



Effect of Discrete Fracture Network density on hydraulic fracturing

Mansour Sharafisafa^{1*}, Zeinab Aliabadian²

1-Faculty of Mining Engineering, Colleges of Engineering and Technology, University of Tehran, Tehran, Iran.

2-Civil Engineering Faculty, K. N. Toosi University of Technology, Tehran, Iran.

Received: 16 October 2024

Accepted: 20 December 2024

(*Corresponding author: m.sharafisafa@ut.ac.ir)

Keywords

Hot Dry Rock (HDR)
Discrete Fracture Network
Hydraulic Fracture (HF)
FDEM
Controlling Factors

Abstract

The effectiveness of hydraulic fracturing fluid injection is influenced by numerous factors, including pre-existing discontinuities such as discrete fracture networks (DFNs). Among the geometric characteristics of DFNs, fracture density is a critical factor. In deep reservoirs, which often consist of hot dry rock (HDR), thermal conduction through the rock and fluid, as well as advection and convective heat transfer within the fluid, can significantly impact fluid–rock interactions. This study examines the influence of DFN density on hydraulic fracture (HF) propagation in HDR, with a particular focus on the thermo-hydro-mechanical (THM) behavior of HDR using the combined finite-discrete element method (FDEM). Key controlling factors, such as flow rate, fluid kinematic viscosity, in-situ stress magnitude, pre-existing fracture aperture, and working fluid temperature, are analyzed. The findings highlight the significant role of DFN density in determining the pattern and extent of HF propagation under varying conditions. Additionally, the interaction between the working fluid and DFNs is shown to vary considerably with changes in these controlling factors. However, the study reveals that variations in DFN density or the values of the controlling factors have minimal impact on the temperature field. This is attributed to the rapid heat exchange between the cold fluid and the HDR, which quickly raises the fluid temperature, resulting in negligible temperature variations.

I. INTRODUCTION

The production of conventional energy resources, such as fossil fuels, is increasingly scarce as the global economy develops. This trend poses significant challenges, creating a growing demand for alternative energy sources. Renewable energy, in particular, is essential for achieving energy conservation, carbon neutrality, and emission reduction goals. Among renewable energy options, geothermal energy stands out as a remarkable clean energy source due to its abundant reserves and widespread distribution [1].

Geothermal energy is a renewable resource with an average capacity factor—the ratio of actual energy output to maximum potential output—of approximately 74.5% [1]. With advanced technologies, the capacity factor of geothermal reservoirs in ideal locations can reach up to 90% [2], making them suitable for baseload power generation. Theoretical calculations estimate that the energy stored in the Earth's upper 10-kilometer

layer is around 1.3×10^{27} J [3]. Given the global energy consumption in 2018 was approximately 6.0×10^{20} J/year [4], geothermal resources could potentially meet global energy needs for about 217 million years. Geothermal resources are categorized into two types: conventional hydrothermal systems and enhanced geothermal systems (EGSs). EGSs, unlike traditional systems, access greater heat by creating fractures in hot dry rocks (HDRs) and injecting fluid into these pathways. The development of EGSs involves several stages: (1) exploration and evaluation, (2) drilling injection and production wells, (3) creating the energy system, (4) cycling fluid injection and production for heat recovery, (5) operating power extraction systems, and (6) maintaining the reservoir [1]. While EGS development is similar to conventional geothermal systems, it incurs higher costs. However, efficient EGS utilization reduces fossil fuel dependency and enhances energy independence.

To improve permeability in typically impermeable and waterless HDRs, artificial fluid

pathways are essential. Hydraulic fracturing, a technique developed in 1949 [5] and first commercially applied in 1950 [6], is widely used to create fractures by injecting high-pressure fluid into HDRs. This method has been extensively employed for gas extraction, hot water recovery, and thermal resource storage [7]. It also finds applications in mining and civil engineering, such as stress relief, excavation expansion, and rock burst prevention [8].

Hydraulic fracturing is a complex process influenced by numerous factors, particularly the geological characteristics of the reservoir. In homogeneous rock without discontinuities, hydraulic fractures (HFs) typically propagate perpendicular to the least principal stress direction [9]. However, natural rock masses often contain anisotropic features like bedding planes, joints, cracks, and faults, which complicate fracture behavior. These features degrade rock properties and significantly influence fracture propagation [10]. Interactions between HFs and preexisting discontinuities can result in branching, offset crossing, and non-planar fracture growth, as observed in field and laboratory studies [11]. These interactions have been studied using analytical methods, experiments, artificial neural networks, and numerical simulations [12]. The interaction type depends on factors like fracture shear strength, in-situ stress, injection rate, and discontinuity orientation [13].

Temperature also plays a critical role in hydraulic fracturing. While most studies focus on room-temperature conditions, EGSs often involve rocks exceeding 200 °C. High temperatures alter rock properties, reducing tensile and compressive strength and elastic modulus [14]. The temperature difference between the working fluid and HDRs creates thermo-hydro-mechanical coupling, leading to thermal cracking [15]. Heat exchange between the fluid and rock must be considered to avoid unrealistic simulations [16].

Numerical modeling is widely used to study HF propagation due to its ability to simulate complex mechanisms. Techniques like the finite element method (FEM), cohesive zone model (CZM), extended finite element method (XFEM), displacement discontinuity method (DDM), and discrete element method (DEM) each have strengths and limitations. For instance, FEM struggles with discontinuities, while DEM is computationally intensive for large-scale models [17]. The combined finite-discrete element method (FDEM), developed by Munjiza [18], integrates FEM and DEM strengths, enabling simulation of fluid flow and crack propagation in complex geological settings [19].

