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Optimization and Field Evaluation of Multi-Cluster Hydraulic Fracturing Using Surface L-Shaped Well in Soft Low-Permeability Coal Seam

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Abstract: This study investigated the effects of injection rate, sand-to-fluid ratio, and cluster spacing on multi-cluster hydraulic fracturing in a surface L-shaped horizontal well targeting the soft, low-permeability, outburst-prone No. 7 coal seam at Yongchun Coal Mine, Guizhou. Laboratory testing of coal and rock mechanical properties, three-dimensional discrete-element simulations in XSite, and comparative field monitoring were combined. The fracture area balance index (FBEI), fracture fluid-volume balance index (FVBI), fracture geometry balance index (FGEI), and comprehensive evaluation index (CEI) were formulated from the fracture area, fluid volume, and equivalent mean aperture of each cluster. The results showed that a higher injection rate increased the overall stimulation extent but intensified fluid competition among clusters. An excessively high sand-to-fluid ratio increased total fracture area and fluid volume while reducing inter-cluster uniformity. A cluster spacing of 5 m provided a favorable balance between stimulation extent and uniform fracture development. The parameter combination of 12 m³/min, 8%, and 5 m achieved the highest CEI (0.9233) among the seven independent combinations, with a total fracture area of 767.00 m² and a total fracture fluid volume of 11.845 m³. During 120 d of field monitoring, the fractured well yielded an average gas concentration of 65.68% and a cumulative methane drainage volume of 261,948.77 m³, both higher than those of the unfractured control well. These findings demonstrate the engineering feasibility and permeability-enhancement potential of the recommended parameter combination under the conditions investigated.

Keywords: Soft, low-permeability coal seam; surface L-shaped horizontal well; XSite; multi-cluster hydraulic fracturing; parameter optimization; gas drainage

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0 Introduction

Coal remains a major component of China’s primary energy mix ^[1-4]. Although China has abundant coalbed methane resources, the low intrinsic permeability of many coal seams limits efficient coalbed methane recovery and mine-gas drainage. Hydraulic fracturing enhances coal-seam permeability by promoting the propagation and coalescence of existing fractures and creating new hydraulic fractures; it is therefore widely used to stimulate low-permeability coal seams ^[5]. In hydraulic fracturing from surface wells, high-pressure fluid is injected into the target seam before mining to initiate and extend fractures, establish extensive flow pathways, improve gas transport, and reduce the risk of coal and gas outbursts ^[6-9].

Outburst-prone coal seams in southwestern China are often soft and weak, have low intrinsic permeability, and contain poorly developed gas-flow pathways. Conventional underground boreholes are susceptible to collapse and deformation and generally have a limited effective drainage radius, making it difficult to establish extensive and stable drainage networks. A surface L-shaped horizontal well provides a long lateral section within the coal seam and can enlarge the stimulated region through staged multi-cluster hydraulic fracturing, offering a practical approach to regional gas control in soft, low-permeability seams. However, during simultaneous fracture growth from multiple clusters, variations in in-situ stress, stress interference between clusters, and competition for fluid can direct flow preferentially into dominant clusters, restrict the growth of other clusters, and produce a nonuniform fracture network. Injection rate controls fluid supply, fracture net pressure, and the driving force for propagation. The sand-to-fluid ratio characterizes the proppant-laden stage and may affect fracture growth and fluid distribution through slurry properties and proppant placement, whereas cluster spacing governs stress shadowing and fracture interaction. Multi-cluster treatment design should therefore account not only for the dimensions of individual fractures and the total fracture extent, but also for overall stimulation, fluid distribution, and the uniformity of fracture growth among perforation clusters.

Previous studies have extensively investigated hydraulic-fracture initiation, propagation, and competition among multiple clusters. Hubbert and Willis ^[10] established the classical theory of hydraulic-fracture initiation. Qu et al. ^[11] and Hou et al. ^[12] examined fracture propagation through laboratory experiments and fracture-mechanics analyses. Chen ^[13] and Rueda Cordero et al. ^[14] further clarified fracture-growth mechanisms by investigating fracture reorientation and interaction with natural fractures, respectively. Qu et al. ^[15], Liu

et al. [16], and Ma and Zeng [17] analyzed the effects of well configuration, natural fractures, and perforation parameters on fracture geometry. Zhao et al. [18] developed a uniformity coefficient for multi-fracture propagation that incorporates fracture length, width, inlet fluid volume, and deflection angle. Liu et al. [19] proposed an improved uniformity index to assess the uniformity of fracture development among clusters. Zhao et al. [20] and Yi and Sharma [21] investigated inter-cluster fluid competition during simultaneous multi-fracture propagation and dynamic slurry distribution. Coupled simulations by Kresse et al. [22] and Zeng et al. [23] further showed that stress shadowing and wellbore-to-fracture flow partitioning jointly govern nonuniform multi-fracture propagation. Shiozawa and McClure [24] demonstrated that proppant settling, fracture closure, and particle transport strongly affect proppant placement among clusters. Although these studies provide a basis for evaluating multi-cluster uniformity, few have linked fracture extent, fluid distribution, and balance metrics to field gas-drainage performance under the in-situ stress conditions of soft, thin coal seams in Guizhou.

Accordingly, this study focused on the soft, low-permeability, outburst-prone No. 7 coal seam at Yongchun Coal Mine, Guizhou. A three-dimensional XSite discrete-element hydraulic-fracturing model was developed using measured in-situ stresses and the physical and mechanical properties of the coal and surrounding rock. A single-factor design was used to examine injection rate, sand-to-fluid ratio, and cluster spacing. The nine numbered cases represented seven independent parameter combinations, with Cases 3, 5, and 8 sharing the same baseline condition. Fracture morphology, area, fluid volume, and aperture were used to formulate FBEI, FVBI, FGEI, and CEI and to rank the parameter combinations in terms of stimulation extent and inter-cluster uniformity. The engineering feasibility and permeability-enhancement performance of the recommended combination were then evaluated using the field treatment curve and 120 d of gas-drainage data from a fractured well and an unfractured control well.

1 Engineering geological conditions and parameter determination

1.1 Engineering geological conditions

The Upper Permian Longtan Formation is the principal coal-bearing unit at Yongchun Coal Mine and has an average thickness of 295.16 m. The cumulative average thickness of the coal seams is 23.10 m, corresponding to a coal-bearing coefficient of 7.83%. Ten seams are mineable, with a combined average thickness of 15.14 m and a mineable coal-bearing coefficient of 5.13%. The No. 7 coal seam in the 1077 working face was selected for this study. The seam has an average thickness of 1.7 m and is classified as Type III structurally damaged coal. Its firmness coefficient is 0.39, the initial gas pressure is 0.78 MPa, the maximum gas content is 18.96 m³/t, the maximum initial velocity of gas diffusion is 23.0, and the maximum drill-cuttings gas desorption index (Δh_2) is 283.0 Pa. These parameters classify the seam as soft, low-permeability, and outburst-prone. The basic gas parameters are listed in Table 1.

Measurements of in-situ stress showed that the maximum horizontal, minimum horizontal, and vertical principal stresses in the No. 7 coal seam were 16.11, 8.92, and 12.06 MPa, respectively, indicating a stress regime dominated by horizontal stress. The coal-seam density was 1,520 kg/m³, and the porosity was 6.52%. Together with the low strength, high gas content, and poorly developed natural flow pathways, these conditions indicate a clear engineering need for hydraulic-fracture stimulation.

1.2 Determination of basic mechanical parameters

Rock-mechanics tests were conducted using a Top 50 HT multi-field coupled rock rheometer (France). The apparatus can apply a maximum axial stress of 500 MPa and maximum confining and seepage pressures of 60 MPa, with a pressure-control accuracy of ± 0.01 MPa. Axial and radial displacement transducers installed in the triaxial chamber enabled simultaneous measurement of specimen deformation. Uniaxial compression and Brazilian splitting tests were performed. The test apparatus is shown in Fig. 1.

Rock cores were collected from the argillaceous siltstone roof of the 1077 working face (Fig. 2). The cores were sealed immediately after recovery to minimize weathering and moisture loss and were subsequently prepared as standard specimens.



Fig. 1. Top 50 HT multi-field coupled rock rheometer



Fig. 2. Roof-rock specimens

Two replicate specimens were tested in both the uniaxial compression and Brazilian splitting tests, and the mean value for each pair was reported. Specimens A1 and A2 were used for uniaxial compression, whereas Specimens C3 and C4 were used for Brazilian splitting. The stress-strain curves and failure modes are shown in Figs. 3 and 4. The roof-rock test results are summarized in Table 1, and the physical and mechanical properties of the No. 7 seam obtained from mine records are listed in Table 4.

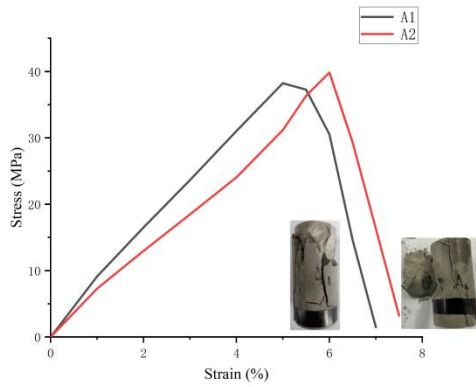


Fig. 3. Stress - strain curves and failure modes of Specimens A1 and A2

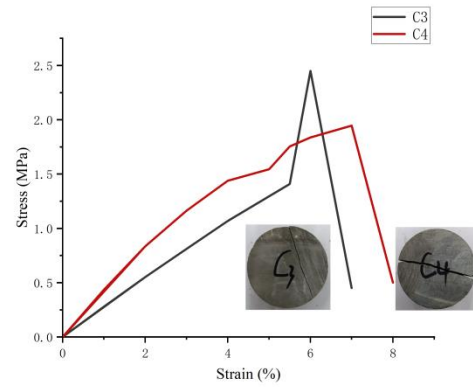


Fig. 4. Brazilian splitting test curves and failure modes of Specimens C3 and C4

Table 1. Physical and mechanical properties of the roof-rock specimens.

Lithology	Uniaxial compressive strength (MPa)	Brazilian tensile strength (MPa)	Elastic modulus (GPa)	Poisson' s ratio	Cohesion (MPa)	Internal friction angle (°)
Argillaceous siltstone	40.6	2.10	10.4	0.28	10.75	31.15

2 Numerical modeling method and analysis

2.1 XSite discrete-element model

Hydraulic fracturing in coal seams is characterized by pronounced discontinuous failure. Because of coal heterogeneity and structural weakness planes, hydraulic fractures commonly branch, deflect, and coalesce as they propagate. Three-dimensional discrete-element simulations were therefore performed in XSite to reproduce crack initiation, growth, and coalescence. The discrete-element method explicitly captures the activation of natural fractures and the discontinuous propagation of hydraulic fractures [25,26] and has been widely applied to hydraulic fracturing and post-fracturing permeability evolution in coal seams [27,28].

