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Nanopore Characteristics and Controlling Factors of the Lower Cambrian Shale Reservoirs in Different Sedimentary Facies Based on Multifractal Analysis

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Abstract

The Lower Cambrian shale has been considered an important target for shale gas exploration in South China. However, systematic research on the differences in pore structure and their controlling factors in shales from different sedimentary facies is still lacking, which hinders the accurate prediction of favorable areas. In this study, pore types, structural parameters, heterogeneity and connectivity of the Lower Cambrian shale samples from the shallow shelf, deep shelf and slope were qualitatively and quantitatively characterized by using field emission scanning electron microscope (FE-SEM), low-pressure CO₂ adsorption (LPCA), low-pressure N₂ adsorption (LPNA) and multifractal theory, in order to reveal the reservoir characteristics and differences among these sedimentary facies. The results show that organic pores dominate the pore space in shales from different sedimentary facies, but their morphology and abundance are controlled by the depositional environment. The shallow shelf shales are characterized by scattered organic pores and abundant intragranular pores. Deep shelf shales feature uniformly distributed bubble-like organic pores and have the highest non-micropore volume. Slope shales contain the most developed micropores, with organic pores mainly occurring within organic matter (OM). Total organic carbon (TOC) is the primary factor controlling pore development. It affects pore connectivity and heterogeneity by regulating the development of pore space. Micropore connectivity increases with TOC content. In contrast, non-micropore connectivity first increases and then decreases as TOC increases. The influence of mineral components on shale pore structure varies with sedimentary facies. Clay minerals promote micropore development in shallow and deep shelf shales by adsorbing abundant OM. Carbonate minerals inhibit micropore development through diluting TOC content and cementing pore. However, dissolution of carbonate minerals can contribute to non-micropore space in shallow shelf shales. Deep shelf and slope shales with TOC between 4% and 6% have optimal pore volume, high connectivity, and low heterogeneity, and are the main intervals for forming high-quality shale reservoirs. This study clarifies the pore structure characteristics and controlling factors of shale reservoirs in different sedimentary facies, providing a theoretical basis for predicting and exploring shale gas sweet spots in the Lower Cambrian of South China.

Keywords: sedimentary facies; micropore; shale; Lower Cambrian; heterogeneity

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1. Introduction

The successful development of shale gas in the United States and Canada has profoundly changed the world energy landscape and demonstrated its enormous resource potential [1]. The green and low-carbon energy transition urgently requires increased shale gas exploration and development. Lower Cambrian marine shales in South China, characterized by large thickness and wide distribution, have become one of the key targets for shale gas exploration and development [2,3]. Although the exploration and development of Lower Cambrian shale gas have made important progress in local areas [3–5], the reservoirs typically show low porosity and high heterogeneity compared to Lower Silurian shales [6], which results in generally low gas content.

The pore structure of Lower Cambrian shales is characterized by strong heterogeneity [6–9]. Pore structure characteristics are mainly controlled by factors such as OM type, TOC content, mineral composition, and maturity [10–12]. Differences in kerogen type and maceral composition are the fundamental factors controlling organic pore development and heterogeneity [13,14]. Maturity is the main mechanism driving the formation and evolution of organic pores and their heterogeneity [11,15]. TOC content and mineral composition affect the development and preservation of organic pores, further complicating their development and heterogeneity [16–18].

TOC content, OM type and mineral composition are mainly determined by depositional environment [19,20]. Lower Cambrian shales formed in various depositional environments in South China, including shallow shelf, deep shelf, and slope facies [21]. Deep shelf shale, which primarily developed in suboxic-anoxic, relatively shallow water environments [22], is characterized by high TOC and abundant biogenic quartz [23]. Its macroalgal assemblage is characterized by the coexistence of planktonic ribbon-like algae and benthic attached branching forms [24], and is marked by elevated TOC and enrichment in biogenic quartz [8], making it a key target facies for Lower Cambrian shale exploration [4,25]. Slope facies shale predominantly formed in anoxic to euxinic deep-water environments with stable hydrodynamic conditions [26]. It exhibits a low-diversity macroalgal assemblage dominated by planktonic ribbon-like algae [24], while its OM and biogenic silica contents closely resemble those of the deep shelf facies [27]. Differences in the depositional environment further enhance the heterogeneity of pore structures within the shale reservoirs. However, current studies have predominantly focused on the pore structure of shales from a single sedimentary facies, or local region [6,8,28–30], leaving a comprehensive analysis of pore structures across different sedimentary facies largely unaddressed. Moreover, although numerous studies have revealed the contribution of OM and brittle minerals to pore development in Lower Cambrian shales [6,29,31], the difference in pore structure characteristics and their primary controlling mechanisms under different sedimentary facies remains unclear. Shale pore structure characterization has primarily relied on experimental methods such as LPCA, LPNA [32,33] and small-angle neutron scattering [34], which can quantitatively determine pore size distribution, specific surface area, and pore volume. However, these techniques do not directly quantify the geometric complexity, irregularity, or spatial heterogeneity of pore structures. The introduction of multifractal theory provides a complementary mathematical framework to quantify such complexity and connectivity [35,36], enabling a comprehensive description of irregular, self-similarity, and other complex characteristics, thereby refining the evaluation of pore structures.

This study focuses on Lower Cambrian black shale reservoirs in South China, specifically targeting reservoirs deposited in shallow shelf, deep shelf, and slope facies. Fe-SEM, organic geochemical analysis, LPCA and LPNA were employed to characterize the pore structures of shales from different sedimentary facies. Multifractal theory was further applied to quantify the heterogeneity and connectivity of nanopore structures. The research

aims to reveal the pore structure characteristics and their controlling factors in shales from different sedimentary facies, providing a theoretical basis for shale gas exploration and development in the Lower Cambrian.

2. Geological Setting

During the Ediacaran–Cambrian (E–C) transition, the South China Craton existed as an isolated microcontinent that drifted from mid-latitudes in the Northern Hemisphere toward equatorial regions [37]. It was primarily composed of the Yangtze and Cathaysia blocks [38]. Extensional tectonics between these two blocks intensified during E–C transition, and sustained lithospheric stretching led to the progressive development of a passive continental margin along the Yangtze Block [39]. Three major depositional facies are recognized across the Yangtze Block, including carbonate platform, transitional, and slope-basin facies from northwest to southeast [38,40,41]. These broad facies can be further subdivided into more detailed depositional environments [21,38]. The carbonate platform and transitional facies correspond to the shallow and deep shelf [21,38]. The slope-basin facies encompasses both the slope and the basin facies [21,38]. Therefore, depositional environments in the middle–upper Yangtze region evolved from shallow shelf to deep shelf, slope, and basin settings from northeast to southwest during the early Cambrian [21], consistent with this hierarchical facies scheme. (Figure 1a), driven by the combined effects of a paleogeographic framework characterized by alternating uplifts and depressions (formed during the Tongwan tectonism) and marine transgression [21,42].

The Well EYC2 is located on the southwestern margin of the Huangling uplift in the middle Yangtze region (Figure 1a). The Lower Cambrian shale succession at this well was deposited in a shallow shelf facies [42,43] and comprises the Niutitang (NTT) and Shipai (SP) formations in ascending order (Figure 1b). The NTT Formation unconformably overlies the underlying Dengying (DY) dolomite with a parallel unconformity, and is conformably overlain by the dark gray mudstones of the SP Formation (Figure 1b). The NTT Formation can be further subdivided into lower and upper members based on lithologic variations (Figure 1b). The lower member is dominated by gray-black shale, with occasional calcareous shale (Figure 1b). The lithology transitions into interbedded dark gray, medium-bedded muddy limestone and calcareous shale, with an upward increase in carbonate content (Figure 1b). Locally, thin interlayers of gray-black carbonaceous shale are also present (Figure 1b).

The Well EYY1 is also located on the southwestern margin of the Huangling uplift (Figure 1a). The Lower Cambrian shale succession was deposited in a deep shelf facies [22,28] (Figure 1a) and consists of the Yanjiahe (YJH), Shuijingtuo (SJT), and SP formations in ascending order (Figure 1b). The YJH Formation is composed mainly of limestone and calcareous shale, and unconformably overlies the DY Formation dolomite as a result of the second episode of the Tongwan tectonization [44]. The SJT Formation exhibits pronounced vertical lithologic variability and can be subdivided into two intervals. The lower interval is characterized by high-TOC black shale, and the upper interval consists of interbedded low-TOC argillaceous limestone, calcareous limestone, and black shale (Figure 1b).

The Well DD1 well is located in the middle Yangtze region (Figure 1a). The Lower Cambrian shale succession was deposited in the slope facies [45] (Figure 1a) and comprises the NTT and Jiumenchong formations in ascending order (Figure 1b). The NTT Formation unconformably overlies the DY dolomite and is conformably overlain by the Jiumenchong Formation (Figure 1b). Chert is well developed at the base of the NTT Formation, whereas the middle–upper intervals are dominated by black shale interbedded with muddy limestone (Figure 1b).

