Pore Structure Characteristics and Controlling Factors of a Tight Sandstone Reservoir in the Paleogene Shahejie Formation, Nanpu Sag, Bohai Bay Basin, China

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ABSTRACT: Tight sandstone reservoirs have ultralow physical properties and strong heterogeneity, and there is a need to describe the corresponding pore structure characteristics systematically to promote research on unconventional reservoirs. The pore structure, controlled by the diagenesis and volcanic activity of the tight reservoirs in the third member of the Shahejie Formation (Es3) of the Gaoshangpu structural belt in the Nanpu Sag, is studied by high-pressure mercury injection, nuclear magnetic resonance, and constant-rate-controlled mercury porosimetry. The results show that the Es3 reservoir can be divided into three types: the pore radii of Type I reservoirs range from 120 to 180 μm, and the throat radii are larger than 1 μm, resulting in good pore connectivity; pore radii of Type II reservoirs are approximately 100 μm, and the throat radii range from 0.1 to 1 μm, resulting in moderate pore connectivity; and pore radii of Type III reservoirs are much smaller than 100 μm, and the throat radii are smaller than 0.1 μm, resulting in worst pore connectivity. The pore size of Type I reservoirs is most sensitive to compaction, and the pore connectivity is mainly controlled by carbonate cementation; the pore throat size and pore connectivity of Type II reservoirs are seriously affected by clay cementation, and pores are mainly formed by dissolution. However, the pore structure of Type III reservoirs is the worst among those investigated in this study but can be further improved by dissolution to a certain extent. Volcanic activity controls cementation and affects dissolution, thus changing the pore structure. A pore structure evolution model is established, which can provide a reference for future oil gas exploration.

1. INTRODUCTION

As an important unconventional resource, tight sandstone oil has attracted a considerable amount of attention worldwide, now, it has become the key target of exploration and development in major petroliferous basins. Tight sandstone oil reservoirs are usually characterized by low porosity and ultralow permeability, and heterogeneous pore structures are very common in tight sandstone oil reservoirs, which seriously restricts the exploration and development of oil gas.

The study of pore structure includes the study of pore type, size, and connectivity. High-pressure mercury injection analysis (HPMI), nuclear magnetic resonance analysis (NMR), constant-rate-controlled mercury porosimetry analysis (CMP), and nano/micro-computed tomography (CT) have been used to study the pore structure. Due to the characteristics of different measurement methods and the limitation of resolution, it is difficult to accurately identify and analyze the pore structure with only one method; therefore, combining several testing methods is necessary.

Several studies have shown that diagenesis and volcanic activity play important roles in the large-scale distribution of reservoirs. Diagenesis directly controls the characteristics of the pore structure and then affects reservoir physical properties. In tight sandstone, after strong compaction, pore size is mainly distributed in the range of several nanometers to tens of microns; narrower pore throats result in more complex pore shapes and worse connectivity, and thus, the comprehensive characterization of pore structure is more difficult, and the reservoir physical properties related to the pore structure are more difficult to predict. Although dissolution can obviously

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improve reservoir porosity, the connectivity of secondary dissolution pores is lower than that of primary pores.\textsuperscript{7,22,29,30} Basaltic volcanic materials easily dissolve and produce an alkaline formation fluid environment, which is beneficial for carbonate cementation.\textsuperscript{17} Meanwhile, chlorite transformed from volcanic materials has contradictory effects on a reservoir, as it could occupy the pore space but might inhibit later compaction and cementation.\textsuperscript{18,31} While volcanic activity could increase the formation temperature, it is easier for carbonate cements to be protected from dissolution in a relatively low-temperature environment.\textsuperscript{32} For source rock, a higher temperature means an earlier hydrocarbon generation threshold and higher maturity, which is of importance for oil gas exploration and development.\textsuperscript{33}

For tight sandstone reservoirs, the pore structure is of great importance; however, few studies have been conducted in the Gaoshangpu structural belt of the Nanpu Sag. The influence of multicycle volcanic activities on diagenesis has not yet been considered there, and the effect of diagenesis on the pore structure is unknown, which has restricted oil gas exploration. In this study, taking the third member of the Shahejie Formation (Es\textsubscript{3}) in the Gaoshangpu structural belt of the Nanpu Sag as an example, different types of tight reservoirs were identified and analyzed. The first member of the Shahejie Formation (Es\textsubscript{1}) in the No. 3 structural belt was chosen as a contrast to the Es\textsubscript{3} because they have similar tectonic, sedimentary contexts, and diagenetic processes, but only Es\textsubscript{3} experienced two volcanic activities,\textsuperscript{33−35} so such a comparison could reveal how volcanic activity has influenced these reservoirs. In this study, (a) the pore structure characteristics of different types of reservoirs are distinguished by various testing methods (HMPI, NMR, and CMP); (b) the influence of the pore structure on the physical properties is determined; (c) the diagenesis types and control effects on the pore structure are distinguished; and (d) the figure 1. comprehensive geologic map of the Nanpu Sag. (a) specific tectonic units of the Bohai Bay Basin, (b) location of the Gaoshangpu structural belt and main structures of the Nanpu Sag, and (c) generalized stratigraphic column of the Nanpu Sag. Adapted in part with Permission from refs 33 and 40. Copyright 2010, Geological Society of America Bulletin; Copyright 2015, Lithologic Reservoirs).
comparative evolution model of the pore structure influenced by volcanic activity is established.

