1 | INTRODUCTION

With the continuous development of unconventional oil and gas reservoirs, hydraulic fracturing has been widely applied in the industry for the enhancement of hydrocarbon recovery. Proppants are pumped into and evenly distributed within the fractures in order to resist the closure pressure after pumping, generating highly conductive flow paths for the hydrocarbon. Therefore, production can be remarkably enhanced. Maintaining a relatively high fracture conductivity is one of the key factors for successful fracturing. Moreover, many factors can contribute as damaging mechanisms to fracture conductivity, such as incomplete removal of gel residue, proppant embedment, and proppant crushing.
Several technologies can be used to maintain fracture conductivity, such as improving proppant material properties and optimizing the combination of different proppants within the pumping schedule. However, conventional methods have limited effects on conductivity because of their cost and physical limitations. As an emerging fracturing technology, channel fracturing has been applied within productive fields since it was originally proposed in 2010. Channel fracturing involves intermittent pumping of proppant-laden and proppant-free fluids into the wellbore to create an open channel in the fracture through which oil and gas flow. Degradable fiber is added to the fluid system to prevent dispersion of the proppant packs during the operation. This technology provides high fracture conductivity (i.e., 2-3 orders larger than conventionally propped fractures) and low cost due to reduced material usage, thereby decreasing the flow resistance of hydrocarbons and increasing production. According to statistics, by applying channel fracturing technology, the improvement of hydrocarbon production ranges from 19% to 98%. Multiple studies have been published on the conductivity of channel fractures; for example, Medvedev et al concluded that the discontinuous distribution of proppant packs largely enhances the channel fracture conductivity and determines the optimal channel width. Additionally, Zheng et al found that with the increase in the distribution density of proppant packs, the channel fracture conductivity increased at the beginning and then decreased rapidly, while Xu et al proposed that fracture width, propped area, and proppant embedment were the key factors affecting channel fracture conductivity. Further, a prediction model of channel fracture conductivity based on the discrete element method was proposed by Zhu et al. Their results suggest that fracturing conductivity increased with larger proppant size and proppant concentration. Recently, Hou et al established a new experimental approach to measure the conductivity of fractures with heterogeneous proppant distribution. Their results confirmed that proppant distribution patterns clearly influenced the flow capacity. Based on these research advances, it is clear that the shape and distribution of proppant packs play a significant role in controlling fracture conductivity.

Compared with conventional fracturing, the shape and distribution of proppant packs in channel fractures are complicated because of the alternate injection and the complex fluid system which features added fiber. Because of this, the proppant distribution geometry models used in the study above were idealized and therefore not fully reflective of the actual fluid structures and behaviors. To the best of our knowledge, the shape and distribution of proppant packs in channel fracturing have not been studied before. Therefore, in this study, a plate fracture experiment was conducted to effectively study proppant transport and placement during the alternate injection process. Because the proppant pack is unevenly distributed within the fracture, it is difficult to associate proppant distribution with experimental parameters. In light of this, we conducted quantitative research on proppant packs based on statistical analysis of the experimental results and proposed a relationship between the proppant pack distribution and the experimental parameters.

Moreover, there are two distinct flow areas, which can be distinguished within the fracture—tiny flow path in the proppant packs and free channel between the packs. However, most researchers have ignored any flow in the proppant packs, treating them as nonflow areas in the calculation. This simplification leads to an incomplete understanding of the flow behavior and inaccurate calculation results. Therefore, in this study, we established a conductivity calculation model based on the lattice Boltzmann method (LBM) to model the fluid flow through a channel fracturing fracture. LBM is a mesoscopic simulation method derived from the Boltzmann equation using a discrete lattice effect, which is often used to solve multiscale flow problems. This method disperses the fluid into a series of fluid micelles that collide and stream on a regular discrete grid in a defined manner. During the streaming process, fluid micelles move to the nearest neighboring lattice nodes in specific directions, while in the collision process, the micelles change their velocity based on the collision equation. Macroscale parameters, such as velocity and pressure, can be obtained by solving the distribution function in the mesoscopic scale.

The organization of this paper is as follows: Sections 2 and 3 present the details and results of the experimental study. Section 4 presents the proppant distribution geometry model based on quantitative research and the numerical model derived by the LBM. In Section 5, the models were applied in order to study three factors affecting the channel fracture conductivity: the pillar-fracture ratio (PFR), distribution pattern of proppant packs, and shape of proppant packs. This paper is concluded in Section 6.

2 EXPERIMENT DETAILS

2.1 Experiment apparatus

The experiment was conducted in a fracture with a length, width, and height of $4 \times 0.006 \times 0.6$ m, which comprised two pieces of parallel transparent plexiglass. Clean fluid and slurry were placed in two tanks, A and B, where the valves could be opened and closed independently. A screw pump was used to pump fluid into the plate and modify the injection rate, which was monitored by the flowmeter near the wellbore. A wellbore with six evenly distributed holes was used to simulate the perforation effect. To precisely observe the proppant transport and placement in the fracture, a high-speed camera was used to record the proppant transport and
generate video documentation, which was synchronously stored in a computer and processed after the experiment. The entire system is shown in Figure 1.

