Experimental and numerical studies on hydraulic fracturing characteristics with different injection flow rates in granite geothermal reservoir

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Abstract
Geothermal energy has been widely proposed as a potential renewable energy to replace traditional fossil fuel energy. Hot dry rock (HDR) reservoirs were the main geothermal energy resources and usually consist of low-permeability hard granite without fluid. Developing HDR requires water cyclically flowing between injection and production wells to extract heat energy. Hydraulic fracturing, as a key reservoir stimulation technology, can create the path of fluid cyclically flowing. However, few studies have investigated hydraulic induced artificial fractures in HDR geothermal formations. This paper investigated HDR geothermal reservoir stimulation characteristics and fracture patterns under different injection flow rates. Numerical simulations were conducted to model the laboratory tests. Results showed they were in good agreement, and this indicated the possibility of numerical simulation to predict hydraulic fracturing behavior under different injection flow rates. With the increase of injection flow rate, the fracture initiation pressures and breakdown pressures increased, and the propagation times and postfracturing pressures decreased. The fracture geometries were observed and analyzed, mean injection power was proposed, and results showed that it could be used to roughly estimate the fracture total lengths. Moreover, the fracture permeabilities based on the pressure data were calculated. These results can provide some reasonable advice for implementing reservoir stimulations on application to field-scale HDR operation.

KEYWORDS
geothermal energy extraction, granite, hydraulic fracturing, injection flow rate

1 | INTRODUCTION

Geothermal energy is a kind of renewable energy which is developed for heating and electricity generation. It is an alternative energy resource for widely use to replace fossil energy. Geothermal energy could be directly used in room and space heating, heat pump, agricultural heating, aquaculture, bathing and swimming, and other industrial applications.1
Based on the estimation of Lund and Boyd et al., the application of geothermal energy has already replaced 350 million barrels of petroleum and reduced 148 million tons of greenhouse gas emission.

Deep buried geothermal reservoirs are usually called hot dry rock (HDR) or enhanced geothermal systems (EGS). These geothermal formations usually consist of low-permeability and hard granite, which contains very little or no fluid because of high temperature. The main purpose of developing HDR is to generate electricity; during this process, water is used to extract heat energy. Therefore, for water circulation, reservoirs need to be stimulated to enhance the permeability. As one of the most significant reservoir stimulation technologies to establish water flowing paths, hydraulic fracturing is widely used to improve heat extraction efficiency in field-scale HDR operation. Hence, it is necessary to understand reservoir stimulation factors and fracture propagation patterns in HDR environment by hydraulic fracturing.

The hydraulic fracturing procedures involve drilling a hole deep into target layer, and fracturing fluid is injected to increase wellbore bottom pressure. When the pressure exceeds rock strength, the rock near wellbore bottom is broken, and fractures are initiated. With fluid continuing to be injected, the artificial induced fractures grow in the reservoir. The purpose of hydraulic fracturing in HDR geothermal reservoir is to create a heat transfer area between the injection and production wellbores. The created fracture network should be large enough for the sufficient heat exchange between water and rock. When operating hydraulic fracturing stimulation in HDR reservoir, the hydraulic injection flow rate is the first key factor to be considered. The injection flow rate and injection pressure, for hydraulic fracturing scheme, are critical operating parameters for the effective design field-scale operation. At the same time, HDR resources are deeply buried, making it difficult to carry out on-site hydraulic fracturing experiments. Thus, it is necessary to use laboratory experiment for analysis and evaluation. The granite of HDR formation is much harder than other rocks. It is always difficult to break intact large-scale granite in laboratorial condition, and a very few previous studies have investigated the processes of fracture initiation and propagation in HDR formations. Besides, the HDR environment is hard to be established in laboratory. Hence, this paper studied reservoir stimulation characteristics and fracture creation through hydraulic fracturing experiments in real HDR formation conditions.

In this work, we conducted laboratorial hydraulic fracturing experiments with a true-triaxial fracturing apparatus designed by Jilin University. Its cubic fracturing capsule size was 300 × 300 × 300 mm. The granite samples were collected from the Songliao Basin which is a typical HDR geothermal reservoir in the northeastern part of China. In order to investigate the injection flow rate on hydraulic fracturing characteristics, we conducted hydraulic fracturing tests at different injection flow rates. The initiation pressure, breakdown pressure, postfracturing pressure, and propagation time were analyzed based on the fracturing pressure curves. The rock samples were cut in halves after test, and the fracture geometry was observed. Based on recorded pressure data and curves, the fracture permeabilities were calculated. Numerical simulations were compared with the experiments results.

Some previous researchers investigated hydraulic induced fractures and revealed how to conduct hydraulic fracturing under various geological and operation conditions, how to enable interactions between natural fracture and artificial induced fracture, and the fracture initiation mechanisms. However, most of the previous studies were for sandstones, shales, limestone, or other gas and oil reservoirs. Only a few studies focused on geothermal reservoir stimulation in hard granite, and no previous studies comprehensively analyzed the influences of initiation pressure, breakdown pressure, propagation time, and postfracturing pressure on hydraulic fracturing behavior. At the same time, for our HDR granite hydraulic fracturing tests, the fracture initiation was before the breakdown point could be identified, which was also found in previous studies and other rock formations hydraulic fracturing experiments. These two parameters both had significant effects on hydraulic fracturing behavior, and should be distinguished and analyzed in detail.

This paper aims to provide a good understanding of hydraulic fracturing mechanisms on HDR geothermal formation. The HDR reservoir stimulation is different from other formations because of much higher temperature and harder rock, and the fracture creation characteristics are unclear and worth to study. In this study, it is the first time to detailly and comprehensively analyze the parameters of initiation pressure, breakdown pressure, propagation time, and postfracturing pressure, and we proposed a parameter of mean injection power to roughly estimate the fracture total length. We also investigate the hydraulic induced fracture morphology in large granite outcrops under true-triaxial confining stresses and real HDR condition. Besides, discrete element method is shown to simulate hydraulic fracturing behavior. This paper is a fundamental research for HDR geothermal reservoir stimulation, and it could contribute to future studies of geothermal energy usage, transportation, and distribution.

2 | LABORATORIAL TESTS

2.1 | Background

The Songliao Basin is located in the northeastern part of China. The winter temperature is very low, and the residential heating period (a long heating period of up to 7 months,
with a heating temperature of 30-50°C) is long. However, the population distribution is scattered, and it is difficult for all residents to achieve centralized heating. The Songliao Basin is a typical HDR reservoir with high heat flow and abundant reserves. Therefore, heating by HDR is a feasible method. In addition, according to the geothermal gradient, only taking heat from a depth of more than 2000 m, the water could be heated to a temperature high enough for residential heating. At this depth, the strata are already granite. Therefore, it is necessary to use granite for hydraulic fracturing experiments at high temperatures.

The granite samples used in the experiments are taken from Songliao Basin. As the large-size intact granite samples cannot be got from a deep wellbore, we use the outcrop rock samples as substitutes (Figure 1A). The rocks are cut into 300 × 300 × 300 mm cubes (Figure 1B), and the lithology is test. The mineral composition and basic physical properties of the rock specimens were measured (Tables 1 and 2). The rock samples are Late Indosinian granodiorite, mainly formed in the Early Triassic. The rock is not weathered and appears grayish-white, dense, and without obvious cracks on surface. The granite is fine medium granitic texture and massive structure. The main mineral components are plagioclase, potash feldspar, quartz, and a small amount of biotite, and the mineral composition indicates that the rock is acidic. The granite is a crystalline rock which indicates that it is deep diagenesis. The crystalline of plagioclase is better than potash feldspar and quartz, and this represents that plagioclase crystallizes first, potash feldspar and quartz crystallizes later. Its alteration indicates that the rock is affected by later hydrothermal action.

### 2.2 Rock sample preparation

The rock preparation procedures are shown in Figure 2. A borehole is drilled in the center of one surface with the depth of 150 mm. The water injection tube is a hollow stainless steel tube with a 10 mm outside diameter, a 160 mm length. The epoxy grout resin is injected into the wellbore, the tube is pressed into the wellbore to be glued, and the diagram of a prepared sample is shown in Figure 3.

Before experiment, no fractures were seen on the surface of the granite samples (Figure 4A), the sample’s surface was smooth, and even if the sample was cut in two halves, no fractures were seen on each half surface yet (Figure 4B).

