RESEARCH ARTICLE

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Determination of Reserve Parameters of Gulong Shale Oil Reservoir and Its Geological Significance

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Abstract

The pore structure of continental shale reservoirs is complex and diverse, exhibiting multi-scale pore size distributions spanning from nanometers to micrometers. In particular, accurate porosity measurement has remained a major challenge in shale reservoir characterization. To achieve accurate porosity determination for continental shale, this study takes the Gulong shale as a case example. Based on the fluid occupancy characteristics of shale pores, the pore space is classified into three types: gas-occupied, water-occupied, and oil-occupied pores. The volumes of these three pore types are measured experimentally via kerosene saturation, ethanol extraction, and solvent washing, respectively, thereby establishing a method for measuring the total porosity of continental shale reservoirs—termed the fluid summation method. The results demonstrate that the micro- to nano-scale pores of Gulong shale exhibit strong imbibition of kerosene, enabling kerosene to serve as an effective saturating fluid for characterizing the gas-occupied pore volume; the free water and clay-bound water in shale can be fully extracted by soaking the crushed sample (particle size: 2–5 mm) in absolute ethanol; and dichloromethane, characterized by strong polarity and a low boiling point, proves to be an effective oil-washing reagent. Validation confirms that the fluid summation method yields accurate porosity measurements for fresh cores of Gulong shale. The successful application of this method provides a reliable basis for the accurate determination of reserve parameters of continental shale oil and gas reservoirs in China, as well as for understanding pore evolution mechanisms and optimizing the identification of sweet spots and sweet intervals.

Keywords: Gulong shale oil, total porosity, fluid addition method, reserve parameters, continental shale reservoir.

1 Introduction

The pore structure of continental shale reservoirs is complex, with diverse pore types and multi-scale pore size distribution from nanometer to micrometer [1]. In particular, the measurement of porosity has always been a difficult point in the field of shale physical

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property research. Accurately measuring key reserve parameters such as shale porosity and saturation is a crucial step in shale exploration.

Porosity is an important parameter for characterizing reservoir physical properties. It is the ratio of the pore volume in the rock to the total volume of the rock [2]. Conventional sandstone has a simple pore structure and relatively single pore types. Generally, effective porosity is selected as the physical property parameter for characterization [3]. However, shale reservoirs have diverse pore types. Taking Gulong shale as an example, Zhang et al. [4] classified its pores into intergranular pores, organic matter pores, clay mineral shrinkage fractures, organic matter shrinkage fractures, intragranular pores, and intercrystalline pores according to the pore genesis types. Microscopic images from environmental scanning electron microscopy show that shale oil is enriched in different types of reservoir spaces in shale reservoirs. Yang et al. [1] believe that the intercrystalline pores and dissolution pores formed by the rock matrix minerals are either unconnected or have extremely poor connectivity. When the content of brittle minerals such as quartz and feldspar is high, natural fractures and induced fractures are likely to form, and the transformation can improve the seepage ability of these pores. Zhao et al. [5] believe that shale reservoirs are mainly composed of nanopores and have a special pore structure. Different from conventional reservoirs, isolated pores in shale reservoirs may also become effective reservoir spaces. After fracturing, the oil and gas in the "dead pores" can be extracted. Therefore, the methods for measuring the porosity of conventional sandstone are often inaccurate for characterizing shale pores. When calculating the porosity of shale reservoirs, these unconnected pores should be taken into account to facilitate the calculation of the oil and gas reserves in shale reservoirs and the optimization of sweet layers and sections.

Currently, the main methods for measuring the total porosity of the core include the saturated liquid method, the helium method, the mercury injection method, the nuclear magnetic resonance method, and the TRA method. The saturated liquid method calculates the porosity based on the amount of liquid injected into the core pores. The process is to first evacuate the core sample, and after the vacuum degree meets the standard, saturate it with liquid. Generally, kerosene, ethanol, water, etc. can be selected. Finally, the porosity is obtained according to the mass difference before and after the rock sample is saturated. This method can only measure the connected pores of the rock and cannot measure the isolated pores. Therefore, it can only calculate the effective porosity but not the total porosity. The helium method is based on Boyle's law. The rock sample is placed in a closed device, and then helium is injected. By measuring the change in pressure before and after the gas enters, the skeleton volume is measured, and then the porosity of the sample is calculated [6, 7]. However, this method is only suitable for porosity measurement in the range of 1.0% - 10.0%, while the total porosity of most shales is above 10.0%, and it is prone to errors due to the influence of the crushing particle size and test pressure. The mercury injection method has strong limitations in characterizing the pore size range and cannot obtain the volume of unconnected pores in the core. The nuclear magnetic resonance method only responds to pores filled with fluid and does not respond to pores without fluid, so it cannot fully characterize the total porosity of the core. The TRA method calculates the total porosity of shale by measuring the volume of the dry distillation products after the crushed core is subjected to dry distillation at different temperatures. However, due to the influence of the high temperature during dry distillation, the light components of the dry distillation products will be lost, and the volume of the dry distillation products needs to be corrected.

In view of the problems in measuring the total porosity of shale, the author selected shale samples from the Qingshankou Formation in the Gulong Sag of the Songliao Basin and conducted research on the influence of oil washing methods, drying temperatures, drying times, etc. on the measurement results of shale porosity. By summarizing the experience of predecessors and combining with the research methods of conventional reservoirs, the author classified and measured various types of pores and established a process for measuring the total porosity of mud shale using the "fluid addition method". First, according to the types of fluids in shale pores, the pores in shale reservoirs are divided into gas-occupied pores, oil-occupied pores, and water-occupied pores. Then, the volumes of these three types of pores are measured respectively. Finally, the total porosity of shale is calculated by adding them up. This method can accurately provide parameters such as the total porosity and fluid saturation of shale without the need for complex calculation models, and can provide technical support for accurately evaluating the performance and production capacity level of shale

