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Reservoir Characteristics and Exploration Potential Evaluation of Lower Cambrian Niutitang Shale in Northern Guizhou: A Case Study of Well QX1

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Abstract: The Lower Cambrian Niutitang Formation in the Northern Guizhou harbors abundant organic-rich mud shale, constituting the most significant marine shale gas reservoir in Guizhou. In this article, the reservoir characteristics of Lower Cambrian Niutitang Formation in Northern Guizhou are analyzed in terms of lithology, mineralogy, organic geochemistry, pore structure, gas content and continuous thickness of shale, and the exploration potential of shale gas in this area is evaluated. The results indicate that the content of brittle minerals in the shale of well QX1 is 65.29% to 95.22% (average of 82.10%). The total organic carbon (TOC) content ranges from 2.06% to 12.10% (average of 5.64%). The organic matter maturity (R_o) within the range of 2.29–2.67%, and the kerogen type is identified as type I. The shale samples from the Niutitang Formation have high TOC content, suitable thermal maturity, and a favorable kerogen type, suggesting good gas generation potential. The results of scanning electron microscopy (SEM) show that intergranular pores, intragranular pores and microfractures are developed in the shale of well QX1, which can provide sufficient storage space for shale gas. The shale exhibits a continuous thickness of 105.66 m in the QX1 well, comprising a gas-bearing interval of 32.89 m at the top (with an effective continuous thickness of 18 m) and a hydrocarbon source rock layer of 75.78 m at the bottom. In comparison with other shale gas regions, Niutitang Formation shale in Northern Guizhou exhibits characteristics such as favorable gas generation conditions, greater storage conditions, excellent gas-bearing, strong frackability, and substantial continuous thickness, it has greater potential for shale gas exploration.

Keywords: South China; shale gas; marine shale reservoirs; organic matter; exploration potential

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1. Introduction

China has made notable progress in the exploration and development of shale gas, with shale gas production has surpassing 220 × 10^8 m^3 by 2021, establishing it as the second-largest shale gas producer globally [1–4]. China possesses enormous potential in shale gas resources, particularly in deep-sea shale reservoirs, marine–continental transition zones, and continental shale systems, showing significant exploration and development opportunities [5–8]. Guizhou is endowed with abundant marine shale gas resources. According to the 2013 assessment of shale gas in Guizhou, the total shale gas resources amount to a remarkable 9.21 × 10^{12} m^3. These resources are primarily distributed among six units: the Lower Cambrian Bianmachong Formation, the Lower Cambrian Niutitang Formation, the Lower Silurian Longmaxi Formation, the Lower Carboniferous Dawuba Formation, the Middle Permian Liangshan Formation, and the Upper Permian Longtan

Formation. These formations contribute 2%, 39%, 16%, 16%, 9%, and 19%, respectively, to the total shale gas resources in Guizhou. The shale gas resources of the Niutitang Formation rank first in total resources in Guizhou, significantly surpassing the second-ranked Longtan Formation. This indicates its exceptional research and development value [9,10]. Over the past five years, shale gas exploration activities in the Northern Guizhou region have become a widely recognized focus) [10–14]. In comparison to regions where shale gas exploration activities have been previously conducted, such as Zhengan, Fenggang, Meitan, Dinshan, and Xishui, well QX1 is situated at the intersection zone of the southeastern margin of the Upper Yangtze Block and the western margin of the Xuefeng Uplift, presenting favorable conditions for hydrocarbon accumulation. However, shale gas exploration efforts in the study area are still in the early stage, with a relatively low depth and breadth of geological investigations. Particularly, the research on the reservoir characteristics of the Lower Cambrian Niutitang Formation is relatively limited, and the exploration potential of shale gas has not been adequately assessed and revealed.

Many scholars have extensively researched the Lower Cambrian Niutitang Formation in the northern region of Guizhou, accumulating a wealth of foundational data. However, existing research has largely been confined to singular discussions on the shale reservoir characteristics and depositional environment of the Niutitang Formation [13,15,16]. Comprehensive studies of the fracture development characteristics, gas content features, and the continuous thickness of mud shale remain relatively limited. This paper systematically analyzes the reservoir characteristics of the Niutitang Formation of the Lower Cambrian System in the QX1 well in Northern Guizhou in terms of the mineral composition, organic geochemical features, pore structure, fracture development characteristics, gas content, and continuous thickness of the organic-rich shale. Furthermore, an evaluation of the shale gas exploration potential in this region is conducted. This study aims to provide geological foundations for the subsequent exploration and development of shale gas in Northern Guizhou.

2. Geological Setting

Guizhou is located in the transitional zone between the Yangtze Block and the southwest segment of the Jiangnan Orogenic Belt (Figure 1a). The Neoproterozoic region has experienced the influence of multiple tectonic events in various directions [17]. From the middle–late Indo–China movement to the Yanshanian, the Xuefeng intraterrestrial deformation tectonic system in Southeastern Guizhou became active [18]. The direction of its activity evolved gradually from the southeast to predominantly in the northwest, primarily manifesting as reverse thrust and overthrust structures, forming a set of arc-shaped structures oriented approximately north to south. In the southeastern part, the predominant structural trend is northeast (NE), while the structures are primarily oriented either NNE or SN in Northern Guizhou. When observed from east to west, these structures sequentially develop between relatively broad synclines and relatively tight anticlines, forming a typical "trough-separation" folding characteristic. This configuration constitutes the Jurassic mountain-type structural pattern in Northern Guizhou [19,20].

According to the division of tectonic units, our study region is located within the Sansui Syncline in the passive margin fold-thrust belt in the southern part of the Yangtze Block (Figure 1b). The region exhibits highly developed folds and fault structures, situated at the intersection of the southeastern margin of the Upper Yangtze Block and the West margin of the Xuefeng Uplift (Figure 1b) [21]. It displays a series of NE–NEE-trending folds and faults, overall demonstrating characteristics of thin-skinned tectonics. The axial trends of these folds are predominantly oriented NE–SW, including complex fold combinations arranged in patterns resembling lines or approximately parallel alignments, characterized by a broad and gentle configuration. In the core areas of the synclines, the formations are primarily composed of Cambrian strata, while Precambrian and Ordovician strata are predominantly exposed in the core areas of the anticlines. Additionally, several NE–NEE-trending faults have developed in the region, primarily consisting of thrust faults with compressional and rotational components, including some normal faults and strike–slip faults. From a planar perspective, these structures exhibit a notable pattern of parallel alignment, forming densely distributed bands (Figure 1).

