Journal of Geomine (2025), 3(4), 263-272
DOI: 10.22077/jgm.2026.10993.1073

Geomechanical modeling and sensitivity analysis of fracture propagation in hydraulic fracturing operation

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Received: 2026 Feb. 14, Revised: 2026 May 29, Accepted: 2026 Jun 28, Published: 2026 Jul. 18

ABSTRACT

Hydraulic fracturing (HF) is a complex well-stimulation technique that involves injecting high-pressure fluid into formations to create fractures and release trapped hydrocarbons. A detailed geomechanical model of the reservoir was developed using core analysis, well logs, and drilling data. Key parameters—including maximum and minimum horizontal stresses (calculated via poroelastic relationships), Young's modulus, Poisson's ratio, Biot's coefficient, and rock tensile strength—were evaluated. Sensitivity analysis revealed that increasing wellbore deviation angle relative to the maximum horizontal stress direction increases the stress intensity factor (SIF), whereas increasing perforation angle reduces it. Enlarging the initial fracture radius also increases the SIF. In reservoirs with high regional stresses, higher injection pressure is required for adequate fracture opening compared to moderate stress conditions. Fracture propagation consistently occurs along the direction of maximum horizontal stress across all simulated scenarios. Optimal selection of the reservoir layer, perforation angle, and injection pressure can enhance reservoir production potential while reducing operational costs and the risk of HF failure.

KEYWORDS

Hydraulic fracturing, geomechanical parameters, injection pressure, sensitivity analysis, fracture propagation

I. INTRODUCTION

Oil wells are subjected to numerous geomechanical challenges from the drilling of the first exploratory well in a field through to reservoir abandonment. These challenges may lead to problems such as wellbore instability, geomechanical complications associated with enhanced oil recovery (EOR) methods—including gas, steam, and water flooding—and hydraulic fracturing (HF). Among the aforementioned issues, except for HF, the others are generally undesirable problems that operators seek to control and prevent. To predict and ultimately mitigate such problems, comprehensive geomechanical analyses are essential. In its simplest form, geomechanical analysis requires coupled flow–stress modeling. In high-temperature reservoirs, fully coupled thermo–hydro–mechanical (THM) analysis is necessary. In certain cases, such as shale stability assessment, simultaneous coupling of flow, stress, temperature, and chemical reactions (THMC analysis) is required (Ali and Sheng, 2015). Sensitivity analysis is one of the most effective approaches for simplifying complex numerical models. Reservoir simulation models typically involve numerous input parameters, not all of which exert equal influence on model outputs. Through sensitivity analysis techniques, less influential parameters can be identified while modeling and forecasting efforts focus on the more sensitive variables, thereby reducing computational time and cost (Mahmoodpour et al., 2021).

HF is a deliberate form of induced instability designed to enhance reservoir productivity. HF has represented a major technological advancement in the petroleum industry. The method of applying pressure within a wellbore to create fractures in rock was first introduced in 1949. At that time, the technique—then referred to as “Hydrafrac”—consisted of two main stages: (i) injection of a viscous fluid containing granular materials such as sand (proppant) under high hydraulic pressure to create and sustain fractures in the formation; and (ii) reduction of fluid viscosity to facilitate flowback from the formation. Several years later, laboratory experiments demonstrated that when a penetrating fluid was used, fractures tended to propagate parallel to bedding planes. In contrast, with a non-penetrating fluid, fractures developed parallel to the core axis (Mahmoodpour et al., 2021). Researchers later concluded that regardless of whether the injected fluid was penetrating or non-penetrating, HFs propagate

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approximately perpendicular to the minimum principal stress (Ji et al., 2020). They further noted that within any interval of a wellbore wall, naturally pre-existing discontinuities may exist. Therefore, the tensile strength of most reservoir rocks is almost negligible, and the pressure required to initiate fracture in the rock is only that necessary to reduce the normal effective stress acting on certain planes at the wellbore wall to a value smaller than zero.

