Geomechanics for Unconventionals Series, Vol XV:

Fracture-Driven Interactions (FDI's) – A Geomechanics Perspective, Part II

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Introduction

In Part I of this two-part article, I introduced Fracture-Driven Interactions (FDIs) as being, mainly, a slightly wider umbrella for what are more commonly called Frac Hits. Frac Hits are dominantly unexpected (and unwanted) pressure communications between wellbores during hydraulic fracturing operations. Also in Part I, I briefly discussed the potential pro's and con's of FDI's (again, primarily Frac Hits) but left it to the reader to evaluate these for their given scenario.

I concluded the Part I article by focusing on the two primary drivers for FDI's: well pairs that are simply spaced too close together and well pairs that have infrequent, unexpectedly long hydraulic fractures (what I called "rogue-length fractures"). With the first scenario, too-closely spaced well pairs, the communication between wells occurs because the created hydraulic fractures and associated drainage areas from the two wells overlap. In the second scenario, the rogue-length fracture scenario, the majority of the hydraulic fractures between a well pair do not communicate and the associated drainage volumes do not overlap; rather, only a single or small subset of created hydraulic fractures communicate across the well pair. I then went on to postulate:

> *The geomechanics of the rogue-length hydraulic fracture scenario comes down to determining and predicting those factors that cause rogue-length hydraulic fractures. These factors include: 1) cluster efficiency; 2) the stress regime and heterogeneities within the stress regime; 3) Stress Shadow effects; and 4) rock fabric.*

In Part II, I'll delve into the details of these causes more deeply, particularly the confluence of stress, pressure and rock fabric on rogue-length hydraulic fractures.

On the Geomechanics of FDI's - Preliminaries

As we touched on in Part 1, geomechanics is the engineering evaluation of the behavioral response of rock (i.e., how does it deform or how does it fail) to (for petroleum geomechanics) oil and gas operations including drilling in that rock, hydraulic fracturing in that rock, and decreasing or increasing pressure (depletion or injection) in that rock. And the behavioral response of that rock is controlled by: 1) stress and stress changes; 2) pressure and pressure changes; 3) material factors or properties for deformation (e.g., Young's modulus) and failure (e.g., strength measures like UCS); and 4) geometry. By defining geomechanics and specifying the components that influence the geomechanics (i.e., the behavioral response of the rock), this creates an organized structure around which we can address the geomechanics behind FDI's.

Geomechanics Modifiers

There are two common geomechanics modifiers that often need to be addressed: temperature effects and chemical effects. Mainly, temperature effects are reflected in stress changes (an increase in stress for a temperature increase and a decrease in stress associated with a temperature decrease, both associated with the expansion or contraction of a rock with temperature changes), though temperature effects are also common in pressure changes (again, an increasing temperature tending to increase pressure). Lesser temperature effects include changes in deformation properties (e.g., Young's modulus) and strength properties (e.g., changes in the coefficient of friction). Chemical effects (but not wholesale diagenetic-like chemical effects) are largely limited to changes in strength and deformational properties. These can be important factors and, on a case-by-case basis, may need to be considered.

A less common modifier, one that I tend not to explicitly consider as such, is time. And by "time", I mean the temporal changes in stress, pressure, mechanical properties and, possibly, geometry, but I don't, in this context, specifically mean the rate of change. While we most often do not consider rate-of-change in many geomechanics evaluations, there are clear exceptions – like the geomechanical evaluation of salt (whether drilling though it or building a cavern in it), which explicitly requires a time and rate-of-change component in the evaluation. Rather, the time I want to consider in this context is more binary or discrete; that is, how might our geomechanical parameters change within the timeframe of well operations and if my well ops are fast enough, I have one set of geomechanical parameters, but if the well ops are spread in time (whether purposeful or accidental) I have another set of geomechanical parameters to deal with.

Time-Independent versus Time-Dependent Effects

Most often, geomechanical evaluation are conducted assuming, for example, time-independent, elastic behavior. In contrast, the most common time-dependent effect that is considered in a geomechanical evaluation is time-dependent, rate-of-change mechanical behavior (with, again, salt behavior serving as the stereotype). Nonetheless there are a number of potential time-dependent effects to consider when dealing with FDI's.