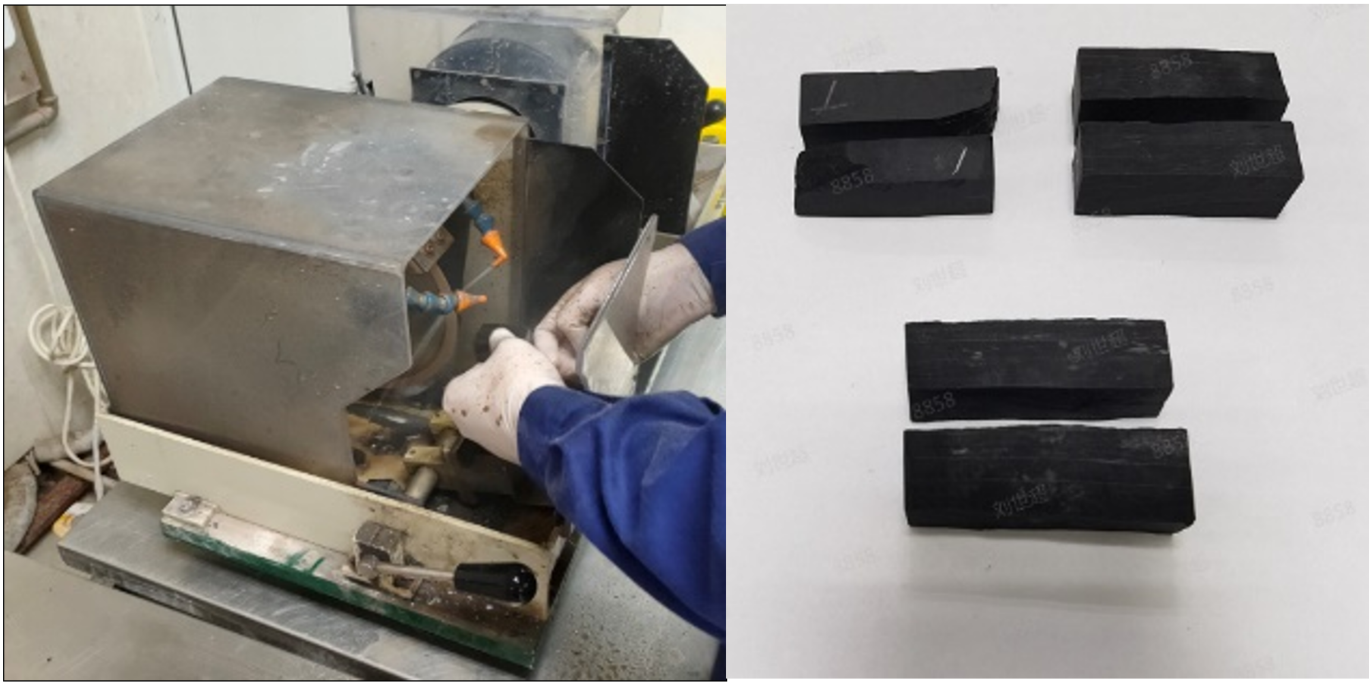

Figure 1. Gulong shale sample pretreatment and forming sample rocks.

Table 1. Comparison of the mineral composition of Gulong shale in the Songliao Basin with domestic and foreign [9].

Area/Basin	Stratigraphic Unit	Clay Mineral Content / %	Quartz Content / %	Feldspar Content / %	Carbonate Content / %	Pyrite Content / %
Songliao Basin	Qing 2nd Member	34.5	32.3	22.3	6.5	4.4
Songliao Basin	Qing 1st Member	36.2	34.6	18.1	8.0	3.1
Jiyang Depression	Lower Es_3	27.8	29.0	4.0	36.2	3.0
Zhanhua Sag	Lower Es_3	14.9	15.8	1.0	65.0	3.3
Weiyuan Area, Sichuan Basin	Longmaxi Formation	30.0	35.0	6.0	25.0	4.0
Ordos Basin	Chang 7 Member	28.2	27.8	15.9	11.7	16.4
Changning Area, Sichuan Basin	Longmaxi Formation	26.0	40.0	4.0	28.0	2.0
Jiaoshiba Area, Sichuan Basin	Longmaxi Formation	23.0	62.0	5.0	6.0	4.0
Southern Texas (USA)	Eagle Ford Shale	30.4	4.7	8.9	53.5	2.5
Fort Worth Basin (USA)	Marcellus Shale	33.0	46.4	7.2	8.2	5.2

reservoirs and the effective exploration of continental shale oil and gas.

2 Samples and Analysis Methods

2.1 Sample Characteristic Description and Pretreatment

The shale samples studied in this paper are all from the fresh cores obtained by conventional coring from the sedimentary section of the Qingshankou Formation in the Gulong area. The samples were prepared by cutting with a liquid nitrogen freezing saw to obtain block samples with a flat and crack-free surface. The mass of the samples is about 25–30 grams (see Figure 1). Table 1 lists some physical and geochemical characteristics of the selected shale samples, including clay mineral composition, Tmax, density, and porosity. The main clay minerals in the samples (which affect the drying temperature) are illite (I) and illite-smectite interlayers (I/S), and chlorite (C). The contents of chlorite/smectite mixtures and kaolinite are relatively low and unevenly distributed, and they are occasionally found. Compared with North American marine shales and other continental shales in China, the Gulong shale has a relatively high clay mineral content and a low carbonate content [8, 9].

2.2 Method for Measuring the Total Porosity of Shale

The fluid types in Gulong shale are mainly divided into three categories: oil, gas, and water. There are three forms of shale oil, namely adsorbed state, free state, and dissolved state (oil and gas are miscible), with the first two being the main forms. The free shale oil is mainly stored in the form of an oil film in the larger intergranular pores and bedding fractures. Inside the organic matter, intercrystalline pores, and intragranular pores, shale oil mostly exists

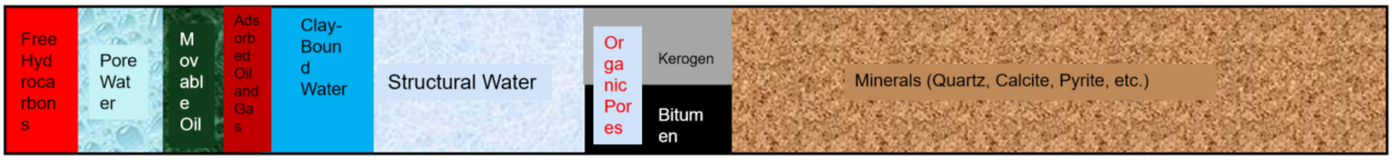

Figure 2. Different occurrence states of Gulong shale water.

in a coexisting state of bound state, dissolved state, and free state [10].

There are various types of water in mud shale, mostly existing in the form of water molecules or water ions. According to the adsorption position of water and clay minerals, it can be divided into surface adsorbed water and interlayer adsorbed water (Figure 2) [11]. The surface adsorbed water is coordinated with the atoms or atomic groups on the surface of clay minerals or combined with the mineral surface through hydrogen bonds. This part of water can be classified as clay bound water and is involved in the calculation of the total porosity of shale. The interlayer adsorbed water is adsorbed by the negative charges between the clay mineral layers and is arranged in an orderly manner. This part of water can be classified as structural water and is not involved in the calculation of the total porosity of shale. In addition, there is also a certain amount of capillary bound water in Gulong shale, which is involved in the calculation of the total porosity.

