Hydraulic Fracture Propagation in Heterogeneous Reservoirs: A Review of Natural Fracture Interaction and Mechanical Stratigraphy

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Abstract: Hydraulic fracturing is the most common mode of recovery of the unconventional reservoirs but its effectiveness is mostly hampered by unpredictability involved in the layout of the rocks underground. The synthesis of the geological and geomechanical settings, which are natural fractures and rock layering, that will dictate the shape and performance of induced fractures is reviewed. The critical discussion of the mechanics that determine the success of a hydraulic fracture in crossing, stopping or diverting along a natural fracture according to the approach angles and stress differences is to be considered. Our other evaluations of the contribution of vertical rock layers to the height and complexity of fractures is in terms of the different stiffnesses and levels of stress they possess. Also, the paper assesses the accuracy of the Discrete Fracture Network (DFN) modeling and investigates the new simulation methods, such as Extended Finite Element Method (EFEM) and Distinct Element Method (DEM) to model fracture paths. Lastly, we touch on the field validation technologies that are microseismic monitoring and fiber-optic sensing. We arrive at a conclusion that, in engineering design, consideration of a high-quality geological data is vital in order to achieve maximum operations and the reduction of the operational risks.

Keywords: Hydraulic fracturing, Geomechanical settings, Natural fractures, Discrete Fracture Network (DFN) and Microseismic monitoring.

Introduction

Background and Motivation

The use of hydraulic fracturing has resulted in paradigm shift of the energy industry across the globe. It has also been used to unlock vast resources of the unconventional hydrocarbon, and in particular, in shale gas and tight oil wells which has not only altered the geopolitical and economical prospect of energy production, but has brought a fundamental change to it (Gandossi and Von Estorff, 2015). This operationally complex process is conceptually simple, fostering the mechanical failure of rock by injecting fluid of high pressure. This aims at forming a conductive passageway that ensures maximum surface contact with the reservoir where trapped fluids can flow to wellbore.

Nevertheless, there is still an unwavering lack of integration between design and implementation. The classical model of hydraulic fracturing, like the Perkins-Kern-Nordgren (PKN) or Geertsma-de Klerk (GdK) models, conventionally idealized and homogenized the subsurface and made it an ideally isotropic, and linearly elastic medium. These layer-cake models assumed

that fractures would develop as bi-wings (simple and symmetric), totally ignoring the fact that the growth could be asymmetrical (Economides and Nolte, 2000). The practical use has amply shown that the masses of natural rocks are hardly ever ideal. Unconventional reservoirs the geological environment (areas) which support unconventional reservoirs are geologically chaotic, having pervasive natural existing fracture, fault, lamination, and large differences in mechanical properties and in-situ stress conditions.

These heterogeneities cannot be taken as simple deviation; they have a first-order domination of fracture trajectory. The induced fracture tends to follow a complicated, branched network as opposed to planar wings. Not taking into consideration these geological facts provokes inefficient completion design, where large amounts of capital go to waste due to the failure of these stages to add to the production process, or worse, causes problems such as screen-outs or cross interference with another well (Schultz et al., 2020). This gap in both theoretical and empirical understanding between idealized theories of mechanics and the more complicated geological reality of the underlying rock mass is therefore an urgent requirement of the industry.

Scope and Objectives

This review is particularly concerned with the geomechanical and geological interaction process on hydraulic fracture propagation in nonhomogeneous media. It is narrowed down to the physical association of hydraulic fractures with natural discontinuities and stratigraphic layering. Although fluid rheology and proppant transport are central aspects of the fracturing process, they are treated here mostly in the framework of their behaviour in highly complex non-planar fracture geometries.

This review has the following major objectives:

1. **Synthesize Interaction Mechanisms:** Check the basic physics of hydraulic fractures interstitial association with the natural fractures, particularly, the criteria according to which they will cross, arrest or bypass.

2. **Analyze Stratigraphic Controls:** In the case of vertical discrepantly different rock properties (mechanical stratigraphy), study how the source of fracture height and containment are determined.

3. **Evaluate Modeling Techniques:** Evaluate the need to incorporate Discrete Fracture Network (DFN) modeling in conjunction with the advanced numerical techniques (EFEM, DEM) in order to obtain the reasonable prediction of the fracture geometry and path in a failure.

4. **Review Validation Methods:** Talk about field diagnostic measures, e.g. microseismic monitoring and tracers, to ground-truth theoretical approach.