The likely most critical time-dependent geomechanical effect to consider with FDI's is pressure and pressure diffusion. When we pump into a formation, in an effort to create a hydraulic fracture, the fracture is formed only when the injection rate exceeds the flow capacity of the formation; that is, the hydraulic fracture is temporary volume storage as a ratio of injection to leakoff[1] rate. When leakoff rate exceeds the injection rate, the hydraulic fracture volume decreases. When leakoff is less than the injection rate, hydraulic fracture storage volume increases. In essence, this means we have pressure in the formation changing as a function of our pump schedule (injection rate and pump time) as well as a function of the leakoff rate from the hydraulic fracture and pressure diffusion through the rock mass.

[1] "Leakoff" is the generic term for fluid volume that leaves the hydraulic fracture into the surrounding rock mass via either direct pore-to-pore fluid flow or through natural fractures or other discrete flow channels from the hydraulic fracture.

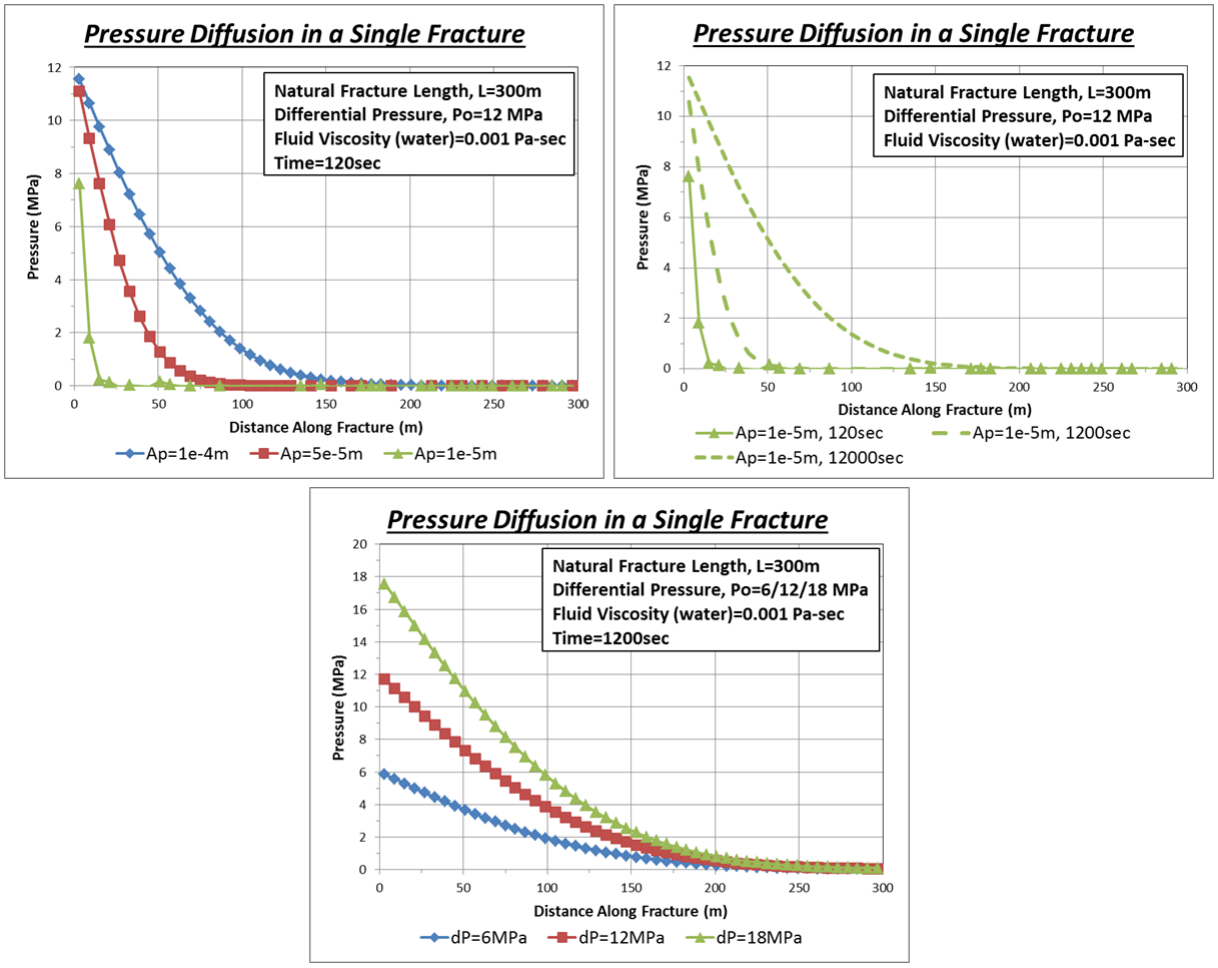

Figure 1: Pressure diffusion profiles into a single natural fracture at 90 deg to a hydraulic fracture. Note the increase in diffusion with natural fracture aperture, with time, and with hydraulic fracture net pressure.