2. GEOLOGICAL SETTING

The Bohai Bay Basin, located in eastern China, is the second-largest petroliferous basin in China. The Nanpu Sag is a small sag, with a total area of approximately 1932 km², in the Bohai Bay Basin, which is generally a compound half-graben-like sag with “North Fault and South overlap” and rich in oil gas resources (Figure 1a,b). According to the structural units, it can be divided into the Gaoshangpu, Liuzan, and Laoyemiao structural belts in the continental area and the offshore area including the Nanpu 1–5 structural belts.

Divided by their sedimentary cycle characteristics, the Shahejie (Es), Dongying (Ed), Guantao (Ng), and Minghuazhen (Nm) Formations were developed from bottom to top in the Paleogene strata. The Es Formation is characterized by fan delta sedimentary facies belts due to the strong activities of the Xinzhuang fault and the Baigezhuang fault, and the stratum thickness is relatively thick. The Ed Formation is a complete sequence, which is composed of a fan delta, a mudstone layer, and coarse-grained alluvium. The sedimentary facies of the Ng Formation and the Nm Formation are mainly fluvial facies (Figure 1c).

The Nanpu Sag contains a large number of volcanic rocks dominated by alkaline basalt, and the total thickness is more than 1200 m. Thirty-seven eruption events were identified in the studied profile and divided into three volcanic activities, namely, Cycle I (Es3), Cycle II (Es1–Ed3), and Cycle III (Ed–Ng), indicating multiple thermal events during the opening and expansion of the Nanpu Sag. The intensity and scale of these three volcanic eruption events are gradually expanded. Cycle I was limited to only the Beipu structural belt and other small areas, and Cycle II extended to the Gaoshanpu and Liuzan areas, with a total area of 250 km². Cycle III was widely distributed in the whole sag, but the main areas affected by volcanic eruptions did not contain the No. 3 structural belt. This volcanism can be interpreted by the diapiric upper-mantle upwelling model.

Previous studies have found that there are three sets of source rocks in the Es3, Es1, and Ed3 Formations in the Nanpu Sag. The reservoirs are mainly distributed in the delta sedimentary facies of Es, Ed, and Ng. The mudstones widely developed in Ng can be used as regional caprocks. Resource evaluation shows that the hydrocarbon yield of the Es3 Formation is not only an important source rock but also an important tight sandstone reservoir and can reach 40% of that throughout the Nanpu Sag. The lithology of Es3 reservoirs in the No. 3 structural belt is mainly lithic arkose, which is characterized by medium-low porosity and medium permeability, the pore types are mainly residual primary intergranular and dissolution pores, and the diageneses include two stages of cementation, strong dissolution, and increasing compaction.

3. METHODS

3.1. HPMI Measurement. A total of 25 samples with different porosities and permeabilities were selected for HPMI measurement. HPMI technology requires mercury to be pressed into the smallest pores of the sample by considerable pressure to analyze the pore structure. An HD-505 high-pressure porosity structure instrument (B096) was adopted for this work. The experiment was carried out at a room temperature of 18 °C and a humidity of 55%, and the test basis was SY/T5346-2005/4.

3.2. NMR Measurement. After the reservoir physical properties and the HPMI experiment, NMR measurements were performed using a RecCore-04 nuclear magnetic resonance rock sample analyzer (B042). According to SY/T6490-2007 and the laboratory measurement specification of NMR parameters of rock samples, the experiment was carried out at a room temperature of 23 °C and a humidity of 56%. During the experiment, the waiting time was 5 s, the echo interval was 0.3 ms, the scanning time was 64, the receiving gain was 50%, and the echo number was 2048. NMR measurements of both the volume of movable water (FFI) and irreducible bulk volume (BVI) were collected on 14 tight sandstone samples. The workflow was as follows: first, the FFI of various samples was measured with an experimental apparatus, and then, a PC-1 petroleum core centrifuge was used to obtain the BVI, which corresponded to a centrifuge capillary pressure of 2.86 MPa.

Relaxation time (T2) distributions from NMR measurements can represent the pore structure of reservoirs from the calculated pore size distribution (PSD), pore connectivity, and effective porosity. The diffusion relaxation rate can be reduced or effectively counteracted by a short echo interval and a low and uniform magnetic field. Therefore, the diffusion relaxation rate can be approximately reduced to

\[
\frac{1}{T_2} = \frac{1}{T_{2s}} = \rho^* \frac{S}{V} = \rho^* \frac{F_3}{r^3}
\]

where \(\rho\) (\(\mu\text{m/}\text{ms}\)) refers to the surface relaxivity, \(S\) (\(\mu\text{m}^2\)) is the pore surface area, \(V\) (\(\mu\text{m}^3\)) is the pore volume, and \(F_3\) is the pore geometry factor, which can be equal to 1, 2, and 3, representing the slit, cylindrical, and spherical pores, respectively.

3.3. CMP Measurement. According to the NMR measurement results, three samples with relatively good physical properties were selected for CMP analysis. An ASPE-730 constant velocity pore instrument was used for testing at a room temperature of 20 °C and a humidity of 37%. The detection basis is the Q/SYDQ2011-89 constant speed mercury injection method. By detecting the pressure fluctuation during the mercury injection process, the pore body was identified according to the sudden decrease in capillary pressure, and the throat was distinguished by the increasing capillary pressure. CMP measurements can provide capillary pressure curves that reflect all of the pores and various geometric characterization parameters, including pore volume and radius, pore throat volume and radius, and pore body-to-throat ratio (PBTR).

