ARMA e-NEWSLETTER

Spring 2014

Special Issue: Geomechanics of Hydraulic Fracturing in Shale Formations

Editor's Note

The ARMA e-Newsletter has been serving members since the fall of 2010. It combines timely articles on technical subjects of interest to the rock mechanics/geomechanics community with ARMA-related news items and announcements. The feedback received to date has been positive, which gives us the incentive to continue this volunteer-based service.

The present Special Issue of the newsletter is the result of a new initiative undertaken by the ARMA Publications Committee and the editorial board. From time to time, we plan to solicit technical notes on a specific topic of wide interest to the membership, review them, and publish them in a special issue dedicated to the selected subject. The first such subject to which this issue is dedicated is geomechanics in petroleum extraction with particular interest to hydraulic fracturing of shale formations [1]. We accepted four technical notes, and they provide the sole focus of this Spring 2014 issue of the newsletter. The lead article, by Paul La Pointe, introduces us to the general field of oil extraction, emphasizing the importance of combining geology and geomechanics in that pursuit. The other three technical notes address different aspects of producing oil from shale formations.

We hope that you will enjoy reading the Special Issue. Your feedback regarding the contents, technical standards, and any other aspects of this issue will be thoroughly appreciated.

If you believe that we should continue with this initiative and publish additional special issues, please send us your suggested topic. You may want to add a list of recommended authors.

We look forward to receiving any constructive suggestions you may have regarding special issues of the ARMA e-Newsletter.

Bezalel Haimson

Chair, ARMA Publications Committee

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[1] Just as we were preparing the final copy of this Special Issue, it was brought to our attention that a conference on "Effective and Sustainable Hydraulic Fracturing " was held in Brisbane, Australia in 2013. The Proceedings of the conference are available free of charge at the following link:

http://www.intechopen.com/books/effective-and-sustainable-hydraulic-fracturing.

Contributions

Submitted by
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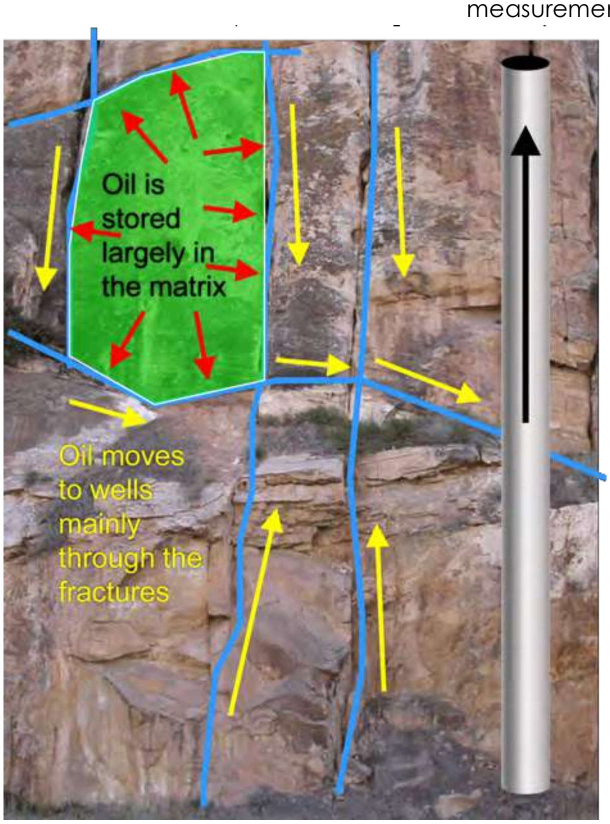
Combining Geology and Geomechanics in the Pursuit of Energy

Background

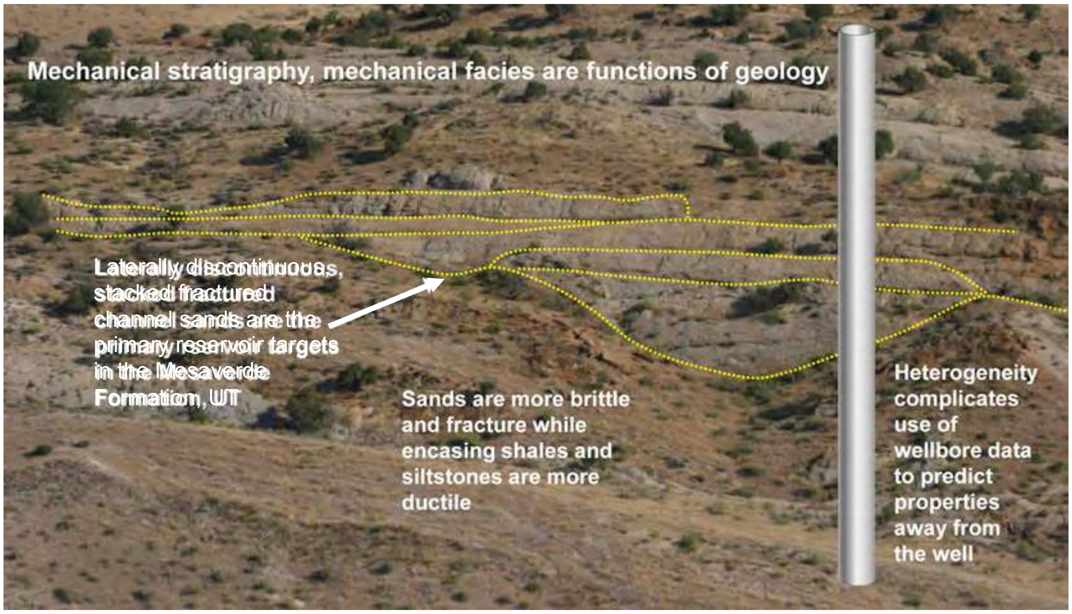
We often hear of the significant role that geomechanics plays in the engineering of energy resources, as Sid Green described in his recent article in this newsletter ("The Changing Energy Picture: The Role of Rock Mechanics and ARMA", ARMA e-Newsletter, Winter, 2014). It also plays an important role in the geology of energy resources, and underscores why rock mechanics is important to both of these technical communities. Nowhere is this as evident as in the petroleum industry where the existence, orientation, size and connectivity of the natural fractures can significantly impact development plans, resource estimates and ultimate recovery.

One of the great challenges in efficiently recovering the oil and gas from reservoirs where natural fractures are important for storage or flow is to predict accurately what the fractures look like away from the wellbore measurements. This challenge is illustrated by a comparison of Ghawar, the world's largest oil field, to the island of Manhattan, home to New York City. The area of Ghawar is approximately 8400 km^2, nearly 100 times larger than Manhattan. Many other significant oil fields are also greater in size than Manhattan. The energy industry makes multi-billion dollar decisions on these fields based upon engineering models of them, which often require an accurate understanding of the natural fracture system throughout the field. Imagine the challenge of predicting the traffic patterns in New York City from the observations at a few intersections. The challenge is similar for fractured reservoirs, and it is in this capacity that the confluence between geology and geomechanics plays an important role in the geological characterization of the rock masses.



Natural fractures play an important role in the early assessment of fields; predicting and mitigating water breakthrough in maturing carbonate fields; planning secondary and tertiary recovery schemes; and in optimizing hydraulic fracturing in unconventional oil and gas shale plays. The engineering solutions to these objectives frequently rely upon 3D reservoir models of the field that specify the location of major faults and the stratigraphic framework; assign matrix saturation, porosity and permeability of the reservoir volume; and in the case where natural fractures are important, estimate directional fracture permeability, fracture porosity, matrix block shape factors and fracture network connectivity/ compartmentalization throughout the field or acreage. These models are then used to dynamically simulate production or well test information in order to build confidence that the property descriptions and geological framework are accurate, and then the models are used to simulate the dynamic performance of the reservoirs and to devise optimal development strategies. The results of these studies are only as useful as the property descriptions of the matrix and fracture system are accurate.

Purely statistical methods, such as the various geostatistical approaches for estimating fracture properties from borehole data, yield models with very high levels of uncertainty away from the wells. The uncertainty can be reduced somewhat by combining the well data with seismic data, and using the seismic data as a "soft" constraint on the interpolation away from well control. However, seismic data has a spatial resolution typically much coarser than either the mechanical layering of a typical carbonate or shale reservoir, as a mechanical layer. This coarse resolution means that seismic data cannot resolve much of the important detail concerning fracture intensity variations and the potential for vertical connectivity among fractured mechanical layers. Moreover, while some seismic attributes of multicomponent data do respond to fracture orientations, the interpretation of fracture directionality when there is more than one fracture set is complex and non-unique.