Under formation conditions, the original oil and gas reservoir of Gulong shale coexists in two phases of oil and gas [23], mainly in the adsorbed state. During the process of the core rising in the wellbore, due to the pressure drop, this part of the light hydrocarbon components will be lost. Using the new technology for restoring the shale oil content of the pressure-maintained and sealed core, the free hydrocarbon content of Well A1 in Gulong shale is 8.15 mg/g, and this part of the light hydrocarbon components is involved in the calculation of the total porosity (Figure 3) [10].

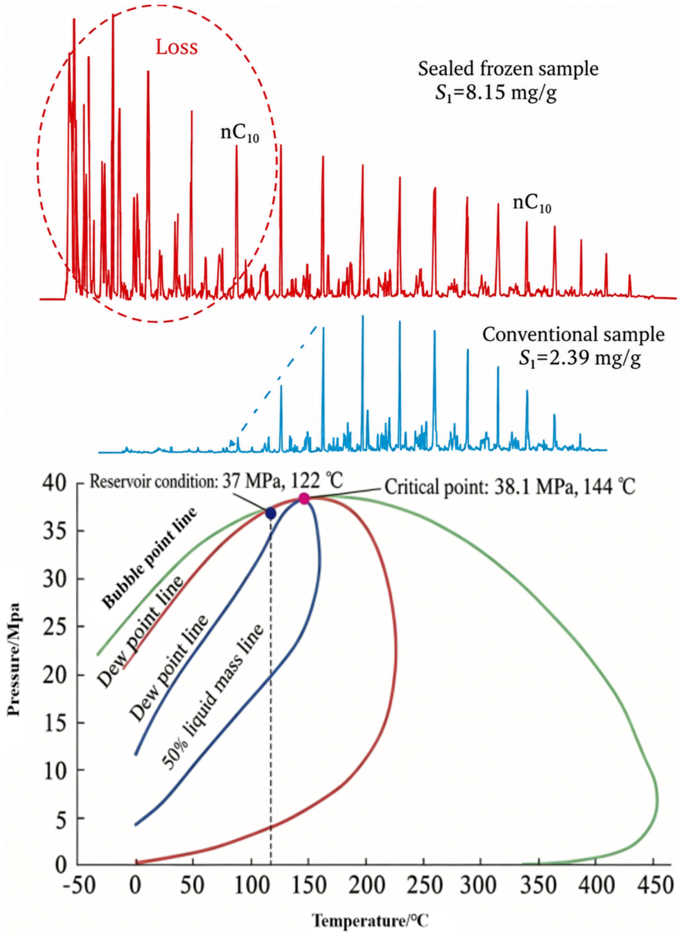

Figure 3. Gulong shale gas (light hydrocarbon) loss and correction [10, 23].

2.2.1 *Measurement of Gas-Occupied Volume*

When the core is taken to the surface, due to the pressure drop, the light hydrocarbon components in the core will be quickly released, which will subsequently affect the calculation of the oil and water saturation of the core. Therefore, to obtain accurate core saturation data, the lost light hydrocarbon components must be measured.

Gulong shale generally develops nanoscale pores, mainly mesopores, with both micropores and macropores. Due to the different capillary forces, different pore sizes have different absorption capacities for different liquids. To characterize the adsorption characteristics of pores of different levels for different fluids, two fresh samples of Gulong shale (after dry distillation at 705°C) were selected and soaked in deionized water and kerosene for self-priming experiments. The saturated samples were then subjected to two-dimensional nuclear magnetic resonance to obtain the T1 - T2 two-dimensional spectrum. As shown in Figure 4, the signal intensities of the core soaked in deionized water and kerosene increased significantly. In the two-dimensional spectrum of the core soaked in kerosene, signals were shown in the nanoscale micropores, mesopores, and macropores of the core, indicating that Gulong

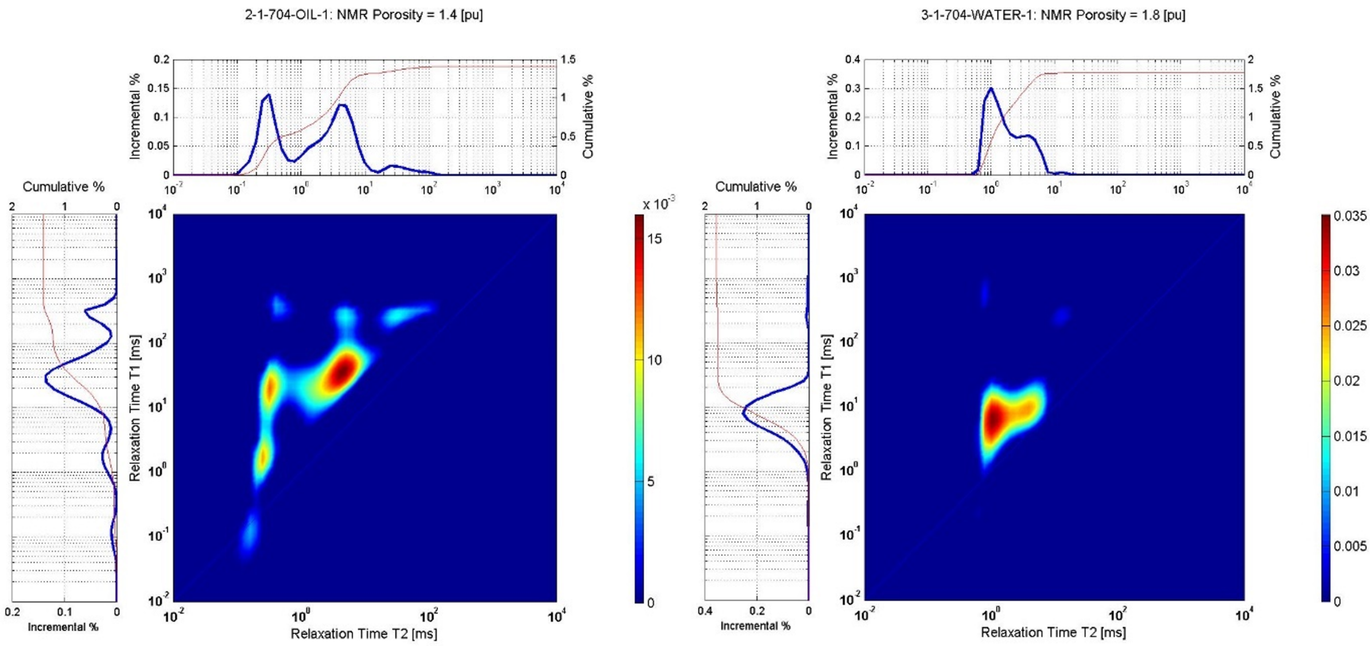

Figure 4. Two-dimensional NMR mapping of self-priming kerosene and water in Gulong shale [24].

