

Geomechanical Aspects of Shale Gas Development

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Abstract

Shale gas development involves aggressive hydraulic fracturing of a naturally fractured rock mass to generate an interconnected open fracture network with a large internal surface area for gas drainage. Conventional hydraulic fracture design software cannot cope adequately with fracture propagation in naturally fractured rock, and it is not clear what form a better design software environment will take, but activity in a number of directions is taking place. Several preliminary options are discussed herein, along with a review of shale gas occurrence and the geomechanical aspects of its development.

Introduction

Decades ago, natural gas occurrence was noted during drilling through the naturally fractured black shales of Appalachia (Ohio Shale, Marcellus Shale, Utica Shale – Charpentier *et al.* 1995) and Texas. However, these fine-grained **N**aturally **F**ractured **R**ocks – NFRs – were considered poor prospects for economic production, despite considerable attention paid to them in the 1980's and 1990's by the United States Department of Energy and Gas Research Institute (e.g. Kruuskaa *et al.* 1998; Curtis 2002). Persistence in their development and the implementation of large volume propped **H**ydraulic **F**racturing (HF) methods in vertical wells led to limited production of the gas in the Antrim Shale (Michigan Basin), Barnett Shale (Fort Worth Basin) and Ohio Shale (Appalachian Basin) during the 1990's and into the first part of the decade of the 2000's. Massive improvements in drill bit technology, top-drive drilling rigs, and down-hole steerable drilling motors made the emplacement of horizontal wells > 1 km long economical by the late 1990's. This was followed by development of new well completion techniques – **M**ulti-**S**tage **H**ydraulic **F**racturing – MSHF – in the period 2000-2008. With these technologies, the “shale gas revolution” had arrived in the United States and Canada, but it was not until about 2010-2012 that the full economic impact was realized.

The key factor was that although shale gas had been produced for decades (anecdotally, the first commercial use of natural gas in the USA was sourced from NFRs in Appalachia in the early 1800's), long horizontal wells developed with MSHF proved to be so highly productive that large-scale shale gas commercialization became possible. To achieve this commercialization and improve the effectiveness of HF in NFRs, special techniques such as slickwater fracturing (water with a friction reducer), high rate (> 8 m³/m) viscous fluid HF with proppant, and microseismic monitoring to gauge effectiveness and HF extent were developed alongside more rapid drilling methods. Seemingly suddenly, vast regions underlain by shale gas suddenly became exploitable, and activity moved from the original fields (mainly the Barnett Shale in the Dallas-Ft. Worth Basin) to deposits in northeastern USA, in northeastern British Columbia, and elsewhere. The price of natural gas was soon driven down from over \$10.00/MMbtu to less than \$4.00/MMbtu by 2009, many coal-fired power plants were put on hold or cancelled in favor of gas turbine generations, US gas imports from Canada declined, American CO₂ emissions dropped, and,

because of the sister resource (shale oil) and natural gas liquids accompanying shale gas, US oil imports plummeted. The economic impact on the USA has been profound, and the sharp economic recovery in the USA from the 2008 World Financial Crisis is attributed in no small part to the surge in shale gas and shale oil development (Jacoby *et al.* 2011).

In the period 2005-2008 it was recognized that MSHF technology being perfected for shale gas was applicable to shale oil deposits – conventional oil trapped in fine-grained rocks, usually the source rocks from whence the oil was generated (in contrast to more conventional reservoirs to where some of the oil migrated after being generated). First in the Bakken Formation of the Williston Basin (Lolon *et al.* 2009), then in the Eagle Ford of the Western Gulf Basin (Bazan *et al.* 2012), the application of MSHF in long horizontal wells has led to the sharpest leap in the history of US oil production: an unprecedented 10^6 barrels of production were added in the USA in the calendar year 2012 (BP 2013).

Shale gas and shale oil development depends on successful MSHF, and this area of rock mechanics has become of great interest to research and practitioners as it is apparent that a great deal remains to be learned about the behavior of naturally fractured low-permeability rock masses when subjected to aggressive HF activity. Specifically, our discipline needs to develop better HF design tools, based on the physics of the problem, not an excessively simplified set of assumptions. Currently, the widely-used commercial HF modeling tools are based solely on mathematical modeling of single planar vertical fractures induced in layered weak rocks that are assumed to be unfractured and linear elastic.¹ No provision for interaction with a NFR medium is made. Even in conditions that correspond reasonably well to the assumptions, i.e. strong unfractured rock masses such as homogeneous sandstones), they serve only as rough approximations that must be carefully calibrated in individual regions, and even in different regions within a given field. At worst, HF modeling tools used too liberally can lead to poor design, production misestimates, and so on.

This review article is an introduction to the broad issue of mechanics and HF in stiff, naturally fractured rocks.

Shale Gas Provenance and Occurrence

Shale gas is defined as natural gas of biogenic or thermogenic origin trapped in the fine-grained host rock where it was generated. In contrast, tight gas sands are low-permeability porous reservoirs to which biogenic or thermogenic gas migrated from a source rock generally found down-dip or below the tight gas reservoir. Biogenic shale gas was generated by anaerobic bacterial decomposition of carbohydrates (plant matter), generally at depths less than 2000 m; thermogenic gas was generated by the anaerobic and thermally activated decomposition of lipids and other algal matter at depths generally greater than 2500 m. In some cases, such as the Colorado Group shallow gas in Alberta (Rice and Claypool 1981), biogenic gas is found in zones comprising fine-grained organic-rich source strata alternating with thin tight gas sands, and even thin coal streaks, with all three lithologies being potential

¹ This critique applies to the great majority of available software, but only to the geomechanics part, not the cost-benefit analysis and other parts. I have avoided being specific because different software environments have somewhat different limitations, and any user is advised to evaluate products carefully to make sure the product meets the need at hand.

contributors to production, although the tight sands dominate the well behavior. These relatively shallow gas occurrences are dominantly of biogenic origin but because thermogenic gas may have seeped upward during geological history from deeper strata, the natural gas in the reservoirs may be of mixed provenance. However, the shale gas occurrences that are the focus of greatest attention in the United States and Canada are thermogenic in origin, geologically old, and may well be locally rich in C₂+ molecules which are economically much more valuable and lead to the search for these “sweet spots”.

Major shale gas deposits that are currently being exploited commercially include the Barnett (Texas), Haynesville (Louisiana), Marcellus (eastern USA NW of the Appalachian Mountains), Horn River Shale (NE BC) and the Montney Shale (NE BC and NW Alberta).

Geological Characteristics of SG Reservoirs

Each reservoir is different, but all reservoirs have similarities. This means that outlines and summaries of the characteristics of thermogenic SG reservoirs are useful for the general assessment of geomechanical properties and for the empirical development of best practices for HF in NFRs through correlative methods. SG reservoirs that are thermogenic in nature are almost invariably black shales, the color resulting from high residual carbon content because of an originally high organic content (Tourtelot 1979). They are marine shales (much more rarely lacustrine) laid down in foreland basins in thicknesses up to 200-500 meters (e.g. maximum H over 150 m for the Horn River SG in BC, over 400 m for thicker parts of the Montney Shale in western Alberta), although most SG reservoirs being exploited in the USA range from perhaps 20 m to 60 m in thickness). The thickness is an important aspect of development, as the implementation of HF treatments to try and cover a SG reservoir over a 200 m height is challenging.

SG reservoirs are generally quartz-illite shales containing little to no swelling clay, and they are of low porosity (<10%) with a microDarcy matrix permeability. Deep burial and great geological age mean that smectitic clay minerals likely laid down with the original sediments have been diagenetically altered to illite and precipitated quartz. This means that the silica content of the SG strata is high (over 40%) and the clay mineral content, dominantly illite, is low (10-40%). This transition is considered to be the major reason that SG strata are naturally fractured (see mechanical properties below) because the smectite-to-illite transition is associated with a substantial volume diminution. Note that if smectite is present, even in small amounts, swelling can have significantly negative effects on HF results using aqueous fluids.

The SG plays being exploited at the present time may be considered as non-tectonic from a structural point of view. Although there are local faults, in general the strata are relatively flat-lying and unfolded. For example, the Marcellus Shale lies under much of the Appalachian Basin (Roen and Kepferle 1993) to the northwest of the Appalachian Mountains, and the SG prospective region stretches from the middle of New York state to the southernmost part of West Virginia, and extends from the disturbed belt (northwestern Appalachian thrust belt) to eastern Ohio and Michigan, underlying about a quarter million square kilometers. It is thicker in the southeast against the thrust belt, but as the formation is more and more deformed and intersected by faults, the gas content is less. To the northwest, the Marcellus Shale tends to have more liquids and C₂+ molecules, and therefore be a more desirable

target. Probably $\frac{3}{4}$ of the Marcellus is undeformed and unfaulted, but naturally fractured. Similar conclusions may be drawn for the Utica Shale that underlies the Marcellus Shale, and also stretches up into the St Lawrence River lowlands in Quebec (Dykstra and Longman 1995). By extension, similar issues such as deformation, faulting, richness in liquids, and so on, extend to other SG deposits.

Mechanical Characteristics of Shale Gas Reservoirs

There are three major issues related to the mechanical properties of shale gas reservoirs: the rock mass deformation properties, the transport properties, and the fabric properties related to the disposition of discontinuities in the rock mass. In particular, the latter is not only difficult to quantify, it is not clear how this system responds to stimulation, and the uncertainty of the fabric condition of the rock mass *in situ* is a contentious issue. The SG targets being pursued in the USA and Canada are considered to be fractured shales (e.g. Gale *et al.* 2007). Tables 1 and 2 are brief summaries of some of the properties of three major SG plays in North America.

Table 1: Petrophysical Properties of Three Selected Shale Gas Deposits

Shale gas play name	Porosity (%)	Permeability (millidarcies)	Clay content (%)	Organic matter (%)	Silica content (%)
Barnett	3-6 ^[5]	0.02-0.10 ^[6]	Below 35 ^[1]	3-10 ^[1]	35-50 ^[1]
Marcellus	6-10 ^[4]	0.13-0.77 ^[7]	10-35 ^[4]	2-10 ^[4]	10-60 ^[4]
Horn River	3.2-6.2 ^[8]	0.0003 ^[9]	20-40 ^[8]	0.5-6.0 ^[8]	45-65 ^[8]

Table 2: Mechanical Properties of Three Selected Shale Gas Deposits

Shale gas play name	Static Young's modulus (GPa)	Static Poisson's ratio	Natural fracture descriptions	Velocity information
Barnett	20-80 @ confining stress 50 MPa ^[2,3]	0.18-0.32, confining stress 50 MPa ^[2,3]	Strike and dip are N50°W, 80-85° ^[2,3]	v_p 3.9-4.2 km/s; v_s 2.5-2.6 km/s, v_p/v_s 1.6 @ stress of 45 MPa ^[2,3]
Marcellus	15.5 at a confining stress of 16 MPa ^[11]	0.16-0.18 ^[12]	One set NE, another striking NW ^[4]	
Horn River	18-31 ^[10]			$V_p/V_s = 1.7$ ^[10]

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These table values are ranges and do not contain the most extreme values reported. Many issues including anisotropy in properties such as stiffness, permeability, resistivity and acoustic response are not addressed. The effects of anisotropy, strain, stress level and microfabric on rock deformation properties are critical factors, and are the subjects of intensive studies (e.g. Fjaer *et al.* 2013). Young's modulus, for example, can be as much as 50% lower in unconfined conditions, compared to *in situ* stress conditions, largely because of the effects of stress-relief-induced microcracking during coring and specimen preparation.