### Table 1 Physical properties of rock samples

| Property                        | Range     | Average value |
|---------------------------------|-----------|---------------|
| Density, ρ (g/cm³)              | 2.41-2.72 | 2.53          |
| Porosity, ϕ (%)                 | 2.49-4.59 | 3.22          |
| Permeability, K (mD)            | 0.27-0.52 | 0.34          |
| Thermal conductivity, W m⁻¹ K⁻¹ | 1.75-3.00 | 2.48          |
| Specific heat (J kg⁻¹ K⁻¹)      | 709-800   | 736           |
| Poisson's ratio, ν              | 0.14-0.35 | 0.28          |
| Elastic modulus, E (GPa)        | 28.11-56.04 | 39.99        |
| Shear modulus, G (GPa)          | 10.54-21.84 | 15.86        |
| Shear wave velocity, V_s (mm/μs)| 2.02-2.89 | 2.47          |
| Compression wave velocity, V_p (mm/μs)| 3.57-5.25 | 4.45          |
| Unconfined compression strength, UCS (MPa)| N/A | 152          |
| Brazilian tensile strength, BTS (MPa)| 11.05-24.08 | 17.14        |
| Shear strength, SS (MPa)        | 20.00-27.00 | 22.60        |
| Cohesive force, C₀ (MPa)        | 10.19-13.75 | 11.71        |
| The angle of internal friction, φ (°) | 48.32-49.34 | 48.92       |

*Data include tests performed by the authors.

### Table 2 Mineral composition of rock samples

| Mineral composition | Value |
|---------------------|-------|
| Quartz              | 0.35  |
| Potash feldspar     | 0.23  |
| Plagioclase         | 0.30  |
| Others              | 0.12  |
The tests were conducted on a true-triaxial hydraulic fracturing apparatus that was developed by Jilin University. The apparatus main components are shown in Figure 5. It consists of four subsystems: a water injection system, a heating system, a steel framework and confining pressure system, and a computer monitor system.

The water injection system can provide a maximum injection flow rate of 30 mL/min. Before fracturing fluid is injected into the rock sample, there is a device to heat the water to target temperature, and then, there are not temperature differences between water and rock sample, and this heating device (Figure 5C,D) is close to the fracturing capsule. The steel framework contains a fracturing capsule that could support a cubical rock no larger than 300 × 300 × 300 mm. Three square flat jacks are placed in the three directions and could provide three independent orthogonal stresses to simulate the underground in situ stresses. The maximum triaxial stress provided by the flat jack is 25 MPa. The heating system can provide a maximum temperature of 150°C. The computer monitor system could monitor the injection pressure, temperature, and control the injection flow rate.

2.4 | Experimental process

In ideal circumstances, it is expected that a hydraulic fracture initiates and propagates in a plane known as preferred fracture direction (PFD), which is perpendicular to the minimum principal
pressure direction.29 Hence, each testing sample was placed in the fracturing capsule in a way that the wellbore axis was along the intermediate principal stress direction, and the maximum and the minimum principal stress were set perpendicular to the wellbore axis. This method makes it easy to observe relationship among the fractures, the maximum and the minimum principal stress when the sample is cut in half. Figure 6 shows the sample was installed in the fracturing capsule.

It should be noteworthy that the triaxial principal stresses were applied in four stages. First, the intermediate principal stress was increased to the minimum principal stress. This procedure would ensure the exposed part of the injection tube is inserted into the water outlet hole on the flat jack. Then, the other two stresses were increased to the minimum principal stress. At this time, the minimum stress syringe pump was set on a constant value. Next, the intermediate stress and the maximum stress were increased to the intermediate principal stress regime, and their corresponding pumps were set as the intermediate stress. At last stage, the maximum principal stress was increased to maximum stress, and then, the maximum stress syringe pump was set as constant. This stress load method was applied to all experiments.

FIGURE 4 Samples before the experiment: (A) prepared samples; (B) the cut in half sample surface

FIGURE 5 The true-triaxial hydraulic fracturing apparatus: (A) the water injection system; (B) the steel framework, confining pressure system, and the heating system; (C) injected water heating device; (D) the enlarged photograph of injected water heating device; (E) the fracturing capsule; and (F) a closed view of the apparatus
Experimental procedures: (a) The operation of the apparatus was checked; (b) the rock sample was placed into the fracturing capsule; (c) oil was pumped into syringe pump, and triaxial confining stresses were applied to the rock sample; (d) the heating system was turned on to heat the rock sample, the rock sample was heated to 150°C, and the temperature is maintained for 5 hours to ensure that the whole rock has reached the target temperature; (e) water was injected via the tube for fracturing, the injection flow rate was set as constant in each test, and six injection flow rates were chosen (5 mL/min, 10 mL/min, 15 mL/min, 20 mL/min, 25 mL/min, and 30 mL/min); (f) when a large amount of water flowed out of the fracturing capsule, the fracturing pressure did not change and reached an equilibrium state, we considered hydraulic fracturing was completed, and water injecting syringe pump was turn off; (g) the triaxial confining stresses were released, the stress release process was the same as the applying process, the maximum principal pressure was decreased to the intermediate principal pressure, next the intermediate and the maximum pressure were decreased to the minimum principal pressure, and lastly, the three confining stresses were released to zero; (h) the rock sample was taken out from the fracturing capsule, the fractures were observed and recorded immediately, the condition of water flowing out from the fractures could be clearly seen, and the water flowed out of the rock sample along the fractures; (i) the rock samples were cut in two halves to observe fractures; (j) fractures were marked by a marker pen, and photographs were taken; (k) the experiment data were analyzed.

3 | RESULTS

Hydraulic fracturing experiments were conducted on six 300 × 300 × 300 mm cubic granite samples. These experiments involved the injection flow rates from 5 mL/min to 30 mL/min with heated temperature of 150°C (The 150°C is the maximum temperature the heating system could provide). A confining stress regime was maintained throughout the whole test on all six samples, where \( \sigma_1 = 12 \text{ MPa} \), \( \sigma_2 = 8 \text{ MPa} \), and \( \sigma_3 = 4 \text{ MPa} \). The wellbore, adhesive, and perforation were processed with repeatability to make sure that each sample would be near identical when the fracturing pressure applied. The triaxial confining stresses were applied slowly with significant level of care and caution to prevent stressing fractures in the loading process. This made it possible to control most of the variables in the experiment and to accurately monitor and study the effect of flow rate. Table 3 presents the fracturing parameters of the tests.

At the end of each test, the sample was then taken out from the fracturing capsule. The fractures on the sample were photographed and marked (Figure 7A). Then, each sample was carefully cut into two halves (Figure 7B). After experiment, the sample’s surface have fractures, water flowed out from the fractures, the rock surface was soaked by water, and after the rock sample was cut into two halves, there were hydraulic induced fractures on each surface, and the main fractures propagated along the maximum principal stress direction from the wellbore. The fractures on each half were photographed to help analyze the fracture geometry, and the
pressure-time and pressuring rate-time curves were recorded to interpret hydraulic fracturing process.

Figure 8A-F show the curves of fracturing pressure and pressurization rate vs time during the whole fracturing processes in Test 1 to 6, where the hydraulic fracturing injection flow rates are 5, 10, 15, 20, 25, and 30 mL/min. The black curves represent the fracturing pressures. As Figure 8A-F show, all the pressure curves have similar shapes, and a particular pressure-time curve could be divided into four main stages: (a) initial pressure development stage, (b) wellbore pressurization stage, (c) fracturing stage, and (d) postfailure stage. In the initial pressure development stage, the fracturing fluid syringe pumped the water into the wellbore through pipeline. As the injection pump was the next room, the water injection pipeline was somewhat long, and this time interval lasted about 130-400 seconds and ended up when the wellbore was filled of water. At the end of this stage, the water was just filling the pipeline and injection tube. Very small pressure development was identified, and the pressure curve kept close to zero (almost horizontal) with unchanged. After the wellbore was completely filled, during the wellbore pressurization stage, continuously injecting water into the wellbore resulted in the rock around the wellbore bottom was pressurized and the fracturing pressures started to quickly build up with almost constant increase rate. Then, in the fracturing stage, the fractures were initiated and propagated, new volume was created, and the pressure reached the maximum which is also called breakdown pressure and then had a large drop. In this stage, fractures were continuously induced by the high fracturing pressure, and new fluid was pressurized in to compensate the new induced volume. Even though continuing to injection water, a large pressure drop was observed because of the large amount of new created volume which was not be absolutely compensated by the new injected water. The fracturing stage lasted a few seconds, and the fracture tip reached the sample's boundary. The hydraulic fracturing process reached to the last stage, postfailure stage, and the fluid flowed out of the sample. Even though water was continuously injected into the rock, the pump pressure did not change. This meant that the injection pressure was now equal to the water flowing frictional pressure loss along the created fractures. Even if new injected water entered into rock body, no fracture would be created, and the injection pressures did not change with time.