XSite is based on the discrete-element method and synthetic rock mass theory and represents the mesoscale structure of coal and rock using discrete elements and their contacts. Normal and shear stiffnesses transmit forces across contacts, whereas bond strength represents interparticle cementation. When the contact stress exceeds the corresponding strength threshold, the bond fails in tension or shear and creates a microcrack. The subsequent propagation and coalescence of microcracks form macroscopic hydraulic fractures. Bond

failure also creates new flow pathways. Fracture aperture controls fluid transmissivity, while fluid pressure loads the fracture walls and alters the stress state of the surrounding coal and rock, thereby producing two-way coupling between fracture deformation and fluid flow.

The mesoscopic parameters of the discrete-element model were calibrated against the uniaxial compression and Brazilian splitting results. Contact normal stiffness, shear stiffness, bond tensile strength, and bond shear strength were adjusted until the elastic modulus, compressive strength, and tensile strength of the numerical specimens agreed with the experimental values. Fig. 5 illustrates the discrete-element contacts, bonding behavior, and failure modes.

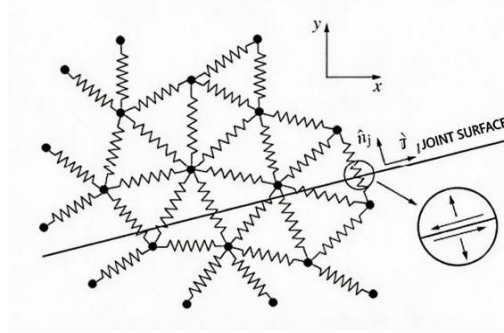


Fig. 5. Schematic of bonded contacts and failure modes in the discrete-element model.

2.2 Governing equations for hydro-mechanical coupling in hydraulic fracturing

XSite uses an explicit discrete-element formulation to solve the motion of coal particles and blocks and bonded contact elements to simulate crack initiation and propagation. Fracturing-fluid flow within the fractures is governed by the cubic law, and fluid pressure is coupled bidirectionally with fracture aperture and solid deformation.

(1) Motion and time integration of discrete elements

Under the prescribed initial stress field, mechanical boundary conditions, and fluid-injection boundary condition, velocity, displacement, and angular velocity in the i -th direction are updated using a central-difference scheme [25,26]:

$$\dot{u}_i^{t+\Delta t/2} = \dot{u}_i^{t-\Delta t/2} + \frac{\Sigma F_i^t}{m} \Delta t \quad (1)$$

$$u_i^{t+\Delta t} = u_i^t + \dot{u}_i^{t+\Delta t/2} \Delta t \quad (2)$$

$$\omega_i^{t+\Delta t/2} = \omega_i^{t-\Delta t/2} + \frac{\Sigma M_i^t}{I} \Delta t \quad (3)$$

where $\dot{u}_i$ and u_i are the velocity and displacement in the i -th direction, respectively; ω_i is the angular velocity; ΣF_i and ΣM_i are the resultant force and moment acting on the discrete element; m is the element mass; I is the moment of inertia; Δt is the mechanical time step; and $i = 1, 2$, and 3 .

(2) Contact-force update and bond failure

The bonded contact forces are updated from the increments in the normal and shear components of relative displacement between adjacent discrete elements:

$$F_n^{t+\Delta t} = F_n^t + k_n \Delta u_n \quad (4)$$

$$F_s^{t+\Delta t} = F_s^t + k_s \Delta u_s \quad (5)$$

where F_n and F_s are the normal and shear forces at the bonded contact; k_n and k_s are the corresponding normal and shear stiffnesses; and Δu_n and Δu_s are the increments in normal and shear relative displacement. Positive normal relative displacement denotes contact closure, and the direction of the shear force follows that of the relative shear displacement.

When the tensile or shear force at a bonded contact reaches the corresponding strength threshold, bond failure occurs:

$$F_n^{tens} \geq F_{n,c} \quad \text{or} \quad \|F_s\| \geq F_{s,c} \quad (6)$$

where $F_{n,s}$ and $F_{s,c}$ are the critical tensile and shear forces of the bonded contact, respectively, and are calculated from the bond

strengths and effective contact area. Bond failure creates microcracks that subsequently propagate and coalesce into macroscopic hydraulic fractures.

(3) Fluid flow equation within fractures

Bond failure creates pathways for fracture flow. Flow of fracturing fluid within a fracture is described by the parallel-plate cubic law. The flow rate between Nodes A and B is:

$$q_{AB} = \beta k_r \frac{a^3}{12\mu_f} [p_A - p_B + \rho_\omega g(z_A - z_B)] \quad (7)$$

where q_{AB} is the flow rate from Node A to Node B; β is a correction coefficient accounting for flow-channel geometry and fracture roughness; a is the hydraulic aperture; μ is the dynamic viscosity; p_A and p_B are the fluid pressures at Nodes A and B; ρ is the fluid density; g is gravitational acceleration; z_A and z_B are the elevations of the two nodes; and k_r is the relative permeability.

(4) Fluid pressure update equation

Within a fluid-flow time step, the net inflow to a node, the change in fracture control volume, and fluid compression satisfy:

$$\Delta t_f \sum_i q_i = \Delta V + \frac{V^t}{K_f} \Delta p \quad (8)$$

Equation (8) yields the following update equation for nodal pressure:

$$p^{t+\Delta t_f} = p^t + \frac{K_f}{V^t} \left(\Delta t_f \sum_i q_i - \Delta V \right) \quad (9)$$

where V^t is the nodal control volume at the beginning of the flow time step; ΔV is the change in control volume caused by fracture opening and discrete-element deformation; K_f is the apparent fluid bulk modulus; Δt_f is the fluid-flow time step; and $\sum q_i$ is the net inflow to the node, with inflow taken as positive. Net inflow raises nodal pressure, whereas fracture opening increases the control volume and lowers pressure. Fluid pressure then acts on the fracture walls, providing two-way feedback between fracture deformation and fluid flow.

2.3 Simulation scheme and results

Injection rate, sand-to-fluid ratio, and cluster spacing were selected as the principal variables on the basis of the geological conditions of the No. 7 seam and the range of field treatment parameters used at Yongchun Coal Mine. Injection rate controls the supply of fracturing fluid, fracture net pressure, and the driving force for propagation. The sand-to-fluid ratio represents the proppant loading during the treatment; its simulated effect depends on how proppant or equivalent fluid parameters are implemented in the model. Cluster spacing controls stress interference and fluid competition between clusters, thereby affecting the uniformity and spatial connectivity of fracture propagation.

The numerical domain measured 160 m $\times$ 50 m $\times$ 10 m. Its longitudinal axis was aligned with the maximum horizontal principal stress, and the wellbore was located at the center of the model. A sufficient distance was maintained between the expected fracture-propagation region and the model boundaries to minimize boundary effects on fracture geometry and the stress field near the fracture tips. The model included the No. 7 seam and its roof and floor to account for the constraints imposed by lithological interfaces.

Three sets of comparative cases were established using a single-factor design. Injection rates of 6, 9, and 12 m³/min were examined while the sand-to-fluid ratio and cluster spacing were held at 8% and 5 m, respectively. Sand-to-fluid ratios of 4%, 8%, and 12% were examined while the injection rate and cluster spacing were held at 12 m³/min and 5 m. Cluster spacings of 4, 5, and 6 m were examined while the injection rate and sand-to-fluid ratio were held at 12 m³/min and 8%. The design comprised nine numbered cases representing seven independent parameter combinations. Cases 3, 5, and 8 had identical parameters and served as the common baseline condition for the three groups.

The physical and mechanical parameters required for the simulations were obtained from mine records and are listed in Tables 2 and 3. The three-dimensional numerical model and perforation-cluster layout are shown in Fig. 6. Because a single-factor design was used, Cases 3, 5, and 8 represent the same parameter combination. The complete simulation matrix is provided in Table 4.

Table 2. In-situ stress and physical properties of the No. 7 coal seam

Coal seam	Thickness (m)	Density(kg/m ³)	Maximum horizontal principal stress(MPa)	Minimum horizontal principal stress(MPa)	Vertical principal stress,(MPa)	Porosity(%)
No.7	1.7	1520	16.11	8.92	12.06	6.52

Table 3. Mechanical properties of the No. 7 coal seam

Coal seam	Young's modulus (GPa)	Poisson's ratio	Tensile strength (MPa)	Compressive strength (MPa)	Internal friction angle (°)	Cohesion (MPa)
No. 7	2.75	0.31	0.71	4.45	30.6	1.67

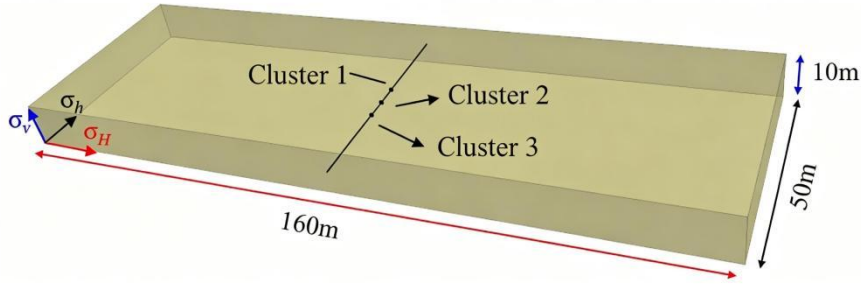


Fig. 6. Three-dimensional numerical model and perforation-cluster layout.

Table 4. Numerical simulation cases.

Variable	Case	Injection rate (m ³ /min)	Sand-to-fluid ratio (%)	Cluster spacing (m)
Injection-rate variation	1	6	8	5
	2	9	8	5
	3	12	8	5
Sand-to-fluid-ratio variation	4	12	4	5
	5	12	8	5
	6	12	12	5
Cluster-spacing variation	7	12	8	4
	8	12	8	5
	9	12	8	6

Hydraulic fracturing was simulated in XSite for each case using the prescribed parameters. The resulting fracture morphologies and aperture distributions are shown in Figs. 7 – 13. The hydraulic fractures generally propagated in the direction of the maximum horizontal principal stress. Most visible fracture elements had apertures of 2 – 15 mm, with larger apertures near the wellbore than at the fracture tips. Cases 1 and 9 produced relatively straight main fractures but limited overall stimulation. Cases 2 and 4 showed comparatively coordinated near-wellbore growth and distal extension. The common baseline case combined relatively large near-wellbore apertures with bilateral propagation, although some clusters remained locally dominant. Cases 6 and 7 exhibited pronounced concentration in a single cluster or on one side of the wellbore. Overall, a low injection rate and large cluster spacing produced relatively uniform fracture distributions but limited stimulation, whereas a high sand-to-fluid ratio and small cluster spacing favored the development of locally dominant clusters. The baseline case provided a comparatively large stimulation extent while maintaining acceptable differences among clusters.

