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A Comprehensive Framework for Geomechanical Characterization in Optimizing Hydraulic Fracturing of Low-Permeability Reservoirs

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Abstract
The rapid growth in the economic importance of unconventional resources, such as shale gas and oil, has dramatically changed the global energy market. However, the profitable extraction of these resources is largely dependent on successful hydraulic fracturing. Hydraulic fracturing is a complex process governed by the delicate interaction of natural and artificial fractures, the in-situ stress state, and the geomechanical properties of rock types. There are significant knowledge gaps in the comprehensive understanding of this complex interaction, which often results in suboptimal fracturing efficiency and lower than expected production rates. This review article aims to fill this gap through a critical assessment and a unified conceptual framework that combines the three fundamental pillars of geomechanical characterization for the optimization of hydraulic fracturing: natural fracture characterization, in situ stress state delineation, and microseismic monitoring of fracture extent. Recent studies, tech specs, alongside field know-how combine to paint a complete picture of current results across each key area. Crucially, combining various testing approaches builds trustworthy rock behavior predictions; understanding differing stresses optimizes fracture designs; moreover, monitoring tiny earthquakes refines those predictive models. This overview provides scientists and engineers a useful guide toward better, more reliable, impactful fracking - even in tough, tight formations.
Keywords: *Low-Permeability Formations; Hydraulic Fracturing; Geomechanics; Natural Fractures; In-Situ Stress; Microseismic Monitoring; Unconventional Reservoirs; Integrated Workflow*

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I. Introduction

The 21st century dramatically altered global energy - not through discovering more oil or gas, yet via tech unlocking resources once trapped within stubborn rock formations. This shift, particularly noticeable in North America, represents a substantial economic and political upheaval: the shale gas boom. Once immense rock areas now blossom as major energy producers, shifting how the world gets its power (Krupnick & Echarte, 2017). This shift centers on fracking a sophisticated technique unlocking substantial oil and gas trapped within shale, dense sandstone, alongside coal beds.

Figure 1. A typical pump-and-lift rig for the extraction of unconventional onshore resources, symbolizing the impact of the shale gas revolution on the energy industry.

These formations are characterized by a rock matrix with extremely low intrinsic permeability (typically below 0.1 millidarcies), meaning that hydrocarbons cannot flow through the rock at economic rates without intervention. Hydraulic fracturing overcomes this limitation by creating a network of highly conductive pathways. The fundamental process involves injecting a specially engineered fluid into a wellbore at pressures high enough to overcome the rock's strength and the in-situ stress, thereby creating tensile fractures (See Figure 2). These fractures are then propped open by a granular material, like sand, which is transported by the fluid, creating a permanent, high-conductivity channel for hydrocarbons to flow from the reservoir to the wellbore.

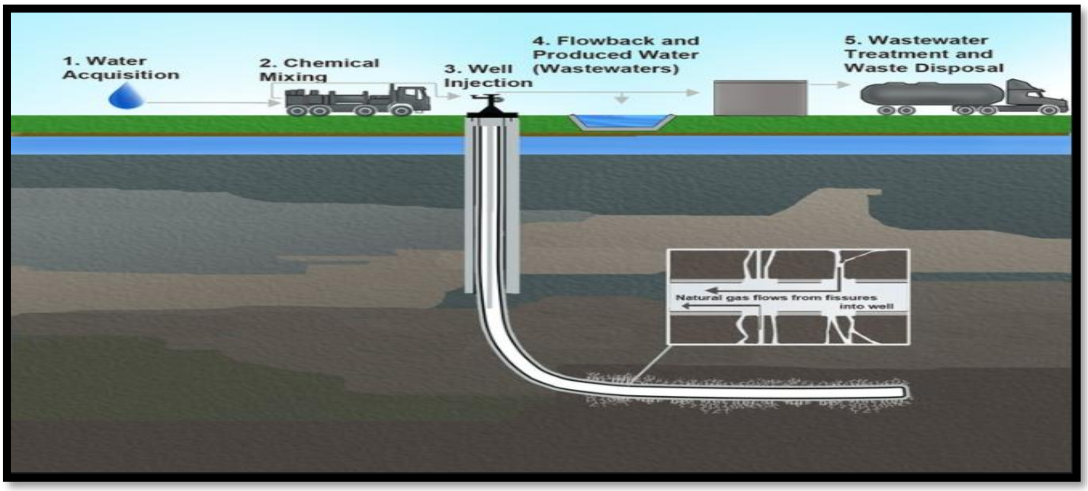

Figure 2. An illustration of the hydraulic fracturing process, showcasing the injection of fluid into a wellbore to create fractures and enable hydrocarbon flow from fissures into the well.

