

## Article

# Fracture Propagation Characteristics and Influencing Factors in Cross-Layer Fracturing of Interlayered Shale Reservoirs

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## Abstract

Hydraulic-fracture transmission across lithologic interfaces governs fracture-height growth and reservoir connectivity in shale–sandstone interbedded reservoirs, yet the coupled effects of mechanical contrast, interface properties, layer geometry, and operational parameters remain insufficiently quantified. A two-dimensional plane-strain hydraulic-fracturing model was developed in ABAQUS by coupling Biot poroelasticity, cohesive-zone damage, and fracture-fluid flow. The model explicitly represents thin, alternating continental shale–sandstone layers, lithology-dependent in situ stress and stiffness, and cohesive interfaces; its implementation was assessed against the KGD solution and published layered-rock fracture morphologies. Under the simulated conditions, increasing the shale-to-sandstone elastic-modulus ratio from 0.4–0.5 to 0.6–0.8 reduced the number of penetrated layers from eight to six. Increasing tensile strength from 4 to 16 MPa reduced the number of penetrated layers from ten to six and the final fracture length from 32 to 21 m, while increasing the maximum aperture from 6.75 to 9.02 mm. A sandstone interlayer thickness of approximately 3 m marked a transition in the present parameter set rather than a universal threshold. Sandstone-centered perforation and higher injection rates promoted vertical connectivity, whereas very high fluid viscosity increased near-wellbore aperture but restricted long-distance fracture-height growth. These results provide a mechanics-based framework for optimizing perforation placement and stage-specific fluid design in continental interbedded shale reservoirs.

**Keywords:** cohesive-zone model; cross-layer fracturing; fracture propagation; hydraulic fracturing; interlayered shale reservoirs; shale–sandstone interbedding



Academic Editor: Zhenzhi Wang

Received: 7 July 2026

Revised: 30 July 2026

Accepted: 31 July 2026

Published: 6 August 2026

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## 1. Introduction

Shale oil and gas development contributes to global energy supply and to the ongoing transition of energy systems [1]. Hydraulic fracturing has become a standard stimulation technology for marine shale reservoirs such as the Barnett and Eagle Ford formations in North America, where large-volume fracturing and complex fracture-network reconstruction have been widely applied. Directly transferring these approaches to continental shale

reservoirs in China, however, is challenging because continental shale intervals commonly show stronger lithologic heterogeneity, thinner interbeds, and more frequent mechanical discontinuities [2,3].

Chinese continental shale intervals commonly contain frequent shale–sandstone, shale–siltstone, and shale–mudstone interbeds. Such laminated successions are especially developed in continental lacustrine settings and form strongly heterogeneous reservoir systems controlled by bedding interfaces and thin mechanical layering [4,5].

Bedding interfaces break stratum mechanical continuity. They strongly affect hydraulic fracture initiation, propagation and cross-layer behavior [6]. Shale and sandstone differ greatly in elastic modulus, Poisson’s ratio, tensile strength and seepage properties. These differences cause fracture deflection, arrest, bifurcation and limited cross-layer extension [7,8]. When a hydraulic fracture meets a lithologic interface, its path is not only controlled by fracture toughness, it is jointly determined by in situ stress, interface bonding strength, rock property contrast and fluid–rock interaction [9,10]. Successful cross-layer fracturing depends on the competition between fracture tip driving force and interlayer resistance [11,12].

Existing studies have revealed important aspects of fracture propagation in layered media. Current hydraulic-fracture modeling frameworks include analytical and semi-analytical fracture models, extended finite element methods (XFEMs), phase-field methods, continuum–discontinuum/finite–discrete element methods, and cohesive-zone models (CZMs) [8,13–20]. Analytical and semi-analytical models are efficient but usually simplify interlayer heterogeneity and interface damage. XFEM and phase-field methods permit flexible non-predefined growth, while DEM/FDEM approaches resolve discontinuous block interaction; however, these methods generally require additional constitutive calibration and greater computational cost [16,17,19]. Recent machine-learning surrogates can accelerate dynamic fracture prediction, although their reliability remains controlled by the coverage and physical consistency of the training set [20]. CZM was selected here because, when implemented with Abaqus pore-pressure cohesive elements, it can represent tensile interface debonding through a traction–shear–separation law while coupling fluid pressure and flow within the cohesive element to its mechanical response. By pre-inserting cohesive elements along the bedding interfaces and the prescribed potential vertical propagation path, the model can simulate cross-layer opening and interfacial debonding without remeshing. This approach is limited to predefined potential paths and therefore does not capture arbitrary fracture branching or unforeseen propagation trajectories [16,18,21–23]. Previous studies nevertheless often isolated one factor or one idealized interface. The present work instead compares geological and operational controls within one consistently parameterized shale–sandstone framework.

In addition to fracture-mechanics algorithms, shale–fluid interaction should also be treated as a key component of engineering modeling frameworks for interbedded shale reservoirs. Minardi et al. [24] experimentally quantified gas-shale water uptake during vapor diffusion and direct flooding and showed that volumetric swelling/shrinkage, stress state, and bedding-related anisotropy strongly affect the apparent imbibed-water volume; neglecting volumetric deformation may overestimate water uptake by more than 40%. Therefore, the interpretation of fluid viscosity, leak-off, pressure transmission, and fracture-height growth in shale–sandstone interbedded reservoirs should be placed in a coupled hydro-mechanical context rather than in a purely hydraulic or purely mechanical framework.

Recent work in adjacent geoenergy domains further emphasizes the need for traceable multiscale parameters and robustness checks. Deep-learning-assisted digital-rock and representative-elementary-volume workflows improve the consistency of pore-structure and flow characterization [25]. Stress-path experiments on deep reservoirs demonstrate that permeability and irreversible damage can vary substantially with effective stress and with

the type of natural or induced fracture [26,27]. Stage-aware injection optimization likewise shows that operational recommendations should be tied to a clearly defined development regime rather than transferred as universal thresholds [28]. Although these studies address different reservoir systems, their methodological implication is directly relevant here: the provenance, sensitivity, uncertainty, and domain of applicability of a fracture-propagation model must be reported explicitly.

Laboratory tests prove multiple factors affect fracture cross-layer capacity. These factors include interlayer bonding, lithology combination, stiffness contrast and interface cementation strength. Wan conducted true triaxial tests and divided fracture propagation into five modes: arresting, bypassing, diversion, vertical extension and vertical extension with diversion [29]. Altammar and Sharma as well as Hadei and Veisakrami analyzed fracture deflection, bifurcation and arrest in shale. They highlighted interface properties as the core control factor [30,31]. Huang et al. and Wang et al. noted that effective fracture propagation in heterogeneous reservoirs depends on local stress difference. It is also limited by stratum sequence, interface strength and rock elastoplastic response [32,33]. Physical simulation and digital image correlation tests show fractures deflect and cross layers unstably in soft–hard interbedded formations. The mechanical mechanism is not fully clarified [34,35].

Previous research provides a basis for understanding fracture propagation in complex reservoirs, but several issues remain unresolved for thin shale–sandstone interbedded formations. First, the conditions under which a fracture penetrates, deflects along, or arrests at a lithologic interface are not yet fully clarified. Second, the relative importance of stiffness contrast, tensile strength, interlayer thickness, perforation position, injection rate, and fluid viscosity has not been systematically compared within a unified numerical framework. Third, reproducible descriptions of cohesive-element placement, interface parameters, mesh resolution, and validation assumptions are often limited, which makes it difficult to evaluate the reliability of numerical predictions. These gaps directly affect perforation placement, pumping-program design, and the estimation of effective fracture height in low-permeability interbedded shale reservoirs.

To address these issues, this study combines fully coupled numerical simulation with a controlled parameter-sensitivity framework. The scientific contribution is threefold. First, the model translates the distinctive architecture of continental lacustrine shale—thin alternating lithologies, frequent mechanically weak interfaces, and lithology-dependent stress and stiffness—into explicit layer and cohesive-interface properties rather than treating the formation as a homogeneous shale. Second, a pressure-assisted energy criterion is used together with the standard traction–separation damage law to discriminate interface damage, continued penetration, and diversion; its use is intentionally limited to this calibrated numerical framework. Third, geological and operational variables are compared using one quantitative effective-penetration definition and normalized responses, while a traceable protocol identifies the solver runs still required for formal convergence, boundary-sensitivity, cost, and uncertainty verification. The analysis therefore identifies the relative mechanisms that control fracture-height growth and clarifies which findings are supported by the reported deterministic cases and which, such as the approximately 3 m transition thickness, remain case-specific.

The rest of this paper is organized as follows: Section 2 presents the governing equations and interface-crossing formulation; Section 3 describes model construction, parameter provenance, verification, and applicability; Section 4 quantifies the controlling factors; and Section 5 separates principal observations, engineering implications, limitations, and future work.

## 2. Theoretical Model

### 2.1. Fluid–Solid Coupling Governing Equations

Hydraulic fracturing is a strongly coupled process involving deformation of the porous rock matrix, pore-pressure diffusion, and progressive fracture damage. Considering the heterogeneity of shale–sandstone interbedded reservoirs, this study establishes a fully coupled poroelastic model based on Biot’s effective-stress theory [36]. The model describes the mechanical response of layered rocks during fluid injection and provides the stress, displacement, pressure, and fracture-aperture fields required for cohesive-element damage evaluation.