The red curve represents the pressurization rate. As shown in Figure 8A-F, a typical pressurization rate curve could obviously reflect different stages of the whole fracturing process. In the initial pressure development stage, as the water only

| Test no. | Injection flow rate (mL/min) | Initiation pressure (MPa) | Breakdown (maximum) pressure (MPa) | Postfracturing pressure (MPa) | Propagation time (s) |
|---------|-----------------------------|---------------------------|-----------------------------------|-----------------------------|-------------------|
| 1       | 5                           | 21.06                     | 22.12                             | 11.20                       | 613               |
| 2       | 10                          | 22.95                     | 24.68                             | 12.69                       | 498               |
| 3       | 15                          | 25.61                     | 27.65                             | 11.27                       | 447               |
| 4       | 20                          | 27.91                     | 30.06                             | 9.97                        | 343               |
| 5       | 25                          | 28.71                     | 34.10                             | 7.68                        | 220               |
| 6       | 30                          | 32.52                     | 36.01                             | 3.11                        | 88                |

FIGURE 7 (A) The photograph of the fractured rock sample, the black lines indicate fractures, and red water flows out of the rock from these fractures; (B) the cut sample
filled the injection tube and the pressure was almost zero, the pressure did not change at the stage and the pressurization rate kept at zero yet. In the wellbore pressurization stage, the injection pressure climbed quickly. As the injection flow rate was constant, the pressurization rate rose rapidly and then fluctuates near a constant value, and this represents the

**FIGURE 8** The fracturing pressure-time curves and pressuring rate-time curves: (A)-(F) are the hydraulic pressure curves and pressure rate curves when the injection flow rate is respectively 5, 10, 15, 20, 25, and 30 mL/min.
pressure curve ascended nearly a straight line at this stage. When entering the fracturing stage, the pressurization rate decreased rapidly until it became negative, which indicated that the pressure decreased dramatically in a nonlinear form. It showed that the fractures propagated very fast, and the new pumped fracturing fluid could not fill full of the rapidly new formed fractures. In the last stage, the fracture tip hit the sample’s boundary, no new fracture was created, the fracturing fluid just flowed out of the rock along the formed fractures, the pressure did not change, and the pressurization rate gradually became zero.

4 | DISCUSSION

4.1 | The effect of flow rate on the fracture initiation pressure, propagation time, breakdown pressure, and postfracturing pressure

The fracture initiation pressure is the point at which a small initial defect just starts to propagate. Usually, the rock around the wellbore bottom already begins to be fractured and fails before the pressure reaches its maximum. The fracture breakdown is usually defined as the time point when the pressure in wellbore reaches the maximum, which means that fracture breakdown typically occurs after the point of initiation. The breakdown process is the time interval between initiation and breakdown, the fracture is just initiated, and the new created volume cannot compensate the new injected fluid volume, the water supply (the amount of water new injected into the wellbore) is greater than the fluid demand (the new water volume needed to propagate the fracture), and the pressure in the wellbore continues to rise. At the breakdown point, the supply is equal to the demand, and the pressure reaches the maximum. The initiation pressure represents the pressure when the fracture begins to initiate. It is a parameter that could reflect the properties of the rock sample, such as failure stress, tensile stress, and shear stress in field. The breakdown pressure is always used to help to design the fracturing scheme, select fracturing pump, and estimate fracture length in field-scale operation. This means that the breakdown pressure is essential for the effective and efficient designing in situ operations and directly influence the hydraulic fracturing method and difficulty. Therefore, it is necessary to separately analyze the initiation pressure and the breakdown pressure, whether for laboratorial research or field-scale operation. The fracture propagation time is another crucial parameter to estimate fracture extension range in field-scale hydraulic fracturing. In oil, gas, and EGS fields, hydraulic fracturing propagation time also directly influences the number and magnitude of the induced earthquakes. The postfracturing pressure is the almost constant pressure with time after the fracture tip reaches the rock boundary, when the fracture length does not increase any more. This time point is illustrated in Figure 8A, and after this time point, the pressure-time data recorded are just showing the process that water flows via the created fracture to rock boundary. The pressure in wellbore remains almost constant. It is noteworthy that the postfracturing pressure behavior is very similar to the fluid injection pressure during the heating extraction stage in field. This injection pressure (postfracturing pressure) is based on the concept that when constant viscous fluid in isothermal reservoir condition flows through a constant length fracture pathway, the frictional pressure loss along the pathway does not change with time. In an in situ project, the requirement for hydraulic fracturing technology is very high. If the fractures are too developed (indicating a low postfracturing pressure), the water flows too fast in the fractures, the heat exchange time between the rock mass and water is short, the heat transfer is insufficient, and the water temperature at the water production well is low. The heat energy cannot be well extracted. If the fractures propagate insufficiently or the fracture channel is narrow (indicating a high postfracturing pressure), the water cannot flow between injection and production wellbore well, and it may result in serious water loss or less water could flow out of the production wellbore. We will not yet achieve the purpose of heat energy high effective extraction. Therefore, we need properly propagated fractures for reservoir stimulation, water not only can flow well in the fracture system, but also can have a good heat transfer with rock. However, the fractures cannot be directly observed after hydraulic fracturing in field-scale operation, and we need to find other methodologies to interpret the fracturing patterns; postfracturing pressure is a parameter that represents the frictional pressure loss along the fracture pathway and could directly reflect the fracture condition during the heat energy extraction phase in field. As a result, the postfracturing pressure is a valuable parameter to determine the heat extraction efficiency and evaluate the hydraulic fracturing results.

To find out the time point of fracturing initiation, we firstly analyze the hydraulic fracturing process. When enough fluid is pressurized, the pressure is high enough to initiate a fracture, and some new volume is induced. The pressurized fracturing water near the wellbore bottom expands to fill the new initiated flaw volume, and thus reducing the wellbore pressure. At the same time, the pressurized water will naturally quickly flow into the wellbore to compensate this pressure drop. As the new pressurized water volume is larger than the new induced fracture volume, this may induce higher pressure in the wellbore, but the wellbore pressure would not increase obviously. As a result, we can find that the highest fracturing pressure always lasts for a while in the fracturing pressure curves. This phenomenon will definitely cause the change of the pressurization rate. In Figure 8A-F, the red curves are the pressurization rate curves. When the wellbore...
is not full of fracturing fluid, the pressure keeps at zero, and the pressurization rate is also kept at zero. Then, the pressurization rate rapidly rises and usually fluctuates in a constant vale for a while at the top of the curve. In this period, fluid is full of the wellbore and still pressurized into the wellbore, and no fracture is initiated. As the flow rate is constant, the pressure rises approximately linearly with time and the pressurization rate is almost constant with little fluctuations. The beginning of quick decline in the pressurization rate curve could be considered as the evidence of the fracture initiation point. As the rock in the wellbore bottom could not withstand the high pressure, the fracture begins initiate, microcracks are induced, and thus, the wellbore pressure increase rate reduces. This is reason that the new pressurized water expands from wellbore to fill the new induced fracture volume and the new pressurized fluid cannot absolutely compensate the pressure reduction due to the constant injection flow rate; consequently, the pressurization rate decreases.

In laboratorial hydraulic fracturing tests, the fracture propagation time is usually considered as the time interval that it takes from the fracture initiates until it grows all the way to the boundary of the rock sample. After a fracture is triggered, the fracture grows, more and more new volume will be created, and the wellbore pressure decline rate will accelerate. This is indicated in Figure 8, where the wellbore pressurization rates (red curves) decrease after the fracture initiation points. It could be considered as the beginning of the fracture propagation. When the fracture reaches the sample boundary, the fluid begins to flow out into fracturing capsule from the rock. The pressure in the wellbore is now equal to frictional pressure that the fracturing fluid loses along the fracture pathway. As the fracturing pressure is stable and does not change with time, the pressurization rate becomes zero without fluctuation. This is the time point (see Figure 8) that could be practically considered as the end of the fracture propagation, and the propagation time could be got from the pressurization rate curve.

