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A Discrete Fracture Network Approach for Evaluation of Hydraulic Fracture Stimulation of Naturally Fractured Reservoirs

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ABSTRACT: This paper describes the development of a 3-dimensional Discrete Fracture Network (DFN) approach for simulation and evaluation of hydraulic fracturing in low permeability fractured rock in the FracMan® reservoir analysis tool. The approach is based on an empirical algorithm approximating the effect of natural fractures and in situ stress on hydraulic fracture propagation. The algorithm distributes frac-fluid between the propagating hydraulic fracture and pre-existing natural fractures to predict both the geometry of the hydraulic fracture, and the reactivation of the natural fracture network. The technique is demonstrated by comparison against ELFEN® geomechanical simulations, and by comparison of simulated and observed microseismic responses.

1. INTRODUCTION

Hydraulic fracturing is increasingly critical for development of natural gas resources in tight sands and gas shales [1-8]. Hydraulic fracturing can be significantly influenced by the geometry and properties of pre-existing natural fractures. While the geometry of hydraulic fractures is driven primarily by the in situ stress field, rock mass anisotropy, and natural fractures in particular, can determine the details of hydrofrac location, size, and orientation. Hydraulic fracture size can be limited by leak-off to natural fractures, but can also be increased where the hydrofrac can extend by propagation of new and reactivation of natural fractures, rather than expending energy on intact rock breakage.

This paper describes the development and verification of a discrete fracture network (DFN) approach for modeling the interaction between natural fractures and hydraulic fractures during the hydrofracturing process, see (Figure 1).

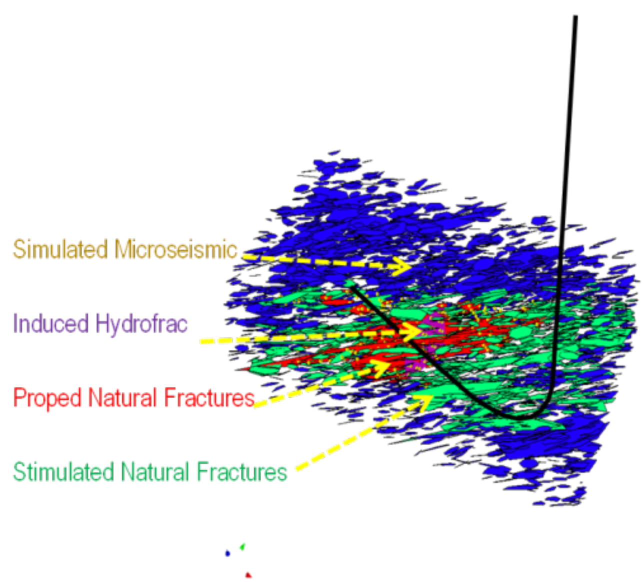


Figure 1. Simulation of hydraulic fracturing, reactivation of natural fractures, and microseismic response in a DFN model.

2. ASSUMED HYDRAULIC FRACTURE MECHANICS

The propagation of hydraulic fractures is assumed to be controlled by:

- The reservoir in situ effective stress, defined by the total stress tensor and reservoir pressure.
- The rock matrix strength, deformability, heterogeneity and anisotropy.

- The geometry, mechanical, and flow properties of the natural fracture system.
- The configuration and operation of the hydraulic injection process itself.

2.1 In Situ Effective Stress

Since hydraulic fracture propagation generally occurs in tension, the minimum principal stress determines both the direction and extent of the hydraulic fracture. In many tectonic settings, the vertical stress is the major principal stress, with the maximum and minimum horizontal stresses on the order of 60% or more of the lithostatic stress. The lithostatic (vertical) stress (σ_v) is often estimated by integration of the density log from the well bottom-hole location to the surface, using

$$\sigma_v = \rho g h \qquad (1)$$

In a theoretical K_0 condition, the maximum and minimum horizontal stresses (σ_H and σ_h) are equal, and can be estimated as a function of the vertical stress and Poisson's ratio (ν) for each material layer, such that

