

Article

Multi-Lithologic Combination Shale Oil Composite Fluid Fracturing Experimental Study on Crack Propagation Law

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Abstract

This study addresses the poorly understood fracture propagation mechanisms in continental shale oil reservoirs with multi-lithologic combinations, specifically those in the lower third member of the Shahejie Formation, Bonan Sag, which exhibit complex lithology, coexistence of bedding planes and natural fractures, and pronounced mechanical anisotropy. We conduct small scale true triaxial hydraulic fracturing physical simulation experiments using limestone mudstone, felsic–lime mixed shale, and their combined rock samples. We innovatively introduce the hydraulic fracture complexity coefficient (F_h), the bedding plane fracture complexity coefficient (F_l), and the comprehensive fracture complexity coefficient (F_T) to enable quantitative evaluation of fracture complexity. The results show that high-viscosity fracturing fluid promotes vertical propagation and improves proppant placement, but yields relatively simple fracture geometry. Low-viscosity fracturing fluid readily activates bedding plane fractures, yet limits fracture height; a combined viscosity strategy can synergistically optimize the overall fracturing performance. The “high–low–high” viscosity sequence achieves the highest comprehensive fracture complexity coefficient (F_T), simultaneously providing large fracture height, high complexity, and effective proppant transport. Although increasing the injection rate significantly reduces the breakdown pressure and increases fracture width, it contributes marginally to vertical fracture growth. For fracturing multi-lithologic shale oil reservoirs, the recommended technical strategy is a “high–low–high” viscosity sequence combined with a moderately increased injection rate” to maximize the stimulated reservoir volume and overall fracturing effectiveness.

Keywords: multi-lithologic combination; lamina; fracture network complexity; composite fluid; physical simulation



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1. Introduction

As the global energy transition accelerates and the exploitation of conventional oil and gas resources becomes increasingly challenging, shale oil—an essential component of unconventional resources—has emerged as a strategic priority for national energy security [1]. Continental shale oil reservoirs in China are geologically characterized by complex multi-lithologic combinations, coexistence of bedding planes and natural fractures, and pronounced mechanical anisotropy. Effective development of these reservoirs critically depends on the adaptive advancement of hydraulic fracturing technology [2]. Compared with multi-cluster fracturing in horizontal wells, vertical well fracturing retains distinctive

advantages in thin interbedded shale oil reservoirs: on the one hand, it can exploit naturally fractured zones to achieve reservoir stimulation volume; on the other hand, it can generate complex fracture networks through high inject rate, thereby reducing both drilling costs and operational risks [3].

Bedding is a defining characteristic of shale formations, and the fracture toughness of bedding planes is typically lower than that of the rock matrix [4]. The interaction between a hydraulic fracture and a bedding plane can result in three modes: crossing, deflection, and arrest [5,6]. Propagation behavior is controlled by bedding plane continuity, thickness, and bonding strength: continuous bedding planes offer the least resistance, whereas discontinuous bedding planes tend to arrest fracture propagation. Thick bedding planes increase the likelihood of fluid leak and fracture diversion; strong bonding promotes fracture crossing, whereas weak bonding facilitates layer delimited growth [7,8]. The type of lamination significantly affects the extent of fracture propagation; laminated mixed shale exhibits the largest fracture area, whereas massive shale shows the smallest [9]. In sand shale interbedded reservoirs, low stress contrast and low dip angles favor bedding plane opening, while high stress contrast and high dip angles promote vertical fracture propagation [10].

Hydraulic fracture propagation in layered strata occurs primarily via tensile failure and shear slip [11]. Weak bedding plane bonding exerts limited inhibition on fracture propagation parallel to bedding but strongly suppresses vertical propagation [12], leading to fractures that exhibit vertical-growth, bedding-plane-confined, or composite propagation modes [13,14]. During the initiation stage, rock properties govern the initiation and propagation behavior [15]; during the propagation stage, irregular pressure fluctuations on the pump pressure curve serve as a diagnostic signature of volume fracturing. Branching, deflection, and communication with natural fractures along bedding planes are critical for fracture network formation [11]. The interaction between hydraulic fractures and natural fractures also encompasses three modes: crossing, propagation along the fracture, and arrest [16,17]. The outcome depends on the approaching angle, stress contrast, and mechanical properties of the natural fractures. High stress contrast and large approaching angles favor direct crossing of natural fractures [18].

A core challenge in hydraulic fracturing of multi-lithologic reservoirs is the inherent complexity of fracture propagation. Discontinuities such as bedding planes, lithologic interfaces, and natural fractures readily induce fracture vertical growth, deflection, or arrest [7,19]. Heng et al. employed a true triaxial geomechanical model testing system, servo controlled pump pressure system, acoustic emission source location, and industrial CT scanning to develop a large-scale physical simulation methodology for shale hydraulic fracturing. Their experiments demonstrated that bedding-plane development, pump pressure, and in situ stress state significantly influence fracture morphology [11]. Guo et al. utilized a true triaxial system to simulate fracturing of shale outcrop horizontal wells, combined with high-energy CT imaging to observe fracture geometry [20]. Chai et al. conducted true triaxial fracturing experiments on cement-encased full-diameter cores [19], while Tan et al. identified five fundamental propagation modes of hydraulic fractures in laminated shale through large-scale triaxial testing [13]. Using a large-scale true triaxial hydraulic fracturing physical simulation system, the effects of injection rate, fluid viscosity, stress contrast, and lithologic interface strength on vertical fracture propagation were systematically investigated using multi-lithologic combination samples with embedded bedding planes and natural fractures [3,21,22]. Chen et al. established the critical conditions for fracture penetration based on the energy release rate [23], and Ma et al. elucidated the influence of in situ stress, lithologic strength contrast, and interface strength on fracture propagation trajectories in coal-bearing strata [24]. Microseismic monitoring is widely

applied for fracture geometry characterization and reservoir stimulation evaluation; the spatial distribution of microseismic events effectively identifies fracture vertical growth behavior [25–28].

Three critical gaps remain in the current literature. First, research on the controlling factors of fracture complexity during fracturing is limited, particularly the absence of systematic experimental data for multi-lithologic combinations [29]. Second, fracture complexity evaluation still relies predominantly on qualitative description, and no unified quantitative characterization approach has been established, hindering process parameter optimization and comparison [30,31]. Third, the accuracy of numerical models coupling engineering parameters with geological conditions remains insufficient, and multi-objective optimization models integrating viscosity, injection rate, and lithologic combination are still nascent [32]. Furthermore, fundamental issues such as the proppant transport behavior within complex fracture networks and the quantitative relationship between fracture complexity and productivity contribution remain unresolved [33], constraining the large-scale deployment of fracturing technology.

Accordingly, this study focuses on the multi-lithologic combination shale oil reservoir in the lower third member of the Shahejie Formation, Bonan Sag. We conduct small-scale true triaxial hydraulic fracturing physical simulation experiments to systematically investigate different fracturing fluid viscosity strategies: single viscosity fluids (10 mPa·s and 100 mPa·s) and combined viscosity sequences (low–high, high–low, low–high–low, and high–low–high). The effects of injection rate (5–20 mL/min) on fracture complexity are examined. By preparing limestone mudstone, felsic–lime mixed shale, and their combined samples, we simulate various lithologic combinations. The hydraulic fracture complexity coefficient (F_h), bedding plane fracture complexity coefficient (F_l) and comprehensive fracture complexity coefficient (F_T) are introduced to enable quantitative evaluation of fracture complexity. Integrating pressure curve characteristics with fracture morphology parameters, we elucidate the controlling mechanisms of viscosity, injection rate, and lithologic combination on fracture complexity and vertical propagation. These findings provide a theoretical foundation and experimental basis for optimizing fracturing designs in multi-lithologic shale oil reservoirs, which is of significance for promoting the efficient development of continental shale oil.