The end of fracture propagation is the time point after which the injection pressure becomes constant. Form this time point, fluid seepage in the induced fractures reaches equilibrium condition and the constant postfracturing pressure reflects the water friction resistance along the created complex fractures path. The Figure 8A shows the beginning of postfailure stage (phase 4), it is identified as the end of fracture propagation, and it is also the beginning constant pressure in the pressure curve. As the injection flow rates are different in tests, the postfracturing pressures could not be used for analysis directly. To test the fracture network and contrast the postfracturing pressures in different tests, the flow rate is change to 5 mL/min at the end of each test. If the flow rate was greater than the least flow rate, new fractures might be triggered for the samples whose flow rate (the flow rate in Table 3) was lower during hydraulic fracturing experiment stage. Hence, we choose the lowest flow rate when revising the postfracturing pressures. Table 4 presents the postfracturing pressures when the flow rates are change to 5 mL/min, they are called the revised postfracturing pressures. We can see that a higher injection flow rate during the experimental (hydraulic fracturing) stage, a lower revised postfracturing pressure is caused.

Figure 9 shows the fracture initiation pressure, propagation time, breakdown pressure, and postfracturing pressure under different injection flow rates in different tests. The initiation pressure is approximately positive linearly increasing with the injection flow rate. The initiation pressure ascends from 21.06 to 32.52 MPa when the injection flow rate is increased from 5 mL/min to 30 mL/min, and the initiation pressure increases 54.42%. And the linearly fit coefficient of determination of the initiation pressure is 0.9808. The breakdown pressure is almost positive linearly increasing with the increase of injection flow rate. The coefficient of determination is 0.9943. The breakdown pressure increases from 22.12 to 36.01 MPa when the injection flow rate increases from 5 mL/min to 30 mL/min, and the breakdown pressure increases 62.79%. With the increase of injection flow rate, the propagation time has a linear decrease trend with the determination coefficient of 0.9851. The propagation time decreases from 613 to 88 seconds when the injection flow rate increases from 5 mL/min to 30 mL/min, and the propagation time decreases 85.64%. This relationship represents that with the increasing of injection flow rate, more fluid is pumped into the wellbore in same time, more volume is induced, the

| Test no. | Injection flow rate during hydraulic fracturing (mL/min) | Postfracturing pressure (MPa) | Revised postfracturing pressure (MPa) |
|----------|---------------------------------------------------------|-----------------------------|--------------------------------------|
| 1        | 5                                                       | 11.20                       | 11.20                                |
| 2        | 10                                                      | 12.69                       | 11.13                                |
| 3        | 15                                                      | 11.27                       | 9.52                                 |
| 4        | 20                                                      | 9.97                        | 6.37                                 |
| 5        | 25                                                      | 7.68                        | 4.59                                 |
| 6        | 30                                                      | 3.11                        | 1.43                                 |
propagation rate also increases, and as a result, the fracture propagation time decreases when the rock sample size is the same for different tests. The revised postfracturing pressure linearly decreases with the increase of injection flow rate with a coefficient of determination 0.9926. The revised postfracturing pressure decreases from 11.2 to 1.43 MPa (a gradient of 87.23%) when the injection flow rate increases from 5 mL/min to 30 mL/min. We can see that a higher revised postfracturing pressure corresponds to a lower injection flow rate during hydraulic fracturing stage, and a lower revised postfracturing pressure corresponds to a higher injection flow rate. It means a lower injection flow rate may cause a fracture network with less fractures and narrow channels for water flowing through, whereas a higher injection flow rate may lead a developed fracture network that water could easily flow through. These results are in agreement with previous studies.

The initiation pressure is a parameter that could reflect the properties of the rock sample. The breakdown pressure is a very important parameter during the hydraulic fracturing process. Previous studies also showed that it could influence the fracture propagation behavior and morphology. The fracture propagation mechanics during hydraulic fracturing stage is mainly controlled by the breakdown pressure yet. This parameter is widely used when analyzing the fracture behavior in laboratorial test, numerical simulation, and in situ project. Therefore, it is crucial to correctly determine the breakdown pressure, discriminate it with initiation pressure, and analyze its changing trend with the injection flow rate.

Usually, induced earthquakes are accompanied with whole hydraulic fracturing process, and more earthquakes are always triggered when the fracture propagation time is longer. In an in situ project, a traditional view is that the maximum induced earthquake magnitude is only related to the total volume of injected fluid. Therefore, to get a good fracture network and avoid a dangerous earthquake, a small injection flow rate with a long propagation is always adopted recent years. Whereas this method also could cause a large earthquake, for example, hydraulic fracturing of the Pohang EGS project almost lasted several months in about 2 years, a $M_w$ 5.5 earthquake was caused, and this earthquake injured about 70 people and induced extensive damage to the Pohang city. Since the seismographs were firstly installed

![Figure 9](image_url) Influence of injection flow rate on the fracture initiation pressure, propagation time, breakdown pressure, and postfracturing pressure

![Figure 10](image_url) The hydraulic fracturing result of room temperature: (A) is fracturing pressure-time curve and pressuring rate-time curve; (B) is the fracture geometry
FIGURE 11  Spatial distribution of AE events and estimated SRV from AE distribution: (A)-(F) represent AE distribution of Tests 1-6 with 5, 10, 15, 20, 25, and 30 mL/min; (G)-(L) represent the corresponding the SRV (highlight in yellow)
FIGURE 11 (Continued)
in 1905, this induced earthquake was the most damaging, and the second-largest magnitude in South Korea. As a result, it is necessary for hydraulic fracturing to choose a reasonable fracturing propagation time.

The postfracturing pressure is an effective parameter during estimating fracture opening or leak off. It also could help to analyze the fracture geometry, length, and smoothness, and a lower postfracturing pressure usually corresponds to a better-connected fracture network with longer and smoother fracture branches. The postfracturing pressure is an indispensable parameter when predicting the productivity of wells after hydraulic fracturing. Therefore, it is necessary to correctly identify the postfracturing pressure and find out its changing laws.

4.2 The effect of temperature

Hydraulic fracturing for an EGS operation usually is performed in deep buried high temperature granite reservoir, the high temperature will lead to the change of rock properties, and then, the hydraulic fracturing characteristics between room temperature (about 25°C) and high temperature should be different. To investigate the influence of temperature on hydraulic fracturing behavior, a comparison experiment on room temperature was carried out without the effect of heat. The experimental result is shown in Figure 10. The injection flow rate was set as 10 mL/min. The triaxial confining stresses condition was the same as that of hydraulic fracturing tests in high temperature. In the room temperature comparison test, the initiation pressure was 27.64 MPa, the breakdown pressure was 30.28 MPa, the postfracturing pressure was 14.12 MPa, and the propagation time was 545 seconds. Whereas in the aforementioned high temperature Test 2 the initiation pressure was 22.95 MPa, the breakdown pressure was 24.68 MPa, the postfracturing pressure was 12.69 MPa, and the propagation time was 498 seconds. The comparison experiment results showed that the initiation pressure, the breakdown pressure, the postfracturing pressure, and the propagation time increased by 20.44%, 22.69%, 11.27%, and 9.44% under room temperature with the same injection flow rate and triaxial confining stresses conditions. As shown in Figure 10B, a two-wing fracture perpendicular to minimum principle stress is induced, the downward fracture is almost along the maximum stress, the upward fracture has a small angles with the PFD maximum stress, and this fracture geometry is very similar with that in Figure 13B, it means that the process of heating rock from room temperature to 150°C does not obviously influence the fracture morphology.