$$\sigma_h = \sigma_h = \sigma_v \left(\frac{\nu}{1-\nu}\right) \qquad (2$$

However for most reservoirs, The direction and magnitude of the horizontal stresses depend on the tectonic conditions. While some reservoirs employ mini-fracturing tests, more commonly in situ stress may be estimated from wellbore breakouts or hydraulic fractures induced by mud weight and visible in fracture image logs (Zoback, 2007). The in situ stress state beyond well control can be estimated by geostatistical methods such as sequential simulation or Kriging, or by paelostress geomechanical modeling, see e.g., Henk (2008).

Hydraulic fracturing is achieved by rapidly pumping in fluid (generally, water) such that the fluid pressure (P) increases, which ultimately reduces the effective normal stress (σ') existing on each fracture, this is defined

$$\sigma' = \sigma - P \qquad (3)$$

The fluid pressure of the hydraulic fracture is not equal to the pump pressure recording in fracturing reports, due to pressure losses at the wellbore, a skin effect. The fracturing pressure (P') is estimated as the pump-pressure, at the depth where the packers are set (P), minus the head loss due to skin (P_S),

$$P' = P - P_s \qquad (4)$$

Hydraulic fractures propagate where the effective normal stress on the plane of hydrofracturing is less than the tensile strength of the rock in that direction, referred to as the "rock toughness" (Zobak, 2007). For sedimentary rocks such as shale, this toughness can be highly anisotropic, such that the direction of hydraulic fracture propagation can deviate from the normal to the direction of minimum stress (i.e, the direction of maximum horizontal stress), see (Warpinski, 1982).

This same fracture fluid pressure propagates into the connected natural fracture system. Where the resulting effective minimum stress is less than the fracture toughness, natural fractures can open and extend in tension. Where the resulting effective stress state exceeds the shear strength, the natural fractures are reactivated, and can move and potentially propagate in shear. This shear causes microseismic events, which can in many cases be observed as extended microseismic clouds, off the plane of the hydraulic fracture.

2.2 Estimation of Hydraulic Pressure in Natural Fractures

The fluid pressure in the natural fractures due to hydrofracturing is difficult to calculate. One approach is to consider upper and lower bound estimates.

1. Upper Bound: For the short time period during which the hydraulic fracture occurs, the hydraulic fracture and the network of connected natural fractures can be considered as a closed hydraulic compartment. In this case, the pressure in the connected natural fracture system can be set equal to the frac-pressure. This requires estimation of the geometry of this hydraulic compartment, based on either the geometric or hydraulic distance from the hydraulic fracture location through the fracture network.
2. Lower Bound: The pressure may be estimated using an analytical solution for the reduction of pressure with the hydraulic distance (r). This decrease in pressure with hydraulic distance is a function of hydraulic diffusivity (the ratio of permeability-thickness to compressibility), and the geometry of flow, which may range from linear (1-D) to radial (2-D) and spherical (3-D) depending on the pre-existing natural fracture network (Doe, 1991). The generalized flow equation is defined by:

$$\bar{h}(r,s) = f_1(s) r^{\nu} K_\nu\left(r\sqrt{\eta s}\right) + f_2(s) r^{\nu} I_\nu\left(r\sqrt{\eta s}\right) \qquad (5)$$

where the individual functions are determined from the specified boundary conditions together with the modified Bessel functions.

The effective pressure in connected natural fractures at a hydraulic distance (r) can be expected to be constrained between these two limits. For the current study, the effective fluid pressure in the connected natural fracture network $P_f(r)$ at a distance r (measured through the connected fracture network) is approximated based on a linear flow assumption as,

$$P_f(r) = P'_{pump}\left(1 - S_0 \frac{r}{r_{max}}\right) \quad (6)$$

Where S_0 is an empirical parameter between 0 and 1, and r_{max} is the maximum distance considered as part of the hydraulic compartment. As the variable S_0 is reduced from 1 to 0, the approximation of the fluid pressure moves from the upper to the lower bound estimate, see (Figure 2).