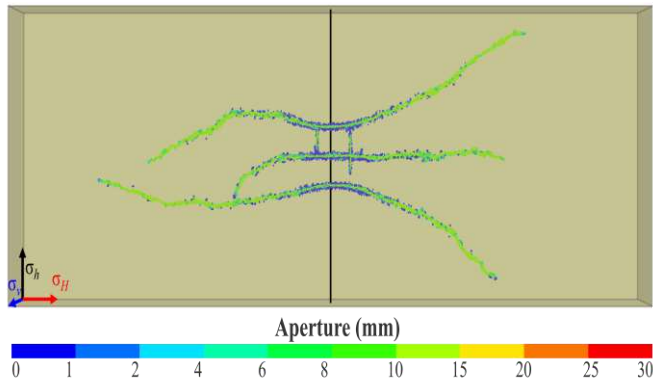


Fig. 7. Fracture morphology and aperture distribution for Case 1.

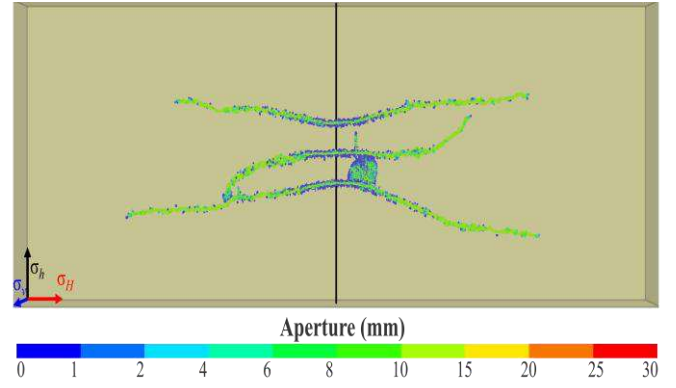


Fig. 8. Fracture morphology and aperture distribution for Case 2.

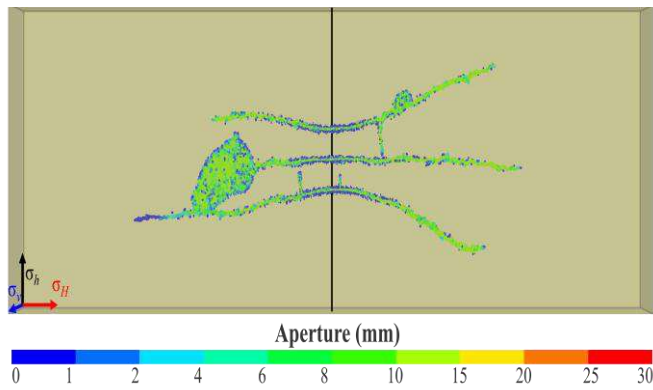


Fig. 9. Fracture morphology and aperture distribution for Case 4.

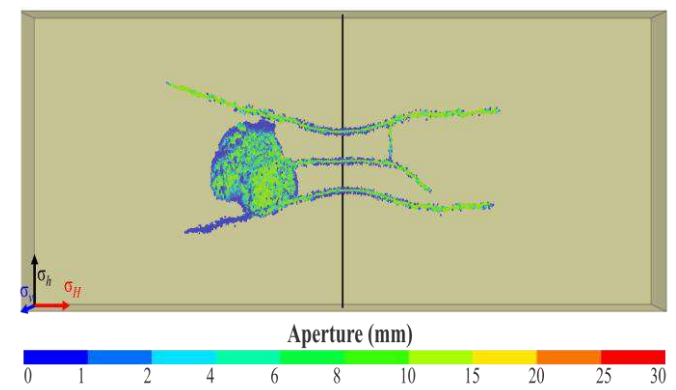


Fig. 10. Fracture morphology and aperture distribution for Case 6.

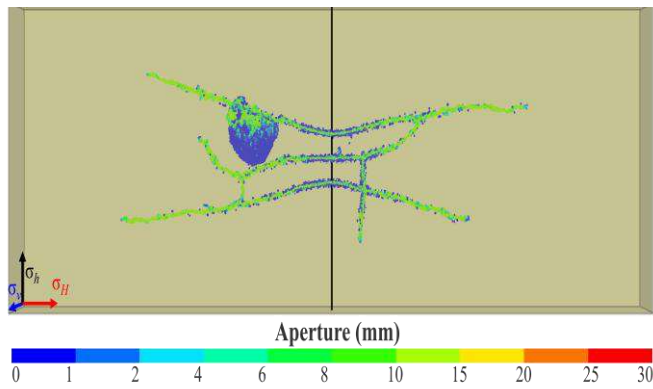
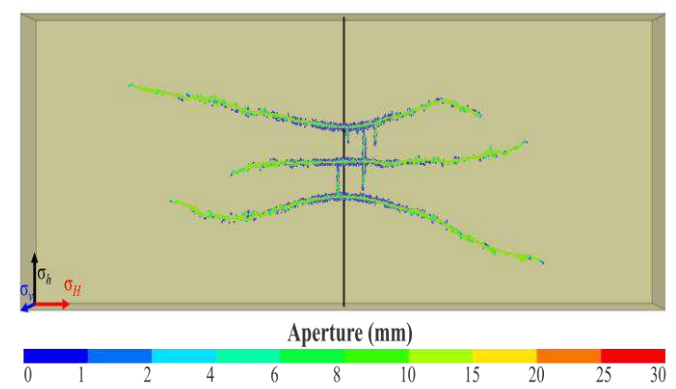


Fig. 11. Fracture morphology and aperture distribution for Case 7.



FFig. 12. Fracture morphology and aperture distribution for Case 9.

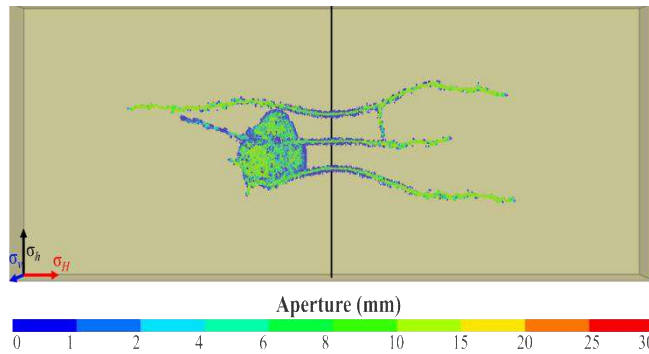
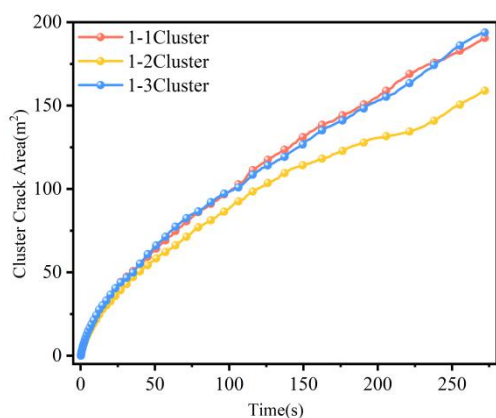


Fig. 13. Fracture morphology and aperture distribution for the baseline Cases 3, 5, and 8.

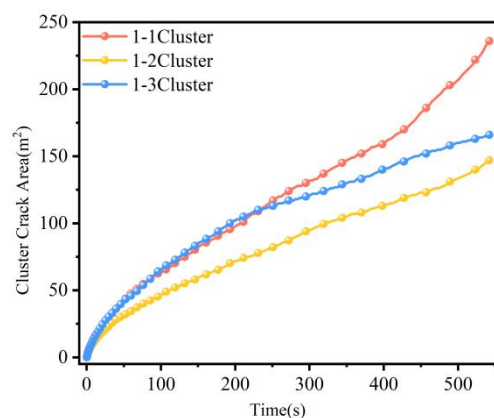
2.4 Response of fracture area and fluid volume

As shown in Figs. 14 and 15, injection rate strongly affected fracture extent and uniformity among clusters. At 6 m³/min, the final fracture areas of the three clusters were 190.54, 158.87, and 193.85 m², respectively, giving a total area of 543.26 m² with only minor differences among clusters. At 9 m³/min, the corresponding areas were 235.87, 146.89, and 166.19 m², and Cluster 1-1 began to dominate. At 12 m³/min, the cluster areas were 224.53, 357.84, and 184.63 m², and the total area increased to 767.00 m². Rapid late-stage growth of Cluster 1-2 reduced the uniformity of fracture-area distribution.

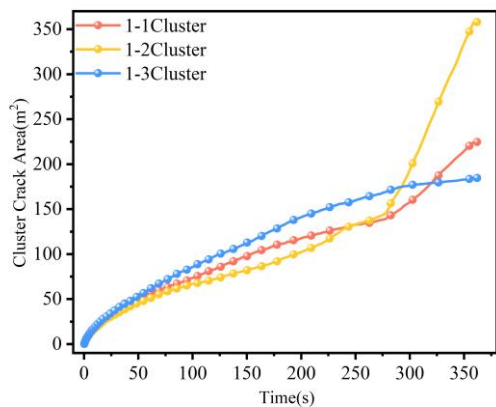
The variation in fracture fluid volume generally followed that in fracture area. At injection rates of 6, 9, and 12 m³/min, the total fluid volumes were 9.285, 9.113, and 11.845 m³, respectively. At 12 m³/min, Cluster 1-2 contained 5.099 m³ of fluid, compared with 3.613 m³ in Cluster 1-1 and 3.133 m³ in Cluster 1-3. Thus, increasing the injection rate enlarged the overall stimulation extent but also increased the preferential distribution of fluid to the dominant cluster.