2.2 Experimental materials and parameters

In this study, the experimental materials were the same as those used in the Zhongjiang Field in the Sichuan Basin and can be described as follows. The fracturing fluid was a hydroxypropyl guar gum cross-linking liquid, with fiber added, mainly including 0.4% hydroxypropyl GG (thickener), 0.1% sodium carbonate (pH adjuster), and 0.1% borax (cross-linker). The viscosity of the fracturing fluid was 110 mPa·s under 170 s⁻¹ shear rate. The proppant was 20/40 mesh Carbo ceramsite, and polyester was used as the fiber. Our previous work showed that given certain ranges of parameter settings, namely fluid viscosity, proppant concentration and size, and fiber condition, the proppant shape and distribution remained similar. Therefore, in this study, we selected a proppant concentration of 20% and a fiber length and concentration of 6 mm and 0.2% (wt.), respectively (Table 1).

To simulate the proppant transport in the fracture effectively, it is crucial to ensure that the fluid dynamic behavior in the experimental plate fracture is the same as that in a real fracture. Based on the similarity principle, the field pumping rate was converted to the experimental injection rate, as shown in Equation (1):

\[ Q_e = \frac{Q_f \times (h_e \times w_e)}{h_f \times w_f \times 2} \times 1000 \]

where \( Q_e \) is the experimental injection rate (L/min), \( Q_f \) is the field pumping rate (m³/min), \( h_e \) is the height of the artificial fracture (m), \( w_e \) is the width of the artificial fracture (m), \( h_f \) is the height of the plate device (m), and \( w_f \) is the width of the plate device (m).

According to statistics on 45 channel fracturing wells in the Sichuan Basin, the pumping rate is 2.5-4.5 m³/min, the average artificial fracture height is approximately 50 m, and the average width is approximately 10 mm. Considering the experimental device dimensions, the injection rates were set to 5 L/min, 10 L/min, and 15 L/min. In addition, the pulse times ranged from 10 to 45 seconds, set at incremental increases of 5, 10, or 15 seconds, accordingly, which was determined by both the field data and laboratory conditions. The experimental settings are listed in Table 2.

2.3 Experimental procedures

1. 50 L of water was placed in tank A (Figure 1), and water was pumped into the plate fracture to remove air.
2. 150 L fiber-laden slurry was added to tank A, 200 L of clean fiber-gel fracturing fluid was added to tank B, and both tanks were stirred at 75 rpm at room temperature (25°C) for 20 minutes.
3. The valve of tank B was opened, and the clean fluid was injected into the plate fracture in order to simulate the pre-pad during the treatment process.
4. With clean fluid having filled in the plate fracture, the injection rate was adjusted to the experimental setting value.
5. The valves of tanks A and B were alternately opened and closed with certain setting pulse times. So, the clean fluid and slurry were injected into the plate fracture intermittently in order to simulate the channel fracturing process.
6. High-speed video was used to record the shape and distribution of proppant packs under different parameters.
7. When the residual fluid reached a level of less than 5% of the tank, a close pump ceased the injection.
8. Continue video recording in order to capture the static settlement behavior for an additional 60 minutes.

3 EXPERIMENT RESULTS

According to field data in the Zhongjiang Field, the fracture closure time for channel fracturing was approximately 30 minutes, and the static settlement experiment illustrated that the shape and distribution of proppant packs remained basically unchanged over that time period. Therefore, in this experiment, we assume that the shape and distribution captured at the end of the transport experiment is the final state.

![Proppant transport experimental system](image-url)
3.1  Injection rate effects

To study the influence of injection rate on the proppant pack distribution in a fracture, this study carried out experiments on injection rates at 5, 10, and 15 L/min under the same pulse time (30 seconds). Figure 2 provides a direct comparison of proppant distribution among the three tests. As the injection rate increased, proppant packs changed from dispersion to integration and became more streamlined. A highly developed channel network was formed in the fracture when the injection rate was 5 L/min, but the channel between the scattered proppant packs was extremely narrow (Figure 2A). As the injection rate increased to 10 L/min, the proppant packs became larger, resulting in fewer channels and poorer connectivity of the channel network. In contrast to the small injection rate case, the channel width in the 10 L/min case was much wider, which introduced potential for higher flow efficiency (Figure 2B). As the injection rate continued to increase, the size of the proppant packs also continued to increase until the plate fracture was completely filled in the longitudinal direction. Large proppant packs had almost no channels; and in addition, a large nonpropped area was formed between the two proppant packs, leading to compromised connectivity (Figure 2C). In this case, the hydrocarbon flow resistance was similar to conventional proppant placement, and it might be expected for the large nonpropped area to result in fracture closure under high pressure.