An economically important aspect of SG (and shale oil) production is that the matrix permeability is highly sensitive to effective stress (drawdown), especially in less stiff shales, and that this effect is largely irreversible because it is associated with the anelastic closure of microfissures (Aldin 2013). The effect is far less pronounced in stiff SG strata, which are usually quartz-illite shales with low clay contents and no swelling clay, whereas the softer SG strata tend to have higher clay contents with perhaps some swelling clay. The important observation is that rapid drawdown of a wellbore may cause microfissure closure and sharp reduction of the matrix permeability in rocks adjacent to the induced HF and natural fractures. This means the well would experience better early-time production, but worse long-term production, resulting in a loss of recovery factor (but perhaps a better cash-flow situation). This is an important geomechanics-related optimization issue, demonstrating that there are important lithological, mineralogical and microfabric aspects of the mechanical properties of gas shales.

The table data refer to small scales (cm), and the important properties of SG reservoirs tend to be at the scale of metres or 10's of metres, and include the effects of fractures and large-scale anisotropy. For example, slight differences in flat-lying lithologies give rise to a large-scale anisotropy as well as heterogeneity. A priori, one would expect mechanical factors such as cohesion, UCS and stiffness to be well-correlated to rock physics factors such as porosity, water content (related to porosity for saturated shales), clay content, cation exchange capacity (related to clay content and type), cementation ratio (from logs), and so on (Dewhurst *et al.* 2008, David 2007).

Natural Fractures

Up-scaling of geomechanics data is a significant challenge, particularly in the case of NFRs. This section discusses some aspects of the presence and behavior of natural fractures.

Are the natural fractures open or closed at depth? This is not an easy question, and there are many natural fracture states that can be noted in semi-quantitative descriptions: open, closed, incipient, cemented, persistent, oriented... If a fracture can easily be observed in a borehole geophysical log (e.g. formation micro-imager resistivity log, borehole acoustic televiewer, acoustic fracture detection log using backscattered radiation analysis), there is no doubt that it exists; likely these fractures, upon examination in core, show surface alterations and mineral deposits that verify that the fracture acted as

a flow path deep in the ground. However, core examination often shows fractures that have opened during the rough handling of core, and although the fracture is clearly a planar surface of geological origin that cuts across bedding surfaces, no visible alterations of the fracture surface can be noted. This fracture is what is called an “incipient fracture” (Dusseault *et al.* 2011) that would, at the surface, be opened by weathering processes, but which at depth is closed and at best is only partially debonded across its surface area. An incipient fracture cannot be detected at depth because the intimate contact and high stress do not lead to a slight opening that would lead to back-scatter of seismic energy or otherwise be amenable to detection. Apparently, there is no method to quantify the relative importance of incipient fractures in the case of NFRs, but their importance seems to be significant.

The origin of natural fractures that are open or that are incipient (a weakness plane not fully opened) must arise from a tendency for lateral shrinkage in the rock at some time during its geological history, or because of the generation of large internal pressures that led to natural hydraulic fracturing. The major mechanisms are discussed here.

When organic (algal or vegetal matter) shales are laid down as organic muds, burial takes place, and much water is expelled from the shales. As burial of thick shale sequences continues, pore pressures build up from the vertical loading (the source of the overpressure in the Gulf of Mexico), and if $p_o > \sigma_{hmin}$, vertical hydraulic fracturing will occur as the only way to relieve the excess pressures. In fact, the flow of this expelled water at high pressures leads to pressurization of sand bodies that are isolated from regional flow regimes, leading to highly pressurized conditions (occasionally $p_o > 0.95 \cdot \sigma_v$). Vertical strains in a non-tectonic compacting environment lead directly to vertical subsidence, but the no-lateral-strain condition associated with flat-lying strata being dewatered leads to a diminution of σ_{hmin} , leading to internal HF, which leads in great part to the NFR fabric that we note in so many locations.

When burial of carbohydrates (vegetable matter) or lipids (algal matter) takes place, bacterial action breaks down the carbohydrates into CH_4 , CO_2 and H_2O , leaving carbon behind, and thermogenesis breaks down the lipids (called Type II kerogen) into hydrocarbons and carbon (hence black shales). The conversion of a semi-solid substance such as kerogen to a fluid (liquid and perhaps gaseous HCs) involves pressurization of the liquid as the matrix stress is thrown on to the fluids as pressure. As above, when $p_o > \sigma_{hmin}$, vertical hydraulic fracturing will occur, and part of the oil and gas can escape to migrate into porous, permeable reservoirs. Once the pressure is largely relieved, the remaining oil and gas can stay in the source rock, and these may, if the organic content is sufficient, form shale gas and shale oil reservoirs in rocks that are now naturally fractured.

A third important mechanism is the conversion of smectite to silica, illite, and water over geological time at depth. Not only is water generated which can increase the pore pressure early in this transition process, but the mineralogical change involves a volumetric shrinkage that can be as high as several percent (>10% if the shale was originally pure smectite). Lateral shrinkage, even a very small amount, has a large consequence on the horizontal stress because of the no-lateral-strain condition in flat-lying strata undergoing uniform changes. In an analogy to thermoelastic shrinkage, if there is a uniform lateral strain taking place in a laterally extensive stratum, then $\Delta\sigma'_h \approx \epsilon_h \cdot E / (1 - \nu)$. Here, the change in lateral effective stress is proportion to the product of the linear strain – $\epsilon_h = \Delta L / L$ – and Young’s

modulus, divided by $(1 - \nu)$, where ν is Poisson's ratio. Even for relatively soft rocks before full induration, say with a value of $E = 5 \text{ GPa}$, a 1% shrinkage ($\epsilon = 0.01$) leads to a loss of effective lateral stress of $\Delta\sigma'_h \approx \epsilon_h \cdot E / (1 - \nu) \approx 0.01 \cdot 5000 \text{ MPa} / (1 - 0.33) \approx 70 \text{ MPa}$. The rock mass has no choice but to develop vertical fractures when the horizontal effective stresses become tensile, and this often happens in nature in a regular pattern, a joint set (Figure 1).



Figure 1: Joint Sets in Outcrops of the Oil Source Rock, Central Sumatra Basin.

Figure 1 shows an outcrop of the source rock that is found 2600-3000 m beneath the center of the Central Sumatra Basin, where it generated oil and gas that migrated to a number of reservoirs in the northeastern part of the basin. The rock shows a very strong and regularly spaced joint set pointing to the nearby mountains, and it is likely that the direction 90° to the major joint set was the direction of σ_{hmin} ($= \sigma_3$) at the time the joints formed, parallel to the mountains, which is the commonly observed minimum stress direction at depth in foreland basins. Deeper in the basin, this rock is a black shale, it is undoubtedly fractured, and is considered prospective for shale oil and shale gas (depending on the depth of burial); here at the outcrops near the mountains, it has never been deeply buried, and this lacustrine formation contains zones of 3-12% algal TOC, and there are nearby coal seams and coaly residues in the shale (leaf and stem fragments).

Well Orientation and Stress State

To maximize reservoir contact area, the horizontal section of the well is drilled parallel to σ_{hmin} , which is usually assumed to also be σ_3 (an assumption that in most cases is correct). This means that in the virgin stress condition, the dominant plane of the fracture network will propagate at 90° to the wellbore axis. Hence, it is important to determine the orientation of the principal stresses at depth.

Although large-scale tectonic fabric gives a first-order estimate of the stress orientations, local effects such as gentle doming or basin subsidence may alter the regional stress fields, and it is best early in development planning to more precisely determine stress orientations. The preferred method for orientation reliability is tiltmeter-based deformation measurement during HF (Fisher *et al.* 2002), as this approach eliminates near-wellbore effects. Microseismic monitoring, particularly of the first fracture in

a horizontal wellbore, can also give good constraints as to the fracture orientation and the tendency for vertical fracture rise, as the microseismic “cloud” tends to form an ellipsoid with the short axis in the direction of σ_{hmin} . In an interesting development in Apache Energy Corporation’s Horn River Basin horizontal well drilling, the first handful of wells was drilled parallel to the mountain front, a reasonable expectation for the orientation of σ_{hmin} ; measurements later led them to rotate their well layout by 30° CCW, to correspond to the σ_{hmin} direction that had been determined (public-domain slides, Apache).

Because the distribution of σ_{hmin} with depth is a vital factor in HF behavior and is a first-order input to any quantitative design process, refinement of methods to determine σ_{hmin} and to also get an estimate of the $\sigma_{hmin}/\sigma_{HMAX}$ ratio is necessary in practice to develop a regional stress orientation map. Because precise and properly conducted leak-off tests to determine σ_{hmin} are expensive, it is necessary to include models that use borehole acoustic data to correlate to stresses, and these correlative models are undoubtedly SG basin-dependent. Use of uncalibrated acoustic measurements to build a σ_{hmin} profile is less desirable. Similar comments (e.g. Fjaer 2006) can be applied to acoustic-based predictions of static moduli and UCS, as the static moduli are also first-order inputs to HF simulation, and the Young’s modulus is highly stress-sensitive in NFR (note that there may also be substantial rate-dependent stiffness effects in the HF process).

Finally, it is important to recall that during active HF, the induced fractures will rise because the density of the fluid is less than the lateral stress gradient ($d\sigma_{hmin}/dz$) (Figure 2); thus, to minimize work for the volume injected, it is easier to grow upward than downward. The amount of rise is of great interest to operators because there is no economic value to the vertical propagation of induced fractures into non-productive horizons. Current HF models are not good predictors of height in the case of high-rate viscous fluid fracturing or gas fracturing of NFRs.