In Equation (1), all stress and strain quantities are written in Voigt notation. The total stress vector is expressed as  $\boldsymbol{\sigma} = \{\sigma_{xx}, \sigma_{yy}, \sigma_{zz}, \tau_{xy}, \tau_{yz}, \tau_{xz}\}^T$ , where  $\sigma_{xx}$ ,  $\sigma_{yy}$ , and  $\sigma_{zz}$  are the normal stress components,  $\tau_{xy}$ ,  $\tau_{yz}$ , and  $\tau_{xz}$  are the shear stress components, and the superscript  $T$  denotes the transpose. The vector  $\mathbf{m} = [1, 1, 1, 0, 0, 0]^T$  indicates that pore pressure acts only on the normal stress components. Although a two-dimensional plane-strain model is adopted, the three-dimensional Voigt form is retained for consistency with the poroelastic constitutive formulation.

$$\boldsymbol{\sigma}' = \boldsymbol{\sigma} - \alpha p \mathbf{m} \quad (1)$$

where  $\boldsymbol{\sigma}'$  is the effective stress vector,  $\boldsymbol{\sigma}$  is the total stress vector,  $\alpha$  is the Biot coefficient,  $p$  is the pore pressure, and  $\mathbf{m}$  is the Voigt vector for pore-pressure coupling.

Neglecting inertial terms, the quasi-static equilibrium equation is expressed in weak form as

$$\int_V \delta \boldsymbol{\varepsilon}^T \boldsymbol{\sigma}' dV = \int_{S_t} \delta \mathbf{u}^T \bar{\mathbf{t}} dS + \int_V \delta \mathbf{u}^T \mathbf{f} dV \quad (2)$$

where  $\delta \boldsymbol{\varepsilon}$  is the virtual strain vector,  $\delta \mathbf{u}$  is the virtual displacement vector,  $\bar{\mathbf{t}}$  is the prescribed traction vector applied on the traction boundary  $S_t$ , and  $\mathbf{f}$  is the body-force vector in domain  $V$ . Here, the subscript  $t$  in  $S_t$  denotes the traction boundary rather than the time variable.

According to the mass-conservation law for a deforming porous medium, the fluid-continuity equation is written in terms of porosity  $\varphi$ , fluid density  $\rho_w$ , Darcy velocity  $\mathbf{v}_w$ , and source/sink term  $q_w$ .

In Equation (3),  $\varphi$  denotes the current porosity rather than a separate undefined fluid volume fraction, and  $\mathbf{v}_w$  is the Darcy seepage velocity. For an incompressible fracturing fluid and no additional matrix source/sink,  $q_w$  is set to zero. This notation is used consistently with the porosity update in Equation (4).

$$\frac{\partial(\rho_w \varphi)}{\partial t} + \nabla \cdot (\rho_w \mathbf{v}_w) = q_w, \quad \mathbf{v}_w = -\frac{k}{\mu_w} \nabla p \quad (3)$$

where  $\rho_w$  is the fluid density,  $\varphi$  is porosity,  $\mathbf{v}_w$  is the seepage velocity vector,  $q_w$  is the source/sink term per unit bulk volume,  $\mu_w$  is fluid viscosity in the porous matrix,  $k$  is permeability,  $p$  is pore pressure, and  $t$  is time.

The porosity  $\varphi$  and permeability  $k$  are updated with volumetric strain using a Kozeny–Carman-type relationship [37].

In Equation (4),  $\varepsilon_v$  is defined as positive for volumetric compression. Therefore, increasing  $\varepsilon_v$  reduces porosity. The permeability update is empirical and is used to represent deformation-induced changes in matrix transmissibility during coupled deformation and fluid-pressure diffusion.

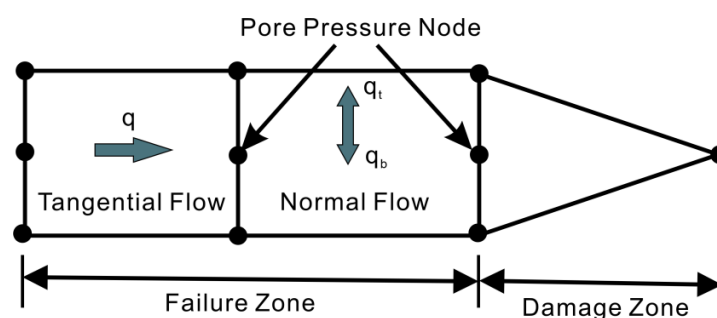
$$\varphi = \frac{\varphi_0 - \varepsilon_v}{1 - \varepsilon_v}, \quad k = k_0 \left( \frac{\varphi}{\varphi_0} \right)^3 \left( \frac{1 - \varphi_0}{1 - \varphi} \right)^2 \quad (4)$$

where  $\varphi_0$  and  $k_0$  are the initial porosity and initial permeability, respectively, and  $\varepsilon_v$  is the volumetric strain.

## 2.2. Cohesive Element and Damage Evolution Model

Zero-thickness pore-pressure cohesive elements are embedded into the finite-element model to simulate fracture initiation and propagation. The cohesive-zone concept follows classical fracture-process-zone theory [22,23] and is implemented through a bilinear traction–separation law in ABAQUS (2022). Damage initiation is governed by a quadratic nominal-stress criterion, whereas damage evolution is controlled by fracture-energy dissipation [21,38]. In the present simulations, cohesive elements are inserted along the predefined potential hydraulic-fracture path and along shale–sandstone interfaces intersected by the expected vertical propagation route. They are not inserted along all finite-element boundaries, which avoids an unrealistically dense fracture network and reduces computational cost.

Fluid flow in cohesive elements includes tangential flow along the opened fracture and normal leak-off into the adjacent formation. The fracturing fluid is treated as an incompressible Newtonian fluid. The flow paths in the damaged cohesive zone are shown schematically in Figure 1.



**Figure 1.** Schematic diagram of the fluid flow in the cohesive element.

In Equation (5),  $\mathbf{T} = \{t_n, t_s\}^T$  is the nominal traction vector,  $\boldsymbol{\delta} = \{\delta_n, \delta_s\}^T$  is the corresponding separation vector,  $\mathbf{K}_0$  is the initial cohesive stiffness matrix,  $D$  is the scalar damage variable,  $\delta_{\text{eff}}$  is the effective separation,  $\delta_0$  is the effective separation at damage initiation, and  $\delta_f$  is the effective separation at complete failure.

$$D = \begin{cases} 0, & \delta_{\text{eff}} \leq \delta_0, \\ \frac{\delta_f(\delta_{\text{eff}} - \delta_0)}{\delta_{\text{eff}}(\delta_f - \delta_0)}, & \delta_0 < \delta_{\text{eff}} < \delta_f, \\ 1, & \delta_{\text{eff}} \geq \delta_f, \end{cases} \quad \mathbf{T} = (1 - D)\mathbf{K}_0\boldsymbol{\delta}, \quad \delta_{\text{eff}} = \sqrt{\langle \delta_n \rangle^2 + \delta_s^2} \quad (5)$$

where  $\mathbf{K}_0$  is the initial cohesive stiffness matrix,  $\boldsymbol{\delta}$  is the separation vector,  $\delta_{\text{eff}}$  is the effective separation displacement, and  $D$  evolves from 0 for an intact cohesive element to 1 for a completely failed element.

Damage initiation follows the quadratic nominal stress criterion considering tension–shear coupling:

$$\left( \frac{\langle t_n \rangle}{t_n^0} \right)^2 + \left( \frac{t_s}{t_s^0} \right)^2 = 1, \quad \langle t_n \rangle = \max(t_n, 0) \quad (6)$$

where  $t_n$  and  $t_s$  are the nominal tractions in the normal and tangential directions, respectively;  $t_n^0$  and  $t_s^0$  are the corresponding nominal strengths; and the Macaulay bracket  $\langle t_n \rangle = \max(t_n, 0)$  ensures that compressive normal traction does not initiate tensile damage.

For mixed-mode fracture, the Benzeggagh–Kenane (BK) law defines the critical fracture energy.

For the Benzeggagh–Kenane (BK) law used in this two-dimensional plane-strain model,  $G_I$  and  $G_{II}$  are the mode-I and mode-II energy-release rates, respectively [38].

$$G_c = G_{Ic} + (G_{IIc} - G_{Ic}) \left( \frac{G_{II}}{G_I + G_{II}} \right)^\eta \quad (7)$$

where  $G_c$  is the mixed-mode critical fracture energy,  $G_{Ic}$  and  $G_{IIc}$  are the mode-I and mode-II critical fracture energies,  $G_I$  and  $G_{II}$  are the corresponding energy-release rates, and  $\eta$  is the BK mixed-mode exponent.