Notably, the flow type in all cases was laminar flow, owing to the low flow velocity and the high-viscosity cross-linked gel. Therefore, changing the injection rate did not affect the flow type, and the turbulence effect was not present in our experiment. This is because when the proppant injection rate is low, the volume of slurry and clean fluid entering the fracture for one pulse time is small, inducing unstable proppant slug. The viscosity of the slurry (with proppant inside) is higher than that of the clean fluid, so the injected

---

**Table 1** Parameters of field application and experimental setup

|          | Fluid viscosity (mPa s) | Proppant concentration (%) | Proppant size (mesh) | Fiber length (mm) | Fiber concentration (%) |
|----------|-------------------------|----------------------------|----------------------|-------------------|-------------------------|
| Zhongjiang Field | 80-140                  | 10%-30%                    | 20/40, 30/50, 40/70  | 6                 | 0.1%-0.3%               |
| Experiment | 110                     | 20%                        | 20/40                | 6                 | 0.2%                    |

**Table 2** Experimental settings for different injection rates and pulse times

| Injection rate (L/min) | Pulse time (s) |
|------------------------|-----------------|
| 5                      | 10, 15, 20, 30, 45 |
| 10                     | 10, 15, 20, 30, 45 |
| 15                     | 10, 15, 20, 30, / |

**Figure 2** Effect of injection rate on the distribution of proppant packs. Case (A) \( \Delta t = 30 \text{ s}, Q = 5 \text{ L/min} \). Case (B) \( \Delta t = 30 \text{ s}, Q = 10 \text{ L/min} \), black area is the channel. Case (C) \( \Delta t = 30 \text{ s}, Q = 15 \text{ L/min} \).
proppant pack is effectively shattered by clean fluid owing to the viscosity distinction, resulting in smaller proppant packs with narrower flow channels. As the injection rate increases, more liquid enters the fracture per pulse time, so the proppant pack tends to be more integrated and stable. In this situation, the shear stress is not sufficient to break up a large proppant pack into smaller portions, but instead elongates the pack into a streamlined shape.

3.2 | Pulse time effects

Figure 3 shows the proppant distribution for different pulse times (10, 20, and 30 seconds) under the same injection rate (15 L/min). As the pulse time decreased, the proppant packs became smaller and the channel between packs became narrower, but overall, the connectivity of the channel network was improved (Figure 3). When the pulse time was 30 seconds, the proppant pack showed a large slug-like distribution (Figure 3A), and a large nonpropped area existed in the fracture, rendering the connectivity between channels inadequate. When the pulse time was reduced to 20 seconds, there was a reduction in the proppant pack size, but more channels were connected with each other (Figure 3B). As the pulse time decreased to 10 seconds, abundant additional channels were generated between the small proppant packs, and the connection was substantially improved over that of other cases (Figure 3C). However, the channel width in this case was the narrowest among the three tests. The mechanism for this phenomenon is similar to that of the injection rate effect. A longer pulse time under the same injection rate indicates that more proppant is injected into the fracture during one single pulse; thus in this circumstance, the proppant packs will be more stable under shear stress.

3.3 | Typical distribution types

Through experimental results, we found that the shape and distribution of proppant packs were controlled by the injection rate and pulse time together. To better study the effects of these two parameters, we defined pulse unit (Pu) as the production of these two parameters:

$$Pu = \frac{1}{60} Q \cdot \Delta t$$  \hspace{1cm} (2)

where $Q$ is the injection rate (L/min) and $\Delta t$ is the pulse time (s). The physical definition of Pu is the injection volume per pulse time, and Pu for each set of experiments was determined by the corresponding injection rate and pulse time. By comparing the experimental results, we found that when Pu was within a certain range, the shape and the distribution of proppant packs could be summarized into the following four typical types (types I-IV) (Figure 4).

Figure 4A shows type I ($Pu \leq 2.5$ L), which featured small, round-like proppant packs that were highly dispersed, with extremely narrow channels between the packs, yet good channel connectivity. Type II ($2.5 \text{ L} < Pu \leq 3.3 \text{ L}$) packs featured a similar, roughly round shape, and were larger than those of type I. The number of channels was fewer, but the channel structure was usually wider, and the overall network connectivity was maintained at a relatively high level, as shown in Figure 4B. Type III ($3.3 \text{ L} < Pu \leq 5 \text{ L}$) packs were more streamlined and larger overall. The channels between packs were wider and although channel networks were present, their connectivity was poor compared with those of types I and II (Figure 4C). For type IV ($Pu > 5$ L), the proppant packs exhibited a slug-like distribution. The flow channel was large, but the connectivity was poor, as the
proppant pack occupied the entire space of the fracture vertically (Figure 4D).