Methodology of Review

In order to achieve the complete analysis, the literature review was structured and aimed at identifying the papers related to peer reviews, conference papers, and industry standard texts published during the period of 2000-2024 majorly. Specific Boolean strings were used to query databases, including OnePetro, ScienceDirect, and Google Scholar, like Hydraulic Fracturing AND Natural Fracture Interaction, Stress Shadowing, Mechanical Stratigraphy and DFN Modeling. The scientific criteria of selection were emphasized on the papers that offered either mechanistic information or experimental backing or substantial field cases researches. The initial screening of about 120 sources was done and the most pertinent seminal articles as well as recent developments were reviewed in further synthesizing them in this report.

Natural Fracture Interaction with Hydraulic Fractures

The existence of natural fracture (NF) in non-standard reservoirs is the only factor that can result in the deviation of the planar development of fractures. These existing discontinuities and their response to a propagating hydraulic fracture (HF) dictate the connectivity of the network and the final volume of stimulated reservoir (SRV) (Gale et al., 2014).

Fundamental Interaction Mechanisms

The physics of HF-NF interaction is governed by a competition between the energy required to break the rock matrix and the energy required to open or slip along a pre-existing weakness. This interaction is controlled by the in-situ stress field, the approach angle, and the mechanical properties of the interface.

The Renshaw and Pollard Criteria

Seminal work by Renshaw (1995) established the foundational criteria for predicting these interactions. Based on linear elastic fracture mechanics (LEFM), their model suggests that a hydraulic fracture will cross a natural interface only if the stress at the tip of the fracture is sufficient to initiate a new crack on the opposite side of the interface before the interface itself slips or opens.

- **Crossing:** The hydraulic fracture propagates directly across the natural fracture. This is the preferred outcome when the goal is to maximize fracture half-length. Crossing is favored when the differential stress (the difference between maximum and minimum horizontal stress) is high. High differential stress effectively "clamps" the natural fracture shut, increasing the shear strength of the interface and making it mechanically easier for the hydraulic fracture to ignore the discontinuity and break through the rock matrix.

- **Arrest/Termination:** The hydraulic fracture energy dissipates upon encountering the natural fracture, halting propagation. This typically occurs when the natural fracture is highly permeable or weak. Fluid leaks off rapidly into the natural fracture, dropping the pressure at the tip of the hydraulic fracture below the critical intensity required for propagation (Guo et al., 2014).

- **Diversion/Offset:** The hydraulic fracture turns and dilates the natural fracture, propagating along it. This often occurs in regimes of low stress anisotropy. If the principal stresses are nearly equal, the path of least resistance may shift from the rock matrix to the pre-existing plane of weakness. The fracture may travel along the NF for a distance before re-initiating into the matrix, creating a "step-over" or "dog-leg" geometry.

Influence of Key Geomechanical Parameters

While the Renshaw 1995 criteria provide the theoretical baseline, several variables add complexity in real-world scenarios:

1. **In-situ Stress Anisotropy:** This is the dominant control. In high-anisotropy environments (e.g., tectonic compression zones), the hydraulic fracture is strongly forced to propagate in the direction of maximum horizontal stress, often ignoring natural fractures (figure1). In low-anisotropy environments, the fracture is more susceptible to influence by the local fabric (Chen et al., 2022; Li, Tang, Guo, & Qi, 2018; Zhou & Bunger, 2018; Zhu et al., 2022)

2. **Angle of Approach:** The angle (θ) at which the hydraulic fracture intersects the natural fracture is critical. Approaches near 90° (perpendicular) favor crossing. Shallow angles (<30°) almost invariably result in diversion or arrest because the resolved shear stress on the interface promotes slippage.