4. RESULTS

4.1. Reservoir Properties. 4.1.1. Reservoir Quality and Classification. From the physical property analysis of the deep tight sandstone reservoir in the Gaoshangpu structural belt, the results show that the distribution range of porosity is 1.1–1.0%, with an average of 11.2%, and the distribution range of permeability is ~15.3 mD, with an average of 0.8 mD. The samples with porosities less than 12% account for 60% of the total, while those with permeabilities lower than 1 mD account for 84% (Figure 2). The compositional maturity and structural maturity are both low. The clay content is relatively high, with an average of 16.6%. According to the clastic rock classification scheme of Folk, the lithology is feldspathic litharenite (Figure 3).

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According to the heterogeneity of permeability, the reservoirs in the study area can be divided into three types. Type I has a permeability greater than 1.0 mD, and the average porosity is 16.4%. Type II has a low permeability within 0.1−1.0 mD, and the average porosity is 10.8%. The average porosity of ultralow-permeability Type III reservoir is 7.7%.

4.1.2. Pore Types and Genesis. Generally, the surfaces of a primary pore are relatively smooth and straight (Figure 4c), and the pore radii are 20−500 μm in this study area (Figure 4a−c). Secondary pores include dissolution intergranular pores (Figure 4d,e) and dissolution intragranular pores (Figure 4e,f). The distribution range of the primary porosity is ~12%, with an average of 3.7%; the secondary porosity is ~3%, with an average of 1.1%. In the study area, the radius of dissolution intergranular pores is 20−180 μm. The radius of dissolution intragranular pores is generally relatively small, less than 100 μm. Due to the relatively deep burial and overlying formation pressure, some rigid particles are easily broken along the cleavage fracture, forming microfractures (Figure 4g,h). A scanning electron microscope (SEM) shows that the intercrystalline pores are mainly developed between clay minerals (Figure 4c,e), whose radii range from several microns (Figure 4i) and are present with low content. It is considered that the intercrystalline pores in the study area account for ~1% and have little effect on the physical properties.

Based on the modification of the classification method for tight reservoirs proposed by Loucks et al.,53 we classified the pore types of Es3 tight sandstones into two categories according to their spatial location: intergranular pores (Inter-Ps) consisting of primary and dissolution intergranular pores, and intragranular pores (Intra-Ps) consisting of dissolution intragranular pores, intercrystalline pores, and microfractures.

The method of using Adobe Photoshop to calculate the thin-section porosity rate was proposed by Zhang et al.54 Point counting software can quantitatively calculate the thin-section porosity of casting thin sections. The results show that Inter-Ps that are mainly developed in Type I reservoirs account for 3.0−8.1% of the pore space, with an average of 5.1%, accounting for 81% of the total porosity; the pore type of Type II is Inter-Ps + Intra-Ps, in which Intra-Ps are dominant, Inter-Ps account for only ~1.4%, with an average of 0.8%, accounting for 32% of the total porosity, whereas Intra-Ps account for 0.2−3.7%, with an average of 1.9%. The porosity of Type III is relatively low, and the thin-section porosity is therefore difficult to identify. A few Inter-Ps and intercrystalline pores, however, can still be observed in Type III rock via SEM.

4.2. Types and Characteristics of Diagenesis. The main diagenetic changes of the tight sandstone reservoirs in the Gaoshangpu structural belt are compaction, dissolution, and multiple cementation.

4.2.1. Mechanical Compaction. The compaction characteristics of the Es3 Formation are as follows: (a) plastic particles deformed and rearranged, and the argillaceous debris presents a pseudoheterobase, leading to more intensive compaction (Figure 5a); (b) point-line contact is the main contact between particles, and some particles are concave−convex contacts (Figure 5b); and (c) under the action of compaction, rigid particles were easily broken at weak places (Figures 4h and 5a).

4.2.2. Dissolution. There are some soluble components that provide a material basis for dissolution. The dissolution of feldspars, debris, and quartz can be observed, resulting in a certain number of Intra-Ps and Inter-Ps, especially around the development of primary Inter-Ps that easily dissolve; therefore, the primary Inter-P radii have expanded. Intra-Ps mainly exist in the interior of debris particles, which may be due to the different compositions (Figure 5b,c).

Feldspar, debris, and quartz are dissolved to varying degrees, among which the dissolution of debris is more obvious, forming irregular particle edges or dissolving some particles inside (Figure 5b−d). The intergranular cements also exhibit weak dissolution (Figure 5c).

4.2.3. Cementation. Carbonate, clay cementation, and authigenic quartz are the main cementation types in the study area. Through casting thin-section identification, early calcite cementation is the main type (Figure 5d). Under cathodoluminescence, orange and red luminescence carbonate can be observed, indicating that more than one stage of cementation has occurred (Figure 5e). Under SEM, some authigenic quartz with a complete crystal form can be observed (Figure 5f), and there are a variety of clay cements, among which, the content of the illite mixed layer is high, followed by kaolinite and chlorite (Figure 5f−h and Table 1). A little gypsum cement (Figure 5h) and kaolinitization of feldspar are shown as indigo blue luminescence under cathodoluminescence (Figure 5i). Microscopically, the particles float in the cement (Figure 5d), mainly in point contact.

4.3. Pore Structure Characteristics. 4.3.1. Pore Size Distribution from HMPI Analysis. The results of HPMI analysis are shown in Figure 6 and Table 2. The coefficient of variation (Cv) refers to the ratio of the standard deviation to the average value and was used here to describe the comparison between the
average value of pore throats and sorting degree and reflect the quality of the pore structure within a certain range. Threshold pressure refers to the capillary pressure corresponding to the maximum connected pore throats in the pore system, which is closely related to the physical properties.