Figure 5 presents the relationship between the distribution type and Pu (representing the injection rate and pulse time). The injection rate and pulse time are the X- and Y-axes, respectively, and the circles represent tests conducted under the corresponding parameters. Four colors are applied to represent the distribution types (blue, green, yellow, and red denote types I, II, III, and IV, respectively). For each test, the result was observed and classified into the specific distribution type. For example, the circle at (30, 10) represents the experiment in which the pulse time and injection rate were 30 seconds and 10 L/min, respectively (Pu = 5). As this Pu is in the range of type III, the circle is yellow. In this manner, each circle was assigned a specific color based on the experiment result, and the color between two circles was predicted by the tendency. Therefore, under laboratory conditions, we could obtain the specific proppant distribution type by adjusting the injection rate and pulse time.

4 | CONDUCTIVITY NUMERICAL SIMULATION MODEL

4.1 | Geometry model

Based on experimental results, the shape and distribution of proppant packs were irregular overall, as well as irregular among like experimental conditions (ie, injection rate or pulse time). Therefore, it was difficult to take the experimental distribution directly as the distribution geometry model in the numerical simulation. For this portion of the study, quantitative statistical analysis was carried out using ImageJ software in order to simplify the complicated distribution of the proppant packs. Statistical parameters included roundness, aspect ratio of the ellipse, and proppant pack size.
The steps were as follows: (a) Distribution patterns of the proppant packs were obtained from the experiment in the same Pu range and binarized; (b) proppant packs were separated along their contours; (c) statistical parameters were calculated for each proppant pack, counting the average value within each Pu range; and (d) the size of the proppant pack was converted from experiment scale (2 m × 0.44 m) into simulation scale (180 mm × 40 mm). This conversion process is shown in Figure 6, and the statistical results are presented in Table 3.

Considering the simulated fracture size, proppant pack size, and shapes, the basic geometric model with different Pu ranges is shown in Figure 7. The roundness of the proppant packs obtained from types I and II was greater than 0.8, and the average aspect ratio of them was less than 1.25, so the shape of the proppant packs was defined as a circular pillar (Figure 7B). The average roundness of the proppant pack of types III and IV was small with a large aspect ratio (Table 3), so we defined the shape of the proppant pack as an ellipse (Figure 7C,D).

In addition, the irregular distribution of proppant packs was also considered by adjusting their relative location to neighboring packs. The offset distance is half of the radius or the short axis of the proppant pack, as shown in Figure 8.

Although there was a deviation from the simplified proppant pack distribution to the actual conditions, the simplified geometry models were obtained based on real proppant pack statistics. Therefore, the real proppant pack features can be suitably characterized by a geometry model.

4.2 | Numerical model

During the conductivity simulation test, water enters from the left side of the fracture at a constant flow rate and flows out through the right side (Figure 9). The pressure drop is generated by the flows in the porous media (i.e., inside of the proppant packs) and the open channel (outside of the proppant packs). Once the pressure drop is acquired, the equivalent conductivity of the fracture can be calculated using Darcy’s law, as shown in Equation (3):

\[
F_e = K_e \cdot w = \frac{Q \mu L}{H \Delta p}
\]

where \(K_e\) is the equivalent permeability of the fracture (m\(^2\)), \(Q\) is the inlet flow, \(L\) is the length of the simulation region (m), \(A\) is the cross-sectional area of the simulated area (m\(^2\)), \(\Delta p\) is the pressure (MPa), and \(\mu\) is the kinematic viscosity of the fluid (Pa s).

It must be pointed out that the physical model is two-dimensional (2-D), and the calculation is conducted for one layer of the fracture. Therefore, the deformation of the proppant packs under confined pressure was not considered. This is appropriate because the main purpose of this study is to use the flow capacity to evaluate and optimize the shape and distribution of proppant packs. To a certain extent, choosing one fracture layer in the width direction (Figure 9) to calculate flow capacity and conductivity can also characterize and evaluate the flow capacity of the overall fracture. However, the effect of fracture width on fracture conductivity should also be considered, which will be discussed in Section 5.1.

In this study, the flow velocity and pressure in the channel fracture were calculated using a multiscale flow model based on D2Q9 (meaning, two dimensions-nine directions) LBM, containing both standard LBM (SLBM)\(^2^9\) and generalized LBM (GLBM),\(^3^0\) SLBM, GLBM, and the resultant multiscale model are described as follows.