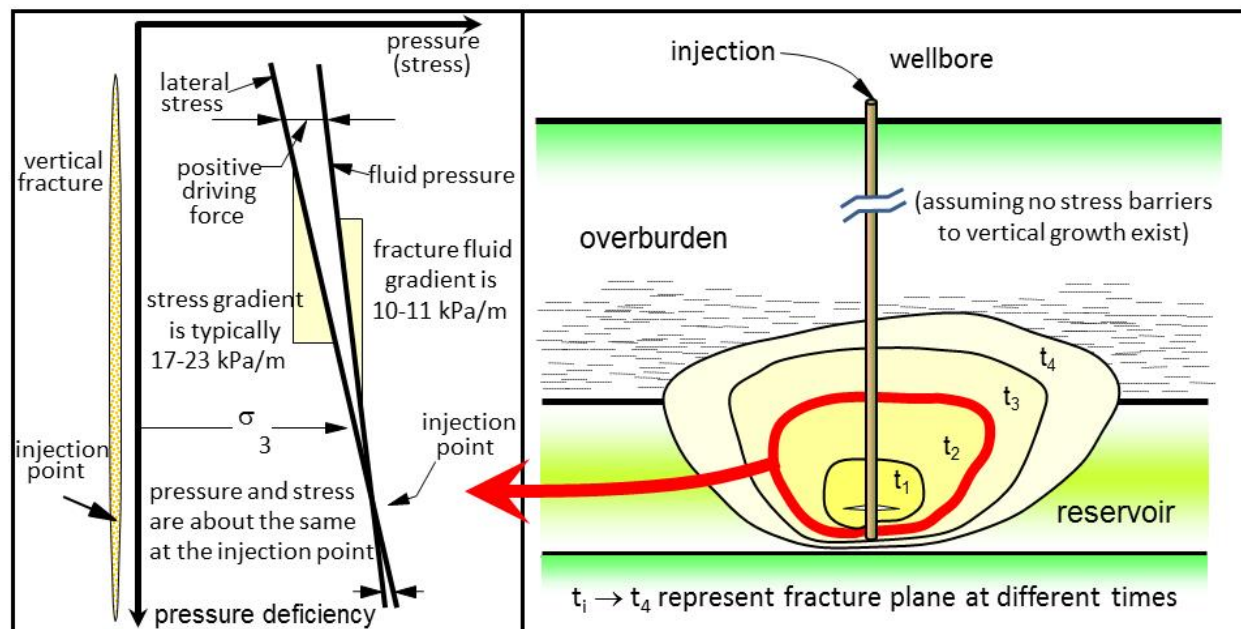


Figure 2: Fractures rise to minimize work because of different stress and pressure gradients

Fracturing and Shear Dilation

In the case of a single HF induced in a non-fractured continuum that has a high cohesion, the work is the combination of the fracture resistance that is overcome, the work of opening of the HF against a stress field, and the viscous fluid flow losses. Work of opening a fracture against the stress field is conceptually expressed for an impermeable rock as $W = F \cdot d \approx (p_f - \sigma_{hmin}) \cdot A \cdot \tilde{\omega}$, where p_f is the pressure in the fracture and σ_{hmin} is the minimum principal stress, A is area of the fracture, and $\tilde{\omega}$ is a measure of the mean fracture width (aperture). The product $A \cdot \tilde{\omega}$ is actually the volume, and because the HF is very thin and planar, only the net stress $(p_f - \sigma_{hmin})$ need be considered. It is instructive to compare this first-order approximation for the work in opening a fracture with the seismic moment equation in earthquake geophysics; they express the same work concept, albeit for shear versus normal displacement. To be complete, a work equation for fracturing should include the viscous energy losses and the work of fracture. However, the work of fracture increases with the square of the length but the work of opening increases with the cube of the length (i.e. the volume), it is apparent that after a relatively small amount of injection, the work of fracture is negligibly small, and essentially all of the work in HF is associated with volume growth and friction losses.

In real fracturing operations, σ_{hmin} is not constant (Dusseault and Simmons 1982), especially for the high-rate viscous fluid injection phase of the HF operation; the fracture is shorter and wider because of the high viscous energy losses down the crack, and the aperture growth in the horizontal direction for a vertical fracture reacts against the rock mass, leading to a stress concentration, evidenced as an increase in σ_{hmin} . Thus, also accounting for the viscous fluid energy losses, the injection pressure will show an increase with time, and this is widely observed in all waste solids injection operations and most large HF treatments. Furthermore, HF operations in sandstones that were initially monitored in the 1980's (e.g. Talebi *et al.* 1991) showed that the microseismic energy release was associated with shearing (Figure 3), with almost no energy detectable from tip parting (confirmed by others in the 1990's, e.g. Warpinski *et al.* 1998).

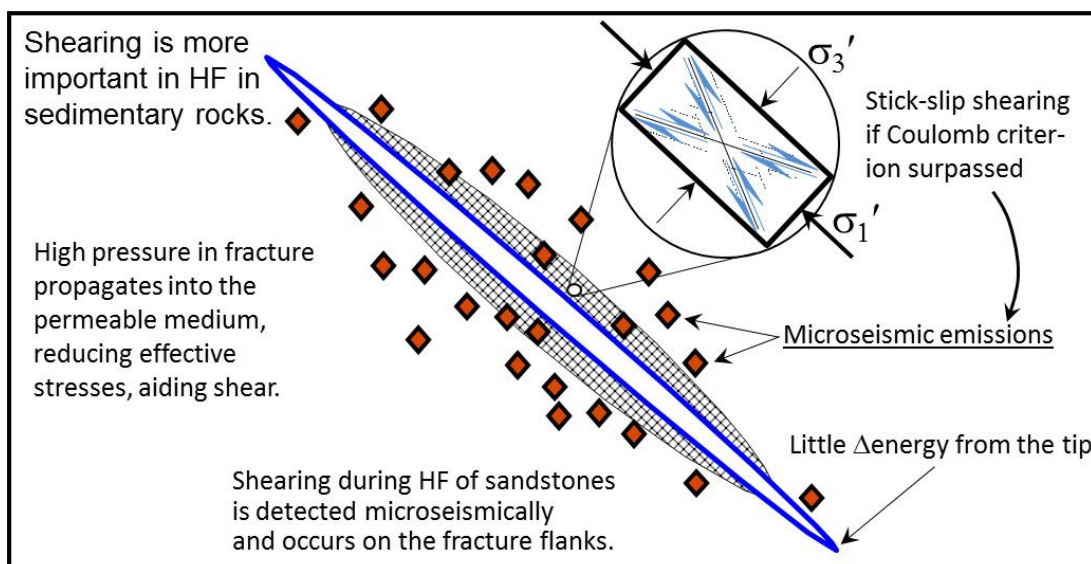


Figure 3: The energy release from shearing dominates microseismic emissions

Stress changes in cases of previous production or thermal stimulation (e.g. Dusseault *et al.* 1988, 2007) may have a major effect on fracture propagation behavior, as well as the effects of previous fracture stages, a subject of current great interest. This occurs at a large scale, but small-scale changes also take place. Consider the propagation of a vertical hydraulic fracture in a NFR such as a SG reservoir, where the matrix blocks have a high resistance to fracturing, but there are natural fractures that are open or incipient, with the dominant fabric sets rotated at some angle to the directions of the principal stresses, which are somewhat different one from the other. The fracture plane follows the local fabric from a work point of view, but as a fracture that is inclined to the orthogonal stress field is opened, it undergoes slip, and the deformation shown in Figure 4 creates a loading condition on the intersected fracture that causes it to be easier to change direction than to continue propagating in the same direction. The longer the fracture length in the deviated direction, the greater the stress that tries to turn the fracture around, something shown previously for continuum fracturing (Mogilevskaya *et al* 2000a and b) and for HF (Warpinski and Teufel 1987). The inset in the figure shows the normal stress that develops across the offset fracture because of the shear motion of the first opened natural fracture

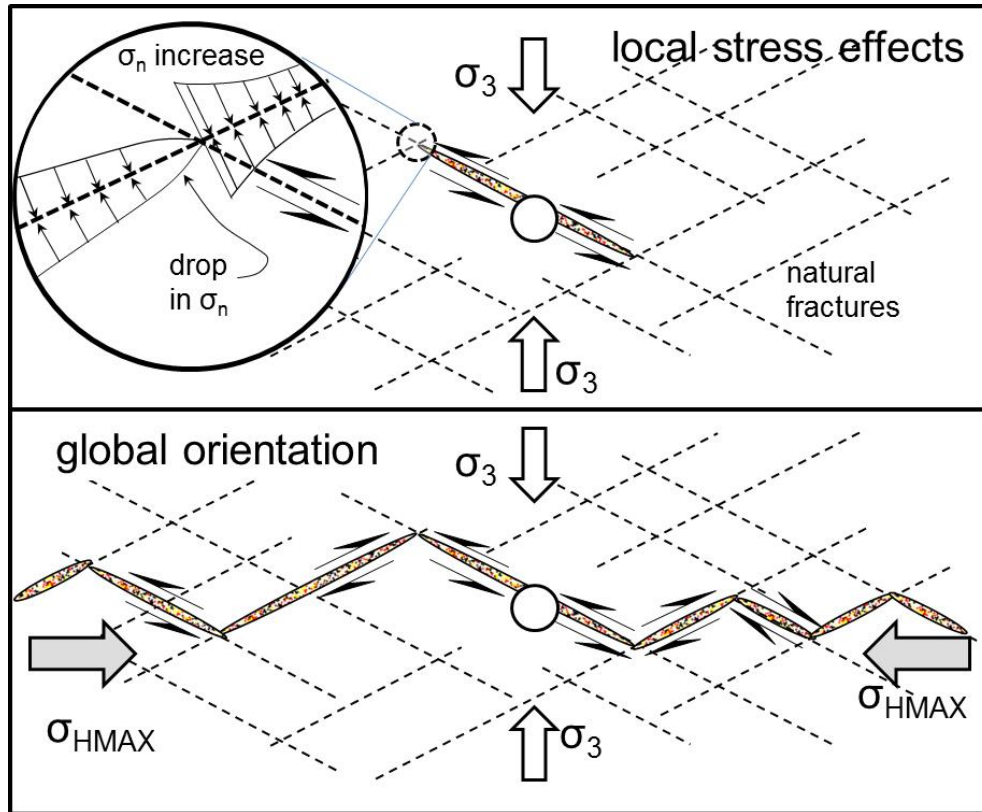


Figure 4: Local and large-scale effects on fracture propagation in NFR

So, at the local scale, a fracture will tend to follow appropriately oriented natural fractures rather than break through fresh rock because of the need to minimize local work, but overall, at the large-scale, the fracture will tend to remain on average at 90° to the direction of σ_{hmin} because of global work minimization requirements.

It was previously mentioned that microseismic shear events were observed to accompany HF, and these shear events in a material such as an unfractured sandstone appear to arise because of a reduction of the confining stress as the pore pressure percolates into the medium. Do such shear events occur in SG MSHF? Yes they do, and mapping them has proven to be highly useful to understand what is actually happening during HF. However, the understanding and interpretation of the microseismic emissions remains semi-quantitative because no models coupling the stress evolution explicitly to the stick-slip events generating MS have been developed in practice.

Appropriately oriented natural fractures in a SG HF operation in a differential stress field will exhibit shear displacement if the pore pressures within them are increased, if the normal effective stress across them is reduced, and most likely it takes place as a combination of the two processes. This is shown for a simple Mohr-Coulomb case in Figure 5. In this case, a combination of pressure increase and normal effective stress decrease led to an intersection of the stress state with the slip criterion of the joints (of course, only one MC failure line is shown, whereas in principal it is a probabilistic issue). Joints oriented in the blue orientations plotted on the small triaxial model inset will have slipped. Since shear in a stiff system with some component of brittle (strain-weakening) behavior is a stick-slip process, microseismic emissions will be generated, and these are used to map the region of shear slip.