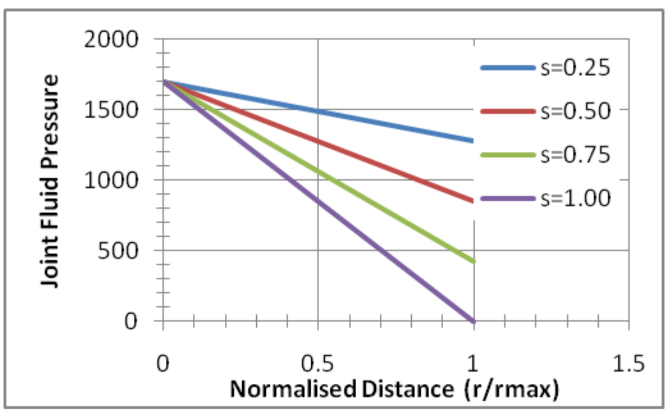


Figure 2. Fluid pressure assumed in connected natural fractures, as a function of distance from the injection location.

2.3 Hydraulic Fracture Propagation

Hydraulic fracture propagation within the context of a homogenous continuum occurs in simple tension, parallel to the direction of maximum horizontal stress. However, in naturally fractured rock masses, the propagation process can be significantly more complex, both due to the interaction of natural fractures with the propagating fracture, and due to local stress redistribution from kinematic interaction of rock blocks defined by faults and fractures.

In the current approach, hydraulic fractures are approximated primarily as simple tension features or as wing tension fractures from existing natural fractures. For simple tensile fractures, this occurs where the minor principal stress exceeds the tensile strength of the material. For wing tension fractures these occur where existing fractures, not necessarily aligned to the minor principal stress, extend with the creation of "wing" cracks that are aligned to the major stress direction. A simplified representation of these two types of fracture processes is given in Figure 3.

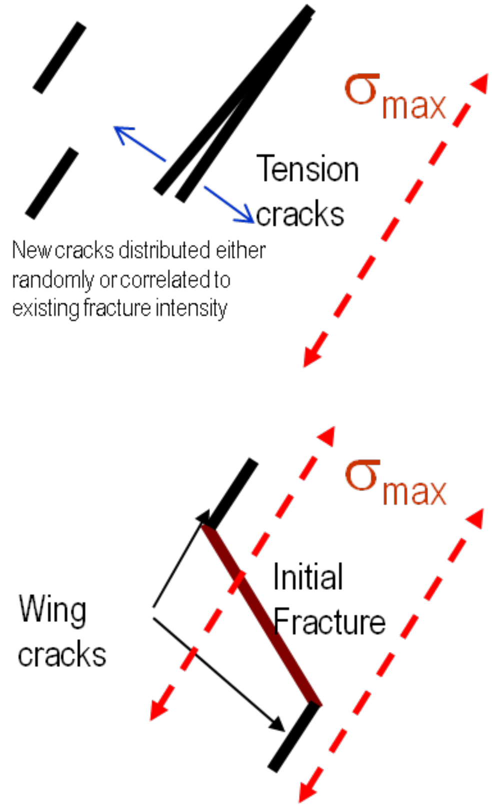


Figure 3. Schematics depicting the simplified nature of tensile crack formation and wing crack extension.

In either case, the fracture is oriented in the direction of the local maximum horizontal stress. As this orientation is assumed known, a key element of the approach is estimation of the vertical and horizontal fracture extent. The vertical extent is assumed to be controlled by hydrostratigraphy (i.e., over and underlying plastic beds, highly fractured layers, or faults). The horizontal extent can then be estimated based on mass balance principles – the total volume of injected frac-fluid (V_i) must match the volume of the opened hydraulic fracture (V_F), plus the volume (V_L) of leak-off to the natural fracture network (and to the rock matrix, in the case of permeable rock).