The distribution range of the pore throat radii of Type I reservoirs is mainly greater than 1 μm. The average ultimate mercury saturation (UMS) is 67.8%, Cv is 1.14, and the threshold pressure is 1.31 MPa (Figure 6a−c). The pore throat radius of Type II is mainly distributed in the range of 0.1−1 μm, the average UMS is 50.0%, Cv is 0.89, and the threshold pressure is 1.43 MPa (Figure 6d−f). The pore throat radius of Type III is mainly distributed in the range of less than 0.1 μm, the average UMS is 28.3%, Cv is 0.81, and the threshold pressure is 3.83 MPa (Figure 6h,i and Table 2).

4.3.2. NMR Results. NMR results are shown in Figure 7 and Table 3. The pore morphologies of Type I reservoirs are unimodal and bimodal. The contents of the two types of pores ($T_2$ distributed in 10−100 ms and $T_2$ distributed in 1.0−10 ms) are basically equal, and the movable water is mainly distributed in large pores. $T_{2\text{cutoff}}$ is 11.6 ms on average, BVI is 10.5% on average, and FFI is 6.4% on average. Type I is characterized by good pore connectivity. The pore morphology of Type II is characterized by a single peak, $T_2$ is concentrated in 1.0−10 ms, the average $T_{2\text{cutoff}}$ is 9.0 ms, BVI is 8.7%, and FFI is 2.8%. Type II is characterized by moderate pore connectivity. Type III pore morphologies are characterized by a single peak. $T_2$ is concentrated at approximately 1.0 ms, contains a few large pores, but is relatively low, which has little effect on the overall pore structure and reservoir physical properties. The average $T_{2\text{cutoff}}$ is 2.7 ms, BVI is 3.4%, and FFI is 0.4%, Type III is characterized by the worst pore connectivity.

4.3.3. CMP Results. Compared with the HMPI results, the CMP results indicate that the pore throat volumes measured in this experiment are smaller, and the permeability is generally lower but closely replicates the original situation of the reservoir. As shown in Table 4, there are obvious differences in pore throat characteristics between these two types. In Type I, the final mercury preservation is more than 70%, and the threshold pressure is approximately 0.2 MPa. The pore radius is mainly concentrated at 120−180 μm, and the throat radius is mainly in the range of 1−3 μm. The PBTR is approximately 100, indicating good pore connectivity. In addition, the threshold pressure of Type II is approximately 0.6 MPa, and the final mercury saturation is only approximately 50%. The pore radius is concentrated at 100−160 μm, the throat radius is

Figure 4. Pore types of the Es$_3$ Formation in the Gaoshangpu structural belt ((a) G23-74, 4221.74 m, primary intergranular pores; (b) G23-74, 4222.67 m, residual intergranular pores filled with clay cement and authigenic quartz; (c) G32-19, 4129.44 m, primary residual intergranular pores; (d) G32-19, 4127.84 m, residual dissolution intergranular pores and authigenic quartz; (e) G23-39, 3826.52 m, secondary intergranular and dissolution intragranular pores; (f) G23-39, 3899.34 m, the dissolution of feldspar grains forms dissolution intergranular pores; (g) G23-39, 3894.29 m, cracks; (h) G23-39, 3826.96 m, microcracks; and (i) G32-19, 4152.07 m, kaolinite, illite, and I/S mixed layer and intergranular pores).
concentrated at 0.6–1.0 μm, and the PBTR is more than 200, which indicates that pore connectivity is moderate (Table 4 and Figure 8b). Since all of the selected samples have better pore structures in their types, the true result should be smaller than that obtained by the test; therefore, the experimental results are consistent with those of the HMPI and NMR.

5. DISCUSSION

5.1. Influence of the Pore Structure on Reservoir Physical Properties. Different reservoir types have different pore structure characteristics; among them, there are obvious differences in threshold pressure and UMS, as shown in Section 4.3.1, indicating that Type I reservoirs are mainly controlled by large connected pores, and the poor physical properties of Type III are mainly caused by small disconnected pores and most invalid pores (Figures 4 and 9). Correlations between the porosity and permeability of different reservoir types and UMS, threshold pressure, and Cv indicate a close relationship between the pore structure and reservoir quality (Figure 9). There are positive correlations between the UMS, Cv, and physical properties, and negative correlations between the threshold pressure and UMS, threshold pressure, and Cv indicate a close relationship between the pore structure and reservoir quality (Figure 9).
pressure and reservoir physical properties. The lower the threshold pressure, the larger the pore throats that control the physical properties, that is, the porosity and permeability with better physical properties are mainly controlled by the relatively large pores and/or throats.