2. Multi-Lithology Combination Shale Rock Mechanics Parameter Test

The two typical lithologies of the multi-lithologic combination shale oil reservoir in the lower third member of the Shahejie Formation, Bonan Sag, are calcareous mudstone and felsic-gray mixed shale. The mineral composition of the downhole core comprises three principal components: quartz, carbonate, and clay. XRD diffraction analysis was conducted to determine mineralogical composition. The results indicate that the dominant mineral constituents of both typical lithologies are quartz and carbonate. Quartz content is higher in felsic–lime mixed shale, whereas carbonate mineral content is slightly higher in lime mudstone. Clay mineral content is comparable between both lithologies and remains at an elevated level, averaging approximately 20%. Overall, the mineral compositions of the two lithologies do not differ substantially.

Tables 1 and 2 present the triaxial compression and Brazilian tensile strength test data for two different lithologies from the lower Es3 interval. The mechanical properties differ substantially between lithologies. Young's modulus and compressive strength of felsic-gray mixed shale are higher than those of lime mudstone. Both the Young's modulus and compressive strength measured parallel to the lamina direction exceed those measured perpendicular to the lamina, indicating pronounced anisotropy. The corresponding anisotropy coefficients reach 2.0 and 1.21, respectively. The tensile strength of lime mudstone parallel

to the lamina is 7.20 MPa, whereas the tensile strength perpendicular to the lamina is 9.42 MPa, yielding an anisotropy coefficient of 1.31.

Table 1. The results of the triaxial compression test.

Number	Lithologic Characters	Direction of Coring	Core Number	Confining Pressure/MPa	Stress Difference/MPa	Elastic Modulus/GPa		Poisson Ratio		Compressive Strength/MPa	
						Value	Coefficient of Anisotropy	Value	Coefficient of Anisotropy	Value	Coefficient of Anisotropy
1	Felsic-gray mixed mud shale	Parallel	1-1-P1	30	329.81	45.53	1.40	0.228	1.02	359.81	1.14
2			1-1-P2		289.55	45.71	1.40	0.285	1.28	319.55	1.01
3			1-1-P3		297.32	44.76	1.37	0.225	1.01	327.32	1.04
4		Vertical	1-1-V		285.93	32.72		0.223		315.93	
5	Lime mudstone	Parallel	1-2-P1	30	247.33	34.67	2.01	0.232	1.02	277.33	1.22
6			1-2-P2		204.38	30.97	1.79	0.213	0.93	234.38	1.03
7			1-2-P3		247.46	37.76	2.19	0.241	1.06	277.46	1.22
8		Vertical	1-2-V		198.310	17.28		0.228		228.31	
9		Parallel	0-1		228.47	36.04	1.62	0.245	1.22	258.47	1.03
10			90-1		221.15	22.27		0.201		251.15	
11		Parallel	0-2		240.35	36.05	1.53	0.228	0.86	270.35	1.08
12		Vertical	90-2		220.37	23.53		0.264		250.37	

Table 2. Results of the tensile strength.

Lithologic Characters	Core Number	Diameter/mm	Thickness/mm	Load Direction	Breaking Load/N	Tensile Strength/MPa	Coefficient of Anisotropy
Lime mudstone	1-2-P	25.28	16.04	Parallel laminae	3050	7.20	1.31
	1-2-V	25.29	15.04	Vertical laminae	5623	9.42	

In this study, the comprehensive brittleness index evaluation method proposed by Lin et al. [34] is adopted. Based on stress–strain curves and energy evolution, and accounting for the influence of mineral composition, weights are assigned to brittle and non-brittle minerals. The results are presented in Table 3. The lower Es3 shale in Bonan Sag exhibits pronounced brittleness anisotropy; the brittleness index parallel to the lamina direction exceeds that perpendicular to the lamina, with an anisotropy coefficient of up to 1.27. The brittleness indices of the two lithologies are comparable; felsic–lime mixed shale exhibits a slightly higher brittleness index (0.47) than lime mudstone (0.44).

Table 3. Evaluation results based on the comprehensive fragility index method.

Lithologic Characters	Core Number	B ₁	B ₂	B	Coefficient of Anisotropy
Felsic-gray mixed mud shale	1-1-P1	0.824	0.682	0.510	1.27
	1-1-P2	0.824	0.643	0.491	1.22
	1-1-V	0.824	0.458	0.403	
Lime mudstone	1-2-P1	0.787	0.633	0.481	1.26
	1-2-P2	0.787	0.597	0.464	1.22
	1-2-V	0.787	0.421	0.380	
Outcrop A	2-1-P	0.920	0.828	0.612	1.20
	2-1-V	0.920	0.621	0.511	

Table 3. Cont.

Lithologic Characters	Core Number	B ₁	B ₂	B	Coefficient of Anisotropy
Outcrop B	2-2-P	0.864	0.751	0.557	1.18
	2-2-V	0.864	0.577	0.470	
Outcrop C	2-3-P	0.709	0.557	0.425	1.21
	2-3-V	0.709	0.385	0.345	

3. Physical Simulation Experiment Research on Fracturing of Multi-Lithologic Combination Shale Oil Reservoir

3.1. Experimental Design

3.1.1. Experimental Equipment

In this experiment, a small-sized true triaxial fracturing simulation experiment device [34], as shown in Figure 1, is employed. The apparatus comprises a confining pressure-loading system, a constant-rate pump system, a data-acquisition system, and auxiliary components. Key specifications are as follows: sample dimensions of 8 cm × 8 cm × 10 cm; triaxial loading along the X, Y, and Z directions according to the effective principal stress; maximum confining pressure of 50 MPa; maximum pump rate of 30 mL/min; maximum injection pressure of 60 MPa; and pressure sampling interval of 1 ms.

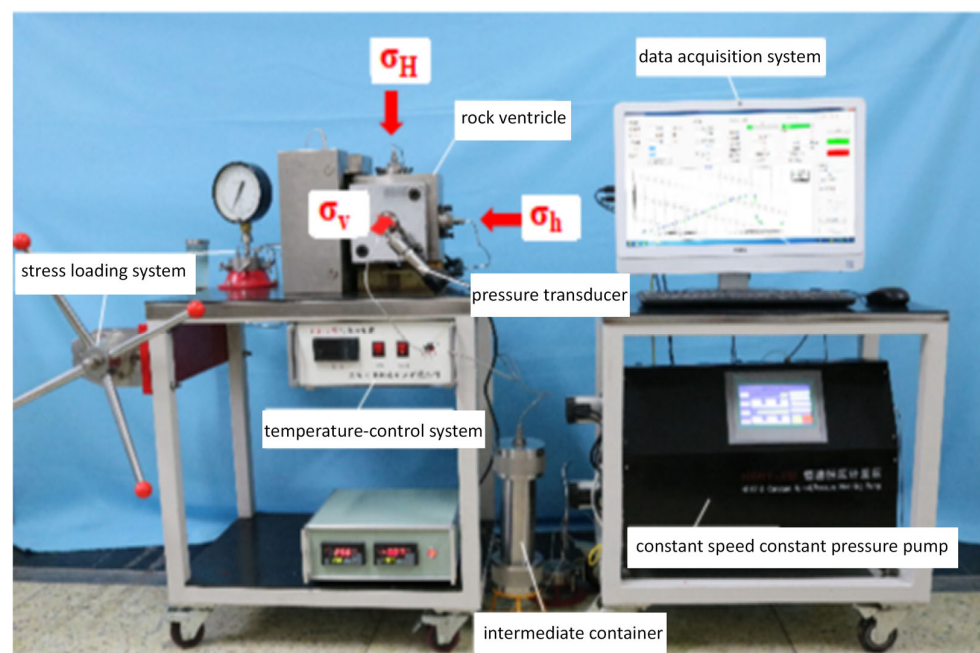


Figure 1. Small-scale true triaxial fracturing simulation experimental apparatus diagram [34].