$$V_i = V_F + V_L \quad (7)$$

The volume of the hydraulic fracture can be approximated as the product of the length (L_f), the height (H_f), and the average aperture (e_f). Thus, the hydraulic fracture length can therefore be estimated as,

$$L_f = \frac{(V_i - V_L)}{e_f H_f} \quad (8)$$

The leak-off to the natural fracture network is described below. In order to simulate the hydraulic fracture, a maximum length (L_F) is first estimated based on realistic assumptions for leak-off. A discretized hydraulic fracture of zero aperture is then inserted to the DFN model. On this new fracture a transient DFN flow simulation then progressively increases the hydraulic fracture aperture, and an estimate is made of the total hydraulic fracture volume and leak-off. This process is repeated until the total volume of the hydraulic fracture, plus the total volume of leak-off, matches the injected fluid volume. This procedure then establishes an estimate of the hydraulic fracture size for the given natural fracture network conditions.

2.4 Connected Natural Fractures

The natural fractures influencing hydraulic fracture propagation can be categorized to three groups (Figure 1),

1. Natural fractures that are directly connected to the well within the perforated frac-stage interval.
2. Natural fractures directly connected to (i.e., intersecting) the hydraulic fracture as it propagates.
3. Natural fractures indirectly connected to the hydraulic fracture, through interconnected fracture networks.

These natural fractures have the potential to improve the drainage volume (where they provide additional connected surface). However, they also have the potential to decrease the size and effectiveness of the hydraulic fracture (where they divert frac fluid, or redistribute stresses, limiting the hydraulic fracture extent.

Knowledge of the geometry and properties of these natural fractures is important to estimation of the propagation of hydraulic fracture, and the corresponding drainage volume. The natural fractures which intersect the hydraulic fracture, and consequently the networks indirectly connected to it, can best be estimated by the discrete fracture network (DFN) approach (Dershowitz, 1996).

In the DFN approach, the pattern of natural fractures is derive and simulated based on specialized analyses of the geometry (location, intensity, size, shape and orientation), hydrologic, and geomechanical properties of the natural fractures. The procedure employed for the analysis of data, conceptual model development, and simulation of the discrete fracture network patterns is given in (Figure 4).

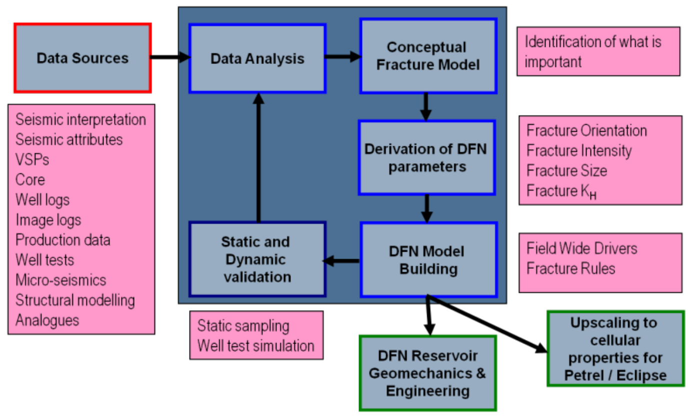


Figure 4. Discrete Fracture Network (DFN) Analysis Workflow.

Once this initial “background natural fracture network” DFN has been simulated (Figure 5), the hydraulic fracture geometry must be estimated based on the in situ stress, local experience, and the intensity of the local natural fracturing. This initial estimate of the hydraulic fracture then forms the basis for a connectivity analysis to determine the network of connected natural fractures via graph theory.