3. **Interface Properties and Cementation:** The nature of the material filling the natural fracture is vital. Calcite-filled fractures may be brittle and strong, potentially allowing crossing. Clay-filled fractures are weak and ductile, promoting shear slippage and arrest. Tests with the use of acoustic emission monitoring have revealed that weak bonding supports shear failure, and strong bonding tensile crossing (Chen et al., 2022; Li, Tang, Guo, and Qi, 2018; Zhou and Bunger, 2018; Zhu et al., 2022).
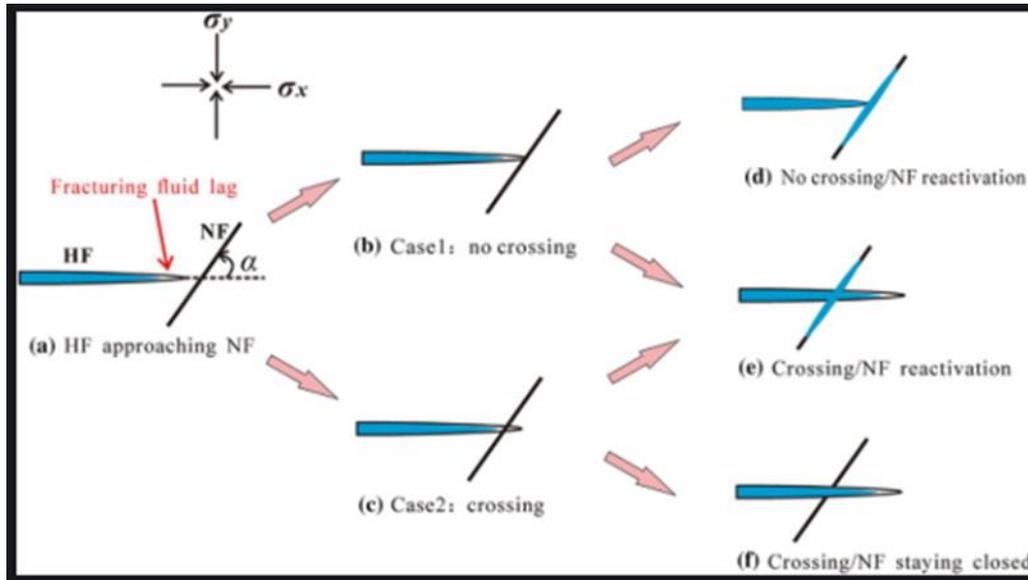
Figure 1: Schematic illustration of modes of fracture propagation of hydraulic fracture in near vicinity of a natural fracture. The diagram generally illustrates crossing, arrest, and diversion (opening/slippage) modes (A), (B), and (C), respectively, with the geometry being complicated (Behnia et al., 2015).

Complex Network Development and SRV

The overall outcome of such interactions is that a network of complex fractures is formed instead of one plane. This complexity is usually measured in Stimulated Reservoir Volume (SRV). A complex network enlarges the contact surface area, which is advantageous to production in ultra-low permeability rock. But it brings about operational problems.

- **Tortuosity:** With the fracture twisting and turning around the natural network, the flow friction is increased. This is presented as high near-wellbore pressure, and can be wrongly interpreted due to wrong interpretation as good fracture growth since this indicates hindered flow.

- **Proppant Transport:** It is not easy to transport proppant around sharp corners (dog-legs). At such restriction points proppant will commonly span across the restriction point and the distal sections of the fracture network will remain unpropped and virtually useless when pumping is terminated (Economides and Nolte, 2000).

Layered Rock Effects on Fracture Height Containment

Although natural fractures affect lateral complexity natural fracture height is regulated by the vertical heterogeneity of the formation mechanical stratigraphy. It is necessary to contain the fracture within the productive zone to prevent the contact with the water-bearing zones or energy wasting on non-productive rock.

The Role of Mechanical Stratigraphy

The layers of sedimentary basins are deposited and this causes vertical changes in rock characteristics. Minimum Horizontal Stress (σ_{hmin}), Young's Modulus (E), and Fracture Toughness (K_{IC}) are the most important properties that affect height growth.

Stress Barriers

The best process to contain height is the stress contrast between layers. Assuming the layer of rocks over the target zone has much greater σ_{hmin}, then it serves as a kind of stress-barrier.

$$\Delta\sigma = \sigma_{barrier} - \sigma_{pay}$$

As the vertical fracture tip goes through the high-stress layer, the fluid pressure needed to open the layer in the high-stress layer is greater than the fluid pressure needed to extend the fracture laterally in the pay zone. As such, the fracture is trapped. When the net pressure is more than this stress contrast, then breakthrough will take place (Economides and Nolte, 2000).