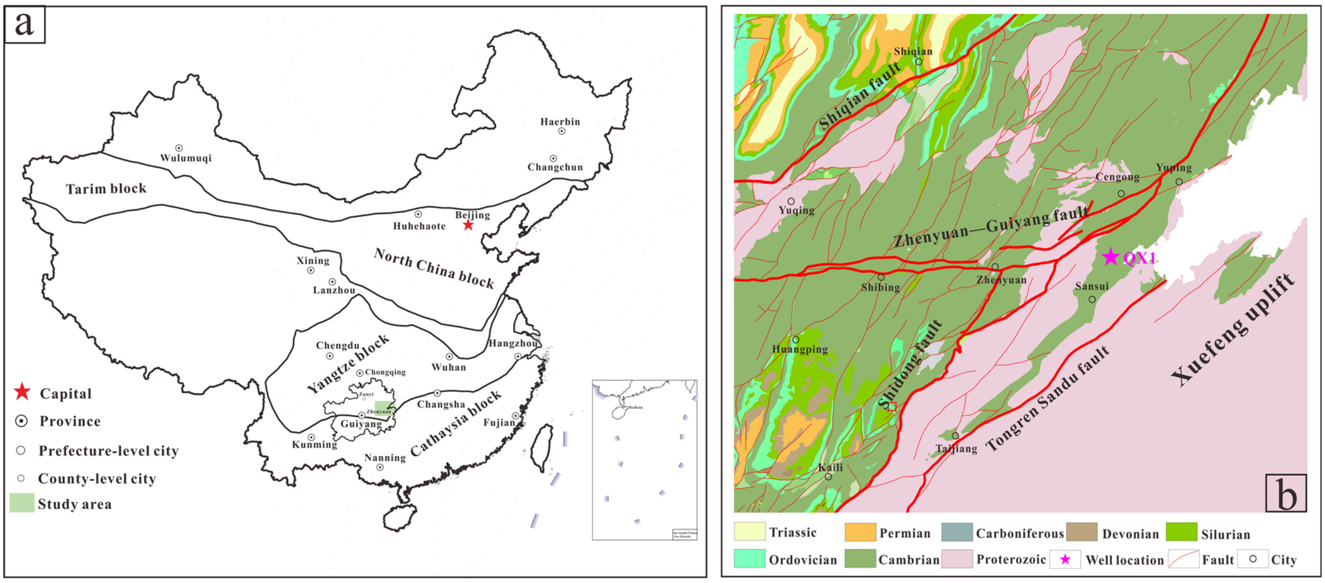

Figure 1. Geological background map of the study area. (**a**) Location and regional geological map of the study area (revised according to the 1: 7.4 million boundary version of the map of China); (**b**) location of the QX1 well.

The drilling operations at well QX1 commenced in the Cambrian Palang Formation, encountering the Bianmachong Formation, the Jiumenchong Formation, the Niutitang Formation, and the Laobao Formation. The drilling continued through the Doushantuo Formation until the completion of drilling in the Nanhua Series Nantuo Formation. In the evaluation of shale gas reservoirs, the effective continuous thickness of the shale, in addition to the total thickness, is considered as one of the crucial parameter [22]. Following the standards outlined in the "NB/T 10398-2020 Technical Specification for the Evaluation of Shale Gas Reservoirs," the QX1 well's continuous hydrocarbon source rock interval in the Niutitang Formation is defined as 573.12 m to 678.78 m, with a continuous thickness of 105.66 m, based on a total organic carbon (TOC) criterion of ≥2.0%. Under similar geological conditions, shale reservoirs with greater thickness and volume evidently possess a larger total gas content and enhanced storage capacity. According to the results of core logging and gas logging (Figure 2), the lithology of Niutitang Formation is mainly carbonaceous silty mudstone; carbon mudstone is gray-black, black cryptocrystalline aggregate, and argillaceous is dominant, followed by carbonaceous, strong reservoir capacity and high total gas generation. In the interval from 572.81 to 605.70 m of the Niutitang Formation, with a drilling thickness of 32.89 m and lithology characterized by carbonaceous mudstone, considering various factors, this section is classified as a gas-bearing layer with an effective continuous thickness of 18 m. The shale gas reserves are abundant, making it favorable for economic exploitation. In the interval from 605.70 to 681.48 m, with a drilling thickness of 75.78 m and lithology characterized by carbonaceous mudstone, considering various factors, this section is classified as a hydrocarbon source rock layer.

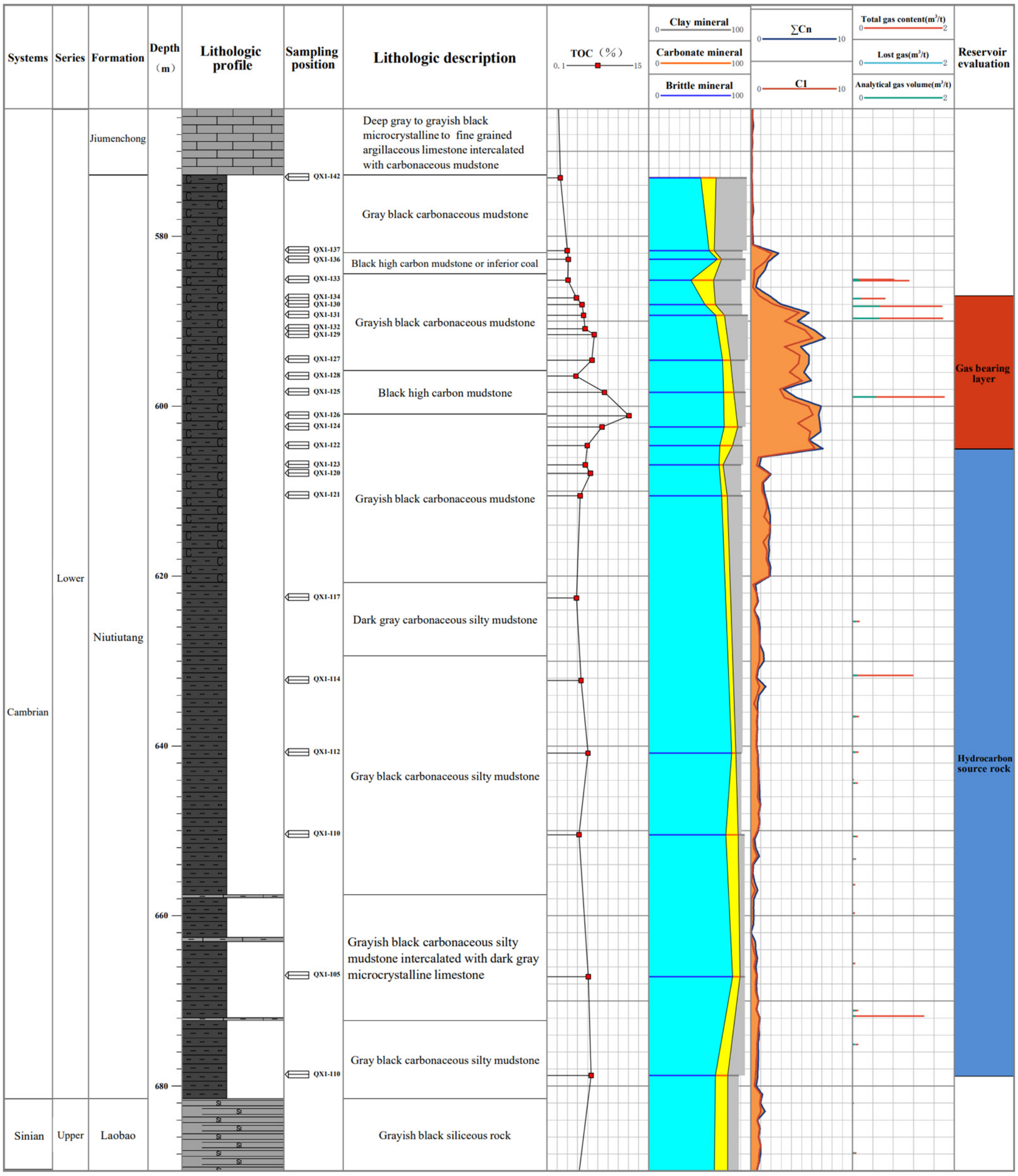

Figure 2. Comprehensive bar chart of a shale section of the Niutitang Formation in QX1 well.

3. Samples and Experiments

3.1. Samples

A detailed experimental analysis was conducted on 25 lithological samples from well QX1 in the study region, employing techniques such as X-ray diffraction, organic geochemistry, scanning electron microscopy, and on-site analyses. Combined with the distribution law of gas logging anomaly data and formation gas-bearing characteristics of QX1 well, the gas logging anomaly points are analyzed, and combined with geological and field desorption data, the gas-bearing thickness of the Niutitang Formation in this well is 32.89 m (effective continuous thickness is 18 m). The lithology is predominantly carbonaceous mudstone, characterized by a gray-black to black color and fine grain size. The sedimentation transitions from slope facies to deep-water continental shelf facies from bottom to top (Figure 2).