This study employs FDEM to investigate the interaction between discrete fracture networks (DFNs) and HFs in high-temperature, deep rock environments. It focuses on the impact of DFN

density on HF propagation, examining low and high DFN densities under varying in-situ stresses, injection rates, fluid temperatures, and viscosities. Simulations of rock domains with varying DFN densities are conducted, and the effects of key parameters are analyzed. The findings provide insights for optimizing hydraulic fracturing in deep HDRs.

II. SIMULATION METHODOLOGY

The Finite-Discrete Element Method (FDEM) is utilized to simulate the initiation and propagation of hydraulic fractures (HF) and their interaction with discrete fracture networks (DFNs) in deep rock formations. The simulations incorporate coupled thermo-hydro-mechanical (THM) analysis to accurately model the injection of fluid into the rock. All 2D models are designed with dimensions of 50 m × 50 m and consist of approximately 35,000 elements. To streamline the analysis, the fluid injection borehole is represented by an injection point located at a mesh node at the center of the model. This approach not only reduces computational time but also has minimal impact on the propagation of hydraulic fractures, as a small borehole in a large model area generates negligible stress distribution and exerts no significant influence on the surrounding medium.

The simulations begin with a mechanical analysis to establish the in-situ stress distribution within the model under a predefined stress regime. Once the in-situ stresses are fully distributed and reach equilibrium, the model transitions to thermo-mechanical coupling, allowing the rock to heat up to 200 degrees Celsius. Subsequently, the THM coupling is fully activated to enable fluid injection into the injection grid. The mechanical properties of the rock matrix and fluid are detailed in Table 1, while the parameters assigned to the microcracks in the DFN are provided in Table 2. It is important to note that the rock is assumed to be impermeable, with no fluid leak-off considered in the simulations.

The initial conditions are defined as follows: the rock has an initial temperature of 200 °C, the injection fluid starts at 20 °C, and the in-situ stresses are initially isotropic, set at 7 MPa in both directions. The primary goal of the study is to explore the impact of DFN density on the development pattern of hydraulic fractures (HF) and to analyze the controlling factors, such as injection flow rate, fluid viscosity, DFN aperture, and the magnitude and direction of in-situ stresses, on fracture propagation behavior. Three models with varying fracture densities are examined: 0.02, 0.06, and 0.1 mean fractures per square meter (m/m²), each with a standard deviation of 1×10^{-5} m/m², as illustrated in Fig. 1 and are derived from our previous study in [20].

TABLE I. MECHANICAL PROPERTIES OF THE ROCK AND FLUID

Parameter	Unit	Value
<i>Rock properties</i>		
Density, ρ	kg/m ³	2550
Young's modulus, E	GPa	50
Poisson's ratio, ν		0.22
Cohesion, c	MPa	22
Tensile strength, f_t	MPa	7
Mode I Fracture energy, G_{Ic}	N/m	120
Fracture penalty, P_f	GPa	$10 \times E$
Normal penalty, P_n	GPa·m	$10 \times E$
Tangential penalty, P_t	GPa/m	$10 \times E$
<i>Fluid properties</i>		
Fluid density, ρ_f	kg/m ³	1000
Kinematic viscosity, μ	m ² /s	1e-6
Fluid bulk modulus, K_f	GPa	0.05
Initial saturation degree		1
Specific heat capacity, C_p	J/kg°C	4190
Thermal conductivity, K	W/m°C	0.6
<i>Thermal properties of rock</i>		
Specific heat capacity	J/kg°C	850
Thermal conductivity	W/m°C	2.5
Linear thermal expansion coefficient	1/°C	1e-3

TABLE II. DFN PARAMETERS

Parameter	Unit	Value
Fracture penalties, P_f	GPa	$10 \times E$
Normal contact penalties, P_n	GPa·m	$10 \times E$
Tangential contact penalties, P_t	GPa/m	$10 \times E$
Friction coefficient, f_r		0.5
Initial aperture, a_i	mm	0.1
Residual aperture, a_r	mm	0.1
Threshold aperture, a_t	mm	0.1

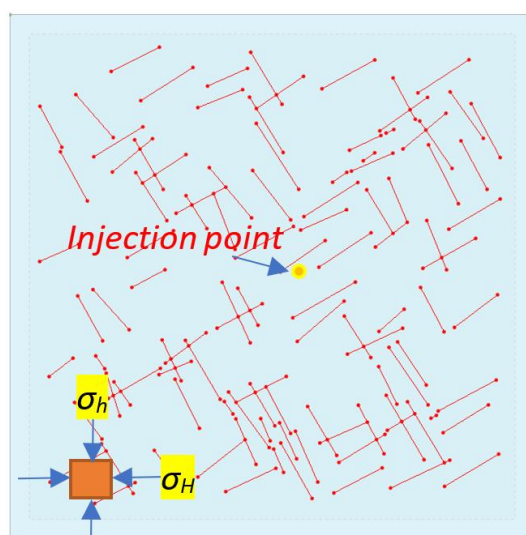


Fig. 1. Geometry of the models with DFN sets and direction of the maximum and minimum stresses.