The relationship between critical fracture energy and fracture toughness is written in plane strain form as

$$G_{mc} = \frac{K_{mc}^2}{E'}, \quad E' = \frac{E}{1 - \nu^2}, \quad m = I, II \quad (8)$$

where  $G_{mc}$  and  $K_{mc}$  are, respectively, the critical fracture energy and fracture toughness for mode  $m$  ( $m = I$  or  $II$ );  $E'$  is the plane-strain modulus;  $E$  is Young's modulus; and  $\nu$  is Poisson's ratio. Thus,  $K_{Ic}$  and  $K_{IIc}$  denote the mode-I and mode-II fracture-toughness values, respectively.

### 2.3. Fluid Flow Within the Fracture

When cohesive elements are fully damaged, the fracture acts as a hydraulic conduit. Assuming Newtonian flow under the lubrication approximation, the governing equation for fracture aperture and pressure is written as follows [39]:

$$\frac{\partial w}{\partial t} - \nabla_\tau \cdot \left( \frac{w^3}{12\mu} \nabla_\tau p_f \right) = q_l \quad (9)$$

where  $w$  is the fracture aperture,  $p_f$  is the fluid pressure inside the fracture,  $\mu$  is the dynamic viscosity,  $q_l$  denotes the leak-off or source/sink term per unit fracture area, and  $\nabla_\tau$  is the tangential gradient operator along the fracture. In simulations without explicit leak-off,  $q_l$  is set to zero.

After finite-element discretization, the pressure equation can be assembled in matrix form as

$$\mathbf{HP} = \mathbf{R} - \mathbf{MW} \quad (10)$$

where  $\mathbf{H}$  and  $\mathbf{M}$  are coefficient matrices associated with pressure diffusion and aperture coupling,  $\mathbf{P}$  and  $\mathbf{W}$  are the nodal pressure and aperture vectors, and  $\mathbf{R}$  contains the injection-rate and boundary-condition contributions.

The pressure at the injection/perforation point is updated using the fluid-compressibility relation.

In Equation (11), superscripts  $n$  and  $n - 1$  denote the current and previous time steps, respectively.  $\Delta V_f$  is the incremental fracture-volume change over the current time step, and  $Q\Delta t$  is the injected fluid volume over the same time step. Thus,  $\Delta t$  denotes the time increment and is not used as a volume-change symbol.

$$p_{inj}^n = p_{inj}^{n-1} + \frac{K_f}{V_f} (Q\Delta t - \Delta V_f) \quad (11)$$

where  $K_f$  is the fracturing-fluid bulk modulus,  $V_f$  is the control volume associated with the perforation/fracture element,  $Q$  is the injection rate,  $\Delta t$  is the time increment, and  $\Delta V_f$  is the incremental fracture-volume change.

## 2.4. Hydraulic Fracture Crossing Criterion

Based on the standard quadratic nominal-stress criterion, the initiation condition for interface damage at a shale–sandstone interface is written as

$$\left(\frac{\langle t_n \rangle}{t_{n,\text{int}}^0}\right)^2 + \left(\frac{t_s}{t_{s,\text{int}}^0}\right)^2 = 1, \quad t_{i,\text{int}}^0 = \lambda_i t_i^0 \quad (i = n, s) \quad (12)$$

where  $t_n$  and  $t_s$  are the nominal interface tractions;  $t_{n,\text{int}}^0$  and  $t_{s,\text{int}}^0$  are the interface normal and shear strengths;  $t_n^0$  and  $t_s^0$  are the intact-rock nominal strengths; and  $\lambda_i$  is the interface strength-reduction factor in direction  $i$ . The stress contrast between layers is imposed through the initial in situ stress field and boundary conditions rather than through an additional non-standard term in the initiation criterion.

For mixed-mode propagation after interface damage initiates, the interface critical fracture energy is evaluated using the same BK-type relationship:

$$G_{c,\text{int}} = G_{\text{Ic}}^{\text{int}} + \left(G_{\text{IIc}}^{\text{int}} - G_{\text{Ic}}^{\text{int}}\right) \left(\frac{G_{\text{II}}}{G_{\text{I}} + G_{\text{II}}}\right)^{\eta_{\text{int}}} \quad (13)$$

where  $G_{c,\text{int}}$  is the mixed-mode critical fracture energy of the interface,  $G_{\text{Ic}}^{\text{int}}$  and  $G_{\text{IIc}}^{\text{int}}$  are the interface mode-I and mode-II critical energies, and  $\eta_{\text{int}}$  is the interface BK exponent. The BK exponent is  $\eta = 1.6$  for intact-rock cohesive elements and  $\eta_{\text{int}} = 1.3$  for shale–sandstone interface cohesive elements in the base case.

A dimensionless penetration index is then used to judge whether the fracture can continue penetrating through the interface under combined fracture-tip energy and fluid-pressure assistance:

$$\Pi_{\text{pen}} = \frac{G}{G_{c,\text{int}}} + \frac{p_w}{p_c}, \quad \Pi_{\text{pen}} \geq 1 \quad (14)$$

where  $\Pi_{\text{pen}}$  is the dimensionless penetration index,  $G$  is the current energy-release rate at the fracture tip,  $G_{c,\text{int}}$  is the interface critical fracture energy,  $p_w$  is the fluid pressure acting on the interface cohesive element, and  $p_c$  is the critical pore pressure for interface debonding and continued penetration.

In the base case, the interface strengths are obtained by applying  $\lambda_n = \lambda_s = 0.85$  to the intact-rock strengths. Equation (12) is used for interface damage initiation, Equation (13) defines the mixed-mode critical energy after interface damage, and Equation (14) evaluates whether the combined fracture-tip energy and fluid-pressure assistance are sufficient for continued cross-layer penetration.

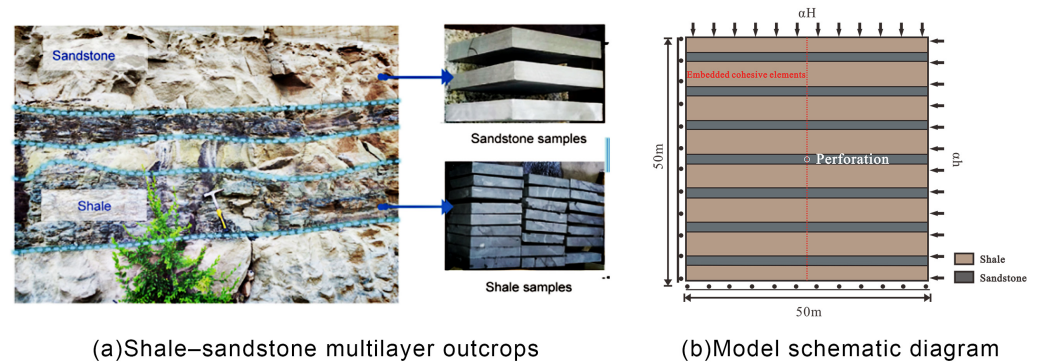
The criterion in Equation (14) is used as a numerical judgment rule within the present cohesive-element framework rather than as a universal analytical fracture criterion.

## 3. Model Establishment and Validation

### 3.1. Geometric Model and Material Parameters

To investigate cross-layer hydraulic-fracture propagation in continental shale–sandstone interbedded reservoirs, we developed a two-dimensional finite-element model. Figure 2a, based on field geological data and core observations, illustrates the frequent alternation of thin shale and sandstone layers in the study area [40]. Building on these observations, Figure 2b distills the key lithological assemblages, layer thicknesses and interlayer interfaces into an idealized mechanical model for numerical simulation. The measured or literature-constrained ranges of elastic modulus, Poisson's ratio, tensile strength, in situ stress, and layer thickness are therefore mapped to representative shale and sandstone layers in Table 1. Sandstone is treated as comparatively stiff and brittle, while shale is represented as more

laminated and mechanically distinct. The sharp contacts are assigned cohesive-interface properties so that penetration, arrest, and limited diversion can be evaluated explicitly.



**Figure 2.** Establishment of numerical model for fracture propagation [40]: (a) shale-sandstone multilayer outcrops; (b) model schematic diagram.

