9.67 9.23</td>
<td></td>
</tr>
<tr>
<td>#11 #12 #13 #14 #15 #16 #17 #18</td>
<td>H221-35 H221-36 J45-20 A236-14-3 A244-10-3 A244-10-4 A263-13-2 A263-13-4</td>
<td>2203.70 2204.00 2204.90 2234.32 2409.23 2413.16 2184.88 2190.32</td>
<td>0.41 0.49 0.45 6.00 0.79 0.85 0.90 0.63</td>
<td>1.785 1.491 1.58 12.13 9.25 8.86 0.818 1.168</td>
<td>0.705 0.629 0.882 0.042 0.944 0.882 0.625 0.588</td>
<td>0.175 0.269 0.007 0.056 0.161 0.241 0.743 0.586</td>
<td>0.38 0.45 0.29 0.153 0.223 0.107 0.81 0.557</td>
<td>0.98 0.71 0.52 0.54 0.54 0.37 0.71 0.557</td>
<td>12.66 12.61 12.61 0.54 0.557 0.54 1.10 1.167</td>
<td>71.78 99.45 72.68 73.90 91.09 78.27 94.34 96.64</td>
<td>6.16 6.53 5.29 5.10 5.85 5.12 9.27 10.22</td>
<td></td>
</tr>
<tr>
<td>Average #11 #12 #13 #14 #15 #16 #17 #18</td>
<td>1.95 0.491</td>
<td>6.78</td>
<td>0.108</td>
<td>0.01</td>
<td>14.23</td>
<td>81.76</td>
<td>6.13</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Type2</td>
<td>#19 #21 #23</td>
<td>2247.00 2272.26 2255.87</td>
<td>2.13 3.77 1.13</td>
<td>0.345 0.195 0.649</td>
<td>4.82 11.72 9.79</td>
<td>0.152 0.200 0.075</td>
<td>0.200 0.200 0.288</td>
<td>0.75 0.75 0.44</td>
<td>11.86 12.48 12.94</td>
<td>72.36 64.99 83.40</td>
<td>6.09 3.93 4.59</td>
<td></td>
</tr>
<tr>
<td>Type3</td>
<td>#24 #25 #26</td>
<td>2389.59 2180.02 2188.06</td>
<td>1.46 0.77 2.45</td>
<td>0.502 0.955 0.300</td>
<td>7.25 2.58 4.55</td>
<td>0.101 0.285 0.162</td>
<td>0.108 0.045 0.172</td>
<td>0.46 0.32 0.81</td>
<td>12.47 10.90 3.35</td>
<td>100.00 100.00 85.35</td>
<td>5.24 8.95 5.59</td>
<td></td>
</tr>
<tr>
<td>Average</td>
<td>1.95</td>
<td>0.491</td>
<td>6.78</td>
<td>0.108</td>
<td>0.55</td>
<td>12.17</td>
<td>84.38</td>
<td>5.73</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

to the total porosity.

The permeability exhibited no significant relationship with the nanopore porosity, but exhibited a significant positive correlation with the micropore porosity. The permeabilities of all the types of reservoirs were positively correlated with the nanopore and micropore porosities, but the correlation was not as notable as that with the total porosity.

The relationship between the permeability and nanopore porosity also presented a fan-like shape (Fig. 9b, 10b). The correlation between the permeability and distribution of micropores was positive and in general was better than that between the permeability and the micropore distribution, indicating that the development of micropores had a greater controlling effect on improving the seepage capacity.

5.2 Relationship between the pore distributions and pore-throat structure parameters

The micro pore-throat system of tight sandstone reservoirs is an organic combination of pores and throats, which comprehensively controls the reservoir volume and seepage capacity. The pore distribution characteristics affect the pore-throat structure characteristics. To clarify the influence of pores of different scales on the reservoir pore-throat structure, certain parameters that could characterize the pore-throat structure were selected to establish the correlations with the nanopore and micropore porosities.

The pores and throats tend to be normally distributed, and the median radius represents the mean value of the throat radius. On the whole, the median radius of the reservoir exhibited a poor correlation with the nanopore porosity but a positive correlation with the micropore porosity.