However, the success of a hydraulic fracturing treatment is far from guaranteed. It is a process governed by a complex and often delicate interplay of geological variables. This depends solely on the geomechanical properties of the bedrock, the strength and direction of the existing in situ stress state, and, more importantly, the existence and nature of the natural fracture system running through the rock mass. One of the main goals is to create a large and efficient stimulated reservoir volume (SRV), i.e. the total volume of rock that is connected to the wellbore through new fracture systems (Mayerhofer et al., 2010). In reservoirs with natural fractures, the interaction between hydraulic fracturing and natural fractures can create a very complex, interconnected system, significantly increasing the SRV (Ren et al., 2024). However, this interaction can also lead to undesirable results, such as inefficient, disconnected fracture systems and excessive fluid leakage to non-productive areas. There are still significant knowledge gaps in the detailed understanding of these geomechanical issues, often leading to stimulation designs based on simplifying assumptions and thus suboptimal fracturing capacity and production rate.

To move from a trial-and-error approach to a predictive and optimized engineering discipline, a holistic framework is required. This review paper provides such a framework by conducting a critical analysis of the three foundational pillars of geomechanical characterization for hydraulic fracturing optimization: (1) the characterization of natural fractures, (2) the determination of the in-situ stress regime, and (3) the monitoring of fracture propagation using microseismic techniques. By synthesizing the state-of-the-art in these domains, this paper proposes an integrated workflow to guide more effective and efficient development of unconventional resources.

The Characterization of Natural Fractures

Natural fractures represent a profound geological duality in low-permeability reservoirs. Existing cracks within rock formations sometimes help oil or gas flow - acting like natural routes improved by fracking to boost production. However, those same fissures could also create trouble; they might hinder new fractures from spreading effectively or serve as channels stealing valuable fluids away from where they're needed. A thorough characterization of the natural fracture network is a prerequisite for any successful stimulation design, approached as a multi-scale problem from centimeters to kilometers.

Multi-Scale Methods of Investigation

Direct Observation (Centimeter to Meter Scale): The most detailed information about natural fractures comes from the direct analysis of rock cores (See Figure 3). Core analysis allows geologists to physically measure fracture properties like orientation, aperture (width), spacing, and mineralization, which indicate its potential to conduct fluid (Mazdarani, Kadkhodaie, Wood, & Soluki, 2023). This is augmented by Computed Tomography (CT) scanning of core samples, which provides a non-destructive, three-dimensional visualization of the internal fracture network. The primary limitation of these direct methods is their small sample volume, which carries a significant risk of sampling bias.

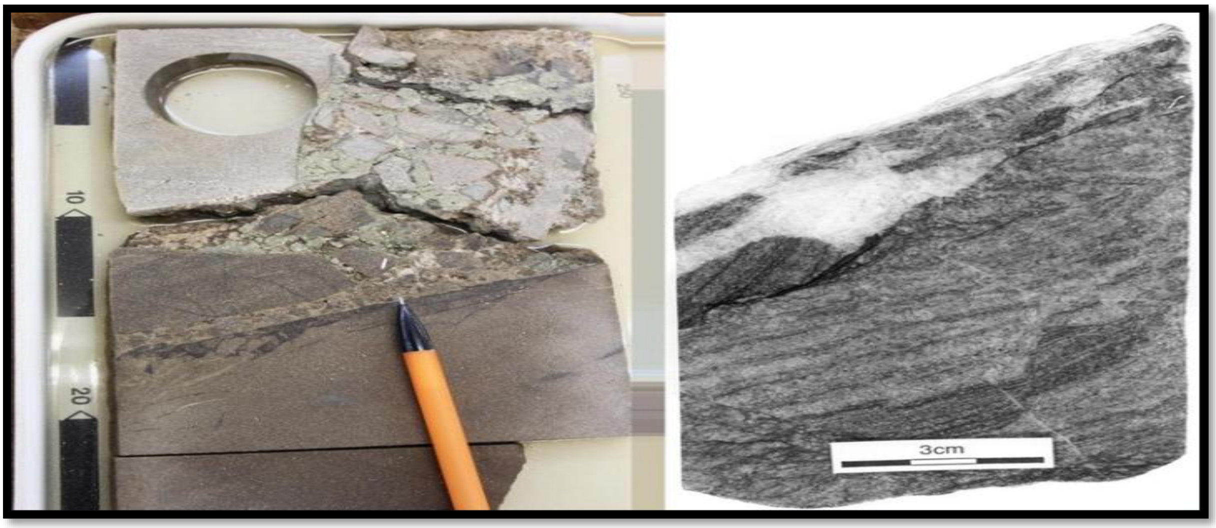

Figure 3. Rock cores illustrating the complexity of characterizing natural versus induced fractures, a critical aspect for optimizing hydraulic fracturing.