Abdollahipour et al. presented a systematic sensitivity analysis to quantify the influence of each parameter on geomechanical modeling. Maximum wellbore wall displacement was considered as the stability indicator. Numerical modeling was carried out using a 3D finite difference method with a Mohr-Coulomb yield criterion-based constitutive model. Results indicated that parameter importance varied depending on rock strength. For weak rocks, the most sensitive parameters were maximum horizontal stress, internal friction angle, and formation pressure, respectively. For strong rocks, the most influential parameters were maximum horizontal stress, mud pressure, and pore pressure (Abdollahipour et al., 2019). Shi et al. investigated the sensitivity of HF propagation parameters in a deep shale oil formation in the Mahu area of the Junggar Basin, China, at depths of 4500–5000 m. The deep shale reservoir exhibited a large horizontal stress differential, resulting in complex fracture geometries during stimulation. To better understand fracture propagation mechanisms, anisotropic characteristics and key physical properties were obtained through mineralogical analysis and Brazilian tensile tests. Results indicated that in-situ stress is the dominant factor controlling fracture propagation direction and geometry. The weak plane characteristics, orientation, and in-situ stress collectively determine whether fractures can propagate across bedding planes (Shi et al., 2022). Jafari et al. (2022) performed a sensitivity analysis of parameters controlling fracture network permeability (FNP). FNP is governed by various fracture network attributes such as fracture length, density, orientation, aperture, and connectivity. A design of experiments (DOE) approach was applied to identify the most critical parameters affecting FNP for different fracture network types, and the results were presented graphically. The authors concluded that the proposed methodology is valuable for static modeling of naturally fractured reservoirs (NFR) and provides further insight into fracture network transmissibility modeling (Oyarhossein and Dusseault, 2022). Zhang et al. discussed the application of HF in multilayered thin tight sandstone gas reservoirs, highlighting challenges such as proper fracture propagation and height control due to complex geological variations. The authors proposed a numerical study based on a real reservoir in the Ordos Basin, analyzing the influencing factors on HF. The study included a sensitivity analysis of geological and fracturing parameters and presented an optimized fracturing scheme that improves productivity while preventing unwanted fracture propagation (Zhang et al., 2023). Helmy et al. conducted a sensitivity analysis of HF parameters to determine the optimal horizontal well spacing in tight oil reservoirs. 3D reservoir simulation models were developed to evaluate the productivity of unconventional reservoirs with low permeability. Parameters such as matrix permeability, HF spacing, half-length, height, and conductivity were analyzed through simulations to enhance oil recovery estimates. The optimal well spacing was calculated to be approximately 300 feet per 100 acres. Economic evaluations of various drilling scenarios were also conducted, highlighting the significance of cost in fracture design optimization (Helmy et al., 2025). Yang et al. focused on the sensitivity analysis of proppant transportation and settling in HF. They emphasized the importance of HF in unconventional oil and gas extraction and highlighted how effective proppant placement is crucial for successful fracturing operations and reservoir productivity. The study employed numerical simulations to assess various factors affecting proppant migration, including the velocity and viscosity of fracturing fluids, proppant characteristics (size and density), fracture surface roughness, and injection position. Key findings indicate that proppant transport efficiency can be influenced by these parameters, affecting their settling behavior and ultimately the effectiveness of the HF process (Yang et al., 2025). Fu et al. discussed a study on the thermohydro-mechanical (THM) coupling model of fractured hot dry rock (HDR) reservoirs. They focused on the sensitivity analysis of mechanical field parameters and examined the dynamic variations in fracture apertures and permeabilities during the heat extraction process. Key findings include the significant impact of temperature changes on matrix elastic modulus and Poisson's ratio, as well as how these changes affect fracture permeability (Fu et al., 2025). Li et al. discussed the challenges and advancements in HF technology for unconventional oil and gas reservoirs, highlighting the importance of multi-well, multi-stage fracturing to enhance recovery rates. The study introduced the Continuous-Discontinuous Element Method (CDEM) for creating a 3-D model that simulates the interactions of flow fields and stress fields. It addressed the complexities involved in fracture propagation paths and emphasized the need to optimize perforation parameters for improved fracturing outcomes (Li et al., 2026). Tao et al. presented a coupled extended finite element-cohesive zone model (XFEM–CZM) to simulate HF propagation under poroelastic effects. The research aimed to improve fracture characterization and design optimization in unconventional reservoirs. The study addressed the challenges in numerical simulation due to the interactions between fluid flow and rock deformation. It compared the XFEM–CZM model with established methods. The findings highlighted the influence of factors such as permeability, leak-off, and viscosity on fracture propagation. Sensitivity analyses indicated that tensile strength, fracture energy, and initial crack length significantly affect fracture growth characteristics (Tao et al., 2026).

Despite significant advancements in geomechanics and fracture mechanics for the design and implementation of HF operations, research gaps remain in the existing literature. Most previous studies have qualitatively evaluated the influence of reservoir rock mechanical parameters on fracture propagation. In contrast, fewer have conducted rigorous quantitative analyses using 3D geomechanical models calibrated with real field data (well logs, core tests, and drilling data). Furthermore, many studies have focused on isolated parameters and have not simultaneously evaluated the coupled interaction among key variables such as well inclination, perforation angle, initial fracture size, and injection pressure. Moreover, existing studies have primarily focused on moderate stress conditions or laboratory-scale environments. Field-scale data under high in-situ stress conditions—such as reservoirs where the maximum horizontal stress (σH) exceeds 40 MPa—have not been sufficiently investigated. Consequently, the precise relationship between required injection pressure and regional stress conditions at the industrial scale remains insufficiently clarified. The present study aims to bridge these scientific and practical gaps by incorporating multi-parameter analysis, advanced crack path modeling, and evaluation under high-stress field conditions using geomechanical modeling and sensitivity analysis.

II. METHODOLOGY

A. Geomechanical Model

In general, developing a comprehensive geomechanical model and thoroughly evaluating the regional in-situ stress regime significantly enhance the accuracy of modeling field-scale operational activities. Fig. 1 illustrates the overall workflow of the modeling process.

To enable replication, the numerical model was implemented in FLAC3D using an explicit finite-difference scheme. The model domain was set to dimensions sufficiently large to eliminate boundary effects, with a graded hexahedral mesh refined near the wellbore and fracture path based on a convergence study that ensured further refinement produced negligible changes in the SIF. The rock followed a Mohr-Coulomb constitutive model with a tensile cutoff, using mechanical properties (Young's modulus, Poisson's ratio, cohesion, friction angle, tensile strength, and Biot coefficient) derived from core analysis and well logs. Initial in-situ stresses (vertical, maximum horizontal, and minimum horizontal) were calculated using poroelastic relationships consistent with reservoir depth and regional stress data. Water was injected with a controlled pressure ramp from the initial reservoir pressure to the target injection pressure over a short rise time. Fracture initiation was assumed to occur when the minimum in-situ horizontal effective stress exceeded the rock's tensile strength, and the SIF was calculated using the displacement extrapolation method at the crack tip.