3.2. Experiments

The testing items for the samples encompass X-ray diffraction experiments, total organic carbon (TOC) analysis, vitrinite reflectance (R_o) measurement, identification of kerogen types and maceral, scanning electron microscopy, rock mechanics testing, and gas content measurement. To quantitatively describe the mineral composition of core samples, the samples were ground into powder and analyzed using X-ray diffraction experiments. The experimental instrument selected for this analysis was the X'pert powder diffractometer. The total organic carbon (TOC) analysis was conducted using the CS230 carbon-sulfur analyzer. The instrument employed for determining organic matter maturity (R_o), kerogen type identification, and maceral characterization was the Scope.A1 polarizing microscope. Scanning electron microscopy (SEM) observations were carried out using the Tescan/OXFORD instrument. Rock mechanics testing utilized the RTR-1000 mechanical testing system. Gas content tests were conducted on Niutitang Formation shale cores through core immersion experiments and on-site analytical methods. High-precision on-site desorption analyzers, shale residual gas testers, and GC4000A gas chromatographs were employed to determine the gas content in drilling cores, and the gas composition was subsequently analyzed. All the aforementioned testing items were conducted in accordance with relevant national or industry standards.

4. Results and Discussion

4.1. Mineralogy

Shale is a complex rock composed of various minerals, including quartz, feldspar (potassium feldspar, plagioclase), carbonate minerals (calcite, dolomite, etc.), and clay minerals. These different mineral components significantly influence the physical properties, pore structure, and gas content of shale. Shales with a high content of brittle minerals (quartz, feldspar, carbonate minerals, pyrite, etc.) exhibit good fracture capability, making them more susceptible to hydraulic fracturing, which results in the formation of complex fractures [10,23–26].

Based on the X-ray diffraction results of 16 core samples from well QX1, the mud shale of the Niutitang Formation is primarily composed of quartz, clay minerals, feldspar, carbonate minerals, and pyrite (Figure 3). The quartz content in the rock ranges from 4.79% to 65.94% (average of 44.66%); feldspar content ranges from 5.47% to 60.78% (average of 22.50%); pyrite content ranges from 0% to 11.48%, with an average of 5.30%; carbonate minerals content ranges from 4.02% to 21.98%, with an average of 9.78%; and clay minerals content ranges from 4.44% to 30.15% (average of 16.20%). Among the clay minerals, the main components include illite, kaolinite, chlorite, and illite/montmorillonite mixed layer. Illite is the predominant clay mineral, constituting over 80% (average of 95.17%), while the content of kaolinite, chlorite, and illite/montmorillonite mixed layer is relatively lower. It is noteworthy that the total content of these brittle minerals ranges from 65.29% to 95.22% (average of 82.10%) (Figure 4). This indicates a very high degree of brittleness in the reservoir, which is conducive to reservoir modification.

Mapping the results of rock mineral composition tests onto a mineralogical ternary diagram (Figure 5), the mineral assemblage of Niutitang Formation shale is predominantly distributed in the vicinity of the felsic mineral end-members (including quartz and feldspar). This distribution pattern indicates that Niutitang Formation shale possesses a high degree of brittleness. The presence of these highly brittle minerals is highly conducive to the development of natural fractures, providing favorable conditions for the accumulation of shale gas. Additionally, it facilitates artificial fracturing operations, enhancing shale gas production and extraction efficiency.

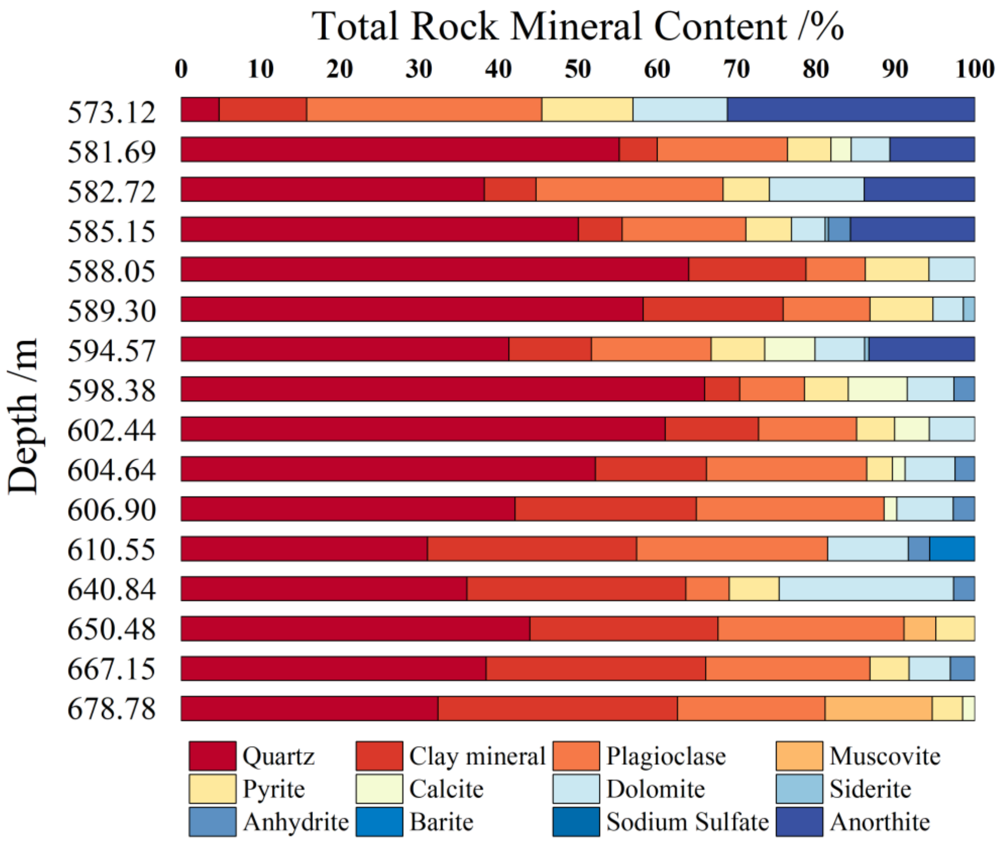

Figure 3. Whole-rock mineralogical statistical analysis chart of well QX1.