3.1.2. Rock Sample Preparation

Based on the mechanical parameter tests and brittleness index evaluation of outcrops A, B, and C described in Section 2, the elastic and strength parameters of these three lithologies are comparable to those of the downhole core, with similar brittleness values, thereby satisfying the requirements for physical simulation of fracture propagation. Specifically, outcrop A represents felsic—lime mixed shale, outcrop C represents lime mudstone, and outcrop B whose mechanical parameters lie between those of outcrops A and C represents argillaceous limestone.

First, the three outcrop samples were cut into cubic rock plates with dimensions exceeding 8 cm according to the predetermined experimental protocol. The perforation

layer thickness was 6 cm, and the adjacent layer thickness was 2 cm. The cubic rock plates were then bonded together using epoxy resin adhesive according to the designated lithological combinations. Following a secondary adhesive application, the assembled block was trimmed to a final cubic specimen of 80 mm × 80 mm × 100 mm. A blind hole with an outer diameter of 15 mm was drilled into the 80 mm × 80 mm face of the specimen to a depth of 53 mm. A steel pipe with an outer diameter of 13 mm (simulating the wellbore) was subsequently fixed in the borehole with epoxy resin adhesive to simulate the cemented casing. The specimen preparation procedure is illustrated in Figure 2.

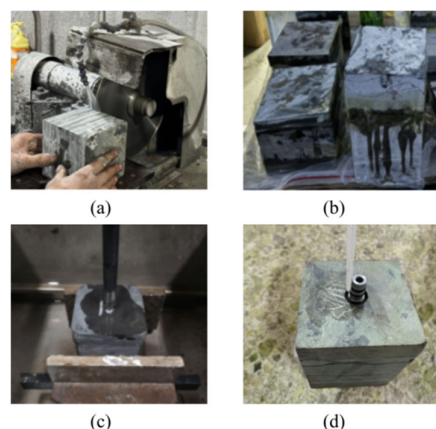


Figure 2. Processing process of core sample: (a) outcrop sample cutting; (b) bonding of different lithology; (c) drilling borehole; (d) well cementation.

The drilling depth is 53 mm, the wellbore length is 43 mm, and a 10 mm open hole section is formed at the bottom of the well. Epoxy resin glue is dripped into the bottom of the well before cementing to prevent cracks from starting from the bottom of the well, and a slit simulation perforation is formed by annular cutting in the open hole section. The depth of the slit is 2–3 mm, and finally a fracturing simulation well sample is formed, as shown in Figure 3.

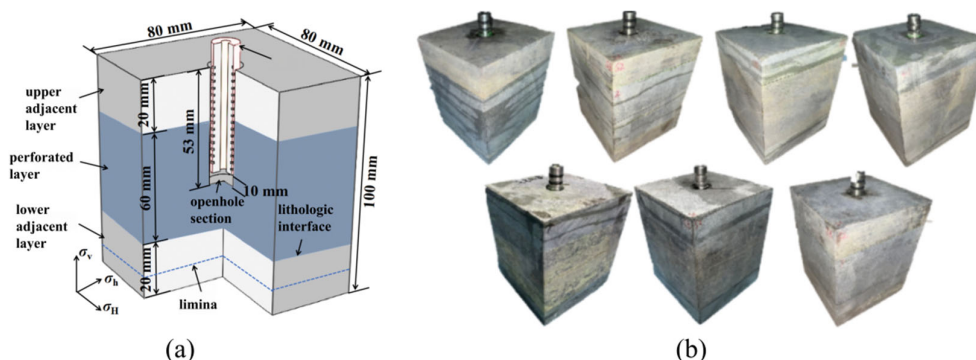


Figure 3. Schematic diagram of rock sample processing: (a) straight well sample processing schematic diagram; (b) fracturing sample.

Due to the limitation of indoor laboratory conditions, the experimental parameter setting mainly refers to the conversion method of field-experiment similarity criterion by Andrew et al. [35].

(1) In-situ stress similarity criterion:

$$R = \frac{\sigma_H - \sigma_h}{\sigma_v - \sigma_h} \quad (1)$$

$$\left(\frac{\sigma'_H}{\sigma'_v} \right)_M = \left(\frac{\sigma'_H}{\sigma'_v} \right)_F, \left(\frac{\sigma'_h}{\sigma'_v} \right)_M = \left(\frac{\sigma'_h}{\sigma'_v} \right)_F \quad (2)$$

In the formula, R is the shape factor, and the laboratory scale is the same as the field scale. σ is principal stress, MPa; σ' is the effective principal stress, $\sigma' = \sigma - p_p$, MPa; p_p is pore pressure, MPa; H, h, v are the maximum horizontal direction, minimum horizontal direction and the vertical direction respectively. M is the laboratory parameter; F is the field parameter.

(2) Similarity criterion of fracturing fluid viscosity and injection rate:

$$\mu_M Q_M = \alpha \mu_F Q_F \left(\frac{E'_F}{E'_M} \right)^3 \left(\frac{K_M}{K_F} \right)^4 \left(\frac{R'_{Mmax}}{R'_{Fmax}} \right) \quad (3)$$

In the formula, μ is the viscosity of fracturing fluid, mPa·s; Q is the injection rate, m³/min, α is the empirical coefficient and this experiment is about 0.85; E' is the plane strain Young's modulus, $E' = \frac{E}{1-\nu^2}$, GPa; ν is Poisson's ratio; K is fracture toughness, MPa·m^{1/2}; and R' is the characteristic radius of fracture, m.

The comparison of field and indoor parameters is shown in Table 4.

Table 4. Comparison of on-site and indoor parameters.

Parameter	On-Site Parameter Values	Experimental Parameter Values
Young's modulus (GPa)	24.2	12–36
Fracture toughness (MPa·m ^{1/2})	3.6	1.54
Fracture characteristic radius (m)	15–32	0.05
Single cluster displacement (m ³ /min)	3–4	5–10 (mL/min)
Fracturing fluid viscosity (mPa·s)	50–70	10–100
Cluster spacing (m)	15–22	6–12 mm

Vertical stress σ_v is consistent with the direction of the wellbore axis, and the minimum horizontal principal stress σ_h and the maximum horizontal principal stress σ_H are perpendicular to the wellbore axis. In order to observe the morphology of hydraulic fractures, the fracturing fluid with a green fluorescent tracer was used to simulate the fracture propagation. During the experiment, the constant-speed constant-pressure pump is used to inject the fracturing fluid from the intermediate container into the simulated wellbore with a constant flow rate. At the same time, the wellhead pressure is dynamically monitored by a high-precision pressure sensor, and the data is transmitted to the computer in real time. When the wellhead pressure decreases rapidly and does not rise again, it indicates that the hydraulic fracture has initiated and extended to the surface of the sample, and the pump is stopped. After the experiment, the samples are taken out, and the fracture initiation and propagation characteristics were analyzed by the staining distribution of the tracer and the wellhead injection pressure curve.

3.1.3. Experimental Scheme

To more intuitively observe fracture propagation and facilitate the investigation of fracture morphology—including fracture length, width, and height—physical simulation experiments were conducted on vertical wellbores using small-scale outcrop cores. The opening conditions of bedding planes and lithologic interfaces were analyzed, and the effects of fracturing fluid viscosity (single and combined), injection rate, and other engineering parameters on vertical fracture propagation, fracture complexity, fracture width, and proppant placement were systematically investigated.

According to the method of layered paste, the wells are combined with three different lithologic combinations of cores, a total of seven blocks. Different lithology combinations are shown in Figure 4.