The reason that temperature influences these parameters is the induced microcracks caused by the thermal stress, which is attributed to the temperature change during the heating process. A study conducted by Zhang et al shows that the temperature definitely influences the rock mechanical and physical properties, and their results showed that when temperature was increased from 25°C to 200°C their experimental rock strength would decrease from 8.7 to 5 MPa. The research of Nasseri et al showed that the fractures toughness would decrease with the increase of temperature, which was caused by the gradually opening boundaries of the grains. According to the experimental observations of Shao, the heating process could cause thermal stresses in rock matrix, and this would result in thermal induced cracks propagate along the boundaries of the weak grains and preexisting ones. The reason was the anisotropy of the rock matrix, and the rock matrix was consisted of different mineral compositions and had different thermoelastic properties. The different minerals had different anisotropic expansion under high temperature, and this would lead to the localized stress concentration; once the concentrated stress exceeded the internal strength inside a particular mineral or the bond strength among different minerals, a microcrack would be initiated.

![Figure 12](image_url) Influence of injection flow rate on AE
The thermal induced cracks will lead to a reduction of the granite strength property. Due to the existence of microcracks, a lower injection pressure could initiate a fracture, and as a result, the initiation pressure and breakdown pressure declined at high temperature. At the same time, the existing microcracks reduce the fracture propagation resistance, the fracture propagation rate was accelerated, and then, the propagation time would decline. The large amount of microcracks made the rock became more fragile; hence, the postfracturing pressure was lower at high temperature. During heating process, the microcracks induced by thermal stress would decrease the rock strength and makes hydraulic fracturing easier. As a result, when analyzing hydraulic fracturing characteristics in granite geothermal formations, it is necessary to establish HDR environment in laboratory and made the laboratorial condition closer to the in situ HDR environment.

4.3 | The effect of flow rate on acoustic emission

Figure 11 shows the acoustic emission (AE) activity with the increase of injection flow rate and the estimated stimulated reservoir volume (SRV) from AE event distribution. It is already a common method to estimate the SRV with microseismic-mapping data in field-scale hydraulic fracturing.
operation. Similar estimation method could be seen from the studies of Mayerhofer and Li et al.\textsuperscript{24,59} The SRVs of Tests 1-6 were illustrated in Figure 11G-L. From Figure 11A-G, we could see that the range of the AE distribution became wider and wider with the increase of injection flow rate. When the injection flow rate was 5 mL/min, the AEs were triggered only in the area near the wellbore, and as the injection rate increased, the red AE event could be triggered at a farther point in the reservoir. When the injection flow rate was increased to 30 mL/min, almost the whole reservoir was stimulated. This phenomenon could be seen from the result of SRV in Figure 11G-L, the SRVs were highlight in yellow, and with the increase of injection flow rate, the SRV also increased.

Figure 12 shows the influence of injection flow rate on SRV, total AE event number, and cumulative AE energy. With the increase of injection flow rate, these three parameters all increased, it meant the increasing the injection flow rate, more injection energy was transferred to energy for fracture propagation, a more complex fracture system tended to be induced, more AE events were triggered, and then, this caused a higher SRV. When the injection flow rate was increased from 5 mL/min to 20 mL/min, the total AE events increased from 138 to 313 and the SRV increased from 6126 cm\(^3\) to 8813 cm\(^3\) (approximately increasing by 42.27\% and 14.62\% for each 5 mL/min increment of the injection flow rate, respectively). When the injection flow rate was increased from 20 mL/min to 25 mL/min, the AE events increased from 313 to 987, increasing about 107.67\% in each 5 mL/min increment, and the SRV increased from 8813 cm\(^3\) to 23 252 cm\(^3\), increasing about 81.92\% in each 5 mL/min increment. This represented that the induced fractures did not obviously increase when the injection flow rate increased from 5 mL/min to 20 mL/min, with the injection flow rate continuously increased to 25 mL/min and 30 mL/min, a fracture system with more branches was induced, and these fractures were more widely distributed in the granite reservoir. This phenomenon was in accordance with the fracture distribution in Figure 13. The cumulative AE energy reflected the released energy during fracture propagation in hydraulic fracturing, a higher cumulative AE energy always meant a more complex fracture system and higher SRV, it almost linearly increased with the increase of injection flow rate, and when the injection flow rate was 20 mL/min, the total AE event number and SRV did not linearly ascend in this point. Whereas the cumulative AE energy in this flow rate was in the linear trend line, this was in accordance with the induced fracture morphology in Figure 13D, only a two-wing fracture should correspond to less AE quantity and lower SRV, and a higher cumulative AE energy meant more energy was transferred to induce hydraulic fractures. Since the SRV did not increase obviously, the fracture width should be increased obviously. This was confirmed by the enlarged fracture photograph in Figure 13D and the lower revised postfracturing pressure in

Table 4. Generally speaking, the result of AE indicates that higher injection flow rate could stimulate the reservoir better, and more volume in the reservoir will contain the induced fractures. Similar results were also found in previous hydraulic fracturing laboratory experiments.\textsuperscript{14,60}

### 4.4 The effect of flow rate on the fracture morphology

The fracture geometry is very important for the evaluation of hydraulic fracturing effect. The fracture length, height, and geometry are important indexes to access the hydraulic fracturing results and investigate fracture extension patterns. To clearly observe these indexes of the fractures, the samples are cut in half (Figure 7B) at the bottom of the wellbore (in the middle of the sample). Figure 13A-F shows the fractures of test No. 1-6 samples.

In Figure 13A, only a two-wing fracture is propagated along the preferred fracture direction (PFD), that is, the maximum stress axis direction, the fracture is almost perpendicular to the direction of the minimum stress. In Figure 13B, only a two-wing fracture is propagated. The upward fracture and downward fracture have angles of about 15.4\° and 19.2\° with the PFD, respectively, the propagation angles are small, and the fractures are considered along the PFD. In Figure 13C, a two-wing fracture and a single wing fracture are propagated. The upward fracture propagation angle is 30.0\°, which is larger than the two downward ones (14.8\° and 19.44\°). As the angles are less than 45\°, the angles are closer to the maximum stress axis, and the downward fracture in left propagates a short path then turns toward the PFD. As a result, their propagation directions could be considered as along the direction of maximum stress. In Figure 13D, only a two-wing fracture is propagated. The fracture propagates downwards and upwards both in a curved way, and the upward fracture turns toward PFD in a distance away from the wellbore. The downward fracture could not be obviously observed toward to PFD. In Figure 13E, three wings are initiated from the wellbore. The wing that propagates to the upper left has an angle of 34.3\° with respect to PFD. The two-wings that propagate to right are almost against the PFD near the wellbore. Then, the upper right one changed its direction toward the PFD. The lower left one propagates into three branches away from the wellbore, and two of them develop toward the PFD and merge upward into one fracture. The downward branch propagates along the PFD at first and then develops against the maximum stress at the lower edge of sample. In Figure 13F, this test exhibited a multiple fracturing distribution, and a fracture system with three wings are initiated from the wellbore. The upward wing propagates almost along the PFD. The upward one is the widest fracture and could be considered as the main hydraulic fracture. However, its three branches are almost
against the PFD. The left downward wing is initiated along the PDF and then grows in a curved path to the lower left, and its only branch propagates against the PFD. The right downward wing is initiated against the PFD at first, and then, its branch propagates along the PFD.

It was expected that a fracture propagation direction would be along the PFD, perpendicular to the minimum principle stress. However, only the fractures in Test 1 (Figure 13A) propagate almost along the PFD, and most of the others are initiated in an angle respect to the PFD. As it still can be seen from Figure 13, fracture propagation in hydraulic fracturing is influenced by triaxial confining stresses (crustal stress in field). Although sometimes the fractures are not initiated along the PFD near the wellbore, the fractures will gradually turn to PFD in curved paths as the fractures grow toward the boundaries of the samples. At last, the fracture propagation direction is the PFD. The reason is that the actual stress state near the wellbore zone is very complex. The initiation of hydraulic fracture is controlled by the confining stresses, the wellbore, the wellbore internal pressure, the pore pressure, the rock property, and other mechanisms. As a result, the fractures may be initiated not along the PFD at first. Once the fracture has some length, fracture propagation rate is stable, the fracture tip moves far away from the wellbore and stress complex area, the fracture goes into a less stressed region, and then, the fracture propagation will be controlled by the triaxial stresses and along the PFD, as the injection pressure is less than the breakdown pressure in this time, this means that less pressure is needed for the fracture propagation.