shale is oleophilic in all pore sizes. The gas-occupied pore volume of Gulong shale in all pore sizes can be characterized by the self-priming kerosene method. However, in the core self-primed with deionized water, signals were only shown in the macropores, and the mesopores and micropores of Gulong shale could not be fully characterized. This is because organic matter pores are widely developed inside the shale and have a wetting characteristic of being oleophilic and hydrophobic. Inorganic pores are generally mainly mesopores and macropores, and the hydrophilicity of different minerals also varies (Figure 5). Therefore, water cannot fully saturate the pores of shale in all sizes [12]. Therefore, compared with deionized water, kerosene is a more suitable reagent for characterizing the pore size of the gas-occupied volume in the rock core.

The calculation formulas for the total volume and gas-occupied volume are as follows:

$$V_1 = \frac{m_3 - m_2}{\rho_1} \tag{1}$$

$$V_2 = \frac{m_3 - m_1}{\rho_1} \tag{2}$$

where V_1 – the total volume of the core, cm^3; V_2 – the gas-occupied volume of the core, cm^3; m_1 – the original mass of the core, g; m_2 – the mass of the core in kerosene after self-priming kerosene, g; m_3 – the mass of the core in the air after self-priming kerosene, g; ρ_1 – the density of kerosene, g/cm^3.

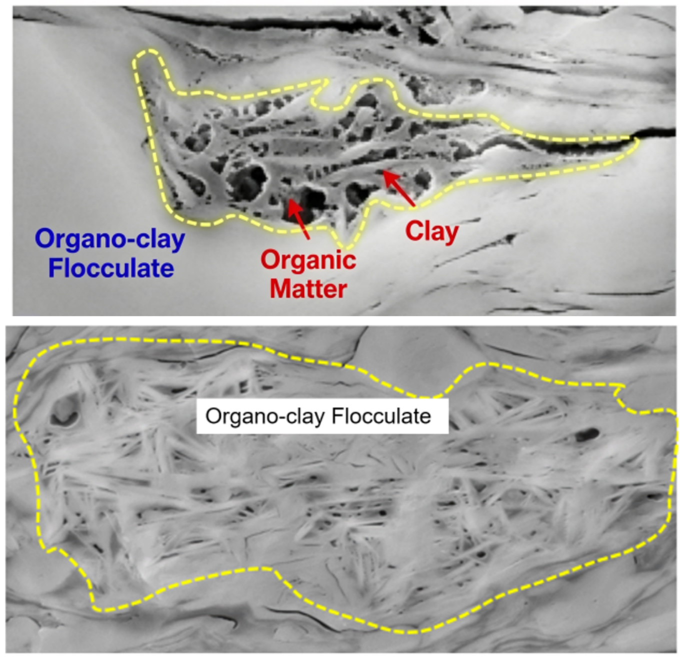

Figure 5. Clay minerals are coupled with organic matter to form flocs [22].

2.2.2 *Measurement of Water-Occupied Volume*

Prepare a dry and well-sealed steel extraction tank. Put the sample into the extraction tank, and crush the sample with the lid on to a particle size of 2–5 mm to ensure that there is no loss of the rock sample mass during the crushing process. Inject a certain amount of absolute ethanol into the extraction tank, seal it, and soak it at room temperature for 48 - 72 hours before measuring the water content. Select a gas chromatograph or a coulomb meter as the

Table 2. Wash oil solvent parameter table.

Solvent	Boiling Point (°C)	Solubility	Polarity
Alcohol-Benzene (1:3)	78.4	Oil, slight water	Non-polar
Dichloromethane	40.1	Oil, slight water	Polar
Chloroform	61.7	Oil	Polar
Acetone	56.5	Oil, water, salt	Polar
Toluene	110.6	Oil	Polar
Xylene	138.0 – 144.4	Oil	Polar
Methanol	64.7	Water, salt	Polar