III. RESULTS AND DISCUSSIONS

This section evaluates the influence of fluid injection rates on the development patterns of hydraulic fractures (HF). The models assume an isotropic in-situ stress condition with a magnitude of 7 MPa in both directions. The injection flow rates are varied from 1 to 2 kg/s, while maintaining a constant fluid kinematic viscosity of 1×10^{-6} m²/s. Figure 2 displays the fluid pressure contours and the development of hydraulically driven fractures in the three models under the two flow rates.

When the density of the discrete fracture networks (DFNs) is low and pre-existing fractures are sparsely distributed, the HF development patterns are relatively similar under both injection rates, except for the longer fracture propagation observed at the higher flow rate. As the DFN density increases to 0.06 m/m², at an injection rate of 1 kg/s, the working fluid generates several hydraulic fractures. Due to the higher density of DFNs near the injection point, fluid pressure accumulates in a narrow zone around the injection point, leading to the formation of additional

fractures. These densely clustered HFs interact with pre-existing fractures, creating pathways for fluid diffusion. The fluid then propagates into the DFNs, dilating them and forming more extensive pathways for further fluid movement. At the higher flow rate of 2 kg/s, the accumulation of HFs near the injection point becomes more pronounced due to the rapid interaction between the high-pressure fluid and the surrounding DFNs, resulting in quicker fracture generation.

In models with very high DFN densities (0.1 m/m²), the formation of fluid-driven fractures is significantly more intense, particularly under the higher flow rate. The generation of numerous HFs causes severe rock fragmentation around the injection point, leading to fluid accumulation in this zone and restricting long-distance fluid flow. Interestingly, the length of HF propagation is greater in models with a DFN density of 0.06 m/m² compared to those with 0.1 m/m². This is because the highly fractured ground in the latter case impedes fluid flow, preventing it from extending as far as in less densely fractured rock.

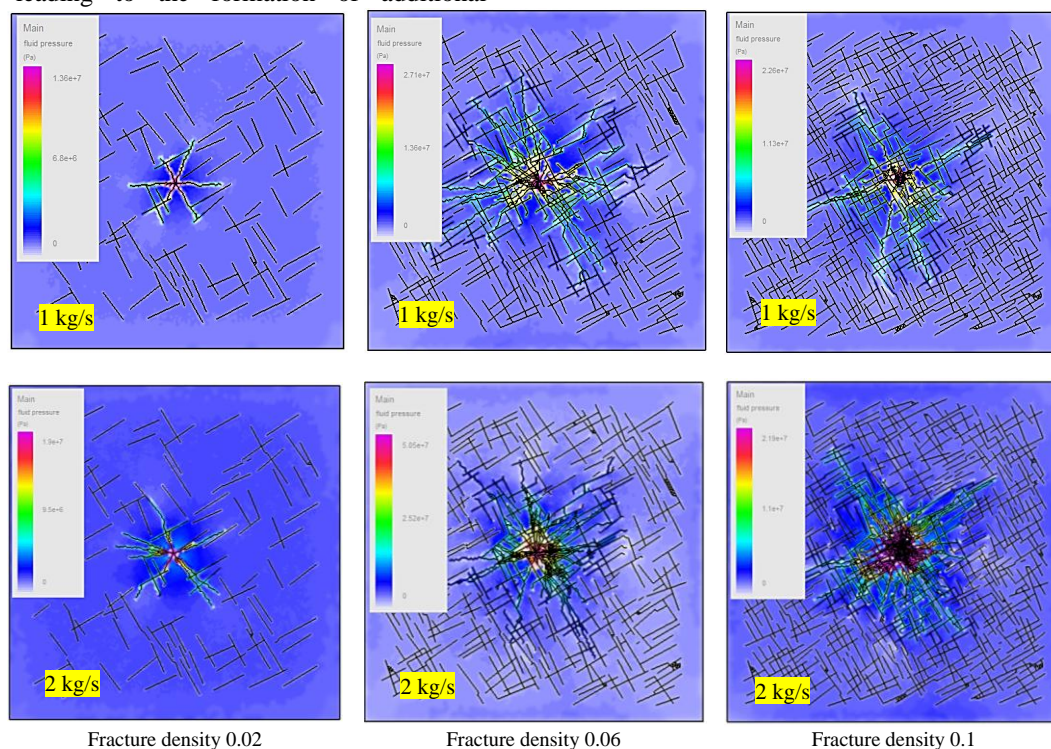


Fig. 2. Development of hydraulic fractures in the models with different DFN densities under various flow rates

Another factor examined is the fluid kinematic viscosity. In this section, the flow rate is held constant at 1 kg/s, while the fluid kinematic viscosity is increased from 1 mm²/s to 2 mm²/s. Figure 3 illustrates the hydraulic fracture (HF) patterns developed in models with varying DFN densities. In models with lower DFN densities, increasing the fluid kinematic viscosity results in more branching of HFs from the newly formed fractures near the injection point, although the

overall length of the fractures is shorter under higher viscosity conditions.

In models with higher DFN densities, the highly viscous fluid causes excessive fracturing around the injection point, resulting in numerous short hydraulic fractures (HFs). The increased viscosity leads to higher fluid pressure buildup in the nearby DFNs, causing them to dilate. However, due to the fluid's reduced mobility, it cannot easily diffuse into DFNs located farther away. As a result, the length

of the HF is shorter compared to models with lower fluid viscosity.