Boundary conditions applied to the numerical model were as follows: zero normal displacement (roller boundaries) on all external faces of the model domain to simulate an infinite medium while preventing rigid body motion; initial in-situ stresses were applied as pre-stresses throughout the domain before injection; no additional external loads or displacements were imposed after initialization. This choice is justified because the model dimensions were sufficiently large that stress and displacement gradients at the boundaries remained negligible during HF injection, thus effectively eliminating boundary effects as recommended in the geomechanical modeling literature.

B. Sensitivity Analysis

Sensitivity analysis is employed as a key tool to identify and rank the parameters influencing the stress intensity factor (SIF) and the performance of HF operations. First, a 3D geomechanical model was developed based on actual reservoir data, incorporating parameters such as Young’s modulus, Poisson’s ratio, Biot’s coefficient, rock tensile strength, pore pressure, and in-situ horizontal and vertical stresses. Each parameter was then varied independently under both minor and major perturbation scenarios to quantify the sensitivity of the results to parameter variations.

The analysis revealed that the wellbore orientation relative to the maximum horizontal stress direction is one of the most sensitive parameters. Specifically, increasing the well deviation angle from 0° to 30° resulted in a 15–25% increase in the SIF. This positive effect becomes more pronounced under high regional stress conditions, exerting a greater influence on fracture propagation. In contrast, increasing the perforation angle from 0° to 60° led to an approximate 10–18% reduction in the SIF, indicating that improper perforation orientation can significantly diminish HF efficiency.

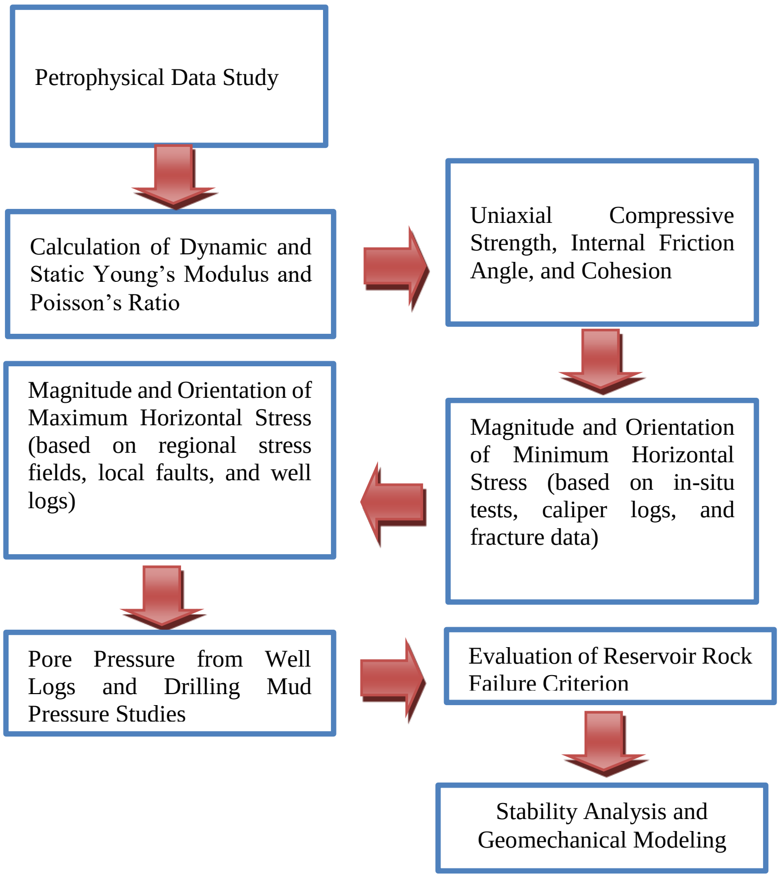

Fig. 1. Workflow diagram for the development of the geomechanical model

Evaluation of the initial fracture radius demonstrated that increasing the radius from 5 cm to 15 cm could increase the SIF by up to 30%. This finding highlights the importance of accurate initial crack design and its role in optimizing injection pressure and ultimate fracture length. Furthermore, the impact of injection pressure on fracture propagation was examined. Results suggested that in reservoirs characterized by higher horizontal stresses, for instance, when the maximum horizontal stress is about 42 MPa, the injection pressure required to achieve the desired fracture aperture is approximately 25–30% greater than that under moderate stress conditions, and it is about 32 MPa. This quantitative relationship provides a practical basis for predicting injection pressure requirements under varying operational stress regimes.

Overall, the conducted sensitivity analysis not only prioritized the governing parameters but also demonstrated that wellbore orientation, initial fracture radius, and injection pressure exert the most significant quantitative influence on the SIF. In contrast, perforation angle has a considerable negative impact. These findings formed the basis for optimal parameter selection in HF design and were directly implemented in the numerical modeling and operational planning. Fig. 2 presents the sensitivity analysis results of the SIF.

III. Results and Discussion

A. *Analysis of Modeling Results*

The results obtained from numerical modeling based on the analyzed parameters are presented in Figs. 3 to 10.

Fig. 3 illustrates the effect of variations in maximum horizontal stress (σ_H) on the SIF (KIC). The results indicate that increasing σH, while keeping other parameters constant, leads to a direct increase in KIC. This trend is attributed to the greater tendency of fractures to open in the direction of elevated horizontal stresses, which increases the strain energy concentration at the crack tip and consequently enhances the SIF. Furthermore, increasing the vertical stress (σ_V), by adding a compressive component normal to the fracture plane, amplifies this effect when combined with higher σ_H, resulting in a uniformly increasing trend in the curve.