Some scholars believe that the HPMI is accurate in the analysis of small throats, but there is a large error in the analysis of large pores. Therefore, the combination of a variety of experiments can more accurately characterize the pore structure. Compared with HMPI, NMR and CMP experiments can characterize full-scale pore throats. Using a centrifugal process, porosity occupied by irreducible water and movable water in the pores can be measured, and the connectivity of pores can also be determined. According to the relationships between porosity, permeability, and BVI at the irreducible water saturation (BVI@Swi), BVI, FFI, and BVI/FFI (Figure 10), the obvious correlations between the physical properties and the pore structure are further explained. BVI@Swi and BVI/FFI are negatively correlated with the physical properties, while BVI and FFI are positively correlated with them. Porosity and permeability are affected not only by the overall pore content but also mainly by the connectivity between pores. The higher the absolute BVI or FFI results, the higher the possibility of interconnection between pores under the condition of a constant reservoir volume. Therefore, even a high BVI could improve the physical properties. The FFI is the most intuitive parameter used to characterize the connectivity of pores. The higher the FFI, the higher the content of pores through which the underground fluid could flow freely, meanwhile, the FFI itself reflects porosity and further indicates the connectivity, representing the permeability of the reservoir; therefore, the physical properties improve with the increase of FFI (Figure 10c,f). As shown in Section 4.3.2, the distributions of FFI in these three types are obviously different; however, the BVI of Types I and II are similar, although they exhibit some differences from Type III. Combined with the conclusion of Section 4.1, we believe that the difference in physical properties may be mainly due to the number of Inter-Ps. The pore type of Type I is mainly Inter-P, while that of Type III is mainly Intra-P. The volume of Inter-Ps is larger, and most of them are primary pores, which are easier to connect, ultimately playing a strong role in controlling the high-quality reservoir. The CMP can effectively preserve the original pore structure under the condition of controlling the mercury injection pressure and further analyze the pore and throat volumes. According to the results (Table 4), the final mercury injection saturation of Type I can reach more than 70%, whereas that of Type II reaches only approximately 50%. This is mainly caused
by the difference in pore mercury saturation in these two types. The final mercury injection saturation is mainly provided by the throats whether in Type I or II. The difference between these two types is not large—approximately 40%—however, the great difference is provided by the pores. The final mercury injection saturation of Type I can reach more than 25%, while that of Type II is only approximately 15%, which also proves the conclusion obtained in the above-mentioned NMR experiments. The number of Inter-Ps is the main factor controlling these physical properties.

5.2. Influence of Diagenesis on the Pore Structure. Compaction was the main diagenesis that caused porosity loss (Figure 11), and the influence of cementation on pores was also strong. The Type I reservoirs were greatly affected by compaction, which made the particles contact more closely, while some primary Inter-Ps remained and they were difficult to completely block without the influence of cementation. Therefore, this type can still preserve massive Inter-Ps, providing space for later oil gas. Type II reservoirs were relatively affected by diagenesis, during which compaction and cementation lead to pore loss. Inter-Ps are mainly the residual primary pores after compaction and carbonate cementation. Additionally, the clay mineral cement has a great influence on the throats. This cement generally precipitated around the original particles. A small amount of clay had little effect on pores but a significant impact on the throats. Several microns of clay may even completely block the throat, resulting in isolated pores and a rapid decline in permeability. In this case, dissolution is the type of diagenesis that improved the pore structure the most, and we found that most of the pores are Intra-Ps formed by dissolution (Figure 5c). Type III reservoirs are mainly affected by cementation, resulting in extremely low porosity. The existence of carbonate cement resulted in space in large numbers between particles being filled, and there are almost no residual Inter-Ps. Dissolution improved this kind of reservoir to a certain extent and produced a few Intra-Ps but had little effect on physical transportation.

Table 2. Experimental Results of High-Pressure Mercury Injection

| sample | porosity (%) | permeability (mD) | THP (MPa) | UMS (%) | MPTR (μm) | Cv | MRE (%) | reservoir type |
|--------|--------------|-------------------|-----------|---------|-----------|----|---------|---------------|
| 1      | 16.9         | 2.79              | 0.50      | 64.8    | 1.49      | 1.09| 49.2    | I             |
| 2      | 16.6         | 3.63              | 0.13      | 71.2    | 5.55      | 1.29| 40.9    |               |
| 3      | 19.1         | 15.25             | 0.05      | 76.5    | 14.06     | 1.40| 32.5    |               |
| 4      | 17.5         | 1.82              | 0.29      | 66.0    | 2.58      | 1.03| 42.0    |               |
| 5      | 17.3         | 1.23              | 0.07      | 66.8    | 10.18     | 1.22| 37.2    |               |
| 6      | 18.1         | 1.99              | 0.25      | 66.3    | 3.00      | 1.11| 42.5    |               |
| 7      | 15.6         | 2.27              | 0.33      | 60.2    | 2.26      | 1.20| 41.0    |               |
| 8      | 20.8         | 3.28              | 0.30      | 73.3    | 2.44      | 1.03| 52.1    |               |
| 9      | 11.1         | 1.15              | 1.04      | 67.8    | 0.71      | 0.88| 56.0    |               |
| 10     | 17.7         | 1.33              | 0.19      | 65.0    | 3.92      | 1.14| 39.9    |               |
| 11     | 13.5         | 0.40              | 5.17      | 31.1    | 0.14      | 0.52| 36.7    | II            |
| 12     | 12.1         | 0.48              | 2.06      | 32.2    | 0.36      | 0.81| 39.7    |               |
| 13     | 10.3         | 0.54              | 0.52      | 58.3    | 1.43      | 0.99| 58.0    |               |
| 14     | 5.8          | 0.21              | 2.03      | 24.0    | 0.36      | 0.73| 81.8    |               |
| 15     | 10.6         | 0.41              | 1.04      | 63.0    | 0.71      | 0.89| 49.9    |               |
| 16     | 15.3         | 0.73              | 0.50      | 63.5    | 1.47      | 0.95| 44.9    |               |
| 17     | 15.8         | 0.87              | 0.29      | 69.3    | 2.51      | 1.12| 47.1    |               |
| 18     | 14.8         | 0.89              | 0.30      | 61.9    | 2.48      | 1.20| 46.3    |               |
| 19     | 9.0          | 0.12              | 0.98      | 46.8    | 0.75      | 0.83| 36.3    |               |
| 20     | 7.7          | 0.07              | 2.07      | 52.0    | 0.36      | 0.65| 51.5    | III           |
| 21     | 6.6          | 0.03              | 2.06      | 20.1    | 0.36      | 0.67| 42.5    |               |
| 22     | 8.3          | 0.06              | 4.96      | 17.3    | 0.15      | 0.57| 31.1    |               |
| 23     | 11.9         | 0.04              | 4.96      | 26.7    | 0.15      | 0.54| 57.1    |               |
| 24     | 7.3          | 0.08              | 5.08      | 22.4    | 0.14      | 0.56| 35.4    |               |