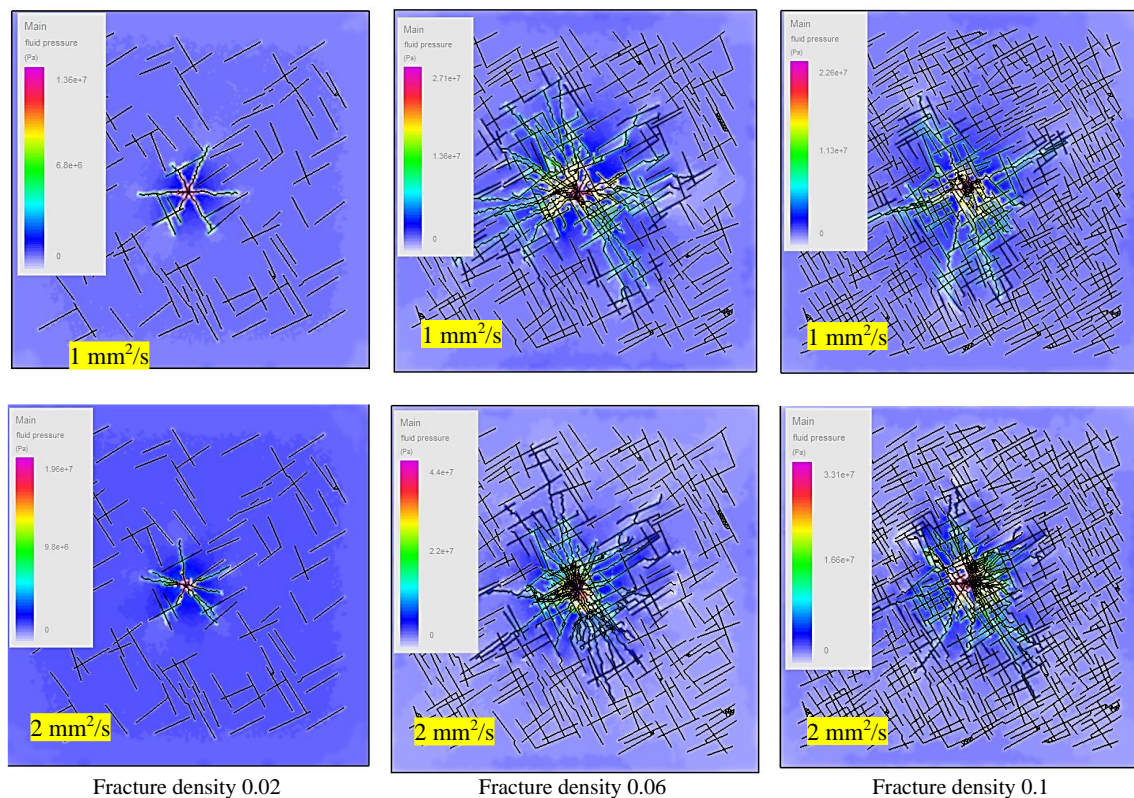


Fig. 3. HF in the models with different DFN densities under various fluid kinematic viscosities

Fig. 4.

Another critical parameter in successful hydraulic fracturing operations is the magnitude and orientation of in-situ stresses. To explore this further, three in-situ stress regimes are examined: (1) isotropic stresses of 7 MPa, (2) anisotropic stresses with $\sigma_H = 14$ MPa and $\sigma_h = 7$ MPa, and (3) anisotropic stresses with $\sigma_H = 25$ MPa and $\sigma_h = 10$ MPa. The results are illustrated in Fig. 4.

Under isotropic in-situ stress conditions, there is no directional preference, and hydraulic fractures (HFs) develop uniformly in all directions, with similar numbers and lengths of fractures. In contrast, under anisotropic stress conditions, models with low DFN density show a clear directional preference for HF propagation, aligning with the orientation of the maximum principal stress. As the difference between the magnitudes of the in-situ stresses increases, fewer HFs are generated in these rocks, and the rock matrix becomes the primary pathway for fracture propagation, with DFNs playing a diminished role in influencing HF development patterns.

In models with high DFN density, the influence of in-situ stress magnitude becomes less

pronounced. For instance, a 7 MPa difference in in-situ stresses has minimal impact on the propagation direction of HFs in densely fractured rocks. However, when the stress difference increases to 15 MPa, a directional tendency becomes more apparent in rocks with a DFN density of 0.06 m/m², though many HFs still develop in other directions. In models with a very high DFN density (0.1 m/m²), the behavior is predominantly controlled by the DFNs rather than the in-situ stress magnitude. The dense distribution of DFNs leads to frequent interactions between the fractures and the fluid, causing the DFNs to dilate and create favorable pathways for fluid flow. As a result, HFs develop in multiple directions, regardless of the high heterogeneity in in-situ stresses.

It is also observed that as the difference between the magnitudes of the in-situ stresses increases, crossing of fractures becomes more frequent in the direction of σ_H (maximum principal stress), while arresting, activation, and dilation are the dominant interaction types in other directions.