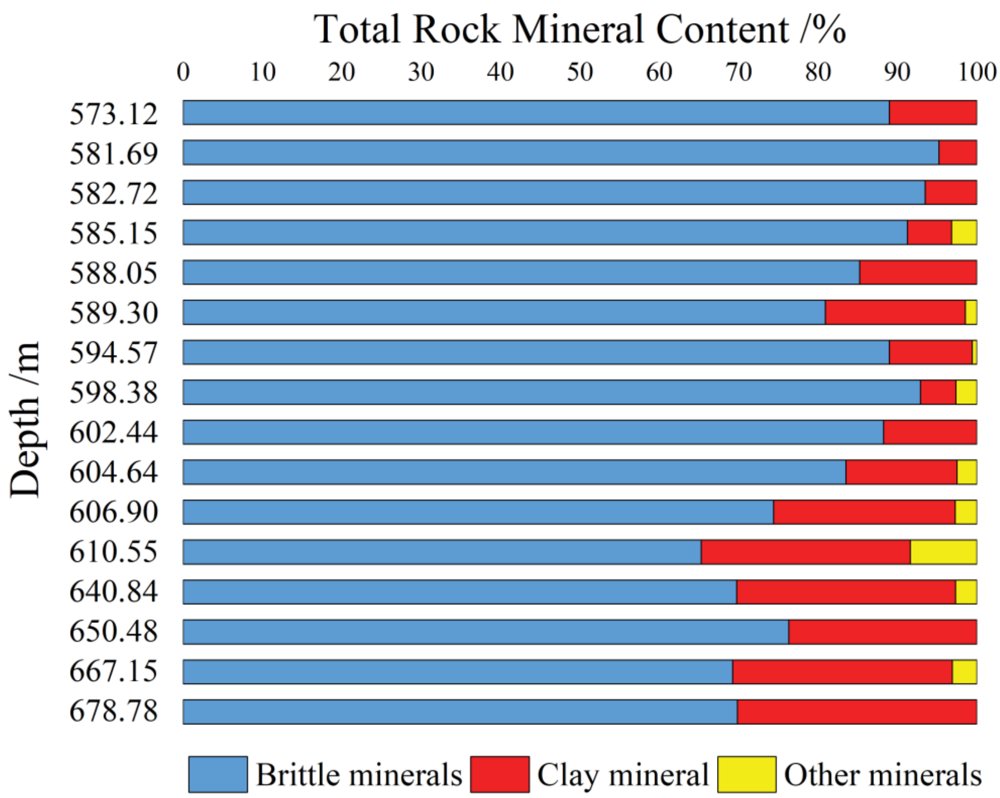

Figure 4. Statistical analysis chart of brittleness, clay, and other minerals in well QX1.

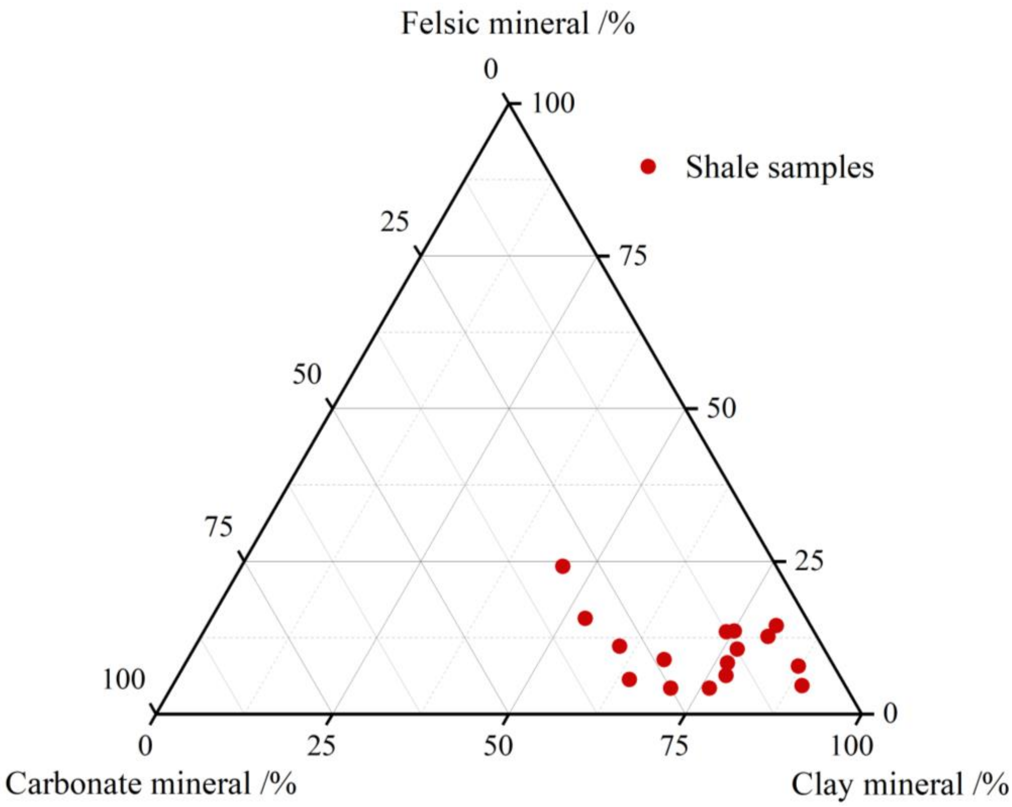

Figure 5. Ternary diagram of shale mineral composition in well QX1.

4.2. Organic Geochemistry

4.2.1. TOC

The abundance of organic matter, as a critical metric, reflects the degree of richness of hydrocarbon-generating precursors within the source rock. Typically, indicators such as total organic carbon (TOC), hydrocarbon generation potential (S_1 + S_2), total hydrocarbon (HC), and chloroform bitumen "A" are used to assess the organic richness of source rocks. However, since Niutitang Formation shale is generally in a high to overmature evolutionary stage, total organic carbon (TOC) is selected as the indicator for assessing organic richness. The organic carbon analysis conducted on 25 shale samples from the Niutitang Formation at well QX1 indicates that the total organic carbon (TOC) content ranges from 2.06% to 12.10% (with an average of 5.64%). There is significant heterogeneity in the Niutitang Formation at well QX1. The upper section (from 572.81 m to 587.00 m, approximately 14 m) exhibits relatively lower TOC, with a trend of gradually increasing TOC from top to bottom. In the middle to lower section (from 587.00 m to the bottom at 681.48 m, approximately 95 m), the TOC range remains generally stable without significant variation (Figure 2). In the shale, 62.5% of the samples have TOC content greater than 5%, while 20.8% of the samples have TOC content ranging from 4% to 5% (Figure 6a). According to Slumberger's classification standard for organic carbon content in shale gas reservoirs (source rocks with TOC values in the range of 2.0–4.0% are considered good, and those with TOC values in the range of 4.0–12.0% are considered very good) [27], it can be determined that the shale samples from the QX1 well in the Niutitang Formation are of good to very good quality as source rocks.

The comprehensive analysis of TOC content and the whole-rock mineral composition of the 16 samples from the Niutitang Formation reveals a significant positive correlation between the content of brittle minerals and TOC content (Figure 6b). Conversely, there is a noticeable negative correlation between clay mineral content and TOC content (Figure 6b). This indicates a favorable association between TOC content and the distribution of brittle minerals and clay minerals. Vertically, with increasing depth, the quartz content in the Niutitang Formation exhibits a low–high–low trend, while the clay mineral content gradually decreases. This trend indicates that the mineral composition of shale will change at different depths, which also needs to be comprehensively considered in shale gas exploration and exploitation.

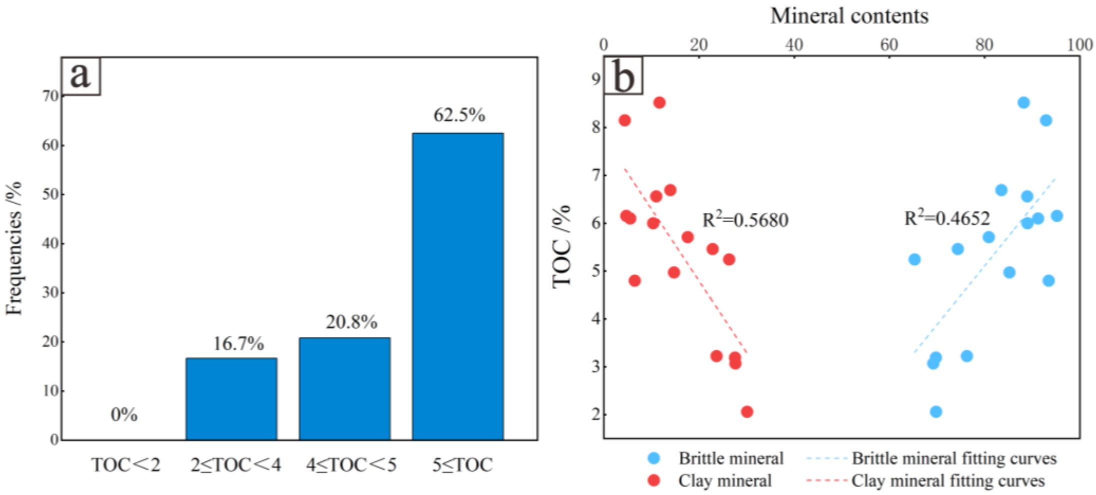

Figure 6. (**a**) Frequency distribution of TOC in well QX1; (**b**) relationship chart between shale TOC content, clay minerals, and clay minerals in well QX1.