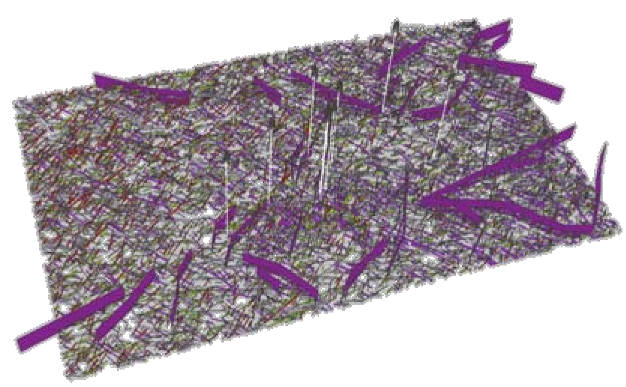


Figure5. Example Discrete Fracture Network (DFN) model including seismic and subseismic faults and background fractures

An example estimated hydraulic fracture and connected natural fracture is shown in Figure 1. For each incremental step of the hydrofrac propagation, the frac fluid is allocated to the network of natural fractures, and is proportional to the distance from the injection location through the network. In addition, the allocation is also dependent on the fracture aperture, and the angle between the new fracture and the attached existing fractures in the network.

The volume of frac-fluid taken by the hydrofrac is estimated based on the frac area and aperture (e), where the aperture itself is estimated from the elastic solution for an expanding elliptical crack as (Sneddon, 1946)

$$e = \frac{1-\nu}{G}\left(P_{pore} - \sigma\right) r_{max} \sqrt{1 - \left(\frac{r}{r_{max}}\right)^2} \qquad (9)$$

Terms υ and G are respectively Poisson's ratio and elastic shear modulus for the host rock. The term σ is the in situ normal stress, and the remaining terms r and r_{max} are as previously defined. This equation can also be used to estimate appropriate equivalent volume aperture of natural fractures taking frac-fluid (Figure 6).

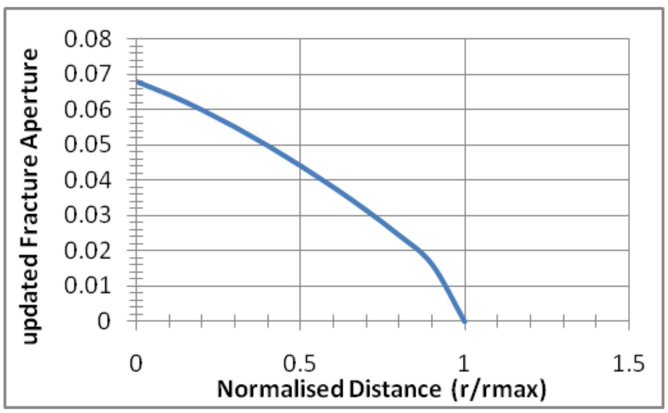


Figure 6. Update to natural fracture aperture during hydraulic fracturing

The simulation of the frac-fluid leak-off to the natural fracture network provides an estimate of the frac-fluid volume essential for the assumed hydraulic fracture geometry. If the hydraulic fracture is assumed too large for the corresponding natural fracture network, the required frac-fluid volume will be greater than that the design frac-fluid volume. This design frac-fluid volume is dictated by operational considerations, and is found through empirical calculations.

The frac-simulation algorithm therefore iterates to a smaller hydraulic fracture geometry configuration. When the simulated and designed frac-fluid volumes are equal, this is an indication that the hydraulic fracture geometry and natural fracture leak-off are consistent. This combined geometry can then be further verified through simulated micro-seismics and geomechanical simulation, and can then be used to predict reservoir drainage.

3. MICROSEISMIC MAPPING OF HYDRAULIC FRACTURES

Shear reactivation and extension of natural fractures, and shearing during hydrofrac generates microseismic waves that can be detected through geophone arrays. A properly designed geophone array can use these waves to triangulate the location and magnitude of fracturing and natural fracture reactivation, see Rutledge (1998) and Eisner (2006).

Conventional hydraulic fracturing analyses are unable to reproduce these patterns, because they do not consider to role of reactivated natural fractures. Hydraulic fracture propagation is fundamentally a tensile process which produces low-energy emissions that are undetectable over distances more than a few meters. The hydraulic fracture itself may in many cases not be visible at all in microseismic monitoring.