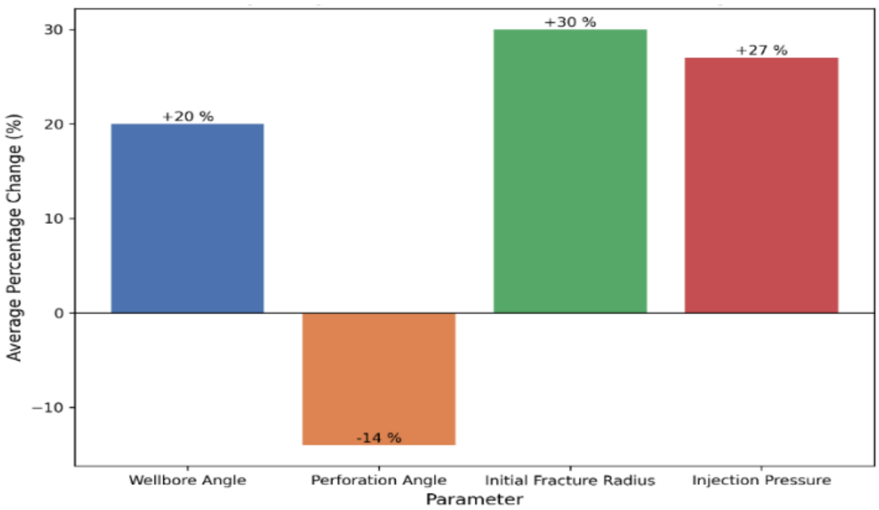

Fig. 2. Sensitivity analysis results

Fig. 4 presents the influence of minimum horizontal stress (σ_h) on KIC. An increase in σ_h promotes fracture closure and reduces the normal stress gradient across the fracture surface, leading to a noticeable decrease in KIC. This reduction becomes more pronounced when σ_h exceeds 30 MPa, highlighting the high sensitivity of the SIF to elevated minimum horizontal stress values.

Fig. 5 examines the ratio σ_H/σ_h. An increase in this ratio reflects greater horizontal stress anisotropy, which directs fractures toward opening along the σH orientation. The results indicate that increasing this ratio from 1.2 to approximately 2.0 results in a significant increase in KIC (exceeding 20%), confirming the dominant role of maximum horizontal stress in facilitating fracture propagation.

Fig. 6 evaluates the effect of vertical stress on KIC. Although increasing σV generally contributes to fracture compression, it may increase the energy concentration at the crack tip and thus elevate KIC under specific horizontal stress regimes. This effect becomes more evident when σH is significantly greater than σh.

Fig. 7 illustrates the influence of fracture plane angle relative to the wellbore axis. Increasing this angle from 0° to approximately 60° results in a gradual decrease in KIC. This reduction can be attributed to the decrease in the effective normal stress component acting perpendicular to the fracture plane. As the angle increases, the fracture opening direction becomes less aligned with the principal tensile stress orientation.

Fig. 8 analyzes the variation of wellbore inclination angle relative to the vertical on KIC. Results indicate that from 0° to 40°, KIC decreases, which is associated with changes in the in-situ stress distribution and a reduction in the effective tensile component acting along the fracture plane. Beyond 40°, KIC increases again, suggesting a shift in dominant fracture orientation and improved alignment with σH.

Fig. 9 presents the effect of wellbore inclination on the required pressure for fracture propagation. From 0° to 40°, the required propagation pressure increases due to changes in the stress distribution around the fracture, which reduces natural fracture opening. However, beyond 40°, the required pressure decreases, indicating more favorable conditions for fracture growth along the dominant stress direction.

Fig. 10 investigates the effect of initial crack size on the initial pressure applied at the crack tip and on KIC. As the initial fracture size increases, the contact area and elastic strain energy storage capacity increase, leading to higher applied tip pressure and a nonlinear increase in KIC. This trend confirms the strong sensitivity of HF behavior to initial crack conditions and underscores their importance in perforation design and injection strategy optimization.

B. Results of Sensitivity Analysis

1) Assessing the sensitivity of results to changes in reservoir wall parameters

As mentioned, variations in the wall properties can affect the analysis results. For the reservoir under consideration, two parameters—wall stiffness and wall height—were modified to evaluate the sensitivity of the hypothetical model to these changes. To this end, the structure was dynamically analyzed for different values of wall thickness (t_1) and wall height (H_1), and the effects on the first vibration mode frequency are presented in Fig. 11. As observed, increasing the wall thickness, and consequently its stiffness, leads to an increase in the first vibration mode frequency, as the model approaches a more rigid behavior. At higher wall thickness values, the sensitivity of the responses to this parameter gradually decreases because the structure approaches full rigidity and the deformations are reduced. Besides, as the reservoir height increases, the wall stiffness decreases, resulting in a reduction in the vibration frequencies.