Borehole-Scale Characterization (Meter Scale): To bridge the gap between core data and the reservoir, advanced wireline logging tools are used. The Full-bore Formation Micro-Imager (FMI) is particularly powerful, generating a high-resolution electrical image of the entire wellbore wall circumference. On these images, fractures appear as distinct sinusoidal traces, from which their precise orientation and aperture can be calculated (See Figure 4). FMI logs can classify different fracture types and provide continuous data along the wellbore, offering a much larger statistical sample than core analysis (Mazdarani, Kadkhodaie, Wood, & Soluki, 2023).

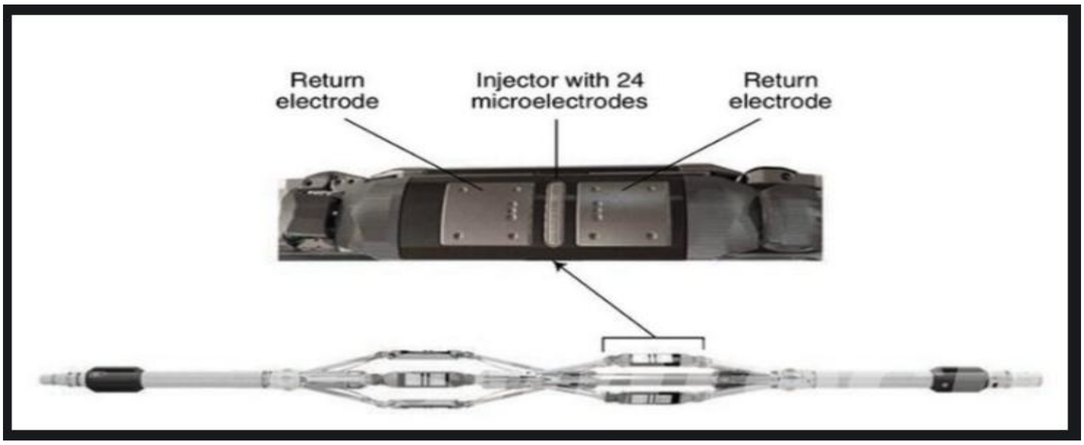

Figure 4. A borehole imaging tool, such as the Full-bore Formation Micro-Imager (FMI), provides continuous, high-resolution data on fractures and other geological features along the wellbore.

Reservoir-Scale Characterization (Kilometer Scale): To understand the fracture network over a much larger area, 3D seismic surveys are employed. While seismic data cannot resolve individual fractures, it can identify larger-scale features indicative of intense fracturing. Seismic attributes such as coherence, curvature, and azimuthal anisotropy are used to map potential fracture corridors or "swarms." For example, azimuthal anisotropy, which analyzes variations in seismic wave velocity with direction, can be effective at identifying the preferential orientation of fracture systems. These techniques don’t quite cut it when you need precision; they give a general overview, yet miss the nuances of how fractures actually behave.

Integration Through Discrete Fracture Network (DFN) Modeling

To make sense of information gathered at different levels, we need one unified picture; that's where Discrete Fracture Network (DFN) modeling comes in. Essentially, DFN modeling builds a randomized, three-dimensional computer simulation of fractures within a reservoir (Golder Associates, 2018), allowing us to visualize its complex structure. Fracture patterns gleaned from rock samples alongside borehole measurements fill a detailed 3D map with individual breaks. Consequently, we can examine how these fractures link, model fluid movement through them, or foresee responses during enhanced recovery techniques. Despite this capability, such maps possess inherent ambiguity; therefore, reliability hinges upon robust, comprehensive initial information.

Table 1. Comparison of Natural Fracture Characterization Methods

Method	Scale	Advantages	Limitations
Core Analysis	Centimeter to meter	Direct observation of physical fracture properties.	Very small sample volume, high potential for sampling bias.
CT Scanning	Centimeter	Detailed 3D visualization of fracture network within the core.	Limited to small core samples.
Wireline Logs (FMI)	Meter	High-resolution, continuous imaging of the borehole wall; robust statistical data on orientation and density.	Limited to the immediate vicinity of the wellbore.
Seismic Methods	Kilometer	Large-scale characterization of fracture corridors and trends over the entire reservoir.	Low resolution, unable to identify individual fractures.
DFN Modeling	Reservoir	Integration of multi-scale data; simulation of fracture properties and connectivity.	Requires significant data input; model uncertainty can be high.