Observed microseismic events rather have shear signatures. The sources of these emissions appear to be pore-pressure induced shear failure where the energy source is in situ stress itself (Majer and Doe, 1986). Hence the microseismic distribution reflects the diffusion of pore pressure away from the hydrofracture along reactivated natural fractures. Consequently, microseismic monitoring can frequently display a broad response cloud, indicating the location and magnitude of microseismic responses on reactivated natural fractures (Figure 7).

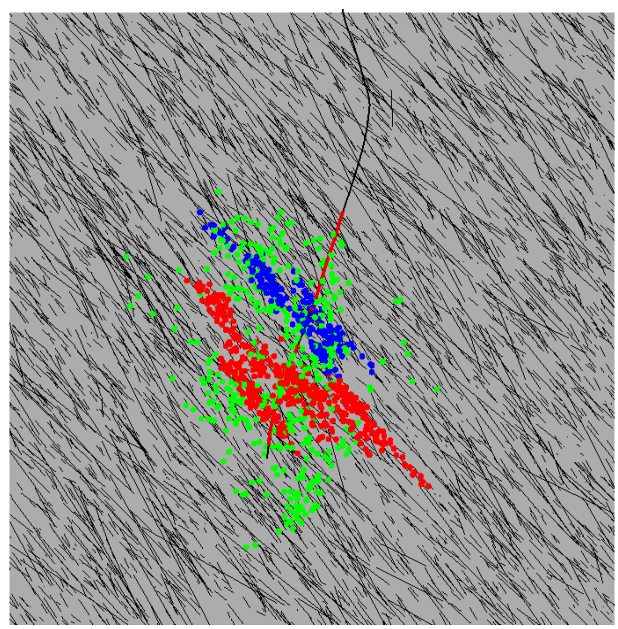


Figure 7. Example display of microseismic response showing reactivated natural fractures from DFN analysis (in red and blue) alongside observed response (in green).

Within the DFN hydraulic fracture simulation workflow, this response can be evaluated by comparing the effective stress state on that fracture against a fracture shear strength criterion, such as Mohr-Coulomb or Barton-Bandis (1990). Figure 8 illustrates this analysis, with pressures in natural fractures calculated according to Eqn. 6 above.

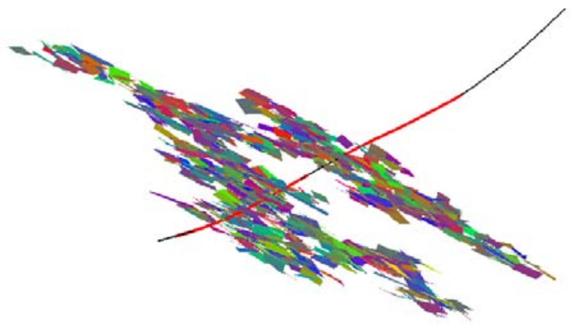


Figure 8. Pressures existing in the stimulated natural fractures computed from fracture shear strength criteria.

4. GEOMECHANICAL SIMULATION TO VERIFY DFN APPROACH FOR HYDRAULIC FRACTURING

The DFN approach described above utilizes empirical rules to describe the propagation of hydraulic fractures, and the reactivation of pre-existing natural fractures during the hydrofracturing process. The ELFEN® geomechanical simulator was used to verify the approach, comparing the geometry of created hydraulic fractures, and simulated microseismic responses. It is a hybrid distinct element/finite element code, and is therefore able to simulate both continuum mechanics and fracture mechanics behavior associated with quasi brittle materials, see [18-20].

A series of 2-D (plane-strain) analyses were carried out to confirm that the hydraulic fracture propagation and microseismic response calculated by the DFN approach are reasonable. These analyses were carried out using the same fundamental assumptions as in the DFN simulation, including,

- Appropriate in situ stress conditions.
- The baseline reservoir fluid pressure.
- Hydrofracturing parameters (pressure, flow rate, time history, perforations).
- Discrete fracture network geometry.
- Rock and fracture strength, deformability, and hydrodynamic properties.