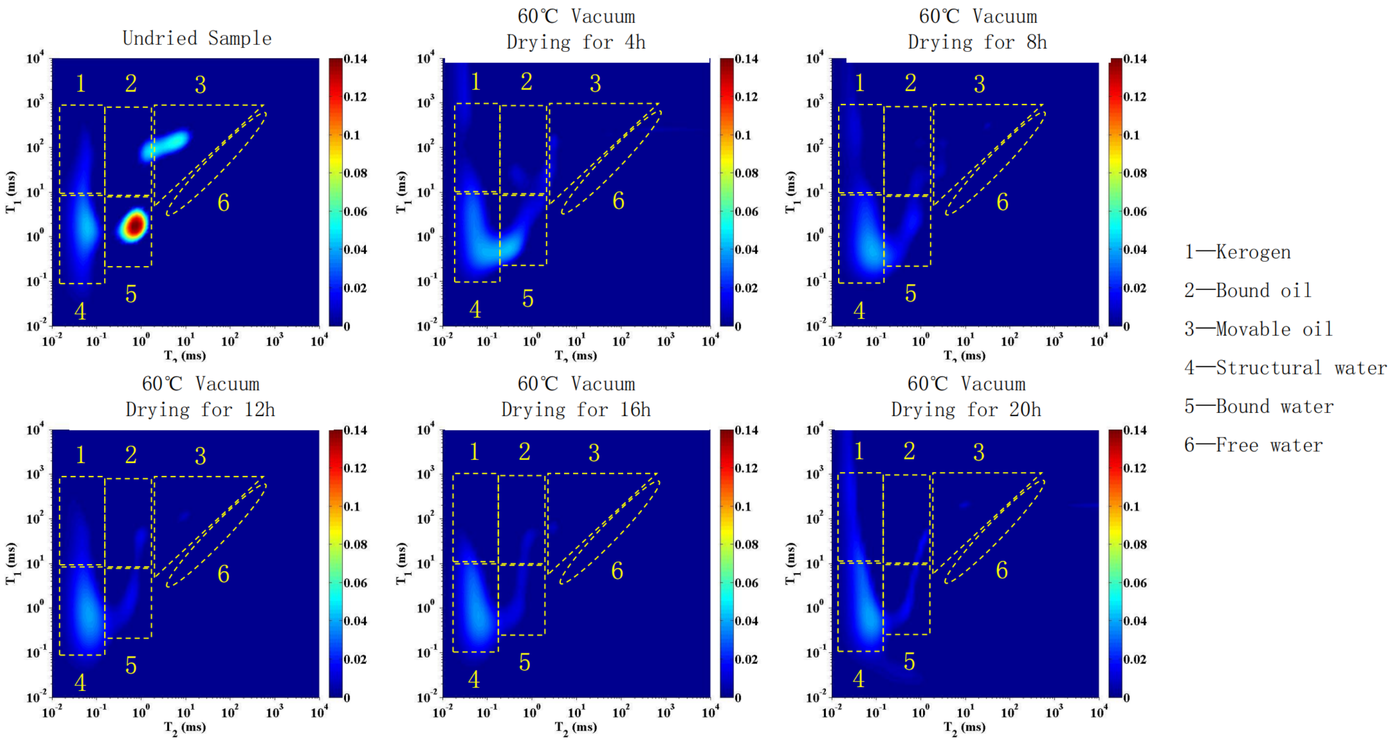

Figure 6. Two-Dimensional NMR Spectra at Different Drying Times of washed oil samples [24].

measuring instrument. After measuring the water content, calculate the water-occupied volume.

2.2.3 *Measurement of Oil-Occupied Volume*

Transfer the sample from the extraction tank to the encapsulation material and encapsulate it for oil washing. The oil washing is carried out according to the solvent extraction method specified in 4.6.4.4 of GB/T 29172-2012. Generally, a dichloromethane solvent with a relatively low boiling point and relatively low toxicity is selected for extraction and oil washing according to the dehydration temperature of clay minerals (Table 2).

The calculation formula for the oil-occupied volume is as follows:

$$V_o = \frac{m_1 - \rho_w V_w - m_4}{\rho_o} \tag{3}$$

where V_o – the oil-occupied volume of the core, cm^3; V_w – the water-occupied volume of the core, cm^3; m_4 – the mass of the core after drying, g; ρ_w – the density of water, g/cm^3; ρ_o – the density of crude oil, g/cm^3.

The oil-washed sample needs to be dried. The goal of drying is to remove water from the pore space without changing the structure of the clay minerals. The drying temperature and drying time are the key factors determining whether there is no water or other residues in the oil-washed sample. As can be seen from Figure 6, as the drying time increases, the signal intensities in the regions of adsorbed oil, movable oil, clay adsorbed water, and capillary water gradually decrease. After 8 hours of drying, the signal intensity decreases the most. After that, as the drying time increases, the signal intensity in the response region changes little, indicating that most of the bound water and clay adsorbed water have been removed after 8 hours of vacuum drying at 60°C. Therefore, the drying time is determined to be 8 hours.

Gulong shale is rich in clay minerals, and the mass fraction of clay minerals can reach 25 - 45%. The main types are illite, illite/smectite interlayers, and chlorite. Compared with other continental shales in China, the clay mineral content in the Gulong shale reservoir is relatively high [13]. Previous studies have shown that after clay minerals are heated to a certain temperature, they will lose the water combined with hydroxyl groups, and this part of water is a part of the crystal structure of clay minerals. It can neither move freely nor store hydrocarbons, so it cannot be involved in the calculation of the total porosity of mud shale. Therefore, when drying the core sample, an appropriate drying temperature should be set according to the dehydration temperature of the mud shale sample. At this temperature, all the free water, capillary water, clay bound water, and oil washing reagents can be removed, and the clay minerals will not lose the water combined with hydroxyl groups. The drying conditions recommended by the API (American Petroleum Institute) and the GRI method are to dry the core at 110°C for 20 hours. Through the in-situ scanning electron microscope image study of samples at different drying temperatures, it is found that the drying temperature of the Gulong shale core above 60°C will cause the destruction of the shale structure, and the effective porosity and total porosity will increase significantly. As the temperature continues to rise, the destructive effect intensifies. As can be seen from Figure 7, when the drying temperature is 60°C, the structure of the clay minerals does not change. When the drying temperature is higher than 90°C, the structure of the clay minerals begins to change. The optimal drying temperature is determined to be 60°C, and the conventional drying at 105°C is not suitable for Gulong shale. Combining the above experimental results, the optimal drying conditions for the oil-washed sample of Gulong shale are determined to be vacuum drying at 60°C for 8 hours.

The calculation expressions for the total pore volume and total porosity of the mud shale sample are as follows:

$$V_3 = V_w + V_o + V_2 \tag{3}$$

$$\phi = \frac{V_3}{V_1} \times 100\% \tag{4}$$

where V_3 – the total pore volume of the core, cm^3; ϕ – the total porosity of the core, %.

3 Sample Analysis Results

3.1 Comparison of Experimental Results

Table 3. Data table for determining total porosity of cores by different methods.

Sample No.	Total Porosity by Fluid Summation Method (%)	Total Porosity by Helium Method (%)
193	12.67	8.18
199	13.05	4.82
201	9.99	7.76
203	14.05	8.07
205	12.59	7.30
207	14.19	9.73
209	13.40	9.23
213	14.95	8.45
215	15.61	8.72
217	15.13	10.78
219	15.26	11.05
221	13.23	11.09
225	11.40	9.80
227	13.52	10.43
Average	**13.6**	**9.0**

A total of 14 core samples were collected from Well Z1H for the determination of total porosity by the fluid summation method and helium porosimetry method (Table 3). The results show that the average total porosity measured by the helium method is 9.0%, while that by the fluid summation method is 13.6%, presenting a significant discrepancy between the two methods. On the one hand, the national standard GB/T 34533-2017 stipulates that the applicable porosity range of the helium method is 1.0%–10.0%; however, the total porosity of Gulong shale is mostly higher than 10%, exceeding the applicable scope of the helium method. On the other hand, the ultra-low permeability caused by nanoscale pores in shale reservoirs hinders gas from fully entering the micropores of shale.