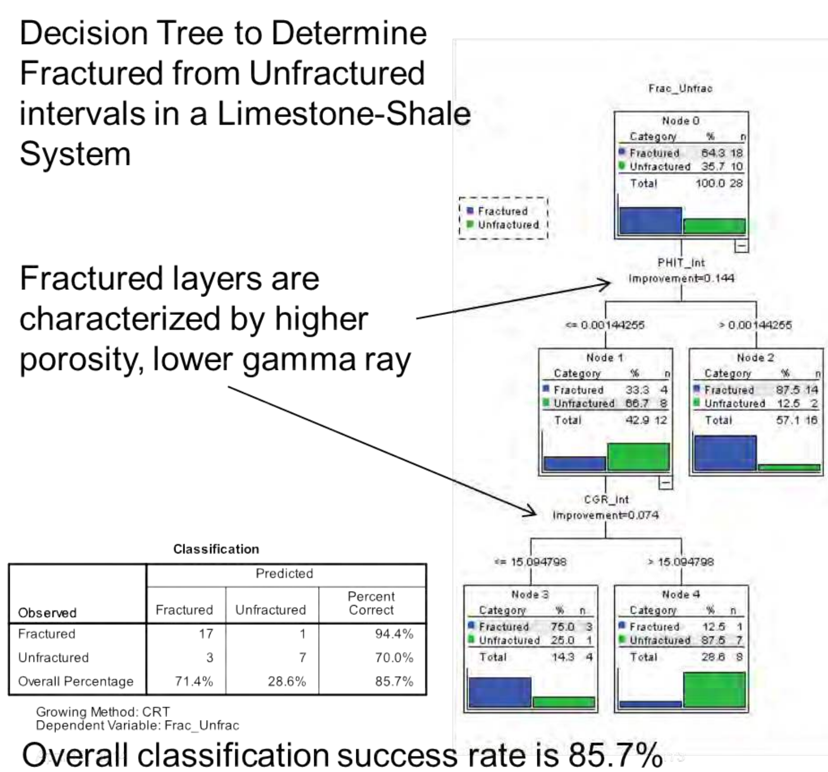


A Way Forward: Geomechanics and Geology

Rock mechanics describes how rock deforms in response to applied loads as a function of material properties. Some of that deformation or strain, depending upon material properties, may be expressed by fractures. Ideally the material properties that could be used to predict brittle fractures are the ratios of elastic to plastic strain at failure of each rock type; the fracture toughness; and the geometry of void space in the matrix. However, these parameters are not measured when oil wells are drilled and completed. Moreover, the deformation of the reservoir rock occurred at some point in the past, perhaps involving multiple episodes, and there were no instruments to measure the stresses in the rock throughout its history when the fractures were being created. It is at this point that the combination of rock mechanics and geology becomes a powerful tool to quantitatively characterize the geology of the natural fracture system.

Data Mining at the Wellbore

Wireline log data contains many measurements that may serve as indirect surrogates for the mechanical properties that influence brittle fracture development. For example, gamma ray logs can help distinguish shales from less clay-rich clastics and carbonates. Various porosity logs can be calibrated to measure matrix, effective or total porosity and the related density parameters. Combinations of logs make it possible to identify a host of different lithologies such as shale, sandstone, limestone, dolomite and anhydrite, or certain elements that are diagnostic of certain minerals. Dipole sonic logs can be processed to yield values of Young's Modulus and Poisson's Ratio. With regards to natural fractures, any measure of rock porosity, density, elastic moduli or lithology is potentially useful in predicting fracture development. Moreover, there are other downhole logs, such as resistivity, photoelectric effect and caliper logs that may be indirect indicators of fractures.



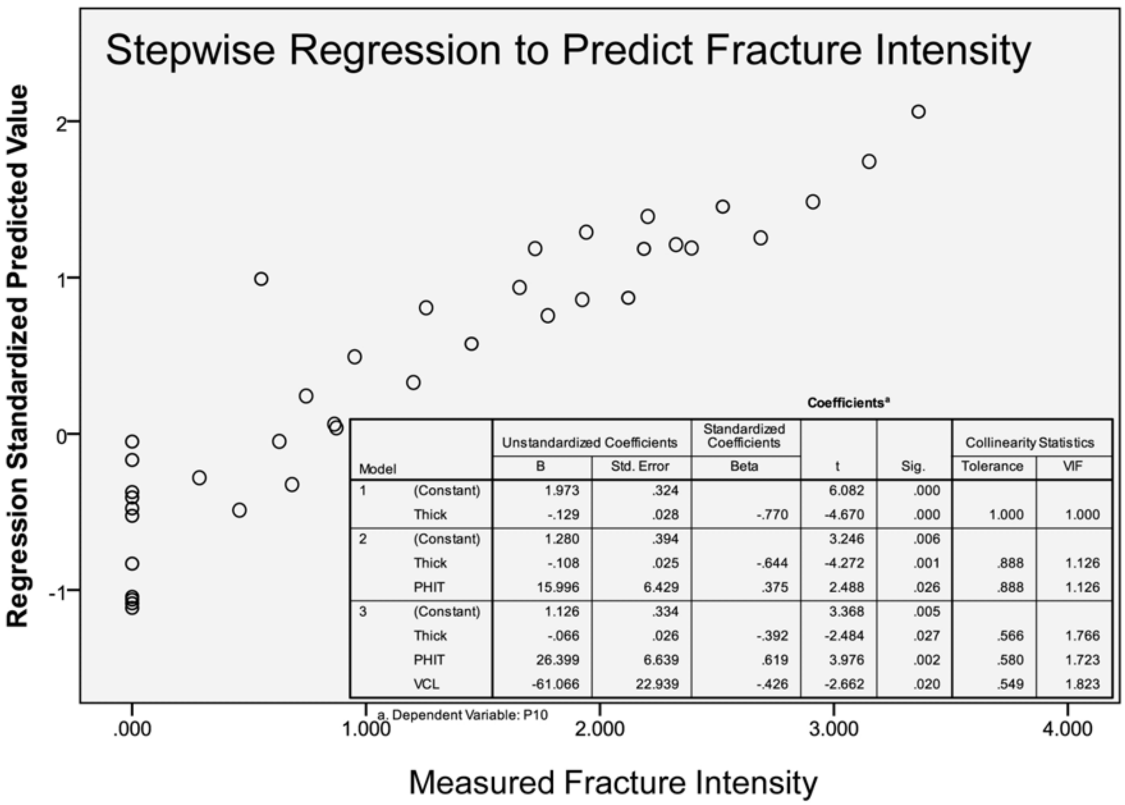
Observed	Predicted: Fractured	Predicted: Unfractured	Percent Correct
Fractured	17	1	94.4%
Unfractured	3	7	70.0%
Overall Percentage	71.4%	28.6%	85.7%

One approach might be to determine the fracture intensity over identified mechanical layers downhole, average various wireline log properties over these intervals, and apply a multivariate statistical method or pattern recognition technique such as neural nets to identify mechanical layers and predict intensity.

This approach only works where all factors influence fracturing in the same manner in all rock types and depositional settings present in the reservoir - a very rare occurrence. Uninformed by geology, this engineering approach will not be optimal.

For example, in many carbonate reservoirs, the rocks are deposited as a series of interbedded shales and limestones. Later diagenesis may lead to the dolomitization which might occur in some portions of the reservoir, producing anhydrite and dolomite. In the undolomitized limestone-shale sequences, the limestone is fractured and the shale is likely unfractured, so logs like gamma ray, density and resistivity may be useful in distinguishing fractured from unfractured rock and density or porosity logs may be useful in predicting variations of intensity in the limestones. Where dolomitization has occurred, however, the dolomite may be highly fractured and the anhydrite unfractured. Gamma ray logs are not useful in distinguishing dolomite, limestone and anhydrite, but neutron density and photoelectric logs are useful and may also indicate the intensity of fracturing in the dolomitized limestone. The important point is that using logs to identify fractured and unfractured rock layers, and the intensity of fracturing within fractured layers, depends upon lithology and other geological factors. Carrying out statistical analyses to predict fracture intensity uninformed by geology is often of little value.