**Table 1.** Geological, hydraulic, cohesive and numerical parameters used in the simulations.

| Parameter                                         | Sandstone             | Shale                 |
|---------------------------------------------------|-----------------------|-----------------------|
| Elastic modulus $E$ (GPa; varied)                 | 31                    | 27                    |
| Tensile strength $t_n^0$ (MPa; varied)            | 10                    | 10                    |
| Poisson's ratio $\nu$                             | 0.15                  | 0.12                  |
| Initial porosity $\phi_0$                         | 0.10                  | 0.10                  |
| Vertical stress $\sigma_v$ (MPa)                  | 48                    | 48                    |
| Minimum horizontal stress $\sigma_h$ (MPa)        | 37                    | 39                    |
| Maximum horizontal stress $\sigma_H$ (MPa)        | 46                    | 46                    |
| Layer thickness (m; varied)                       | 2                     | 5                     |
| Initial permeability $k_0$ ( $m^2$ )              | $1.0 \times 10^{-13}$ | $1.0 \times 10^{-13}$ |
| Biot coefficient $\alpha$                         | 1.0                   | 1.0                   |
| Fluid bulk modulus $K_f$ (GPa)                    | 2.2                   | 2.2                   |
| Base viscosity $\mu$ (Pa·s)                       | 10                    | 10                    |
| Base pumping rate $Q$ ( $m^3/min$ )               | 10                    | 10                    |
| Cohesive stiffness $K_0$ ( $MPa \cdot m^{-1}$ )   | $3.0 \times 10^4$     | $3.0 \times 10^4$     |
| Mode-I energy $G_{Ic}$ ( $J \cdot m^{-2}$ )       | 100                   | 80                    |
| Mode-II energy $G_{IIc}$ ( $J \cdot m^{-2}$ )     | 300                   | 240                   |
| Interface reduction factor $\lambda$              | 0.85                  | 0.85                  |
| BK exponent $\eta/\eta_{int}$                     | 1.6/1.3               | 1.6/1.3               |
| Mode-I toughness $K_{Ic}$ ( $MPa \cdot m^{0.5}$ ) | 1.78                  | 1.48                  |
| Shear toughness $K_{IIc}$ ( $MPa \cdot m^{0.5}$ ) | 3.08                  | 2.56                  |
| Leak-off coefficient ( $m \cdot s^{-0.5}$ )       | $1.0 \times 10^{-14}$ | $1.0 \times 10^{-14}$ |
| Model size/refined mesh size (m)                  | 50/0.5                | 50/0.5                |

A  $50\text{ m} \times 50\text{ m}$  plane-strain domain is established in ABAQUS (Figure 2). The vertical section contains alternating 5 m shale and 2 m sandstone intervals, with boundary-buffer material completing the model height; the perforation is centered in sandstone. A geostatic initialization step applies the lithology-dependent minimum horizontal stresses (37 MPa in sandstone and 39 MPa in shale), the common maximum horizontal stress (46 MPa), and the vertical stress (48 MPa). The geostatic step adopted an initial increment of 1.0, a minimum increment of  $1 \times 10^{-5}$ , and a maximum of 10 increments. Normal displacements are constrained on the lateral and bottom boundaries, the overburden load is applied at the top, and injection begins only after the initial stress field has reached numerical equilibrium.

The rock matrix is discretized with first-order plane-strain pore-pressure elements, and zero-thickness pore-pressure cohesive elements represent the expected vertical fracture route and the intersected shale-sandstone interfaces. The global matrix mesh is 0.5 m; the

perforation, cohesive path, and lithologic interfaces are locally refined to 0.1 m. Cohesive elements are not inserted along every finite-element boundary; the model is intended to resolve the dominant cross-layer path and interface response rather than arbitrary branching in all directions.

The matrix elastic and strength values are selected from the core/outcrop and published ranges discussed in Section 1, while stress values represent the target continental interbedded setting. The interface reduction factors are not direct intact-rock properties:  $\lambda_n = \lambda_s = 0.85$  represents a moderately cemented contact and scales the intact normal and shear strengths in Equation (12). This value is treated as a modeling assumption that requires case-specific calibration. Initial permeability is uniform within each lithology but is not held constant during deformation; it is updated through Equation (4). Consequently, the assumptions are isotropic effective elasticity within each layer, homogeneous initial properties inside each layer, and a simplified cohesive interface—not globally constant permeability.

The present two-dimensional plane-strain model is intended to investigate the fracture-initiation and propagation tendencies within a representative cross-section of the shale-sandstone interlayer system. The model does not explicitly resolve the out-of-plane fracture front; therefore, the simulated fracture path and damaged zone should be interpreted as sectional responses rather than as a complete three-dimensional fracture geometry. In particular, this model fails to reproduce the three-dimensional air-bag-shaped fractured zone surrounding the perforation tunnels. These processes require a P3D, planar-3D, or fully three-dimensional hydro-mechanical model with explicit layer interfaces and heterogeneous stress and mechanical properties.

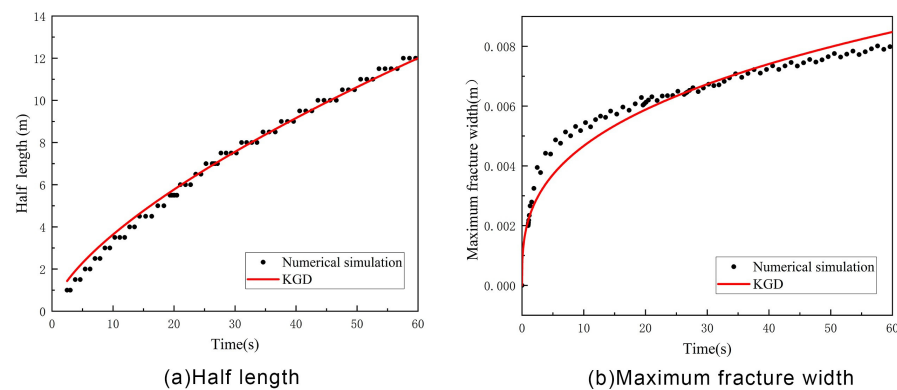
### 3.2. Model Validation

The model is validated against the classical KGD analytical solution. In this benchmark, hydraulic-fracture growth is treated as a plane-strain problem with constant out-of-plane height in a homogeneous linear-elastic medium. The fracture half-length and aperture vary with time, whereas the fracture height is not solved explicitly.

For the KGD benchmark calculation, a homogeneous plane-strain domain is used with the sandstone elastic modulus and Poisson ratio listed in Table 1, a minimum horizontal stress of 37 MPa, an injection rate of 10 m<sup>3</sup>/min, and a fluid viscosity of 10 Pa·s. The external boundaries are placed sufficiently far from the fracture to minimize boundary effects during the comparison time. The same cohesive stiffness, fluid bulk modulus, and local mesh refinement listed in Table 1 are used in the benchmark model.

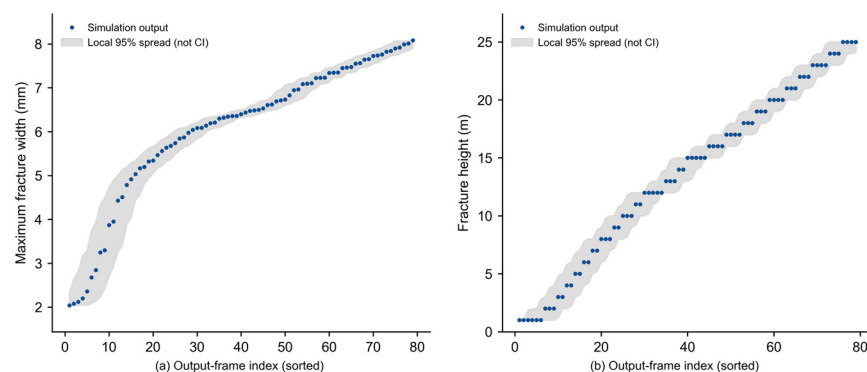
Fracture half-length and maximum aperture are recorded and compared with the KGD analytical curves (Figure 3). The numerical curves reproduce the magnitude and time-dependent trend of the homogeneous KGD benchmark at the resolution shown. The comparison verifies the qualitative behavior of the coupled implementation and cohesive-flow algorithm.

The model reproduces the principal modes reported in published laboratory and field-oriented studies: direct penetration, arrest or diversion at weak interfaces, and asymmetric growth caused by lithologic strength contrast [11,18,19,29–35]. In particular, the simulated transition from penetration to interface-controlled growth agrees qualitatively with DIC/AE observations of discontinuous cross-layer fracture-process zones [18] and with true-triaxial/FDEM observations of penetration, arrest, and T-shaped or asymmetric fracture patterns [19]. The comparison supports physical applicability but does not remove the need for future case-specific calibration against core-scale pressure histories, CT/DIC fracture geometry, microseismic height, and treatment-pressure diagnostics [41].



**Figure 3.** Comparison between the theoretical solution and numerical solution: (a) half length; (b) maximum fracture width.

To further quantify the deterministic simulation outputs, ranked maximum-aperture and connected-height results are summarized in Figure 4. Across the saved frames from 0 to 59.6 s, the maximum fracture aperture increased from 2.04 to 8.08 mm, whereas the connected fracture height increased from 1 to 25 m. The stepwise height response reflects sequential cohesive-element failure along the prescribed cross-layer path, while the smoother aperture response reflects coupled fluid pressurization, fracture opening and interface damage.



**Figure 4.** Ranked numerical outputs during coupled fracture propagation: (a) output-frame index (sorted); (b) output-frame index (sorted).