4.2.2. Maturity

Organic maturity is a critical factor in evaluating the potential hydrocarbon generation and resource prospects of a region or specific source rock. It reflects the degree of transformation of organic matter into oil and gas within sedimentary rocks. A large number of hydrocarbons will be generated only when the maturity of organic matter reaches a certain threshold. In a certain range of maturity, the higher the maturity of shale organic matter, the more favorable for hydrocarbon generation [23,28]. Param commonly used to characterize organic maturity include vitrinite reflectance (R_o), pyrolysis peak temperature (T_{max}), and isomerization param of biomarkers. Based on the measurement results of these param, organic maturity can be classified into several stages, including immature, low mature, mature, high mature, and overmature stages [5].

According to the R_o value test results of four black shale samples from the Niutitang Formation in well QX1, the R_o values of the samples range from 2.29% to 2.67%, with an average value of 2.52% (Table 1). Referring to the maturity stage division criteria for black shales in southern China (R_o values between 1.3% and 2.0% are considered to be in the high maturity stage, corresponding to the generation of light condensate oil and wet gas; while R_o values between 2.0% and 3.0% are classified as early overmaturity, corresponding to the generation of dry gas) [28], it is determined that the tested samples belong to the early overmaturity stage of evolution, mainly generating dry gas. This discovery is consistent with the complex multi-stage thermal history evolution in Northern Guizhou and the fact that the maturity of thermal evolution is generally greater than 2.5% [9]. It is proved that the shale gas reservoir of QX1 well has appropriate thermal maturity within the thermal maturity range of 2.0–3.0%, which is beneficial to hydrocarbon generation.

Table 1. The organic matter maturity and kerogen types of the Niutaitang Formation shale from well QX1.

Deep/m	Sample Type	R_O/%	TI	Type
585.15	Black shale	2.58	85.25	I
589.30	Black shale	2.29	85.75	I
598.38	Black shale	2.50	87.25	I
610.55	Black shale	2.67	81.25	I

4.2.3. Organic Matter Type

The type of organic matter reflects the material origin of kerogen in organic-rich shale. Different types of organic matter correspond to different hydrocarbon generation abilities and the threshold values of different oil and gas window phases, making it an important parameter for evaluating the potential of source rock resources. Determination of the organic matter type index (TI) was conducted on four shale samples, and the results revealed that the TI values of the samples ranged from 77.25 to 87.25, which indicated that the type of organic matter was type I. Comprehensive analysis shows that the mother source of gas-bearing shale in the Niutitang Formation mainly comes from lower aquatic organisms such as algae, indicating that the overall gas generation capacity is strong (Table 1).

4.3. Reservoir Characteristics

4.3.1. Physical Property

The porosity and permeability of shale are not only important factors in controlling the content of free gas but also determine the occurrence state of shale gas to a certain extent. The porosity and permeability of seven core samples of the Niutitang Formation in the QX1 well were tested by pulse overpressure method. The results show that the effective porosity of the Niutitang Formation is 0.52–1.23%, with an average of 1.01%, all below 5%; the permeability is between 7.07×10^{-3} mD and 9.97×10^{-5} mD, with an average 0.0022 mD (Table 2). Overall, it reflects that the shale in the study area is dominated by low porosity and ultra-low permeability, which is beneficial to the in situ accumulation and preservation of hydrocarbon gas. In the process of exploitation, the reservoir needs to be reformed to enhance the percolation of gas.

Table 2. The organic matter maturity and kerogen types of the Niutaitang Formation shale from well QX1.

Depth/m	Sample Type	Confining Pressure/MPa	Porosity/φ(%)	Permeation Rate/K (10^{-3} μm^2)
581.69	Black shale	6.09	1.200	7.07×10^{-3}
585.15	Black shale	6.13	1.266	7.83×10^{-3}
594.57	Black shale	6.23	1.103	1.34×10^{-4}
606.90	Black shale	6.35	0.521	1.59×10^{-5}
610.55	Black shale	6.40	1.082	1.75×10^{-4}
650.48	Black shale	6.82	1.146	3.67×10^{-4}
678.78	Black shale	7.11	0.739	9.97×10^{-5}

Combined with the above data, this paper explores the influence of lithology and mineral composition changes on reservoir physical properties. The results show that, as a whole, the lithology of the reservoir changes from shallow to deep, and gradually changes from carbonaceous mudstone to carbonaceous silty mudstone, while the porosity and permeability of the samples also gradually decrease. It is inferred that the chimerism between the particles of silty mudstone is closer, so the porosity and permeability of the samples are lower, which is beneficial to the preservation of hydrocarbon gases. Overall, there is an obvious negative correlation between brittle mineral content and porosity and permeability, while clay mineral content and porosity and permeability are opposite. It is inferred that the content of brittle minerals can effectively reduce the porosity and permeability of the samples.

4.3.2. Pore Characteristics

At present, two micropore classification methods have been widely recognized by scholars. One of the classification methods is that based on the study of Barnett and Woodford shale, SLATT and other scholars classify micropores into six main categories: organic pores, microfractures, clay intergranular pores, fecal granular pores, clastic intragranular pores and intragranular pores [29]. Another classification method, proposed by LOUCKS, divides shale matrix pores into three categories: intergranular pore, intragranular pore and organic pore [30].

Based on the observation and analysis of the shale samples of the Niutitang Formation in QX1 well under SEM, combined with the characteristics of pore structure and genesis, it is considered that LOUCKS classification is more suitable for the study of shale fractures in the Niutitang Formation in QX1 well, which can be divided into four types: intergranular pore, intragranular pore, organic pore and microfracture [30]. Among them, intergranular pores and intragranular pores are the most predominant pore types in the samples. Additionally, there is a certain amount of microfractures developed, but organic pores are less developed. Although organic pores are generally less developed, the well-developed intergranular pores, intragranular pores, and microfractures can enhance the storage capacity of the shale reservoir, providing sufficient space for shale gas accumulation.

(1) Intergranular pores are voids formed by the mutual support of mineral particles during their accumulation, and their geometric shapes are often elongated and polygonal [31]. From the scanning electron microscope images, it can be observed that in QX1 well, intergranular pores are highly developed, with pores mostly appearing as narrow or wedge shaped. These pores are mainly situated around the support areas of brittle mineral particles like quartz and feldspar, as well as at the contact points between clay minerals and brittle minerals (Figure 7a–c). The pore diam range mostly between 0.5 and 3 μm, with the largest reaching up to 60 μm. These interconnected pores provide the primary storage space for organic matter.
(2) Intragranular pores are a type of pore formed within mineral particles, often exhibiting irregular geometric shapes [23]. According to the observation of electron microscope, the intragranular pore of QX1 well shale is a relatively developed pore type, and the morphology is mainly dissolution pore. Intragranular pores are mostly observed in silicate minerals such as quartz and feldspar, as well as on the surfaces of blocky pyrite. Dissolution pores often appear elliptical or irregular, primarily at the nanometer scale, with pore diam mostly below 300 nm. These pores develop on individual mineral particles, exhibiting poor connectivity, which is unfavorable for the preservation of organic matter (Figure 7d,e).
(3) Microfissures are formed by minerals in the process of diagenesis or organic matter in the process of hydrocarbon generation [32]. The development of microfractures can connect the matrix pores of shale and play a positive role in the extension of artificially induced fractures. Based on the scanning electron microscope images, it is inferred that the main controlling factors for microfractures in the Niutitang Formation of well QX1 are tectonic stress and organic acid dissolution. These fractures have undergone multiple stages of modification, and microfractures are filled to varying degrees by minerals such as pyrite, carbonate, or organic matter. Irregular microfractures are well developed, with widths ranging from tens to hundreds of nanometers and lengths varying from several micrometers to tens of micrometers, showing good connectivity (Figure 7f,g).
(4) Organic pores are formed during the hydrocarbon generation process of kerogen and typically represent an effective pore network in three-dimensional space. These pores play a crucial role as significant storage space for shale gas [30]. Organic pores are not universally present in all shales, and their development is influenced by factors such as organic matter type and maturity [33]. In Niutitang Formation shale in well QX1, abundant organic matter is observed, but the development of organic pores is limited, and their connectivity is poor (Figure 7h,i). Organic pores in the shale are primarily located within the organic matter between inorganic mineral particles. These pores are irregularly distributed, sometimes enclosed by clay, and exhibit organic matter shrinkage cracks with small diameters.