The Determination of the In-Situ Stress Regime

The in-situ stress state is the unseen, yet dominant, force field within the Earth's crust that governs the behavior of hydraulic fractures. It dictates the direction in which fractures will propagate, the pressure required to create them, and whether they will remain open after treatment. A thorough understanding of the in-situ stress regime is therefore one of the most critical elements in optimizing hydraulic fracturing.

Fundamental Stress Concepts and Anderson's Classification

The in-situ stress state is described by three mutually perpendicular principal stresses: the vertical stress (Sv), the maximum horizontal stress (SHmax), and the minimum horizontal stress (SHmin). The vertical stress is typically assumed to be equal to the weight of the overlying rock column and can be calculated from density log data. The relative magnitudes of these three stresses define the faulting regime, as first classified by Anderson (1951).

- **Normal Faulting Regime (Sv > SHmax > Shmin):** Occurs in extensional tectonic settings where the crust is being stretched apart.
- **Strike-Slip Faulting Regime (SHmax > Sv > Shmin):** Occurs in settings where tectonic plates slide past one another.
- **Thrust (or Reverse) Faulting Regime (SHmax > Shmin > Sv):** Occurs in compressional tectonic settings where the crust is being squeezed.

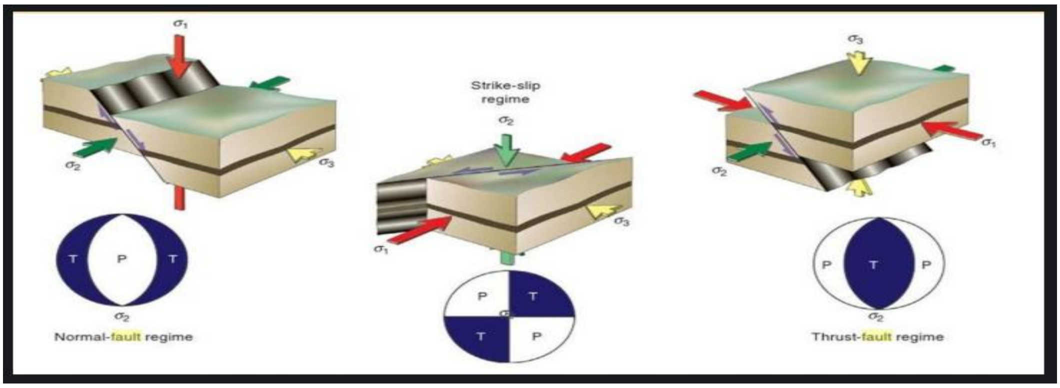

Figure 5. Anderson's Fault Classification, illustrating the principal stress orientations (σ1, σ2, σ3) for normal, strike-slip, and reverse fault regimes.

The faulting regime has a profound impact on hydraulic fracturing. As established by Hubbert and Willis (1957), hydraulic fractures always open against the path of least resistance, which is the direction of the minimum principal stress. Therefore:

- In a **normal faulting regime**, the minimum stress is horizontal (Shmin), so hydraulic fractures will be **vertical**.
- In **strike-slip or thrust faulting regimes**, the minimum stress is the vertical stress (Sv), so hydraulic fractures will be **horizontal**.

The vast majority of unconventional reservoirs are in normal or strike-slip faulting regimes, leading to the creation of vertical hydraulic fractures. In this common scenario, the fractures will propagate in a plane perpendicular to the minimum horizontal stress (Shmin), meaning their azimuth is aligned with the maximum horizontal stress (SHmax).

Building a 1D Mechanical Earth Model (MEM)

The foundational tool for characterizing the in-situ stress state is the 1D Mechanical Earth Model (MEM). A 1D MEM is a continuous, depth-based numerical representation of the in-situ stresses and rock mechanical properties along a wellbore path (Schlumberger, n.d.). It is constructed by integrating a wide array of data, including:

- **Density logs** to calculate the vertical stress (Sv).
- **Sonic logs** to determine rock mechanical properties.
- **Pore pressure data** from formation tests.
- **Direct stress measurements** from Leak-Off Tests (LOTs) or Diagnostic Fracture Injection Tests (DFITs) for calibration (Fei et al., 2024).
- **Caliper and image logs** to identify borehole breakouts and drilling-induced tensile fractures, which are direct indicators of the horizontal stress orientation.

The resulting 1D MEM delivers a close look; crucial for figuring out how to fracture rock effectively (See Figure 6).