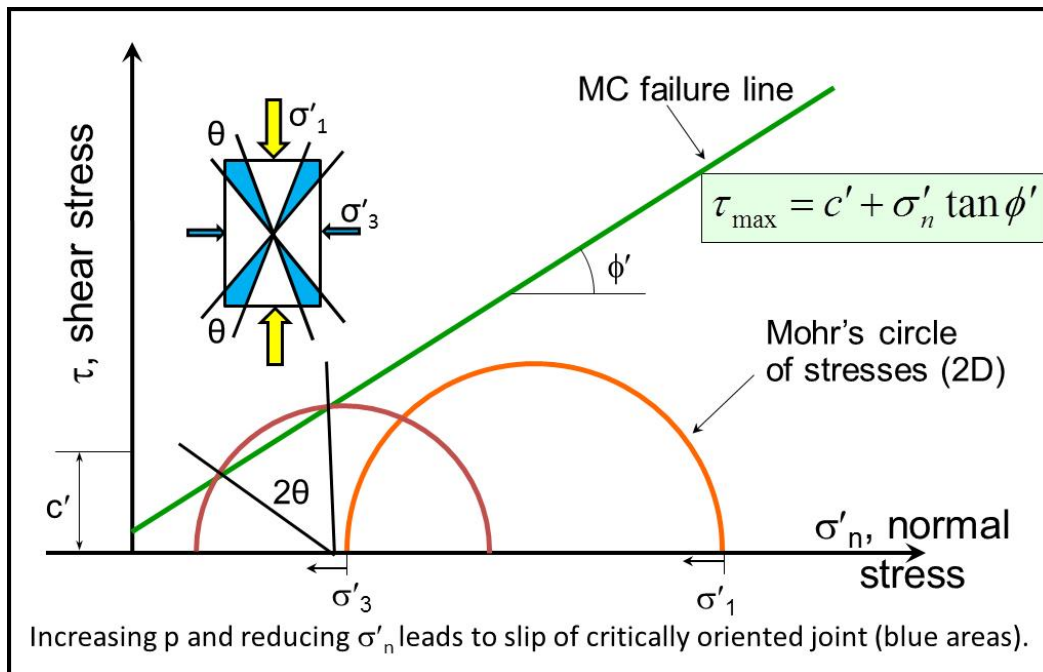


Figure 5: Properly oriented joint surfaces will slip before opening during injection

The mechanisms that arise to increase the permeability of a naturally fractured rock during HF are two-fold:

1. Opening or wedging of natural fractures takes place, and generally, it is desirable to have these fractures propped with a high permeability granular agent.

2. When shear displacement takes place, remnant increased conductivity is left behind after the stick-slip event through a process of self-propping (although this conductivity increase does partially disappear with time (creep) and effective stress (partial closure and crushing of asperities)).

The wedging of a crack in a stiff NFR leads to an opening of a crack far in advance of the wedge, if the wedge is a solid; if the wedge is the injected fluid under HF conditions, of course the injected fluid can be much closer to the tip of the wedged portion. This knowledge, in the context of the discussion above, helps explain the strategy of initially using a viscous fluid at extremely high injection rates ($> 8 \text{ m}^3/\text{min}$) containing high concentrations of proppant. This process wedges open many natural fractures, and most importantly, because of wedging and opening, additional fractures are opened so that a high-connectivity propped fracture zone is created. The proppant lags behind the fluid, even if it is high viscosity, because of the narrowness of the opened paths (frictional retardation, arching, etc.). So, in the absence of any shear dilation, the zone that is generated has a central region where the fracture apertures are wide and propped (at least partially) with granular proppant. Surrounding this is a region where the rigid blocks have rotated slightly, so that there are aperture openings that increase the fracture conductivity, generating an ellipsoid (approximately) defining an enhanced fracture conductivity region of high internal surface area which helps increase the CH_4 diffusion to the fractures, to flow to the wellbore.

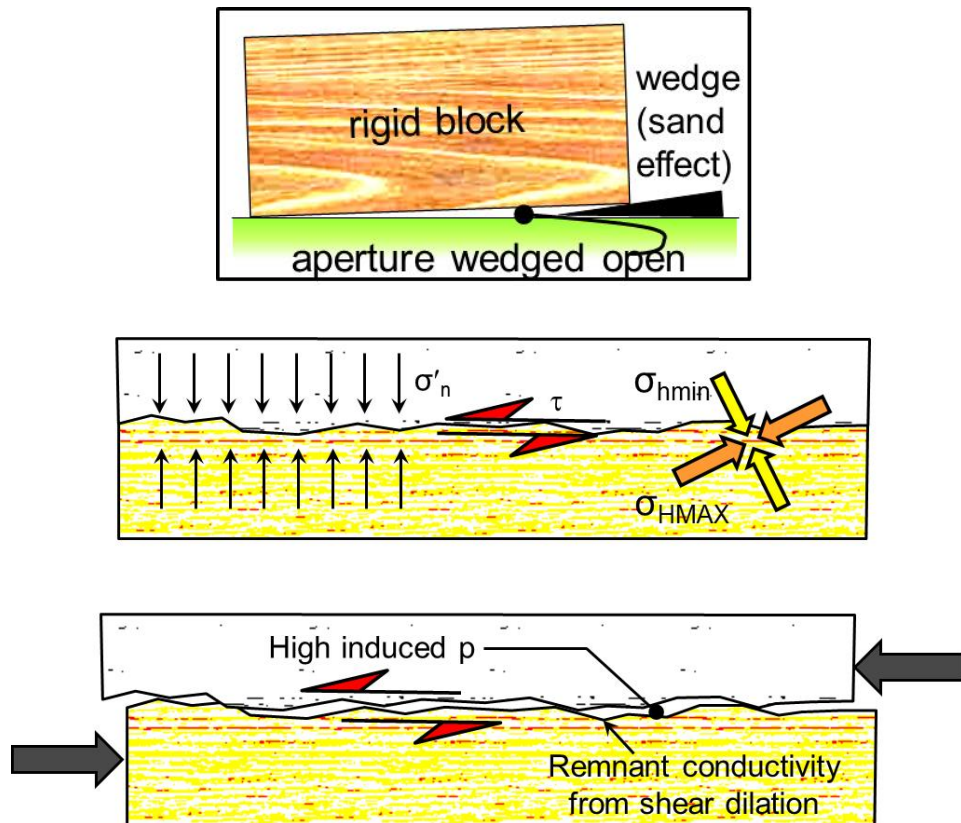


Figure 6: Wedging and shear dilation and conductivity increase

However, the MS emissions that were observed around HF's in the 1980's and 1990's were, in cases involving NFR, clearly taking place far from where the sand was reaching, and arguably even in conditions where the pore pressure had not yet penetrated. This led eventually to the concept of shearing along natural fractures, with a remnant conductivity arising because of shear dilation of the rough fracture surface (Figure 6). Indeed, a shear displacement as small as 1 mm is sufficient in a hard rock to increase the conductivity by an order of magnitude or more if the original fracture was largely closed.

Once this effect was realized, a new approach, high-rate slickwater fracturing, became widely used, usually after the viscous fluid fracturing phase with proppant, to try and stimulate the SG reservoir far from the propped region. Slickwater is water with a small amount of a friction reducing substance such as a polyacrylamide. This permits a dramatic lowering of the resistance to flow, so that, in principle, water and elevated pore pressures can propagate far from the propped zone. MS monitoring has demonstrated conclusively that this is taking place, as the ellipsoid of MS events during slickwater fracturing is much fatter and extensive than for the high-viscosity HF phase. The flow paths can be thin, and if the leak-off potential of the SG rock mass is low, the shear dilation effect can propagate out 200-300 m in some cases, developing a region around the sand-propped zone that is much larger in volume than the sand propped zone. The increase in conductivity of the natural fractures that have been sheared gives again a much greater surface area from which the gas to slowly diffuse. So, there is a differentiation between the "propped volume" (or "sand zone") and the "stimulated volume", which can be many times the volume of the sand zone (Figures 7 and 8 show the shearing and the rigid block displacement concepts at the field scale).

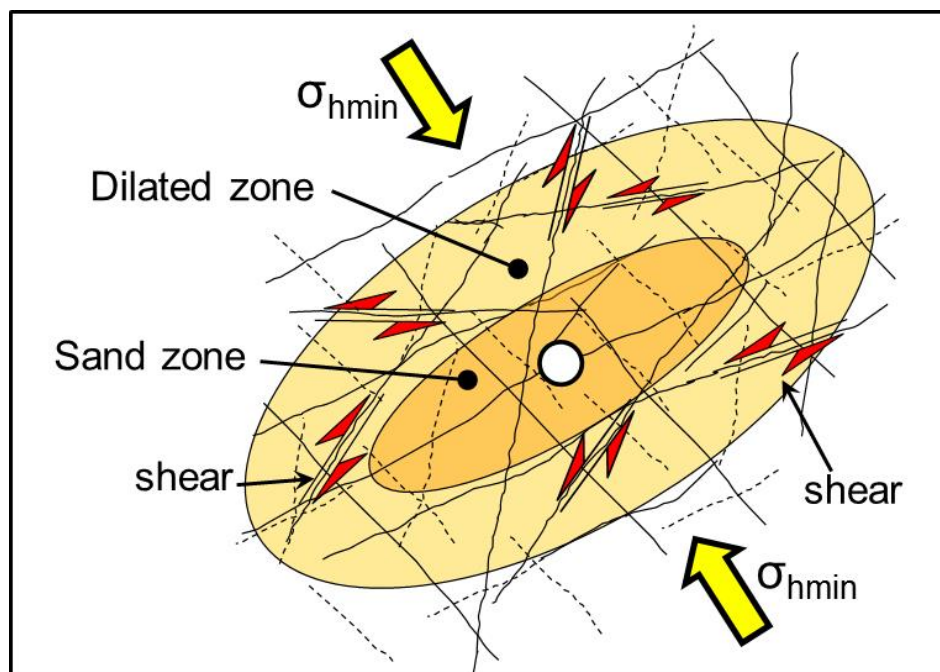


Figure 7: The sand-propped zone and the stimulated (dilated) zone

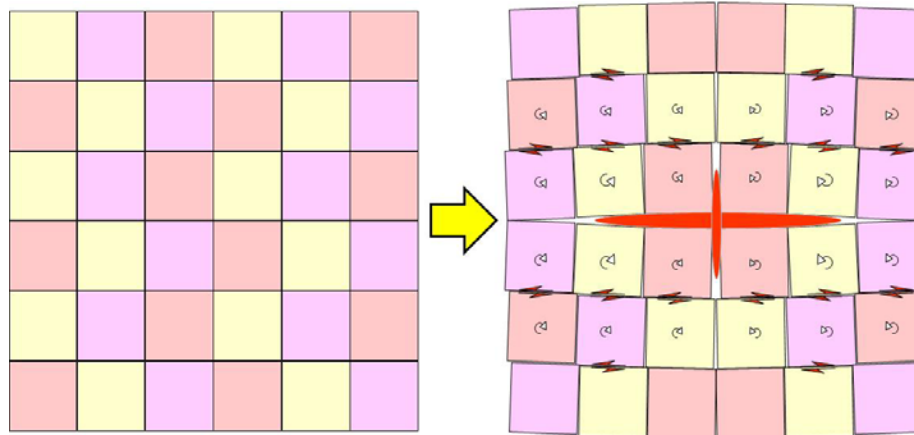


Figure 8: The concept of rigid block movements in high pressure HF with sand wedging

It is important to determine how large of a stimulated zone can be generated in real cases because this will help dictate the optimum well spacing, whether an additional upper row of wells is needed in a thick reservoir, the best spacing of fracture sites along the wellbore, what is the optimum size and rate of the HF treatment, at what depth in the reservoir should the wells be drilled, and so on. In this decision-making process, many other factors must also be considered, such as whether the shale is water sensitive (a gas or gelled propane may alternatively be used as the fluid at much greater expense), whether the first fractures affect the behavior of the subsequent fractures along the wellbore, whether there may be advantages to simultaneously or alternately fracturing adjacent wells, and so on. Figure 9 shows, in a simple manner, the disposition of two wells in a SG development, with ellipsoids representing the stimulated volumes.