Multivariate methods such as binomial or multinomial logistic regression, probabilistic neural nets and Decision Trees (shown above) are useful for distinguishing fractured from unfractured rock when geology is taken into account to select subsets where causal mechanisms for fracturing are homogeneous. Once the fractured intervals are selected, it is then possible to apply another multivariate method, in this case Multivariate Linear Regression, to predict fracture intensity. In addition to clay percentage ("VCL") and porosity ("PHIT"), an additional geomechanical variable appears in the stepwise regression results shown below: mechanical layer thickness ("Thick"). It is common that the fracture intensity is inversely proportional to the layer thickness in many sedimentary rocks of similar lithology, and the regression results show that it is also an important, statistically significant variable in this case.



Coefficients[a]

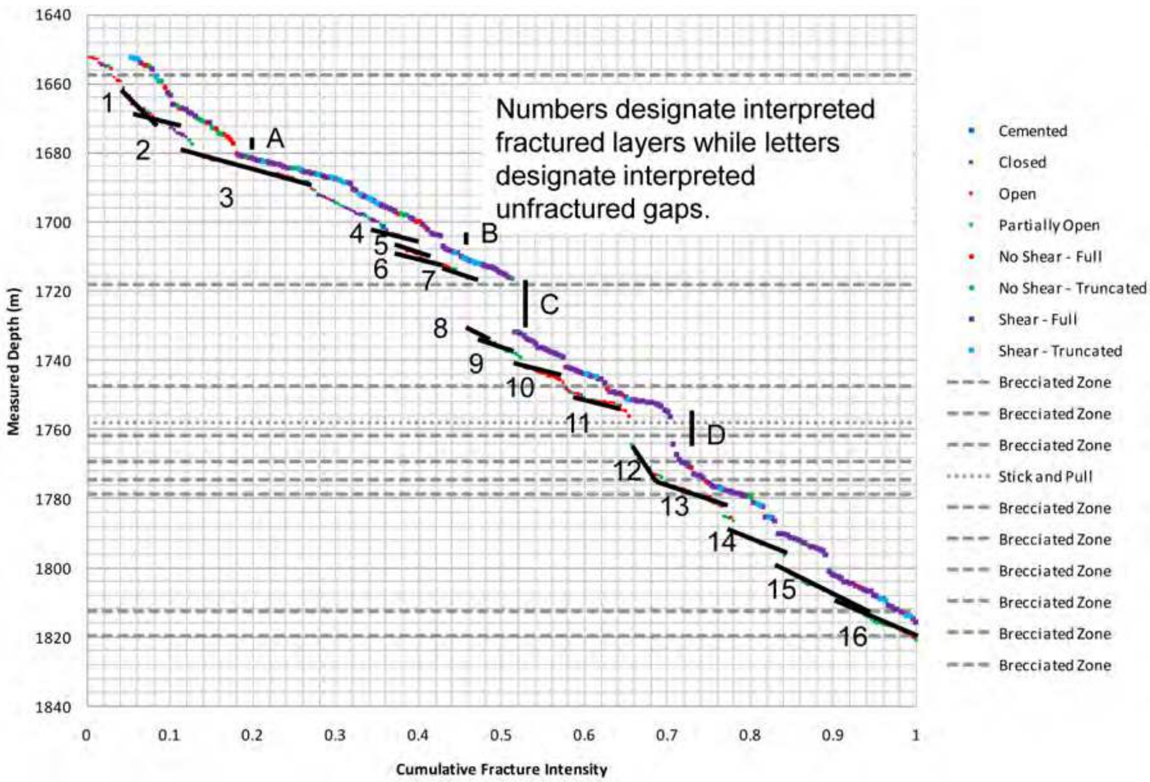
Model		Unstandardized Coefficients B	Unstandardized Coefficients Std. Error	Standardized Coefficients Beta	t	Sig.	Collinearity Statistics Tolerance	Collinearity Statistics VIF
1	(Constant)	1.973	.324		6.082	.000		
	Thick	-.129	.028	-.770	-4.670	.000	1.000	1.000
2	(Constant)	1.280	.394		3.246	.006		
	Thick	-.108	.025	-.644	-4.272	.001	.888	1.126
	PHIT	15.996	6.429	.375	2.488	.026	.888	1.126
3	(Constant)	1.126	.334		3.368	.005		
	Thick	-.066	.026	-.392	-2.484	.027	.566	1.766
	PHIT	26.399	6.639	.619	3.976	.002	.580	1.723
	VCL	-61.066	22.939	-.426	-2.662	.020	.549	1.823

a. Dependent Variable: P10

The results make geological and geomechanical sense, in that fracture intensity increases with total porosity and decreases with increasing shale content and layer thickness. Current rock mechanics understanding (Tang and others, 2008) suggests that fracture spacing decreases with increasing extensional strain, until at a certain ratio of strain to spacing, no new fractures are generated. Rather, the energy goes into propagating or opening existing fractures, and at this point, fracture spacing scales with mechanical layer thickness.

The strategy for developing a dataset for these types of multivariate analyses requires blending both geological and geomechanical understanding. A geologist might subdivide the well into various facies, but in fact, the facies don't necessarily function as individual mechanical units. Often the layers in which the fracturing forms consists of many meters of mixed facies bounded by a significantly ductile facies, such as shale or anhydrite. These layers are not of uniform thickness, so simply binning the wireline and fracture intensity data into fixed-length intervals misses the geological structure of the data.

Geomechanics theory indicates that fracturing which develops in mechanical layers is typically in brittle layers bounded by ductile layers, and that fracture intensity is relatively homogeneous in each layer. For layers with similar lithologies, as previously noted, the spacing or intensity should relate to layer thickness. Simple plots of normalized cumulative fracture intensity (CFI), such as the one shown below, are a convenient way to identify possible fractured mechanical layers. Any portion of the graph where the points approximate a straight line indicates homogeneous fracture intensity. Gaps are portions of the well where no fractures were found (denoted by letters on the chart), and straight line segments denote portions of the well with near-constant fracture intensity (numbered intervals on chart). As the CFI chart shows, many of the straight-line segments are bounded by unfractured rock.

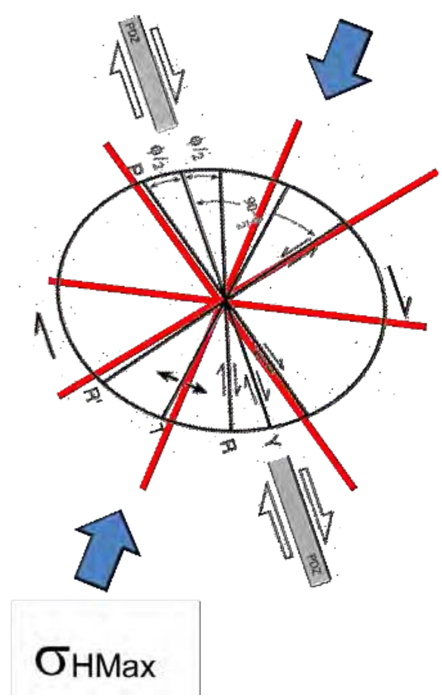


Fracture orientations vary throughout a rock mass or petroleum reservoir. It is often necessary to predict the orientations of fractures in a large volume of rock from data gathered in a few wells. Making estimates from purely statistical models produces a model with significantly higher uncertainty and possibly unusable results.

However, fractures occur due to geological processes rooted in mechanics. One very old but very useful model for the deformation of rock and the generation of fractures is known as the Riedel Model (Riedel, 1929; Cloos, 1928), which describes how fractures form in a transpressive tectonic environment. The process for testing whether this model is useful requires first understanding the tectonic history of the area of interest, then collecting data to evaluate the model, and finally comparing the model predictions to the measured data.

The Riedel model is predicated upon large scale shearing of the crust. The rock undergoing this shear deforms locally in compression, extension and shear, as shown by the diagram. It was important to gather fracture orientations in as many locations as possible to test alternative geomechanical theories as to how the fractures formed and what their orientations should be as a result. The diagram to the right shows the main fracture orientations that were found. The red lines indicate the strike of the fracture sets measured in the field, while the black ellipse and inset black lines show the fracture strikes predicted by the Riedel model for transpressive rock fracturing.