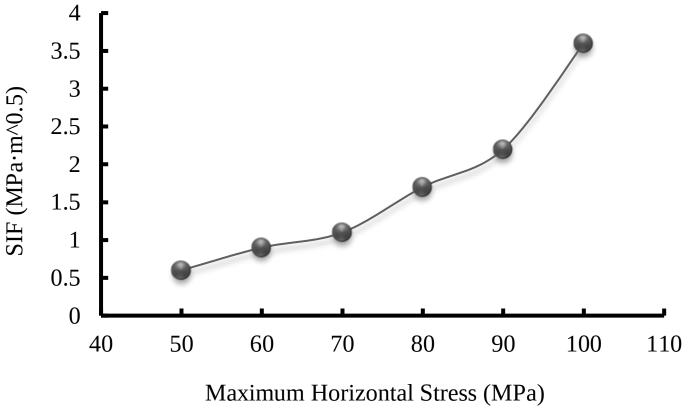

Fig. 3. Variations of maximum horizontal stress relative to the SIF

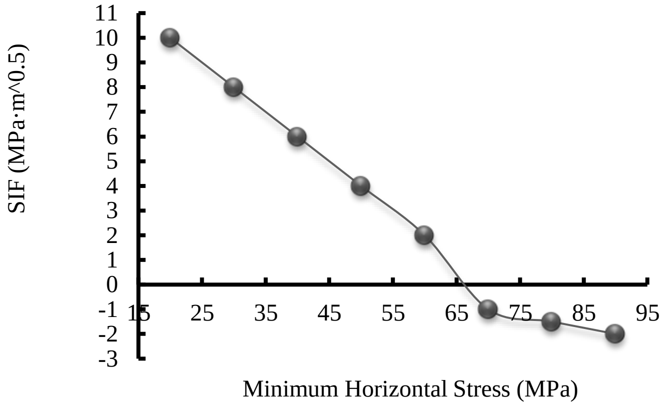

Fig. 4. Variations of minimum horizontal stress relative to the SIF

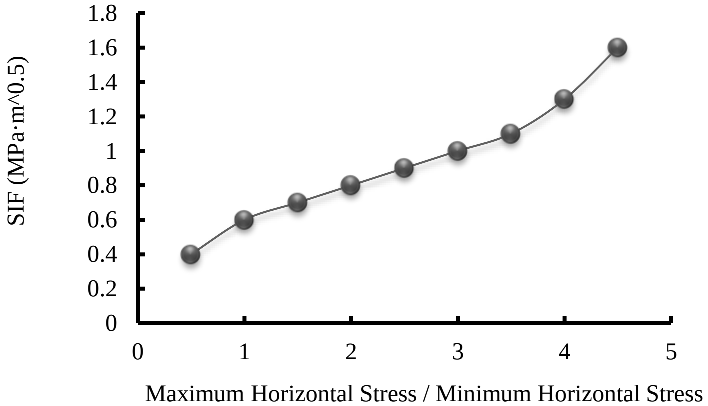

Fig. 5. Variations of the maximum-to-minimum horizontal stress ratio relative to the SIF

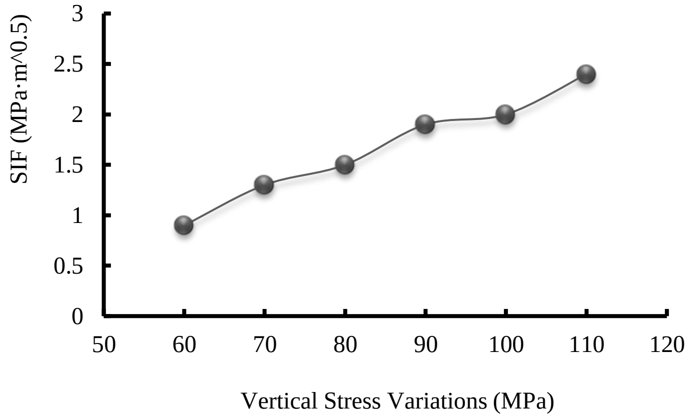

Fig. 6. Variations of vertical stress relative to the SIF

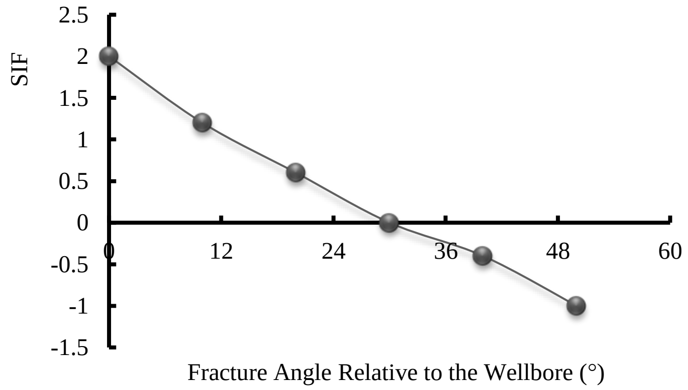

Fig. 7. Variations of the fracture angle relative to the wellbore as a function of the SIF