## 4. Parametric Study and Results

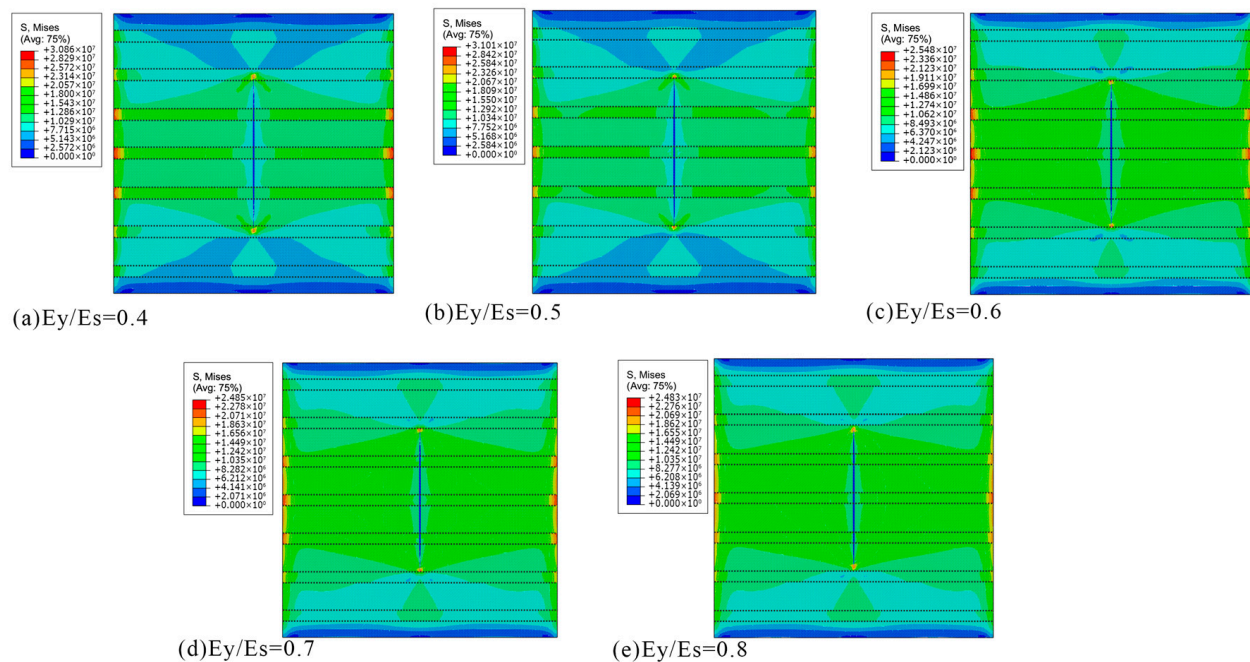
### 4.1. Impact of Elastic-Modulus Contrast on Cross-Layer Fracture Propagation

Throughout this work, mechanical contrast is characterized by the shale-to-sandstone elastic-modulus ratio  $E_y/E_s$  [12]. Unless otherwise stated,  $Q = 10 \text{ m}^3/\text{min}$  and  $\mu = 10 \text{ Pa}\cdot\text{s}$ . Effective penetration of a layer is defined as the fluid-connected main fracture traversing the full thickness of the rock stratum and propagating into the adjacent layer.

The simulation results show that elastic-modulus contrast strongly controls vertical penetration (Figure 5). At  $E_y/E_s = 0.4\text{--}0.5$ , the main fracture penetrates approximately eight layers, whereas at  $E_y/E_s = 0.6\text{--}0.8$  the count is approximately six. This is a 25% reduction in penetrated-layer count and corresponds to a decrease in normalized connected height HD from approximately 0.67 to 0.5.

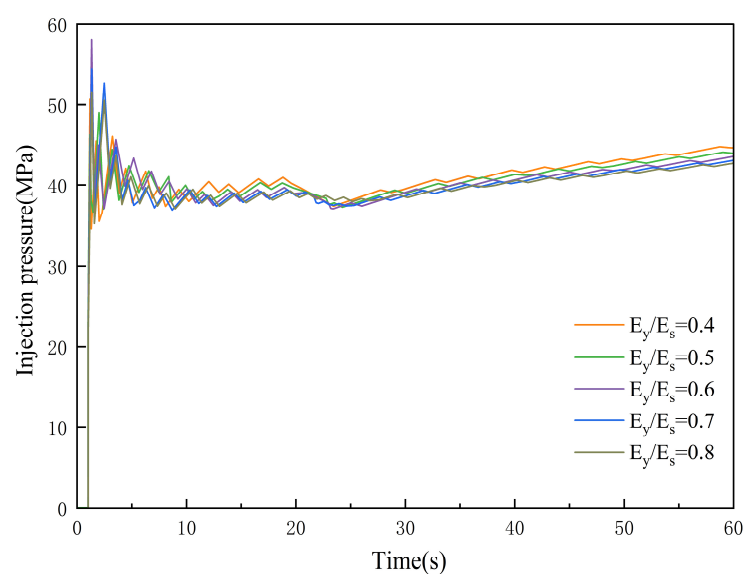
A larger modulus contrast enhances local stress concentration at the fracture tip and increases deformation incompatibility across the interface. This reduces the tendency for the fracture to become arrested or diverted along bedding planes and helps the fracture penetrate into adjacent layers. Conversely, when the modulus contrast is small, the in-

terface acts as a more effective barrier, and the fracture tends to remain confined within fewer layers.



**Figure 5.** Hydraulic-fracture propagation maps for different shale-to-sandstone elastic-modulus ratios ( $E_y/E_s$ ) under  $Q = 10 \text{ m}^3/\text{min}$  and  $\mu = 10 \text{ Pa}\cdot\text{s}$ : (a) 0.4; (b) 0.5; (c) 0.6; (d) 0.7; (e) 0.8.

As shown in Figure 6, the injection-pressure response varies moderately with  $E_y/E_s$ . The early pressure oscillation reflects rapid cohesive-element damage and fracture opening near the perforation, whereas the later rising trend corresponds to continued fracture extension and increasing flow resistance. Although the pressure response is not strictly linear with  $E_y/E_s$ , cases with larger stiffness contrast generally show stronger vertical penetration, confirming that fracture geometry should be interpreted together with the pressure history.

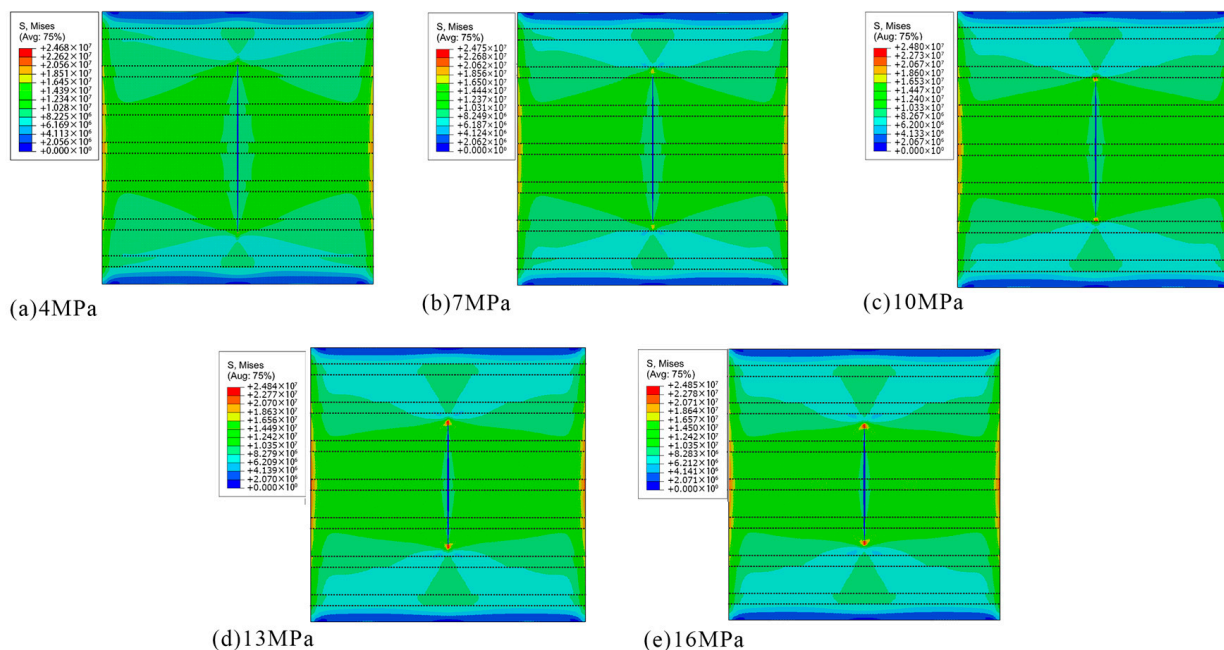


**Figure 6.** Injection-pressure response for different elastic-modulus ratios  $E_y/E_s$ .

#### 4.2. Impact of Tensile Strength on Cross-Layer Fracture Propagation

Reservoir tensile strength is set to 4, 7, 10, 13 and 16 MPa. In situ stress and stratum conditions are kept unchanged.

Results show that tensile strength is a dominant factor controlling vertical fracture geometry (Figure 7, Table 2). At 4 MPa, the rock fails readily in tension. The resulting fractures are long and relatively narrow, with a maximum fracture aperture of 6.75 mm and a fracture length of 32 m, and they penetrate 10 layers. At 7 MPa, the penetrated-layer count decreases to eight. At 10–16 MPa, vertical growth is limited to six layers. The fracture morphology then changes to a shorter and wider geometry. At 16 MPa, the maximum aperture reaches 9.02 mm, whereas the fracture length decreases markedly.