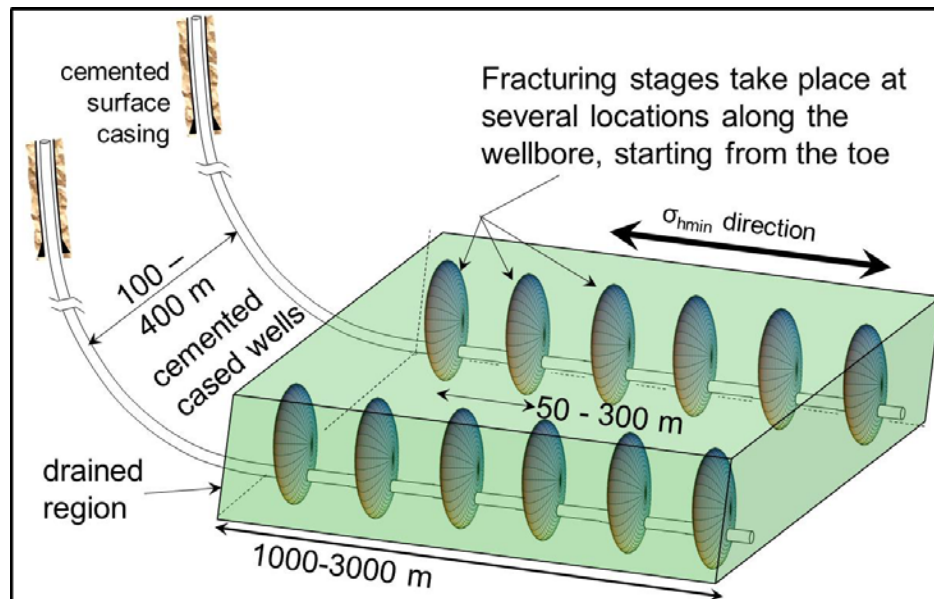


Figure 9: Well placement and optimization issues

Modeling Induced Fracturing

Classical approaches to HF design in the industry involve closed-form solutions, semi-analytical or integral solutions, and numerical methods based on some form of boundary discretization. Closed-form approaches include the Sneddon penny-shaped crack or elliptical variants, 2-D approximations such as the Geertsma-de Klerk-Kristianovic approach (e.g. Geertsma and de Klerk, 1969) and the Perkins-Kern-Nordgren approach (e.g. Nordgren 1972), modified crack solutions such as the Barenblatt-Dugdale method to eliminate the stress singularity associated with a sharp crack, the Eshelby solution, integral hypersingular methods (Mogilevskaya *et al.* 2000a and b), and various integrated and modified versions of these methods. Fracture initiation criteria at the borehole wall dealt with solutions for stresses around boreholes in cases of elastoplastic rocks or elastic rocks, some solutions coupled, some not (Wang and Dusseault 1991 a&b), and with some solutions it was found that fracture initiation a short distance within the borehole wall was possible. However, these and related solutions failed to address fracture propagation in a naturally fractured rock mass, although attempts to explain the physical processes involved with natural stresses and fabric, including stress changes, were quite common (Dusseault 1977; 1989, Dusseault and Simmonds 1982). Here I only cite mainly my own articles, but there are dozens of excellent articles following 1980 by Pollard, Rice and others, and over 8800 articles involving hydraulic fracturing in the Society of Petroleum Engineering library base alone, including both Journal and Conference articles.

The advent of Discrete Element Methods allowed the study of fractures in granular media with differential stresses and cohesive bonding between grains (e.g. Thallak *et al.* 1991), and these are undergoing rapid development for HF in NFR's.

More recently, mathematical models that are more rigorously coupled and that can incorporate strong fabric elements (faults, natural fractures that are strongly or weakly persistent...) have been developed and used. Some of these are based on Discrete Element Methods, on Extended Finite Element analysis, and on various hybrid formulations. Here, the current work of two students is briefly presented: one is a DEM investigation of strong fabric using UDEC™ (an Itasca Product), the second is a new hybrid model for thermal-hydraulic-mechanical (THM) coupling using a hybrid Displacement Discontinuity – Finite Difference coupled formulation.

Some Results Using 2-D DEM Models

The software UDEC™ is being used to look at the impact of strong fabric on the propagation of hydraulic fractures (Pirayehgar 2013). UDEC™ is a discrete element formulation widely used in rock mechanics to simulate the response of a jointed rock mass. The effect of strong rock fabric on the propagation of hydraulic fractures in a NFR can be explored as a set of numerical experiments, using models with different types of fabric and varying differential principal compressive stresses. The medium is constructed with strong fabric comprising joint surfaces that are frictional, or they can be frictional-cohesive with strain-weakening, whereas the matrix blocks cannot be fractured. The model is hydraulically coupled, as flow in the joints (1-D cracks) is linked to the mean joint aperture that changes during the simulations.

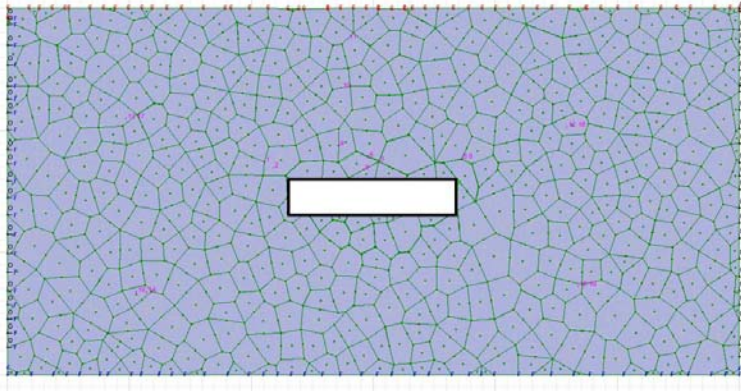


Figure 10: A Voronoi tessellation with a central opening subjected to injection

Figure 10 shows a Voronoi tessellation, which represents a 2-D rock mass with intersecting joints connected at nodal points. Such an array might be taken to represent a random array of joints but with no dominant orientation (no strong fabric). Alternatively, one may design a fracture array with strong oriented fabric of various types to explore the interaction of joint fabric and the directions of the principal stresses. In these simulations, numbers have been deliberately left off so that only the general results are shown for a few of the cases being studied. The outside of the array is subjected to a stress, isotropic or differential, and the rectangular opening is subjected to a boundary pressure greater than the far-field pressure, so that pressure diffusion takes place, as shown in Figure 11, which is a realization of pressure diffusion into the fracture system, and it is to be noted that if a stronger differential stress is applied, there is greater anisotropy in the distributions of the pore pressure, as fractures approximately normal to the minimum principal stress open more easily than those at 90° , and the differential behavior magnitude is related to the stress difference in a non-linear manner.

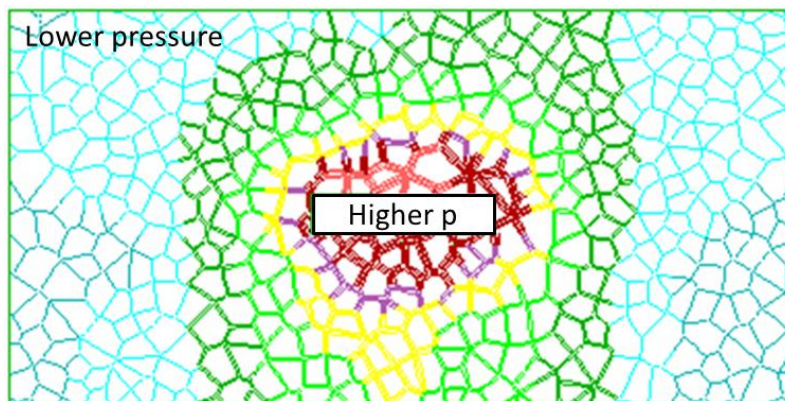


Figure 11: Pressure diffusion into a Voronoi-style fracture system

Figure 12 shows some of the effects that can be studied, whether injection takes place along a line, at a point, or, in this case, along the boundaries of an opening. On the left-hand side is a plot of joints that have undergone sufficient displacement that they are not in direct contact; i.e., they have “opened” in response to the hydraulic injection. Of greater interest in the context of SG stimulation is the propensity

for shearing. In these simulations, slip has occurred along a number of favorably oriented surfaces, with right- and left-lateral shear (conjugate shear), and one might suppose that in each case a microseismic event has occurred and a discrete amount of energy consumed (as work). The amount of energy associated with the stick-slip even is small compared with the work done to generate the distortions in the mass (UDEC permits the displacements to all be tracked, so that work calculations - $F \cdot d$ - can be undertaken). An energy formulation for the energy release of the slip event is being explored.