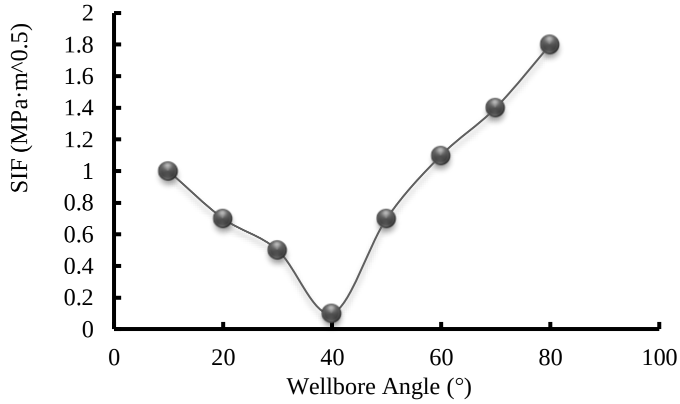

Fig. 8. Variations of the wellbore angle as a function of the SIF

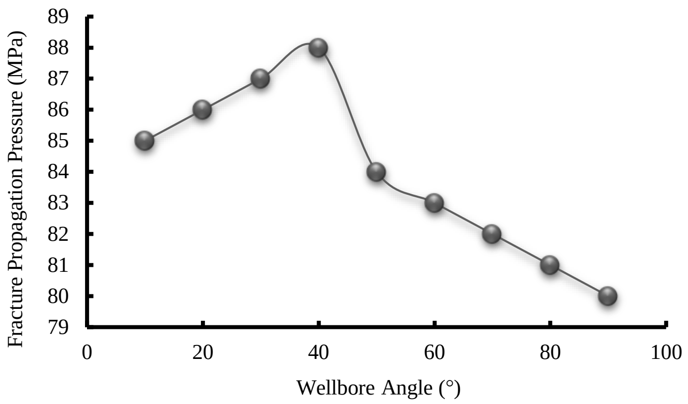

Fig. 9. Minimum fracture propagation pressure versus wellbore angle

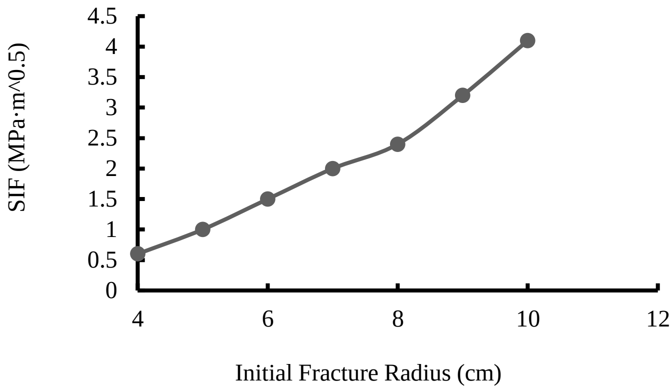

Fig. 10. Effect of initial fracture radius on the SIF

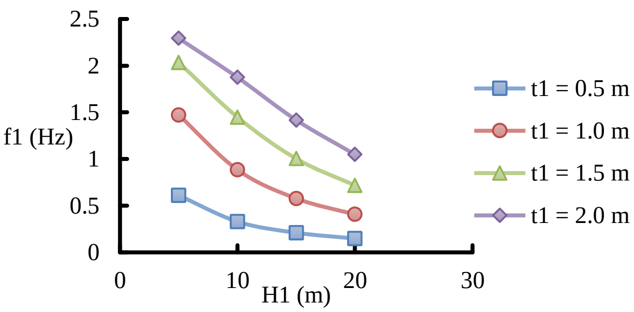

Fig. 11. Sensitivity of the first mode frequency to changes in reservoir wall thickness and height

In the following, the effects of two parameters—the flexibility of the reservoir walls and their height—on the dynamic responses of the structure are examined. To this end, the wall thickness (t_3) and wall height (H_2) are varied within a reasonable range, and the sensitivity of the responses to these changes is evaluated. Fig. 12 depicts the sensitivity of the first vibration mode frequency to modifications in the walls. As observed, increasing the wall thickness leads to an increase in the structural mass at higher elevations, reducing the overall stiffness of the system and, consequently, decreasing the vibration frequency. Similarly, increasing the wall height has the same effect, reducing the overall stiffness of the system and resulting in a downward trend in the frequency curve.

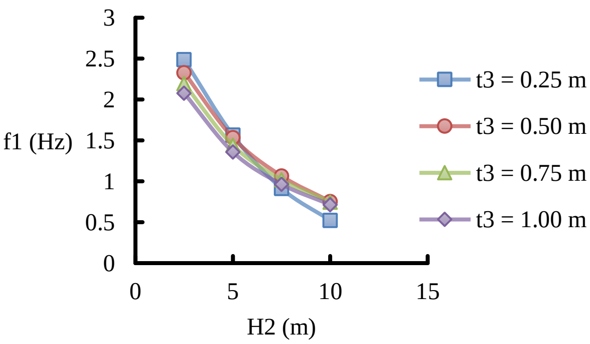

Fig. 12. Sensitivity of the first mode frequency to changes in reservoir wall thickness and height

2) *Assessing the sensitivity of results to changes in reservoir base parameters*

At the reservoir base, the thickness and width of the base significantly influence the dynamic responses. Fig. 13 shows the variation of the first mode frequency with changes in the base thickness and width. Increasing the reservoir base thickness (t_2), and consequently its stiffness, enhances the overall rigidity of the structure, increasing the frequencies. This increasing trend continues until the base behavior becomes fully rigid, after which the sensitivity of the results to this parameter diminishes. It is also observed that increasing the base width L raises the structural mass at elevations above the ground level, which reduces the overall stiffness of the system and, consequently, decreases the frequencies.

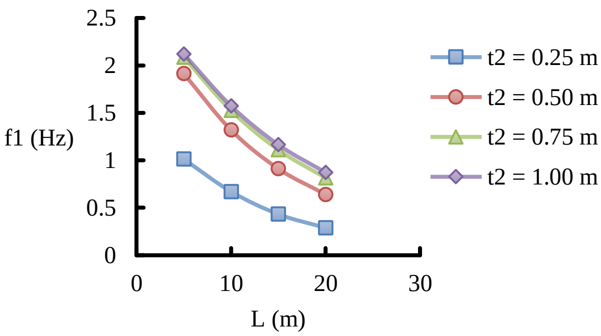

Fig. 13. Sensitivity of the first mode frequency to changes in the reservoir base thickness

3) *Assessing the sensitivity of results to changes in fluid parameters*

The effects of fluid-related parameters on the dynamic responses of the coupled structure–fluid system were examined. To this end, the system was analyzed for different wave velocities (c) and varying reservoir fill levels (H_3/H_2), and the sensitivity of the responses to these changes was evaluated (Fig. 14). As observed, increasing the reservoir fill level, and consequently the mass of the upper portion of the system, leads to a decrease in the frequencies. It is also observed that variations in wave velocity, and thus changes in fluid compressibility, have no significant effect on the dynamic responses within a reasonable range of values.