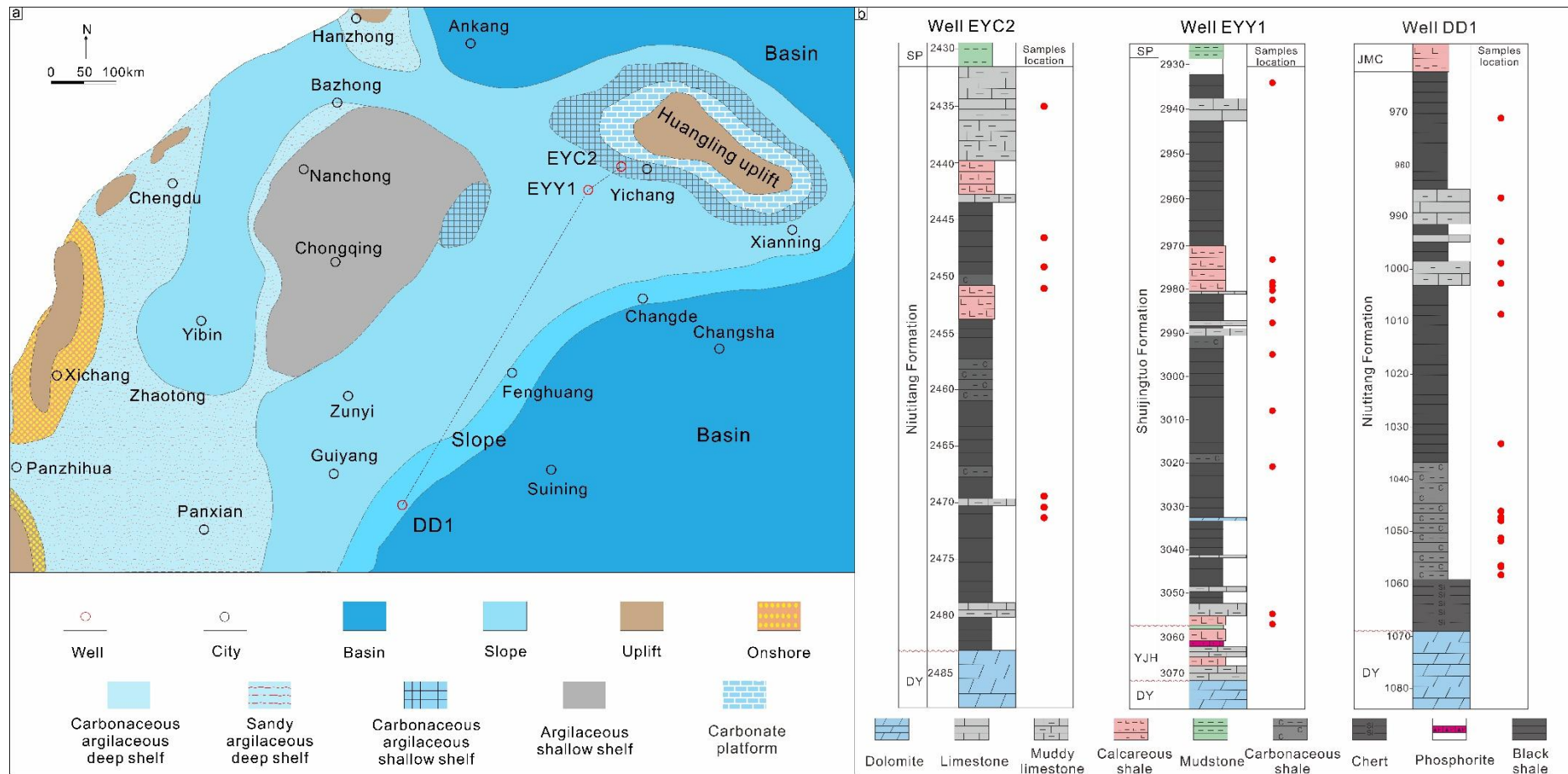


Figure 1. (a) Sedimentary facies distribution in the middle-upper Yangtze region during the Early Cambrian, modified from Liu et al. [21]; (b) Lithology columns and sampling locations of EYC2 (shallow-water shelf), EYY1 (deep-water shelf), and DD1 (slope facies). EYY1 modified from Liu et al. [23].

3. Samples, Experiments and Methods

3.1. Samples

A total of 34 Lower Cambrian shale samples were systematically collected from different sedimentary facies across the Yangtze Block, including 7 samples from the NTT Formation in the shallow shelf, 12 samples from the deep shelf SJT Formation in the deep shelf, and 15 samples from the slope NTT Formation in the slope. Detailed sampling locations and basic information are provided in Figure 1b and Table S1. Some EYY1 samples are sourced from Liu et al. [23].

3.2. Experiments

Optical petrographic observations were conducted using a Zeiss Axioskop 40 A pol polarized light microscope (Oberkochen, Germany). Appropriate magnifications were selected based on sample characteristics, and images were acquired under both plane-polarized and cross-polarized light to examine mineral morphologies.

Samples were cut into $\sim 1.5 \times 1 \times 0.5$ cm blocks, cleaned, and dried before being mounted on sample stubs using conductive adhesive tape. Microstructural observations were performed using a Hitachi SU8000 FE-SEM (Tokyo, Japan), operated at accelerating voltages of 1.0–15.0 kV and working distances of 8–15 mm. Detailed analytical procedures are described in Liu et al. [23].

For TOC analysis, powdered samples (200 mesh) were treated repeatedly with 10% HCl to remove carbonate minerals, rinsed with distilled water to neutrality, and dried at 120 °C for 12 h. TOC measurements were conducted using a LECO CS-744 carbon–sulfur analyzer (St. Joseph, MI, USA). A precision of $\pm 0.2\%$ was achieved for replicate determinations using LECO 501–024 standards. TOC analysis was performed at China University of Geosciences, Beijing, China.

Polished sections perpendicular to bedding were prepared for solid bitumen reflectance measurements using a microscope equipped with a 3Y-Leica DMR XP microspectrophotometer (Wetzlar, Germany). A cubic zirconia standard with a reflectance of 3.11% was used for calibration. At least 50 random measurements were collected for each sample. Bitumen reflectance (BR_o) was converted to equivalent vitrinite reflectance using the relationship $EqVR_o = (BR_o + 0.41)/1.09$ [46].

Mineral compositions were determined by X-ray diffraction using a Bruker D8 Advance diffractometer (Karlsruhe, Germany) on powdered samples (200 mesh). Analytical conditions and data interpretation followed Feng et al. [17].

Pore structure characterization was conducted using a Micromeritics ASAP 2020^M system (Norcross, GA, USA). Crushed samples (20–40 mesh) were dried at 383.15 K for 12 h to remove moisture and volatile impurities, followed by degassing under vacuum for 10 h. Low-pressure N₂ and CO₂ adsorption experiments were then performed. Adsorption temperatures were 77.35 K (101.3 kPa) for N₂ and 273 K for CO₂, with corresponding relative pressure (p/p_0) ranges of 0.009–0.995 and 0.00001–0.032, respectively. Based on low-LPNA data, pore size distribution and SSAs were calculated using the Barrett–Joyner–Halenda and Brunauer–Emmett–Teller models, respectively, with an effective pore size range of 1.7–230 nm [47]. Micropore volume and surface area were derived from LPCA data using the DFT density functional theory model and the Dubinin–Astakhov equation, with an effective pore size range of 0.33–2.0 nm [48]. Pore classification follows the International Union of Pure and Applied Chemistry, with micropores < 2 nm, mesopores 2–50 nm, and macropores > 50 nm. Except for the TOC analysis, these analyses were performed at the State Key Laboratory of Deep Earth Processes and Resources, Guangzhou Institute of Geochemistry, Chinese Academy of Sciences, Guangzhou, China.

3.3. Multifractal Theory

Multifractal theory has been extensively described in previous studies [35,36]; therefore, only a brief overview of the box-counting-based multifractal method is provided here. Relevant parameters are summarized in Table 1.

Table 1. Nomenclature.

L	the maximum relative pressure	i	serial number of the test site
K	the number of segments that divide the interval,	ε	the scale of the box
α_i	the i th singularity index in the set	P_i	the probability value of gas adsorption volume in the i interval
q	exponent	$N\alpha(\varepsilon)$	number of units
$\tau(q)$	mass exponent	$D(q)$	generalized fractal dimension
$f(\alpha)$	multifractal spectra	$u(q, \varepsilon)$	partition function

Fractal characteristics of pore structures were quantified from gas adsorption data using the box-counting method [49]. The relative pressure range was first treated as an interval of length L and subdivided into N equal segments (boxes), each with a size of $\varepsilon = L/2^K$ ($K = 1, 2, 3, \dots$). The mass probability function of the i th box is defined as:

$$P_i(\varepsilon) = \frac{N_i(\varepsilon)}{\sum_{i=1}^{N(\varepsilon)} N_i(\varepsilon)} \quad (1)$$

where $N_i(\varepsilon)$ represents the adsorption capacity of the i th box. The probability function $P_i(\varepsilon)$ is related to ε as follows:

$$P_i(\varepsilon) \propto \varepsilon^{\alpha_i} \quad (2)$$

where α_i denotes the singularity exponent. Let $N_\alpha(\varepsilon)$ represent the number of boxes with the same α value. then:

$$N_\alpha(\varepsilon) \sim \varepsilon^{-f(\alpha)}, \varepsilon \rightarrow 0 \quad (3)$$

The function $f(\alpha)$ represents the multifractal spectrum, describing the fractal dimension of subsets characterized by the same singularity exponent. The relationship between $f(\alpha)$ and $\alpha(q)$ can be calculated as follows [49,50]:

$$\alpha(q) \propto \frac{\sum_{i=1}^{N(\varepsilon)} [u_i(q, \varepsilon) \lg \varepsilon]}{\lg \varepsilon} \quad (4)$$

$$f(\alpha) \propto \frac{\sum_{i=1}^{N(\varepsilon)} [u_i(q, \varepsilon) \lg u_i(q, \varepsilon)]}{\lg \varepsilon} \quad (5)$$

$$u_i(q, \varepsilon) = \frac{P_i^q(\varepsilon)}{\sum_{i=1}^{N(\varepsilon)} P_i^q(\varepsilon)} \quad (6)$$

Here, q denotes the moment order, which ranges from -10 to 10 in this study. The denominator in Equation (6) corresponds to the partition function, which is defined as:

$$u(q, \varepsilon) = \sum_{i=1}^{N(\varepsilon)} P_i^q(\varepsilon) \varepsilon^{\tau(q)} \quad (7)$$

where $\tau(q)$ is the mass function, defined as:

$$\tau(q) = \lim_{\varepsilon \rightarrow 0} [\lg u(q, \varepsilon) / \lg \varepsilon] \quad (8)$$

In addition to the $f(\alpha)$ – α spectrum, multifractal behavior can also be characterized using the q – $D(q)$ formalism, which is introduced from an information theory perspective [49,50]. The generalized fractal dimension $D(q)$ is defined as:

$$D_q \begin{cases} \frac{\tau(q)}{q-1} (q \neq 1) \\ \lim_{\varepsilon \rightarrow 0} \frac{\sum_{i=1}^{N(\varepsilon)} P_i \times \lg P_i(\varepsilon)}{\lg \varepsilon} (q = 1) \end{cases} \quad (9)$$

The Hurst is commonly used to characterize pore structure connectivity [36] and is calculated as:

$$H = \frac{D2 + 1}{2} \quad (10)$$

Higher H values indicate better pore connectivity [36,51]. The width of the multifractal spectrum, $\Delta\alpha = \alpha_{10} - \alpha_{-10}$, reflects the heterogeneity of the probability measure distribution within the fractal system [36,52]. Larger $\Delta\alpha$ values indicate greater heterogeneity in pore size distribution [36,52].

4. Results

4.1. TOC and Mineral Composition

TOC contents of the Lower Cambrian shale samples range from 0.4 to 10.4%, with an average of 4.1% (Figure 2). TOC values vary systematically with sedimentary facies, being highest in slope facies (1.9–10.4%, avg. 6.1%), followed by deep shelf facies (1.7–5.0%, avg. 3.0%), and lowest in shallow shelf facies (0.4–3.9%, avg. 1.6%) (Figure 2).

The slope facies shales are dominated by quartz, clay minerals, and feldspar (Figure 2). Quartz is the most abundant component, averaging 49.1%, whereas feldspar contents range from 5.7% to 14.3% (avg. 10.4%). Clay mineral contents show substantial variability (9.5–46.9%, avg. 22.5%), and pyrite contents are generally <10% (Figure 2). In contrast, shallow and deep shelf facies shales are primarily composed of quartz, carbonate minerals, and clay minerals, with pyrite and feldspar typically <15% (Figure 2). In deep shelf shales, quartz contents range from 23.6% to 56.4% (avg. 39.9%), clay minerals from 5.5% to 43.0% (avg. 24.9%), and carbonate minerals vary widely from 2.0% to 53.1%. Shallow shelf shales show quartz contents of 12.9–52.7% (avg. 33.7%), carbonate minerals of 6.9–74.1% (avg. 39.9%), and clay minerals of 8.9–27.3% (avg. 17.4%) (Figure 2).