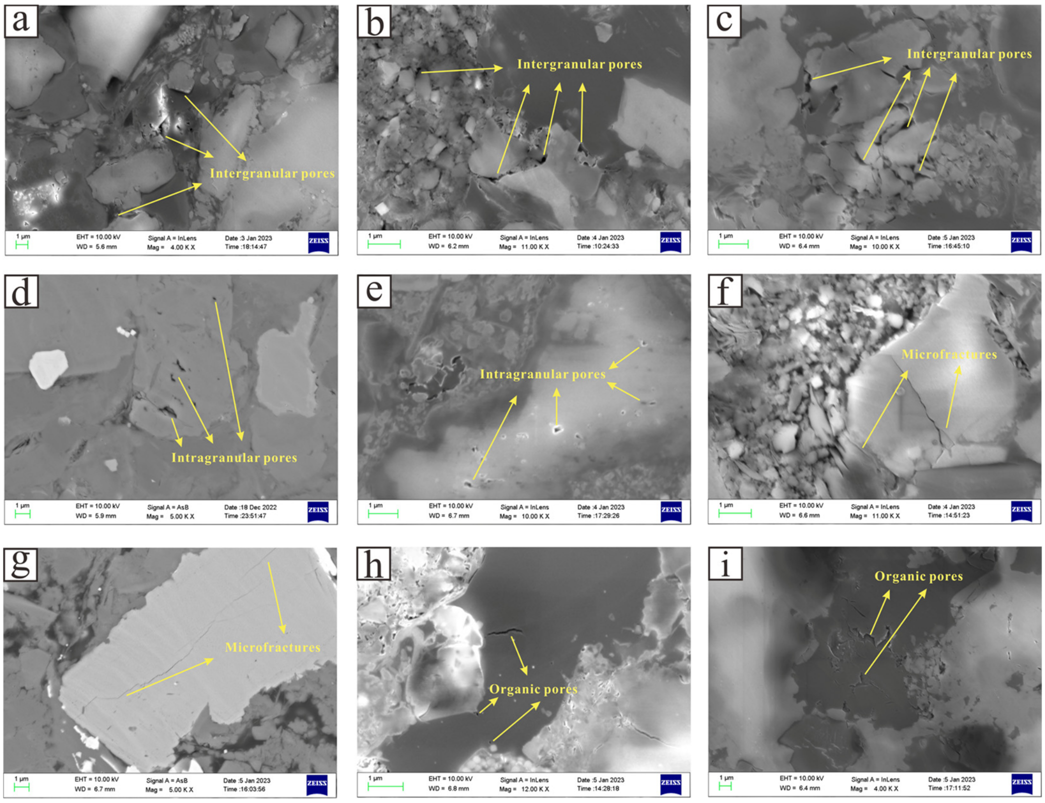

Figure 7. Scanning electron microscope images of different pore types in Niutaitang Formation shale from well QX1. (**a**–**c**) Intergranular pores. (**d**,**e**) Intragranular pores. (**f**,**g**) Organic pores. (**h**,**i**) Microfractures.

4.4. Fracture Characteristics

The shale reservoir has the characteristics of low porosity and low permeability. Therefore, natural fracture has become a vital factor in shale gas exploration and development. Natural fractures act as an important reservoir space in the reservoir, but also provide more channels for artificial fracturing. However, fractures, as fluid flow channels, increase the permeability of shale reservoirs, but may also destroy the preservation conditions of shale gas, resulting in a partial outflow of natural gas, thus reducing the storage of shale gas [12,34,35].

Based on the observation results of the QX1 well core, horizontal fractures are the most developed in the black shale section of the Niutitang Formation, followed by high-angle and vertical fractures, with fewer low-angle oblique fractures. The fractures have a width ranging from 0.05 to 5 mm and are predominantly filled with calcite and pyrite. The overall fractures are developed, and the cores are broken in 572 m, 576 m, 590 m, 593 m, 627 m, 633 m, etc. The characteristics of core fractures in the Niutitang Formation are summarized as follows (Figure 8):

(1) Horizontal fractures are well developed in all intervals of the formation, with fracture density generally not exceeding 10 fractures/m. These horizontal sutures are rich in types, among which bedding fibrous vein sutures are the most common, and most of them are filled with calcite veinlets (Figure 8a). The bedding slippage characteristics are shown in the strata 584.71 m, 589.60 m, 612.71 m, 649.76 m, etc., and scratches are seen (Figure 8d). In the strata between 572 m and 600 m, the horizontal fracture is the most developed, which is the key factor to control the lateral migration of shale gas.

(2) High-angle fractures are developed throughout the entire interval of the Niutitang Formation. The fracture length can reach up to 0.3 m, but the fracture density is generally not greater than 5 fractures/m. These fractures are observable at various depths, including 580.28 m, 583.50 m, 587.13 m, 591.48 m, 610.50 m, and 619.00 m(Figure 8b).

Most of the seams were filled with empty sutures and calcite veins/veinlets, and occasionally scratched (Figure 8f). The permeability of the sharply inclined high-angle fracture will increase with the decrease in the angle between the direction of the fracture and the maximum compressive stress of the current formation, which will have a certain impact on the preservation of shale gas.

(3) Vertical fractures are primarily developed in the fractured sections of the Niutitang Formation cores. The fracture width is typically less than 1 cm, and the length does not exceed 30 cm. Stepped vertical seams (Figure 8c) and scratches (Figure 8e) are common, and these seams are usually accompanied by calcite filling. The existence of these fractures may lead to the lateral migration of shale gas across the formation interface, and eventually lead to the upward escape of shale gas, which poses a certain threat to the vertical preservation conditions of shale gas.