How is this time-dependency important? Recall that Stress Shadows – the local changes in the in-situ stress field (dominantly an increase in the minimum principal stress, Shmin) – are caused by the hydraulic fracture deformations (i.e., volume storage), which is time-dependent. More importantly, the resistance to shear failure within the rock mass (for both the matrix and structural features like bedding planes and natural fractures) is largely controlled by the local effective stresses, which move in opposition to pressure changes (pressure goes up, effective stresses go down and the shear resistance goes down). So at the moment the injection pumps are shut down, pressure in the hydraulic fracture begins to decline while pressure in the rock fabric is both increasing (to some maximum) and moving further away from the hydraulic fracture (i.e., the area of increased pressure around the hydraulic fracture is expanding – which means the area of reduced effective stresses on the rock fabric is expanding). Left alone, over a long-enough time period pressure diffusion from the hydraulic fracture will cease and rock fabric pressure will return to virgin reservoir pressure.

Coming back to Stress Shadows again, Stress Shadows are the stress changes (in all three principal stresses and local shear stresses) due to the deformations associated with the hydraulic fracture (volume storage). As this volume storage changes (again, related to the injection/leakoff ratio) and the hydraulic fracture dimensions change (length, especially, but also height and width), then the Stress Shadows change (i.e., both their magnitude and position in 3D space). So the time-dependency of Stress Shadows is two-fold. First, Stress Shadows are dynamically changing with injection time (as the hydraulic fracture grows in dimension) and Stress Shadows are changing as pressure leaks off from the hydraulic fracture after pumps have been shut down and the fracture dimensions regress (until the hydraulic fracture closes on proppant). Essentially then, Stress Shadows are constantly changing from the moment injection starts until the hydraulic fracture closes on proppant. And concurrent hydraulic fracturing operations, if they are close enough spatially, will interact with, and possibly be influenced by, the changing magnitude and position of Stress Shadows.

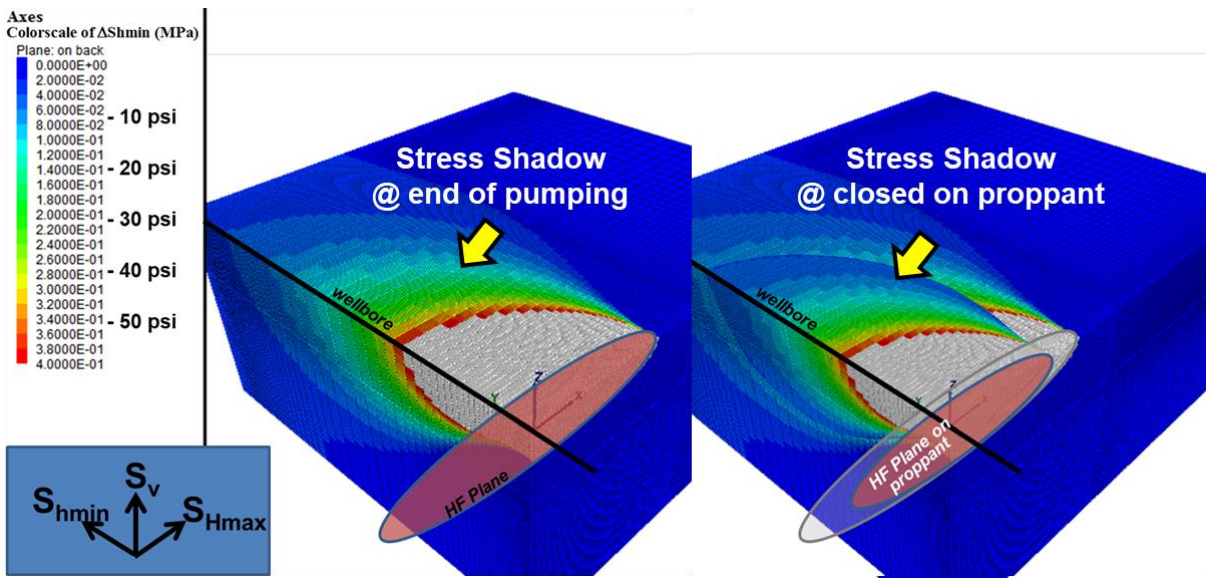

Figure 2: Stress Shadow (change in Shmin) at the end of pumping (left) and after closure on proppant (right).