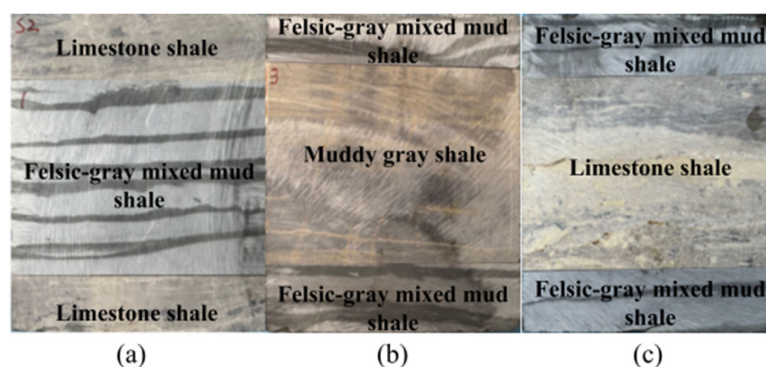


Figure 4. Different lithology combination methods: (a) lithologic combination 1: limestone shale and felsic-gray mixed mud shale; (b) lithologic combination 2: felsic-gray mixed mud shale and muddy gray shale; (c) lithologic combination 3: felsic-gray mixed mud shale and limestone shale.

The simulation experiment scheme of core fracturing with different lithologic combinations is shown in Table 5. The experiment focuses on the effect of fracturing fluid viscosity and combination, displacement, and proppant particle size on artificial fractures and their layers/interfaces and interlayers, and analyzes the opening conditions of layers/interfaces, fracture propagation and main control factors.

Table 5. Experimental scheme for small-scale model.

Number	Lithologic Characters	Sample Characteristics	Fracturing Fluid Type	Experimental Displacement (mL/min)	Proppant	Experiment Purpose
1 [#]	Lithology 1	Dense development of laminae	High-viscosity fracturing fluid (100 mPa·s)	5	400–600 mesh	Clarified the effect of fracturing fluid viscosity on lamina opening.
2 [#]	Lithology 1	Dense development of laminae	Low-viscosity fracturing fluid (10 mPa·s)	5	400–600 mesh	
3 [#]	Lithology 2	Laminate + fracture	High–low-viscosity fracturing fluid (100–10 mPa·s)	5	200–300 mesh	Clarified the influence of different fracturing fluid viscosity combinations on fracture morphology
4 [#]	Lithology 2	Laminate + fracture	High–low–high-viscosity fracturing fluid (100–10–100 mPa·s)	5	200–300 mesh	
5 [#]	Lithology 3	Layer + interlayer	Low–high-viscosity fracturing fluid (10–100 mPa·s)	5	200–300 mesh	
6 [#]	Lithology 3	Laminate + crack + interlayer	Low–high–low-viscosity fracturing fluid (10–100–10 mPa·s)	5	200–300 mesh	Clarified the influence of displacement on fracture morphology
7 [#]	Lithology 1	Dense development of laminae	Low-viscosity fracturing fluid (10 mPa·s)	20	200–300 mesh	

3.1.4. Limitations of Artificial Bonding Interfaces and Effect of Boundary-Induced Stress

The scaling effect issue in laboratory hydraulic fracturing studies has been extensively discussed. Athavale and Miskimins [36] noted the significant scale disparity between

centimeter-scale laboratory specimens and meter-scale field fractures, wherein boundary effects can markedly alter the fracture propagation path. To address this issue, Warpin-ski et al. [37] established a dimensionless similarity criterion system based on stress ratio and fluid parameters, providing a theoretical foundation for extrapolating laboratory re-sults to the field. From the perspective of rock fracture mechanics, Bažant's [38] brittle fracture scaling law theory indicates that when the characteristic specimen size is compa-rable to the fracture-process-zone (FPZ) scale, Linear Elastic Fracture Mechanics (LEFM) is no longer applicable, and the nominal strength exhibits pronounced size dependence. Li et al. [39] further confirmed through investigations on Marcellus shale that the apparent fracture toughness of shale increases with specimen size until a stable value is reached. Qiu et al. [40] demonstrated through stress transfer studies that, in small-scale specimens, boundary constraints cause significant deviation of the internal stress field from the in-finite body assumption. Hyman et al. [41] systematically described, from a multi-scale perspective, the coupled factors involved in upscaling parameters from the core scale to the reservoir scale, including pore structure, fracture connectivity, and stress field heterogeneity. Fu et al. [42] proposed an energy-equivalence-based upscaling method for fracture swarms, providing a numerical framework for translating laboratory results to field applications. It should be noted that the above criteria are primarily applicable to homogeneous media, whereas the presence of bedding interfaces and lithology interfaces in multi-lithology composite shale exacerbates the complexity of scaling effects [13,43]. Dehghan showed that the interaction between natural fractures and hydraulic fractures exhibits stronger nonlinear characteristics in small-scale specimens, as boundary effects alter the degree of anisotropy of the local stress field. [44] Given the experimental constraints and the absence of a validated quantitative methodology for assessing boundary effects, it is essential to ex-plicitly define the conditions under which laboratory findings may be reliably extrapolated to field applications.

The equivalence between epoxy-resin-bonded multi-lithologic specimens and natural reservoir interfaces remains inadequately demonstrated. Wang et al. showed that the shear strength and frictional properties of cemented interfaces determine hydraulic fracture cross-ing, dilation, or arrest behavior, which artificial bonding layers with uniform mechanical properties cannot replicate [17]. Sheng et al. confirmed that bedding plane shear strength correlates strongly with bonding strength, indicating that artificially bonded interfaces lacking natural diagenetic cementation may exhibit unrealistic mechanical responses [45]. Bakhshi et al. demonstrated via lattice simulations that interface shear strength and stress anisotropy govern fracture crossing, parameters inherently difficult to match with artifi-cial bonding agents [46]. Lin et al. observed that bonding strength significantly controls hydraulic fracture vertical propagation, implying that uncharacterized artificial interfaces are insufficient proxies for natural laminae [47]. Rutter and Mecklenburgh measured stress-dependent permeability evolution in natural shale bedding planes governed by surface roughness and asperity contact mechanics, features that smooth artificial bonding layers cannot reproduce [48]. Chen et al. further showed that tensile strength contrast across cemented interfaces determines the competition between debonding and matrix fracture, suggesting artificial interfaces may alter the dominant failure mode [49]. Zoback emphasized that the frictional resistance and permeability of pre-existing discontinuities are fundamental to hydraulic fracture containment, yet artificial interfaces rarely exhibit equivalent frictional stability characteristics [50]. Xian et al. acknowledged that epoxy resin interfaces exhibit substantially different bonding characteristics from natural diagenetic cementation, potentially leading to misestimated fracture heights [51]. Shan et al. and Huang and Liu both identified bedding plane tensile strength relative to the rock matrix as the dominant factor controlling fracture vertical containment and crossing versus ar-

rest behavior [52,53]. Collectively, these studies indicate that artificial bonding interfaces may substantially distort fracture propagation trajectories, misrepresent failure mode competition, and compromise the representativeness of laboratory-derived conclusions for field-scale applications.

In conclusion, due to the influence of scale effects and adhesion interfaces, we will carefully elaborate the applicable conditions for extrapolating laboratory conclusions to the field.

3.2. Effect of Viscosity and Combination of Fracturing Fluid on Fracture Distribution

Fracturing fluid viscosity is a critical parameter that significantly influences fracture propagation, fluid loss control, and treating pressure.

(1) The effect of low-viscosity and high-viscosity fracturing fluid on fracture propagation.

The lithology of the perforation layer of 1[#] and 2[#] samples is felsic-gray mixed mud shale, and the lithology of the upper and lower adjacent layers is gray mudstone. The displacement of the pre-flush stage and the sand-carrying fluid stage is set to 5 mL/min. Under the condition of low viscosity (10 mPa·s), the fracture morphology and pressure curve of 1[#] sample are shown in Figure 5. The breakdown pressure of the sample is 21.45 MPa, forming two longitudinal hydraulic fractures. The upper fracture is arrested at the interlayer interface, and the lower fracture activates two bedding-plane fractures and is arrested at the laminae. The fracture height is limited, at only 5.5 cm. The fracture morphology and pressure curve under the condition of high viscosity (100 mPa·s) of 2[#] sample are shown in Figure 6, and the fracture pressure of the sample is 38.97 MPa, forming two longitudinal hydraulic fractures. The crack penetrates through the specimen, propagates through the layer, and the crack height is 10 cm.