1. Standard lattice Boltzmann method (SLBM)

Containing the distribution function variation of particle micelles during collision and migration, the governing equation of the SLBM is expressed as follows:

\[
f_{1\alpha}(r + \xi_\alpha \delta_t, t + \delta_t) - f_{1\alpha}(r, t) = -\frac{1}{\tau}(f_{1\alpha}(r, t) - f_{1\alpha}^q(r, t))
\]  

where \(f_{1\alpha}\) is the distribution function in the lattice in the \(\alpha\) direction; \(\alpha = 1, 2 \ldots 9\); \(r\) is the position of the particle in the flow field; \(\delta_t\) is the time step; \(\tau\) is the relaxation time, which was determined by the viscosity of the fluid; and \(\xi_\alpha\) is the speed in the \(\alpha\) direction, which is determined by the D2Q9 model\(^2^4\):

\[
\xi_\alpha = \begin{cases} 
0, & \alpha = 1 \\
\sqrt{2} \left( \cos \left( \frac{(\alpha - 1)}{4} \pi \right), \sin \left( \frac{(\alpha - 1)}{4} \pi \right) \right) c, & \alpha = 2, 3, 4, 5 \\
\sqrt{2} \left( \cos \left( \frac{(\alpha - 1)}{4} \pi \right), \sin \left( \frac{(\alpha - 1)}{4} \pi \right) \right) c, & \alpha = 6, 7, 8, 9 
\end{cases}
\]  

The variable \(f_{1\alpha}^q\) is the equilibrium distribution function in the \(\alpha\) direction, and the expression is as follows:
where $\omega_1$ is the weighting factor defined in the D2Q9 model as $\omega_1 = 4/9$, $\omega_2-5 = 1/9$, and $\omega_6-9 = 1/36$; $C_s$ denotes the sound velocity of the lattice, defined as $C_s = 1/\sqrt{3}$; and $u_1$ is the flow velocity at the macroscale.

The macroscale parameters, such as density, velocity, and pressure, are obtained by calculating the distribution function of each lattice point on the mesoscopic scale:
The porosity was predicted by the empirical prediction formula based on rock compaction theory and can be expressed as follows:

\[ \phi = \phi_0 e^{-0.02171P} \]  

where \( \phi \) and \( \phi_0 \) are the original and compacted porosities; and \( P \) is the efficacious closing stress (MPa). The permeability of the proppant pack is obtained by the API conductivity test, and the required parameters for this study are shown in Table A1 in Appendix A. Therefore, the macroscale density and velocity are calculated as follows:

\[ \rho_2 = \sum_a f_{2a} \]  
\[ \rho_2 u_2 = \sum_a \xi_{2a} f_{2a} + \frac{\delta_i}{2} \rho_2 F \]  

where \( F \) is the sum of the resistance of the porous medium and the external force, expressed as follows:

\[ F = - \frac{\phi_{\nu}}{K} |u| - \frac{\phi F^\phi}{\sqrt{K}} + |u| u + \phi G \]  

where \( G \) is the external total volume force; \( K \) is the permeability of the porous medium; \( \nu \) is the viscosity of fluid; \( \phi \) is the porosity; and \( F^\phi \) signifies the pore structure parameter, which is determined by the Ergun empirical formula.

2. Generalized lattice Boltzmann method

Guo et al. obtained the GLBM equation by introducing an external force term into the SLBM equation in order to simulate the porous media seepage at the representative element volume (REV) scale, expressed as follows:

\[ f_{2a}(r+\xi_{2a} \delta, t+\delta t) - f_{2a}(r, t) = -\frac{1}{\tau} (f_{2a}(r, t) - f_{2a}^e (r, t)) + \delta_i F_{2a} \]  

where \( f_{2a}^e (r, t) \) is the equilibrium distribution function in the porous media area. This can be expressed as:

\[ f_{2a}^e = \omega_a \rho \left[ 1 + \frac{\xi_{2a} u_2}{C_s^2} + \frac{(u_2 \xi_{2a})^2}{2 \phi C_s^4} - \frac{u_2^2}{2 \phi C_s^2} \right] \]  

where \( \rho \) is the lattice density, \( u_2 \) is the velocity, and \( C_s \) is the sound velocity of the lattice.

The force function of the GLBM is as follows:

\[ F_{2a} = \omega_a \rho \left[ 1 - \frac{1}{2\tau} \right] \left[ \frac{\xi_{2a} F}{C_s^2} + \frac{u_2 \xi_{2a}^2 F}{\phi C_s^4} + \frac{u_2 F}{\phi C_s^2} \right] \]  

where \( F \) is the sum of the resistance of the porous medium and the external force, expressed as follows:

\[ F = \frac{\phi_{\nu}}{K} u - \frac{\phi F^\phi}{\sqrt{K}} |u| u + \phi G \]
flow information are transmitted to the channel flow regions (Figure 11B). Distribution functions derived from different evolutionary rules at two different scales constantly exchange flow information.