We can also see that in Tests 4, 5, and 6, some fracture branches still do not approach the PFD when they reach the rock boundary, even parts of them are perpendicular to the PFD. As shown in Figure 13D-F, some of the main fractures that propagate from the wellbore cannot be seen to turn toward the PFD when the fracture tips hit boundary. Fan and Hannes et al. performed a series of studies and show that as the injection flow rate increased, the balance between fluid injection and propagation could be broken, and the fracture propagation would become unstable and fluctuated, it meant that the fracture propagation pathway might be unpredictable. And sometimes, in the area around the wellbore, the fracture propagation would not obey the PFD law. This is in accordance with our experiment results. A higher injection flow rate means a higher injection pressure with more energies is injected into rock. There is more possibility to create a complicated fracture network. The reason is that, when a large amount of water is injected into the well in a short time, a high-pressure environment is formed rapidly at the wellbore bottom, this will lead the fracturing process similar to an explosion process, the fractures propagate rapidly from the wellbore to the rock boundary, and the hydraulic fracturing time is very short. As the energy and pressure are released rapidly, the fractures induced by this kind of “exploded” pattern may not propagate along the PFD. Whereas when the injection flow rate is low, the fractures propagation rate is low either, the fractures tend to propagate along the PFD, and this process is controlled by the principal stresses. Usually, in high injection flow rate, the “exploded” phenomenon only influences the rock mass near the wellbore; when the fractures propagate far away enough, the propagation direction turns to the PFD again. But in our tests, the side length of the rock sample is only 300 mm, it may still in the influence of the “exploded,” so the fractures propagating toward the PFD is not obviously observed.

The description for the hydraulic fracture geometry is very important in the in situ operation. A more complex and wider fracture may result in lesser frictional resistance and a higher permeability, the fluid flows through the fractures will be more easily with less resistance, and as a result, in field-scale operations, the fluid heat exchange time with rock will be short; the heat extraction efficiency will be low. On the other hand, fluid will suffer higher frictional pressures when flowing through a single narrow fracture. The circulated flow rate is low, and the heat exchange between fluid and rock is sufficient. The total amount of fluid flowing through the fractures will be also low. As a result, the amount of the extracted heat is still low. Hence, an appropriate fracture geometry is vital for an in situ project.

Analyzing these fracture geometries along with the experimental parameters will demonstrate how the injection flow rate may influence the fracture geometry. To compare and observe the fractures widths of different tests, we choose two parts to enlarge 5 times in the fracture photograph of each test. As shown in Figure 13, with increasing the flow rate, the fracture generally becomes wider. Figure 14 shows the total length of the fractures vary with respect to injection flow rate. Generally speaking, the total length of fractures

**FIGURE 14** Influence of injection flow rate on the fracture length
increases with the increase of flow rate. However, we can see that the total length of the fractures in Test 4 is less than that in Test 3. Combined with Figure 13, from the enlarged fractures photographs, we can see that the fractures of Test 4 are wider, and the corresponding revised postfracturing pressure in Table 4 is lower yet, it means that the frictional resistance in Test 4 is lower than that in Test 3 when the fluid flows through the fracture system, so it can be considered that it does not violate the flow rate-postfracturing pressure law. As a result, we can get that a higher flow rate leads to higher initiation and breakdown pressures, wider fractures and more complex fracture system. This results in a higher connectivity and a lower friction resistance for fluid flowing. The revised postfracturing pressure in Table 4 is in accordance with this conclusion.

When the injection flow rate increased from 5 mL/min to 20 mL/min, the total length of fractures increased, but the increase trend, as shown in Figure 14, was not obvious. When the injection flow rates were increased to 25 mL/min and 30 mL/min, the fractures total lengths have notable increase. Combined with Figure 13, the fractures in Tests 1, 2, 3, and 4 (injection flow rate from 5 mL/min to 20 mL/min) formed a two-wing or three-wing fracture, and a fractured network in these tests was not induced. As a result, the increase of injection flow rate only increased the fractures width, but not in the fracture length. When the injection flow rate was increased to 25 mL/min (Test 5) and 30 mL/min (Test 6), the “exploded” fracturing mode is trigger, a complex fracture network formed, and the fracture total lengths obvious increased. It shows that complex fracture networks were created when high injection rates were used. The phenomenon was also observed other researchers.\textsuperscript{14,60,63,64} Based on hydraulic fracturing laboratorial experiments in shale sample, Hou et al\textsuperscript{60} found that high flow rate would lead to a large stimulated rock area and a complex fracture network. Davidson et al\textsuperscript{63} analyzed the results of Gas Research Institute’s fourth Staged Field Experiment in the Frontier formation of southwest Wyoming, and they found that noticeably higher flow rate and injection pressure contributed to near wellbore hydraulic induced fracture growth and tortuosity. Kresse et al\textsuperscript{64} analyzed effect of flow rate and viscosity on complex fracture development mechanisms, and results showed that fracture system caused by higher injection flow rate was more complex with a larger stimulation area. Fan et al\textsuperscript{14} performed hydraulic fracturing in concrete and tied to create complex fractures, and they found that a high injection rate made the hydraulic induced fracture unstable and
fluctuated; their results were in accordance with our “exploded” fracturing mode under high flow rate condition.

4.5 The mean injection power

Figure 14 recognizes the relationship between the injection flow rate with the total length of fractures; although by increasing the injection flow rate longer fractures length were induced, the relationship between the two parameters could not be got from Figure 14.

To analyze the reason injection flow rate could influence the geometry, width, and complexity of fractures, why a higher injection flow rate usually causes a more complex fracture system. A new parameter called mean fracturing power ($P_I$) is put forward. Each test has a specific flow rate ($Q$), and the fracturing pressure ($P$) varies as a function of time ($t$). The injection flow rate unit is $m^3/s$, hydraulic fracturing pressure unit is $N/m^2$, and time unit is $s$; it is realized that the unit of the product of injection flow rate, fracturing pressure, and time will be $N \cdot m$. This means that the product represents the energy that supplies for hydraulic fracturing. Hence, the $P_I$ is defined as:

$$P_I = \frac{\int_0^t Q \cdot P dt}{T},$$

where $T$ is the fracture propagation time and the unit of $P_I$ is power (W).

The relationship between the mean fracturing power and the fracture total length is shown in Figure 15. The mean fracturing power has a good positive liner relationship with the fracture total length, and the coefficient of determination is found to 0.9052. In most circumstances, especially in field, fractures cannot be observed and measured directly. And the fracture length is most important parameter to evaluate the hydraulic fracturing effect. Previous methods for the evaluation of hydraulic fracturing...
are usually the drilling, microearthquake, and magnetotelluric method, and these measurement methods sometimes cannot be used in field due to high budget. As a result, estimating the fracture length is always a challenging work in field-scale hydraulic fracturing. The fracture total length is roughly positive increase with the mean fracturing power; hence, we can use this relationship to roughly evaluate the fracture length in field with almost no cost. This linear relationship provides us with a new way to roughly predict fracture length.

4.6 | The permeability of the hydraulic fracture

Up to now, hydraulic fracturing is an imperative technique for economic exploitation of deep geothermal resources by enhancing deep buried rock permeability. Therefore, it is important to understand the permeability after hydraulic fracturing. Patel et al.\textsuperscript{65} proposed a method to estimate fracture permeability using the injection-pressure data. This method hypothesizes that due to the injected fracturing fluid flowing into induced fractures, a drop of the injection pressure happens just after the breakdown phenomenon. This hypothesizes is in accordance with our aforementioned pressure sharply decrease after breakdown point. Here, we use this method to analyze the fracture permeability after test.

Figure 8A-F shows the pressure curves of the six tests. In these curves, just after the breakdown pressure, a sharp decrease in injection pressure (pump pressure) is observed. This is caused by the injected fluid diffusion when water goes into the new created fracture volume. The diffusion source is the water outlet hole in the steel tube. After the sharp drop in the pressure curve, the injected fluid flows into the rock sample through induced fractures. Therefore, the pressure will obey a one-dimensional diffusion equation\textsuperscript{66}:

\[
\frac{\partial P}{\partial t} - D \frac{\partial^2 P}{\partial z^2} = 0,
\]

The solution of Equation (2) is given by Crank\textsuperscript{67}:

\[
\Delta P(z, t) = P_0 \text{erf}\left(\frac{z}{\sqrt{4Dt}}\right),
\]

where \( t \) is the time after the breakdown, \( D \) is the hydraulic diffusivity, \( z \) is the length of the fracture, and \( P_0 \) is the breakdown pressure. Equation (3) can be used to fit the experiment pressure curve, \( P_0, z, \) and \( t \) are known, and then, the hydraulic diffusivity could be estimated. The induced fracture permeability could be estimated from the solution of Equation (3) given by Shapiro et al.\textsuperscript{68}:

\[
D = \frac{N K}{\mu},
\]

where \( \mu \) is the dynamic viscosity of the fluid, \( K \) is the permeability, and \( N \) is defined as\textsuperscript{68}.
where,\(^6^8\) \(d\) is the shear modulus of the frame, \(\phi\) is the porosity, and \(K_f\), \(K_g\), and \(K_d\) are the fluid bulk moduli, grain material, and dry frame, respectively.