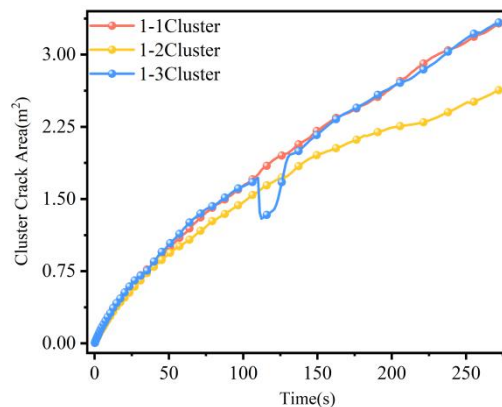
Case 1: fracture area



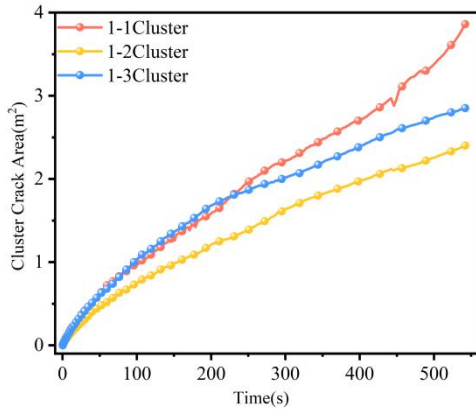
Case 2: fracture area



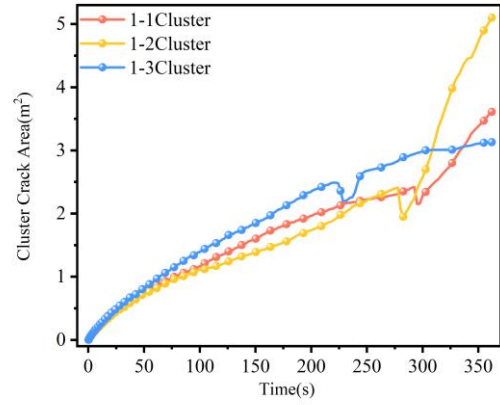
Case :fracture area



Case 1: fluid volume



Case 2: fluid volume



Case 3: fluid volume

Fig. 14. Evolution of fracture area and fluid volume for each cluster at different injection rates.

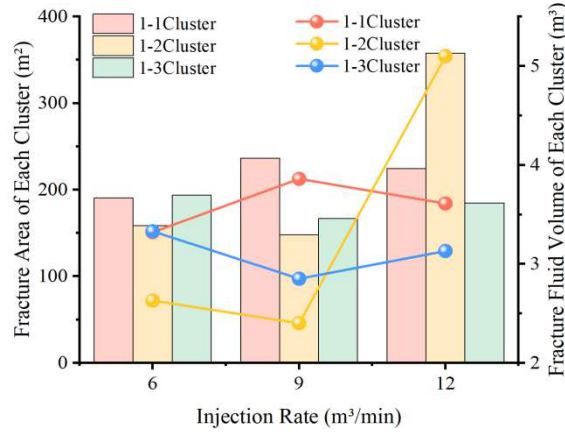
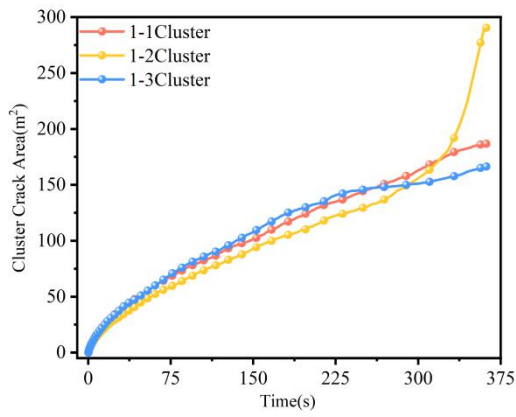


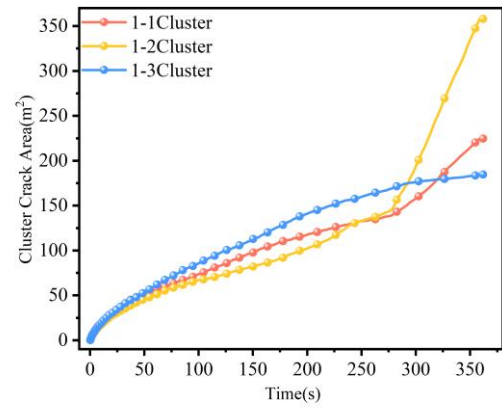
Fig. 15. Fracture area and fluid volume of each cluster at different injection rates.

As shown in Figs. 16 and 17, at an injection rate of $12 \text{ m}^3/\text{min}$ and a cluster spacing of 5 m, the final fracture areas were 186.71, 290.38, and 166.34 m^2 at a sand-to-fluid ratio of 4%, giving a total area of 643.42 m^2 . At 8%, the corresponding areas were 224.53, 357.84, and 184.63 m^2 , with a total of 767.00 m^2 . At 12%, the areas were 194.42, 499.53, and 178.83 m^2 , and the total reached 872.77 m^2 . As the sand-to-fluid ratio increased, the late-stage growth advantage of Cluster 1-2 became progressively more pronounced, and the 12% case showed the largest difference in fracture area among clusters.

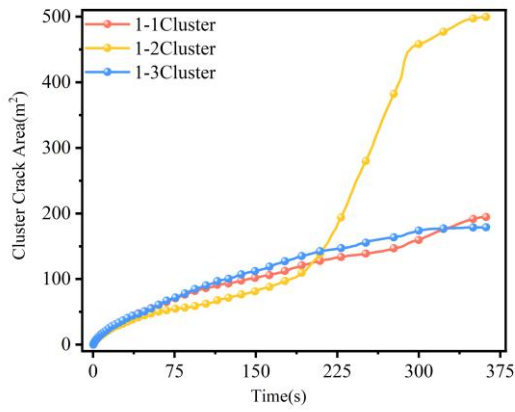
The corresponding total fluid volumes were 10.401, 11.845, and 12.437 m^3 . At a sand-to-fluid ratio of 12%, Cluster 1-2 contained 6.675 m^3 of fluid, whereas Clusters 1-1 and 1-3 contained 2.867 and 2.895 m^3 , respectively, indicating pronounced fluid concentration in the dominant cluster. Under the assumptions of the present model, increasing the sand-to-fluid ratio enlarged the overall fracture extent, but an excessively high ratio markedly reduced the uniformity of fracture-area and fluid-volume distribution.



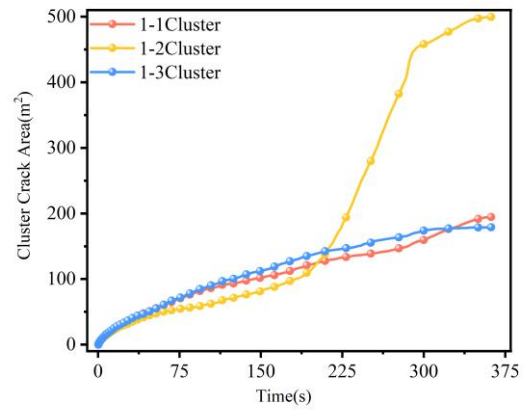
Case 4: fracture area



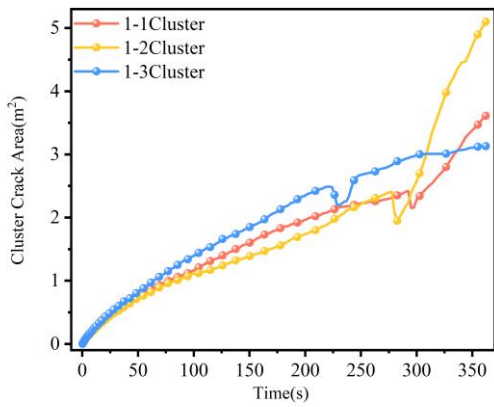
Case 5: fracture area



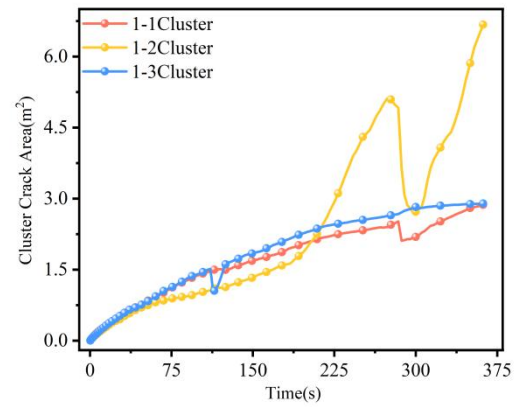
Case 5: fracture area



Case 3: fluid volume



Case 5: fluid volume



Case 6: fluid volume

Fig. 16. Evolution of fracture area and fluid volume for each cluster at different sand-to-fluid ratios.

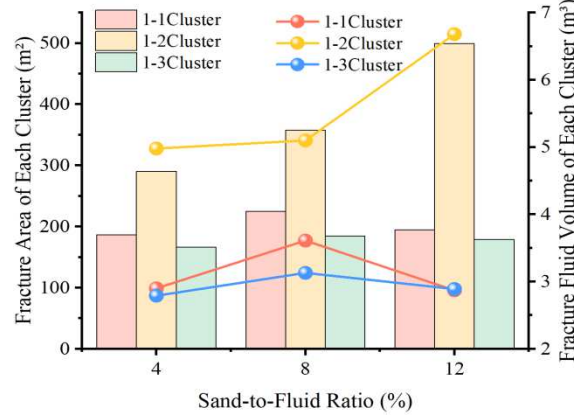
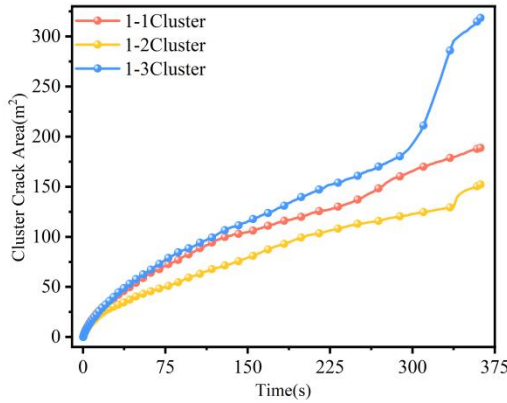


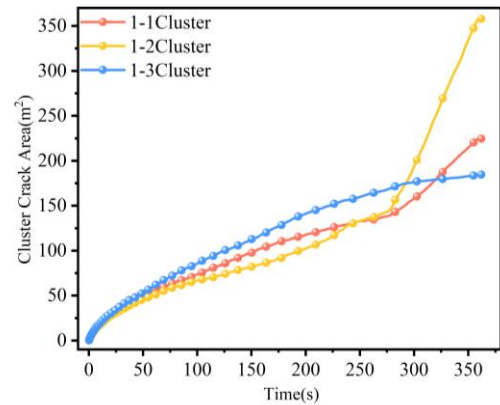
Fig. 17. Fracture area and fluid volume of each cluster at different sand-to-fluid ratios.

As shown in Figs. 18 and 19, at an injection rate of $12 \text{ m}^3/\text{min}$ and a sand-to-fluid ratio of 8%, the final fracture areas were 188.67, 152.07, and 318.33 m^2 at a cluster spacing of 4 m, with Cluster 1-3 clearly dominant. At 5 m, the corresponding areas were 224.53, 357.84, and 184.63 m^2 , giving a total area of 767.00 m^2 . At 6 m, the areas were 193.76, 161.56, and 184.80 m^2 , representing the most uniform distribution, although the total area was only 540.12 m^2 .