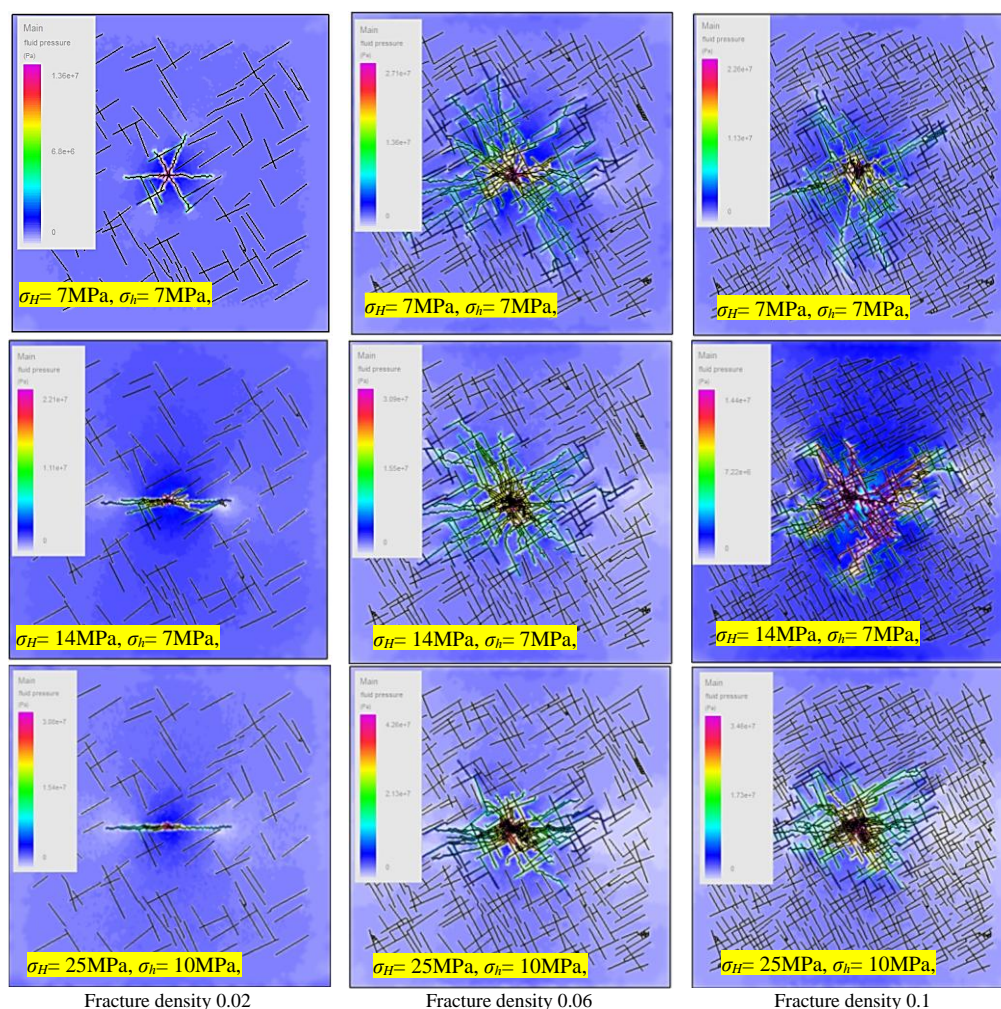


Fig. 5. Development of HFs in the models with different DFN densities under different in-situ stress regimes

Another critical parameter to evaluate is the aperture of the discrete fractures. Among the physico-mechanical characteristics of the DFN, the opening of fractures (aperture) plays a significant role in shaping the fluid trajectory through pre-existing discontinuities. This factor substantially influences the propagation behavior and performance of hydraulic fractures (HFs). In this section, the aperture of discrete fractures is increased from 0.01 mm to 0.02 mm, and the analysis results of HF propagation are presented in Fig. 5.

In models with a low DFN density of 0.01 m/m² and a small fracture aperture, the HFs frequently interact with adjacent DFNs, often crossing them. Conversely, when the aperture is larger, the analysis reveals activation and offset interaction types, as the wider apertures act as broad pathways that allow fluid to flow more rapidly into the fractures, activating them. However, the length and number of HFs formed in models with high-aperture DFNs are comparable to those in models with low-aperture DFNs.

As shown in the results, rocks with a 0.01 mm aperture exhibit high fluid pressure development over a larger area (indicated by red and yellow contours) around the injection point. However, this pressure buildup is confined to a short distance from the injection point (shown by blue contours). This pattern reverses as the DFN aperture increases. With larger apertures, the area experiencing intense fluid pressure decreases, while the region affected by fluid flow expands significantly, as evidenced by the blue contours of fluid pressure extending across the entire DFN domain in models with a 0.5 mm aperture.

This occurs because, with smaller apertures, fluid can only flow a short distance, leading to significant pressure buildup within the DFNs. The flow is then restricted due to the narrow channels. In contrast, larger apertures allow fluid to flow more freely through the DFNs over greater distances, reducing pressure buildup near the injection point. Overall, in models with larger apertures, the dominant interaction types between pre-existing DFNs and newly formed HFs are dilation and activation. In contrast, crossing and arresting are the

primary interaction types observed in models with smaller apertures.