Table 2. Experimental Results of High-Pressure Mercury Injection

aTHP, threshold pressure; UMS, ultimate mercury saturation; MPTR, maximum pore throat radii; Cv, coefficient of variation; and MRE, mercury removal efficiency.

Figure 7. NMR curves of different types of reservoirs ((a) $T_2$ distribution before centrifugation and (b) $T_2$ distribution after centrifugation).
properties, which is the reason for the ultralow physical properties.

5.2.1. Control of Compaction on the Pore Structure. Compaction controls the properties of pore throat connectivity (Figure 12). The content of rigid particles, such as quartz, represents the anticompa
tion ability, and reservoirs with stronger compaction resistances can preserve more primary Inter-Ps during the burial process.

As the content of rigid particles increases, the content of primary pores becomes high, which affects the pore connectivity to a certain extent. The high quartz content might be due to the original source, indicating a high movable water content (Figure 12a,b). In Type I reservoirs, the control of compaction on pore properties is the reason for the ultralow physical properties.

Table 3. Nuclear Magnetic Resonance Experimental Data

| no. | depth (m) | nuclear magnetic porosity (%) | permeability (mD) | $T_{2\text{max}}$ (ms) | BVI@Swi (%) | BVI | FFI | BVI/FFI | reservoir type |
|-----|-----------|-------------------------------|-------------------|------------------------|------------|-----|-----|---------|----------------|
| 1   | 3899.34   | 14.8                          | 2.79              | 19.40                  | 65.58      | 9.71| 5.09| 1.91    | I              |
| 4   | 4151.46   | 17.5                          | 1.82              | 15.41                  | 57.11      | 9.99| 7.51| 1.33    |                |
| 5   | 4156.69   | 17.3                          | 1.23              | 9.35                   | 61.32      | 10.61| 6.69| 1.59    |                |
| 6   | 4157.89   | 18.1                          | 1.99              | 8.68                   | 61.11      | 11.06| 7.04| 1.57    |                |
| 7   | 4161.23   | 15.6                          | 2.27              | 1.83                   | 64.29      | 10.03| 5.57| 1.80    |                |
| 8   | 3903.22   | 17.2                          | 3.28              | 13.98                  | 67.01      | 11.51| 5.66| 2.03    |                |
| 1-1 | 4152.07   | 17.7                          | 1.33              | 12.21                  | 59.39      | 10.51| 7.19| 1.46    |                |
| 13  | 3824.82   | 8.8                           | 0.41              | 6.02                   | 80.56      | 7.08| 1.71| 4.14    | II             |
| 14  | 3923.03   | 13.4                          | 0.73              | 21.18                  | 81.48      | 10.89| 2.48| 4.40    |                |
| 2-1 | 4158.97   | 14.8                          | 0.89              | 3.57                   | 69.52      | 10.29| 4.51| 2.28    |                |
| 2-2 | 4162.65   | 9.0                           | 0.12              | 5.33                   | 73.89      | 6.65| 2.35| 2.83    |                |
| 17  | 3799.24   | 1.8                           | 0.03              | 2.64                   | 91.03      | 1.65| 0.16| 10.15   | III            |
| 21  | 3803.88   | 4.7                           | 0.04              | 1.89                   | 83.69      | 3.97| 0.77| 5.13    |                |
| 3-2 | 3823.93   | 5.0                           | 0.08              | 3.67                   | 93.07      | 4.62| 0.34| 13.43   |                |

*BVI, irreducible bulk volume; FFI, volume of movable water; and BVI@Swi, BVI in irreducible water saturation.

Table 4. Constant-Rate-Controlled Mercury Porosimetry Experimental Data

| no. | depth (m) | porosity (%) | permeability (mD) | $P_{50}$ | $R_{50}$ | THP (MPa) | FMS (%) | PBMS (%) | TMS (%) | MPBR ($\mu$m) | MTR ($\mu$m) | PBTR | reservoir type |
|-----|-----------|--------------|-------------------|---------|----------|-----------|---------|----------|---------|------------|-------------|------|----------------|
| 1   | 3899.34   | 17.4         | 1.48              | 1.63    | 0.45     | 0.23      | 73.78   | 27.27    | 46.51   | 152.05     | 2.12        | 104.87 | I              |
| 8   | 3903.22   | 18.0         | 1.50              | 1.59    | 0.46     | 0.24      | 73.46   | 25.27    | 48.20   | 154.38     | 2.27        | 94.21  | I              |
| 14  | 3923.03   | 13.6         | 0.20              | 4.81    | 0.15     | 0.68      | 54.39   | 16.24    | 38.14   | 145.60     | 0.87        | 205.88 | II             |

*THP, threshold pressure; FMS, final mercury saturation; PBMS, pore body mercury saturation; TMS, throat mercury saturation; MPBR, mean pore body radius; MTR, mean throat radius; and PBTR, pore body-to-throat ratio.