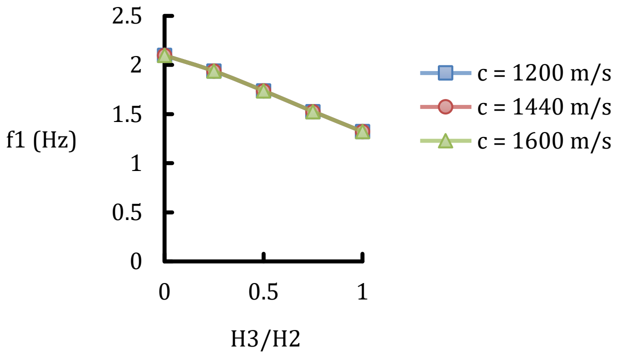

Fig. 14. Sensitivity of the first mode frequency to fluid compressibility and reservoir fill level

IV. Discussion

In the first stage, the behavior of horizontal and vertical stresses in the reservoir was studied separately and then in a coupled state. The results indicated that the vertical stress distribution is primarily governed by the weight of the rock column and formation depth, showing a uniform and steadily increasing trend with depth. In contrast, horizontal stresses are strongly influenced by rock anisotropy, natural fractures, porosity, and pore pressure. In areas of the model with high permeability and elevated pore pressure, the horizontal stress decreased by approximately 10–15% relative to the regional average, whereas in dense, low-porosity zones, the horizontal stress increased up to about 12 MPa. This deviation from a linear stress-strain relationship between horizontal and vertical stresses arises from their dependence on anisotropic elastic properties and non-hydrostatic pore pressure conditions. The quasi-plastic mechanical behavior refers to an inelastic, plastic-like response in which rock undergoes irreversible deformation and stress redistribution along with stiffness degradation. However, the process is gradual and often governed by damage and microcracking rather than ideal plastic flow. In anisotropic reservoirs, this results in a system response to injection pressure that does not follow classical linear elasticity assumptions.

From an elastic parameter perspective, the Young's modulus and Poisson's ratio play a significant role in determining the magnitude and direction of induced stresses. In the present model, increasing the Young's modulus from 20 to 32 GPa enhanced rock deformation resistance, resulting in an approximately 8% increase in maximum horizontal stress near the well. Conversely, increasing the Poisson's ratio from 0.23 to 0.31 amplified the volumetric deformation capacity of the rock and led to a reduction in vertical stress. The combination of these two effects shifted the stress distribution pattern toward brittle and failure-prone behavior, particularly in zones with high pore pressure and Biot coefficients between 0.7 and 0.8. Pore pressure analysis revealed that micro-scale pressure increases in the porous matrix surrounding fractures reduce the effective stress, thereby increasing the likelihood of fracture opening and propagation. Numerically, this corresponded to a radial stress drop along the wellbore of about 4 MPa, indicating the onset of induced fracture growth along the minimum horizontal stress direction.

For the evaluation of Darcy and non-Darcy flows, the 3D geomechanical model was run under two separate conditions to investigate differences in reservoir mechanical behavior under linear and nonlinear flow regimes. Under Darcy flow, the pressure–flow relationship was nearly linear, with no significant stress variations; the production rate was directly proportional to pressure drop and permeability, and stress changes around the well remained within 95–105% of the initial values. In the non-Darcy case, implemented via the Forchheimer relation, flow resistance increased, causing an asymmetric stress distribution. Non-Darcy flow led to horizontal stress concentration around fractures, altering the balance between vertical and horizontal stresses. At the moment of injection, the maximum horizontal stress increased by up to 6% relative to the Darcy case, while the reservoir output decreased by approximately 10–12%. This behavior demonstrates that in low-porosity and highly heterogeneous zones, fluid compression and pressure drop due to nonlinear friction can significantly alter stress states and reduce production efficiency.

The FLAC3D model, with its capability to account for coupled flow–stress effects, also revealed reservoir deformations and injection-induced displacements at a local scale. Displacement vector analysis showed maximum divergence along the maximum horizontal stress direction, directly corresponding to the location and orientation of fracture propagation. These results validate the HF theory assumption that fractures propagate perpendicular to the minimum horizontal in-situ stress. Moreover, the stress history during injection demonstrated that as pore pressure rises and effective stress approaches zero, overcoming tensile strength, the reservoir enters a tensile failure stage, generating a new fracture at an angle of approximately 30° to the well axis.

In the sensitivity analysis of geomechanical parameters, the primary goal is to identify the subset of model input variables that exert the greatest influence on the mechanical and hydraulic behavior of the reservoir, enabling the model to achieve both realism and reduced complexity. Numerical analyses based on the 3D geomechanical model using FLAC3D identified four critical parameters: rock porosity, internal friction angle between grains, compressive and tensile strength of the rock, and particle cohesion. Each of these parameters not only affects the magnitude and orientation of induced stresses around the well but also governs pore pressure distribution, fluid transmissibility, and ultimately reservoir production rates.