So we have two main time dependencies – pressure diffusing into the rock fabric changing the local effective stresses and Stress Shadows changing the local total stresses and shear stresses. There are two other potential time-dependent effects to consider and these are related to temperature changes and chemical changes.

Temperature changes are most often ignored except in cases with very deep, hot wells (e.g., HPHT wells). Nonetheless, any temperature change will cause a change in stress and pressure as a function of the coefficient of thermal expansion. Where formation temperature is decreased, both the rock and fluid volume will shrink and stresses and pressures reduced. If formation temperature was somehow increased, then stresses and pressure would be increased. Like pressure, temperature can essentially diffuse into the rock mass (conduction) or be transported into the rock mass by the fluid (convection). These processes (conduction and convection) are both time-dependent.

The other potential time-dependent effect to consider is a chemical effect. While, again, largely ignored in most geomechanical evaluations, fluid chemistry has been shown to influence the mechanical properties of the rock, primarily through the strength properties. Most hydraulic fracturing fluids are aqueous in nature. These water-based fluids can and do interact with the rock formations they are injected into – whether they be sandstones or shales. Particularly in the case of shales, aqueous frac fluids will interact with clays and other clay-like mineral tending to reduce their strength (both in tension and in shear), potentially making them easier to hydraulically fracture or shear during fracturing operations. As movement of the fluid is time dependent, then any chemical effect will also be time dependent.

On the Geomechanics of FDI's – Specifics

Hopefully I've set the stage for getting into the weeds on how stress and stress changes, pressure and pressure changes, and rock fabric can promote or inhibit rogue-length hydraulic fractures. By building off the definition of geomechanics:

- *The behavioral response of rock to the four main geomechanical parameters (stress, pressure, mechanical properties and geometry).*

we can capture the components we need to consider for FDI's:

- *The four main considerations for hydraulic fracturing (cluster efficiency, stress field and stress field heterogeneity, Stress Shadows, and rock fabric); and*
- *Time-dependent factors (pressure and pressure diffusion, time-dependent Stress Shadows, and possible time-dependent thermal and chemical effects).*

In Part I of the article, I addressed the issue of cluster efficiency on FDI's and will not delve into this much further (because it is really a simple math issue – more clusters, less fluid per cluster; less clusters, more fluid per cluster and larger frac dimensions for a given stage volume). However, though not covered in this article, mention has to be made that the diverters used to improved cluster efficiency, particularly far-field diverters, may, themselves, contribute to rogue-length hydraulic fractures.

Total Stress Effects on FDI's

A fundamental concept in hydraulic fracturing is that what controls frac length is frac height. Recall that the hydraulic fracture is volume storage and what creates this storage is omni-directional fluid pressure, which means the storage volume is created wherever it is easiest to be created. Since the storage volume opens against the stress field, it is the lower stress areas that will be favored for volume storage (i.e., the location of the hydraulic fracture). This is also why the fracture opens against the minimum stress (the minimum horizontal stress in a normal faulting stress environment, Shmin); that is, the least energy is required to open storage volume (frac width) in the direction of Shmin since it is the direction of the least normal stress.

Since, in most environments, the primary source of horizontal stress is the weight of the overlying formations, generally Shmin increases with depth. This suggests that at the depth of the well

perforations, the stress will be some value laterally away from the wellbore (as a function of depth and mechanical properties) but will tend to be greater below (deeper than) the wellbore and lesser shallower than the wellbore. This then suggests that, in many cases, the preferred fracture growth direction (where the storage volume is created) is upwards rather than laterally outwards or downwards as upwards tends to be towards a lower stress environment.

So, this is hydraulic fracturing 101, right? Yes, but with a wrinkle!

Pre-drill – and even pre-stimulation – there is essentially a static stress field (profile) within the rock (ignoring, for the moment, other well stimulation or production effects). If we knew this static stress profile, we could model the hydraulic fracture growth and make an informed estimate of hydraulic fracture length. However, Stress Shadows make the stress field dynamic!