Modulus Contrasts

Differences in stiffness (Youngs Modulus) are also involved. Fracture which is started in a soft material (low modulus) when passing to a stiff material (high modulus) is frequently constricted at the tip. The limitation further decreases the pressure drop, which prevents vertical growth (figure 2). On the other hand, fracture blunting can also be caused by becoming softer (Olson, Laubach, and Lander, 2009).
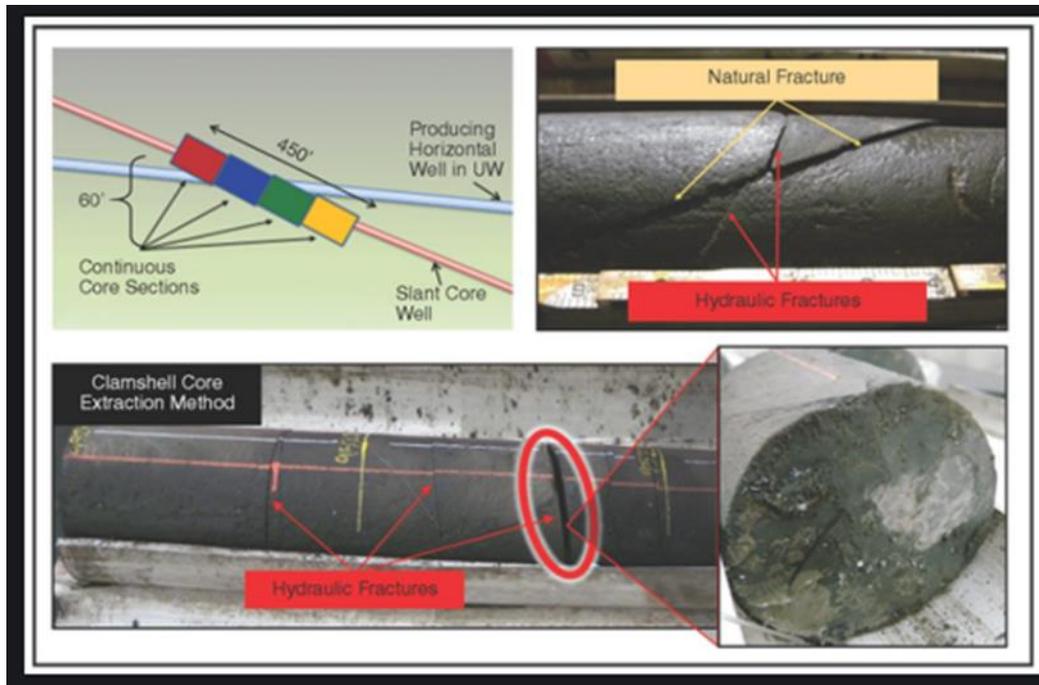

Figure 2: Cross-section development of hydraulic fracture growth improved by mechanical stratigraphy where layers are taken as obstacles (Ciezobka, Courtier, & Wicker, 2018).

Interface Delamination and T-Shaped Fractures

In case a vertical hydraulic fracture hits a horizontal bedding plane, the interaction is similar to the interaction Characterized by HF-NF mentioned above. When the interface is weak (e.g. a clay-rich bedding plane), the fracture might stop and bend horizontally and delaminate the interface.

- **T-Shaped Geometry:** In case the pressure is sufficient, one may have the fracture propagating laterally along the bedding plane as well as continuing its upward course and assuming the T-shape. This presents a complicated geometry that cannot be propelled easily.

- **I-Shaped Geometry:** Without strong interfaces or points of stress, the fracture extends vertically without limit creating an I shaped. Although this is simple it is not always good when it results in out of zone growth.

Discrete Fracture Network (DFN) Modeling

In order to model the complex interactions performed above, the industry has not only abandoned continuum models to Discrete Fracture Network (DFN) modeling. DFN, a stochastic model of the natural fractures system, clearly identifies the geometry and properties of individual fractures in the rock volume space (3D) (Dershowitz and Einstein, 1988).

Principles of DFN Generation

A DFN is a process determined by data that involves transformation of 1D data of the well bore into a 3D volumetric model.

1. **Data Acquisition:** Its major inputs are the image logs (FMI/UBI), which gives the fracture orientation and fracture intensity along the wellbore, and the core data, which gives scaling laws of fracture length and height.

2. **Stochastic Population:** The volume of the reservoir is filled at random since we only know the fractures at the wellbore. Algorithms generate fractures based on probability density functions for size (often power-law distributions), orientation (Fisher distributions), and spatial intensity (P_{32} - fracture area per unit volume).