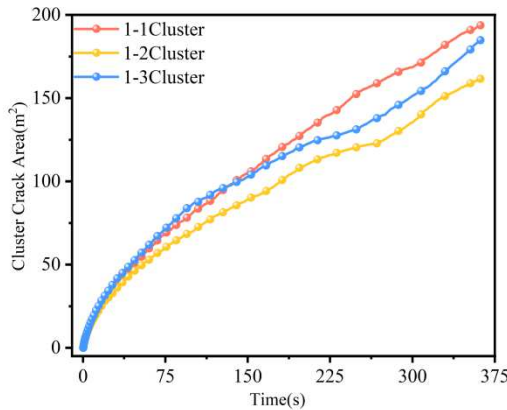
At cluster spacings of 4, 5, and 6 m, the total fracture fluid volumes were 9.394, 11.845, and 9.098 m^3 , respectively. At 4 m, Cluster 1-3 contained 3.892 m^3 of fluid, exceeding the volumes in the other two clusters. At 5 m, Cluster 1-2 contained 5.099 m^3 . At 6 m, the cluster fluid volumes ranged from 2.712 to 3.249 m^3 , representing the most uniform distribution. Increasing cluster spacing therefore weakened competition among clusters; however, an excessively large spacing reduced both the overall stimulation extent and the spatial connectivity of the fractures.



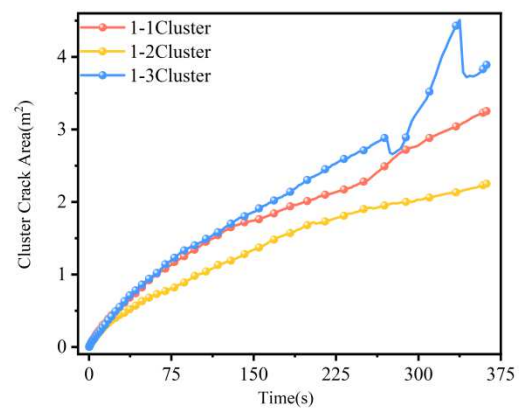
Case 7: fracture area



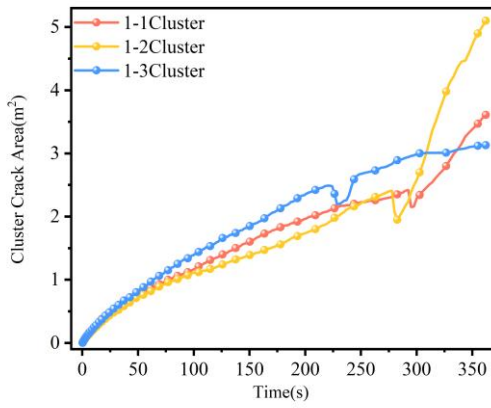
Case 8: fracture area



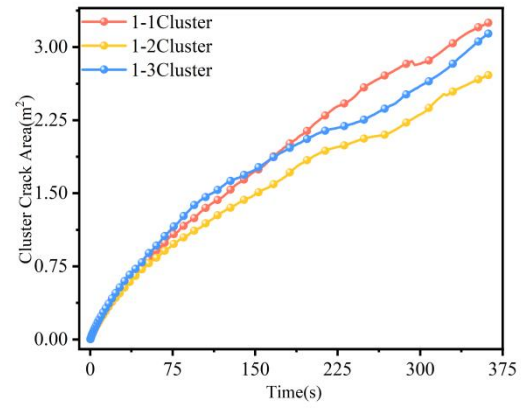
Case 9: fracture area



Case 7: fluid volume



Case 8: fluid volume



Case 9: fluid volume

Fig. 18. Evolution of fracture area and fluid volume for each cluster at different cluster spacings.

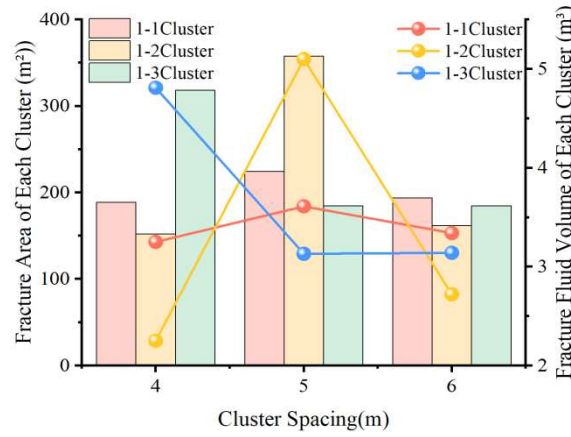


Fig. 19. Fracture area and fluid volume of each cluster at different cluster spacings.

2.5 Numerical analysis of fracture morphology

2.5.1 Effect of injection rate on fracture morphology

At a sand-to-fluid ratio of 8% and a cluster spacing of 5 m, increasing the injection rate changed both the extent of fracture propagation and the distribution of growth among clusters. At the lowest injection rate, the three clusters developed relatively uniformly, but the total fracture area and fluid volume were small. At the intermediate rate, a locally dominant cluster began to emerge. At the highest rate, the overall stimulation extent was larger, but the dominant cluster propagated substantially faster than the others. Thus, a higher injection rate increased the driving force for propagation while amplifying differences in initiation and growth resistance among perforation clusters, thereby intensifying fluid competition (Figs. 20 and 21).

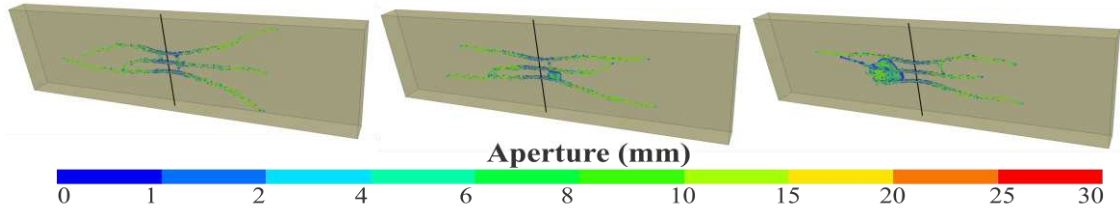


Fig. 20. Three-dimensional fracture morphology and aperture distribution at different injection rates.

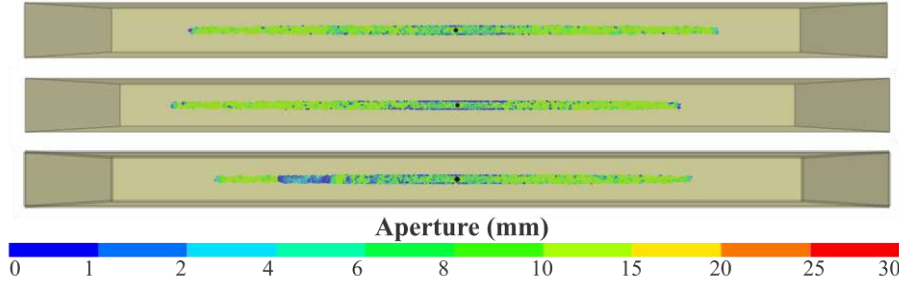


Fig. 21. Plan-view fracture morphology and aperture distribution at different injection rates.

2.5.2 Effect of sand-to-fluid ratio on fracture morphology

At an injection rate of 12 m³/min and a cluster spacing of 5 m, increasing the sand-to-fluid ratio from 4% to 12% increased the total fracture area and fluid volume but also intensified concentration in the dominant Cluster 1-2. The overall fracture extent was relatively small at 4%. A sand-to-fluid ratio of 8% combined a comparatively large fracture extent with relatively uniform fluid distribution, whereas 12% produced the largest total area but excessive growth of a single cluster. Thus, increasing the sand-to-fluid ratio was not uniformly beneficial. Because proppant transport and post-treatment fracture support were not explicitly modeled, these results are interpreted primarily in terms of simulated fracture growth and fluid distribution (Figs. 22 and 23).

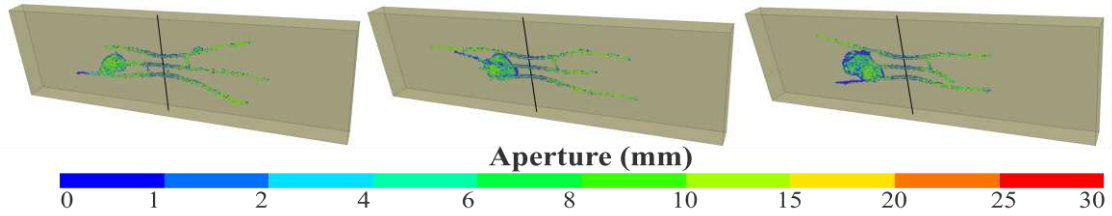


Fig. 22. Three-dimensional fracture morphology and aperture distribution at different sand-to-fluid ratios.

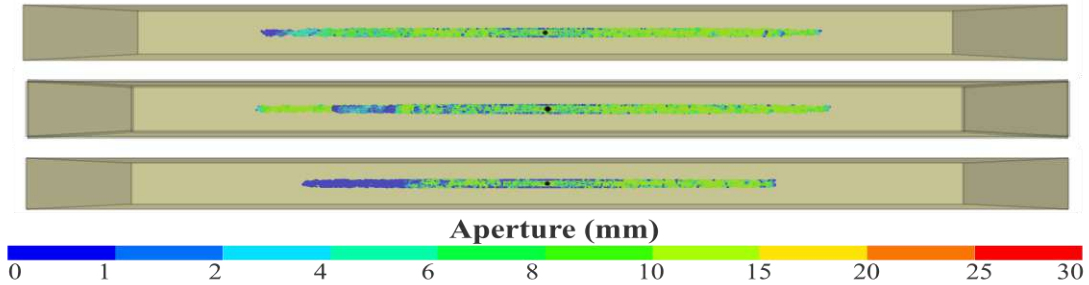


Fig. 23. Plan-view fracture morphology and aperture distribution at different sand-to-fluid ratios.

2.5.3 Effect of cluster spacing on fracture morphology

At the prescribed injection rate and sand-to-fluid ratio, cluster spacing clearly affected fracture interaction and fluid distribution among clusters. At 4 m, locally dominant clusters were evident, suggesting that strong inter-cluster interaction promoted preferential fluid entry into the dominant cluster. At 6 m, the three clusters developed most uniformly, but the overall fracture extent was small. At 5 m, the stimulation extent was substantially larger than at 6 m, while the distribution among clusters was more uniform than at 4 m, indicating a compromise between extent and uniformity. Overall, an excessively small cluster spacing intensified competition among clusters, whereas an excessively large spacing could reduce both the overall stimulation extent and fracture connectivity [22,23]. The fracture morphology and aperture distributions are shown in Figs. 24 and 25.