Suppose for a moment, one cluster of a five-cluster stage takes the initial frac fluid. A hydraulic fracture grows from that cluster, which creates a local increase in Shmin around that fracture due to the Stress Shadow effect. Now the second cluster kicks off and the hydraulic fracture from this cluster grows in the new, dynamic stress field (that is, the original static stress field with the Stress Shadow effect from the first hydraulic fracture superimposed). Now consider this process for the remaining clusters for the stage, assuming 100% cluster efficiency. Each new hydraulic fracture propagates against a stress field composed of the original, static stress field plus all the Stress Shadow effects from the preceding fractures.

Intuitively, this process leads to asymmetric hydraulic fracture growth as subsequent hydraulic fractures propagate in an ever-changing stress field.

Now consider for a moment that the original static stress profile was favorable for hydraulic fracture height growth. The first hydraulic fracture dominantly grows upwards rather than outwards. As the second hydraulic fracture starts to grow, it finds the higher stress above the perforations (due to the Stress Shadows associated with the upward growth of the first hydraulic fracture), which essentially forces it to grow more in the lateral direction (creating a longer hydraulic fracture). Now consider this effect on the remaining clusters in our five-cluster stage. The result is, likely, an ever-increasing hydraulic fracture length.

One last part of our "wrinkle" – what if the hydraulic fractures do not initiate sequentially from our five-cluster stage but are somewhat random (i.e., instead of the toe cluster going first, then the second to toe cluster and so on until the heel-side cluster, what if the order was middle cluster, then toe-side, then second from the heel-side cluster and so on in random order)? What do the frac lengths look like for the five clusters in this scenario?

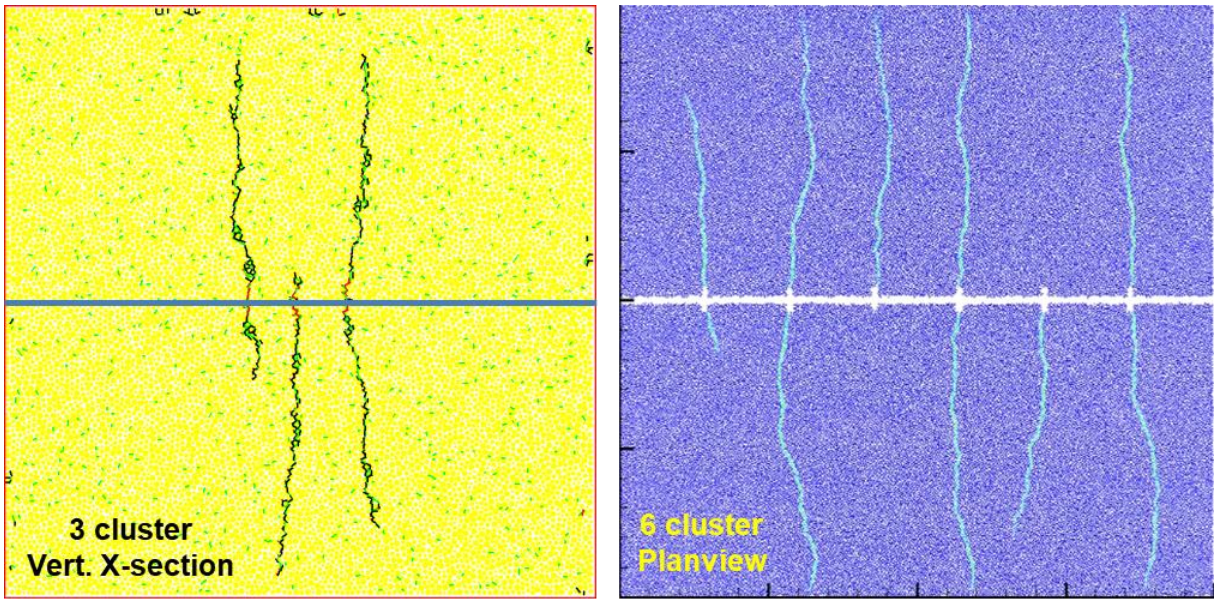

Figure 3: Asymmetric fracture growth due to Stress Shadows. In the vertical x-section (left), the first and third fracs grow upwards into lower stress; however, the middle cluster only grows downwards due to the increased stress in the layer above the wellbore. In the planview (right), asymmetric horizontal growth from the six clusters is seen due to Stress Shadows.