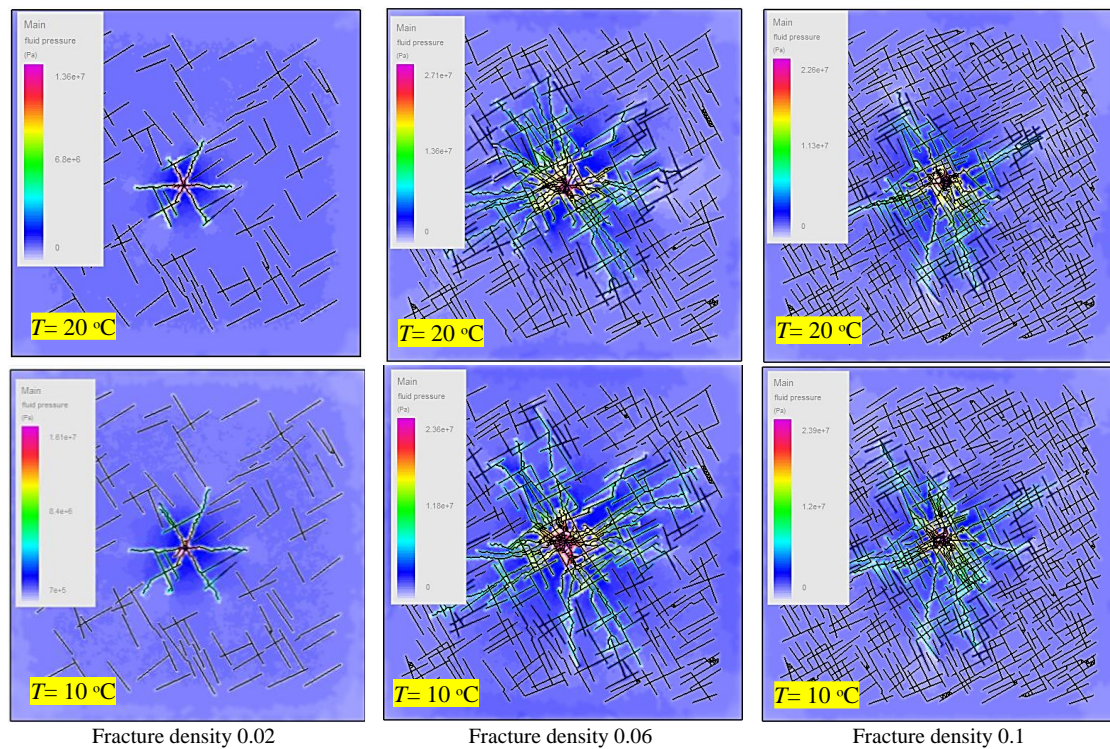


Fig. 6. Development of HF in the models with different DFN densities with different fluid temperatures

It is important to examine the variation in fluid pressure at the injection point to evaluate the influence of the aforementioned parameters on the breakdown pressure. Under the effect of flow rate, there is a noticeable difference in breakdown pressures. Specifically, the breakdown pressure increases with higher flow rates and rises significantly in models with higher DFN densities (Fig. 6a). A similar trend is observed when examining the impact of fluid kinematic viscosity and in-situ stresses, as shown in Fig. 6b-c. The greater the stress difference, the higher the breakdown pressure becomes. However, changes in DFN aperture and fluid injection temperature do not significantly affect the breakdown pressure, which remains nearly constant across all conditions in all models.

That said, the density of DFNs plays a dominant role in influencing fluid pressure after the breakdown pressure is reached. Interestingly, unlike the trends observed in Fig. 6a-c, the fluid pressure in models with lower DFN apertures or higher fluid temperatures increases when the DFN density is high (Fig. 6d-e). This occurs because, under conditions of smaller apertures or higher fluid temperatures, the working fluid tends to remain concentrated in a relatively small area around the injection point, leading to a rise in fluid pressure. Additionally, these conditions promote more interactions between the fluid and nearby DFNs, resulting in less fluid loss.

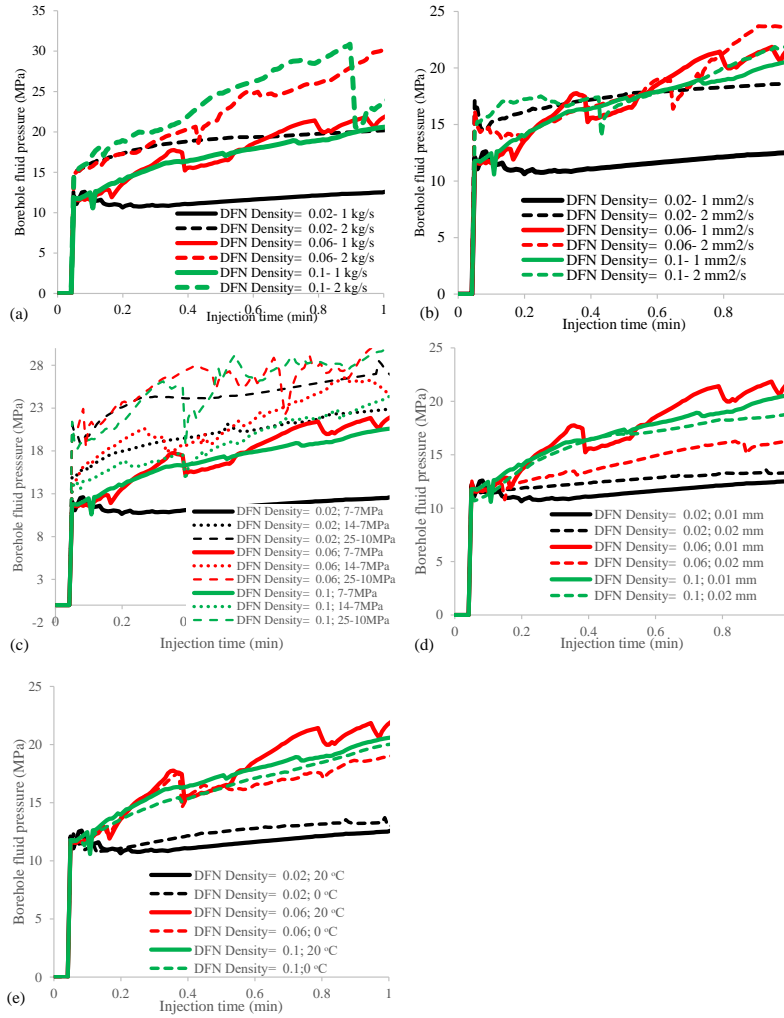


Fig. 7. Changes in fluid pressure at the injection point under varying (a) flow rates, (b) fluid kinematic viscosities, (c) in-situ stresses, (d) DFN apertures, and (e) fluid temperatures.