The oil saturation measured by the proposed method ranges from 30.97% to 59.47%, with an average value of 45%. Yan et al. [14] carried out field one-dimensional nuclear magnetic resonance (1D-NMR) oil saturation measurement on 544 samples from 8 wells in the Gulong area, obtaining an average oil saturation of 62%. The oil saturation determined in this study is lower than the field 1D-NMR results. The reason is that the 1D-NMR method adopts the effective porosity of bulk core samples for oil saturation calculation, whereas this study uses the total porosity of crushed samples, leading to a lower calculated oil saturation. Meanwhile, after saturating rock samples with manganese chloride aqueous solution in the 1D-NMR test, the water signal cannot be completely shielded, and part of the

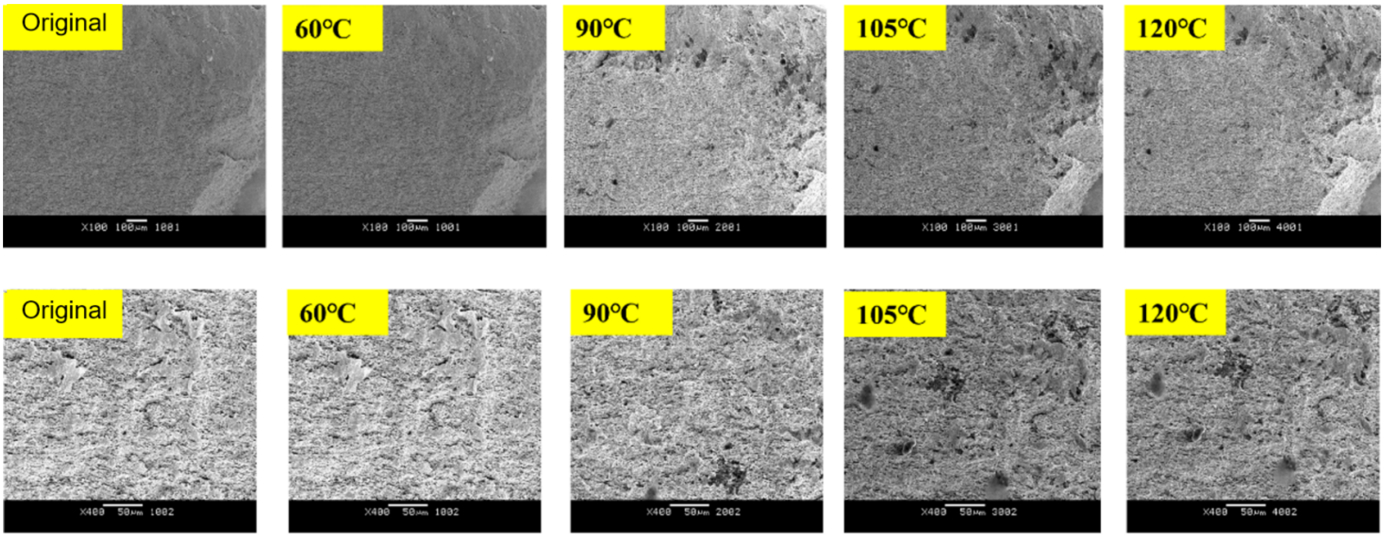

Figure 7. Two-dimensional NMR patterns of different drying temperatures for washed oil samples [24].

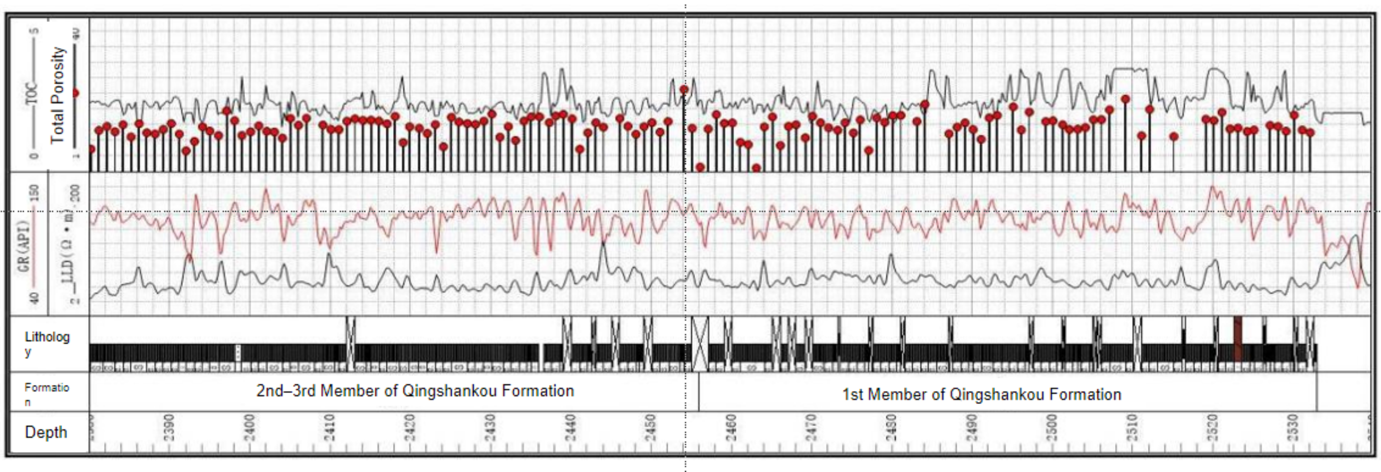

Figure 8. Total core porosity and logging curve, TOC comprehensive diagram.

water signal is misidentified as the oil signal, which ultimately results in an overestimated oil saturation.

3.2 Experimental Results and Logging Response Characteristics

Logging curves including natural gamma ray, acoustic interval transit time, bulk density and resistivity, as well as TOC content of Well A8 were selected to establish a comprehensive single-well interpretation profile combined with core total porosity (Figure 8). Natural gamma ray logging measures the natural gamma radiation intensity of formations; in shale reservoirs, it is positively correlated with shale content and reflects the clay mineral distribution characteristics [15]. Total organic carbon (TOC) is a fundamental geochemical index in the study of hydrocarbon source rocks. It can be used to evaluate oil source rocks, characterize organic matter abundance, judge hydrocarbon generation efficiency, transformation efficiency and thermal evolution degree, calculate hydrocarbon generation quantity, and infer the primary migration direction of petroleum [16]. Comparative analysis indicates that the variation trend of core total porosity is strongly consistent with natural gamma ray and TOC content.