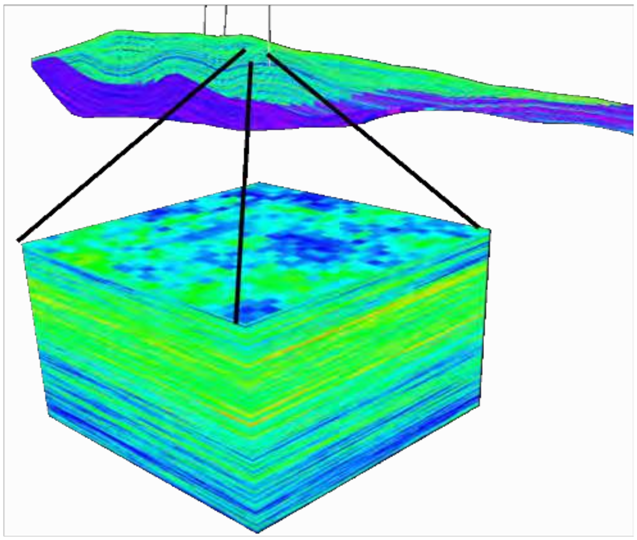
The agreement was excellent, giving confidence in predicting how the fractures formed and what orientations might have been away from measured data at the wells.

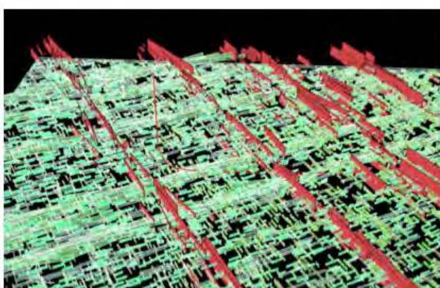


Once the geomechanical information has been integrated with the geological data, it is possible to make estimates of fracture intensity and orientation away from the wells with increased confidence. The colors in the diagram showing a cross-section through the model and an inset portion as a data cube show the estimates of fracture intensity in the reservoir model, where blue represents lower intensity and yellows and reds represent higher intensity.

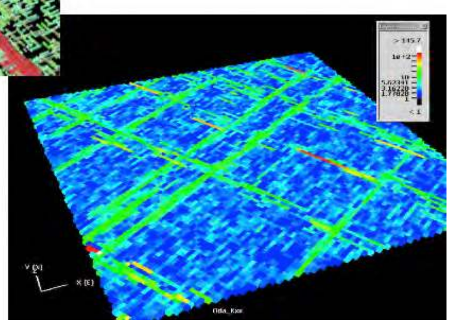
This grid of data can be used in many different ways. One way is to create a Discrete Fracture Network (DFN) model from it. A DFN model is an object modeling approach in which faults and fractures are represented as polygons, and the orientations, intensity and other properties are constrained by the estimates contained in the grid.

One use of a DFN model is to estimate continuum properties for a finite-differenced-based dynamic multiphase flow model, as shown by the continuum grid model in the lower right-hand corner of the inset diagram. Other uses include incorporation of effective fracture properties into various commercial geomechanical or coupled geomechanical/fluid flow codes to solve more complex problems.





Creating a Discrete Fracture Network (DFN) model from the orientations and intensity estimated from the combined geomechanical-geological model



Calculation of upscaled continuum properties for a compositional multiphase dual permeability simulator, including fracture porosity, directional fracture permeability and "shape factor"

Conclusions

These illustrations show how geological characterization benefits from incorporation of geomechanics, and likewise, how an engineering application - the efficient extraction of oil and gas - benefits from being coupled to reservoir geology through geomechanics A common approach to many engineering site characterization problems is to collect a large number of samples and then to produce an input data set through some sort of statistical or geostatistical analysis. This sort of approach - measure what the rock properties are and interpolate them using statistics - doesn't work very well for many large engineering projects related to the extraction of petroleum, production of geothermal energy or the disposal of high-level spent fuel waste, It doesn't work because the spatial patterns that govern the heterogeneity are often much more complex than can be represented by simple stationary spatial statistics. On the other hand, the reservoir geologist can describe the details of fracturing at a well from an image log or core, and through knowledge and application of geomechanical principles, greatly improve predictions of fracturing away from well control, thereby overcoming a daunting geological problem through the use and understanding of geomechanics.

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Tang, C. A., Z. Z. Liang, Y. B. Zhang, X. Chang, X. Tao, D. G. Wang, J. X. Zhang, J. S. Liu, W. C. Zhu, and D. Elsworth, 2008. Fracture spacing in layered materials: a new explanation based on two-dimensional failure process modeling. American Journal of Science, Vol. 308, 49–72.

A Modeling-Inspired Approach to More Effective Hydraulic Fracture Stimulation of Shale Formations

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Over the past decade, the extraction of natural gas from shale deposits has changed the energy landscape. This extraction relies on the generation of multiple hydraulic fractures (HFs) from deep horizontal wells. Because the matrix permeability of the reservoir is low, HFs need to be created relatively close to one another. Large gaps between HFs correspond to unstimulated reservoir volume containing gas/oil that will not be produced. The fracturing of these kilometer- long horizontal wells is typically done in 10-30 stages (see Fig. 1 in which a single stage of length Z is shown). The length of these stages is typically similar to the height *H* of the reservoir or "pay zone". HF growth is commonly contained within the pay zone by stress barriers formed by jumps in the confining geological stress field, as illustrated in Fig. 1. It is economically desirable to initiate and attempt to simultaneously propagate multiple HFs within each such stage. Once the fracturing of one stage is complete, the whole process is shifted along the horizontal well, and repeated until the entire well has been covered by fractured stages.

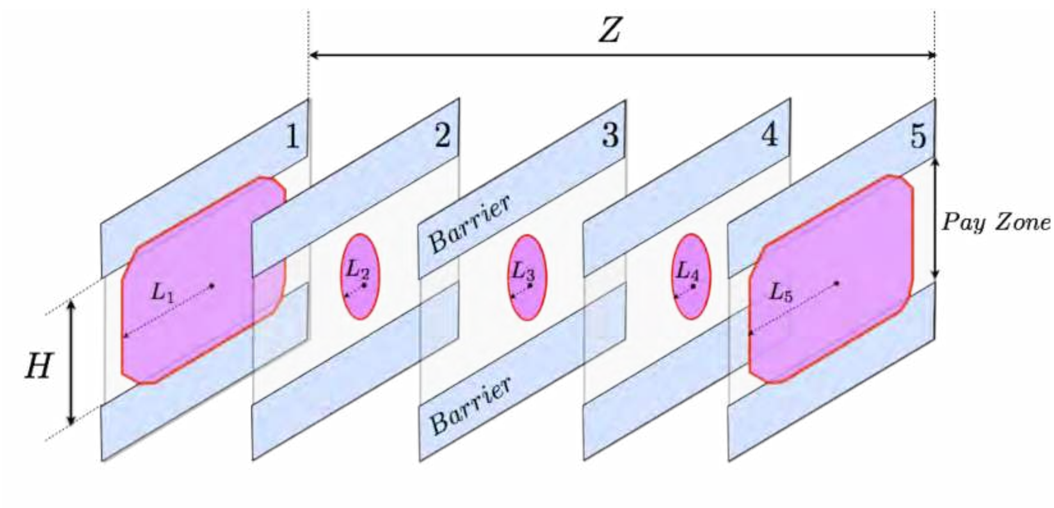
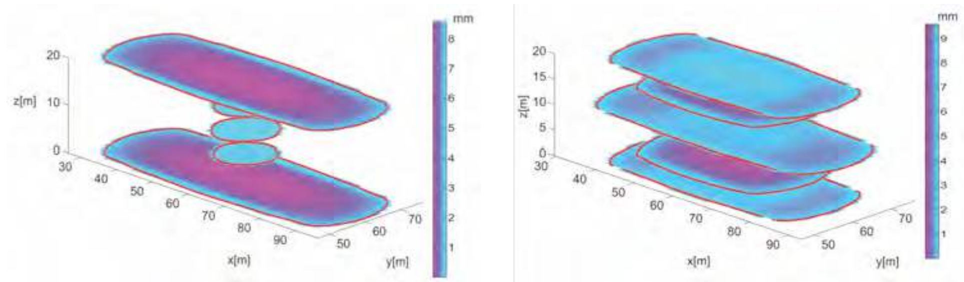


Fig. 1 A stage of length Z comprising five hydraulic fractures (HF 1-5) assumed to be initiated in a pay zone of height H, and to grow within planes numbered 1-5 and to have maximum dimensions $L_1 – L_5$, respectively.