3. **Hydraulically Active vs. Geologic DFN:** A major challenge is distinguishing between the total "geologic" DFN and the "active" DFN. Many natural fractures are cemented and mineralized, acting as barriers rather than conduits. The modeling process (figure 3) must filter the population to include only those fractures likely to reactivate under induced stress (Gale et al., 2014).
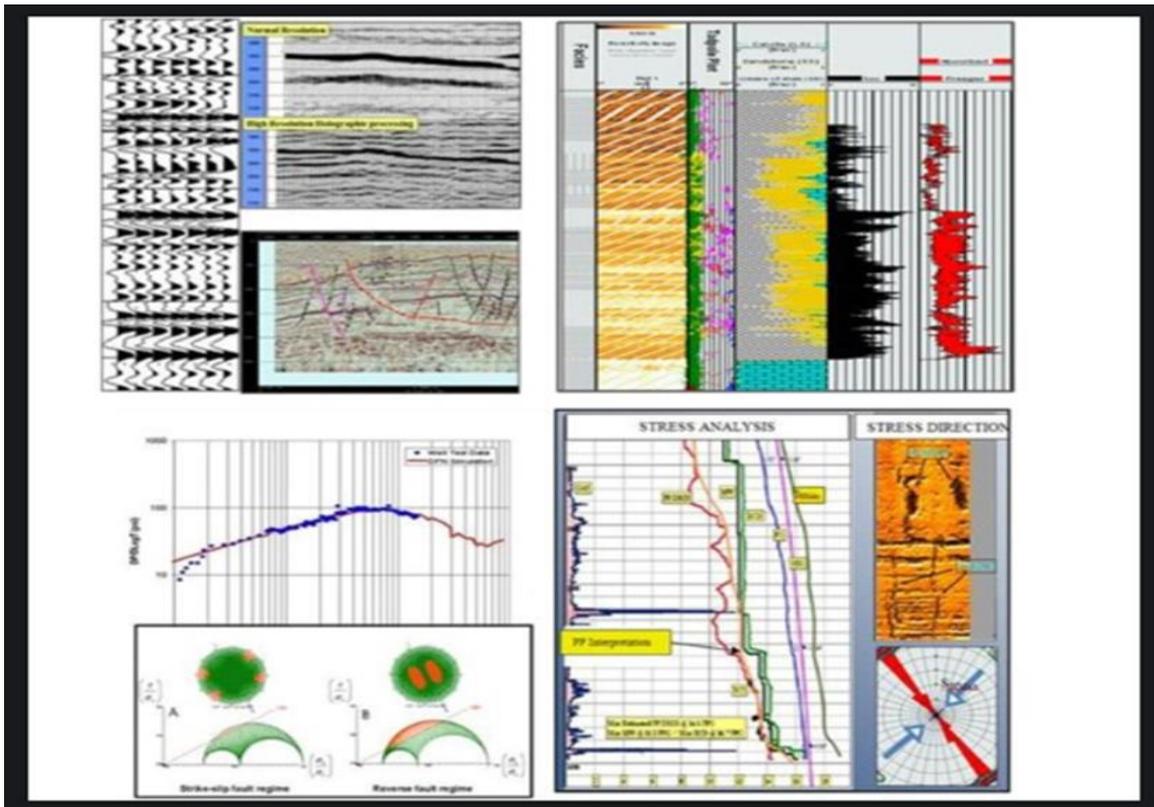

Figure 3: Illustration of a Discrete Fracture Network (DFN) model depicting interconnected fractures within a rock matrix, generated from wellbore image logs (TASK Fronterra, 2014).

Integration with Geomechanics

The DFN serves as the "fabric" for the simulation. When integrated into a geomechanical simulator, the model calculates the intersection of the propagating hydraulic fracture with the DFN elements. It is possible to predict discrete hits of a discrete fraction (inter-well communication) and estimate the total stimulated volume. However, the accuracy of a DFN is inextricably linked to the quality of the input data. A pervasive issue is the "non-uniqueness" of the models; multiple different DFN realizations can statistically match the wellbore data but produce vastly different flow behaviors.

Numerical Simulation of Complex Fracture Propagation

The mathematical simulation of fracture propagation in heterogeneous media requires solving coupled problems involving fluid flow, solid deformation, and fracture mechanics. Several numerical methods have competed for dominance in this space.

Comparative Analysis of Numerical Methods

The primary methods used in the industry are the Finite Element Method (FEM), Extended Finite Element Method (XFEM), Boundary Element Method (BEM), and Distinct Element Method (DEM).