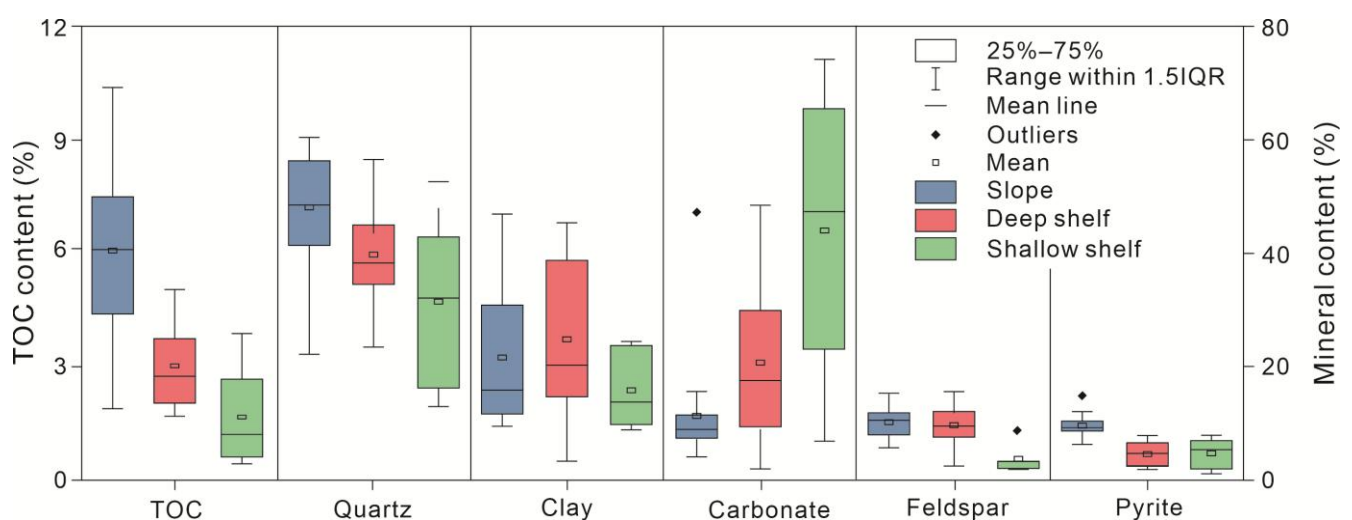


Figure 2. Distribution of TOC and mineral composition contents in shale samples from slope facies (N = 15), deep shelf facies (N = 12), and shallow shelf facies shale (N = 7).

TOC contents of the Lower Cambrian shales increase with increasing quartz content (Figure 3a), but the positive correlation weakens once quartz exceeds ~55%. During the early Cambrian, rising relative sea level limited terrigenous input, resulting in low contributions of detrital quartz and feldspar [53]. Instead, Quartz was predominantly derived from biogenic sources, particularly sponge spicules (Figure 4), which became increasingly abundant and diverse [6,54]. Under anoxic to euxinic conditions of the early Cambrian ocean [55], these biogenic siliceous components were efficiently preserved and contributed both dissolved silica and OM during diagenesis [56]. Consequently, moderate increases in biogenic quartz are associated with enhanced OM accumulation. However, excessive silica input likely diluted OM, leading to a plateau in TOC at high quartz contents [12].

In contrast, TOC decreases systematically with increasing carbonate mineral content (Figure 3b), reflecting a carbonate dilution effect. Shallow and deep shelf shales, located proximal to the northeastern carbonate platform, received substantial carbonate detritus transported basinward under weathering-driven processes [57]. This influx of carbonate material diluted organic matter concentrations in shelf settings. The relationship between TOC and clay mineral content is more complex and shows no clear systematic trend (Figure 3c), suggesting that clay minerals exert a less direct control on OM enrichment in these shales.

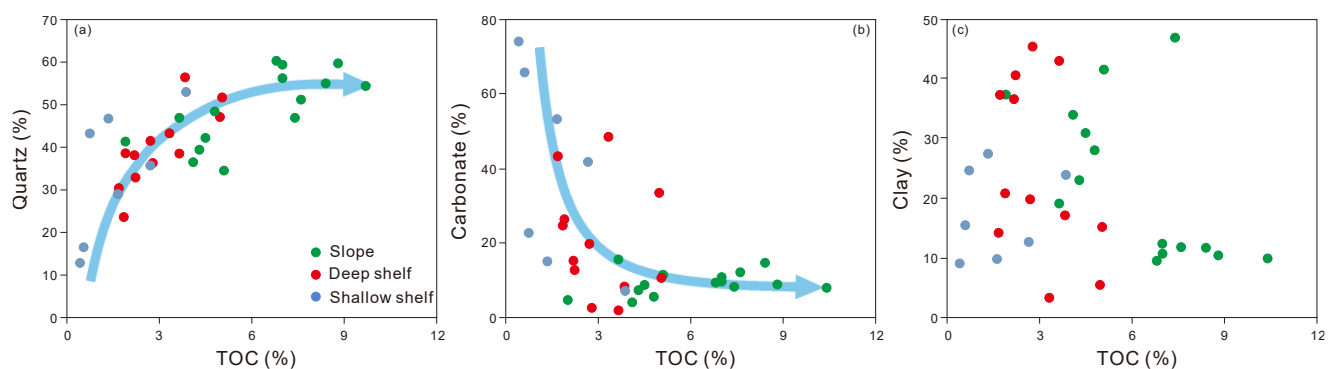


Figure 3. Plots showing relationships of TOC with mineral components for the studied shale samples. (a) TOC vs. quartz; (b) TOC vs. carbonate; (c) TOC vs. Clay.

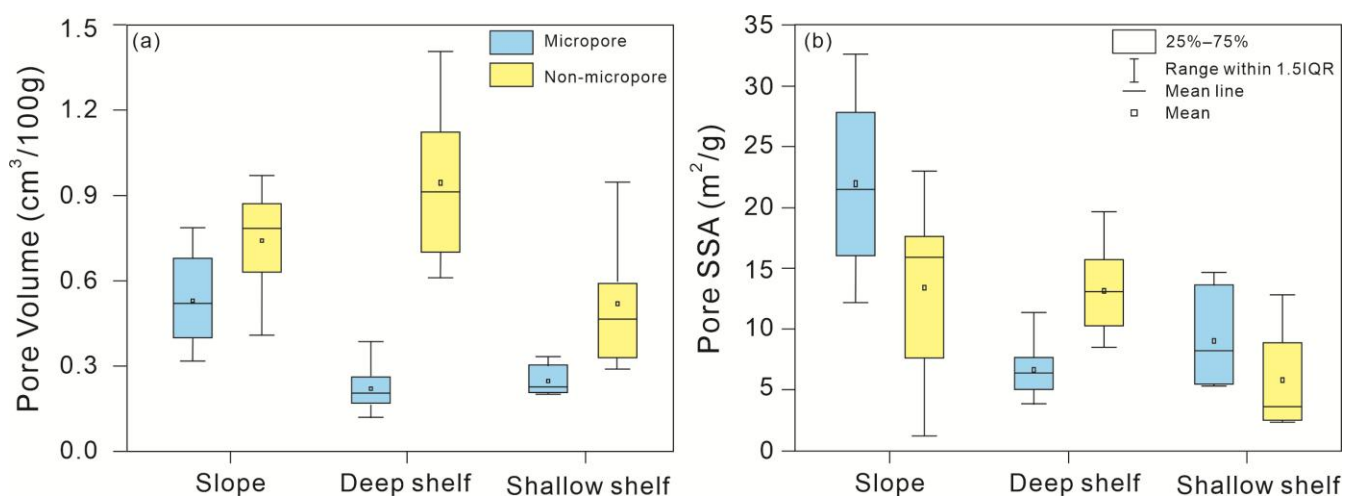


Figure 4. Pore structure parameters of Lower Cambrian shale (a) micropore volume and non-micropore volume of slope facies, deep shelf and shallow shelf shale; (b) micropore specific surface area and non-micropore specific surface area of slope facies, deep shelf and shallow shelf shale. Some data on pore volume and specific surface area of deep shelf shale sourced from Liu et al. [23]. SSA = specific surface area.

4.2. Pore Structure Parameters

Pore structure parameters vary systematically among different sedimentary facies in the Lower Cambrian shales (Figure 4). Slope facies shales exhibit the highest micropore volumes, ranging from 0.27 to 0.73 cm³/100 g (avg. 0.50 cm³/100 g). Micropore volumes in shallow shelf shales (0.20–0.33 cm³/100 g; avg. 0.25 cm³/100 g) are slightly higher than those in deep shelf shales (0.12–0.39 cm³/100 g; avg. 0.22 cm³/100 g) (Figure 4a). In contrast, deep shelf shales are characterized by the highest non-micropore volumes (0.61–1.41 cm³/100 g; avg. 0.95 cm³/100 g), whereas shallow shelf shales show the lowest values (avg. 0.52 cm³/100 g) (Figure 4a). Despite these differences in pore volume, slope facies shales display the highest SSAs for both micropores (8.57–29.21 m²/g; avg. 20.28 m²/g) and non-micropores (4.86–19.15 m²/g; avg. 14.56 m²/g) (Figure 4b). Shallow shelf shales have higher micropore surface areas (5.30–14.62 m²/g; avg. 9.09 m²/g) but lower non-micropore surface areas (2.40–12.78 m²/g; avg. 5.85 m²/g) compared to deep shelf shales, which exhibit micropore surface areas of 0.86–11.33 m²/g (avg. 6.64 m²/g) and non-micropore surface areas of 8.54–18.95 m²/g (avg. 13.22 m²/g) (Figure 4b). Overall, pore volume is dominated by non-micropores across all facies, whereas micropores contribute most significantly to the SSAs.

5. Discussion

5.1. Pore Structure Characteristics and Controlling Factors in Shales

5.1.1. Pore Types and Characteristics

Lower Cambrian shale samples display different sedimentary fabric characteristics across different facies. Slope facies shales are characterized by the widespread occurrence of siliceous bioclasts, particularly sponge spicules (Figure 5a). Deep shelf shales exhibit interbedded mixed layers of OM with calcareous and siliceous components (Figure 5b), whereas shallow shelf shales are dominated by carbonate laminae, with OM occurring as bands between these laminae (Figure 5c). These contrasting sedimentary fabrics result in variations in dominant pore types among facies, although OM pores and inorganic pores are prevalent in all samples (Figure 5d–i). OM commonly occurs as aggregates associated with clay mineral interparticle pores or as pore-filling phases within interparticle spaces (Figure 5d–f). Deep shelf and Slope shales are relatively enriched in quartz (Figure 2) that is dominated by microcrystalline quartz aggregates (Figure 5d,e). These rigid frameworks provide pore space for OM accumulation and enhance resistance to compaction [12]. In contrast, shallow shelf shales, characterized by lower quartz contents, tend to preserve OM within interparticle pores associated with pyrite (Figure 5f).