In summary:

- *It is wrong to design hydraulic fracture lengths (and the associated knock-on issues including well spacing) based solely upon the pre-drill/pre-stimulation static stress field/profile.*
- *When hydraulic fractures are close enough spatially, they create a dynamic stress field that alters the propagation (i.e., dimensions) of subsequent hydraulic fractures.*
- *The effect of Stress Shadows (which create the dynamic stress field) on fracture dimensions becomes a function of: 1) the initial, static stress field; 2) the dimensions of the created hydraulic fractures; and, <u>most importantly</u>, 3) the timing and spatial position of individual hydraulic fractures.*
- *As the Stress Shadow for a given hydraulic fracture is dynamic with that fracture's changing dimensions (from frac initiation all the way to closure on proppant), the created dynamic stress field is highly complex and very difficult to accurately predict.*
- *The Stress Shadow-induced dynamic stress field affects not only hydraulic fractures within a given stage but also hydraulic fractures between stages and can affect hydraulic fractures between wells (e.g., Zipper completions or Cube developments) as, primarily, a function of spatial position and timing.*

Simply put, the Stress Shadow effect itself can be (but is not guaranteed to be) the driver for rogue-length hydraulic fractures, which increases the potential for FDI's.

Pressure Effects on FDI's

A fundamental principle of geomechanics is that the rock responds to (that is, the behavior is controlled by) the effective normal stress as opposed to the total normal stress. More simply, the presence of pore pressure within the rock serves to partially balance the total stress acting on the rock leading to a local, effective stress at the grain-scale. If we assume that the vertical stress acting at the top of a given reservoir is 10,000 psi (total stress) due to the weight of the overburden and the pressure within the reservoir itself is, say, 6000 psi, would the 10,000 psi vertical total stress controls the deformation and failure of the reservoir rock or would the critical stress be something smaller due to the presence of the 6000 psi pressure? In actuality, pore pressure serves to reduce the stress acting on the rock grains and, in this scenario, the vertical effective stress, which does control the deformation and failure of the rock, would likely be between 4000 and 6000 psi.

Again, fundamentally, pore pressure serves to offset (i.e., reduce) the normal stress acting on the rock grains (and controlling its behavior). This offset is typically from 60% to 100% of the pressure, with increasing pressure decreasing the normal effective stress and decreasing pressure leading to an increase in normal effective stress. Equally important, whereas changing pore pressure results in a change in the normal effective stress, changing pressure does not alter the shear stresses acting within the rock or along structural features (like faults or natural fractures).

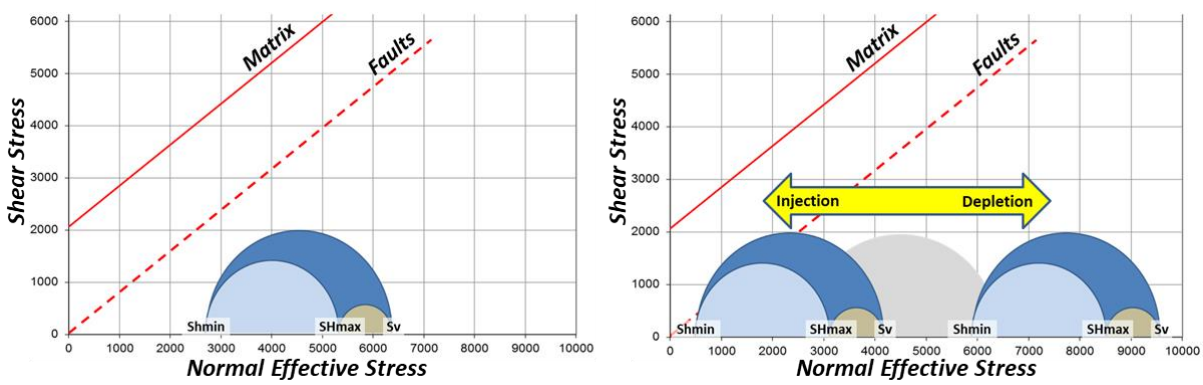

Figure 4: Initial stress state on a Mohr-Coulomb Failure Diagram (left). Shift of the stress circles leftward towards the failure surface with injection or shift rightward away from failure with depletion (right).