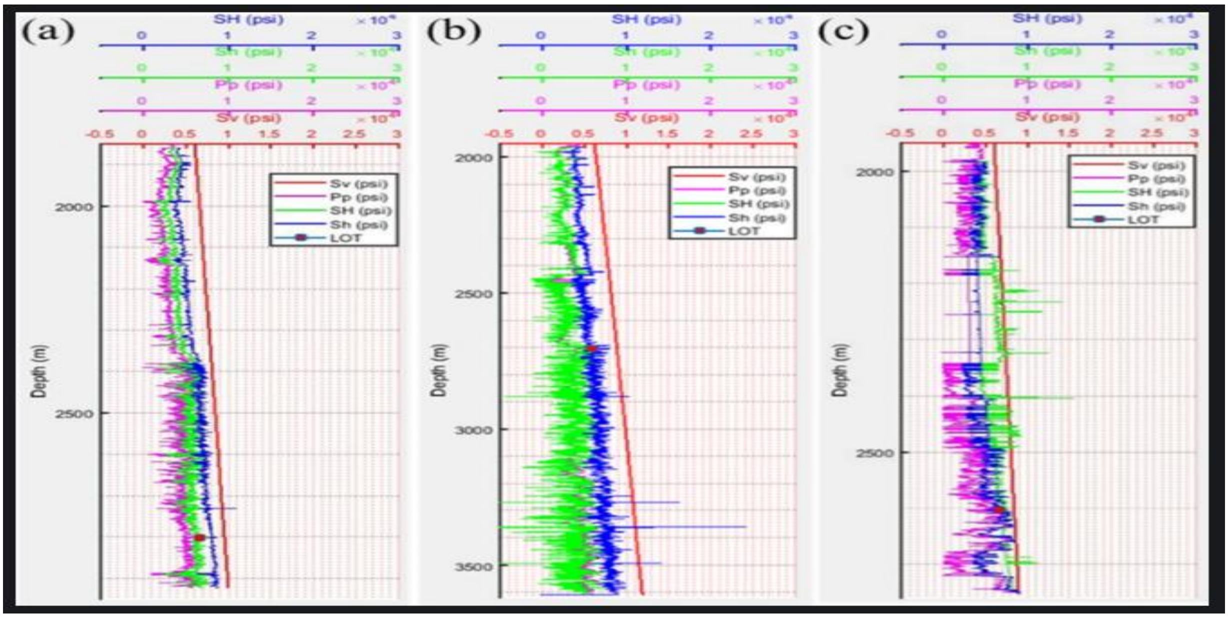

Figure 6. A one-dimensional geomechanical model (1D MEM) showing how stresses - vertical, maximum horizontal, minimum horizontal - change with depth within a rock layer, alongside other characteristics.

Direct and Indirect Measurement Techniques

The 1D MEM relies on calibration from both direct and indirect stress measurement techniques.

- **Direct Measurement:** To figure out how much pressure rock layers have on a well, people use methods such as the Leak-Off Test alongside the Diagnostic Fracture Injection Test. Both directly show the lowest horizontal stress. They work by sealing off part of the borehole then slowly pumping in fluid to start a tiny crack. The pressure at which the fracture closes after injection is stopped provides a robust estimate of Shmin (Fei et al., 2024).
- **Indirect Measurement:** The orientation of the horizontal stresses can be inferred from stress-induced wellbore failures. When a well is drilled, it creates a stress concentration around the borehole. In an anisotropic

horizontal stress field, this can lead to compressive failure on the sides of the wellbore aligned with Shmin, creating features called **borehole breakouts**. It can also cause tensile failure on the sides aligned with SHmax, creating **drilling-induced tensile fractures**. These features are readily identifiable on caliper and image logs, providing a reliable and continuous indicator of the SHmax orientation (Eberhardt, 2017; see Figure 7).