Inducing all the HFs to simultaneously develop evenly throughout the stage is known to be restricted due to a phenomenon called stress shadowing. Stress shadowing causes localization of the HF growth in the two end fractures of the array while the growth of the interior fractures is severely stunted. This situation is represented schematically in Fig. 1, in which the maximum lengths L2 – L4 of the interior fractures 2-4 are much smaller than those of the end fractures 1 and 5. The mechanism for this is that the two elastic half- spaces adjacent to the array do not exert nearly the same resistance to growth on the end fractures 1 and 5 as the resistance exerted by the nearest-neighbor fractures on any of the interior fractures 2-4.

Increasing Z to reduce the mutual competition between the growing fractures can alleviate this inefficient situation. However, this option is not desirable economically as a lower density of fractures would significantly reduce the volume of natural gas produced by the well. Assisted by numerical simulations using a novel parallel planar simulator [1] that is able to model the full 3D stress coupling between the HF, we have established an alternative that requires no additional cost to the current practice. The new strategy involves placing fractures 2 and 4 (which we call interference fractures) close to the end fractures 1 and 5 to interfere with their runaway growth. This interference provides an opportunity for fracture number 3, in the middle of the array, to grow at roughly the same rate as the two end fractures. This situation proceeds until the three fractures (1, 3, and 5) dominating the growth reach a critical size beyond which it becomes more favorable for the interference fractures 2 and 4 to grow. After the transition to this regime, the interference HFs take up most of the injected fluid and also promote growth of the other fractures in the array by displacing fluid away from the well-bore toward the tips of fractures.

The final simulated results for uniformly-spaced and "interference" arrays are shown in Figs. 2a and 2b, respectively. These snapshots of the HF growth are shown for equal injected volumes and using the same values for all other parameters except for the spacing between the HFs within the array. The net result of the unexpected and complex dynamics is an array of thinner fractures with significantly more surface area (5004 m^2) shown in Fig 2 (b) compared to the surface area (3424 m^2) of the uniform array shown in Fig 2 (a). The uniform array shown in Fig 2 (a) stores most of this volume in the two run-away end fractures, while the interference array shown in Fig 2 (b) has distributed the same volume over thinner fractures with a significantly larger surface area.



(a) (b)

Fig. 2 a) Footprints of uniformly distributed HF exhibit stress shadowing. b) Footprints of an array of HF with interference fractures, which exhibits a significantly larger fractured area. The footprints are colored by the fracture opening field.

Adopting a common assumption that the volume of released hydrocarbons is proportional to the total fractured area in the array, this increase in area could amount to a 46% increase in the production of the well. Not only could this technique improve the profitability of the wells but it could also reduce the environmental impact by making better use of the often-scarce water resources.

Reference

Peirce, A. P. and Bunger, A. P. (In Review). Interference fracturing: Non-uniform distributions of perforation clusters that promote simultaneous growth of multiple hydraulic fractures. *Soc. Pet. Eng. J.* pre-print available at: http://hdl.handle.net/2429/45492.

A New Geomechanical Modeling Approach for Simulating Hydraulic Fracturing and Associated Microseismicity in Fractured Shale Formations



Submitted by Andrea Lisjak (left), Omid Mahabadi (center) and Patrick Kaifosh (not pictured) Geomechanica Inc., Toronto and
Giovanni Grasselli (right), University of Toronto

Introduction

The economical development of gas-bearing shale formations relies heavily on hydraulic fracturing (HF), a stimulation technique that enhances the effective drainage from low-permeability reservoirs through the creation of an interconnected fracture network. The importance of natural fractures as a dominant geological control in this process has been widely recognized (e.g., Gale et al., 2007). However, the role of rock fabric during HF is mostly neglected by conventional design tools. Such tools typically assume the rock mass to be homogeneous, isotropic and linear elastic, and simulate the HF as a bi-planar, tensile crack propagation process (see Adachi et al. (2007) for a review). Therefore, in recent years, there has been a growing interest in the development of advanced geomechanical models that can more realistically capture the physics of discontinuous, heterogeneous and anisotropic reservoirs. In particular, techniques based on the Discrete Element Method (DEM) are inherently well-suited for the explicit incorporation of strong fabric features, such as faults and joints (e.g., Al-Busaidi et al., 2005; Nagel et al., 2013). In this paper, a new approach based on a two-dimensional hybrid finite-discrete element method (FDEM) (Munjiza, 2004; Mahabadi et al., 2012) is presented.

Modeling technique: FDEM

In FDEM, the solid rock domain is discretized by a triangular mesh with embedded cohesive crack elements. During elastic loading, stresses and strains are assumed to be distributed over the finite elements (i.e., the continuum portion of the model), which are therefore treated as linear elastic under plane strain assumptions. Upon exceeding the peak strength of the rock (in tensile, shear, or mixed mode), the strains are assumed to localize within a narrow zone, commonly known as the fracture process zone (FPZ). The mechanical nonlinearities developing in the FPZ are lumped into a stress-displacement relationship implemented at the crack element level (Fig. 1a).

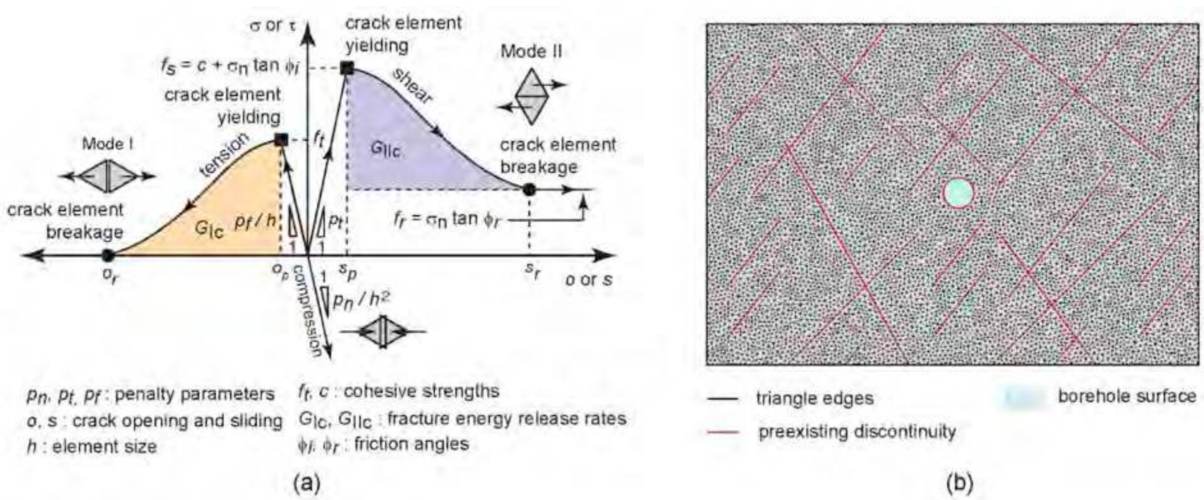


Figure 1. The FDEM geomechanics solver. (a) Constitutive behaviour at the contact between bonded triangular element pairs. (b) Example of FDEM model incorporating a DFN.

The progressive mechanical breakdown associated with fracture nucleation and growth within the continuum is therefore captured by the softening and breakage of the crack elements. Fracture trajectories are therefore restricted to the initial element topology. As the simulation progresses through explicit time stepping, displacements, rotations and interactions of newly-created discrete bodies occur and new contacts are automatically recognized. Also, the kinetic energy released during fracture propagation is recorded to evaluate the microseismic activity generated by the model (Lisjak et al., 2013a).

Stiffness and strength anisotropies typical of bedded and naturally-fractured shale formations are modeled with a transversely isotropic elastic law (Lisjak et al., 2014) combined with a directional cohesive fracture model (Lisjak et al., 2014a). This modeling approach has been qualitatively and quantitatively validated by simulating the fracturing processes of Opalinus Clay, a shale formation currently investigated in Switzerland as a potential host rock for a deep geologic repository (Lisjak, 2013).

In addition, following an approach similar to that of other discontinuum models (e.g., Mas Ivars et al., 2011), the capability to directly account for Discrete Fracture Networks (DFNs) has been added to the FDEM solver. A DFN is explicitly captured by a mesh topology having elements aligned with the pre-existing discontinuities (Fig. 1b). The crack elements across the DFN length are then fully debonded (i.e., purely frictional discontinuities) or assigned degraded cohesive strength parameters.