There are two avenues of influence on FDI's due to formation pressure changes. First, since the existing shear stresses within a rock formation are not altered with pressure changes, increasing pressure, which results in a reduction in the normal effective stress and a reduction in the resistance of the rock (both matrix and structural features) to shear failure, pushes the rock (again both matrix and structural features) towards shear failure. Shear failure, particularly along structural features, often increases the flow capacity along the structural feature, which potentially increases the leakoff rate from the hydraulic fracture. Second, pressure changes do alter the local total stresses (due to the pressure link between total and effective stresses). This effect is evident in what is commonly seen as the parent/child wellbore relationship.

Years ago, a client of ours mentioned that they had developed the concept of "stress capture". The idea was that they saw better stimulation results when a subsequent frac stage was pumped as soon as possible after the preceding frac stage. In reality, what they had discovered was effectively "pressure capture" wherein they saw better stimulation results when the second stage was pumped before the formation pressure supercharge from the preceding frac stage was allowed to diffuse away. The pressure supercharge from the first stage reduced the normal effective stress and made the rock fabric more prone to shear failure during the second stage frac operations.

With parent well depletion, the formation pressure goes down and the normal effective stress goes up; however, the total normal stress goes down as well. This is, for the most part, a geometry effect and the amount of reduction in, for example, Shmin, is a function of the shape and size of the depleted area. This effect, a reduction in Shmin (or closure stress) with depletion is well known in higher permeability, higher pressure reservoirs such as those in the Gulf of Mexico as well as layered reservoir systems in which a given layer may be depleted before another layer is put on production.

Nonetheless, with depletion the total stress will decline, which means the depleted area of the formation will preferentially hydraulically fracture over a non-depleted portion of the formation. Because fracture propagation occurs at the tip of the propagating fracture and for some short distance ahead of the physical tip, the influence of the depleted area is not akin to a magnet that is drawing the fracture toward it. Rather, the influence of the depleted area on fracture propagation only occurs once the tip reaches the depleted (and therefore reduced Shmin) region of the formation. Simply, if the existing conditions would allow for symmetric hydraulic fracture growth from a wellbore, this will occur until such time as the tip of the fracture wing towards the parent well reaches the reduced stress region around the parent. At this point, fracture growth on the side of the wellbore away from the parent will be retarded or may even regress while propagation towards the parent accelerates.

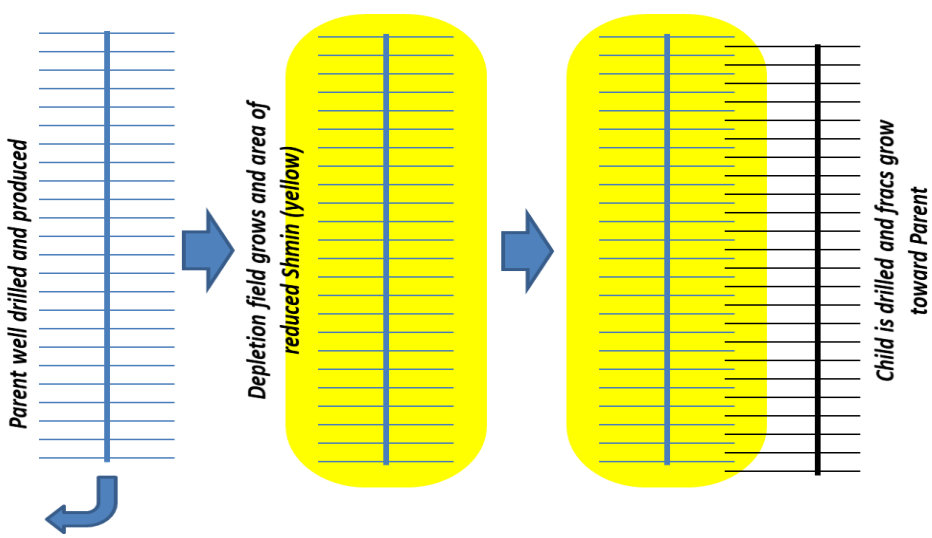

Figure 5: Conceptual model of Parent - Child asymmetric hydraulic fracture growth.

Consider if, due to Stress Shadows for example, the original hydraulic fracture lengths from the parent well were of irregular length with the occasional rogue-length hydraulic fracture. The associated depletion area for these irregular-length hydraulic fractures would also be highly irregular. Now consider fracture propagation from a child well towards this parent well with the irregular depletion area. What effect might this have on irregular fracture lengths from the child and, particularly the generation of rogue-length hydraulic fractures from the child towards the parent?