Inorganic pores in shales from different sedimentary facies are dominated by interparticle and intraparticle pores (Figure 5c–i). Interparticle pores are mainly developed within microcrystalline quartz aggregates, where pore spaces between quartz crystals are commonly filled with OM (Figure 5d,e). Similar pore-filling relationships are observed in pyrite aggregates, although irregular pores also occur between pyrite grains and OM (Figure 5f). Intraparticle pores are primarily associated with dissolution within reactive minerals such as calcite and dolomite (Figure 5g–i). In slope facies shales, where carbonate mineral contents are relatively low (Figure 2), intraparticle pores are mainly developed within pyrite aggregates and are commonly filled with OM (Figure 5g). In contrast, shallow and deep shelf shales contain higher proportions of carbonate minerals, and dissolution pores within calcite are frequently observed (Figure 5h,i). However, intraparticle pores in brittle minerals generally exhibit poor connectivity and make only a minor contribution to the overall pore system [58].

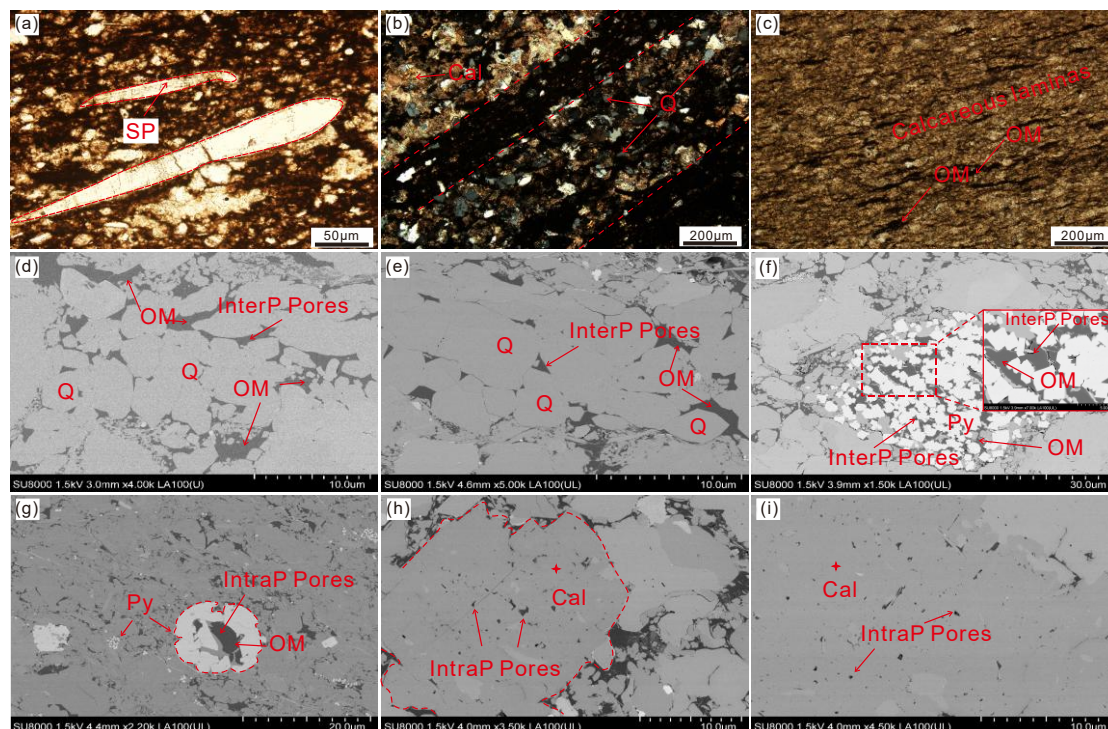


Figure 5. Sedimentary structures and pore development characteristics of Lower Cambrian shale samples. (a) Sponge spicules in slope facies shale, DD1-3; (b) interlamination of organic matter with quartz and carbonate minerals in deep shelf facies shale, EYY1-1; (c) calcareous laminae and banded organic matter in shallow shelf shale, EYC-5; (d) interparticle pores within a microcrystalline quartz framework, partially filled with organic matter, DD1-7; (e) interparticle pores within a microcrystalline quartz framework, partially filled with organic matter, EYY1-4; (f) interparticle pores among pyrite grains filled with abundant organic matter, EYC2-2; (g) intraparticle pores within pyrite grains filled with organic matter in slope facies shale, DD1-7; (h) intraparticle pores formed by dissolution of calcite in deep shelf facies shale, EYY1-6; (i) intraparticle pores formed by dissolution of contiguous calcite in shallow shelf facies shale, EYC2-6.

Organic pores dominate the pore system in Lower Cambrian shale samples, but their development varies markedly among sedimentary facies. Deep shelf shales contain abundant organic pores, with diameters reaching up to ~200 nm, predominantly exhibiting bubble-like morphologies (Figure 6a–c). These pores are relatively uniformly distributed within large OM domains (Figure 6a,c). Organic pores are widely developed within clay minerals, whereas they are less common in microcrystalline quartz-rich domains (Figure 6b). This heterogeneous distribution likely reflects the catalytic effect of clay minerals on OM thermal evolution, as well as the limited ability of microcrystalline quartz frameworks to resist compaction at this stage [59]. In addition, organic pores within OM associated with brittle minerals (e.g., pyrite) are well developed, as these minerals provide rigid frameworks that enhance resistance to compaction (Figure 6c). In contrast, slope facies shales exhibit significantly fewer organic pores (Figure 6d–f). Organic pores are mainly developed in OM associated with clay minerals and display heterogeneous sizes, with pores preferentially occurring in the central portions of OM domains (Figure 6d–f). Organic pores are rare in shallow shelf shales and occur only sporadically. Organic pores in shallow shelf shales are typically associated with OM hosted in interparticle spaces between brittle mineral grains, where intraparticle pores within these minerals are also observed (Figure 6d–f).

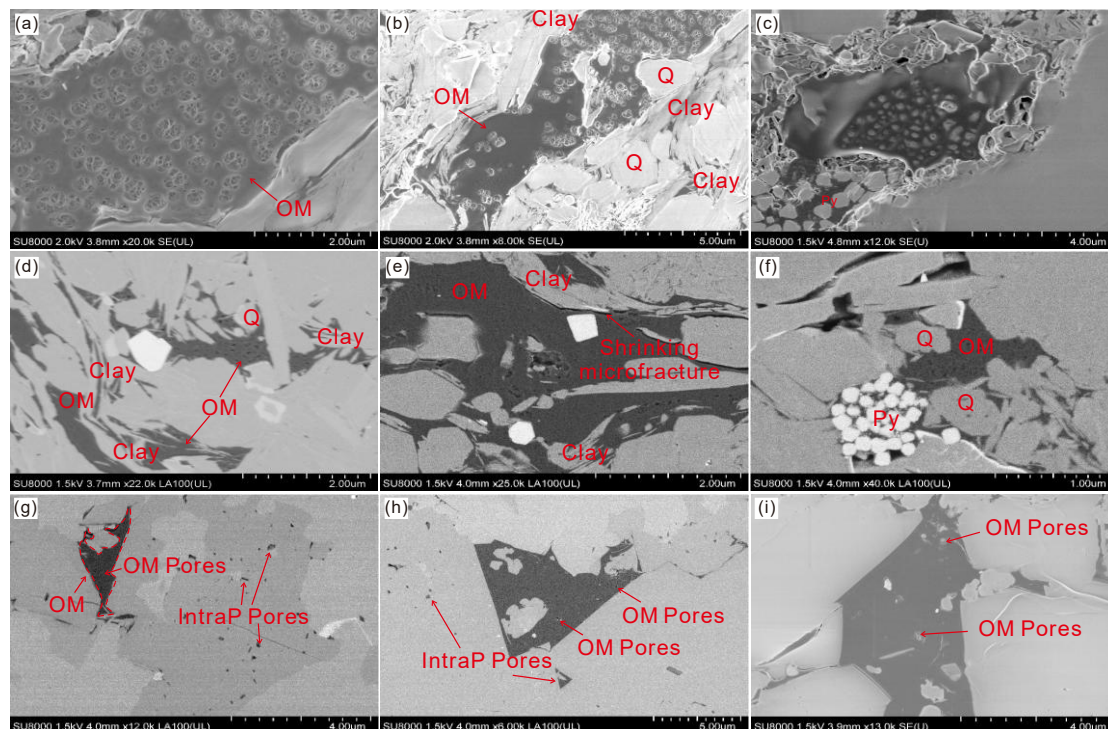


Figure 6. Characteristics of organic pores in Lower Cambrian shale samples. (a) Widely developed organic pores in deep shelf shale, EYY1-3; (b) heterogeneous distribution of organic pores in deep shelf shale, concentrated around clay minerals, EYY1-5; (c) abundant organic pores developed within the framework of brittle minerals (e.g., pyrite), EYY1-5; (d) organic matter associated with clay minerals and its pore development in slope facies shale; organic pores are restricted to the central part of organic matter, DD1-7; (e) massive organic matter between clay mineral particles, with pores developed only in the center and showing heterogeneous sizes, DD1-7. (f) Organic matter between clay minerals and brittle mineral grains, with more developed organic pores adjacent to clay minerals, DD1-8; (g) organic matter among brittle mineral grains in shallow shelf shale, containing sparse organic pores, while abundant intraparticle pores are developed within brittle minerals, EYC2-2; (h) organic matter fills the framework formed by brittle minerals with well-developed intraparticle pores, within which organic pores are sparsely developed, EYC2-3; (i) sparsely developed organic pores, EYC2-3.

5.1.2. Influence Factors of Pore Structure

TOC, maturity, and mineral composition are widely considered as the primary controls on the development and evolution of nanopore systems in shales [60]. The Lower Cambrian shale samples analyzed in this study exhibit a relatively narrow range of maturity, with $EqVR_o$ values of 2.5–3.2%, indicating an overmature stage. There is little variation in maturity levels among different sedimentary facies of shale. At this stage, pore systems are still preserved and have not yet reached the threshold of disappearance [2]. Within this limited maturity range, the effect of maturity on pore development is expected to be minimal [2]. Therefore, TOC and mineral composition are identified as the dominant factors controlling pore structure development in the Lower Cambrian shales.