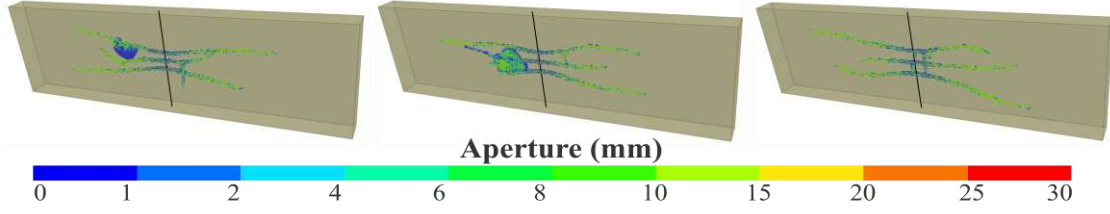


Fig. 24. Three-dimensional fracture morphology and aperture distribution at different cluster spacings.

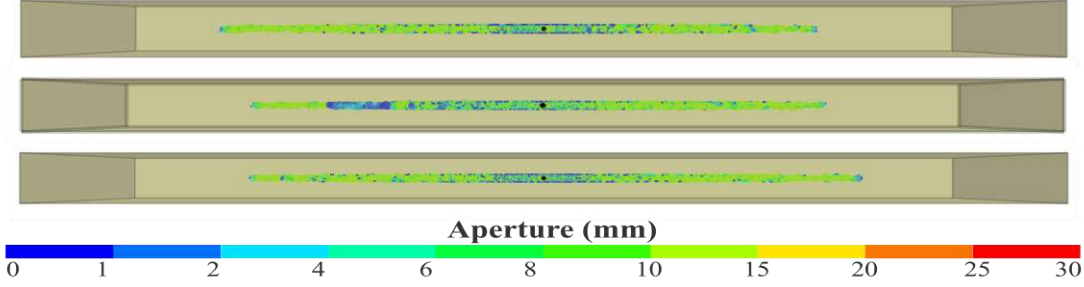


Fig. 25. Plan-view fracture morphology and aperture distribution at different cluster spacings.

2.6 Multi-cluster fracture balance and comprehensive evaluation

The performance of multi-cluster hydraulic fracturing depends on both the overall extent of fracture propagation and the degree of fluid competition and nonuniform growth among perforation clusters. Previous studies have characterized multi-fracture uniformity using fracture length, width, inlet fluid volume, deflection angle, and fracture volume [18,19]. Stress interference and flow redistribution during simultaneous fracture propagation are major drivers of competition among clusters [20-23]. Accordingly, this study considered total fracture area and fluid volume together with a fracture area balance index, fracture fluid-volume balance index, and aperture-based fracture geometry balance index. These metrics were integrated into a comprehensive evaluation index to rank the investigated parameter combinations.

(1) Multi-cluster fracture balance metrics

To place all balance indices on a common scale from 0 to 1, the resource-allocation fairness index proposed by Jain et al. [29] was linearly transformed so that 0 denotes complete dominance by a single cluster and 1 denotes identical values for all clusters. The general balance function is defined as:

$$B_{(x_1, x_2, \dots, x_n)} = \frac{1}{n-1} \left[\frac{\left(\sum_{i=1}^n x_i \right)^2}{\sum_{i=1}^n x_i^2} - 1 \right] \quad (10)$$

where x_i is the evaluation parameter for the i -th perforation cluster, and n is the number of clusters ($n = 3$ in this study).

When the evaluation parameters are identical for all perforation clusters, $B = 1$, indicating perfectly uniform inter-cluster distribution. When the parameter is concentrated entirely in one perforation cluster, $B = 0$, indicating a highly nonuniform distribution. Therefore:

$$0 \leq B \leq 1$$

(2) Fracture area balance index

Fracture area represents the effective stimulation extent contributed by each perforation cluster. Let A_i denote the fracture area generated by the i -th cluster at the end of the simulation. Following the concept of multi-fracture propagation uniformity [19] and the normalized form of Jain's fairness index [29], the fracture area balance index (FBEI) is defined as:

$$FBEI = \frac{1}{n-1} \left[\frac{\left(\sum_{i=1}^n A_i \right)^2}{\sum_{i=1}^n A_i^2} - 1 \right] \quad (11)$$

An FBEI value close to 1 indicates that the fracture areas generated by the three perforation clusters are similar and that the stimulated area is distributed more uniformly. A lower FBEI indicates that fracture area is concentrated in locally dominant clusters and that competition among clusters is stronger. FBEI quantifies only the uniformity of area distribution and does not represent the magnitude of the total fracture area.

(3) Fracture fluid-volume balance index

The fluid volume within the fractures reflects both the fluid distributed to each perforation cluster and the corresponding fracture capacity. Studies of simultaneous multi-fracture propagation and slurry distribution have shown that differences in cluster-entry resistance, fracture-growth resistance, and stress interference cause dynamic flow redistribution [20,21]. Let V_i denote the fracture fluid volume associated with the i -th cluster. The fracture fluid-volume balance index (FVBI) is defined as:

$$FVBI = \frac{1}{n-1} \left[\frac{\left(\sum_{i=1}^n V_i \right)^2}{\sum_{i=1}^n V_i^2} - 1 \right] \quad (12)$$

An FVBI value close to 1 indicates a more uniform distribution of fracturing fluid among the three clusters. A lower FVBI indicates preferential fluid entry into locally dominant clusters and a more pronounced imbalance in inter-cluster flow.

(4) Fracture geometry balance index

Zhao et al. [18] noted that assessments of multi-fracture uniformity should account for both geometric parameters and inlet fluid volume. Because the available XSite outputs did not include all descriptors of fracture geometry, fluid volume per unit fracture area was used as the equivalent mean aperture of each cluster, enabling an aperture-based assessment of geometric uniformity. The equivalent mean aperture of the i -th fracture cluster is:

$$\bar{b}_i = \frac{V_i}{A_i} \quad (13)$$

where $\bar{b}_i$ is the equivalent mean aperture of the i -th cluster (m), and V_i and A_i are the fracture fluid volume and fracture area of that cluster, respectively. The uniformity of equivalent mean aperture among the perforation clusters is then defined as the fracture geometry balance index (FGEI):

$$FGEI = \frac{1}{1-n} \left[\frac{\left(\sum_{i=1}^n \bar{b}_i \right)^2}{\sum_{i=1}^n \bar{b}_i^2} - 1 \right] \quad (14)$$

An FGEI value close to 1 indicates similar equivalent mean apertures among the fracture clusters and a more uniform relationship between fracture volume and fracture area. A lower FGEI indicates greater differences in aperture characteristics among clusters.

(5) Composite index of stimulation extent and inter-cluster balance

FBEI, FVBI, and FGEI quantify inter-cluster uniformity. If fracturing performance were evaluated solely using these indices, a case with limited fracture growth but uniform cluster development could receive an artificially high score. The overall stimulation extent must therefore also be considered. For the j -th case, total fracture area and total fracture fluid volume are defined as:

$$A_{T,j} = \sum_{i=1}^n A_{ij} \quad (15)$$

$$V_{T,j} = \sum_{i=1}^n V_{ij} \quad (16)$$

Total fracture area and fluid volume are normalized using the maximum-value method:

$$\tilde{A}_j = \frac{A_{T,j}}{\max(A_{T,j})} \quad (17)$$

$$\tilde{V}_j = \frac{V_{T,j}}{\max(V_{T,j})} \quad (18)$$

The stimulation extent index (SEI) is then defined as:

$$SEI_j = \left(\tilde{A}_j \tilde{V}_j \right)^{\frac{1}{2}} \quad (19)$$

An SEI value close to 1 indicates a larger combined stimulation extent in terms of total fracture area and fracture volume. To combine

the uniformity of fracture area, fluid distribution, and equivalent aperture, the inter-cluster balance evaluation index (BEI) is defined as:

$$BEI_i = (FBEI_j \bullet FBBI_i \bullet FGEI_j)^{\frac{1}{3}} \quad (20)$$

The geometric mean limits compensatory effects among the component indices; consequently, a low value of any individual balance metric constrains the BEI. Parameter optimization should provide an adequate overall stimulation extent while avoiding excessive fluid concentration in dominant clusters. Weights of 0.60 and 0.40 were therefore assigned to the stimulation-extent and inter-cluster balance components, respectively, and the comprehensive evaluation index (CEI) was defined as:

$$CEI_j = SEI_j^{0.60} BEI_j^{0.4} \quad (21)$$

The CEI ranges from 0 to 1, with higher values indicating better overall performance in terms of fracture-propagation extent, fracture fluid volume, and uniform development among fracture clusters.

(6) Comprehensive evaluation of the simulation cases

For each case, the fracture area and fracture fluid volume at the final valid time step were used for evaluation. Cases 3, 5, and 8 had identical parameters and were therefore treated as a single independent parameter combination. The balance and comprehensive evaluation results are listed in Table 6, and the CEI values are compared in Fig. 26.

Table 5. Balance and comprehensive evaluation results for the simulation cases.

Case	Injection rate – sand-to-fluid ratio – cluster spacing	A_T / m^2	V_T / m^3	FBEI	FVBI	FGEI	BEI	SEI	CEI
1	6 m ³ /min-8%-5m	543.26	9.285	0.9887	0.9832	0.9993	0.9904	0.6817	0.7915
2	9 m ³ /min-8%-5m	548.95	9.113	0.9373	0.9414	0.9993	0.9589	0.6789	0.7795
3/5/8	12 m ³ /min-8%-5m	767.00	11.845	0.8839	0.9355	0.9923	0.9362	0.9149	0.9233
4	12 m ³ /min-4%-5m	643.42	10.401	0.9096	0.8689	0.9893	0.9213	0.7852	0.8370
6	12 m ³ /min-12%-5m	872.77	12.437	0.6928	0.7646	0.9909	0.8067	1.0000	0.9176
7	12 m ³ /min-8%-4m	659.07	9.394	0.8569	0.9334	0.9718	0.9195	0.7553	0.8171
9	12 m ³ /min-8%-6m	540.12	9.098	0.9915	0.9913	1.0000	0.9943	0.6728	0.7866

Note: FBEI, fracture area balance index; FVBI, fracture fluid-volume balance index; FGEI, fracture geometry balance index based on equivalent mean aperture; BEI, balance evaluation index; SEI, stimulation extent index; CEI, comprehensive evaluation index.