4 Discussion

4.1 Distribution of Total Porosity and Saturation of Shale

For the shale of Well A8 in Gulong area, the total porosity ranges from 1.84% to 21.41% with an average of 11.88%. Approximately 90% of the samples have total porosity mainly distributed in the range of 8%–16%, and the total porosity shows an increasing trend with burial depth. The water saturation varies from 7.16% to 88.43%, with an average of 58.56%; 90% of the samples are concentrated in the water saturation range of 40%–80%. Water saturation decreases first and then increases with depth, reaching the minimum

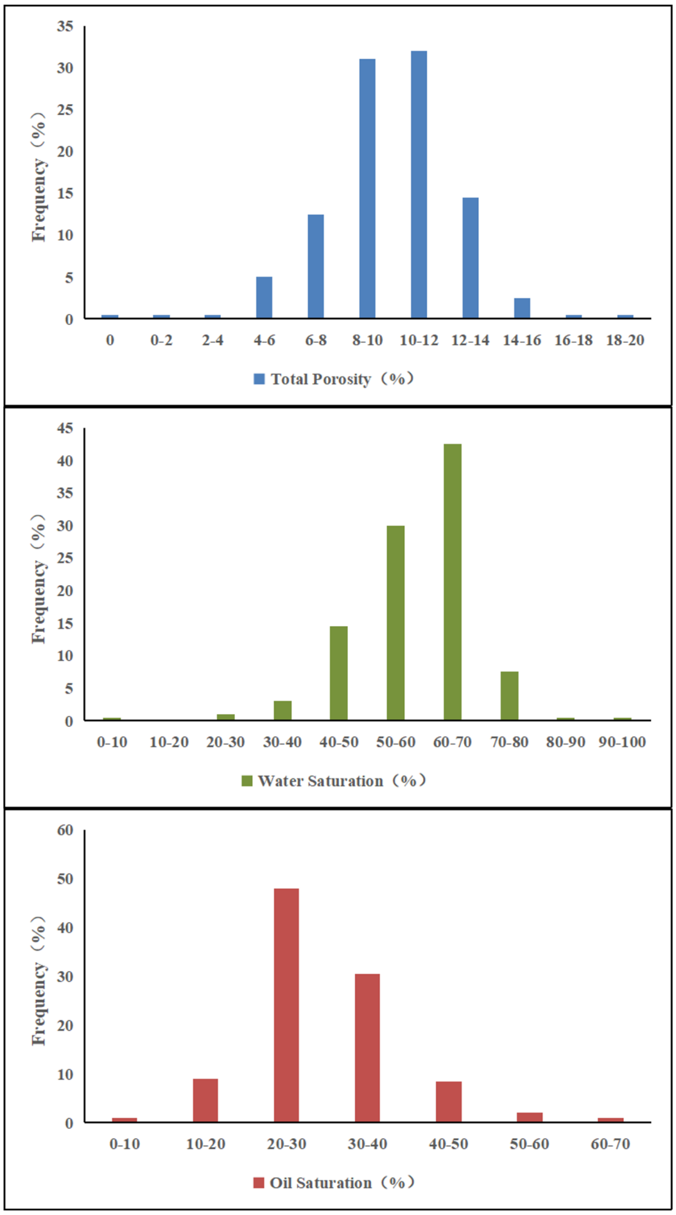

Figure 9. Histogram of total porosity and oil-water saturation distribution of shale.

value at about 2420 m. The oil saturation ranges from 0.55% to 68.64%, with an average of 29.77%; 90% of the samples are mainly distributed in the oil saturation interval of 10%–50% (Figure 9). Oil saturation increases first and then decreases with depth, reaching the maximum value at approximately 2420 m (Figure 10).

4.2 Controlling Factors of Shale Pore Development

Shale is characterized by self-generation and self-storage, acting as both hydrocarbon source rock and reservoir rock. Its pore evolution is an extremely complex physicochemical process controlled by geological conditions such as organic-inorganic compositions and thermal maturity of shale [17]. During the hydrocarbon generation process of shale, continuous hydrocarbon generation from kerogen is accompanied by volume shrinkage of kerogen, and the residual volume forms nanopores inside organic matter. Consequently, the more organic matter consumed, the higher the development abundance of organic-related pores. Meanwhile, organic acids generated during hydrocarbon generation dissolve carbonate minerals, forming secondary pores via mineral dissolution, which is conducive to hydrocarbon accumulation [18].

Correlation analysis (Figure 11) shows that the coefficients of determination (R^2) between total porosity and TOC, shale content, S_1, and S_2 are 0.1, 0.14, 0.11, and 0.1, respectively, all lower than 0.3, indicating a poor linear correlation. It is demonstrated that single-factor linear analysis cannot fully explain the variation of total porosity. Therefore, a neural network analysis was adopted for the above influencing factors. The neural network model consists of two processes: forward propagation of data stream and back propagation of error signals. The model is composed of an input layer, hidden layers and an output layer. Data is transferred layer by layer from the input layer to hidden layers, with the state of neurons in each layer only affecting the next layer, and the output is obtained at the output layer in forward propagation. When the error between the predicted value and expected value exceeds the target error, the network error propagates backward along the transmission path. The steepest descent method is used to adjust neuron weights to reduce errors, and forward propagation is performed again after the error is transmitted back to the input layer. The two processes are repeated until the error between the actual output and expected output meets the requirement, completing model training [19]. Logging data should be normalized before analysis to eliminate the influence of magnitude differences among different data types [20].

The importance analysis of independent variables reveals that shale content and TOC are the key factors controlling shale porosity development. Total porosity presents an increasing trend with the rise of thermal maturity. It is inferred that during the evolution of hydrocarbon source rocks, continuous hydrocarbon generation of kerogen forms a large number of residual pores, leading to the increase of total porosity (Figure 12).