Fluid-pressure-induced fracturing is captured by a simplified hydro-mechanical solver based on the principle of mass conservation for a compressible fluid injected into a deformable solid (Fig. 2). The model is hydro-mechanically coupled in the sense that variations in fluid volume due to elastic deformation and fracturing affect the pressure of the fluid, which, in turn, affects rock deformation and failure. At each simulation time step, the FDEM solver computes the rock deformation, updates the fracture topology and hydraulic interconnectivity, determines the void volume, and computes the intra-crack fluid pressure as a function of the fluid volume and the prescribed injection flow rate.

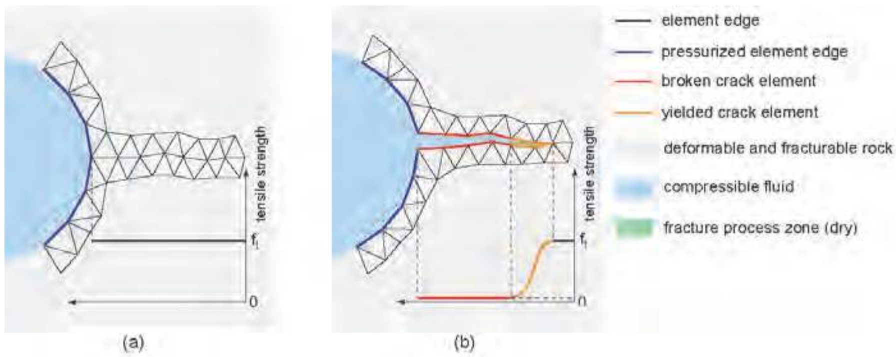


Figure 2. Conceptual diagram of HF process in FDEM. (a) Initial configuration with an intact pressurized borehole. (b) Growing HF and associated cohesive strength distribution along the fracture trajectory. For illustration purposes, only selected triangular elements are shown.

In the examples presented below, the rock matrix is assumed to be impermeable and the HF investigation is restricted to the toughness-dominated regime of propagation (Detournay, 2004), for which the fluid viscosity is neglected. In other words, the intra-crack fluid pressure is assumed uniform along the fractures and the HF process is captured as a temporal sequence of hydraulic equilibrium states. For the case of models with an embedded DFN, the fluid pressure is applied only inside those open DFN fractures that are hydraulically connected to the injection borehole.

Numerical examples

The newly-developed numerical approach was first validated against a closed-form solution and then used to simulate HF stimulation of a discontinuous shale reservoir. For the first case the rock mass was assumed to be isotropic and homogeneous with an uncased borehole subjected to a constant injection rate. As shown in Fig. 3a, the model captures well the injection pressure response: a linear portion is followed by a sudden drop in pressure at the time of fracture nucleation, before stabilizing to a steady-state value. The calculated breakdown pressure, P_b, is approximately equal to the theoretical value computed according to the theory of linear elasticity: $P_b = 3\sigma_h - \sigma_H + f_t$, where σ_h and σ_H are the minimum and maximum in-situ principal stresses, respectively, and f_t is the tensile strength of the rock (3.5 MPa). The simulated steady-state pressure, P_s, tends, as expected, to the σ_h value. The associated fracture patterns simulated in the borehole near field (Fig. 3b) vary as a function of the in-situ stresses; a transition from a complex radial pattern to a localized bi-wing fracturing is captured as field stress anisotropy is introduced.

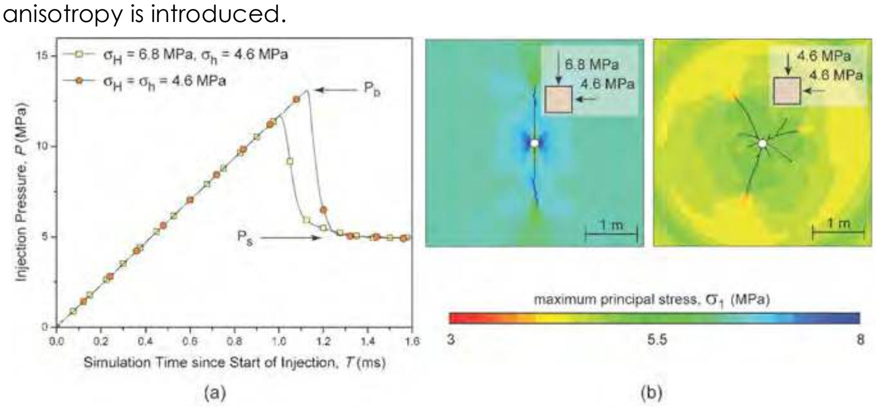


Figure 3. Simulation of HF from an uncased borehole under homogeneous and isotropic rock mass conditions.
(a) Emergent injection pressure response for two in-situ stress fields. (b) Associated near-field fracture patterns.

The second model was used to investigate HF in a horizontal well placed within a naturally-fractured shale formation in Northeastern British Columbia, Canada. The in-situ stress field was assumed to be σ_v = 63 MPa and σ_h = 50 MPa, thus corresponding to a completion depth of about 2.5 km with a stress ratio $K_0 = \sigma_h/\sigma_v$ = 0.8. A simplified DFN, consisting of two fracture sets inclined at ±45° to the directions of the principal stresses, was embedded into the model (Fig. 4a). The strength parameters of these 'incipient' fractures were chosen such that they were partially open under the given in-situ stresses. The installation of a stiff casing (i.e., steel and cement) was explicitly simulated as well as the fluid injection through six perforation tunnels (Fig. 4a). The simulated fracturing sequence highlights the role played by the pre-existing rock mass discontinuities during HF growth, which results in a complex fracture pattern instead of the classic bi-wing cracks (Fig. 4b). In particular, the emergent fracturing process consists of a combination of breakage through the intact rock bridges and shearing along the DFN discontinuities. In agreement with the conceptual model proposed by Dusseault (2014), at the local scale the HF tends to follow the DFN discontinuities favorably oriented for slipping, while at the global scale, it tends to develop in the direction parallel to the maximum in-situ stress, σ_v.