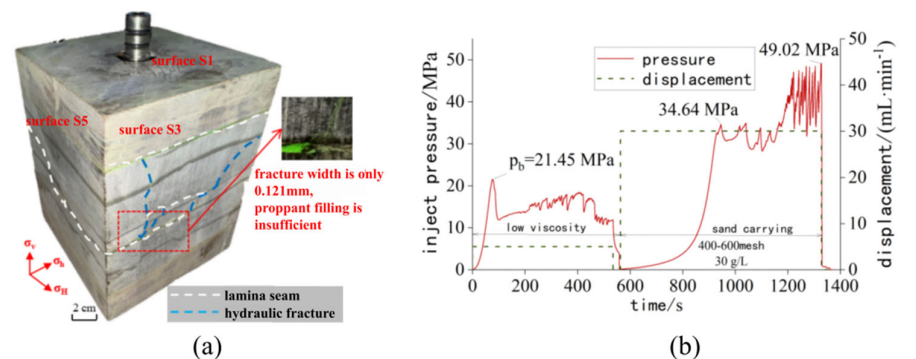


Figure 5. Pressure curve and fracture morphology of sample 1[#]: (a) fracture geometry; (b) pressure curve.

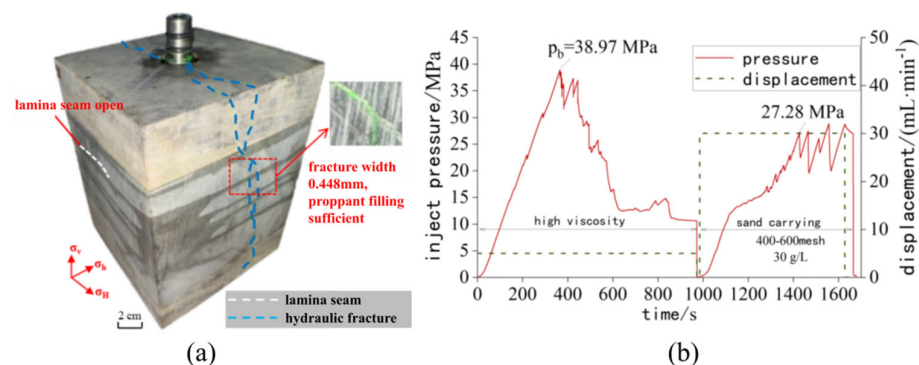


Figure 6. Pressure curve and fracture morphology of sample 2[#]: (a) fracture geometry; (b) pressure curve.

It is found that the use of high-viscosity fracturing fluid can significantly increase the fracture pressure. When the viscosity of fracturing fluid increases from 10 mPa·s to 100 mPa·s (corresponding to low and high viscosity in the field), the fracture pressure increases by 1.73 times. At the same time, the effect of high-viscosity fracturing fluid on increasing fracture width is also very significant. As shown in Figure 6a, the slit width of 2[#] sample is 0.448 mm, and the proppant filling effect is better, while the slit width of 1[#] sample is only 0.121 mm, and the proppant is almost invisible, as shown in Figure 5a. The pressure curve also shows that in the pre-liquid stage, the 2[#] sample reaches a large reduction after reaching the fracture pressure, reaching 25.15 MPa, indicating that the sample is completely broken, and the crack width is large, while the extension pressure curve is less undulating, indicating that the crack is relatively straight. On the contrary, the extension pressure of 1[#] sample fluctuates violently, indicating that the crack width is narrower, and the crack is more tortuous.

The experiment shows that high-viscosity fracturing fluid can reduce fluid leak-off, which facilitates hydraulic fracture extension and enhances vertical growth. However, under high-viscosity conditions, the hydraulic fracture tends not to open bedding planes, resulting in relatively simple fracture geometry. Although low-viscosity fluid readily communicates with laminae, it is more likely to be arrested by interlayer interfaces and bedding planes. Therefore, it is necessary to investigate the effects of various fracturing fluid viscosity combinations (high–low, high–low–high, low–high, and low–high–low) on fracture propagation morphology to improve stimulation effectiveness.

- (2) The effect of high–low-viscosity and high–low–high-viscosity combination fracturing fluid on fracture propagation.

The lithology of the perforation layer of 3[#] and 4[#] samples is argillaceous limestone, and the lithology of the upper and lower adjacent layers is felsic-gray mixed mud shale. The displacement of the pre-flush stage and the sand-carrying fluid stage is set to 5 mL/min and 30 mL/min, respectively. The 3[#] sample was fractured by the high–low viscosity combination (100–10 mPa·s), as shown in Figure 7. In the high-viscosity stage, the fracture pressure is 25.17 MPa, and the artificial fracture propagates through the natural fracture. After the upper and lower parts pass through the interlayer interface, they are cut off by the lamina and fail to penetrate the sample. The fracture height is 7.8 cm. In the low viscosity stage, there is no extension in the longitudinal direction of the crack, but two stripe layer cracks are opened, and two natural cracks are activated. At the same time, the interlayer interface is opened, and the crack complexity is obviously improved, which is consistent with the previous research results. The 4[#] sample was fractured by the high–low–high viscosity combination (100–10–100 mPa·s), and the fracturing results are shown in Figure 8. The fracture morphology is more complex as a whole, which is in the cross shaped pattern, accompanied by branch fractures. A total of three stripe-layer fractures are opened, and two natural fractures are activated. Artificial fractures run through the sample, and the fracture height is 10 cm.

The elastic modulus of the upper and lower adjacent layers reaches 41.06 GPa. Due to this high elastic modulus, the hydraulic fracture is arrested by the laminae before reaching the specimen boundary after penetrating the interlayer interface, thereby limiting the ability of the fracture to propagate vertically through the layer, as shown in Figure 7a. The 4[#] sample continues to expand after the deflection occurs at the extension to the lamina, and finally penetrates the sample, as shown in Figure 8a. Therefore, the use of high–low–high viscosity combined fracturing fluid can further increase the fracture height while taking into account the complexity of the fracture, and the fracture height is increased by 1.28 times. At the same time, the high–low–high viscosity combination method can significantly increase the seam width to improve the proppant placement effect. The pressure-curve sand-

carrying stage also shows that when the proppant uses the same particle size concentration, the pressure of the 3[#] sample sand-carrying stage rises rapidly to 39.75 MPa in the later stage, and there is obvious sand plugging. The sand-carrying pressure of the 4[#] sample is low, the peak pressure is 23.50 MPa, and the proppant placement effect is better.

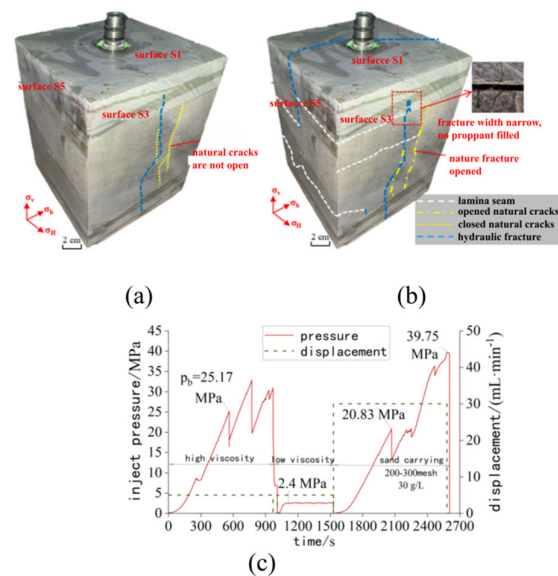


Figure 7. Pressure curve and fracture morphology of sample 3[#]: (a) fracture morphology in high-viscosity stage; (b) fracture morphology in high-low-viscosity stage; (c) pressure curve.