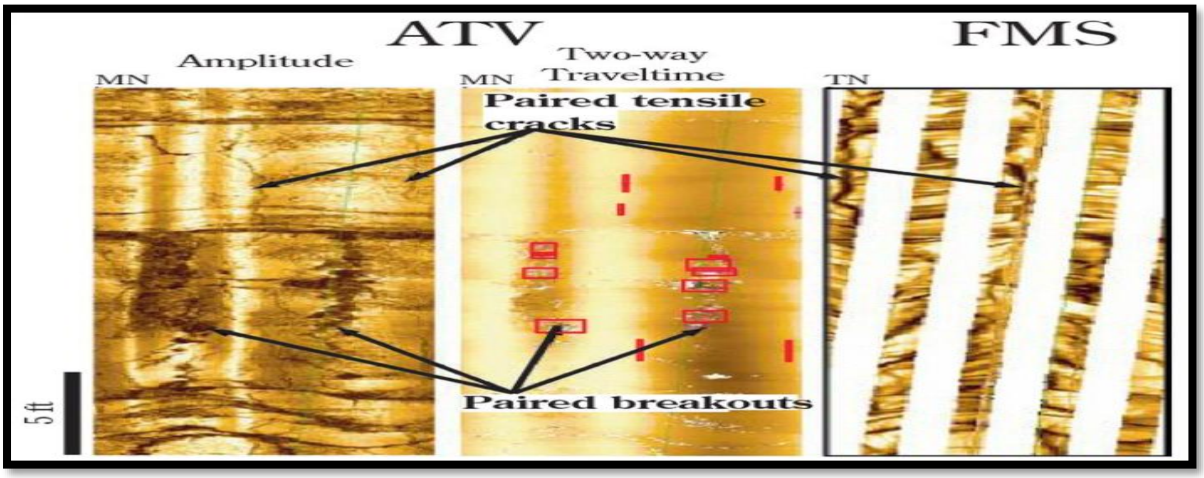

Figure 7. Borehole wall images from acoustic (ATV) and resistivity (FMS) tools showing paired tensile cracks aligned with the maximum horizontal stress and paired breakouts aligned with the minimum horizontal stress.

Table 2. Comparison of In-Situ Stress Measurement Techniques

Technique	Measurement	Advantages	Limitations
Leak-Off Test (LOT)	Shmin (magnitude)	Relatively simple direct measurement.	Can be affected by wellbore conditions and near-wellbore stress alterations.
DFIT	Shmin (magnitude)	Provides robust direct measurement and information on fracture closure pressure.	Can be time-consuming and expensive to perform.
Borehole Breakouts	SHmax (orientation)	Can be identified from standard logs; provides continuous data.	Only provides orientation information, not magnitude.
Tensile Fractures	SHmax (orientation)	Clear indicator on image logs.	Only provides orientation information; less common than breakouts.

Challenges and Uncertainties

The most significant challenge in stress determination is **stress heterogeneity**. The in-situ stress state is rarely uniform and can vary significantly, both vertically between different rock layers and laterally across a field. A 1D MEM only represents the stress state at the wellbore, and extrapolating this information away from the well can be highly uncertain. Future research is focused on developing robust 3D geomechanical models that can capture this spatial heterogeneity.

Microseismic Monitoring of Fracture Propagation

Once a hydraulic fracturing treatment begins, the geomechanical model is put to the test. Microseismic monitoring is the primary tool for "seeing" into the reservoir in real-time and observing the dynamic process of fracture propagation (Eaton, 2017). It acts as a crucial feedback mechanism, allowing for the validation of pre-treatment models and understanding the actual effectiveness of the stimulation.

Principles: Listening to the Rock Break

Hydraulic fracturing generates a series of small seismic events, or microearthquakes, caused by the shearing or opening of the rock fabric. Microseismic monitoring involves deploying an array of sensitive receivers (geophones) to "listen" for these events. The arrival times of the seismic waves at different geophones are used to triangulate and pinpoint the event's location (x, y, and z coordinates). By locating thousands of these events, a map of the affected reservoir region can be created (See Figure 8).

Data can be acquired using several types of arrays:

- **Downhole Arrays:** Geophones are placed in a nearby monitoring well, providing the highest signal-to-noise ratio and the most accurate event locations but with limited spatial coverage.
- **Surface Arrays:** A large grid of geophones is deployed on the surface, offering wide coverage but suffering from lower signal-to-noise ratio and less accurate locations.
- **Buried Arrays:** Geophones are buried in shallow boreholes, offering a compromise with better signal quality than surface arrays and wider coverage than downhole arrays.