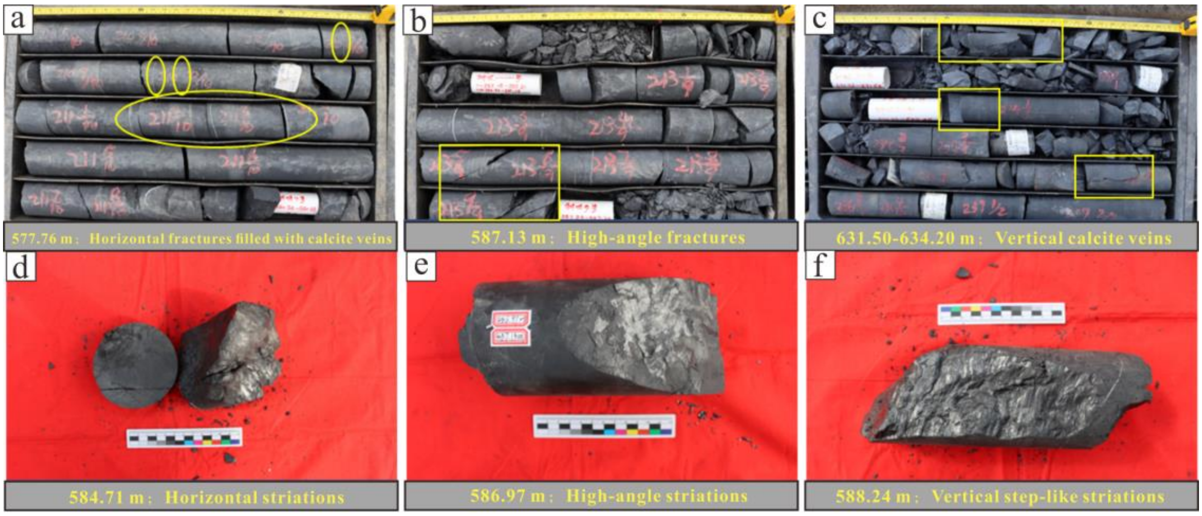

Figure 8. Rock core fracture characteristics in well QX1. (**a**) Horizontal fractures. (**b**) High-angle fractures. (**c**) Vertical fractures. (**d**) Horizontal striations. (**e**) High-angle striations. (**f**) Vertical striations.

In summary, the overall fracture density of Niutitang Formation shale in well QX1 gradually decreases with increasing burial depth. This trend suggests that the upper part of the shale has a higher gas content compared to the lower part. This observation is further supported by on-site analysis results, as evident in Figure 2, where the total gas content in well QX1 shows a decreasing trend from top to bottom. This result also indicates that horizontal fractures and high-angle fractures in the Niutitang Formation play a positive role in the preservation of shale gas. Conversely, the vertical fractures developed in the fractured sections of the Niutitang Formation pose a disadvantageous impact on the vertical preservation conditions of shale gas. In general, there is a positive correlation between quartz content and the number of fractures [36,37]. Combining the mineral composition content chart of Niutitang Formation shale, it can be observed vertically that the quartz content gradually decreases from the shallow layers to the deep layers. This may be one of the reasons leading to the overall decrease in fracture density.

4.5. Gas-Bearing Properties

The most direct reflection of shale gas enrichment is gas content, and on-site analysis is the most direct method for measuring shale gas content. In addition, core water immersion experiments are widely used for their intuitive characteristics in measuring gas content in shale [38].

From the core water immersion experiment (Figure 9), it is evident that in Figure 10a, the gray-black silty mudstone of the Niutitang Formation (well depth: 634.13 m) shows a small amount of discontinuous small gas bubbles escaping, indicating a lower gas content and weaker adsorption capacity. In Figure 10b, the black carbonaceous mudstone of the Niutitang Formation (well depth: 595.97 m) exhibits continuous gas bubble release along fractures, forming a beaded pattern, indicating a higher gas content and stronger adsorption capacity.

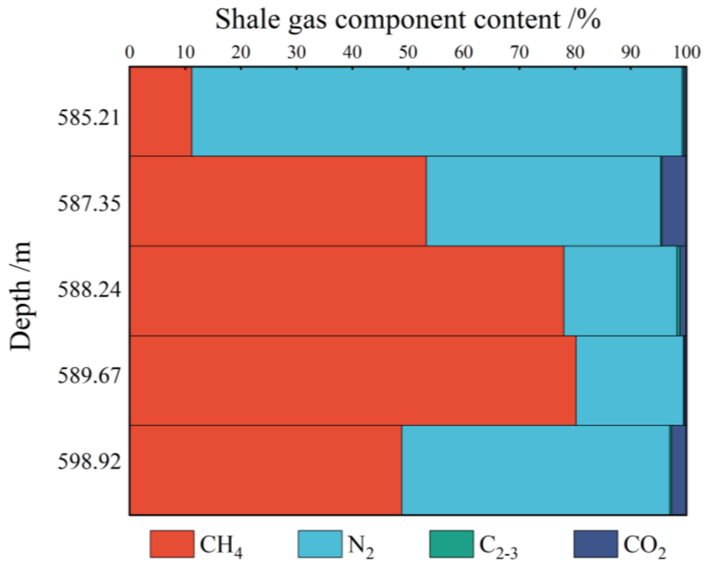

Figure 9. Statistical analysis of shale gas composition in well QX1.

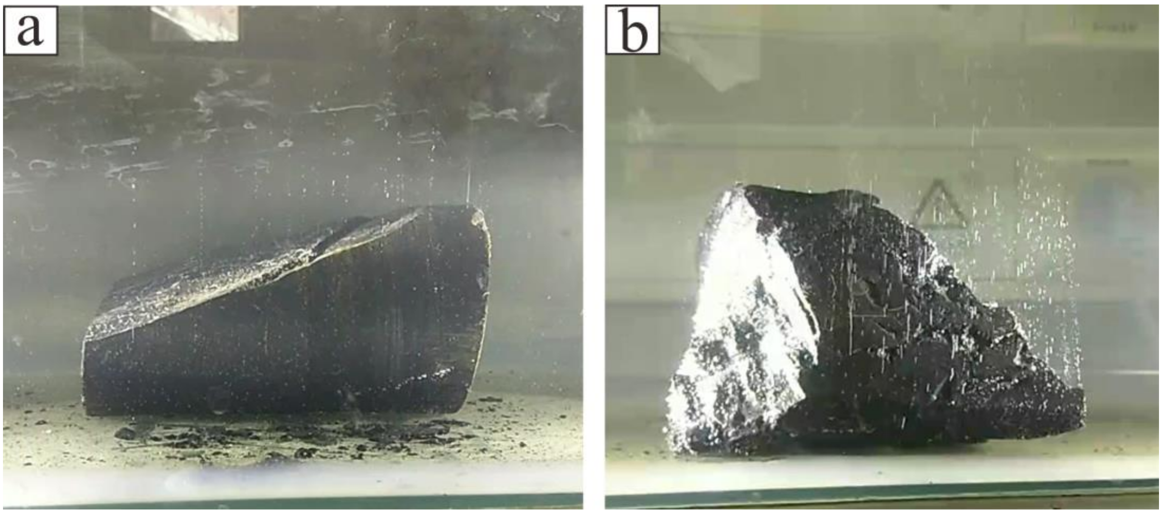

Figure 10. Characteristics of water immersion experiments on well QX1 core samples. (**a**) Grayish-black silty mudstone of the Niutaitang Formation. (**b**) Black carbonaceous mudstone of the Niutaitang Formation.

The on-site analysis tests conducted on 20 shale samples from the Niutitang Formation in well QX1 show the following results (Figure 2): the desorbed gas volume ranges from 0.015 to 1.043 m^3/t (average of 0.265 m^3/t); the residual gas volume ranges from 0 to 1.078 m^3/t (average of 0.221 m^3/t); the total gas content ranges from 0.030 to 1.810 m^3/t (average of 0.582 m^3/t). The total gas content of the upper black carbonaceous shale is higher than that of the lower carbonaceous silty mud shale, reaching a maximum of 1.810 m^3/t. Combined with the results of the core immersion experiment, this indicates that the upper black carbonaceous shale has better gas content and stronger adsorption capacity. Through the correlation analysis (Figure 11), combined with the mineral composition and organic geochemical characteristics of the previous samples, the gas-bearing changes in the samples were studied. The results show that the correlation between gas content and TOC content is not obvious, while the correlation between brittle mineral content and total gas content is negative, and the correlation between clay mineral content and total gas content is positive. It shows that the gas content of the sample is mainly controlled by mineral composition and is less affected by TOC.