Figure 8. CMP-derived capillary pressure curves of the total pores, pore bodies, and throats (sample No. 1 is from a Type I reservoir, whose mercury saturation is mainly controlled by pores with radii larger than 1 $\mu$m; sample No. 14 is from a Type II reservoir, whose mercury saturation is mainly controlled by pores with radii 0.1–1 $\mu$m).
In Type II reservoirs, clay cement controls the throat size (Figure 12c,d). This is because in this kind of reservoir, compaction has the lowest impact, and the pore throats are the largest in the study area; therefore, the pore size is more sensitive to compaction.

5.2.2. Cementation Destroys the Pore Structure. Affected by volcanic activities, dissolution of the volcanic material resulted in an alkaline pore fluid, which was advantageous in the formation of carbonate cement. The influence of two cycles of volcanic activities after the deposition of Es3 on diagenesis is important in the Nanpu Sag. The volcanic activities not only changed the formation fluid properties but also provided chlorite via the soluble volcanic material, which protected the pore structure from later compaction and cementation or throat pluggings.

There is no doubt that carbonate cementation was destructive to these reservoirs, and the plugging of pores by cement was the main reason for the destruction of the pore structure. The results show that there is a strong correlation between the carbonate content and the related pore structure parameters (Figure 13). Carbonate cementation plays a strong role in controlling pore connectivity. When the formation fluid rich in Ca²⁺ passed through larger pore throats, which formed carbonate cementation. With the increase in the cement content, the original interconnected pores were gradually blocked until became isolated pores, resulting in the rapid decline in pore connectivity (Figure 13a,b). The brine inclusions in cements generally represent the formation age of the cements. The homogenization temperature of inclusions in the study area is 80−100 °C. It was considered that the carbonate cements in Es3 are mainly formed at approximately 28.1−30.0 Ma, which is basically consistent with Cycle II volcanic activity, indicating that there is a certain connection between them.

At the same time, clay cement can effectively reduce the size of throats. In Type II reservoirs, clay cement controls the throat size (Figure 13g,h), possibly because after the early compaction and cementation, most of the pore structure of this type was destroyed, leaving only the smaller pore throats in which carbonate cement was more difficult to precipitate; however, smaller clay minerals, especially chlorite from the dissolution of the volcanic material, were cemented effectively. This part of the cement blocked throats, resulting in a rapid decline in connectivity (Figure 13g−i). Although the content of chlorite in the study area is not high, chlorite transformed from volcanic minerals mainly precipitates on the grain surface as the lining (Figure 5f), greatly controlling the pore structure of the clay minerals, leading to the further blockage of the originally small throats, further deteriorating the pore connectivity and the rapidly decreasing FFI (Figure 13i).

5.2.3. Dissolution Can Effectively Improve the Pore Structure. Volcanic activity increased the formation temperature, which promoted the maturity of source rocks and generated more organic acids and CO₂, which might have led to reservoir dissolution, and the alkaline formation fluid influenced by volcanic material dissolution could also lead to the partial dissolution of quartz (Figure 5b,d). Figure 14 indicates that dissolution had a certain control on the pore structure, but the higher the dissolution rate, the worse the pore structure, which is contrary to common knowledge. The ratio of secondary porosity to primary porosity is defined as the dissolution rate. As discussed above, relatively high-quality reservoirs mainly contain more Inter-Ps, while the main products of dissolution are Intra-Ps, whose objects are feldspar, debris, and some quartz. The dissolution of carbonate cement, mainly blocked pores, is inhibited by higher temperatures and alkaline formation fluids caused by volcanic activity. Here, the overall dissolution porosity was approximately 1.1%. There is a slight difference between Types I and II in the content of dissolution pores; therefore, the improvement effect is more obvious for Type II than Type I because of their low porosity. This led to the highest dissolution rate of samples with the most common physical properties (Figure 14).
To a certain extent, dissolution can also promote the production of high-quality reservoirs. Some of the dissolution in this study area took place along the periphery of the primary pores, and the edge of the particles continued to be eroded, resulting in the superposition of dissolution Inter-Ps and primary Inter-Ps. This dissolution, especially in Type I (Figure 4a), could improve the pore structure because it not only increased the radius of pores but also made more pores connect; however, dissolution can only be used as a supplement to the primary pores, and the corresponding contribution to the physical properties is not high (Figure 14). However, dissolution pores are dominant in Type II (Figure 5b,c and 14c). For Type III reservoirs, due to the influence of intense compaction and cementation, the thin-section porosity is basically not developed.

Figure 10. Controlling effect of the pore structure according to NMR on reservoir physical properties (scatter diagram of nuclear magnetic porosity vs (a) BVI in irreducible water saturation, (c) BVI, (e) FFI, and (g) BVI/FFI; permeability vs (b) BVI in irreducible water saturation, (d) BVI, (f) FFI, and (h) BVI/FFI. Legends are shown in Figure 2).
At this time, although the total amount of pores provided by dissolution is low and the connectivity is poor, the pore structure can be improved to a certain extent (Figure 14b). Therefore, in Type I, the pore type is still primary and dissolution is used as an auxiliary to improve the pore structure, and the pore structure of Type II is mainly improved by dissolution. In Type III, in which cementation is seriously affected, dissolution can improve the pore structure to only a certain extent.