Initially, porosity, as the most influential structural parameter, was examined. Porosity is directly related to compressibility and permeability and implicitly affects pore pressure and effective stress distribution in the geomechanical framework. Numerical results showed that increasing porosity from 8% to 18% reduced the average effective stress around the well by approximately 12–15%. This reduction enhanced the formation's tendency to fracture, particularly under high injection pressures, where lateral fractures in higher-porosity zones activated earlier than in other regions. From a fluid flow perspective, higher porosity increased effective permeability, raising the Darcy flow rate by about 10%; however, under non-Darcy conditions, due to local friction and flow turbulence, fluid transmissibility increased by only about 4%, highlighting the reservoir's true nonlinear behavior. These results indicate that high porosity without sufficient cohesion not only reduces mechanical stability but also promotes particle detachment and sand production. Therefore, porosity must be considered from both mechanical and hydraulic perspectives in HF design.

The internal friction angle between grains, the second sensitive parameter, serves as an index of resistance to sliding and fracture initiation. Numerical analysis showed that increasing the friction angle from 26° to 38° significantly altered induced stresses around the well. At low friction angles, shear stresses quickly exceeded the failure threshold, expanding the plastic zone. Conversely, at higher friction angles, particle stability against sliding increased, limiting plastic deformation and better controlling stress concentration in the target injection area. From a fluid flow perspective, higher friction angles preserved formation integrity, reducing local fracture compression and resulting in more uniform flow paths. Numerically, this appeared as a steady increase in fluid transmissibility by 3–5% relative to the baseline, demonstrating the positive correlation between particle stability and flow efficiency.

Next, the effect of rock strength, including compressive and tensile strength, on stress-inducing behavior was evaluated. Increasing compressive strength from 80 to 120 MPa in the target formation increased horizontal stress by about 10%. It stabilized the stress distribution pattern, whereas decreasing tensile strength from 6 to 4 MPa accelerated fracture formation. In this case, the critical pore pressure for fracture initiation decreased from approximately 34 to 30 MPa, illustrating the direct influence of tensile strength on fracture pressure. This relationship is vital for HF design, indicating that formations with lower tensile strength are prone to failure even under modest injection pressures. In comparison, higher compressive strength confines stress zones and prevents unwanted fracture propagation. Thus, optimal rock strength must balance controlled fracturing with effective fluid transfer.

Particle cohesion, the final parameter in the sensitivity analysis, plays a key role in formation stability. Reducing cohesion from 3.5 to 2 MPa caused large zones around the well to enter plastic deformation, with nonlinear increases in induced stresses. This not only reduced local stability but also significantly decreased production rates during injection due to over-compressed flow paths. Conversely, high particle cohesion controls shear stresses, allowing the formation to withstand pore pressure uniformly. Hydrodynamically, higher cohesion preserved the pore network and prevented microchannel closure, with Darcy flow transmissibility increasing by 6–8% relative to the baseline. These findings underscore that the correct combination of rock strength and cohesion is necessary for achieving mechanical stability and uniform flow during HF and production operations.

The sensitivity analysis results indicate that the dependence of production rate and induced stress behavior on geomechanical parameters is highly nonlinear. No single parameter solely governs reservoir behavior; rather, it is the combined effect that controls formation stability and fluid transfer efficiency. Specifically, simultaneous increases in porosity and friction angle to approximately optimal values (15% and 32°, respectively), while maintaining compressive strength and cohesion at moderate levels (≈90 MPa and 3 MPa), yield the highest efficiency in stress distribution and production rate. In the numerical model, these conditions resulted in an approximately 10% reduction in effective stress around the well and an 18–22% increase in production rate, consistent with previously reported field HF observations.

In summary, the sensitivity analysis serves not only as a tool to identify critical parameters but also as a method to establish causal relationships between rock mechanical properties and fluid hydrodynamics. Induced stresses around the well are directly influenced by porosity, cohesion, and friction angle, whereas fluid transmissibility is controlled by the combination of rock strength and pore pressure. Therefore, accurate reservoir performance prediction and optimal HF design are valid only when the effects of these four factors are simultaneously evaluated within a fully coupled 3D flow–stress model, as achieved in this study using FLAC3D.

V. Conclusion

3D modeling of in-situ stresses and calculation of key parameters, including Young's modulus, Poisson's ratio, Biot's coefficient, pore pressure, and tensile strength of the rock, were carried out to determine the stress-inducing structure of the reservoir and to evaluate the effects of well orientation and perforation angle on fracture propagation patterns. Reservoir behavior from a geomechanical perspective represents an interdisciplinary field, integrating rock mechanics, fluid hydrodynamics, and energy transformation phenomena within porous media.

The main objective of the numerical analysis using the 3D geomechanical model was to investigate the mechanical, hydraulic, and dynamic behavior of the reservoir under realistic stress and pore pressure conditions using FLAC3D. This model is capable of dynamically simulating the reservoir rock structure, stress field variations, fluid–rock interactions, and changes in production rate in response to variations in elastic, geometric, and boundary parameters. Using data from core samples, well logs, and rock mechanics tests, the initial model was established, including distributions of Young's modulus, Poisson's ratio, cohesion, internal friction angle, compressive and tensile strengths. The initial in-situ stress field was then calculated using poroelastic relations and implemented in the 3D model to replicate the natural pre-injection or pre-production state of the formation.

The numerical findings indicate that the proper combination of elastic parameters and pore pressure levels governs both the stress distribution pattern and the production rate. Specifically, higher Young's modulus, lower Poisson's ratio, and moderate Biot's coefficient enhance reservoir stability and optimize Darcy flow production. Conversely, under high pore pressure and non-Darcy flow conditions, reservoir stability decreases, and stress concentration causes a relative reduction in production rate. The 3D model demonstrates that reservoir geomechanical behavior is not uniform at the field scale but is highly dependent on local variations in parameters and pressure distribution. Only a multidimensional, coupled flow–stress–heat analysis can provide accurate predictions of actual reservoir performance.

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