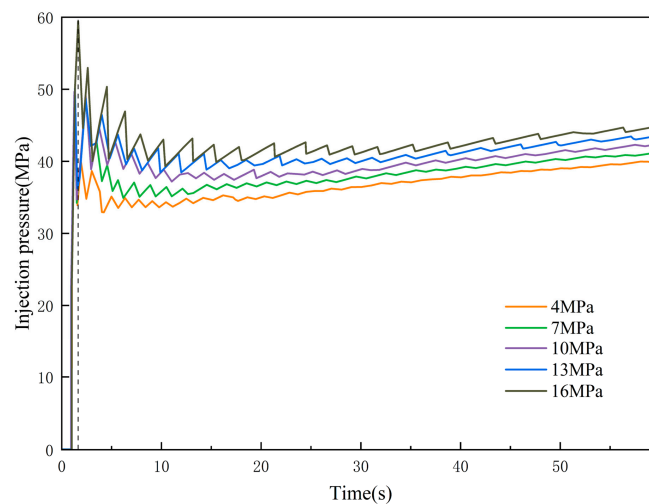


**Figure 7.** Hydraulic-fracture propagation maps for different tensile strengths under  $Q = 10 \text{ m}^3/\text{min}$  and  $\mu = 10 \text{ Pa}\cdot\text{s}$ : (a) 4 Mpa; (b) 7 Mpa; (c) 10 Mpa; (d) 13 Mpa; (e) 16 Mpa.

**Table 2.** Effect of tensile strength on penetrated-layer count, maximum fracture aperture, and final fracture length.

| Tensile Strength (MPa) | Effectively Penetrated-Layer Count | Maximum Fracture Aperture (mm) | Final Fracture Length (m) |
|------------------------|------------------------------------|--------------------------------|---------------------------|
| 4                      | 10                                 | 6.75                           | 32                        |
| 7                      | 8                                  | 7.3                            | 28                        |
| 10                     | 6                                  | 8.1                            | 24                        |
| 13                     | 6                                  | 8.65                           | 22                        |
| 16                     | 6                                  | 9.02                           | 21                        |

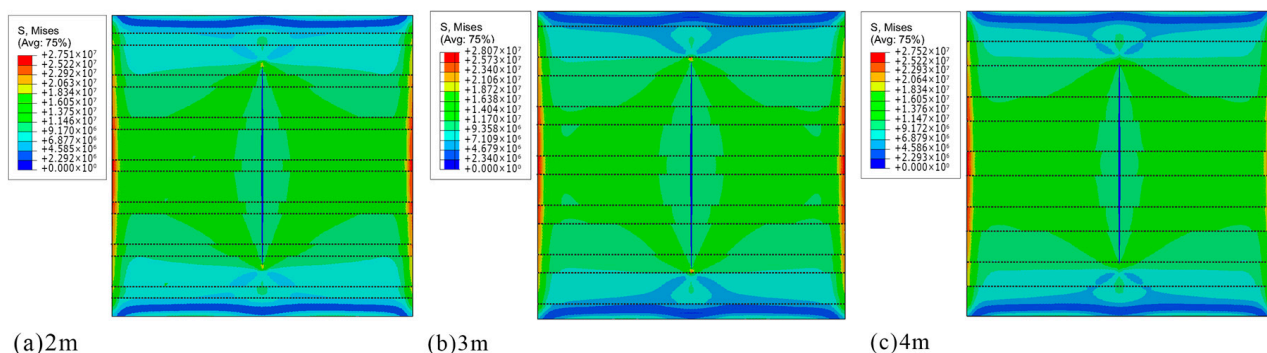
Low tensile strength reduces the critical energy required for interface failure; thus, fractures can cross multiple interfaces under relatively low net pressure. By contrast, higher tensile strength increases both the breakdown pressure and the pressure needed to sustain propagation (Figure 8). More hydraulic energy is therefore consumed in overcoming rock resistance, which tends to increase fracture width near the wellbore but suppresses long-distance vertical propagation and the formation of a large-scale cross-layer fracture network.



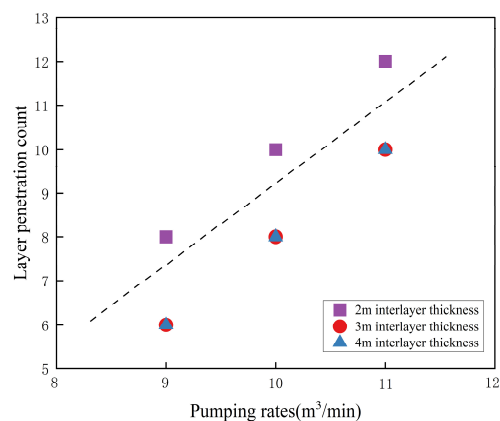
**Figure 8.** Injection-pressure response for different tensile strengths.

#### 4.3. Impact of Interlayer Thickness on Cross-Layer Fracture Propagation

With  $\mu = 10 \text{ Pa}\cdot\text{s}$  and  $Q = 10 \text{ m}^3/\text{min}$ , increasing sandstone-interlayer thickness from 2 to 3 m reduces the penetrated-layer count from approximately 10 to 8; increasing thickness to 4 m produces only a limited additional change (Figures 9 and 10). Under the base-case stress and material conditions, approximately 3 m therefore marks the onset of barrier-dominated behavior, not a universal cutoff. The one-factor comparison indicates a negative thickness–penetration association, but its interaction with stress, strength, interface cementation, and pressure transmission must be evaluated in the planned multivariable uncertainty analysis.



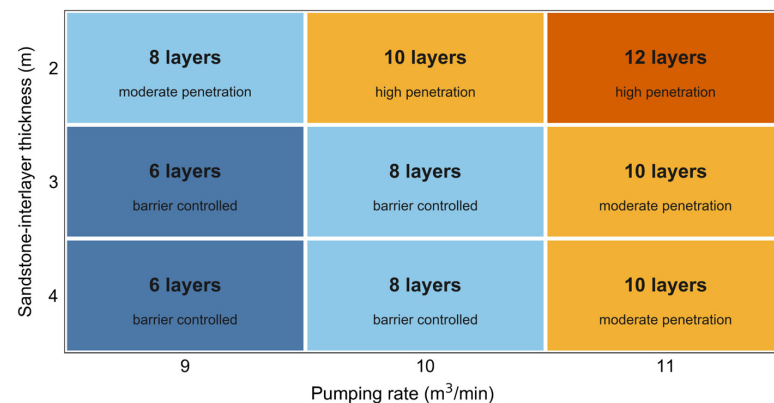
**Figure 9.** Hydraulic-fracture propagation maps for different sandstone interlayer thicknesses: (a) 2 m; (b) 3 m; (c) 4 m.



**Figure 10.** Effect of sandstone interlayer thickness on fracture length and penetrated-layer count.

Increasing interlayer thickness lengthens the propagation path inside the stiffer barrier layer and increases pressure loss before the tip reaches the next interface. The fracture-tip driving force is therefore less able to overcome the combined stress and strength barrier. This transition thickness is not universal; it depends on stress contrast, material strength, interface cementation, pumping rate, fluid viscosity, and perforation location.

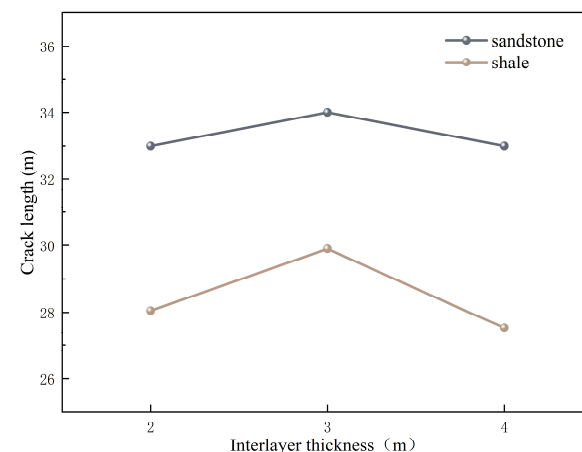
The classification heatmap (Figure 11) consolidates the interaction between sandstone-interlayer thickness and pumping rate. For a 2 m interlayer, the penetrated-layer count increased from eight to ten and twelve as the pumping rate increased from 9 to 10 and 11 m<sup>3</sup>/min, respectively. For both 3 and 4 m interlayers, the corresponding counts were six, eight and ten. Thus, increasing pumping rate partly offsets the barrier effect, whereas the nearly identical 3 and 4 m classifications indicate that, within the tested range, the main transition to barrier-controlled propagation had already occurred near 3 m.



**Figure 11.** Classification of cross-layer fracture propagation as a function of sandstone-interlayer thickness and pumping rate.