Relationships between pore structure parameters and TOC in the Lower Cambrian shales are complex (Figure 7). Micropore volume and SSAs increase markedly with increasing TOC (Figure 7a,b), reflecting the predominance of micropores within OM [61]. Higher TOC provides a greater material basis for micropore development, a relationship widely reported in Permian shales [62] and the Wufeng–Longmaxi formations [63]. Consistent with this trend, slope facies shales, which exhibit the highest TOC contents (Figure 2), also show the largest micropore volumes. In contrast, non-micropore volume and

surface area show a non-linear relationship with TOC, initially increasing and then decreasing, with a maximum at TOC values of 4–6% (Figure 7c,d). This pattern is consistent with observations from other Lower Cambrian shales [64]. At higher TOC levels, non-micropore volume decreases, likely due to the ductile nature of OM, which reduces resistance to compaction and promotes pore collapse during diagenesis [23,64]. Some deep shelf samples with relatively low TOC exhibit anomalously high non-micropore volumes, possibly due to the presence of microfractures. At comparable TOC levels, shallow shelf shales generally display lower non-micropore volumes than deep shelf shales (Figure 7c). This difference likely reflects variations in OM type, with type I–IIa OM dominating in deep shelf and slope facies, and type IIb–III OM in shallow shelf facies, which exerts an additional control on pore structure development [65].

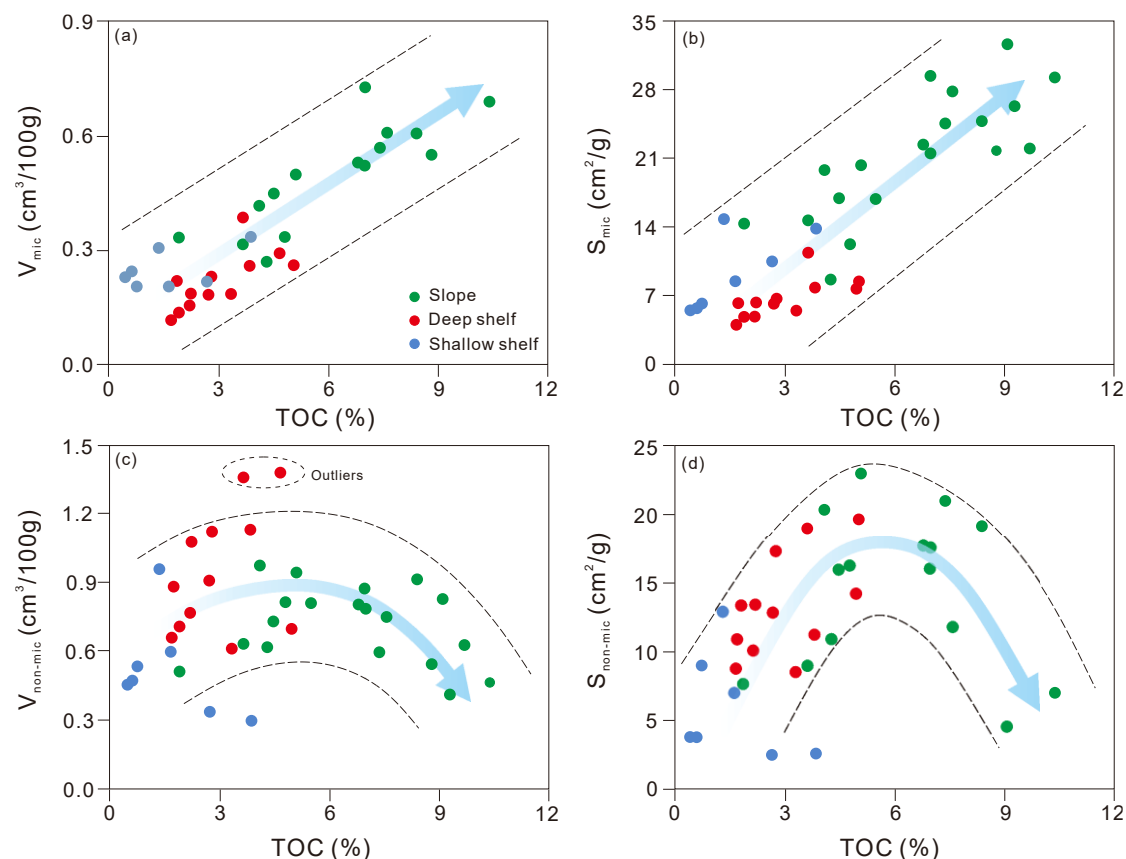


Figure 7. Plots showing relationships of TOC with pore structure parameters for the studied shale samples. (a) TOC vs. micropore volume; (b) TOC vs. micropore specific surface area; (c) TOC vs. non-micropore volume; (d) TOC vs. non-micropore specific surface area.

Given that SSAs and pore volume exhibit similar trends (Figure 7), the following discussion focuses on the influence of major mineral types on micropore and non-micropore volumes.

Quartz is one of the most important mineral components in shales and plays a critical role in reservoir development and producibility [6,66–68]. Organic-rich siliceous shale intervals of the Lower Cambrian are widely regarded as “sweet spots” for shale gas exploration [4]. In this study, micropore volume increases significantly with TOC (Figure 8a), whereas non-micropore volume shows an initial increase followed by a decrease with increasing TOC (Figure 8b). Quartz can form rigid frameworks during early diagenesis, enhancing resistance to compaction and thereby facilitating the preservation of organic pores [69]. However, excessive quartz contents may dilute OM and degrade pore systems through intense siliceous cementation [6]. As compaction and cementation progressively

reduce larger pores, some non-micropores may evolve into micropores. Notably, quartz content shows a strong positive correlation with TOC (Figure 3a). Given its predominantly authigenic origin, quartz itself contributes limited pore space directly; instead, its primary role is to form a rigid framework that protects organic pores from compaction (Figure 5d,e). Therefore, the apparent influence of quartz on pore structure largely reflects the control exerted by OM. Overall, TOC is identified as the primary control on pore structure development in Lower Cambrian shales.

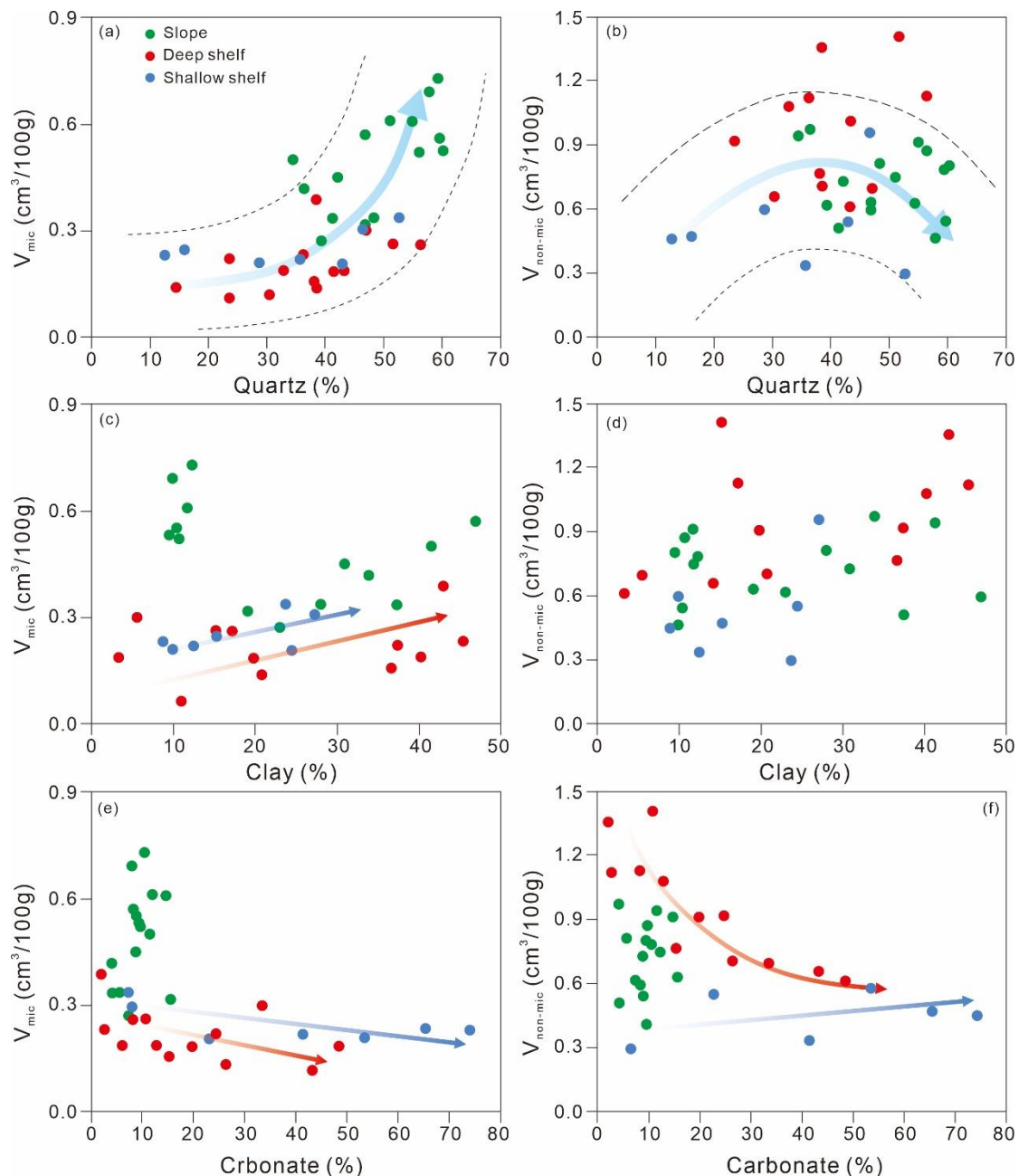


Figure 8. Plots showing relationships of mineral composition with pore volume for the studied shale samples. (a) Quartz vs. micropore volume; (b) quartz vs. non-micropore volume; (c) clay vs. micropore volume; (d) clay vs. non-micropore volume; (e) carbonate vs. micropore volume; (f) carbonate vs. non-micropore volume. The light blue arrows indicate the overall variation trend of all shale samples; the dark blue arrows represent the variation trend of shallow shelf shale; and the red arrows denote the variation trend of deep shelf shale.

Clay minerals represent a critical component in shale pore evolution. They not only host abundant micropores themselves [70], but also release silica during diagenesis, promoting the formation of authigenic quartz [71]. This quartz may either form rigid frameworks that help preserve pore space [71,72] or reduce porosity through siliceous cementation [12]. However, the influence of clay minerals on pore structure varies considerably among different stratigraphic units and regions. Previous studies report contrasting relationships, including positive correlations between clay content and pore volume [29,30] as well as negative or negligible effects [73]. In this study, the relationship between clay content and micropore volume differs among sedimentary facies. In shelf facies shales, micropore volume increases with increasing clay content (Figure 8c). This trend reflects the combined effects of intrinsic micropores within clay minerals. In addition, clay minerals may catalyze hydrocarbon generation, further promoting organic pore development [64]. In contrast, no clear relationship is observed between clay content and micropore volume in slope facies shales (Figure 8c). This likely reflects the dominance of OM control, as samples with relatively low clay contents (~10%) exhibit very high TOC values (~8%; Figure 3c), masking the effect of clay minerals. Moreover, no significant correlation is observed between clay mineral content and non-micropore volume across all samples (Figure 8d).