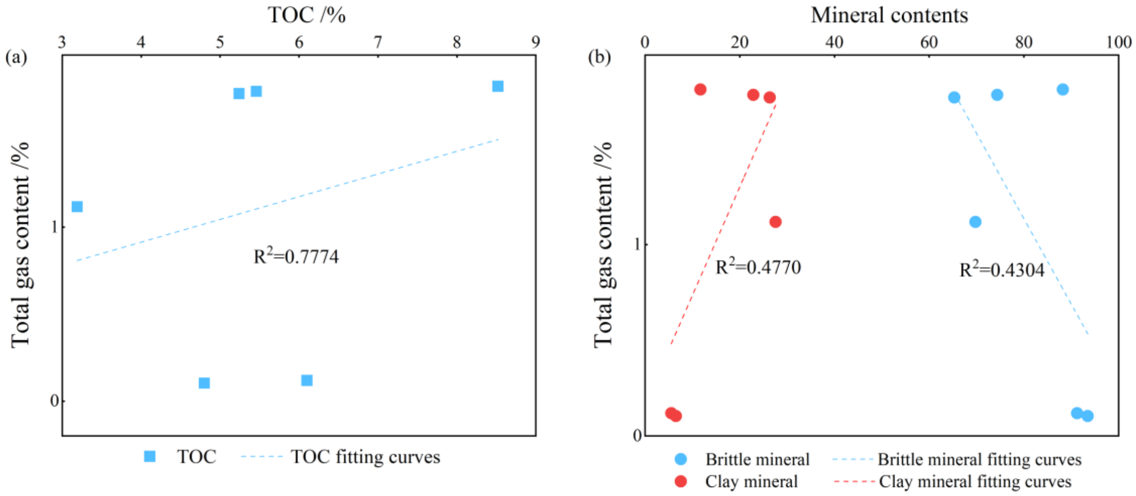

Figure 11. The relationship between reservoir characteristics and gas content. (**a**) The correlation between TOC and total gas content. (**b**) Correlation between mineral composition and total gas content.

In the gas samples obtained from on-site desorption, five samples were selected for gas composition analysis. The results show that the main components of the gas samples from this well are CH_4 and N_2, with small amounts of CO_2 and $C_{2–3}$. Except for the gas sample from 584.96 to 585.21 m, where the N_2 content is significantly greater than the CH_4 content, the CH_4 content is greater than the N_2 content in the other four gas samples (Figure 10). The correlation analysis of gas component content was carried out according to the mineral composition and organic geochemical characteristics of the samples. It is considered that the CH_4 content of the sample is positively correlated with the TOC content, but inversely correlated with the R_o content and clay mineral content. It is speculated that there are more N_2-related adsorption sites in clay minerals.

5. Shale Gas Exploration Potential Evaluation

Over the course of years, shale gas exploration and development have undergone significant advancements, there have been many successful commercial development of shale gas blocks and stratigraphic units both domestically and internationally [9,23,39–42]. The basic param such as organic matter content, thermal evolution degree, kerogen type, brittle mineral content, pore type and shale thickness of the Niutitang Formation shale gas reservoir in QX1 well are compared with them (Table 3). It can be seen that the Niutitang Formation shale gas reservoir in well QX1 has good basic geological static characteristics.

(1) The thickness of shale in the study region is thicker than that of Lewis shale in San Juan Basin, and the thickness of Lewis shale is the thickest among the five shale gas systems in the United States [33]. Therefore, it is considered that the study region has a more favorable shale thickness. Furthermore, as mentioned earlier, the Niutitang Formation shale reservoir in the study region has a gas-bearing layer with a continuous thickness of up to 32.89 m and an effective continuous thickness of 18 m, as well as a source rock layer with a continuous thickness of up to 75.78 m. This indicates that the study region has more favorable gas content and hydrocarbon generation conditions.
(2) Mud shale exhibits high organic matter abundance (with an average as high as 5.64%); appropriate thermal maturity (with an average of 2.51%), indicating good gas generation potential.
(3) Diverse pore types with strong adsorption capacity and sufficient space for shale gas accumulation.

Table 3. Comparison of shale gas reservoir parameters.

Area	Stratigraphy	TOC/%	R_O/%	Kerogen Type	Brittle Mineral Content/%	Pore Type	Thickness of Organic-Rich Mud Shale/m
San Juan Basin in the United States	Lewis	0.45–2.5	1.6–1.9	III	10–60	Organic pores, microfractures	61–91
Chuannan area of the Sichuan Basin	Wufeng–Longmaxi Formation	0.82–9.64	1.7–2/7	III	51.32 (mean)	Inorganic pores organic pores, microfractures	30–50
Well YX1 in Northern Guizhou	Niutaitang Formation	0.3–6.86	1.47–2.56	II	51.34–91.42	Mud pore, bedding gap, interlayer gap, dissolution pores	34.44
Well QX1 in Northern Guizhou	Niutaitang Formation	2.06–12.10	2.29–2.67	I	65.29–95.22	Intergranular pores, intragranular pores, organic pores, microfractures	105.66
Well JC-1 in Northern Guizhou	Longtan formation	0.56–9.58	1.99–3.26	II	5.96–87.27	Intergranular pore, intragranular pore, microfracture	48.03
Well RX1 in Northern Guizhou	Wufeng–Longmaxi Formation	3.99–5.18	2.36–2.78	II	68.90 (mean)	Intergranular pores, intragranular pores, organic pores	22.28

The mud shale is primarily composed of quartz, clay minerals, feldspar (potassium feldspar, plagioclase), carbonate rocks, and pyrite. The content of brittle minerals is relatively high, surpassing that of gas-producing shales in North America. This is conducive to the development of natural fractures, contributing to the analysis of shale gas accumulation conditions and artificial fracturing for extraction. Combining the development status of fractures in Niutitang Formation shale in the study region with the results of core immersion experiments and on-site analysis experiments, it is revealed that the shale gas reservoir exhibits excellent gas manifestations, demonstrating good gas adsorption performance and high gas content. According to the comparative analysis of fundamental param in various study regions, it is concluded that the Niutitang Formation shale gas reservoir in the QX1 well exhibits outstanding gas generation potential, excellent storage performance, and significant hydraulic fracturability. Therefore, it holds great promise for shale gas exploration.

6. Conclusions

(1) The shale lithology of the Niutitang Formation in the study region is mainly carbonaceous silty mudstone; carbon mudstone is gray-black, black cryptocrystalline aggregate, argillaceous is dominant, followed by carbonaceous. The mineral composition of shale varies greatly—mainly quartz (average content of 44.66%) and feldspar (average content of 22.50%). The total content of each brittle mineral is 65.29% to 95.22% (average of 82.10%), showing a high degree of brittleness, which is conducive to reservoir reconstruction.

(2) The samples from the Niutitang Formation exhibit high total organic carbon (TOC) content (with an average of 5.64%). Among these, 62.5% of the samples have TOC content exceeding 5%, and 20.8% fall within the range of 4–5%. The R_o values of the tested samples range between 2% and 3%. The organic matter in the samples is classified as type I. The organic geochemical param indicate that the shale samples from the Niutitang Formation possess high total organic carbon (TOC) content, appropriate thermal maturity, and favorable kerogen type, suggesting greater gas generation potential.

(3) The core samples exhibit well-developed intergranular pores, intragranular pores, and microfractures, enhancing the adsorption capacity of the shale reservoir and providing sufficient storage space for shale gas. The mud shale in the Niutitang Formation exhibits well-developed fractures and good gas apparentness. Combined with the results of core immersion experiments and on-site analysis experiments, it

indicates that the shale gas reservoir possesses excellent gas adsorption capacity and high gas content.

(4) The organic-rich mud shale in the Niutitang Formation of the QX1 well in Northern Guizhou possesses favorable conditions for gas generation, high gas content, good storage conditions, excellent fracturability, and a significant continuous thickness. It exhibits excellent potential for shale gas exploration.

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