### 4.3 Boundary conditions

A solid boundary condition was chosen for this study, based on the following reasoning. The velocity of a node is obtained by streaming and collisions from the distribution functions of the nodes around it. However, the nodes on the boundary have three unknown distribution functions (denoted by red dotted lines in Figure 12). In this study, a heuristic collision boundary format was used on the solid boundary, and an unbalanced rebound dynamic boundary format was adopted on the inlet and outlet boundaries.32

#### 4.3.1 Solid boundary

The actual boundary in the API chamber is a solid, nonslip boundary; thus, a standard rebound format was adopted on the solid-liquid boundary of the flow field. The boundary follows the conservation of mass and momentum, as well as the distribution function of bounces in the original direction, and its expression is as follows:

\[
\begin{align*}
    f_{3,6,7} &= f_{5,9,8} \\
    \rho &= f_1 + f_3 + f_5 + 2(f_4 + f_7 + f_8)
\end{align*}
\]

(18)

Inlet boundary: The steady flow rate boundary was adopted for the inlet boundary. The \( f_{2}, f_6 \), and \( f_9 \) on each time step boundary will be determined by other direction distribution functions, fluid density, and the inlet velocity of a node, as follows:

\[
\begin{align*}
    f_2 &= f_4 + \frac{2}{3} \rho u_x \\
    f_6 &= f_8 - \frac{1}{2}(f_3 - f_5) + \frac{1}{6} \rho u_x \\
    f_9 &= f_6 + \frac{1}{2}(f_2 - f_4) + \frac{1}{6} \rho u_x
\end{align*}
\]

(19)

#### 4.3.2 Outlet boundary

The free exit boundary and principle of adjacent point equality are adopted to determine the outlet boundary. Therefore, the unknown distribution function on \( f_{4,7,8} \) and \( f_{7,8} \), and the \( L_X \) outlet boundary node is equal to that of the adjoining \( L_X - 1 \) point:

\[
f(L_X, J)_{4,7,8} = f(L_X - 1, J)_{4,7,8}
\]

(20)

### 4.4 Conductivity calculation

Combining all the equations mentioned above, a computer code was written by Visual Basic.NET for the fracture conductivity calculation. Figure 13 shows our procedure for solving the fracture conductivity in a flow chart. When the calculation result reaches accuracy, the density, velocity, and pressure for every node in the flow field can be obtained.
Therefore, the pressure differential between the inlet and outlet of the fracture can be effectively calculated, followed by the equivalent conductivity using Equation (3).

### 4.5 Model validation

First, model validation was carried out by simulating water flows between two parallel plates, and the velocity profiles of different pressure drop cases were compared with the analytical solution by solving the Naiver-Stokes equation for incompressible fluid in the flow field, irrespective of the inertial force. Figure 14 shows the velocity profile calculated using the analytical solution and LBM. The velocity magnitudes predicted by the present study were in good agreement with the analytical solutions under different pressure gradient conditions.

Figure 15 shows the comparison of conductivities calculated by the cubic law and LBM simulation. Cubic law illustrates that the fracture flow is proportional to the cube of the fracture width in the fracture composed of two smooth plates. The results showed that the simulated fracture conductivity was consistent with the analytical velocity based on cubic law, confirming the validity of our mode.

### 5 SIMULATION RESULTS AND DISCUSSION

The investigation of the effects of proppant pack on fracture conductivity is presented in this section. The inlet velocity was set to $4.17 \times 10^{-4}$ m/s, and the fluid flow through the fracture was water with viscosity of 1 mPa s and density of...
1000 kg/m$^3$. The obtained geometry models are presented in Section 4.1.

### 5.1 Pillar-fracture ratio

For this study, pillar-fracture ratio (PFR) was defined as the ratio of the propped area to the entire fracture area. We used type I as the basic geometry model and simulated the fluid flow in different PFRs from 30% to 60%. Figure 16 shows the velocity and pressure distributions under different PFRs. As the PFR increased, the channels between the proppant packs became narrower, causing variations in the velocity and pressure distribution. Changing the size of the proppant pack would not significantly affect the main fluid flow path because the tortuosity of the flow channel remained unchanged. However, the average velocity in the fracture was 2.2 times larger when the PFR increased from 30% to 60% (Figure 16A,C), which indicates a higher flow resistance for larger PFR cases. Moreover, the increasing propped area narrowed the channel width, resulting in a greater local pressure drop and enlarging the pressure differential of the entire flow field (Figure 16B,D).

The above results show that a larger channel between proppant packs in small PFR cases could reduce the flow resistance if the fracture remained open throughout the well life. However, for a specific proppant distribution pattern, a smaller PFR caused a larger nonpropped area, resulting in premature closure of the flow channel under pressure. According to Wang et al.,34 average width was dominated by the PFR when the proppant distribution patterns were similar to each other. Specifically, in their study, under a flow pressure of 5 MPa and an in situ pressure of 20 MPa, the average fracture width in the channel area for PFR = 30% was approximately 0.1 mm, which was 10 times smaller than that of PFR = 70%. A similar conclusion was also proposed by Wang,35 who studied the channel fracture width distribution under different channel areas and closure pressures by using the nonlinear contact theory. In their study, these numerical simulation tests were carried out under the condition that the closing pressure was 50 MPa and the fluid pressure was 10 MPa. Figure 17 shows the fracture width distribution under different PFRs. Results indicated that the fracture width was highly related to the PFR, in that, as the PFR increased from 18.7% to 52.5%, the average width of the channel increased by nearly 6.2 times. Under such high closing stress conditions, when the PFR was around 50%, the channel remained open. However, as the PFR continued to increase, the proppant packs contacted with each other and the channel disappeared, resulting in a significant decrease in conductivity (Figure 17D). It should be noted that there is an optimal PFR, which supports the maximum effective conductivity in fractures.23,36

Overall, the conductivity of the channel fracture is governed by the flow efficiency and fracture width. Because the main purpose of this study was to evaluate and optimize the shape and distribution of proppant packs on the flow capacity under the same PFR, we therefore set PFR = 50% for all the following simulation tests and then assumed that the fracture width of all tests was identical under certain conditions of pressure and rock mechanics. Based on this, it was possible to compare the flow efficiency for different types of distribution by applying a 2-D calculation model.