5.3. Different Pore Structure Evolution Models Affected by Volcanic Activity

Different evolution models of the pore structure have developed in the Gaoshangpu and No. 3 structural belts.33,35 There were three volcanic cycles between the Eocene and Miocene Epochs, and two later cycles developed in Gaoshangpu but did not develop in the No. 3 structural belt.33,35 Similar tectonic and sedimentary contexts however have different pore structure evolution models, which may be caused by volcanic activities. Volcanic activities changed the fluid environment and properties in different structural belts, resulting in strong differences in diagenesis strength, and finally showed different pore structure evolutions.

In Cycle II (31.0−25.3 Ma), the Es3 reservoirs experienced early compaction and were cemented strongly and some quartz dissolved to some extent (Figure 5b,d). Pore fluids became alkaline due to the dissolution of the volcanic rocks,17,31 as mentioned above, which provided a material basis for strong cementation. Basaltic volcanic materials are easily transformed into chlorite and cemented along the particle edge. These chlorites occupied throats in Type II (Figures 13g−I and 15) or protected the pore structure of Type I reservoirs from later diagenesis.7,18 At this time, the pore structures of Type II and III Es3 reservoirs were seriously damaged, and only the high-quality Type I with many Inter-Ps still had some interconnected pores, similar to the Es1 reservoirs (Figure 15). In comparison, Es1 only experienced weak mechanical compaction and early cementation, weaker than those experienced by Es3, due to the lack of volcanic materials providing a strong alkaline environment.34,35

During the oil gas filling period (approximately 25.0 Ma58), higher formation temperatures caused by volcanic activity could inhibit the dissolution of carbonate cements,32 and the overall effect of dissolution on the Es3 reservoir is not as strong as that of Es1.35 Continuous volcanic activity played an important role in these different phenomena. Type III is filled with early carbonate cements, which were first preserved due to the high-temperature and alkaline formation fluid; although the formation fluid
changes to acidic due to large-scale oil gas migration, only a small amount of acidic fluid entered and dissolved the rock to slightly improve the pore structure due to the absence of pore throat space. There is no such strong cementation in Type II, so acidic fluid entered and dissolved much of the feldspar and debris and effectively improved the pore structure, but the dissolution of cement was also blocked by temperature, so it was difficult to form high-quality reservoirs similar to Type I. In addition, in Type I, there are many interconnected pores, which were easily formed by dissolution along the residual primary pores after the
dissolution fluid entered, improving the pore structure, but still weaker than Es1 reservoirs. In contrast, the acidic pore fluid easily entered the Es1 reservoirs and dissolved primary sedimentary grains and/or cements sometimes completely (Figure 15).

The effect of Cycle III (approximately 23.0 – 5.3 Ma) should be similar to that of the previous cycle; however, higher temperatures caused by volcanic activity continuously protected the cement from dissolution,32 and the deeper burial led to stronger compaction; therefore, basically no large pores existed, and only a few late cements precipitated in Es3. Because volcanic activity changes fluid properties and promotes cementation, late cementation occurred, even in tight Es3 reservoirs (Figure 15). Generally, we observed only one cement phase, and this conclusion is consistent with the previous understanding of the study area.34,58 In the same period, the Es1 reservoirs experienced late cementation, and some pores were blocked but the intensity was not high due to the lack of a material basis transformed by volcanic activity.

6. CONCLUSIONS

(1) Low-porosity and ultralow-permeability tight sandstone reservoirs with low compositional maturity and structural maturity are developed in the Es3 Formation in the Gaoshangpu structural belt of the Nanpu Sag, and the main rock type is feldspathic litharenite. Intergranular, intragranular, and intercrystalline pores and microcracks have developed in these reservoirs. High-quality reservoirs and pore structures are mainly controlled by compaction, carbonate cementation, clay cementation, and dissolution.

(2) There are three types of reservoirs. The permeability of Type I reservoirs is greater than 1 mD, the average porosity is 16.4%, the pore type is mainly Inter-P, the pore radii are distributed between 120 and 180 μm, and the throat radii are larger than 1 μm. The permeability of Type II varies from 0.1 to 1 mD, the average porosity is 10.8%, pore radii are approximately 100 μm, and throats range from 0.1 to 1 μm; the permeability of Type III is less than 0.1 mD, the average porosity is 7.7%, the pore radii are far less than 100 μm, throat radii are less than 0.1 μm, and the pore connectivity is the worst. The content of large pores is the key factor in the difference in physical properties of Type I and II reservoirs, and the effectiveness of pores and/or throats is for Type III.

(3) Different diagenetic effects play key roles in controlling the pore structure of various reservoirs. The pore size of Type I reservoirs is the most sensitive to compaction, and the pore connectivity is controlled by carbonate cementation. Dissolution can also improve the pore
structure; the pore throat size and pore connectivity of Type II reservoirs are seriously affected by clay cementation, and pores are mainly formed by dissolution, while the pore structure of Type III reservoirs is the worst, which is improved by dissolution to a certain extent.

(4) Volcanic activity is an important factor in controlling diagenesis. Changing the properties of the formation fluid can promote the cementation of carbonate and the dissolution of quartz; chlorite transformed from volcanic materials protects Type I reservoirs from later compaction and cementation but blocks throats in Type II, resulting in an exponential decrease in the physical properties. The higher temperature caused by volcanic activity was the main inhibitor of the dissolution of carbonate cement.

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Notes
The authors declare no competing financial interest.

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