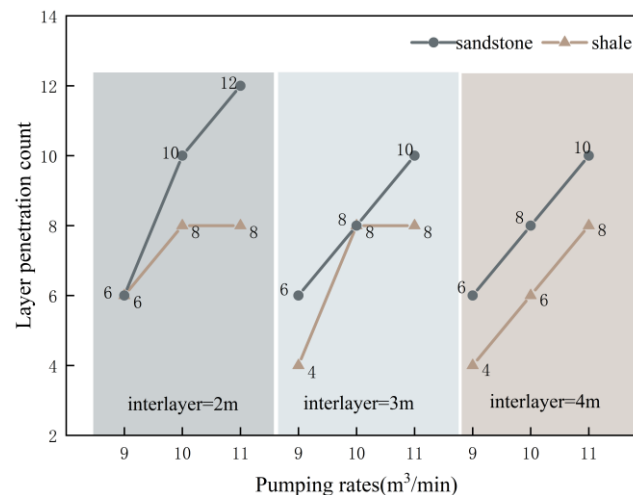
#### 4.4. Impact of Perforation Location on Cross-Layer Fracture Propagation

Figure 12 compares sandstone-centered and shale-centered perforation under identical injection conditions. For the 2 m interlayer case, sandstone initiation produces a final fracture length of 32.5 m and connects 10 layers, whereas shale initiation produces 28 m and six layers. Sandstone-centered perforation therefore increases final length by 16.1% and penetrated-layer count by 66.7% relative to shale-centered perforation. The same direction is retained at a 4 m interlayer thickness, showing that initiation lithology changes both the available hydraulic driving force and the amount of bedding-related dissipation before the first interface is crossed.



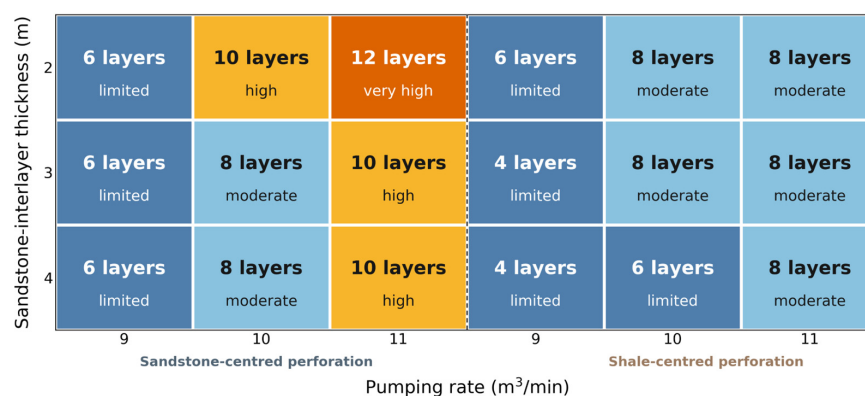
**Figure 12.** Comparison of fracture propagation when the perforation is located at the center of a sandstone layer and at the center of a shale layer.

Sandstone has higher brittleness and comparatively more uniform mechanical properties, which favor the formation of a stable main fracture and preserve sufficient net pressure for vertical breakthrough. Shale-initiated fractures, by contrast, encounter denser bedding planes, stronger anisotropy, and higher clay-related ductility. These features promote deflection, bifurcation, or bedding slip, dissipate hydraulic energy, and ultimately reduce vertical penetration and the in-plane connected vertical extent (Figure 13).



**Figure 13.** Effect of perforation lithology and interlayer thickness on fracture penetration capacity.

Figure 14 provides a joint classification of the perforation-location, interlayer-thickness and pumping-rate effects. At a 2 m interlayer thickness, sandstone-centered perforation increased from 6 to 12 penetrated layers as the pumping rate increased from 9 to 11 m³/min, whereas shale-centered perforation remained within six to eight layers. The sandstone-centered cases also reached 10 penetrated layers at 11 m³/min for the 3 and 4 m interlayers, while the shale-centered cases reached only eight layers. At 9 m³/min, shale-centered perforation was especially restricted for the 3 and 4 m interlayers, with four penetrated layers. These results show that the benefit of sandstone-centered perforation is most apparent when the interlayer barrier is thick or the pumping rate is low.



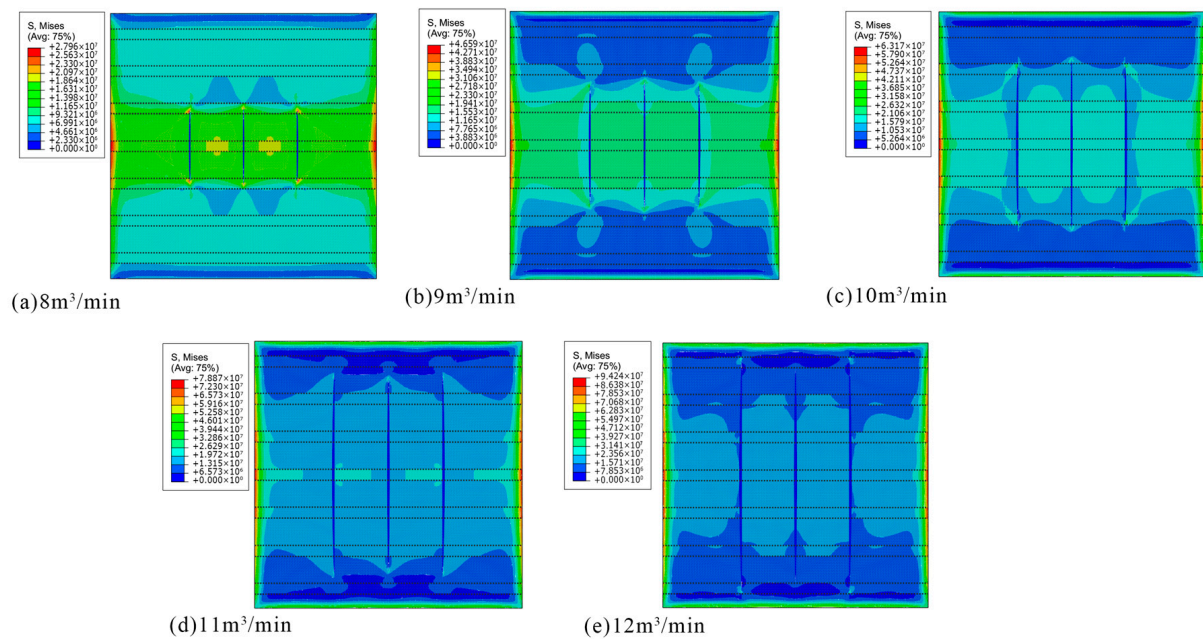
**Figure 14.** Classification of cross-layer fracture propagation for sandstone-centered and shale-centered perforation.

#### 4.5. Impact of Injection Rate on Cross-Layer Fracture Propagation

To examine the influence of injection rate, three injection points with 10 m horizontal spacing are used to represent simultaneous multicluster stimulation [42]. In the two-dimensional plane-strain model, these injection points are idealized as line-source perforations rather than finite three-dimensional clusters. Therefore, the results are used

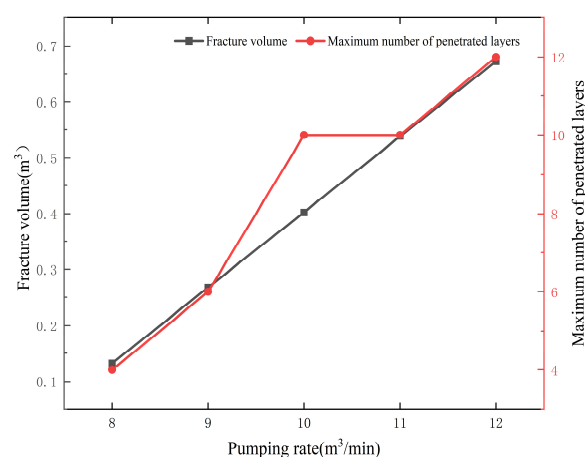
to compare relative trends in cross-layer propagation and should not be interpreted as a complete representation of field-scale 3D stress-shadow behavior.

As the injection rate increases from  $8 \text{ m}^3/\text{min}$  to  $12 \text{ m}^3/\text{min}$ , the vertical penetration increases progressively from four to twelve layers (Figure 15). Specifically, at  $10 \text{ m}^3/\text{min}$ , the outer fractures penetrate eight layers while the central fracture reaches 10. At  $12 \text{ m}^3/\text{min}$ , the fractures penetrate twelve layers and extend further along the interfaces. This occurs because a higher injection rate supplies more hydraulic energy per unit time, elevates the pressure at the fracture tip, and accelerates damage and failure of the cohesive elements.



**Figure 15.** Fracture-propagation maps under different pumping rates: (a)  $8 \text{ m}^3/\text{min}$ ; (b)  $9 \text{ m}^3/\text{min}$ ; (c)  $10 \text{ m}^3/\text{min}$ ; (d)  $11 \text{ m}^3/\text{min}$ ; (e)  $12 \text{ m}^3/\text{min}$ .

A higher injection rate increased the in-plane connected vertical extent of the simulated fracture system (Figure 16). Both wellbore pressure and fracture-tip pressure rise, the driving force for interface failure is enhanced, and the stress interaction among the three fractures becomes more pronounced at high rates. Under these conditions, the dominant propagation pattern shifts toward stronger vertical extension accompanied by local interface sliding. Consequently, high pumping rates improve both the height of an individual fracture and the multi-layer connectivity of the overall fracture system.