### 5.2 Distribution pattern of the proppant pack

Figure 18 shows the channel fracture conductivity of different proppant pack distributions for PFR = 50%. One important
conclusion was that the arrangement modes of proppant packs influenced the fracture conductivity. By comparison, regardless of the distribution type, the conductivity was highest when proppant packs were placed in the left-right staggered arrangement mode. The average conductivity of the fracture with the left-right staggered arrangement was 10.2% higher than the normal arrangement, 42.8% higher than the mix staggered cases, and 55.4% higher than the up-down arrangement.

To better explain this phenomenon, we analyzed the simulation results for type III. Figure 19 shows the velocity and pressure fields for different proppant pack arrangements. Under normal arrangement, the fluid mainly flowed through the linear channel between the two rows of proppant packs (Figure 19A1, A2). Under left-right staggered arrangement, the flow path was similar to the evenly arranged one. However, the cross-section between proppant packs under this arrangement slightly increased, resulting in lower flow resistance.
Under the misalignment of the up-down staggered arrangement, the tortuosity of the flow path increased, resulting in a narrower channel and increased flow resistance. Therefore, the average velocity and pressure drop of this arrangement were the highest among the four cases (Figure 19C1,C2). The mixed staggered arrangement was a combination of the up-down and left-right staggered arrangements. Under this condition, the velocity was influenced by the high tortuosity and the wider local cross-section, so the average velocity and flow resistance were smaller than those under the left-right arrangement conditions, but larger than those under the up-down arrangement (Figure 19D1,D2).

Figure 18 also indicates that the fracture conductivity was greatly affected by the proppant distribution type. Regardless of the arrangement mode, type III yielded the highest conductivity. The average conductivity of type II was slightly less

(Figure 19B1,B2). Under the misalignment of the up-down staggered arrangement, the tortuosity of the flow path increased, resulting in a narrower channel and increased flow resistance. Therefore, the average velocity and pressure drop of this arrangement were the highest among the four cases (Figure 19C1,C2). The mixed staggered arrangement was a combination of the up-down and left-right staggered arrangements. Under this condition, the velocity was influenced by the high tortuosity and the wider local cross-section, so the average velocity and flow resistance were smaller than those under the left-right arrangement conditions, but larger than those under the up-down arrangement (Figure 19D1,D2).

Figure 18 also indicates that the fracture conductivity was greatly affected by the proppant distribution type. Regardless of the arrangement mode, type III yielded the highest conductivity. The average conductivity of type II was slightly less
(by 9.2%) than that of type III. However, the conductivity of type III was dramatically larger (1.39 and 2.3 times, respectively) than those of types I and IV. Figure 20 shows the velocity and pressure fields of different distribution types under identical normal arrangement modes. The proppant packs in type I were small and closely arranged, and the channel between the proppant packs was narrow. Pressure loss in the flow field (Figure 20A1,A2) resulted from the resistance of the fluid flowing through the narrow gap. As for type II, the flow channel between proppant packs was wider than that of type I, resulting in a lower flow velocity; the larger cross-section also reduced the flow resistance, so the conductivity was larger than that of type I (Figure 20B1,B2). The cross-section for type III was larger than that of type II, and the streamlined shape of the elliptical proppant pack tended to reduce the resistance by suppressing the vortex at the rear end of the packs. Because the pressure difference was small, the fracture conductivity of type III was larger than that of type II (Figure 20C1,C2). For type IV, the proppant packs occupied almost the entire fracture space in the longitudinal direction, thereby generating a large resistance when the fluid flowed through such an extremely narrow channel. Therefore, conductivity was the lowest among the four distribution types (Figure 20D1,D2).

**Table 4** Summary of experimental parameters for type III

| Injection rate (L/min) | Pulse time (s) | Pu  |
|------------------------|---------------|-----|
| #1                     | 10            | 20  | 3.33 |
| #2                     | 10            | 30  | 5.00 |
| #3                     | 15            | 15  | 3.75 |
| #4                     | 15            | 20  | 5.00 |
Parameter optimization

As discussed above, the fracture in which the proppant packs were placed for type III had the maximal conductivity across all conditions. Therefore, the Pu range of type III was optimal. The corresponding combinations of injection rate and pulse time for type III are listed in Table 4.