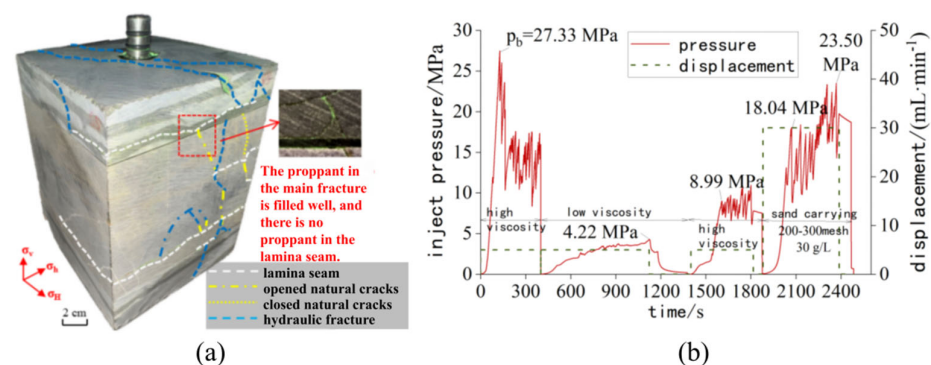


Figure 8. Pressure curve and fracture morphology of sample 4[#]: (a) fracture morphology in high-low-high-viscosity stage; (b) pressure curve.

- (3) The effect of low-high-viscosity and low-high-low-viscosity combination fracturing fluid on fracture propagation.

The lithology of the perforation layer of 5[#] and 6[#] samples is gray mudstone, and the lithology of the upper and lower adjacent layers is felsic-gray mixed mud shale. The displacement of the pre-flush stage and the sand-carrying fluid stage is set to 5 mL/min and 30 mL/min, respectively. The 5[#] sample was fractured by the low-high viscosity combination (10–100 mPa·s), as shown in Figure 9. In the low-viscosity stage, the pressure curve fluctuates frequently and rises slowly, there is no obvious fracture pressure, and the crack propagation is slow, showing the strong plastic characteristics of the sample. An artificial crack is formed, the upper part is cut off by the interlayer interface, and the lower part is cut off from the lamina. At the same time, three stripe layers are activated, and the crack height is limited, only 5.5 cm. In the high-viscosity stage, the artificial crack passes through the interface, and extends to the top of the sample after large displacement deflection. There is no obvious change in the lower part, and the crack height is 7 cm. The

6[#] sample was fractured by the low–high–low viscosity combination (10–100–10 mPa·s), and the fracturing results are shown in Figure 10. The plastic characteristics of the sample are obvious. The low-viscosity and high-viscosity fracture pressures are low, which are 6.26 MPa and 8.18 MPa respectively. Two artificial cracks are opened. The upper part of crack 1 is cut off by the lamina, and the lower part is cut off at the interface between the layers. Three stripe layers are activated to form stepped cracks. The upper part of fracture 2 is extended through the interlayer interface, and the lower part is cut off by the interlayer interface. The fracture height is 7.5 cm.

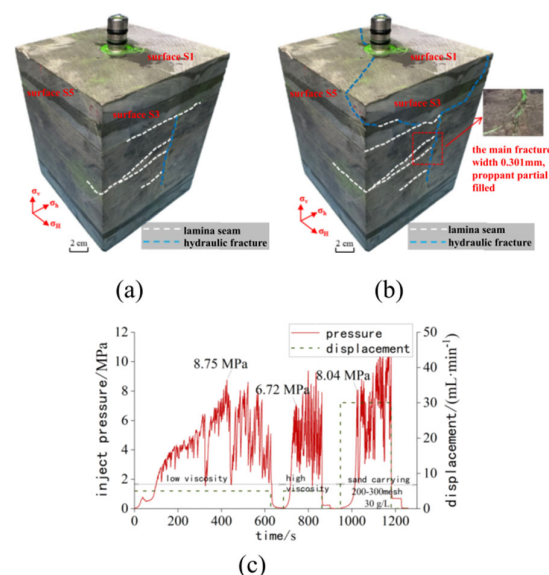


Figure 9. Pressure curve and fracture morphology of sample 5[#]: (a) fracture morphology in low-viscosity stage; (b) fracture morphology in low–high-viscosity stage; (c) pressure curve.

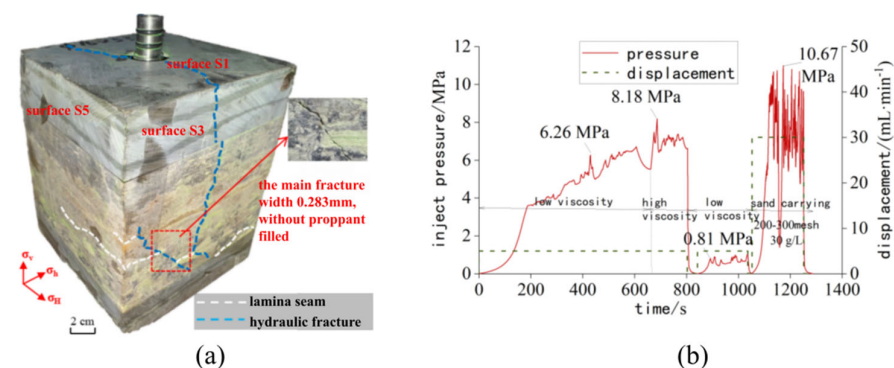


Figure 10. Pressure curve and fracture morphology of sample 6[#]: (a) fracture morphology in low–high–low-viscosity stage; (b) pressure curve.

Comparative analysis reveals that the low–high viscosity combination (10–100 mPa·s) can effectively promote both hydraulic fractures and bedding-plane fractures. The initial stage employs low-viscosity fluid, which facilitates the opening of bedding-plane fractures. The secondary stage utilizes high-viscosity fluid, significantly enhancing the vertical propagation of hydraulic fractures. The third stage reverts to low-viscosity fluid, but the stimulation effect is marginal, because after high-viscosity fracturing, the apertures of both bedding plane and hydraulic fractures increase substantially—an effect particularly pronounced in rocks with strong plastic character—whereas low-viscosity fluid exhibits high fluid leak-off and cannot readily generate pressure. The pressure curve confirms that in the third fracturing stage, the pressure is only 0.81 MPa, as shown in Figure 10b.

3.3. The Influence of Displacement on Fracture Distribution

High-rate fracturing can improve operational efficiency, promote complex fracture network formation, enhance proppant transport capacity, and increase the stimulated reservoir volume. This section investigates the influence of injection rate on fracture propagation morphology, as shown in Figures 5 and 11. The lithology of the perforation layers of 1[#] and 7[#] samples is felsic-gray mixed mud shale, and the lithology of the upper and lower adjacent layers is gray mudstone. The type of fracturing fluid is low-viscosity fracturing fluid (10 mPa·s). Under the condition of displacement of 5 mL/min, the fracture pressure of the sample is 21.45 MPa, and two longitudinal hydraulic fractures are formed. The upper part is cut off from the interlayer interface, and the lower part activates two stripe seams, which are cut off at the lamina joints. The fracture height is limited to only 5.5 cm. Under the condition of displacement of 20 mL/min, the fracture pressure of the sample is 9.12 MPa, and multiple peaks appear in the pre-stage of the fracturing curve, indicating that the multi-stripe layer is activated. The height of the artificial crack is limited, only 5.8 cm. The upper part is cut off by the lamina, and the lower part passes through the interface between the layers and extends to the bottom of the sample.