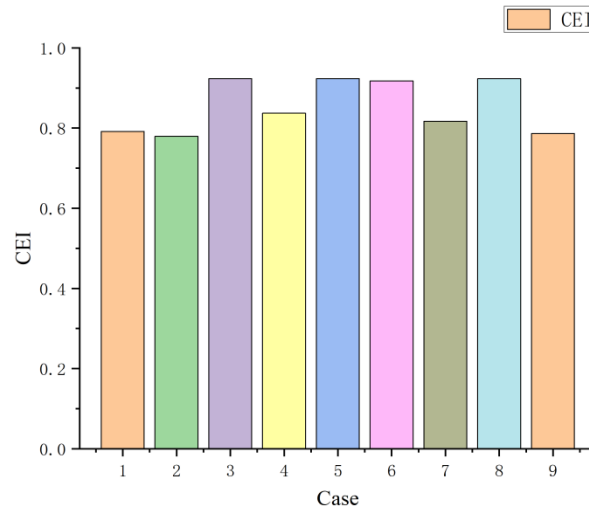


Fig. 26. Comparison of the comprehensive evaluation index (CEI) among different cases.

As shown in Table 6, FBEI, FVBI, and FGEI were all close to 1 for Cases 1 and 9, indicating relatively uniform development of the three clusters at a low injection rate or large cluster spacing. However, the total fracture areas were only 543.26 and 540.12 m², and the total fluid volumes were 9.285 and 9.098 m³, respectively, resulting in SEI values of 0.6817 and 0.6728. High inter-cluster uniformity

355 therefore did not necessarily correspond to a large stimulation extent.

356 When the injection rate increased from 6 to 12 m³ /min, the total fracture area of the baseline case increased from 543.26 to 767.00
357 m² , and the total fluid volume increased from 9.285 to 11.845 m³ , showing that a higher injection rate substantially enlarged the overall
358 stimulation extent. Meanwhile, FBEI decreased from 0.9887 to 0.8839, indicating stronger competition from the dominant fracture cluster
359 at the higher injection rate. Nevertheless, FVBI remained at 0.9355, indicating that severe imbalance in fluid distribution among the three
360 clusters did not occur.

361 At a sand-to-fluid ratio of 12%, the total fracture area and total fluid volume reached 872.77 m² and 12.437 m³ , respectively, and
362 SEI was 1.0000, representing the largest stimulation extent among all cases. However, FBEI and FVBI decreased to 0.6928 and 0.7646,
363 respectively, markedly below the values for the other cases. These results indicate that both fracture area and fluid volume were strongly
364 concentrated in Cluster 1-2. Although this case produced a large fracture extent, excessive growth of the dominant cluster reduced
365 stimulation uniformity along the horizontal section.

366 At a cluster spacing of 4 m, FGEI decreased to 0.9718, the lowest value among the cases, indicating that strong inter-cluster stress
367 interference increased differences in both fracture area and equivalent aperture. At 6 m, FBEI, FVBI, and FGEI reached 0.9915, 0.9913,
368 and 1.0000, respectively, indicating the highest inter-cluster uniformity, although the overall stimulation extent remained limited.

369 The comprehensive evaluation showed that the case with an injection rate of 12 m³ /min, an average sand-to-fluid ratio of 8%, and
370 a cluster spacing of 5 m achieved a CEI of 0.9233 and ranked first among the seven independent parameter combinations. Although this
371 case did not yield the most uniform distribution of fracture area or fluid volume, it produced a large total fracture area and fluid volume
372 while maintaining relatively high FBEI, FVBI, and FGEI values. It therefore provided a favorable overall balance between stimulation
373 extent and uniform fracture development among clusters. Under the model parameters and weighting scheme adopted in this study, 12
374 m³ /min, 8%, and 5 m were selected as the preferred parameter combination.

375 **3 Evaluation of hydraulic-fracturing performance**

376 **3.1 Field test-well layout and treatment design**

377 To extend the pre-drainage coverage of the No. 7 seam before mining the 1077 working face, a surface L-shaped horizontal well
378 was positioned below the Biaosi Limestone in the roof and within 2 m of the coal seam.

379 One fractured well (SL1-Y) and one unfractured control well (SL1-S) were constructed. The horizontal sections of both wells were
380 positioned near the roof of the No. 7 coal seam, and comparable well locations, gas-drainage suction pressures, and monitoring procedures
381 were used to minimize differences in geological setting and operating conditions. Well SL1-Y was completed with downward-oriented
382 perforations and subjected to staged hydraulic fracturing, whereas SL1-S was not fractured. Because each group contained only one well,
383 the comparison was treated as an engineering case study rather than a statistically replicated experiment.

384 The pumping schedule for SL1-Y comprised pad fluid, proppant-laden fluid, and displacement fluid. The injection rate was increased
385 stepwise, and sand-to-fluid ratios of 4%, 8%, and 12% were applied sequentially. The 8% stage used 150 m³ of net fluid, accounting for
386 68.2% of the total proppant-laden fluid. The sand-to-fluid ratio was calculated as the proppant volume divided by the net fluid volume
387 for each stage, yielding a net-fluid-volume-weighted average of 7.1% over the entire proppant-laden stage. The field cluster spacing was
388 5 m. In Table 7, Q, V_f, and V_s denote the injection rate, stage net fluid volume, and stage proppant volume, respectively. Field operations
389 are shown in Fig. 27, and the pumping schedule is provided in Table 7.



390

Fig. 27. Field hydraulic-fracturing operations.

Table 7. Pumping schedule for Well SL1-Y

No	Stage	Net fluid volume (m ³)	Injection rate (m ³ /min)	Sand-to-fluid ratio (%)	Proppant volume (m ³)	Proppant type
1	Bridge-plug deployment	50	0.5-2.5	--	--	--
2	Ball-drop fluid	20	2.5	--	--	--
3	Pad fluid (110 m ³)	30	1.5-8.0	--	--	--
4		80	1.5-8.0	--	--	--
5		60	8-12	4	2.4	40/70-mesh quartz
6	Proppant-laden fluid (220 m ³ ; stepwise	50	8-12	8	4.0	sand; total: 6.4 m ³
7	ratios of 4%–8%–	50	8-12	8	4.0	20/40-mesh
8	12%)	50	8-12	8	4.0	quartz
9		10	8-12	12	1.4	sand; total: 9.2 m ³
10	Displacement fluid	20	12-0	--	--	--
11	Total	420	--	--	17.6	--

3.2 Hydraulic fracturing treatment curve

The treatment consisted of pad-fluid injection, proppant-laden-fluid injection, and displacement. Fig. 28 shows the treatment pressure, injection rate, and sand-to-fluid ratio.

During the pad-fluid stage, the injection rate was gradually increased to approximately 8 m³/min to establish flow through the wellbore and perforations, initiate fractures in the coal and surrounding rock, and create initial fracture pathways. The wellhead pressure fluctuated markedly and reached a peak above 45 MPa. These fluctuations may have resulted from the opening of perforation channels, fracture initiation in the coal and surrounding rock, activation of natural weakness planes, and changes in wellbore friction. Because no proppant was added during this stage, the sand-to-fluid ratio remained zero.

During the proppant-laden-fluid stage, the injection rate was increased beyond 8 m³/min and maintained near the target value. The sand-to-fluid ratio was raised stepwise from 4% to 8% and then to 12%, with an average of approximately 8%. As proppant concentration increased, flow resistance in the wellbore and fractures also increased. Treatment pressure generally remained between 30 and 40 MPa, with moderate fluctuations. No abrupt anomalies occurred in either the injection rate or the sand-to-fluid ratio, indicating that the stepwise addition of proppant improved transport capacity while reducing the risk of sudden screenout.

During the displacement stage, proppant addition ceased, and displacement fluid was injected to move the remaining slurry from the wellbore into the fractures. After pumping stopped, the injection rate fell to zero, and wellhead pressure gradually declined because of fluid leakoff and pressure dissipation within the fractures. Overall, the field treatment achieved the target injection rate of 12 m³/min and an average sand-to-fluid ratio of approximately 8%, demonstrating the operational feasibility of the principal recommended parameters.

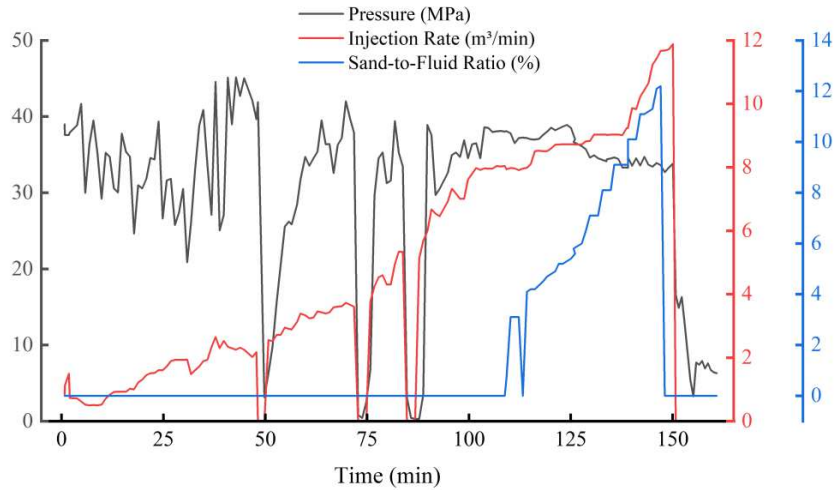


Fig. 28. Treatment pressure, injection rate, and sand-to-fluid ratio during hydraulic fracturing.

3.3 Gas drainage performance

3.3.1 Temporal evolution of gas concentration in the surface wells

Gas drainage from the target low-permeability coal seam was monitored continuously for 120 d in Wells SL1-Y and SL1-S. Comparable gas-drainage suction pressures, well configurations, and monitoring procedures were maintained to improve comparability between the two wells. The temporal variation in gas concentration is shown in Fig. 29.

During the first 20 d, gas concentration in both wells initially increased and then decreased, reflecting the combined effects of stress adjustment and the early activation of fracture pathways. In SL1-Y, gas concentration remained mainly between 65% and 73% and reached a peak of 73%, indicating high-concentration drainage during the start-up period. In SL1-S, gas concentration ranged from 30% to 56%, with a maximum of 56%, and the difference between the two wells generally exceeded 15 percentage points. The higher concentration in SL1-Y is consistent with enhanced fracture connectivity and lower resistance to gas flow after hydraulic fracturing, whereas drainage in SL1-S relied primarily on the natural fracture system.

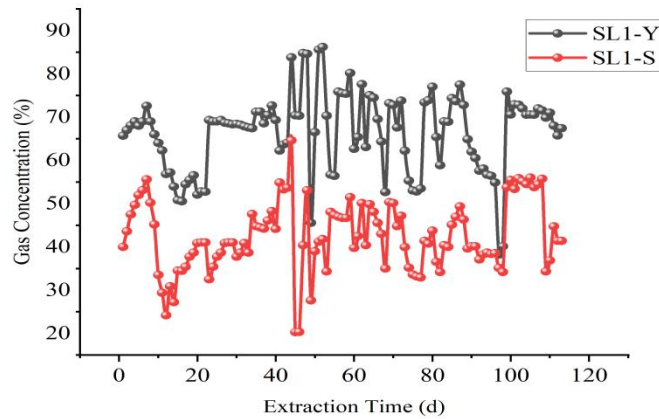


Fig. 29. Gas concentration in surface Wells SL1-Y and SL1-S.