Table 1: Comparison of Numerical Simulation Methods for Hydraulic Fracturing

Method	Description	Strengths	Limitations
FEM (Finite Element Method)	Discretizes the domain into a mesh.	Good for poroelasticity and complex heterogeneities.	Requires re-meshing as the fracture grows, which is computationally expensive.
XFEM (Extended FEM)	Enriches the mesh with discontinuous functions.	Allows fractures to grow *through* elements without re-meshing. Excellent for crossing criteria.	Computationally intensive; complex implementation for 3D intersecting networks.
BEM / DDM (Displacement Discontinuity)	Discretizes only the fracture boundaries (surfaces).	Extremely fast and efficient. Good for large-scale stress shadow calculations.	Struggles with heterogeneous rock properties (modulus changes) and complex leak-off.
DEM (Distinct Element Method)	Models rock as discrete blocks/particles.	Naturally handles shear slip, block rotation, and opening of pre-existing fractures.	Very high computational cost; calibration of micro-parameters to macro-properties is difficult.
Phase Field	Uses a continuous field variable to track damage.	Handles branching and merging topology changes naturally.	Requires very fine mesh resolution at fracture interfaces.

State-of-the-Art: Coupled Hydro-Mechanical Models

The industry trend is moving toward fully coupled solutions. For example, XFEM (figure 4) is increasingly used to model the near-wellbore complexity where accurate fracture turning is critical (Dahi-Taleghani & Olson, 2011). Conversely, for field-scale optimization where thousands of stages must be simulated, BEM (often coupled with a simplified DFN) remains the workhorse due to its speed (Minkoff, Stone, Bryant, Peszynska, & Wheeler, 2003).

A significant advancement is the ability to model "stress shadowing." This is the phenomenon where the opening of one fracture compresses the surrounding rock, increasing the stress for subsequent fractures. In heterogeneous media, stress shadowing can cause subsequent fractures to twist or arrest entirely, leading to uneven stimulation.
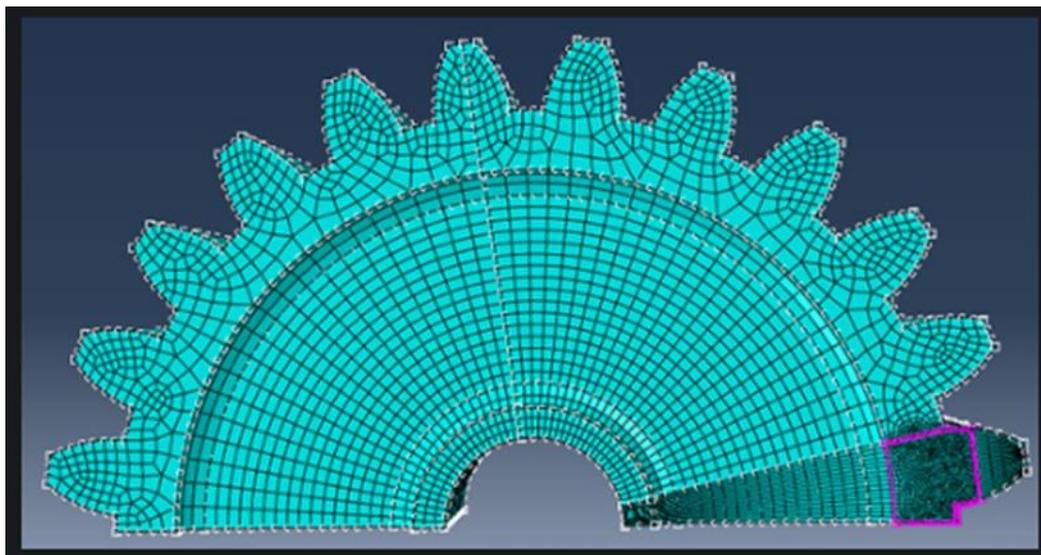

Figure 4: A 3D Extended Finite Element Method (XFEM) framework for fluid-driven fracture propagation in anisotropic rock (Technia, 2022).

Field Validation through Microseismic and Tracers

No matter how sophisticated the model, validation is required. Since the reservoir is inaccessible, remote sensing techniques are employed.

Microseismic Monitoring

Microseismic monitoring detects the acoustic energy released by rock failure during fracturing. It acts effectively as a "stethoscope" for the reservoir.