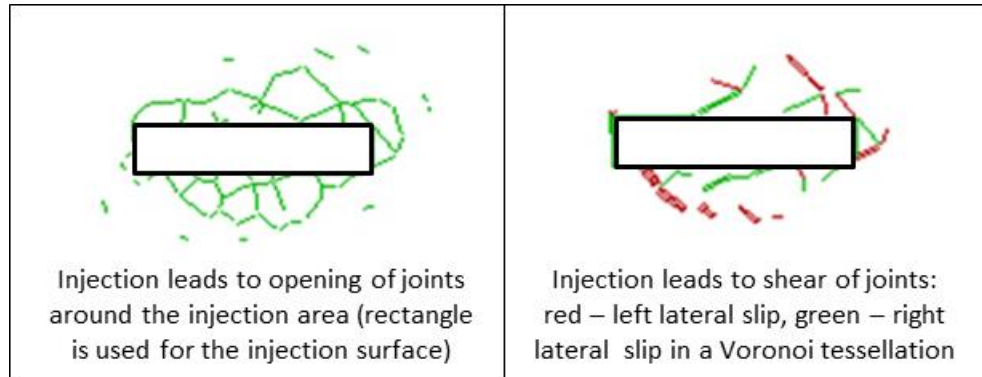


Figure 12: Opening of fractures and slip along favorably oriented fractures

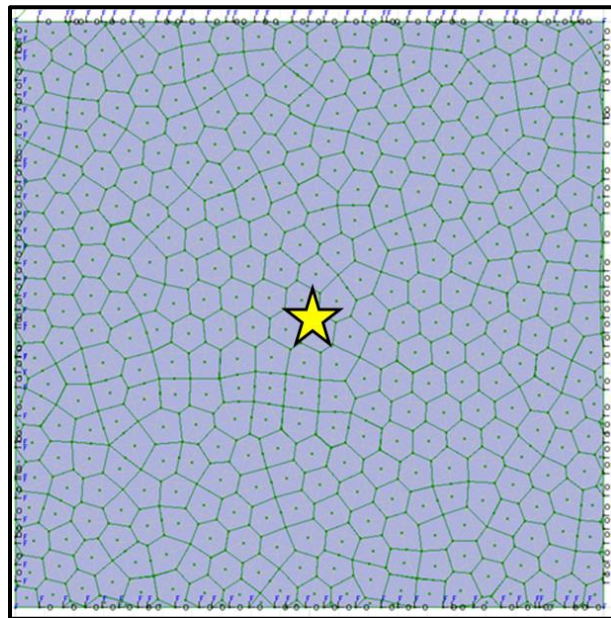


Figure 13: Injection at a point (star is centered on the center of a joint surface and represents the injection point in a Voronoi tessellation)

Here, another tessellation in a differential stress field is subjected to injection at a point, Figure 13. The yellow star is centered at the midpoint of a joint surface in the array, and HF is initiated by injecting at an increasing pressure that becomes greater than the minimum principal stress – at which point joint surfaces near the borehole that are close to 90° to $\sigma_{\min}$ should open. In fact, that is exactly what is observed in the simulations. The black line in Figure 14 is sketched to emphasize the region where the

fracture is opened. We now see a number of effects that could have been anticipated from a careful consideration of the physical effects:

- The fracture opening follows the local joints (of course, in this case the matrix blocks cannot fracture) to form an “average orientation” that is normal to σ_{hmin} .
- Branching can occur, although shortly thereafter, one of the branches dominates and the other is suppressed.
- The beginning of a fracture network is seen, and short vertical paths are close to opening and could likely be opened and “propped” if the injection pressure can be made large enough.

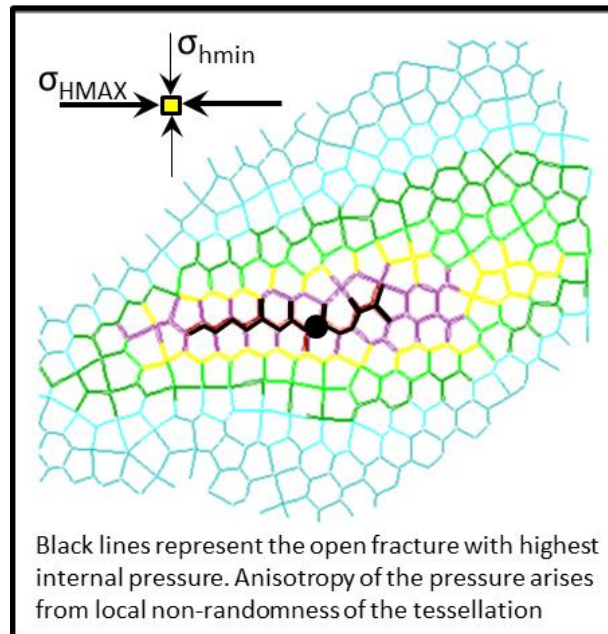


Figure 14: Injection at a point leading to HF, the pressure distribution is plotted. The black lines have been added to emphasize the HF location and the propagation path

In the next set of pictures (Figure 15), some results are shown for a case of the presence of a strong fabric element. There has been concern expressed that HF near an existing fault can trigger slip along the fault and generate a seismic event of significance (e.g. Richter Magnitude 2.5 or larger). The second row of figures shows the pore pressure progression on the left, with the fractures that have been opened hydraulically in black. The right hand figure shows the elements that have slipped, and clearly the presence of the fault has led to a large amount of slip focused on the fault plane, with the strongest slip displacement occurring near the injection borehole. In this simulation, slip occurred before the opening of the hydraulic fracture, and the slight rotation of the fracture away from the plane is because of stress field modifications associated with the fault slip.

In principle, the DEM approach can be used to determine the seismic moment, and the impact on shear slip propagation of the constitutive law for the fault (cohesion – friction law with strain weakening) can be explored. Work calculations can be undertaken to look at the various sources of energy storage

(elastic strain energy) or dissipation (slip), and likely the energy losses from viscous dissipation could be clarified as well, helping to clarify HF processes in NFRs.

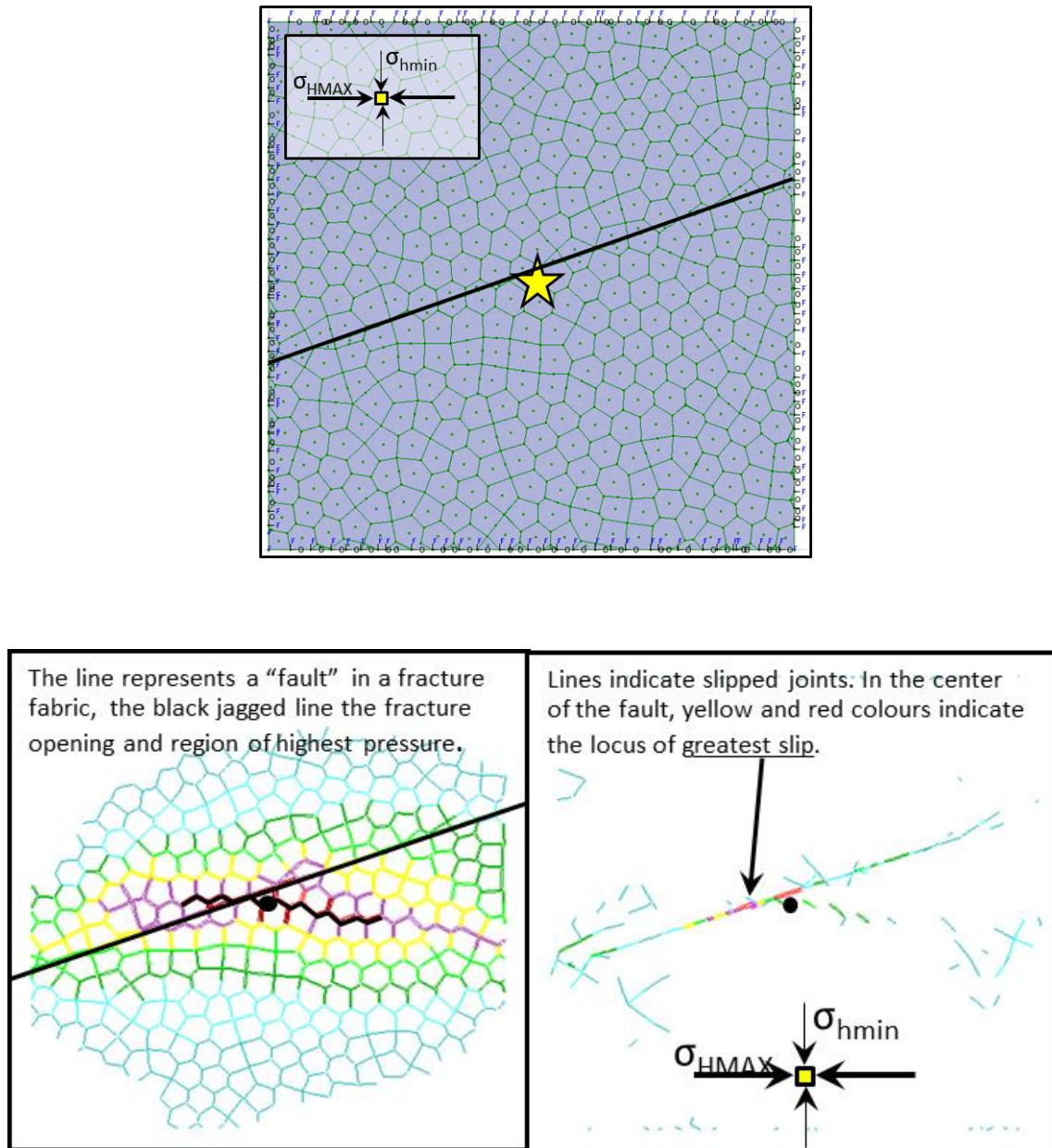


Figure 15: A DEM realization of HF in a rock mass with a nearby fault plane

The DEM method holds considerable promise for clarification of the effects of strong fabric and differential stress fields, opening of cracks, and shear dilation; there is also the possibility of including inertial effects in crack slip, at least at a macroscopic scale. Some deficiencies include impermeable elastic matrix blocks, the lack of thermal flux capability, and issues associated with the nature of the constitutive laws for the joint stiffness and conductivity relationships. For large arrays, the DEM is computationally demanding, and for 3-D problems it remains beyond the capability of design

engineering efforts, although, as with all computational engineering problems, this limitation gradually becomes less over time.

Some Results Using a Novel THM Coupled FD-DD Formulation

Figures 16, 17 and 18, along with the simulation parameters in Table 3, show some results from a new hybrid 2-D approach based on Displacement Discontinuity – DD - treatment of the fractures and a Finite Difference - FD - approach for the flow network and seepage into rock blocks (Jalali 2013).

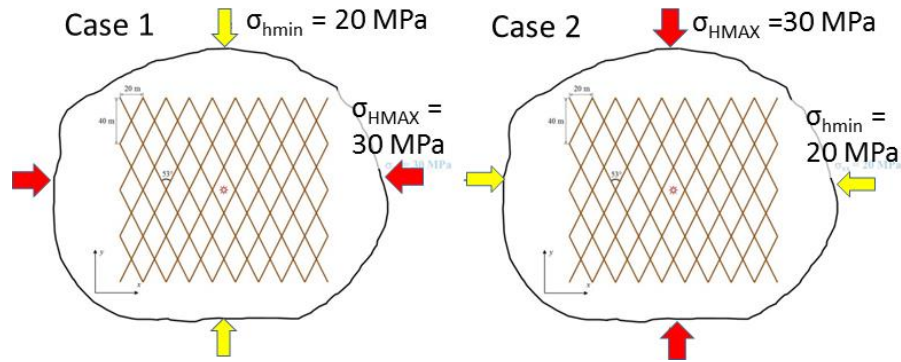


Figure 16: Fractured medium with strong mis-aligned fabric and differential stress field. The fracture array is effectively a fractured region embedded into a 2-D poroelastic infinite continuum, therefore issues of scale will arise (block size versus array size)

Table 3: Properties for the simulations in the next two figures

Drained Poisson's ratio (ν)	0.25	Undrained Poisson's ratio (ν_u)	0.35
Young's modulus (E)	20 GPa	Initial pressure (p_0)	16 MPa
Initial fracture aperture (w_0)	0.1 mm	Fracture maximum closure (w_{res})	50 μ m
Fracture normal stiffness (K_n)*	10 GPa/m	Fracture shear stiffness (K_s)	10 GPa/m
Fluid compressibility (c_f)	7×10^{-10} 1/Pa	Fluid dynamic viscosity (μ)	1 cP
Production fluid rate (Q_{prod})	10^{-5} m ³ /s	Fluid density (ρ_f)	1000 kg/m ³
Matrix permeability (k_m)	0.05 mD	Matrix porosity (ϕ_m)	0.25
Biot's coefficient (α)	0.8	Dilation angle (ψ)	5
Cohesion (σ_c)	0	Friction angle (ϕ)	30

In addition to flux, the average pressure in each fracture segment is calculated using the FD method, based on a cubic fracture flow law, then the pressures are incorporated into the DD calculations to determine aperture, and iterations performed to fully couple the stress and the hydraulic conditions. In the example chosen, after five days, the aperture has decreased about 3%, with an effect on the conductivity. The amount of aperture compliance is set by a constitutive stiffness law based on Bandis *et al.* (1983), and the stiffness can be varied to simulate non-elastic compliance as long as the pressure changes are monotonic.