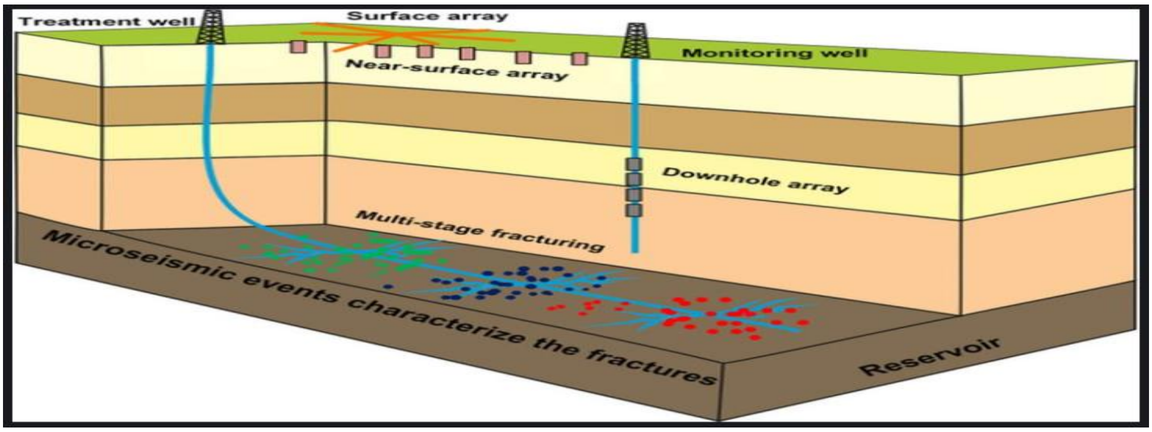

Figure 8. Schematic of a multi-stage hydraulic fracturing operation in a horizontal well with surface, near-surface, and downhole arrays for monitoring the resulting microseismic events.

Key Insights from Microseismic Data

The map of microseismic event locations provides several critical insights:

- **Fracture Geometry and SRV Estimation:** The spatial distribution of the microseismic events forms a "cloud" that directly visualizes the fracture network's geometry. The dimensions of this cloud provide a direct estimate of the fracture length, height, and azimuth, allowing for the calculation of the Stimulated Reservoir Volume (SRV) (Cipolla & Wallace, 2014; Ren et al., 2024).

- **Source Mechanism Analysis:** Advanced analysis of the seismic waveforms can reveal the source mechanism of each event, distinguishing between tensile failure and shear failure. A dominance of shear events, for example, suggests that the stimulation is primarily reactivating the pre-existing natural fracture network (Eaton, 2017).

Table 3. Comparison of Microseismic Monitoring Systems

System	Advantages	Limitations
Downhole Array	High signal-to-noise ratio; most accurate event locations.	Limited spatial coverage; can be expensive to deploy a dedicated monitor well.
Surface Array	Wide coverage; can monitor multiple wells simultaneously; lower operational cost.	Lower signal-to-noise ratio; less accurate event locations, especially for depth.
Buried Array	Improved signal-to-noise ratio compared to surface arrays; wider coverage than downhole arrays.	More expensive and logistically complex to deploy than surface arrays.

Limitations and Advanced Techniques

A significant portion of rock deformation during fracturing can be **aseismic**, meaning it occurs slowly without generating detectable seismic events. Therefore, the microseismic cloud may not represent the full extent of the hydraulically created fracture network. To overcome these limitations, advanced techniques are emerging. **Distributed Acoustic Sensing (DAS)** is a game-changing technology that uses a fiber-optic cable installed in the wellbore as a dense array of thousands of seismic sensors. Distributed Acoustic Sensing delivers detailed information about how cracks begin and spread near boreholes - a valuable addition to typical seismic tracking methods (Jayaram et al., 2019).

Synthesis: The Integrated Geomechanical Workflow

Understanding rock mechanics means combining detailed study, careful modeling, alongside ongoing adjustments. To get the most from fracking, link what we know about the reservoir to how we plan treatments, watch things happen during treatment, then analyze results – continually refining our approach.

A Five-Step Geomechanical Workflow

To get the most from hydraulic fracturing, a standard process usually involves these five stages (See Figure 9):

1. **Data Acquisition and Integration:** We collect every bit of earth science information such like seismic surveys, borehole records, rock samples - then combine it all to get a complete picture.
2. **Geomechanical Model Building:** We construct a detailed picture of rock behavior within the reservoir by combining available information. For each well, we develop a simple profile representing mechanical earth layers. Moreover, we simulate the complex network of existing cracks in the rock. Consequently, this yields a three-dimensional map illustrating how stiffness varies across the entire area.
3. **Hydraulic Fracture Modeling:** A rock mechanics model feeds directly into a fracking program. That program helps craft the best well stimulation plan by testing different options – like how much liquid to use, its flow speed, or what amount of solid material to include.
4. **Microseismic Monitoring and Calibration:** During the fracturing treatment, microseismic data is acquired in real-time. The observed fracture geometry is compared against the predictions from the hydraulic fracture model. Discrepancies are used to calibrate and update the geomechanical model.
5. **Production Analysis and Optimization:** After the well is brought online, production data is analyzed to evaluate the effectiveness of the stimulation. This analysis, combined with the calibrated geomechanical model, is used to identify opportunities for further optimization on subsequent wells. The workflow then repeats, with each new well benefiting from the lessons learned.