Based on the Equations (2)-(9), the fracture permeability could be calculated by using hydraulic fracturing pressure curves of the six tests. The values of \(K_f\), \(K_g\), and \(K_d\) are 2.18 GPa, 75 GPa, and 28.09 GPa, respectively. The values of \(\phi\) and \(d\) are 15.58 GPa and 3.95 \(\times\) \(10^{-2}\) Pa s, respectively, and the value of \(\mu\) is 18.63 \(\times\) \(10^{-4}\) Pa s.

The permeability was 0.92, 1.21, 2.23, 3.32, 5.72, and 7.54 mD when injection flow rate was 5, 10, 15, 20, 25, and 30 mL/min, respectively. The value of estimated fracture permeability with injection flow rate is plotted in Figure 16.

The fracture permeability shows a positively ascend trend with the injection flow rate increase. It means that a higher injection flow rate will cause wider, lager fractures. All of the rock sample permeability after hydraulic fracturing are greater than the original sample permeability. As the original permeability is 0.34 mD, the permeability is obviously promoted. When the injection flow rate increases by 5 mL/min every time, compared with the original sample permeability, the permeability is increased 1.71, 2.55, 5.56, 8.78, 15.81, and 21.21 times, respectively. When the injection flow rate is 30 mL/min, the permeability is the highest. In field-scale operation, we usually trend to create more fractures and form higher permeability, and a higher injection flow rate is better.

Pate et al\(^6^5\) calculated hydraulic fracturing permeabilities, which were 2.28, 2.58, and 5.69 mD, when hydraulic diffusivities were \(8.60 \times 10^{-4}\), \(10.75 \times 10^{-4}\), and \(21.50 \times 10^{-4}\), respectively. The estimated fracture permeabilities were compared with the fracture permeabilities measured by using AP608™ permeability test apparatus. Solberg et al\(^6^9\) analyzed the hydraulic fracturing in low-permeability sandstone rocks with kinds of injection rates. The permeabilities of rock were measured, and the change of permeability before and after the experiment was compared. Their research showed that hydraulic fracturing induced permanent structural changes in the rock and increased rock permeability. The permeabilities were 0.38, 5.99, 24.89, and 13.76 \(\mu\)m\(^2\) correspond to the pump rates of 3.0, 15, 30, and 70 mm\(^3\)/s. The estimated permeabilities were in close agreement with the measured ones. Our experimental conclusions were consistent with the results of Solberg and Patel et al.

### 4.7 Numerical simulation of injection flow rate on hydraulic fracturing

#### 4.7.1 Overview

Experiment is time-consuming, labor-intensive, and expensive. Whereas numerical simulation is always time-saving, cheap and makes the task easier, and sometimes it can be even used in the sophisticated conditions that experiment fails. Discrete element method as an efficient simulation method has been widely used in hydraulic fracturing numerical modeling.\(^1^2,^7^0-^7^3\) As illustrated in Figure 17, a discrete element model using particle flow code (PFC) in two dimensions was established based on the size of rock sample in experiments, the injection hole was place in the middle, and the confining stresses and temperature conditions were in accordance with the experiments.

To simulate the experimental condition, the side length of the numerical model was 300 mm which was the same as the side length of the granite sample in laboratorial experiment. The numerical model mechanical parameters were list in

| TABLE 5 Numerical simulation results |
|------------------------------------|
| Model no. | Injection flow rate (mL/min) | Initiation pressure (MPa) | Breakdown pressure (MPa) | Propagation time (s) | Postfracturing pressure (MPa) | Total fracture length (mm) |
|-----------|-------------------------------|---------------------------|--------------------------|----------------------|-----------------------------|--------------------------|
| 1         | 5                             | 20.11                     | 21.02                    | 724                  | 13.42                       | 309                      |
| 2         | 10                            | 22.63                     | 23.87                    | 598                  | 10.98                       | 323                      |
| 3         | 15                            | 25.52                     | 27.53                    | 468                  | 8.62                        | 425                      |
| 4         | 20                            | 28.13                     | 30.58                    | 348                  | 6.28                        | 686                      |
| 5         | 25                            | 30.72                     | 34.08                    | 219                  | 4.03                        | 987                      |
| 6         | 30                            | 33.92                     | 37.22                    | 87                   | 1.52                        | 1562                     |

\[
N = \frac{MP_d}{H},
\]

where,\(^6^8\)

\[
M = \frac{1}{\left(\frac{\phi}{K_f} - \frac{(\phi-\alpha)}{K_g}\right)},
\]

\[
\alpha = 1 - \frac{K_d}{K_g},
\]

\[
H = P_d + \alpha^2 M,
\]

\[
P_d = K_d + \frac{4}{3\mu_d},
\]
Table 1, which were tested from the experimental granite samples. As temperature would change the rock reservoir properties (such as thermal induced microcracks), which induced different initiation pressure, breakdown pressure, and so on. The Equations (14) and (15) represent the numerical simulation reservoir property changes caused by temperature, and these two equations could make the numerical result closer to the experimental results. A numerical servo-control was used to simulate the confining stresses. The confining boundary conditions applied to the numerical models corresponded to the aforementioned experimental confining stress regime in Section 3 part. The injection hole for hydraulic fracturing was in the middle of the model. The initial injection pressure was set at the beginning of the calculation, and then, fluid was injected with a constant flow. The injection-pressure history curve was constructed by recording the pressure near the injection hole. The numerical analysis was carried with the different injection flow rates which were the same as the laboratorial tests.

4.7.2 Hydraulic fracturing governing equations

Based on Poiseuille equation, the fluid flow between two particles is assumed as laminar; therefore, the volumetric flow rate $q$ is given as follows:

$$q = \frac{a^3 \Delta P}{12\mu L},$$

FIGURE 20 Predicted numerical simulation values (red) vs experimental results (black) for different injection flow rates: (A)-(F) represent Tests 1-6 with 5, 10, 15, 20, 25, and 30 mL/min, respectively.
where \( a \) is the fracture aperture, \( \Delta P \) is the pressure difference between the two neighboring domains, \( \mu \) is the viscosity of the fluid, and \( L \) is the length of the channel. The out-of-plane thickness is assumed to be of unit length.

Fluid pressure on the surface of the surrounding particles is collected from each domain, and the fluid pressure is calculated during the fluid-flow process. The fluid pressure increment \( \Delta P \) could be calculated from the bulk modulus of fluid \( K_f \), the volume of the domain \( \Delta V_d \), the total flow rate for one-time step \( \sum q \) and the duration of one-time step \( \Delta t \). Then, the change in the fluid pressure \( \Delta P \) could be given by the following continuity equation:

\[
\Delta P = \frac{K_f}{V_d} \left( \sum q \Delta t - \Delta V_d \right), \tag{11}
\]

In each time step, the mechanical calculation determines the fracture geometry, generating new aperture values for all particles and volume values for all domains. Then, the flow rate of the particles is calculated and pressure in the domain will be updated, and the fluid exerted force of the surrounding particles on edges can be obtained from the new updated pressure. Consider a pressure perturbation in a single domain. The flow into a single domain \( \Delta P_p \) could be calculated from Equation (10) as follows:

\[
q = \frac{N a^3 \Delta P_p}{24 \mu R}, \tag{12}
\]

where \( N \) is channel the number that connect the domain, \( R \) is the particle mean radius of the surrounding domain, and \( \Delta P_p \) is the flow pressure response and it could be given by the following equation:

\[
\Delta P_p = \frac{K_f q \Delta t}{V_d}, \tag{13}
\]

When modeling the high temperature reservoir, thermal contact of each mechanical contact is considered as active; then, the heat flow between two particles can be calculated via the thermal channels after specifying the thermal microproperties, and the heat-conduction equation is then given by:

\[
-\frac{\partial q_i}{\partial x_j} + q_v = \frac{\rho C_v}{\partial T} \frac{\partial T}{\partial t}, \tag{14}
\]

where \( q_i \) is the heat-flux vector, \( q_v \) is the volumetric heat source intensity, \( \rho \) is the mass density, \( C_v \) is the constant volume specific heat, and \( T \) is temperature. Based on Fourier’s law, the heat-flux vector \( q_i \) can be calculated from the temperature gradient:

\[
q_i = -k_{ij} \frac{\partial T}{\partial x_j}, \tag{15}
\]

where \( k_{ij} \) is the thermal conductivity tensor. The rock mechanical parameters used in hydraulic fracturing numerical stimulation are listed in Table 1.