Figure 21 shows the relationship between the aspect ratio of proppant packs and fracture conductivity. The Pu for all cases was in the type III range, and the PFR was 50%. This result indicates that channel fracture conductivity increases with increasing aspect ratio, owing to the larger aspect ratio of the proppant packs which leads to lower flow resistance and a relatively wider channel.

Figure 22 shows the average aspect ratio for the four test cases in Table 4, which was obtained by quantitative statistics as shown in Section 4.1. We found that when the range of Pu matched that of type III, the aspect ratio of the packs evidently increased as the injection rate increased, and slightly decreased as the pulse increased. Therefore, the optimal injection rate was 15 L/min under laboratory conditions, and the pulse time was 15-20 seconds.

Considering the complexity of field construction, we recommend the optimal pulse time to be approximately 20 seconds. According to a similar principle, the experimental rate can be converted to the field condition by Equation (21):

\[ Q_f = \frac{1}{1000} \times \frac{2Q_e}{h_e \times w_e} \times (h_f \times w_f) \]  

which can be solved by predicting the fracture width and height in the fracturing process. Furthermore, the recommended field pumping rates for different fracture widths and heights are proposed in Figure 23.

It should be noted that the recommendation presented above is only suitable for the specific parameter range obtained from the Zhongjiang Field (Table 2). If the parameters are not in this range, the method can be applied in order to obtain the corresponding optimal parameters.

CONCLUSIONS

In this study, the shape and distribution of proppant packs under different injection rates and pulse times were studied.
experimentally. The distribution pattern was classified into four typical types (types I–IV), and the experimental parameter range for each type was proposed. To optimize the parameters, a fracture conductivity simulation was conducted. The geometry model was obtained through quantitative research of the proppant pack, and the numerical model was established based on the LBM. The main conclusions are as follows:

1. The shape and distribution pattern of the proppant packs are determined by the injection rate and pulse time together. As the injection rate and pulse time increase, the proppant pack changes from dispersion to integration, but the connectivity of the channel network worsens.

2. Pu is defined as the product of the injection rate and pulse time in order to describe the joint effects of these two parameters on proppant packs. As Pu increases, the proppant shape transforms from round-like into streamlined, the size becomes larger, and the dispersion structure becomes simpler. However, connectivity gradually deteriorates.

3. Flow resistance decreases dramatically as the PFR decreases. However, fracture width also either decreased or completely closed in small PFR cases due to the closure pressure, resulting in relatively low conductivity even though the flow efficiency is high.

4. When the PFR is maintained at 50%, the conductivity of the fracture is influenced by both the arrangement mode and, primarily, the distribution type. Regardless of the arrangement mode, the channel fracture of type III has the largest conductivity.

5. The corresponding Pu range for type III is from 3.3 L to 5 L, and the optimal injection rate and pulse time are 15 L/min and 15-20 seconds under experimental conditions. The recommended pumping rate for the field was proposed using a similar principle.

The conductivity model used in this study is based on 2-D LBM, without regard to the proppant pack deformation and the variation of fracture width under closure pressure. The simulation component of this study was conducted to reveal the flow characteristics and calculate equivalent conductivity in the channel fracture under the same PFR. We recommend that in order to comprehensively study the flow characteristics and accurate fracture conductivity under high closure pressure, a three-dimensional LBM model and deformation model should be established. Continuous study of these issues will be conducted in the future.

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APPENDIX A

Seepage parameters for GLBM

The seepage parameters of the proppant pack are necessary to solve the fluid flow in porous media when using GLBM. In this study, standard API conductivity tests for the proppant-fiber mixture were conducted to obtain the permeability and fracture width under different closure pressure conditions (Figure A1). The proppant was Carbo prop 20/40 mesh, and the fiber concentration was set to 0.2 wt.%.

![Proppant-fiber mixture measurement using standard API conductivity test](image)

TABLE A1 Seepage parameter for numerical simulation

| Closure pressure (MPa) | W (mm) | F (μm cm²) | D (μm²) | Φ (%) |
|------------------------|--------|------------|---------|-------|
| 6.9                    | 4.686  | 191.93     | 409.58  | 40.77 |
| 13.8                   | 4.584  | 182.29     | 397.67  | 35.10 |
| 20.7                   | 4.435  | 171.25     | 386.13  | 30.22 |
| 27.6                   | 4.31   | 158.76     | 368.35  | 26.01 |
| 34.5                   | 4.198  | 149.62     | 356.41  | 22.39 |
| 41.4                   | 4.076  | 137.28     | 336.80  | 19.28 |
| 55.2                   | 3.839  | 114.09     | 297.19  | 14.29 |
| 69.0                   | 3.614  | 94.21      | 260.68  | 10.59 |

*W is the width of the simulated fracture. F and D are the conductivity and permeability of the proppant pack, respectively. Φ is the porosity of the proppant pack.