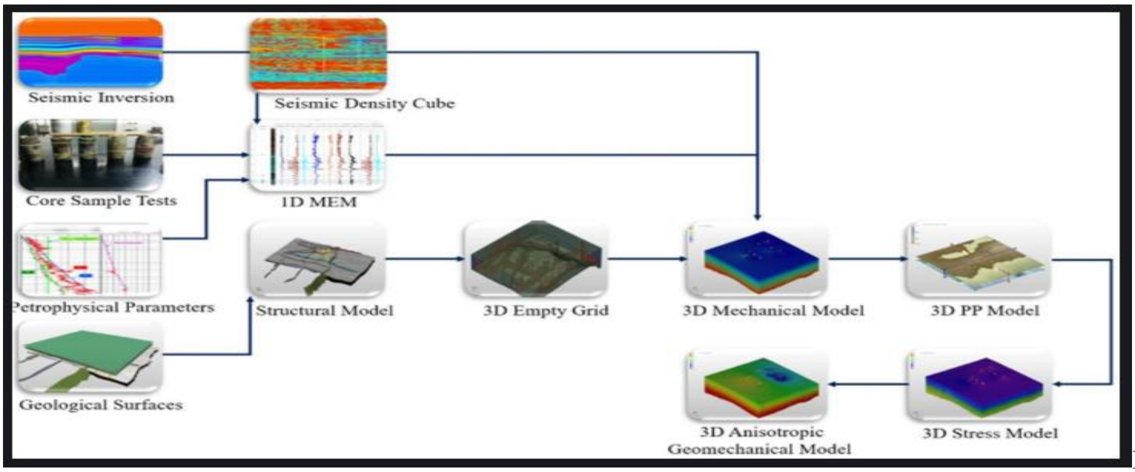

Figure 9. An example of a 3D geomechanical modeling workflow, highlighting the integration of various input data sources—from seismic inversion and core tests to a 1D MEM—to build a comprehensive 3D stress model.

Future Outlook: The Next Frontier in Reservoir Stimulation

The field of geomechanical characterization is constantly evolving. The future of reservoir stimulation will be shaped by several key trends that promise to further enhance our ability to optimize hydraulic fracturing.

- **Machine Learning and Big Data:** The hydraulic fracturing process generates vast amounts of data. Machine learning algorithms are increasingly being used to analyze these large datasets to identify complex, non-linear patterns that are not apparent through traditional analysis (Ma & Ye, 2025). These models can be used to build predictive tools for optimizing completion designs and forecasting production with greater accuracy (Li et al., 2024).
- **Coupled Modeling Advances:** Fracturing rocks is surprisingly complicated physically. Newer computer programs use detailed, connected simulations - incorporating water, mechanics, chemistry, heat - to better mimic how fluids move, rock changes shape, then chemicals react within it (Wang et al., 2017).
- **Fiber-Optic Sensing Technologies:** Downhole acoustic sensing alongside distributed temperature sensing is really changing how we watch what happens inside wells. They give detailed, ongoing readings of stress

likewise temperature throughout the whole well - a remarkably clear view of hydraulic fracturing as it unfolds (Jayaram et al., 2019).

- **Proppant Placement Challenges:** Getting proppant where it needs to go within tricky fractures is still hard. Scientists are now working on new kinds of proppant alongside better ways to predict how it moves, aiming for longer-lasting, productive wells (Guo et al., 2024)

II. Conclusions

Figuring out how to get more from shale oil wells is tricky, requiring knowledge of rock behavior. What mattered most became clear: fissures in the stone, immense underground force. We noted those, alongside even small quake shudders - bringing everything together into a single understanding.

The report suggests a single plan isn't just helpful - it's essential for overcoming habitual problems. Our findings demonstrate:

- To figure out what a rock will do, we need to study it - how it acts, also how that changes when it's bigger or smaller.
- How naturally occurring rock exists dictates how it reacts to pressure deep below ground, significantly influencing cracking patterns during well stimulation. Consequently, this merits careful consideration when designing these procedures.
- Building dams isn't merely observing shifts beneath the ground; it refines techniques for forecasting breaks in rock formations.
- To boost the reservoir's performance, we'll need updated equipment - perhaps machine learning, alongside fiber optic cables. Now, these advancements function together as one integrated setup.

Energy companies could team up to better extract materials, subsequently devising improved methods for boosting output while thoughtfully managing current resources for long-term viability.

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