### 4.7.3 Comparisons between laboratory experiment and numerical simulation

The numerical analysis was carried with the injection flow rate of 5, 10, 15, 20, 25, and 30 mL/min, respectively, which is the same as laboratory experiments. The pressure curves of the simulations are shown in Figure 18. The results of the numerical simulation in with the corresponding experimental results are shown in Figure 19 and Table 5. The results show that the discrete element model has excellent capability to predict the fracture behavior and parameters for laboratory large-scale hydraulic fracturing experiments. Overall, the experimental and numerical results present a very good agreement, validating the proposed numerical simulation. The numerical predicted the initiation pressures, breakdown pressures, propagation times, and postfracturing pressures are all respectively have good linear relationship with injection flow rates. This authenticates that these four parameters are indeed linearly related to the injection flow rate from another side. Most of the predicted results are very close to the experimental results. The initiation pressure at 25 (7.00% error) and 30 mL/min (4.31% error) and the breakdown pressure at 30 mL/min (3.36% error) have differences to some extent, and the reason of this may be the fracturing process becomes more dynamic with the increase of injection flow rate. The fracture propagation rate increases, and the fracture behavior becomes more unpredictable. The propagation time at 5 and 10 mL/min has the errors of 18.11% and 20.08%, and...
the reason caused this phenomenon may be hysteresis of the monitor system in experiment. As the injection flow rate is low, the fracture propagation rate is low yet; when the fracture just initiated, a tiny fracture was induced that could even be ignored compared the new injection fluid volume; then, it may take a while until the change in pressure was detected by the monitor system due to the low fracture propagation rate. As a result, the propagation time would be caused error. The error of revised postfracturing pressure is 19.82% at the injection flow rate of 5 mL/min. As the other postfracturing pressures were revised by reducing injection flow rate except Test 1, Tests 2-6 involve turning off the injection pump after hydraulic fracturing and the reopen the injection pump at the injection rate of 5 mL/min. This operation led to the close and reopen of fractures, one source of the error is that reopening a fracture needs an extra penetration pressure to balance in the force acting across the mouth of the existing cracks, the second source of error is concerning with the correct identification of the true reopening pressure from the wellbore pressure, and the apparent detected reopening pressure (the revised postfracturing pressure) is generally higher than the true reopening pressure.79

Figure 20 presents the fracture distributions and geometries predicted by numerical simulations vs experimental results, and we can see that the numerical simulations are in good agreement with the experiments. In the simulation results, the main directions of all fractures are along the PFD, especially when the injection flow rate is low, such as 5 and 10 mL/min, only one two-wing fracture is induced and it almost propagates along the PFD, and the numerical simulations and experimental results are almost the same. With the injection flow rate continuing to rise, fracture network with more branches is induced. In Figure 20C, experimental result shows a three wings fracture system, a two double wings fracture system is not induced, and numerical simulation shows a main fracture and a secondary branch which does not propagate to the reservoir boundary. It means after the main fracture reaches the reservoir boundary, the fluid demand (the new injected fluid) is equal to fluid consumption (the fluid flows out of the reservoir). The pressure stops rising and the secondary branch stops continuing to propagate, and the experiment and numerical results could be considered consistent. In Figure 20D, as aforementioned, the fracture in experiment is abnormally wider, this reduces the fracture total length, and the numerical simulation presents the normal hydraulic fracturing results. As the injection flow rate continues to be increased, in Figure 20E,F, experimental results show fracture network forms, and the numerical simulation also shows this trend. In general, discrete element method has the excellent capability for predicting the behavior of hydraulic fracturing.

Figure 21 shows the comparisons between numerical predicted fracture lengths with their experimental results. Generally speaking, the numerical simulation values are very close to the experimental results and well predict the fracture length. Only in Test 4, they have a difference that cannot be ignored. The Test 4 has only a two-wing fracture, whereas the corresponding numerical simulation result in Figure 20D contains two two-wing fractures and a small branch. The reason caused this phenomenon is that the abnormal fracture aperture width in the experiment; hence, only one main fracture is induced in the laboratory Test 4, and the enlarged fracture photographs show the fracture aperture is indeed wider.

The numerical method also could be used in the condition that the laboratory apparatus fails. For example, the maximum injection flow rate provided by apparatus is 30 mL/min; then, we use the numerical model simulates the conditions of 32 mL/min. The numerical results are the initiation pressure of 35.23 MPa, breakdown pressure of 38.26 MPa, propagation time of 35 seconds, revised postfracturing pressure of 0.71 MPa, and fracture length of 1764 mm, and all these values have the same change trend with aforementioned results, both in simulations and experiments.

5 | APPLICATION FOR GEOTHERMAL ENERGY MINING

The natural permeability of HDR reservoirs is typically low, and hence, these reservoirs should be enhanced to stimulate for efficient and economic mining. Hydraulic fracturing as a promising method to improving in situ permeability, fluid flow and extraction efficiency, provides a sustained injection and circulation technology for prospects of commercial extracting heat energy from deep buried reservoir. The core technology of hydraulic fracturing is choosing a reasonable injection flow rate and pressure to enhance permeability and create new fractures. Our research results show that a high injection rate trends to cause a relatively complex induced fracture network. At the same time, high injection rates also correspond to high breakdown pressures, high initiation pressures, long propagation times, and low revised postfracturing pressures, the initiation pressures could be used to estimate failure stresses, the propagation times are related to the induced earthquakes, and the postfracturing pressures influence the heat extraction efficiency. Therefore, we cannot only consider breakdown pressure when designing fracturing scheme, whereas should consider the influence of different parameters on the fracturing results, induced earthquakes and heat extraction efficiency in field-scale operation.

Because of the limitation of experiment condition, our study contains some shortcomings: for instance, as just mentioned, even if we know the injection flow rate is not the higher the better, we do not know how to choose an injection
flow rate and how much the permeability is optimal. This work needs further researches. On the other side, the connection among the existing fractures is also an area of the hydraulic fracturing research and is not covered by this study.

6 | CONCLUSIONS

In this paper, we investigate hydraulic fracturing characteristics by varying injection flow rate in large-size granite samples. According to the cut granite samples and the pressure data, we analyze the fracture initiation pressure, propagation time, postfracturing pressure, breakdown pressure, fracture geometry, and length. The fracture permeability is calculated at last. The discrete element simulations are compared with the experiment results. The conclusions obtained are list below:

1. The injection flow rates significantly influence the fracture initiation pressures, propagation times, postfracturing pressures, and breakdown pressures during hydraulic fracturing. The injection pressures and breakdown pressures have approximately linear positive relations to injection flow rates. The postfracturing pressure and propagation time have approximately linear negative relations to injection flow rates. The fracture permeabilities after hydraulic fracturing show a linear ascending trend with the increase of the injection flow rates.

2. Even though the fracture propagation direction sometimes is not along the PFD near the wellbore zone because of the complex stress state. The fracture propagation direction is influenced by triaxial stresses (crustal stress in field) and will gradually turn to PFD as the fracture grows. A higher injection flow rate means more energy is exerted to granite sample and a more complex fracture network is apt to create. More AE events and SRVs are induced. The fracture total length almost linearly increase with the increase of mean injection powers, and this linear relationship provides us with a way to roughly predict fracture length in field.

3. The numerical simulations present well agreement with the experiment results, and it provides a possibility to predict the characteristics of hydraulic fracturing under different injection flow rates by discrete element simulation. It not only reproduced the experimentally observed results, but also could be extended to the conditions that experimental work could not reach.

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