The influence of carbonate minerals on pore development varies markedly among sedimentary facies. In slope facies shales, where carbonate contents are relatively low, their effects on both micropore and non-micropore volumes are negligible (Figure 8e,f). In contrast, deep shelf shales show systematic decreases in both micropore and non-micropore volumes with increasing carbonate content (Figure 8e,f). For shallow shelf shales, micropore volume decreases with increasing carbonate content (Figure 8e), whereas non-micropore volume shows an opposite trend, increasing with carbonate abundance (Figure 8f). Carbonate minerals in the shelf area are predominantly of detrital origin [57]. Their influx exerts a dilution effect on OM (Figure 3c), thereby limiting the development of organic pores. In addition, carbonate cementation may occlude pore space and hinder both OM preservation and pore retention. However, carbonate minerals are also prone to dissolution, generating abundant intraparticle pores (Figure 5h,i). In shallow shelf shales, which are characterized by relatively low TOC, such dissolution-derived intraparticle pores constitute an important component of the non-micropore system (Figure 6g,h), explaining the positive relationship between carbonate content and non-micropore volume in shallow shelf facies.

Overall, TOC is the primary control on pore structure development across different sedimentary facies. The influence of quartz is largely indirect, reflecting its association with OM and its role in forming rigid frameworks that resist compaction. Clay minerals promote micropore development in shallow and deep shelf shales through their intrinsic porosity. In contrast, carbonate minerals generally inhibit pore development in deep shelf shales and suppress micropore formation in shallow shelf shales, but can enhance non-micropore development in shallow shelf settings through dissolution processes.

5.2. Multifractal Characteristics of Pore Systems and Their Controls

Multifractal analysis based on LPNA and LPCA indicates that both micropore and non-micropore systems in the Lower Cambrian shales exhibit clear multifractal behavior (Figures 9–11). For both pore systems, the generalized dimension $D(q)$ decreases monotonically with increasing q and displays an inverse S-shaped trend (Figures 9a,d, 10a,d and 11a,d). For micropores, $D(q)$ decreases most rapidly at $q < 0$, with a rate significantly higher than that of non-micropores. This pattern suggests that micropore systems exhibit stronger heterogeneity and greater sensitivity to scale variations, particularly in the low-probability regions (i.e., larger or less frequent pores). In contrast, when $q > 0$, $D(q)$ values

of micropores are nearly identical across different depositional settings, likely reflecting the limited pore size range captured by CO₂ adsorption (Figures 9a, 10a and 11a). Non-micropores show a more uniform decrease in $D(q)$ across the full q range (Figures 9d, 10d and 11d). The $f(\alpha)$ derived from both LPCA and LPNA exhibit convex parabolic shapes (Figures 9b,e, 10b,e and 11b,e), confirming the multifractal nature of pore size distributions. Micropore spectra are generally wider than those of non-micropores, despite being less symmetric, indicating a higher degree of structural complexity and heterogeneity within micropore systems [36]. The $\tau(q)$ increases with q and exhibits a convex upward trend for both pore systems (Figures 9c,f, 10c,f and 11c,f). For micropores, $\tau(q)$ values converge at $q > 0$ but diverge significantly at $q < 0$, whereas non-micropores show convergence only near $q = 0$.

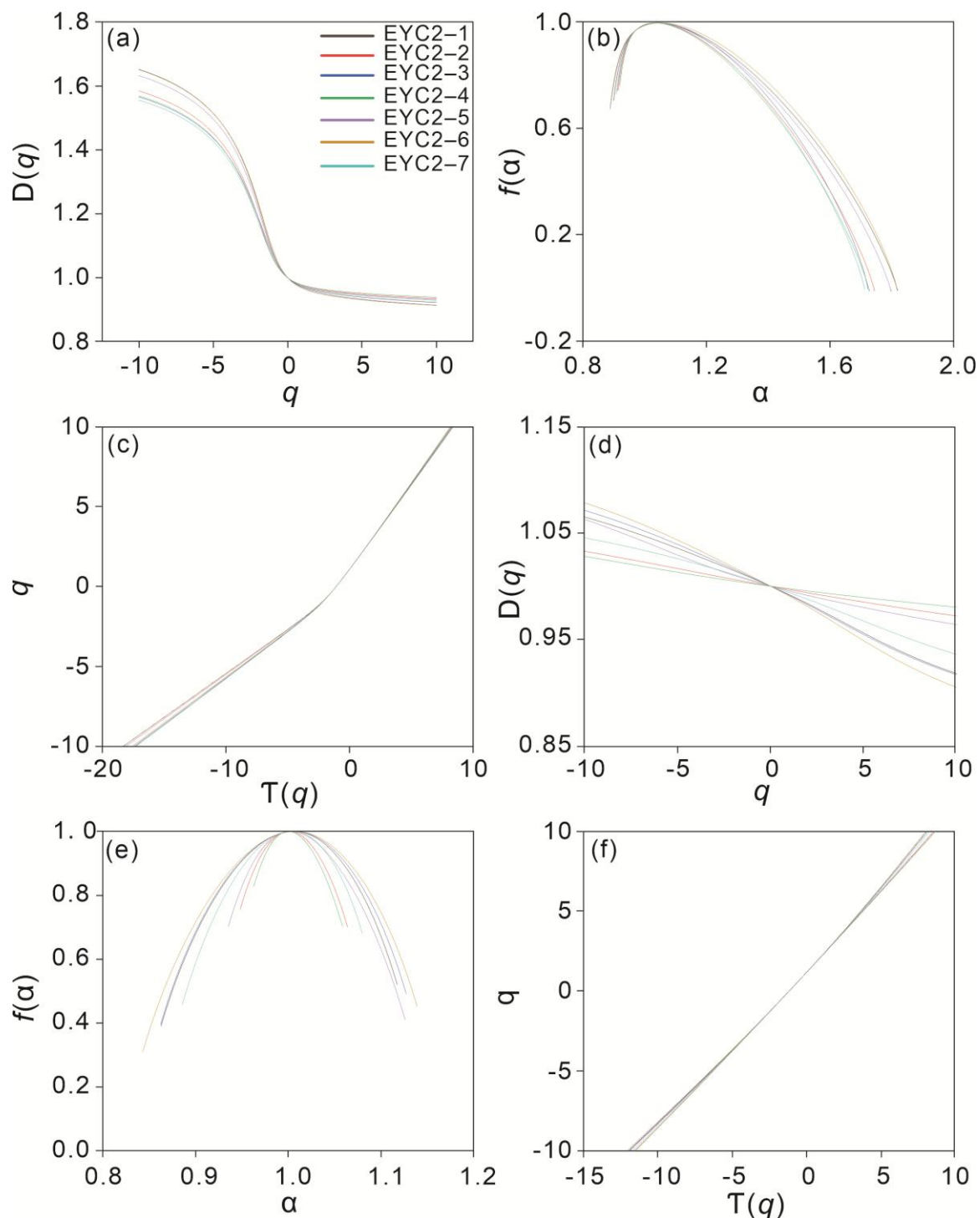


Figure 9. Multifractal analyses of non-micropores and micropores of the shallow shelf shale samples, respectively, based on their LPNA and LPCA data. (a) Generalized fractal dimension vs. statistical moment based on LPCA. (b) Multifractal spectrum based on LPCA (c). Mass index function vs. statistical moment based on LPCA. (d) Generalized fractal dimension vs. statistical moment based on LPNA. (e) Multifractal spectrum based on LPNA (f). Mass index function vs. statistical moment based on LPNA.

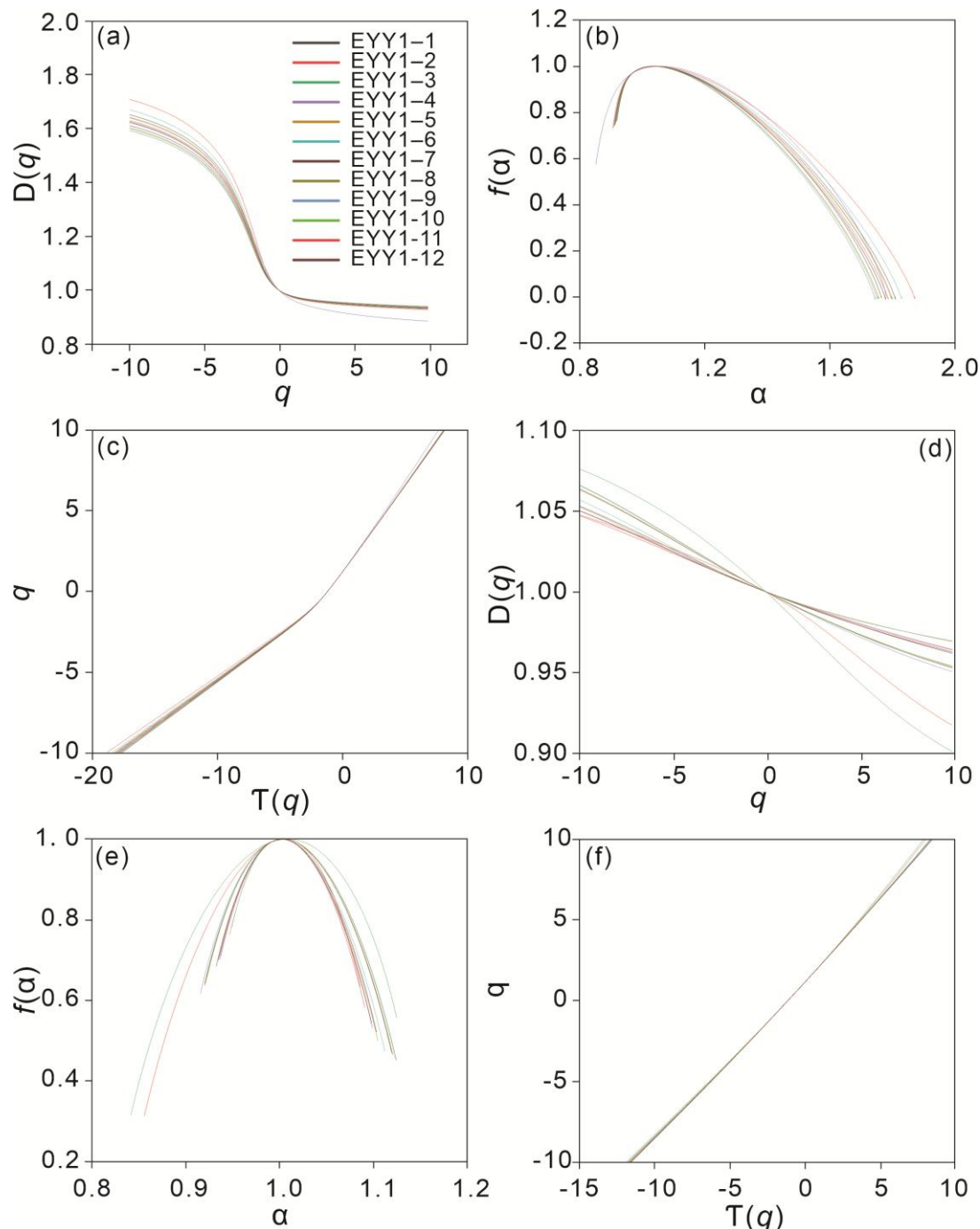


Figure 10. Multifractal analyses of non-micropores and micropores of the deep shelf shale samples, respectively, based on their LPNA and LPCA data. (a) Generalized fractal dimension vs. statistical moment based on LPCA. (b) Multifractal spectrum based on LPCA (c). Mass index function vs. statistical moment based on LPCA. (d) Generalized fractal dimension vs. statistical moment based on LPNA. (e) Multifractal spectrum based on LPNA (f). Mass index function vs. statistical moment based on LPNA.