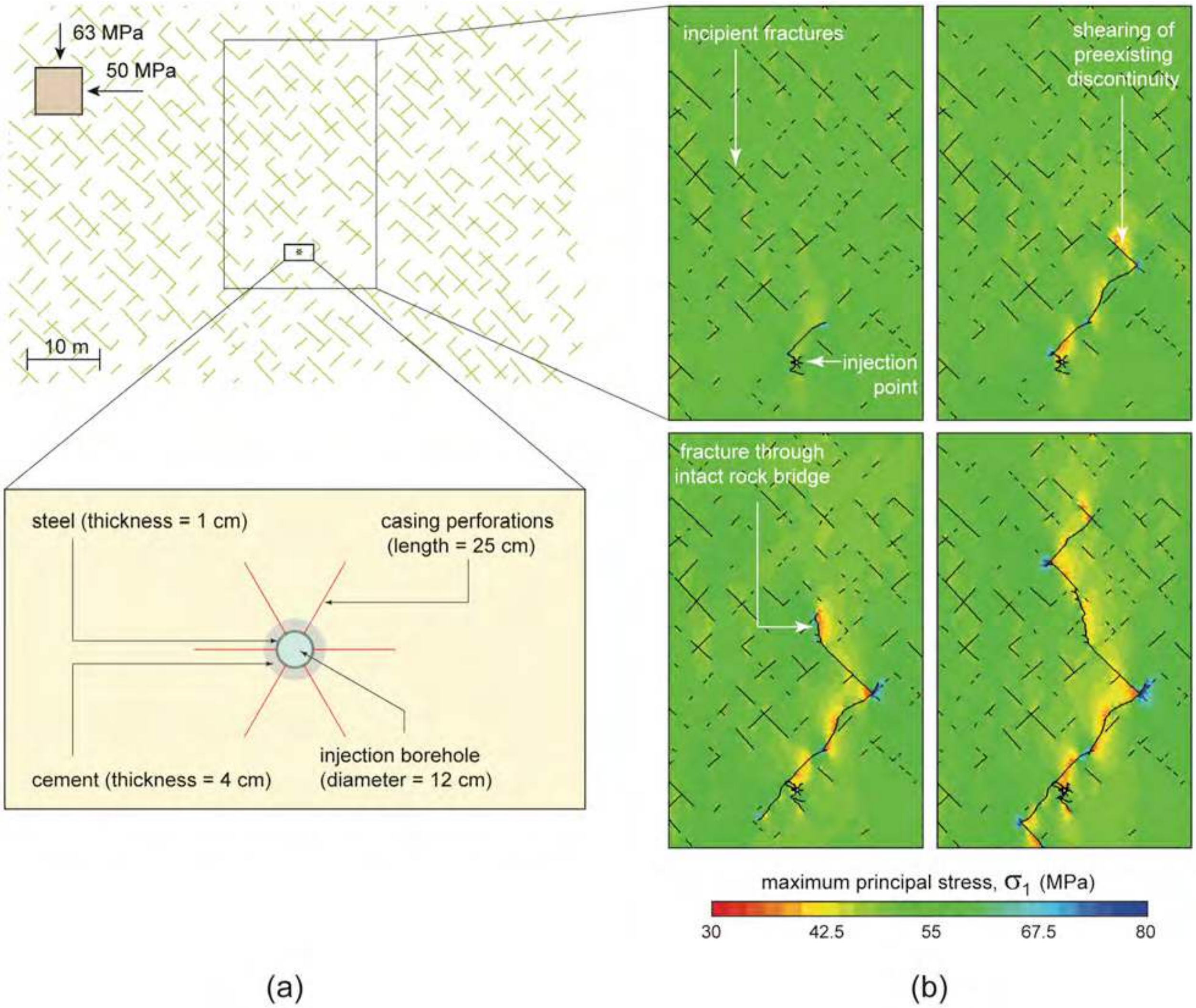


Figure 4. Simulation of HF from a perforated cased borehole in a fractured reservoir.
(a) Geometry of the adopted DFN with zoomed-in view of the injection borehole. The two discontinuity sets are oriented at ± 45° to the in-situ principal stresses and have average spacing and rock bridge length of 2 m. The average fracture length varies between 2 and 4 m.
(b) Simulated fracture trajectory and associated contour of maximum principal stress.

Concluding remarks

The results illustrated in this paper are part of an ongoing research effort to develop and further validate 2D and 3D numerical models that could aid in the design and optimization process of HF in shale reservoirs. The presented FDEM approach appears to hold great promise as a tool to obtain unique geomechanical insights into HF under realistic rock mass conditions. Furthermore, the inherent ability of the method to generate synthetic seismic events is currently being further investigated at the reservoir scale, with the ultimate goal of improving the current understanding and interpretation of microseismic data, through the explicit evaluation of their geomechanical causes (i.e., forward modeling) (Fig. 5). In future studies, a more accurate hydro-mechanical coupling will be introduced to account for viscous dissipations within the fracture network as well as for matrix leak-off effects.

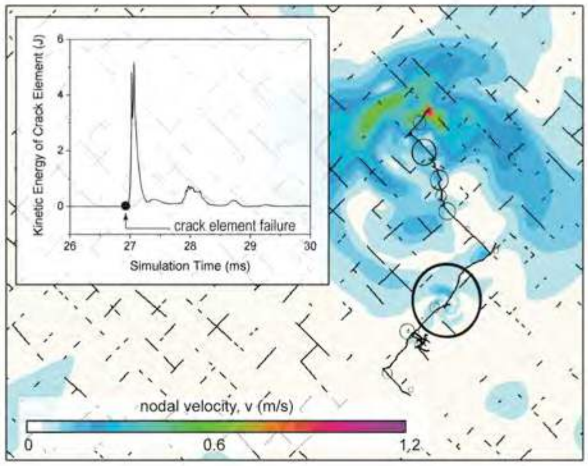


Figure 5. Nodal velocity field at the time step corresponding to the final stage of the HF process depicted in Fig. 4. The black circles correspond to the cumulative hypocenter location of clusters of microseismic events. The diameter of each circle is proportional to the total kinetic energy computed at the source (see inset graph). Further details can be found in Lisjak et al., 2013.

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Interaction between Hydraulic Fracture and Discrete Fracture Network in Shales

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Introduction

Extraction of the abundant reserves of shale gas in North America and elsewhere in the world has been made economical over the last 15 years because of advances in two technologies: horizontal drilling and multi-stage hydraulic fracturing. Multi-stage fracturing from a horizontal section of the borehole, typically 700 m – 1500 m in length, allows effective stimulation of the production horizon. Although hydraulic fracturing has been used in successful commercial applications in conventional reservoirs since 1949, there is still a lack of understanding of the effects of hydraulic fracturing in these shale-gas, "unconventional," reservoirs. This often leads to unreliable borehole completion designs.

The main difficulties in achieving reliable borehole completion design arise from: 1) complexity of the physical processes involved, 2) geological complexity, uncertainty and spatial variability and 3) relatively limited access (typically a single borehole) to the treated formation. Even hydraulic fracturing of a formation, which can be idealized as homogeneous, isotropic and continuous, involves complex, non-linear, hydromechanical processes occurring on different length scales. Shale gas reservoirs, on the length and time scales of interest during the hydraulic fracturing stimulations, cannot be properly approximated as homogeneous or continuous. Hydraulic fracturing and stimulation of shale formations are critically affected by interaction between the hydraulic fracture and the discrete fracture network (DFN). This interaction affects not only the speed of hydraulic fracture propagation, but also the stimulation of the reservoir, or the extent of DFN that undergoes inelastic deformation (i.e., slip and opening). Thus, in order to be able to analyze and design a hydraulic fracturing treatment, it is necessary to have not only analytical tools capable of simulating propagation of fluid-driven fracture in discontinuous (already fractured) rock mass, but also to have a way of characterizing the DFN in the formation of interest.

Despite all of the advances in recent years, characterization of pre-existing fractures in reservoirs that are accessed directly by one or just a few boreholes is difficult and involves lot of uncertainty (particularly with respect to the fracture size distribution). The uncertainty and spatial variability in the DFN geometry suggest that these problems cannot be properly treated deterministically. Typically, major faults and discontinuities with well-known geometry need to be represented deterministically, while the rest of the pre-existing fractures must be considered stochastically using a statistical model constrained by the available field data (i.e., fracture density, orientation and fracture-length distribution). Thus, to be useful, the numerical models must be able not only to simulate complex processes in complex geological settings, but also to address uncertainty in the input data. One way to address such uncertainty is to run multiple simulations for different realizations of the DFN.

Fracture Network Engineering Approach

Unlike civil and mining engineering situations, direct access to the subsurface is not possible from a borehole. This means that in order to understand the rock mass response to fluid injection, we must rely on other field data that are available. These include injection pressure and flow rate as functions of time, microseismic signals (now being monitored and processed with increasing frequency) and tracer tests during production.

The microseismic data provide information on location, time, magnitude and source mechanics of local instabilities (events) caused by fluid injection in the rock mass. Although microseismic events may result from either fracturing of the intact rock or seismic slip on pre-existing fractures, the magnitudes of events associated with intact rock fracturing are typically below the threshold of recording equipment, and therefore are not included in the recorded microseismic data [1]. Very often, the extent of microseismic activity is assumed to correspond to the stimulated rock volume (SRV). Although there should be a correlation, it is not clear that these two volumes are the same [1]. For example, if a microseismic event is caused by change in the total stress, it might not be connected to the borehole by a continuous high-permeability (i.e., stimulated) region. Microseismic data do not allow a clear distinction to be drawn between events that are caused by total stress change ("dry events") and events caused by fluid pressure change ("wet events").

Taking maximum advantage of the microseismic signals and their proper interpretation requires a numerical model that is capable of generating synthetic microseismicity. Such numerical models can be calibrated by comparing the model results with the observed field microseismicity (and the injection-pressure data) until the predicted and observed data are in a close agreement. This is the essence of the Fracture Network Engineering (FNE) [2] method. The calibrated model can be used for interpretation of the field microseismicity. Also, forward-looking analyses can be carried out then to simulate how an assumed fracture network will behave for different stimulations, with the goal of establishing design criteria for the field project and engineering the most effective fracture network required for the purpose (Figure 1).

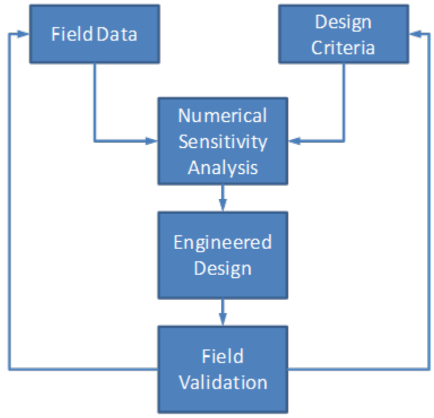

Figure 1. Fracture Network Engineering design cycle.