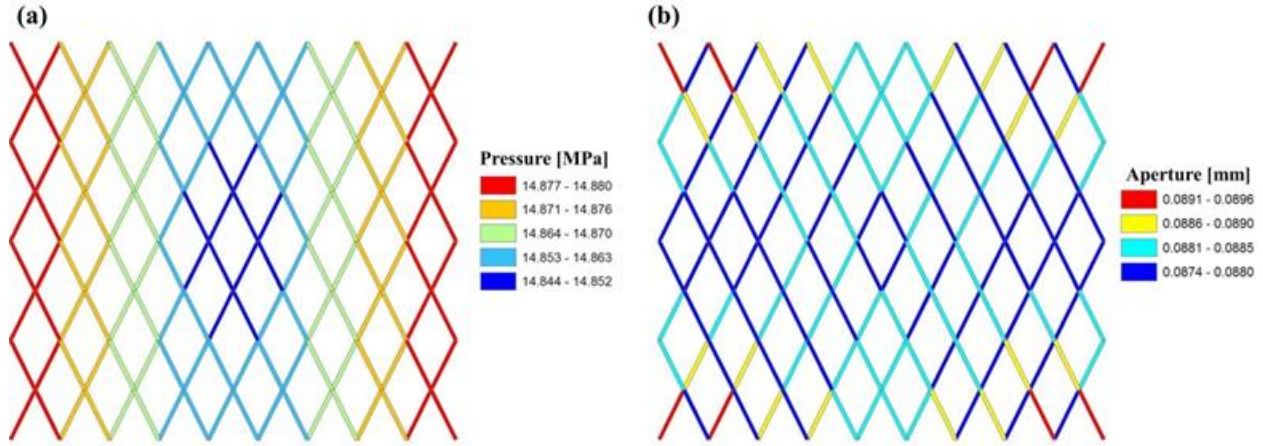


Figure 17: Pressure response (a) and aperture (b) after 5 days of constant rate production from Case 1 model (fracture network embedded in a 2-D continuum)

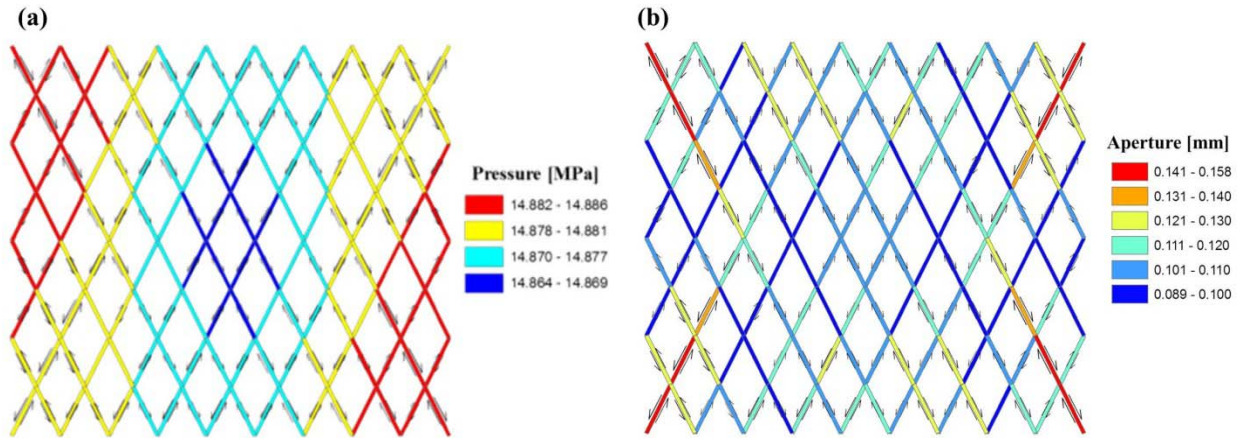


Figure 18: Pressure response (a) and aperture (b) after 5 days of constant rate production showing the direction of slip along fracture surfaces, arrow size scaled to displacement

Although geometrically regular arrays are shown, a Voronoi tessellation or a non-homogeneous distribution of fractures can be implemented, as well as different strongly oriented rock joint fabric systems. Figure 19 is an example of the aperture evolution with fluid injection or production into a brick array (differential orientation of strong fabric with continuous joints in the x direction but discontinuous ones in the y direction, but the same external stresses). On the right hand side, note how the apertures are large because the fractures are embedded into a continuum, so issues of scaling have arisen (the numbers of fractures would have to be much larger as well as the overall model size to avoid this effect). Because the DD-FD method is computationally efficient, it is possible to explore issues of scale with reasonable computational effort, although we have not yet done so.

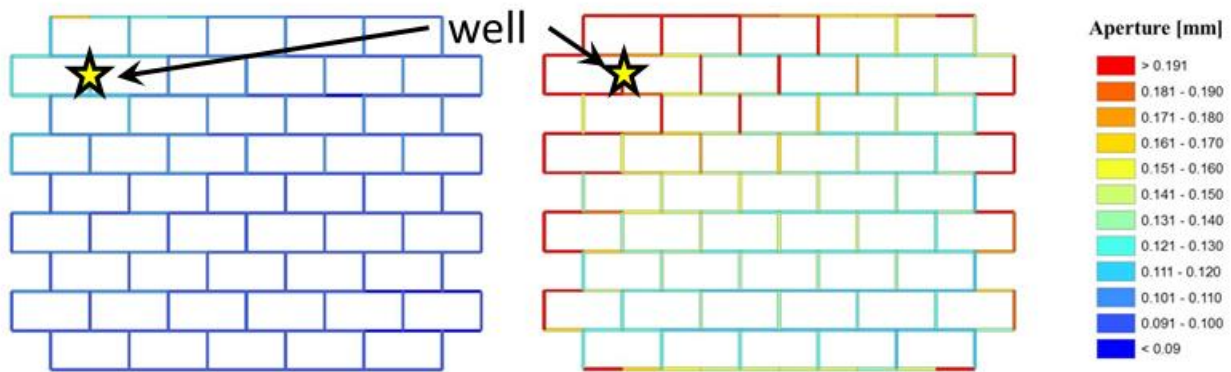


Figure 19: Injection or production in a brick model of a fractured medium embedded in a continuum with an off-centre well. Left: aperture distribution after one day of cold fluid injection. Right: aperture distribution after four days of fluid production

The DD method exploits influence functions for an elastic rock, and the displacements at the fracture intersection points between adjacent elements are made compatible mathematically so that the elastic stresses may be solved quickly at any point in the rock mass, without further discretization of the rock blocks or the surrounding rock mass (see for example Dusseault et al. 2007). Similarly, for the matrix blocks, boundary flow elements are used to predict the pressure propagation with the rock blocks.

In addition, the new formulation was designed to include the effects of temperature through the use of convective-conductive heat transfer calculations using boundary elements for heat flow, conduction of heat into the matrix blocks, cooling of the liquid flow through the fractures, and the thermoelastic strains induced in the matrix and how this affects the stresses and the fracture aperture. Because the changes of fracture aperture are linked through the FD calculations to the fluid flux and pressure, a full thermo-hydronechanical (THM) coupling is achieved. In general, when realistic fracture constitutive laws and thermoelastic matrix block properties are used, the thermal effects of fracture aperture (increasing for cooling, decreasing for heating) are dominant for realistic cases such as cold water injection into a deep reservoir ($\Delta T \approx -40-100^\circ\text{C}$), thermal injection for heavy oil viscosity reduction in a fractured carbonate (e.g. Shafiei et al 2013), liquid nitrogen injection (no gas capability yet) or geothermal exploitation (although the model cannot accommodate steam injection or production at this stage).

The use of influence functions for the solution to heat flow, fluid flow, stresses and displacements leads to computational speed far greater than any method that involves block discretization. Of course, computational efficiency is, to some degree, at the expense of an ability to incorporate internal block heterogeneity, anisotropy, plasticity or other non-linear processes. In addition to solutions such as these for various cases of stipulated rock fabric and properties, this method can be used as an efficient “quick-assessment” method to study parametric variability and stochastic property cases to assess risk. Parametric variation analysis can be used to determine the sensitivity of the case to various inputs such as joint compliance, the nature of the joint flow law, rock matrix properties and so on. Different types of

fabric can be studied, and this may give insight, for example, to the shearing behavior discussed previously (in these THM coupled simulations, a constant dilation angle is used). Furthermore, stochastic simulation (e.g. Monte Carlo simulation) using different distribution functions of properties can be carried out in a reasonable time, giving guidance as to what problem domains are worthy of more detailed analyses incorporating some forms of non-linearity.

The following figures show some results for the injection of cool water into a single fracture in a poroelastic medium to demonstrate some of the model capabilities.