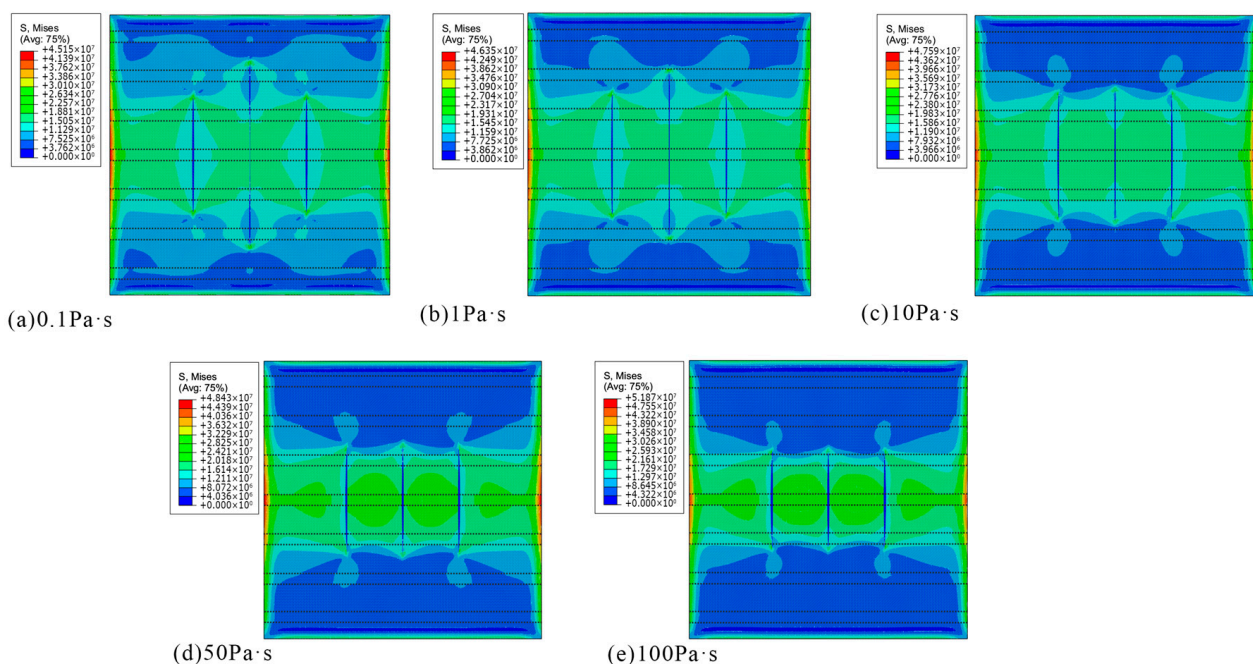


**Figure 16.** Effect of pumping rate on penetrated-layer count and fracture width.

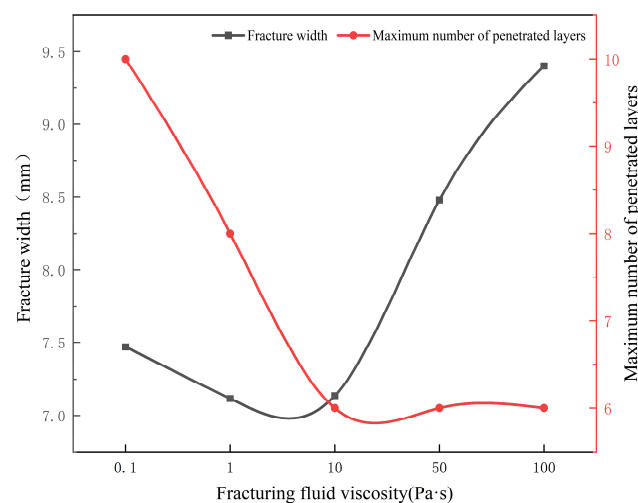
#### 4.6. Impact of Viscosity on Cross-Layer Fracture Propagation

When pumping capacity is limited, high-viscosity fluids are often used to improve proppant-carrying capacity. Five viscosity levels are considered: 0.1, 1, 10, 50, and 100 Pa·s.

The results reveal competing viscosity effects (Figures 17 and 18). At 0.1 Pa·s, efficient pressure transmission to the tip yields a long fracture and approximately ten connected layers. At 100 Pa·s, the penetrated-layer count is approximately four, a 60% reduction, while maximum aperture increases strongly near the wellbore. The width response is non-monotonic because moderate viscosity can retain pressure and limit leak-off, whereas very high viscosity increases frictional pressure loss and concentrates opening close to the perforation. The five deterministic cases show an overall negative viscosity–penetration association, but no rank coefficient is reported without a completed multivariable sampling analysis. The x-axis of Figure 18 is plotted as uniformly spaced nominal viscosity categories (0.1, 1.0, 10.0, 50.0, and 100.0 Pa·s) so that all five cases remain legible.



**Figure 17.** Fracture-propagation maps under different fracturing-fluid viscosities: (a) 0.1 Pa·s; (b) 1 Pa·s; (c) 10 Pa·s; (d) 50 Pa·s; (e) 100 Pa·s.



**Figure 18.** Effect of fracturing-fluid viscosity on fracture width and maximum penetrated-layer count.

Therefore, viscosity has competing effects. Moderate viscosity may support fracture extension by maintaining sufficient pressure while limiting excessive leak-off, whereas very high viscosity favors aperture growth near the wellbore and restricts long-distance height growth. This explains the non-monotonic width trend and the reduction in penetrated-layer count at high viscosity.

## 5. Conclusions

A fully coupled fluid–solid cohesive-zone model was developed for hydraulic-fracture propagation in thin continental shale–sandstone interbeds. The formulation explicitly represents lithology-dependent properties and interface damage, applies a quantitative hydraulic-connectivity criterion for effective penetration, and reports normalized response measures. The KGD curves provide a homogeneous implementation benchmark, and published layered-rock experiments provide morphology-level corroboration.

Across the tested ranges, lower  $E_y/E_s$ , lower tensile strength, thinner sandstone interlayers, sandstone-centered perforation, and higher injection rate promote connected fracture-height growth. Increasing tensile strength from 4 to 16 MPa reduces the penetrated-layer count from ten to six and final length from 32 to 21 m, while maximum aperture increases from 6.75 to 9.02 mm. Very high viscosity produces the opposite geometric tradeoff: greater near-wellbore opening but weaker long-distance vertical connectivity.

Among the reported onefactor cases, increasing the injection rate from 8 to 12 m<sup>3</sup>/min yields the maximum rise in the penetrated-layer count, which increases from four to twelve. Increasing tensile strength from 4 to 16 MPa reduces the penetrated-layer count from 10 to 6 and the final fracture length from 32 to 21 m, whereas the separate 100 Pa·s viscosity case reduces the penetrated-layer count from approximately ten to four.

The approximately 3 m sandstone-interlayer transition is valid only for the present stress, strength, interface, and pumping ranges. It must be recalibrated before field use.

Perforating a comparatively brittle sandstone interval can improve the probability of forming a vertically connected main fracture, and a higher early-time rate is more effective for interface crossing than simply increasing fluid viscosity. A practical sequence for continental siliciclastic shale is low- to moderate-viscosity slickwater or hybrid fluid during the height-growth stage, followed by a viscosity ramp or a crosslinked-gel stage for proppant transport. Fine 100-mesh proppant can enter narrow cross-layer branches before larger 40/70-mesh proppant supports the main fracture. Acidizing should not be assumed beneficial for shale–sandstone intervals and should be considered only after mineralogical tests confirm acid-soluble cement and acceptable fines/clay sensitivity.

The present results should be interpreted within the scope of the numerical framework. A two-dimensional plane-strain representation is used; consequently, out-of-plane fracture growth, finite wellbore and cluster spacing, and three-dimensional stress-shadow effects are not resolved. Within each shale or sandstone layer, the elastic response and permeability are represented by homogeneous, isotropic effective properties. Spatial variability, transverse isotropy, permeability anisotropy, and stress-dependent directional flow are therefore not captured. The interfaces are assigned simplified cohesive properties, whereas field interfaces may have heterogeneous cementation, roughness, and scale-dependent shear dilation. Natural-fracture networks, arbitrary off-path branching, proppant transport and embedment, non-Newtonian fluid rheology, and thermal coupling are also omitted.

Accordingly, the model is intended to identify relative trends and mechanisms rather than to predict a unique field treatment design. Future work should develop fully coupled three-dimensional hydro-mechanical-thermal simulations that incorporate spatially variable lithologic and interface properties, anisotropic permeability, and explicitly represented natural fractures. These developments should be supported by layered-core true-triaxial

tests and CT/DIC/AE observations, then validated at the field scale by jointly matching treatment-pressure and shut-in/falloff data, microseismic fracture height, and production response. Physics-constrained surrogate models may then be used for uncertainty propagation and treatment optimization within clearly stated applicability bounds.

**Author Contributions:** Z.W. and L.W. supervised the study. X.C., L.K. and N.L. conducted the theoretical analysis. L.W., Z.W., L.K. and X.C. performed the model derivation. D.A. and N.L. performed the numerical modeling. N.L. wrote the manuscript. L.W., Z.W., L.K. and X.C. were involved in discussions and manuscript revisions. All authors reviewed the manuscript. All authors have read and agreed to the published version of the manuscript.

**Funding:** This research received no external funding.

**Data Availability Statement:** The data that support the findings of this study are available from the corresponding authors upon reasonable request.

**Conflicts of Interest:** Author D.A. was employed by The First Oil Production Plant of Qinghai Oilfield, China National Petroleum Corporation. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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