IV. CONCLUSION

This study presents the results of hydraulic fracture (HF) development simulations in hot, fractured rock formations using the combined finite-discrete element method (FDEM). The primary objective is to evaluate the influence of discrete fracture network (DFN) density under varying conditions, including flow rate, fluid kinematic viscosity, in-situ stresses, DFN aperture, and working fluid temperature. The DFN density is varied from 0.02 to 0.06 and 0.1 m^2/m^2 , and the controlling parameters are adjusted to draw the following conclusions:

DFN Density Impact: The results highlight the significant influence of DFN density on fluid injection patterns. In low-density DFNs, pre-existing fractures have minimal impact on HF development. However, in high-density DFNs, fractures significantly affect HF extension, leading to higher fluid pressure buildup.

Flow Rate Effects: Increasing the flow rate causes severe fracturing near the injection point in high-density DFNs. The dense fractures act as barriers, rapidly increasing fluid pressure.

Additionally, the interaction type shifts from activation and offset to crossing, promoting the development of more HFs over longer distances.

High-Density DFNs and Fluid Parameters: In reservoirs with high-density DFNs, HF development is primarily controlled by the DFNs rather than fluid properties. High-viscosity fluids fracture the surrounding rock matrix, generating excessive HFs in a confined area, which results in fluid loss and shorter HFs.

In-Situ Stress Influence: The magnitude of in-situ stresses dictates the direction and extent of HFs. Low-density DFNs have little control over HF propagation, whereas high-density DFNs strongly influence HF direction, causing fractures to develop in all directions regardless of in-situ stress anisotropy.

DFN Aperture Effects: Increasing the DFN aperture leads to higher fluid pressure in low-density DFNs but lower pressure in high-density DFNs. This behavior is due to wider and denser fluid pathways that facilitate easier fluid flow, reducing pressure buildup. In high-density DFNs,

larger apertures enable fluid to diffuse, activate, and dilate fractures, resulting in offset fractures and shorter hydraulic fractures (HFs). In contrast, smaller apertures in dense DFNs resist dilation and activation, allowing fluid to cross and interact with adjacent fractures, which results in longer HFs.

Fluid Temperature Impact: Changes in working fluid temperature have minimal influence on HF patterns and extension. However, they induce a unique fluid-fracture interaction known as shrinkage thermal cracking, which occurs between a continuous HF and a parallel pre-existing fracture. Rapid heat exchange between these fractures and the surrounding hot rock generates numerous short HFs.

These findings offer valuable insights into the intricate relationships between hydraulic fractures and discrete fracture networks under diverse geological and operational conditions. This study is pure numerical simulation with no practical data because of lack of access to any operating geothermal site. While we appreciate this limitation and the limitations imposed by the utilized method, this study can be considered a starter for further studies backed by actual data. To achieve more precise outcomes, sensitivity analysis needs to be conducted; however, a sensitivity analysis demands massive computations which is not within the scope of this study and can be a topic for future research.