The relationships between the median radii of the different types of reservoir and the nanopore and micropore porosities were different. The median radius of the type 1 reservoir was not notably correlated with the nanopore and micropore porosities, while the median radius of the type 2 and type 3 reservoirs exhibited significant positive correlations with the nanopore and micropore porosities (Fig. 9c, 10c), and the correlations with the nanopore porosities were even stronger.

These results indicated that the pore development played a controlling role on the distribution of the median radius, specifically for the type 2 reservoir, the median radius of which was between 0.042 μm and 0.285 μm, with an average of 0.129 μm, and the type 3 reservoir, which had a median radius between 0.063 μm and 0.285 μm, with an average of 0.140 μm. Thus, the throat development was more affected by the nanopores.

The radius mean value refers to the average position of the overall throat distribution. The larger the radius mean value is, the smaller the mean value of the overall pore-throat system, and the greater the system influences the shape of the capillary pressure curve. Narrow throats dominate the overall pore-throat system.

To a certain extent, the radius mean value of the tight sandstone reservoir in the study area was negatively correlated with the nanopore porosity, but it was negatively correlated with the micropore porosity; the
The radius mean value of each type of reservoir was also negatively correlated with the nanopore and micropore porosities (Fig. 9d, 10d). The relationship between the radius mean value and the nanopore porosity presented a fan-like distribution, and the three types exhibited notable zoning. The curve slope gradually decreased from the type 1 to the type 2 to the type 3 reservoir. The distribution of the radius mean values and micropore porosities showed a linear relationship, and the slopes of the curves of the three reservoirs were similar. The correlation coefficient of the type 3 reservoir was the highest, and the corresponding pore development characteristics had the strongest effect on controlling the throat distribution, followed by that of the type 2 reservoir, while the type 1 reservoir had the worst correlation.

The effective porosity was weakly positively correlated with both the nanopore and micropore porosities. However, the effective porosity of each type of reservoir was positively correlated with the nanopore and micropore porosities.

The relationship between the effective porosity and nanopore porosity also presents a fan-like shape, and the slope of the curves gradually increased from the type 1 to the type 2 to the type 3 reservoir (Fig. 9e, 10e). The effective porosity had a positive relationship with the distribution of micropores, and the slope of the curves gradually decreased from the type 1 to the type 2 to the type 3 reservoir.

The correlation between the effective porosity and nanopore distribution was generally better than that between the effective porosity and micropore distribution. When analyzing by the reservoir type, both the nanopores and micropores had a strong controlling effect on the effectively connected volume of the reservoir, and the controlling effect of the nanopores was stronger, which may have been because the connectivity was actually
influenced by nanosized throats, and the development of these throats was mainly controlled by the nanopore distribution.

6 Conclusions

(1) By performing large-area high-resolution imaging, image processing and NMR experiments combined with a reservoir pore size characterization method, qualitative and quantitative pore size characterizations of tight sandstone reservoirs were achieved. Based on the pore size distribution, the tight sandstone reservoir was characterized by three main patterns with different amplitudes of the former peaks and latter peaks. The former peak corresponded to the scale of the nanopores, and the latter peak corresponded to the scale of micropores. Then, the tight sandstone reservoir was divided into three types: the type 1 reservoir contained more nanopores and fewer micropores, and the volume ratio of nanopores to micropores was 82:18; the type 2 reservoir contained similar amounts of nanopores and micropores, and the volume ratio of nanopores to micropores was 47:53; and the type 3 reservoir contained fewer nanopores and more micropores, and the volume ratio of nanopores to micropores was 35:65.

(2) The throat distribution of the different types of reservoirs had distinct characteristics of increasing deviation. The throat radius distribution curve of the type 1 reservoir had a weak single peak, and the peak value was within the range of 0.01 μm to 0.025 μm. The throat radius distribution curve of the type 2 reservoir exhibited a single peak with a peak value between 0.1 μm and 0.25 μm. The throat radius distribution curve of the type 3 reservoir was unimodal with a peak value between 0.1 μm and 0.25 μm. Due to the influence of the pore size distribution, the pore-throat structure parameters of the different types of reservoirs also exhibited notable differences. With the increase in micropores, the micro pore-throat structure characteristics of the reservoirs gradually improved.

(3) By analyzing the relationships among the porosity...
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