Table 4: Model parameters, single 40 m fracture, differentially stressed poroelastic medium

Drained Poisson's ratio (ν)	0.25	Undrained Poisson's ratio (ν_u)	0.35
Young's modulus (E)	10 GPa	in-situ horizontal stress (σ_{xx})	30 MPa
in-situ vertical stress (σ_{yy})	20 MPa	in-situ shear stress (σ_{xy})	0
Initial pressure (p_0)	10 MPa	Initial temperature (T_0)	80°C
Initial fracture aperture (w_0)	0.1 mm	Fracture maximum closure (w_{res})	50 μ m
Fracture normal stiffness (K_n)	100 GPa/m	Fracture shear stiffness (K_s)	100 GPa/m
Fluid compressibility (c_f)	7×10^{-10} 1/Pa	Fluid dynamic viscosity (μ)	1 cP
Fluid thermal conductivity (k_{Tf})	0.6 J/m $^{\circ}$ Ks	Fluid density (ρ_f)	1000 kg/m ^{3}
Fluid specific heat (C_f)	4200 J/kg $^{\circ}$ K	Rock heat diffusivity (c^T)	5×10^{-5} m ^{2} /s
Matrix permeability (k_m)	1 mD	Matrix porosity (ϕ_m)	0.25
Fluid thermal expansion (β_f)	2.4×10^{-5} 1/ $^{\circ}$ K	Rock thermal expansion (β_s)	2.1×10^{-5} 1/ $^{\circ}$ K
Biot's coefficient (α)	0.8	Dilation angle (ψ)	0
Cohesion (σ_c)	0	Friction angle (ϕ)	30
Injection fluid rate (Q_{inj})	2×10^{-6} m ^{3} /s	Injection temperature (T_{inj})	50°C

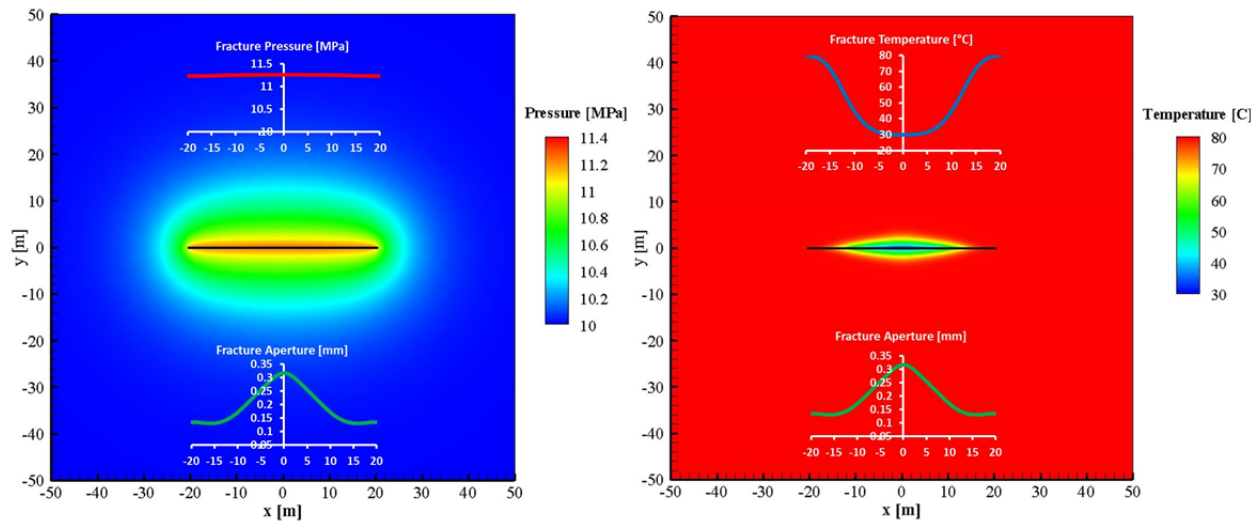


Figure 20: Pressure and temperature after 10 hours of cold fluid injection

In Figure 20, the fracture aperture as the result of cooling is plotted on the bottom, and the fracture pressure and temperature in the fracture along the top. The contours represent pressures and

temperatures within the rock matrix. Because of the thermoelastic effect on the aperture, the impact of thermal rock matrix strains is strong in fractured rock masses.

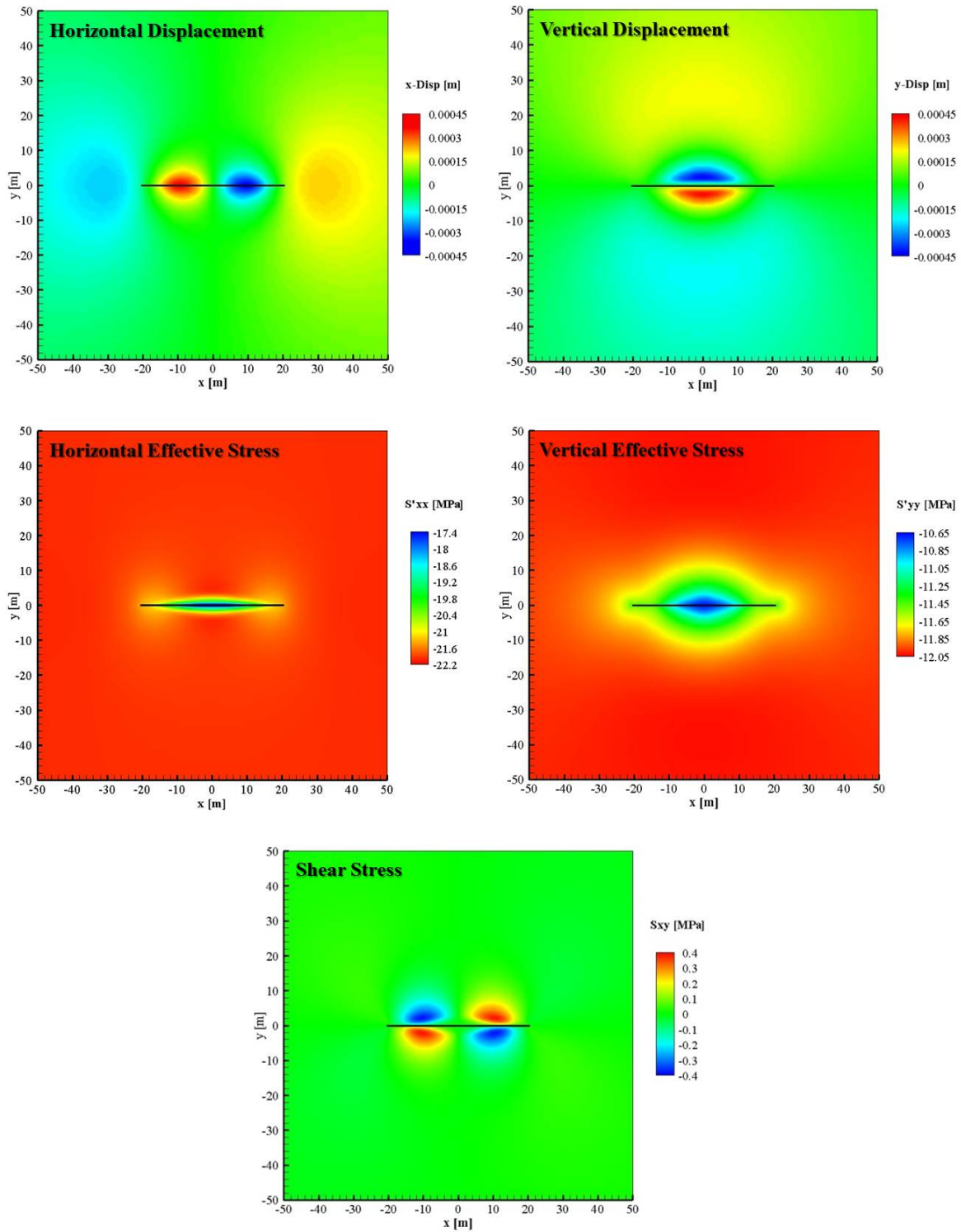


Figure 21: Displacements (horiz, vert), stresses (σ_h' , σ_v' , τ_{xy}) for the case stipulated above

Figure 21 shows various displacements and stresses generated during the simulation for a single fracture. It is not possible to show all the details here, but we have found that there are subtle but important effects that are difficult to “conceptually predict” in advance because of the interplay of the various coupled processes that affect fracture aperture, flow rate, pressure, volume change, stresses, shear displacement and dilation, changes in fracture conductivity, and so on.

A potential application of the method is to serve as a “first-order coupling” with a petroleum reservoir simulator. The term “first-order coupling” is intended to convey the idea that integrating the new method with a petroleum simulator does achieve a great level of coupling for a fractured medium, but with the limitations stipulated previously. The approach would be the following: reservoir 3-phase simulators are based on 3-D grid blocks with the corners defined by finite difference nodes; the reservoir model would be constructed as well so that the surfaces of the 3-D grid blocks correspond to natural fracture surfaces; the DD-FD simulation would be geometrically identical; and, iteration between the two models at appropriate time steps can give a far more realistic result than a conventional grid block simulator.

Conclusions

Optimization of HF design in NFRs requires development of hydromechanically coupled mathematical models that can reasonably simulate induced fracture network development in rock masses with strong fabric (weak joints in a strong rock). In many cases, these should be thermally coupled models as well. Some of the outstanding questions that are relevant to the engineering planning of MSHF might include

- What is the effect of penetrative oriented defects (persistent joint sets) on the interconnected fracture network creation?
- How does stress anisotropy impact interconnected fracture network characteristics (aspect ratio, branching...)?
- Can the interaction between stress anisotropy and a joint system that deviates from the principal stress directions be rationally quantified for practical application?
- How might a single massive-scale planar feature (through-going fault) modify interconnected fracture network development?
- Can we realistically simulate the impact of stress changes that are induced by early fracture stages on the later stages, and how these changes might modify the major interconnected fracture network characteristics?
- Will HF and MSHF simulations in NFRs become genuinely predictive tools or will they always have to be calibrated extensively with *in situ* measurements (deformations, MS emissions)?

The DEM method has current limitations that may be at least partially resolved in future realizations. It is highly useful for understanding in a conceptual and semi-quantitative manner how HF can interact with natural fracture systems, how remote slip occurs under injection without fracture opening, and likely for work estimates. A DD-FD approach developed by Jalali (2013) holds promise as a computationally efficient means of exploring THM coupling in complex naturally fractured systems. The combined effects of thermal and poromechanical strains under different thermohydraulic loading, different fabric types and stress fields, and differing material parameters lead to some subtle effects

that are now amenable to more rapid study. The DD-FD model can be coupled with other approaches iteratively (using geometric similarity), or as a rapid “first-look” to study parametric sensitivity and stochastic realizations. Both these methods have promise in evolving toward a design aid for HF in NFR.

Future developments will include extended finite element methods to track details of fracture propagation, including the possibility of tensile rupture through intact rock blocks. Eventually, an explicit link based on energy calculations will be made between the slip that can be simulated in these various mathematical approaches and the MS emissions in the field, with the potential for more rigorous elastic inversion of the MS emissions to delineate approximate stress field evolution during fracturing. For the first time, through the use of appropriate constitutive laws, we may be able to monitor an evolving stress field through the MS emissions.

For all of these methods, going to a full 3-D model realization carries challenges, not only computationally, but in terms of data input and data display. Good visualization tools have greatly improved mining and reservoir engineering, and development of good tools to examine stresses, displacements, joint slip locations and direction, temperatures, pressures and flow rates. Incorporation of geological heterogeneity, with all of its attendant uncertainties, is another challenge, common to all parts of geomechanics, and especially in NFRs.

Design is a multi-faceted exercise integrating many tools, not the least of which are experience and a deep understanding of mechanics. Mathematical models are a valuable aid to design in determining quantitative recommendations, but also in informing the design engineer of the mechanisms and consequences. They will never replace judgment, but better models make the design process more rational, reducing uncertainty in several important ways.

Shale gas has changed the energy picture in the world. Now, shale oil (also in naturally fractured rocks that require HF stimulation) is contributing new petroleum resources in North America, and soon in the rest of the world (primary estimates suggest an increase of 20% in recoverable reserves already - <http://energy.usgs.gov/OilGas/ReserveGrowth/ReserveGrowthPublications.aspx> - with much data to be collected and analyzed in decades to come. In the Middle East, the vast naturally fractured reservoirs that are gradually approaching the end of their first productive cycle because of water encroachment will soon begin redevelopment using horizontal wells, hydraulic fracturing, and gravity-stabilized drainage. All these resources depend on good hydraulic fracture design for optimization of recovery: that is the purview, in large part, of the specialist in Petroleum Geomechanics.

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