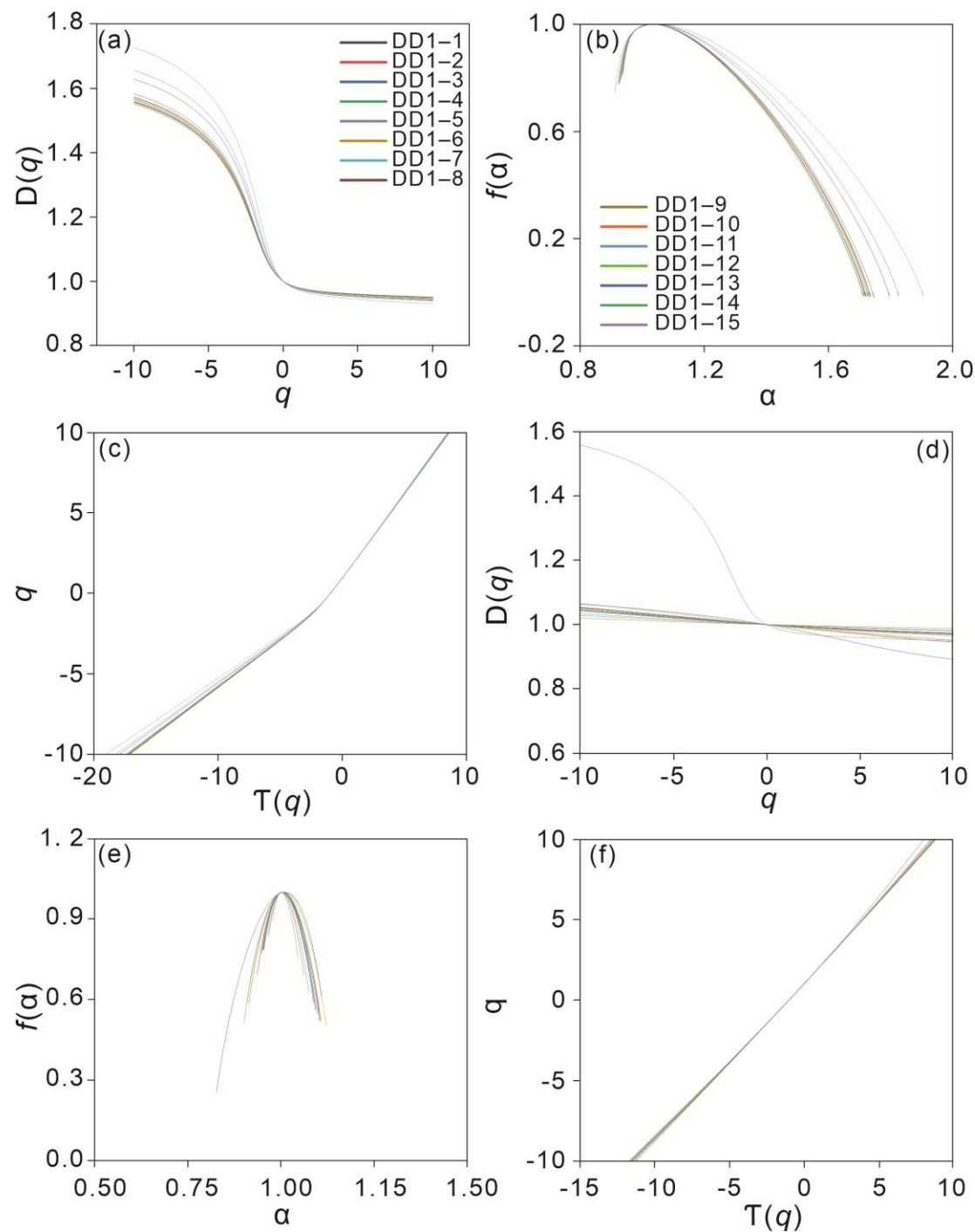


Figure 11. Multifractal analyses of non-micropores and micropores of the slope shale samples, respectively, based on their LPNA and LPCA data. (a) Generalized fractal dimension vs. statistical moment based on LPCA. (b) Multifractal spectrum based on LPCA (c). Mass index function vs. statistical moment based on LPCA. (d) Generalized fractal dimension vs. statistical moment based on LPNA. (e) Multifractal spectrum based on LPNA (f). Mass index function vs. statistical moment based on LPNA.

The Hurst is commonly used to characterize pore connectivity in porous media, with lower values indicating poorer connectivity [74]. In the Lower Cambrian shales, H values for non-micropores range from 0.989 to 0.999 (avg. 0.995), significantly higher than those of micropores (0.970–0.987; avg. 0.983) (Table S2). This indicates that non-micropore systems generally exhibit better connectivity than micropores across all sedimentary facies (Figure 12a), consistent with previous studies [27]. Micropore connectivity varies

markedly among sedimentary facies. Shallow shales display H values of 0.970–0.983, deep shales 0.968–0.983, and slope facies shales the highest values of 0.983–0.987, suggesting more favorable micropore connectivity in slope facies (Figure 12a). This enhancement may reflect the higher TOC and more effective pore preservation in slope facies. Nevertheless, micropore connectivity in the Lower Cambrian shales remains generally lower than that reported for the Bakken Formation [36]. For non-micropores, H values are comparable between deep shelf and slope facies shales, and both are higher than those in shallow shelf shales (Figure 12a), indicating relatively better connectivity in deeper-water facies.

The $\Delta\alpha$ provides a quantitative measure of pore structure heterogeneity, reflecting the dispersion of pore size distributions, with larger values indicating stronger heterogeneity [18,36,51]. In the Lower Cambrian shales, $\Delta\alpha$ values for micropores range from 0.741 to 0.928 (avg. 0.838), significantly higher than those for non-micropores (0.069–0.295; avg. 0.178) (Table S1), indicating that micropore systems are substantially more heterogeneous. Among different sedimentary facies, micropore $\Delta\alpha$ values in slope facies shales are lower than those in both shallow and deep shelf shales (Figure 12b), suggesting reduced heterogeneity in slope facies. This pattern is likely related to improved pore connectivity, which tends to homogenize pore systems [27,75]. Deep shelf shales exhibit slightly higher $\Delta\alpha$ values than slope facies shales and markedly higher values than shallow shelf shales (Figure 12b), indicating more heterogeneous pore size distributions in deeper-water environments.

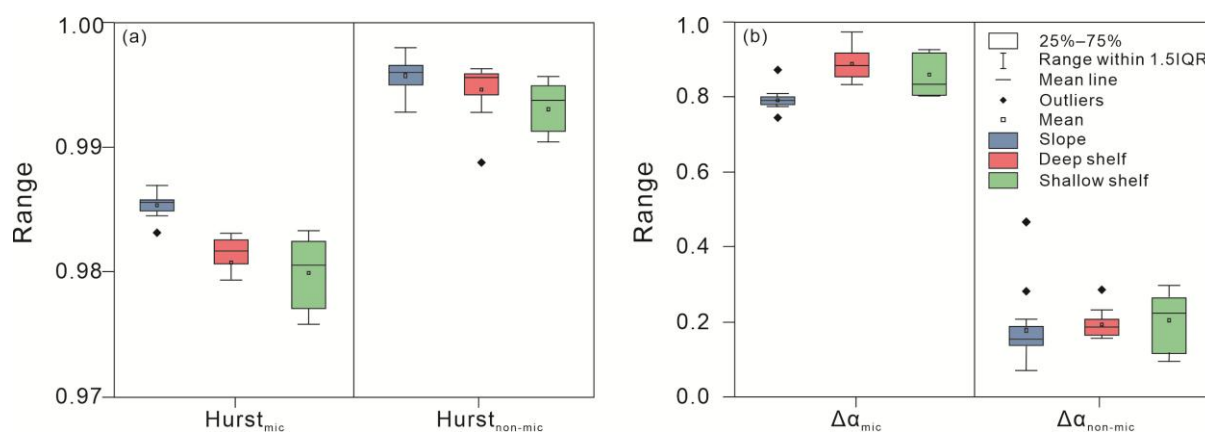


Figure 12. Range of pore connectivity and heterogeneity of Lower Cambrian shale samples (a) Hurst value of Lower Cambrian shale samples; (b) $\Delta\alpha$ of Lower Cambrian shale samples. See Figure 2 for the legend.

Correlations between pore volume, heterogeneity, and connectivity are shown in Figure 13. For micropores, increasing pore volume is associated with a marked decrease in heterogeneity (Figure 13a) and a corresponding increase in connectivity (Figure 13b). This relationship suggests that the growth of micropore volume promotes the development of interconnected pore networks, thereby enhancing connectivity while reducing structural heterogeneity [23]. A similar but less systematic trend is observed for non-micropores. With increasing non-micropore volume, heterogeneity generally decreases (Figure 13c), whereas connectivity increases (Figure 13d). However, some samples exhibit anomalous behavior, likely reflecting mixed pore origins, such as the coexistence of organic pores and dissolution pores within carbonate minerals. In such cases, relatively large pore volumes do not necessarily translate into improved connectivity, and heterogeneity may remain high. Overall, pore volume exerts a first-order control on both pore connectivity and heterogeneity. Given that TOC is the dominant factor controlling pore structure development in Lower Cambrian shales, its influence on pore heterogeneity and connectivity is further examined. As shown in Figure 14, TOC exerts a systematic control on micropore structure

across all sedimentary facies. Micropore heterogeneity decreases with increasing TOC (Figure 14a), whereas connectivity increases (Figure 14b). This trend reflects the strong positive relationship between TOC and micropore volume and surface area (Figure 7a,b), which promotes the development of more uniform and better-connected pore networks. In contrast, non-micropores show a non-linear response to TOC. Heterogeneity initially decreases and then increases with TOC (Figure 14c), while connectivity first improves and subsequently declines (Figure 14d), with an inflection point at ~4–6% TOC. This threshold coincides with the transition observed in non-micropore volume trends, indicating that excessive OM may enhance compaction and reduce the effectiveness of larger pore systems.