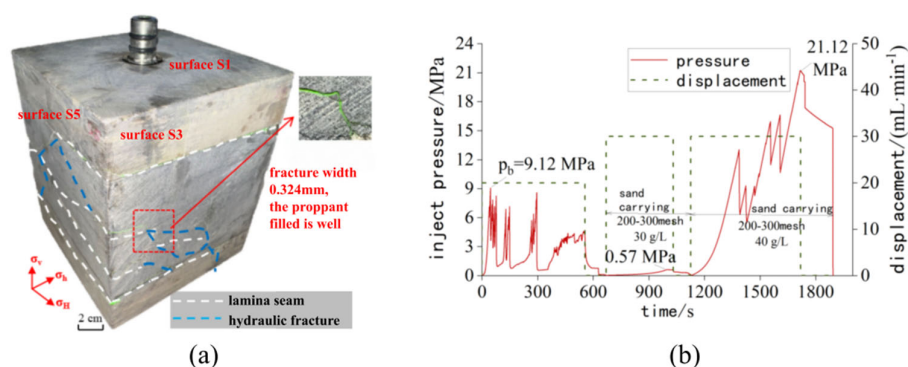


Figure 11. Pressure curve and fracture morphology of sample 7[#]: (a) fracture geometry; (b) pressure curve.

The comparison shows that the effect of hydraulic fracture vertical penetration under high injection rate is marginal. This is because under low-viscosity conditions, bedding plane fractures are readily opened. The fracturing fluid rapidly leaks off after activating numerous bedding-plane fractures, resulting in a low breakdown pressure of only 9.12 MPa and limited vertical penetration. Compared with increasing injection rate, the use of high-viscosity fracturing fluid to promote fracture height and enhance vertical penetration is more effective, although fracture width can be substantially increased at high injection rates, as shown in Figures 5a and 11a. When the injection rate is increased from 5 mL/min to 20 mL/min, the fracture width increases from 0.121 mm to 0.324 mm. The pressure curve shows that the 7[#] sample uses 200–300 mesh proppant. At a concentration of 30 g/L, the treating pressure is only 0.57 MPa. When the concentration is increased to 40 g/L, the treating pressure peak reaches 19.76 MPa. The proppant particle size of the 1[#] sample is the same. When the concentration is 30 g/L, sand plugging occurs in the later stage of sand-carrying, indicating that the high displacement has a significant effect on increasing the fracture width and the sand-carrying effect is better.

3.4. Quantitative Characterization of Fracture Complexity

In order to quantitatively analyze the influence of different fracturing fluid viscosity and combination, displacement and other factors on the complexity of cracks, the number of cracks, crack length, crack height and complexity coefficient produced by hydraulic fracturing of each sample under different experimental conditions are counted. The results

are shown in Table 6, and the relationship between the construction parameters and the complexity of the cracks is studied.

Table 6. Quantitative characterization of fracture complexity.

Number	Fracture Geometry	Number of Laminated Stitches	Number of Longitudinal Seams	Total Fracture Height (cm)	Actual Fracture Height (cm)	Total Fracture Length (cm)	Actual Fracture Length (cm)	F_l	F_h	F_h'	F_T	Dimensionless Fracture Height
1 [#]	The fracture intersects parallel bedding planes, and multiple bedding planes open.	2	2	8	7.5	12.5	7.5	0	1.125	0.582	0.444	0.92
2 [#]	Two simple hydraulic fractures form, penetrate the specimen, with no bedding-plane opening	0	2	12	8	8.2	7.5	0.500	1.045	0.389	0.291	1.67
3 [#]	Artificial fractures expand through natural fractures, and natural fractures and multi-stripped fractures open at the same time.	3	2	9	7.5	9.2	7.5	0.647	1.359	0.546	0.615	1.30
4 [#]	The multi-stripe layer opens, the main seam expands along the natural fracture and cuts off at the lower lamina. The path is tortuous, forming a complex branch seam.	3	3	9.5	7.5	11.3	7.5	0.610	1.048	0.681	0.646	1.67
5 [#]	A large number of laminae are activated, and artificial cracks propagate through laminae. The crack propagation path is stepped.	5	2	11	9.7	11.6	7.5	0.762	1.140	0.402	0.582	1.17
6 [#]	Two artificial cracks are formed. Fracture 1 communicates with multi-stripe layers. The crack propagation path is stepped. Fracture 2 penetrates the sample upwards.	3	2	10.7	8	8.0	7.5	0.689	1.402	0.438	0.564	1.25
7 [#]	The multi-stripe layer is opened, the artificial crack is cut off by the lamina, and the crack height is limited.	4	2	9	7.5	9.2	7.5	0.742	1.359	0.418	0.580	1.16

The artificial fracture complexity coefficient (F_h) is defined based on fracture tortuosity, which characterizes the deviation of the actual fracture path from an ideal straight line trajectory [13,54]. The ratio of actual path length (l_r) to linear distance (l) and the ratio of actual height (h_r) to linear height (h) are dimensionless measures widely adopted for fracture geometry characterization [55,56]. The actual fracture path is measured by tracing the visible fracture trajectory on dissected sample surfaces, while the straight line distance is measured between the initiation point and the farthest termination point [20].

The lamina fracture complexity coefficient (F_l) captures the interaction between hydraulic fractures and pre-existing bedding planes. Laminated shales exhibit strong mechanical anisotropy at bedding interfaces, where fracture toughness is significantly lower than the rock matrix [12,57]. Hydraulic fractures may cross, divert along, or be arrested by these interfaces depending on the approaching angle and stress contrast [58,59]. A higher F_l indicates enhanced lamina activation, which promotes fracture network complexity through branching mechanisms [60].

The comprehensive coefficient (F_t) uses equal weighting of F_h and F_l , following established normalization practices in fracability evaluation [61]. This formulation assumes both primary fracture tortuosity and lamina activation contribute equally to overall stimulation effectiveness. It is acknowledged that fracture complexity is multi-dimensional, ideally incorporating connectivity, aperture distribution, conductivity, and stimulated reservoir volume [55,62].

Artificial fracture complex coefficient F_h calculation formula:

$$F_h = n \times \frac{l_r}{l} \times \frac{h_r}{h} \quad (4)$$

The complex coefficient of artificial fracture is normalized to obtain F'_h :

$$F'_h = \frac{F_h}{F_{h \max}} \quad (5)$$

Laminate seam complex coefficient F_l calculation formula:

$$F_l = \frac{m}{m_{\max}} \quad (6)$$

Comprehensive fracture complex coefficient F_T calculation formula:

$$F_T = 0.5F'_h + 0.5F_l \quad (7)$$

where n denotes the number of fractures; l_r denotes the actual length of the crack, cm; l represents the straight-line length of the extension range of the seam length, cm; h_r represents the actual height of the crack, cm; h represents the linear distance of fracture height extension in the fracture, cm; m represents the number of lamina seams; f_h represents the complex coefficient of artificial fracture; f_l denotes the complexity coefficient of bedding plane; and f_T represents the comprehensive fracture complexity coefficient.

Table 6 shows the calculation results of quantitative characterization of crack complexity of seven samples. Comparing 1[#] and 2[#] samples, it is found that the complexity of artificial fractures in high-viscosity fracturing fluid is higher, reaching 0.582, while the complexity of artificial fractures in low-viscosity fracturing fluid is only 0.389, but the complexity of lamina fractures can reach 0.5. In the end, the complex coefficient of artificial fracture of high-viscosity fracturing fluid increases by 49.6% compared with that of low-viscosity fracturing fluid, and the complex coefficient of comprehensive fracture decreases by 34.5%. It can be seen that the viscosity of single-fracturing fluid cannot take into account both the effect of crossing layer and the complexity of fracture at the same time, and the fracturing effect is limited. Among the four different viscosity combinations of fracturing fluid, the complexity of artificial fractures is: 4[#] sample high–low–high-viscosity combination (0.681) > 3[#] sample high–low-viscosity combination (0.546) > 6[#] sample low–high–low-viscosity combination (0.438) ≈ 5[#] sample low–high-viscosity combination (0.408); the complexity of the lamination seam is: 5[#] sample low–high-viscosity combination (0.762) > 6[#] sample low–high–low-viscosity combination (0.689) > 3[#] high–low-viscosity combination (0.647) > 4[#] sample high–low–high-viscosity combination (0.610). The comprehensive fracture complexity is: 4[#] sample high–low–high-viscosity combination (0.646) > 3[#] sample high–low-viscosity combination (0.615) > 5[#] sample low–high-viscosity combination (0.582) > 6[#] sample low–high–low-viscosity combination (0.564).