From Day 20 to Day 80, both wells exhibited frequent fluctuations as the stress and seepage fields approached dynamic equilibrium. Gas concentration in SL1-Y ranged from approximately 50% to 85% and exceeded 80% on several occasions, whereas that in SL1-S was generally 30–50%. With continued drainage, depletion of free gas and a decline in desorption supply produced an overall downward trend. Gas concentration in SL1-Y decreased from approximately 75% to 67% but remained above 60%, whereas that in SL1-S decreased to approximately 35–45%.

Over the full monitoring period, the average gas concentration in SL1-Y was 65.68%, or 1.64 times that in the control well, corresponding to a relative increase of 63.8%. The persistent difference between the wells indicates that the fractured well maintained more effective pathways for gas flow throughout the monitoring period. The methane drainage rates of both wells showed an early peak, intermediate fluctuations, and a later decline, broadly consistent with the evolution of gas concentration. SL1-Y maintained a higher methane drainage rate than SL1-S during most of the monitoring period, supporting the effectiveness of hydraulic fracturing in improving gas transport.

3.3.2 Temporal evolution of methane drainage rate in the surface wells

Methane drainage rate reflects the combined effects of seam permeability, fracture conductivity, and gas availability and is therefore an important indicator of surface-well drainage performance. Both wells exhibited an early peak, intermediate fluctuations, and a late decline, broadly consistent with the evolution of gas concentration (Fig. 30).

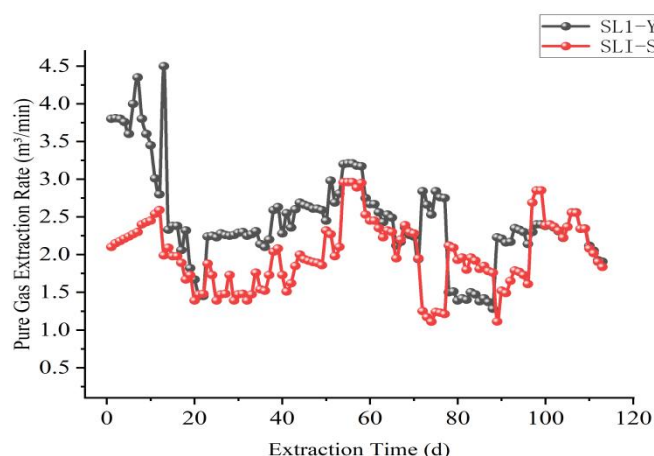


Fig. 30. Methane drainage rate in surface Wells SL1-Y and SL1-S.

During the initial drainage stage, rapid activation of the hydraulic fractures and stress adjustment caused the methane drainage rate of SL1-Y to rise quickly to a peak of 4.5 m³/min and remain mainly between 3.5 and 4.5 m³/min. By contrast, the rate in SL1-S increased gradually to approximately 2.5 m³/min without a distinct peak, indicating substantially lower initial production capacity.

During the intermediate stage, gas supply and production approached a dynamic balance, and both wells exhibited periodic fluctuations. These variations were associated with stress adjustment, fracture opening and closure, and changes in gas desorption. The methane drainage rate of SL1-Y generally remained between 2.0 and 3.2 m³/min, whereas that of SL1-S was mainly 1.2 – 2.8 m³/min and repeatedly fell below 1.5 m³/min. The control well therefore had a lower and less stable drainage rate.

As the available gas was progressively depleted and desorption slowed, the methane drainage rate in both wells declined. The rate in SL1-Y decreased from approximately 2.5 to 1.9 m³/min, whereas that in SL1-S decreased to approximately 1.1 – 2.0 m³/min and showed more frequent periods of low production.

Over the complete monitoring period, the average methane drainage rate was 2.78 m³/min for SL1-Y, 44.7% higher than the 1.92 m³/min recorded for SL1-S. The cumulative methane drainage volume was 139,817.65 m³ for SL1-S and 261,948.77 m³ for the fractured well, SL1-Y.

Compared with the unfractured well SL1-S, SL1-Y showed a 44.7% higher average methane drainage rate, an average gas concentration 1.64 times greater, and a cumulative methane drainage volume 1.87 times greater. Both wells exhibited an early peak, intermediate fluctuations, and a late decline in methane drainage rate, with the rate variations broadly tracking the evolution of gas concentration. The consistently better drainage performance of SL1-Y provides field evidence that hydraulic fracturing improved gas-flow conditions around the well.

4 Discussion

(1) The XSite hydro-mechanical model was developed using measured in-situ stresses and the physical and mechanical properties of the coal and surrounding rock and was calibrated at the macroscopic scale against laboratory test results. The simulated fractures generally propagated in the direction of the maximum horizontal principal stress and exhibited larger apertures near the wellbore,

consistent with the expected response under a stress regime dominated by horizontal stress. During 120 d of field monitoring, the fractured well achieved an average gas concentration of 65.68% and a cumulative methane drainage volume of 261,948.77 m³, compared with 40.10% and 139,817.65 m³, respectively, for the unfractured control well. The agreement in overall engineering trends between the simulated stimulation extent and the field drainage response supports the use of the model for relative comparisons among the investigated parameter combinations. However, field drainage also reflects geological heterogeneity, well placement, and operating conditions and therefore does not directly validate the simulated fracture geometry.

(2) Increasing the injection rate strengthened the driving force for fracture propagation and enlarged the overall stimulation extent, but it also amplified differences in initiation and propagation resistance among perforation clusters. Once a cluster formed a low-resistance flow path, fluid preferentially entered that cluster, promoting continued growth of the dominant fracture while suppressing the others. A higher injection rate therefore did not necessarily produce synchronous growth of all clusters. Increasing the sand-to-fluid ratio enlarged the total fracture area and fluid volume; however, FBEI and FVBI decreased substantially at 12%, indicating that fracture area and fluid became concentrated in a locally dominant cluster. A sand-to-fluid ratio of 8% provided a favorable balance between fracture extent and inter-cluster uniformity. Because proppant settling, bridging, placement, and post-shut-in fracture closure were not explicitly modeled, the results for sand-to-fluid ratio should be interpreted only as changes in simulated fracture growth and fluid distribution, rather than as direct predictions of long-term conductivity. Cluster spacing affected multi-cluster development through stress interference and fluid competition. A spacing of 4 m produced pronounced local dominance, 6 m yielded more uniform clusters but a smaller overall extent, and 5 m provided a favorable balance between extent and uniformity.

(3) Selecting parameters solely on the basis of total fracture area may favor cases in which a dominant cluster grows excessively, whereas evaluation based only on uniformity may overestimate cases with insufficient stimulation. FBEI, FVBI, and FGEI were therefore used to characterize inter-cluster uniformity, SEI was used to characterize overall stimulation extent, and CEI was constructed to provide a comprehensive ranking. The case with an injection rate of 12 m³/min, a sand-to-fluid ratio of 8%, and a cluster spacing of 5 m achieved the highest CEI (0.9233). Although this case did not maximize any single extent or balance metric, it provided a favorable balance between total stimulated area and uniform fracture development among clusters. Because CEI depends on the index definitions and assigned weights, the recommended parameters apply to the geological conditions, model assumptions, and parameter ranges considered in this study and should not be regarded as a universal optimum.

(4) This study has several limitations. The mesoscopic parameter set used in the numerical model is not unique, the implementation of the sand-to-fluid ratio does not fully represent proppant transport, and the field comparison involved only one fractured well and one control well, without multi-well replication or direct fracture monitoring. Future work should integrate microseismic monitoring, tracer testing, or pressure diagnostics to verify fracture extent and should incorporate proppant transport, fracture closure, and post-fracturing gas flow to improve the reliability of model predictions and parameter evaluation.

5 Conclusions

Laboratory testing of coal and rock mechanical properties, three-dimensional XSite discrete-element simulations, and field monitoring of gas drainage were combined to investigate multi-cluster hydraulic-fracture propagation and drainage response in a soft, low-permeability coal seam under different injection rates, sand-to-fluid ratios, and cluster spacings. FBEI, FVBI, FGEI, and CEI were formulated from the fracture area, fluid volume, and equivalent mean aperture of each cluster. The effects of the treatment parameters on overall stimulation extent, fluid distribution among clusters, and the uniformity of fracture development were evaluated, and the engineering applicability of the recommended combination was assessed using 120 d of data from a fractured well and an unfractured control well. The principal conclusions are as follows:

(1) A three-dimensional XSite discrete-element hydro-mechanical model was established using the measured in-situ stresses and the physical and mechanical properties of the No. 7 coal seam and surrounding rock at Yongchun Coal Mine. The hydraulic fractures generally propagated in the direction of the maximum horizontal principal stress. Most visible fracture elements had apertures of 2 – 15 mm, with larger apertures near the wellbore and continued extension of the main fractures toward the distal region.

(2) Injection rate, sand-to-fluid ratio, and cluster spacing all affected stimulation extent and inter-cluster uniformity. Increasing the injection rate enlarged the stimulation extent but intensified competition from the dominant cluster. Under the assumptions of the present model, an excessively high sand-to-fluid ratio increased total fracture area and fluid volume but reduced FBEI and FVBI. A spacing of 4 m produced pronounced local dominance, whereas a spacing of 6 m resulted in insufficient overall stimulation; a spacing of 5 m provided

a favorable balance between extent and uniformity.

(3) FBEI, FVBI, and FGEI were formulated from the fracture area, fluid volume, and equivalent mean aperture of each cluster and were combined with SEI to construct CEI. For the case with an injection rate of 12 m³/min, a sand-to-fluid ratio of 8%, and a cluster spacing of 5 m, FBEI, FVBI, and FGEI were 0.8839, 0.9355, and 0.9923, respectively, and CEI was 0.9233, ranking first among the seven independent parameter combinations. The total fracture area and total fluid volume were 767.00 m² and 11.845 m³, respectively.

(4) The recommended combination was implemented in the field using a stepwise increase in injection rate and sequential sand-to-fluid ratios of 4%, 8%, and 12%. The 8% stage was the principal proppant-laden stage, and the net-fluid-volume-weighted average ratio was 7.1%. During the 120 d monitoring period, the average gas concentration in the fractured well was 1.64 times that in the unfractured control well, and the cumulative methane drainage volume was 1.87 times greater. These field results support the engineering feasibility of the recommended combination in the study area and demonstrate the practical value of the model.

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Competing interests

The authors declare no competing financial interest.

Data availability

All data generated or analyzed during this study are included in this published article.

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