Numerical Model Application to Fracture Network Engineering

The numerical models based on the discrete element method (DEM) can serve as the analytical component in the FNE. In the DEM, an assembly of blocks (polygonal or polyhedral) or particles can be used to represent the mechanical behavior of the fractured rock mass. Contacts between the blocks can open or slide to approximate the behavior of pre-existing or newly created fractures. Although the DEM typically does not represent partially fractured blocks or allow fracture propagation through a block, both effects can be achieved by gluing (i.e., assigning certain bond strength in normal and shear directions) some parts of the interfaces between the blocks and allowing progressive failure of the interfaces, as dictated by evolution of the contact stresses during simulation.

The procedure is illustrated by the following example, in which the three-dimensional DEM code *3DEC* [3], is applied to a problem of hydraulic fracturing in a naturally fractured reservoir [4]. One part of the sensitivity study was to investigate the influence of the DFN connectivity (as a function of fracture size and density) on the way in which the fluid injection affected reservoir stimulation. Two DFNs were used, one fully connected and one sparsely connected, as shown in Figure 2.

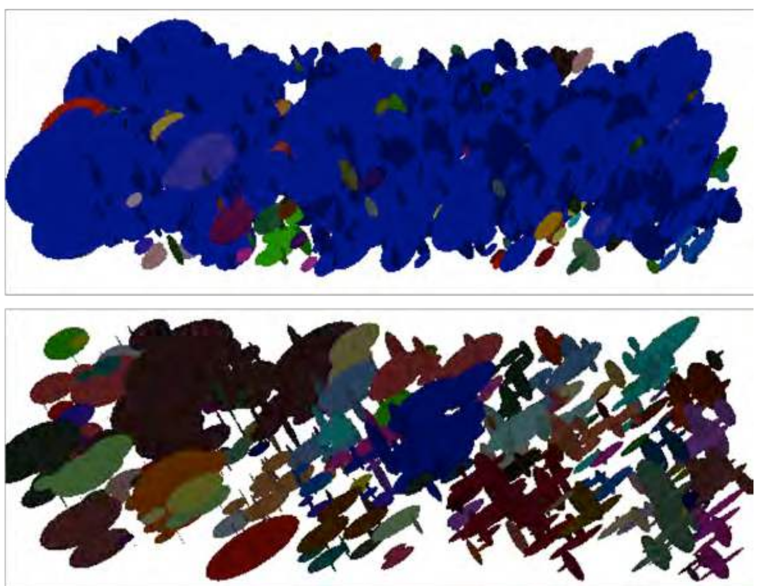

Figure 2. Fully connected (top) and sparsely connected (bottom) 3DEC DFN realizations.
Clusters of connected fractures have same color. Taken from [4].

Figure 3 shows a horizontal cross-section (indicated in Figure 4) through the stimulated network. Distribution of fluid pressure after 50 minutes of injection is indicated by the color scale. The maximum horizontal principal stress is in the x-direction (i.e., horizontal in the plane of the plot) and the minimum horizontal principal stress is in the y-direction (i.e., vertical in the plane of the plot). Thus, in the plot, the trace of the hydraulic fracture is horizontal through the middle of the model. The plot indicates that the better connected DFN results in better stimulation of the naturally fractured reservoir, as also confirmed by more quantitative measures. That result is to be expected. However, the contour plot of the hydraulic fracture apertures (shown in Figure 4 with pressure contour plot on the surface of the hydraulic fracture limited vertically within the stimulated reservoir) indicates an interesting response. The apertures do not follow the general trend that is expected from classical Hydraulic Fracture Models, such as KGD and PKN [5]. As a result of interaction between the hydraulic fracture and the DFN, and slip on the pre-existing joints intersected by the hydraulic fracture, the apertures in the plane of the hydraulic fracture do not vary smoothly and gradually as usually predicted. Instead, they are very non-uniform and even discontinuous. It is expected that such distribution of apertures will have a significant effect on proppant transport and placement.

Instead, they are very non-uniform and even discontinuous. It is expected that such distribution of apertures will have a significant effect on proppant transport and placement.

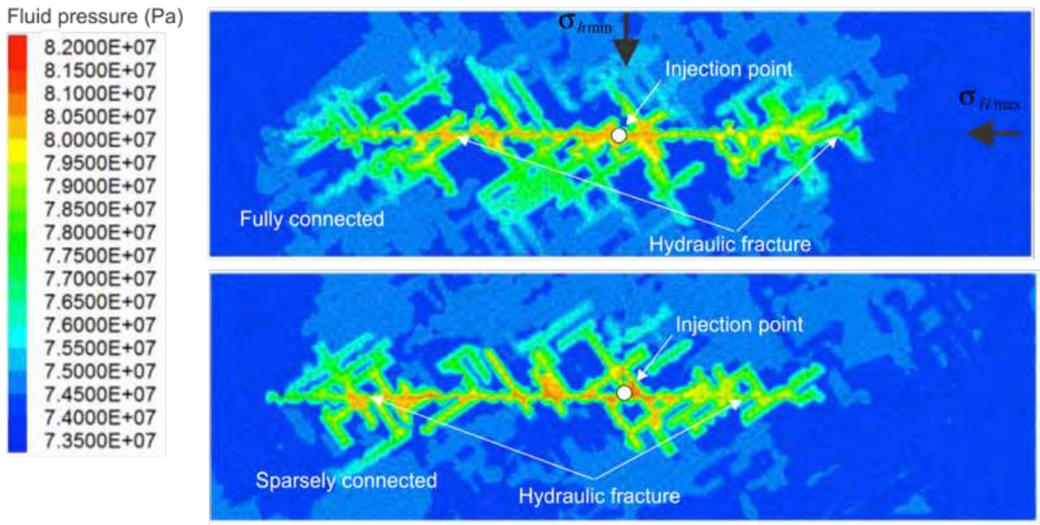

Figure 3. Fluid pressure distribution on a horizontal cross-section cutting through the injection point after 50 minutes of injection for two DFN realizations. Taken from [4].

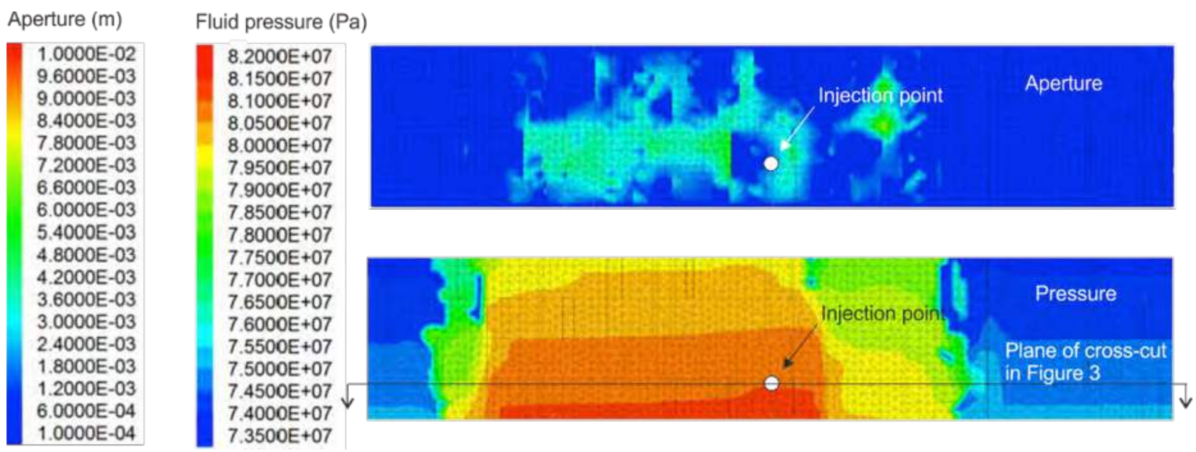

Figure 4. Distribution of fracture aperture and fluid pressure for the sparsely connected DFN in the plane of hydraulic fracture. Taken from [4].

Conclusions

The DFN can have a profound effect on hydraulic fracture propagation, its interaction with the surrounding rock mass, and eventually the effect of fluid injection on reservoir stimulation. As the example indicates, analysis of rock mass stimulation by fluid injection requires analytical tools, such as numerical models based on DEM, which can represent discontinuities explicitly. The FNE approach, based on the use of these numerical models and field observations, promises to be an engineering design tool for operations that involve complex coupled processes in complex geological environments in which explicit representation of pre-existing fractures is essential.

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