3.5. Pressure Response Analysis

To quantitatively interpret hydraulic fracturing behavior, key pressure parameters for all seven samples are summarized in Table 7.

Table 7. Key pressure parameters for all samples.

No.	Fracturing Fluid	Pump Rate (mL/min)	Breakdown Pressure (MPa)	Treating Pressure During Proppant Injection (MPa)	Pressure Fluctuation
1 [#]	Low viscosity (10 mPa·s)	5	21.45	Sand plugging at late stage (30 g/L), no peak reported	Violent
2 [#]	High viscosity (100 mPa·s)	5	38.97	Satisfactory placement, no peak reported	Relatively smooth
3 [#]	High–low viscosity (100–10 mPa·s)	5	25.17 (high-viscosity stage)	39.75 (screen-out)	Moderate
4 [#]	High–low–high viscosity (100–10–100 mPa·s)	5	~25 (high-viscosity stage)	23.50	Moderate
5 [#]	Low–high viscosity (10–100 mPa·s)	5	Not obvious	—	Frequent (low-viscosity stage)
6 [#]	Low–high–low viscosity (10–100–10 mPa·s)	5	6.26 (low)/8.18 (high)	0.81 (third stage)	Not explicitly described
7 [#]	Low viscosity (10 mPa·s)	20	9.12	0.57 (30 g/L)/19.76 (40 g/L)	Multiple peaks (pre-breakdown)

Increasing fluid viscosity from 10 mPa·s to 100 mPa·s (1[#] → 2[#]) raises the breakdown pressure by 81.7% (21.45 → 38.97 MPa), attributable to greater viscous flow resistance near the fracture tip [11]. High pump rate reduces effective stress ahead of the fracture tip: 7[#] at 20 mL/min drops to 9.12 MPa, 57.5% lower than 1[#] [21]. The extremely low breakdown pressures of 6[#] (6.26/8.18 MPa) in plastic mudstone reflect its low Young's modulus.

The 25.15 MPa pressure drop of 2[#] corresponds to an aperture of 0.448 mm and effective proppant placement, versus 0.121 mm for 1[#]. Low-viscosity fluid experiences rapid leak off, limiting net pressure and width. Samples 3[#] and 4[#] share similar initial breakdown pressures (~25 MPa), yet diverge during proppant injection: 3[#] experiences screen-out at 39.75 MPa, while 4[#] peaks at only 23.50 MPa, indicating that the high–low–high viscosity schedule achieves superior fracture conductivity.

Violent oscillations in 1[#] correspond to tortuous paths with repeated branching and arrest at laminae. Multiple pre-breakdown peaks in 7[#] indicate sequential lamina activation, but rapid dissipation limits height (5.8 cm). Frequent fluctuations in 5[#] confirm that lamina opening dominates in plastic rock. Sample 4[#] demonstrates that switching to high-viscosity fluid after initial low-viscosity injection facilitates vertical extension.

The sharp rise to 39.75 MPa in 3[#] is definitive screen-out. Sample 4[#] avoids this via final high-viscosity widening, keeping treating pressure below 23.50 MPa. Sample 7[#] operates at 0.57 MPa (30 g/L), yet 40 g/L raises the peak to 19.76 MPa. The third stage pressure of 6[#] is merely 0.81 MPa, demonstrating that post-high-viscosity low-viscosity injection cannot build pressure due to excessive leak-off.

Breakdown pressure increases with viscosity but decreases with pump rate and plasticity. Pressure drop magnitude correlates with fracture width and inversely with lamina activation intensity. Elevated treating pressure during proppant injection indicates screen-out risk. The high–low–high-viscosity schedule (4[#], $F_T = 0.646$, height 10 cm) provides the optimal balance between complexity and proppant transport efficiency.

4. Discussion

This study systematically investigated hydraulic fracture propagation characteristics in multi-lithology combination shale oil reservoirs through small-scale true triaxial hydraulic fracturing physical simulation experiments, and proposed a quantitative complexity coefficient system for evaluating fracture complexity. However, the following limitations remain due to experimental constraints. First, the specimen dimensions (8 cm × 8 cm × 10 cm) are considerably smaller than field-scale, the boundary effects and the applicability of similarity criteria to heterogeneous layered media require further validation, and the epoxy-resin-bonded artificial interfaces cannot fully replicate the stress-dependent mechanical behaviors of natural bedding planes. Second, the total number of specimens is limited (seven samples), and replicate experiments are lacking for the optimal high–low–high-viscosity sequence and pump-rate comparison. Third, the experiments employed vertical wellbore configurations, without addressing stress interference and fracture competition inherent to horizontal-well multi-cluster fracturing. Fourth, the quantitative relationship between the comprehensive fracture complexity coefficient (F_t) and actual productivity contribution has not yet been established.

To address the above limitations, future research is recommended in the following directions: (1) Conduct large-scale physical simulations and systematically characterize the key mechanical parameters (shear strength, friction coefficient, etc.) of artificial interfaces and natural bedding planes to validate scale effects and improve the applicability of similarity criteria. (2) Conduct supplemental replicate experiments and complete the parameter matrix of pump rate and fluid viscosity to verify the reproducibility of the main findings. (3) Carry out horizontal-well multi-cluster fracturing physical simulations to investigate multi-fracture initiation, propagation, and inter-cluster competition under different lithologic combinations and injection parameters. (4) Integrate fracture complexity coefficients with reservoir numerical simulation to establish a quantitative correlation between F_t and single-well productivity, providing a basis for field-fracturing parameter optimization. (5) Develop coupled thermo-hydro-mechanical numerical models and perform joint validation with laboratory experiments and field microseismic monitoring data, forming an integrated “experiment–simulation–monitoring” research framework.

5. Conclusions

This study presents small-scale true triaxial physical simulation experiments on multi-lithology combination shale oil reservoirs from the lower Es3 member of the Bonan Sag. The effects of fracturing fluid viscosity, viscosity combination strategies, and injection rate on hydraulic fracture propagation were investigated using seven cubic samples (8 cm × 8 cm × 10 cm). The following preliminary findings are drawn under these specific experimental conditions:

- (1) Single-viscosity fluids exhibit a distinct trade off. High-viscosity fluid (100 mPa·s) promotes vertical growth through bedding planes, generates larger fracture width, and improves proppant placement, but produces simpler fracture geometry with limited bedding-plane opening. Low-viscosity fluid (10 mPa·s) activates multiple bedding planes and enhances fracture network complexity, yet results in limited fracture height, narrow fracture width, and poor proppant transport. Neither single viscosity condition can simultaneously optimize both vertical penetration and fracture network complexity.
- (2) Among the four viscosity combination strategies tested, the high–low–high sequence (Sample 4[#]) achieved the highest comprehensive fracture complexity coefficient ($F_T = 0.646$), combining relatively large fracture height (9.5 cm) with complex fracture geometry. However, this observation is based on a single sample without replicate

testing, and its statistical robustness remains unverified. While combined viscosity strategies show promise for balancing complexity and vertical growth, their relative ranking requires further experimental validation.

- (3) Increasing the injection rate from 5 mL/min to 20 mL/min (low-viscosity condition) reduced breakdown pressure from 21.45 MPa to 9.12 MPa and increased fracture width from 0.121 mm to 0.324 mm, thereby improving proppant transport. However, its contribution to vertical penetration of the main hydraulic fracture was marginal (~5.5 cm to ~5.8 cm). These observations are derived from only two samples (1[#] and 7[#]) under low-viscosity conditions; data for high-viscosity scenarios are absent, limiting the scope of this finding.

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