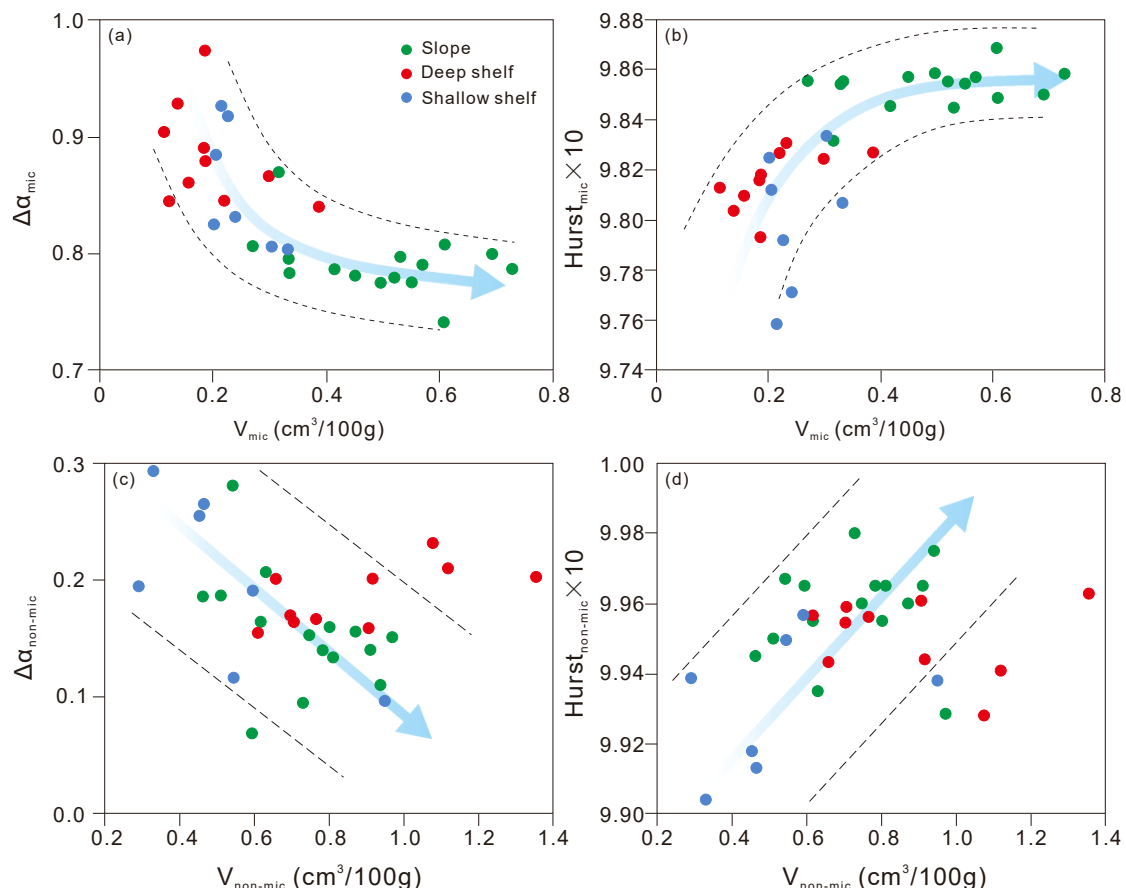


Figure 13. Plots showing relationships of pore volume with pore heterogeneity and connectivity for the studied shale samples. (a) Micropore $\Delta\alpha$ vs. micropore volume; (b) micropore Hurst vs. micropore volume; (c) non-micropore $\Delta\alpha$ vs. non-micropore volume; (d) non-micropore Hurst vs. non-micropore volume.

The dominant control of TOC on pore structure, heterogeneity, and connectivity indicates that OM abundance not only governs storage capacity through micropore development, but also indirectly regulates gas flow by influencing pore network connectivity. In particular, the positive relationship between TOC and micropore volume (Figure 7a), coupled with reduced heterogeneity and enhanced connectivity at higher TOC levels (Figure 14a,b), suggests that organic-rich intervals represent favorable targets for gas storage. However, the non-linear response of non-micropore systems to TOC highlights a critical threshold (~4–6%), beyond which excessive OM may promote compaction and reduce effective pore connectivity. This finding implies that optimal shale gas reservoirs are not necessarily associated with the highest TOC, but rather with moderate to high TOC levels that balance pore preservation and connectivity.

Slope and deep shelf facies exhibit more favorable pore systems, characterized by higher micropore volumes, improved connectivity, and lower heterogeneity compared to shallow shelf facies. These characteristics indicate that deeper-water depositional environments are more conducive to the development of effective shale gas reservoirs. Exploration of Lower Cambrian shale gas should preferentially target deep shelf and slope facies with TOC values of ~4–6%. At this range, these facies exhibit optimal pore volume, moderate siliceous content, enhanced pore connectivity, and reduced heterogeneity, collectively representing the most favorable conditions for high-quality shale reservoir development.

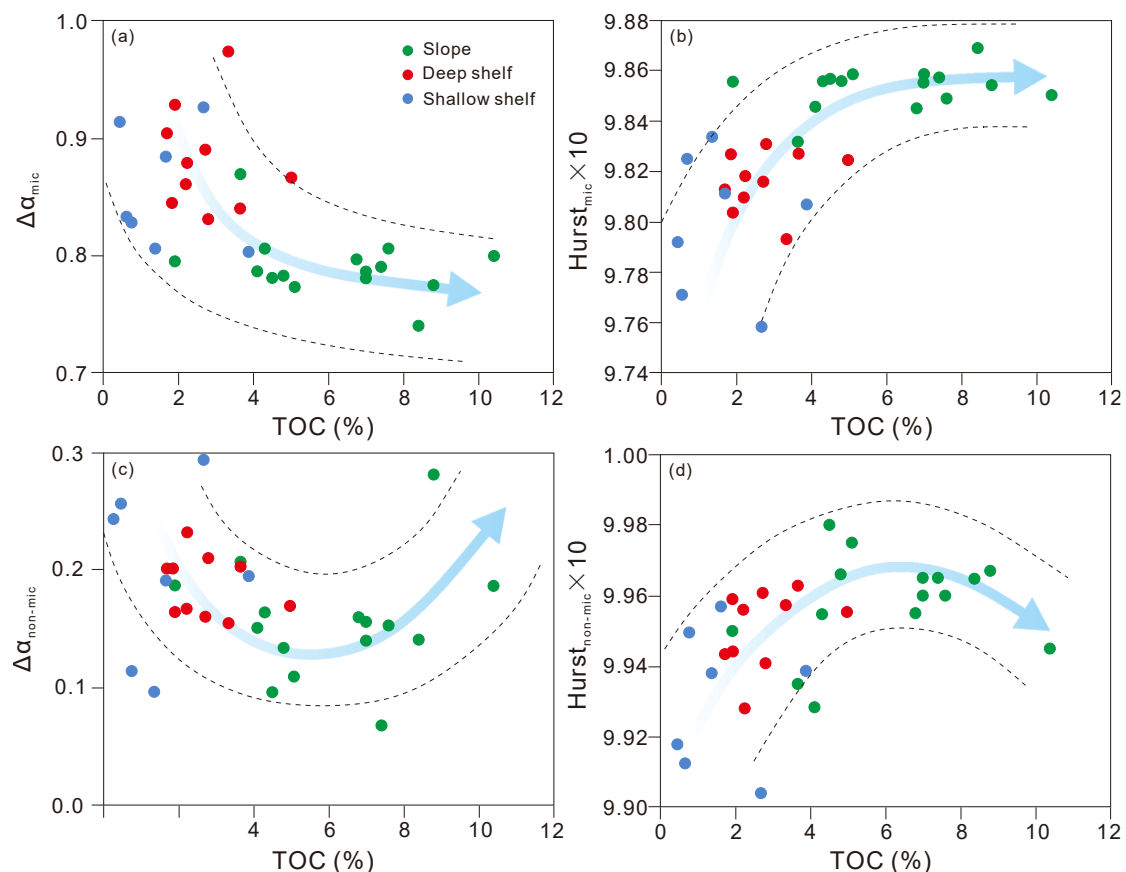


Figure 14. Plots showing relationships of TOC with pore heterogeneity and heterogeneity for the studied shale samples. (a) Micropore $\Delta\alpha$ vs. TOC; (b) micropore Hurst vs. TOC; (c) non-micropore $\Delta\alpha$ vs. non-micropore volume; (d) non-micropore Hurst vs. non-micropore volume.

5.3. Limitations

Although this study reveals how the sedimentary environment influences shale reservoir pore structure by controlling organic matter content, several limitations remain. First, the number of samples from each sedimentary facies is limited and uneven. Whether the current sample size adequately represents the overall pore structure of each facies requires further validation. Future work should include more samples to ensure statistical representativeness. Second, during pore structure measurement, the potential influence of microcracks on pore parameters (especially non-micropore volume) is difficult to eliminate. Additional characterization methods (e.g., CT, SANS) should be integrated in future studies to more accurately constrain the pore structure. Third, thermal maturity is a key factor controlling pore development. Although we selected samples with as similar maturity as possible, some differences still exist among the three facies, which may affect our results. Subsequent studies should use samples with more tightly matched maturity to address this limitation.

6. Conclusions

(1) Pore systems in Lower Cambrian shales across different sedimentary facies are dominated by organic pores, but their morphologies vary significantly. Deep shelf shales contain abundant, uniformly distributed bubble-like organic pores, whereas slope facies shales exhibit fewer pores, mainly concentrated within OM interiors. In contrast, shallow shelf shales show only sparse and poorly developed organic pores.

(2) TOC is the primary control on pore structure. Micropore volume and SSAs increase consistently with TOC, with slope facies shales exhibiting the highest values due to elevated TOC. In contrast, non-micropore parameters show a non-linear response, peaking at TOC values of ~4–6%, with deep shelf shales displaying the highest non-micropore development at moderate TOC levels.

(3) Mineral composition exerts facies-dependent controls on pore development. Quartz primarily influences pore structure indirectly by correlating with TOC and forming rigid frameworks that preserve organic pores. Clay minerals promote micropore development through their intrinsic porosity and association with OM. Carbonate minerals generally inhibit micropore development via dilution and cementation, but can enhance non-micropore volume through dissolution-related intraparticle pores.

(4) TOC governs pore connectivity and heterogeneity through its control on pore volume. Micropore connectivity increases and heterogeneity decreases with increasing TOC, whereas non-micropores exhibit a non-linear response, with connectivity first increasing and then decreasing at TOC values of ~4–6%. Shales deposited in deep shelf and slope facies with TOC of ~4–6% exhibit optimal pore volume, high connectivity, and relatively low heterogeneity. From the perspective of pore structure, these intervals represent the most favorable intervals for a high-quality shale reservoir.

Supplementary Materials: The following supporting information can be downloaded at: <https://www.mdpi.com/article/10.3390/fractalfract10070432/s1>, Table S1: Basic information, TOC content, and mineralogical composition of the studied shale samples; Table S2: Calculation of multifractal singular spectrum of Lower Cambrian shale samples from different sedimentary facies in Yangtze Block.

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