The current analysis includes a fully dynamic explicit time integration technique, a material description that permits the strength degradation and fracture of brittle materials under both compressive and tensile stress states, a topological update procedure for modifying the element mesh as the fractures propagate, and an automatic scheme that controls the interaction of the rock fragments. The flow of frac-fluid is modeled as laminar (Darcy) flow, within the natural and hydraulic fractures, and is based on cubic law flow assumptions, see Labao (2007).

The geomechanical model reports fracture and rock mass displacement, stress, material state variables, normal and shear stress components, and state of slip. This slip information provides a simulated microseismic response which can be compared directly to both measured microseismic monitoring, and the DFN simulation of microseismic response.

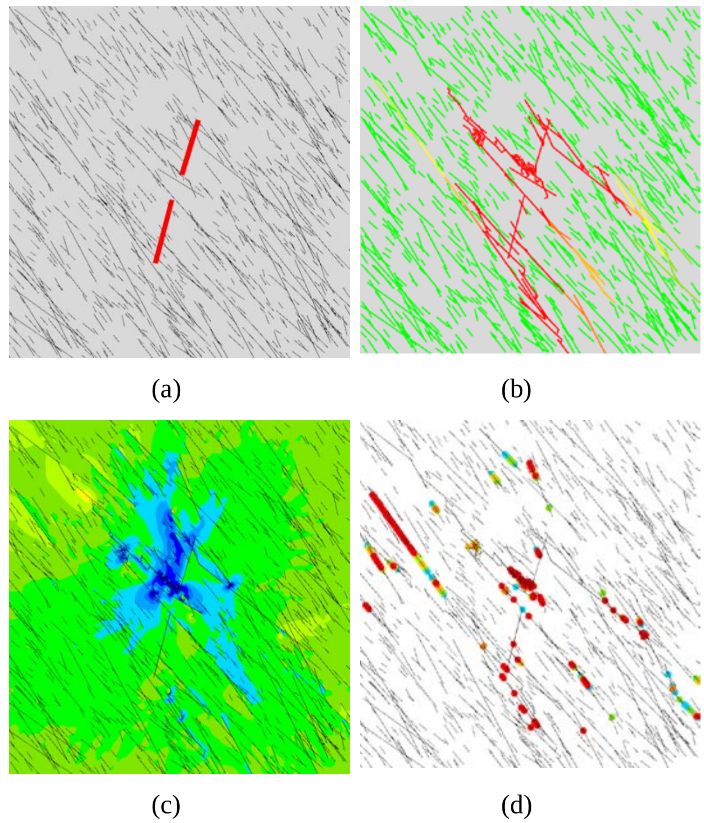


Figure 9. Geomechanical simulation of hydraulic fracturing and natural fracture reactivation, showing a) initial fractured domain, b) the joint fluid pressure , c) the major horizontal stress, and d) microseismic locations.

Figure 9 presents the predicted response from the geomechanical simulation that can be compared to the DFN prediction shown in Figure 7. The pattern of microseismicity, and the geometry of the hydraulic fracture, is similar, but not identical. This is consistent with the difference in geomechanical approaches, but significantly increases confidence in the use of the semi-analytical DFN approach.

Microseismic monitoring provides a direct measure of the hydraulic fracturing process. Unfortunately, the accuracy of field measurement is limited by the geometry of geophone arrays (which are normally located in a single well), and by their inability to detect purely tensional events.

5. COMPARTMENTALIZATION AND DRAINAGE VOLUMES

An additional approach for verification of the DFN hydraulic fracture simulation approach is to compare the effective drainage in the post-frac DFN model to actual oil or gas production. This approach relies upon the hypothesis that production of gas from tight sands and gas shales is directly proportional to the size of induced fracturing, and possibly in some cases the additional drainage due to reactivated natural fractures (La Pointe et al., 1997), two techniques are employed:

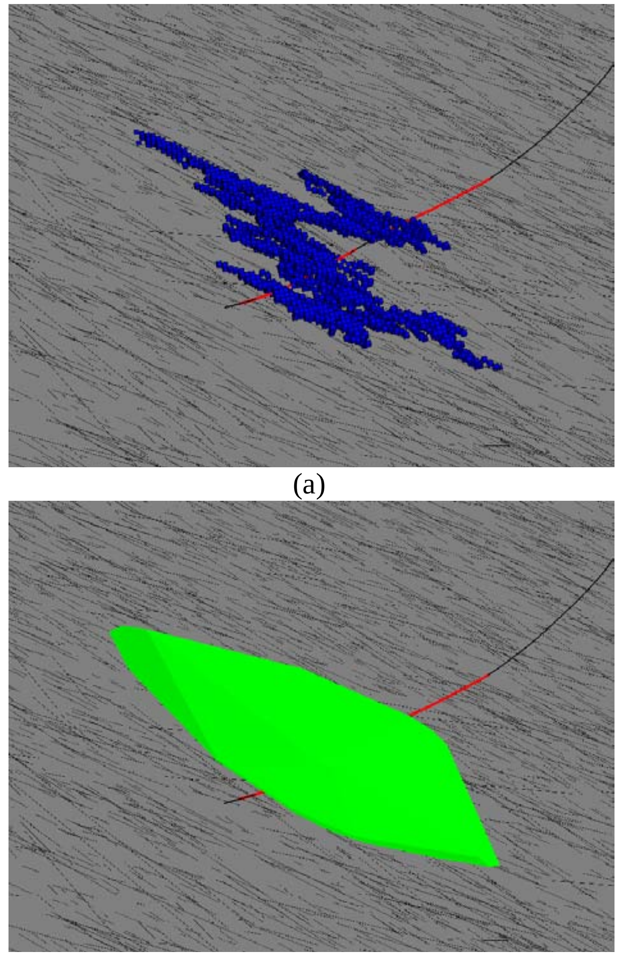
- The Slab Approach: Estimation of the tributary drainage volume based on an assumed drainage depth from the rock matrix, and calculated areas of the simulated hydraulic fracture, and possibly the area of that portion of natural fractures with enhanced permeability following hydrofracturing.
- The Convex Hull Approach: Estimation of the tributary drainage volume as a convex hull of rock matrix which fully contains the hydraulic fracture and reactivated natural fractures.

The slab approach, based on a small assumed thickness and considering only the hydraulic fracture, provides a lower bound estimate on the tributary drainage volume; the convex hull approach, considering all reactivated natural fractures, provides an upper bound estimate of the tributary drainage volume.

The results of this study indicate that the hydraulic fractures simulated by the 3-Dimensional DFN approach, together with the slab based calculation of tributary drainage volume, provide a good prediction of production in specific gas shale formations. This provides a further indication of the potential value of the DFN hydraulic fracture simulation approach for optimizing the levels of recovery achievable from low permeability unconventional gas reservoirs.

3 CONCLUSIONS

This paper has demonstrated the development and validation of an approximate discrete fracture network (DFN) approach for evaluation of hydraulic fracturing in naturally fracture rock masses. The approach is limited by the ability to estimate in situ stress, uncertainty in the local natural fracture network geometry and hydraulic properties, and by the simplified representation of both hydraulic fracture propagation and leak-off to the natural fracture network.



(a)

(b)

Figure 10. Predicted drainage volumes from the DFN simulation using both (a) the slab based approach, and (b) the convex hull approach.

Nevertheless, this approach, when calibrated to observed microseismic activity, can produce practical results for predicting fracture behaviors and production from wells that lack seismic monitoring. . It is able to explicitly model the interaction of the hydraulic fracture and the natural fracture network. The approach can be compared directly to detailed geomechanical simulations with the hybrid distinct element/finite element approach, while still maintaining full three dimensional geometry. The approach has produced tributary drainage volumes consistent with shale gas production observed in case study projects.

Additional development and validation are required, as this approach is applied to progressively more complex naturally fractured shale-gas and tight sand systems.

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