V. REFERENCES

- [1] Lu SM (2018) A global review of enhanced geothermal system (EGS). *Renewable and Sustainable Energy Reviews*, 81, 2902-2921
- [2] Edenhofer O, Pichs-Madruga R, Sokona Y, Seyboth K, Kadner S, Zwickel T, Matschoss P (Eds.) (2011) *Renewable energy sources and climate change mitigation: Special report of the intergovernmental panel on climate change*. Cambridge University Press
- [3] Lund JW, Bjelm L, Bloomquist G, Mortensen AK (2008) Characteristics, development and utilization of geothermal resources—a Nordic perspective. *Episodes Journal of International Geoscience*, 31(1): 140-147
- [4] Dudley, B (2018) BP statistical review of world energy 2018. Energy economic, Centre for energy economics research and policy. British Petroleum, Available via <https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy/electricity.html>, 5
- [5] Clark JB (1949) A hydraulic process for increasing the productivity of wells. *J Pet Technol* 1(01) :1-8
- [6] Suchy, D. R., & Newell, K. D. (2011). Hydraulic fracturing of oil and gas wells in Kansas. Kansas Geological Survey.
- [7] Sherratt J, Haddad AS, Wejzerowski F, Rafati R (2021) Optimising well orientation in hydraulic fracturing of naturally fractured shale gas formations. *J Nat Gas Sci Eng* 94:104141
- [8] Chen B, Xiang J, Latham JP, Bakker RR (2020) Grain-scale failure mechanism of porous sandstone: an experimental and numerical FDEM study of the Brazilian Tensile Strength test using CT-Scan microstructure. *Int J Roc Mech Min Sci* 132:104348
- [9] Cheng Y, Lu Y, Ge Z, Cheng L, Zheng J, Zhang W (2018) Experimental study on crack propagation control and mechanism analysis of directional hydraulic fracturing. *Fuel* 218:316-324
- [10] Li D, Wang E, Li Z, Ju Y, Wang D, Wang X (2021) Experimental investigations of pressure stimulated currents from stressed sandstone used as precursors to rock fracture. *Int J Roc Mech Min Sci* 145:104841
- [11] Dehghan AN (2020) An experimental investigation into the influence of pre-existing natural fracture on the behavior and length of propagating hydraulic fracture. *Eng Frac Mech* 240:107330
- [12] Sarmadivaleh M, Rasouli V (2014) Modified Reinshaw and Pollard criteria for a non-orthogonal cohesive natural interface intersected by an induced fracture. *Rock Mech Rock Eng* 47(6) :2107-2115
- [13] Cheng W, Jin Y, Chen M (2015) Experimental study of step-displacement hydraulic fracturing on naturally fractured shale outcrops. *J Geophys Eng* 12(4) :714-723
- [14] Yin T, Li X, Cao W, Xia K (2015) Effects of thermal treatment on tensile strength of Laurentian granite using Brazilian test. *Rock Mech Rock Eng* 48(6) :2213-2223
- [15] Chaki S, Takarli M, Agbodjan WP (2008) Influence of thermal damage on physical properties of a granite rock: porosity permeability and ultrasonic wave evolutions, *Constr Build Mater* 22(7):1456-1461
- [16] Salimzadeh S, Paluszny A, Zimmerman RW (2016) Thermal effects during hydraulic fracturing in low-permeability brittle rocks. In 50th US Rock Mechanics/Geomechanics Symposium, OnePetro
- [17] Potyondy DO, Cundall PA (2004) A bonded-particle model for rock. *Int J Roc Mech Min Sci* 41(8) :1329-1364
- [18] Munjiza AA (2004) *The combined finite-discrete element method*. John Wiley Sons
- [19] Yang L, Wu S, Gao K, Shen L (2022) Simultaneous propagation of hydraulic fractures from multiple perforation clusters in layered tight reservoirs: Non-planar three-dimensional modelling. *Energy* 124483
- [20] Sharafisafa, M., Aliabadian, Z., Sato, A. et al. Coupled Thermo-hydro-mechanical Simulation of Hydraulic Fracturing in Deep Reservoirs Using Finite-Discrete Element Method. *Rock Mech Rock Eng* 56, 5039–5075 (2023). <https://doi.org/10.1007/s00603-023-03325-z>

تأثیر چگالی شبکه شکست گسسته بر شکستگی هیدرولیکی

منصور شرفی صفا^{۱*}، زینب علی‌آبادیان^۲

۱- دانشکده مهندسی معدن، دانشکدگان فنی، دانشگاه تهران، تهران، ایران.

۲- دانشکده مهندسی عمران، دانشگاه صنعتی خواجه نصیرالدین طوسی، تهران، ایران.

دریافت: ۱۴۰۲/۰۷/۲۵؛ پذیرش: ۱۴۰۳/۰۹/۳۰

(*نویسنده مسئول: m.sharafisafa@ut.ac.ir)

چکیده

اثرگذاری تزریق سیال شکست هیدرولیکی تحت تأثیر عوامل متعددی قرار دارد، از جمله ناپیوستگیهای اولیه مانند شبکه‌های گسستگی گسسته در میان ویژگی‌های هندسی DFN، تراکم شکستگی یک عامل حیاتی محسوب می‌شود. در مخازن عمیق که اغلب از سنگ‌های خشک داغ (HDR) تشکیل شده‌اند، انتقال حرارت از طریق سنگ و سیال، و همچنین جابه‌جایی و انتقال حرارت جابجایی درون سیال می‌تواند تأثیر قابل توجهی بر واکنش سیال-سنگ داشته باشد. این مطالعه به بررسی تأثیر تراکم DFN بر گسترش شکست هیدرولیکی (HF) در HDR می‌پردازد، با تمرکز ویژه بر رفتار ترمو-هیدرو-مکانیکی HDR (THM) با استفاده از روش ترکیبی المان محدود-گسسته (FDEM)، عوامل کنترل‌کننده کلیدی مانند دبی جریان، ویسکوزیته سینماتیکی سیال، بزرگی تنش برجا، بازشدگی اولیه شکستگی اولیه و دمای سیال مورد تحلیل قرار گرفته‌اند. یافته‌ها نقش قابل توجه تراکم DFN را در تعیین الگو و گسترده‌گی انتشار HF تحت شرایط مختلف برجسته می‌کنند. علاوه بر این، نشان داده شده است که تعامل بین سیال و DFNs با تغییر در این عوامل کنترل‌کننده، به میزان قابل توجهی متفاوت است. با این حال، مطالعه نشان می‌دهد که تغییرات در تراکم DFN یا مقادیر عوامل کنترل‌کننده تأثیر ناچیزی بر میدان دما دارند. این امر به دلیل تبادل سریع حرارت بین سیال سرد و HDR است که به سرعت دمای سیال را افزایش می‌دهد و در نتیجه تغییرات دما ناچیز خواهد بود.

سنگ خشک داغ (HDR)، شکستگی هیدرولیک شبکه گسسته (HF)، FDEM، عوامل کنترل‌کننده

واژگان کلیدی