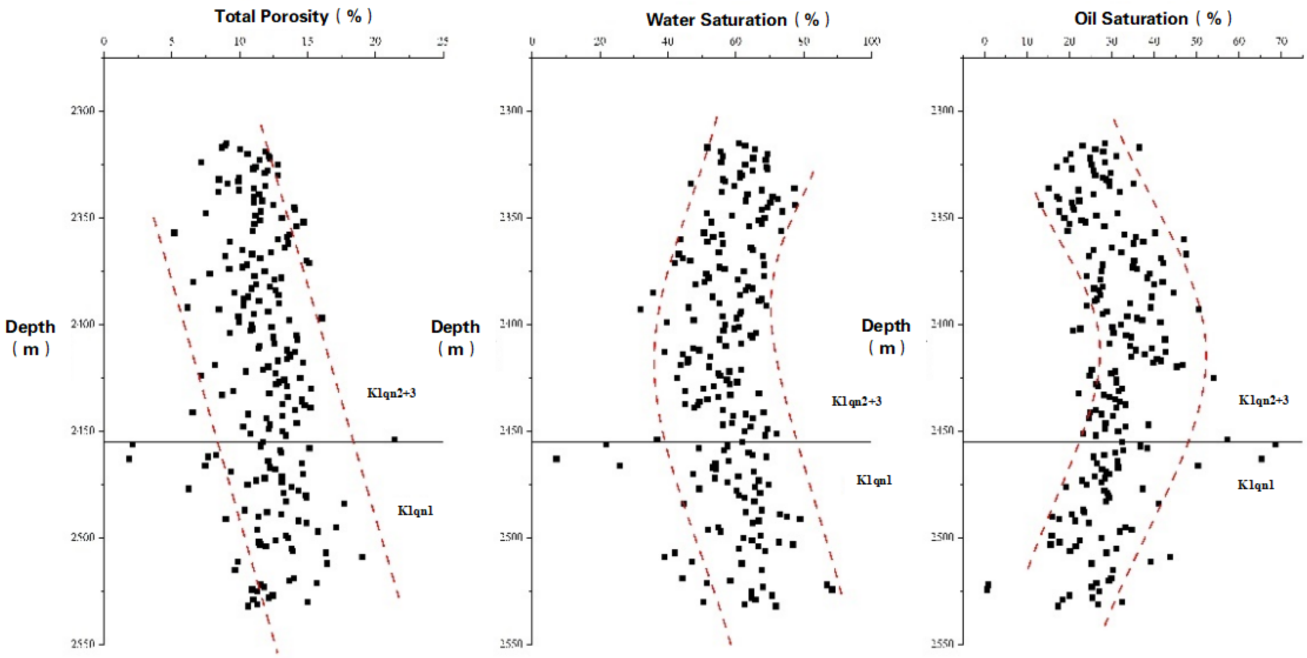

Figure 10. Variation of total porosity and oil-water saturation of shale with burial depth.

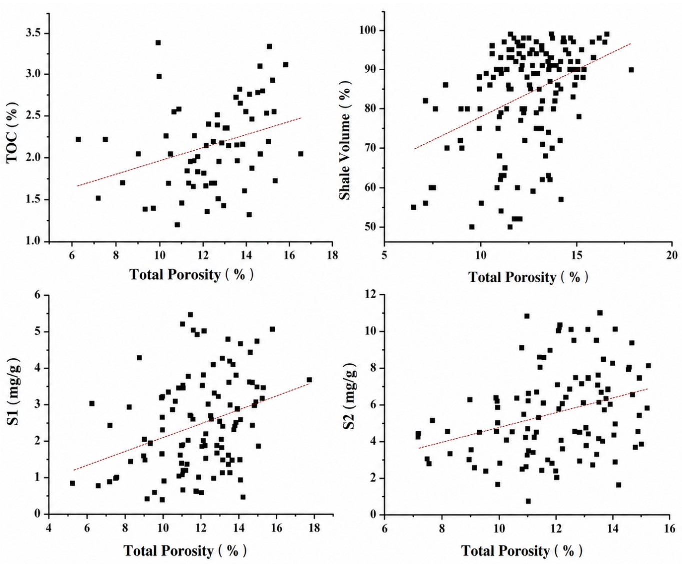

Figure 11. Correlation analysis of total porosity of shale.

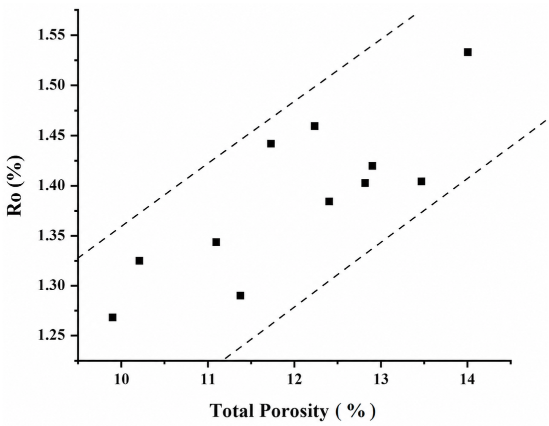

Figure 12. Correlation between total porosity and vitrinite reflectance (Ro).

5 Conclusions and Significance

Shale oil research and exploration have attracted increasing attention from domestic petroleum industry researchers and scholars. In 2018, two horizontal wells, Songyeyou 1HF and Songyeyou 2HF, were deployed targeting the dominant sweet spot intervals of the 1st Member of Qingshankou Formation oil shale. Both wells obtained commercial oil flow after production testing in 2019, marking the first high-yield oil flow acquired by horizontal drilling in pure shale intervals. The organic-rich shale of Qingshankou Formation in Gulong Sag, Songliao Basin is well developed, possessing broad exploration prospects [21]. Therefore, studying physical property parameters such as total porosity of shale reservoirs is of important practical significance. In this paper, the fluid summation method was applied to determine and analyze total porosity, and the controlling factors of shale pore development were discussed. The main conclusions are as follows: (1) By dividing shale volume types and combining the processes of saturation, extraction and oil washing, the fluid summation method can calculate core total porosity, solve the technical difficulty in measuring shale total porosity, and improve the accuracy and efficiency of porosity measurement. This method has the advantages of simple principle, high accuracy and convenient operation. (2) Gulong shale develops a combined pore structure of organic pores and laminar fractures with favorable reservoir physical properties. For Well A8, the total porosity ranges from 1.84% to 21.41% with an average of 11.88%, and 90% of samples are mainly distributed in 8%–16%. Total porosity increases gradually with burial depth. (3) The development of total porosity is affected by multiple factors, among which thermal maturity, shale content and TOC content are the dominant controlling factors. Higher diagenetic evolution degree contributes to better development of matrix pores and laminar fractures, as well as improved pore connectivity. (4) Compared with the helium method, the fluid summation method can fully characterize nanoscale pores of shale and increase the measured total porosity by more than 4 percentage points. It has important reference and application value for oil reserve calculation, main production layer division, understanding shale pore evolution characteristics and establishing logging interpretation models.

Data Availability Statement

Data will be made available on request.

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Conflicts of Interest

The authors are affiliated with the State Key Laboratory of Continental Shale Oil, Daqing 163712, China and the Central Laboratory of Exploration and Development Research Institute of Daqing Oilfield, Daqing 163712, China. The authors declare that these affiliations had no influence on the study design, data collection, analysis, interpretation, or the decision to publish, and that no other competing interests exist.

AI Use Statement

The authors declare that no generative AI was used in the preparation of this manuscript.

Ethical Approval and Consent to Participate

Not applicable.

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