- **Shear vs. Tensile:** Most microseismic events are generated by shear slippage on natural fractures (shear events), not the opening of the hydraulic fracture itself (tensile events). Therefore, the "cloud" of dots represents the reactivated natural fracture network (the SRV), not necessarily the propped hydraulic fracture (Cipolla et al., 2010).

- **Geological Correlation:** Interpretation involves overlaying the microseismic cloud on the DFN and stress map. A long, linear cloud usually indicates a high-stress anisotropy regime where the fracture ignored natural complexity. A diffuse, globular cloud is an indicator of a successful activation of a complicated network (Mayerhofer et al., 2010).

Chemical and Radioactive Tracers

Connectivity is directly evidenced by tracers. Operators can check on offset wells by injecting unique isotopes or chemicals during certain phases which will indicate a breakthrough.

- **Frac Hits:** When a tracer used in Well A is found in Well B within hours it confirms that it is directly connected by highly conductive fractures.

- **Flowback Analysis:** The cleanup efficiency can also be measured by tracers. When the tracers of the toe of the well are never recovered, it indicates that the toe stages are not in production, which may be as a result of heterogeneity induced stress shadowing (Warpinski, Branagan, Peterson, Wolhart, and Uhl, 1998).

Fiber-Optic Sensing (DAS/DTS)

The new frontier validation is fiber optics. The Distributed Acoustic Sensing (DAS) transforms the fiber cable into microphones.

- **Waterfall Plots:** The DAS data is presented in the form of a waterfall plot (acoustic intensity versus depth versus time). This enables the engineers to have a clear view of the clusters of perforations that are actually absorbing fluid as well as those being excluded because of stress or hardening of rock.

- **Strain Measurement:** New low-frequency DAS (LF-DAS) has the ability to measure the real-time actual strain on the casing, which is used as a proxy of fracture width aperture opening (Denney, 2012).

Discussion and Future Outlook

Synthesis of Findings

The review confirms that the homogeneous assumption is a past phenomenon that is a relic. The fracture geometry is the major influence of rock heterogeneity. The contact with natural fractures forms the required surface area of production, whereas mechanical stratigraphy determines the vertical container of that production. It is the successful operator who plans to accommodate the heterogeneity, not to disregard it. This includes recognition of the location of these sweet spots of high natural fracture intensity with the DFNs and location of the landing zones with the stress profiles with maximum height containment.

Unresolved Challenges

1. **Proppant Transport in Complex Networks:** Although we can model the fluid orifice opening a complicated network, we find it difficult to assume whether proppant might be able to bend the corners. Intersection of the fracture bridging is a major cause of ineffective production.

2. **Upscaling:** The extrapolation of the laws between core samples (centimeters) and reservoir grids (kilometers) is associated with uncertainty. DFN using a log data is useful in estimating millimeters of log data to the acres of reservoir.

3. **Real-Time Control:** The ultimate goal is "smart" fracturing using live DAS/microseismic data to adjust pump schedules on the fly. While the hardware exists, the processing algorithms are not yet fast enough for true closed-loop automation (Mohaghegh, 2017).

Future Directions

Future research lies in the domain of **Physics-Informed Machine Learning**. By training neural networks on massive datasets of physics-based simulations (XFEM/DEM), we may create surrogate models that can predict complex fracture propagation in seconds rather than days. Also, the use of these geomechanical principles is moving out of hydrocarbons into Enhanced Geothermal Systems (EGS), where a fracturing of hot heterogeneous granite is necessitating the same stress and natural fracture interaction mastery (figure 5).

Figure 5: Crack propagation in granite, a common material in EGS, demonstrating the complexity PIML aims to mode (Richter, 2018).

Conclusion

Geomechanical optimization of hydraulic fracturing in non-conventional reservoirs is essentially a geomechanical problem. This review has shown that rock heterogeneity in the form of natural fracture networks and mechanical layering has a preponderant dominance on fracture propagation. The development of complex network simulations based on DFNs and other sophisticated numerical tools (XFEM, DEM) as a replacement of the simple bi-wing models is a needed change of perspective of the industry.

Technologies based on field validation such as microseismic monitoring and fiber-optic sensing have bridged the loop, and they give the empirical evidence to tune these complicated models. In the future, the next generation of reservoir stimulation will be characterized by the combination of the high-fidelity geological characterization and the fully coupled hydro-mechanical simulations. This data-driven, geologically-grounded approach is the only viable path to enhancing recovery factors and ensuring the economic sustainability of fractured reservoirs.

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