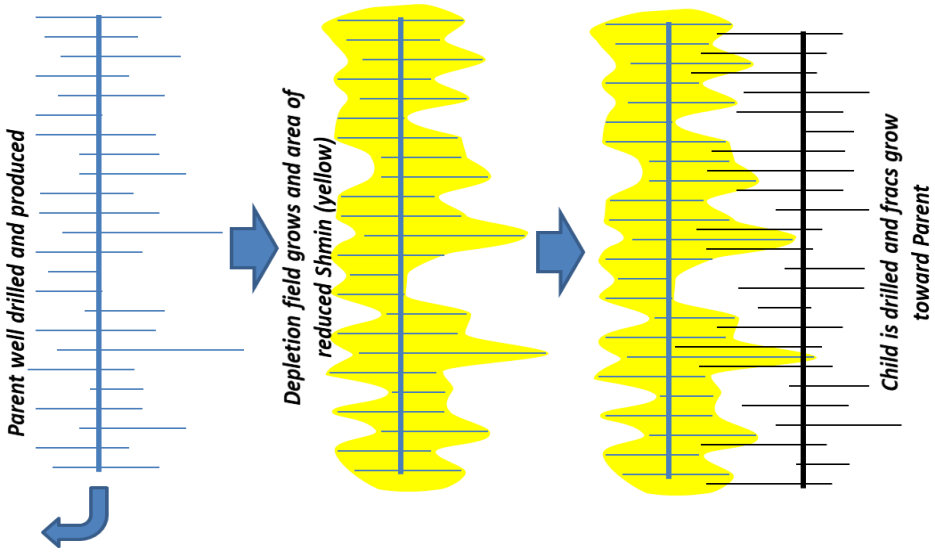

Figure 6: More realistic model of Parent - Child asymmetric hydraulic fracture growth accounting for initial asymmetric growth from the Parent.

In summary:

- *Fluid leakoff during a hydraulic fracture stimulation affects the created storage volume of the created hydraulic fracture. If leakoff is increased, by, for example, shear-induced slippage along permeable structural features like bedding planes and natural fractures, then hydraulic fracture dimensions will be reduced. Conversely, if the frac volume is based upon a given leakoff through the rock fabric that does not occur, then hydraulic fracture dimensions will increase.*
- *As shear slippage along structural features is controlled by the normal effective stress, which is driven by pressure changes, the timing and magnitude of the shear slippage (and associated flow/leakoff rate) is related to the pressure change and diffusion rate of the pressure through the rock fabric.*
- *Because a hydraulic fracture opens against the minimum total stress, hydraulic fracture growth is preferentially in areas where Shmin is lower in magnitude. Within the area of depletion from a parent well, Shmin is reduced. This has the effect, once the hydraulic fracture tip from a child well reaches the parent well depletion area, of providing a preferential propagation path for the hydraulic fracture. At best, this creates asymmetric hydraulic fracture lengths on either side of a child lateral with the longer wing length towards the parent well. At worst, the preferential growth*

of the child hydraulic fracture in the depleted area around a parent well is a significant contributor to rogue-length hydraulic fractures.

Simply put, formation pressure changes can influence both the magnitude of the hydraulic fracture dimensions as well as the asymmetry of the hydraulic fracture., either or both leading to rogue-length hydraulic fractures.

Rock Fabric Effects on FDI's

While the concept of rock fabric from a geological sense is perhaps well defined, rock fabric – or better, geomechanics rock fabric, is the spatial variation of deformational and strength properties within the rock matrix and discrete features, like bedding planes or natural fractures, that may have deformational and strength properties themselves as well as aperture and permeability and which may separate rock with different stress and pressure conditions. These parameters all may affect hydraulic fracture propagation.

The effect of rock fabric on hydraulic fracture propagation and the occurrence of FDI's can be grouped into three causes: 1) changes in rock fabric that influence fluid leakoff from the hydraulic fracture; 2) rock fabric that impedes fracture propagation in a given direction resulting in additional growth in other directions; and 3) open rock fabric, filled with fluid, that provides a preferential pathway for fracture propagation to follow and/or serves as a pressure communication conduit between wellbores.

Where rock fabric has greater flow capacity, particularly flow capacity along discrete features which can be influenced by Stress Shadows and shear failure, there will be greater leakoff from the hydraulic fracture. When this occurs, there is less volume storage in the fracture and its dimensions are correspondingly smaller.

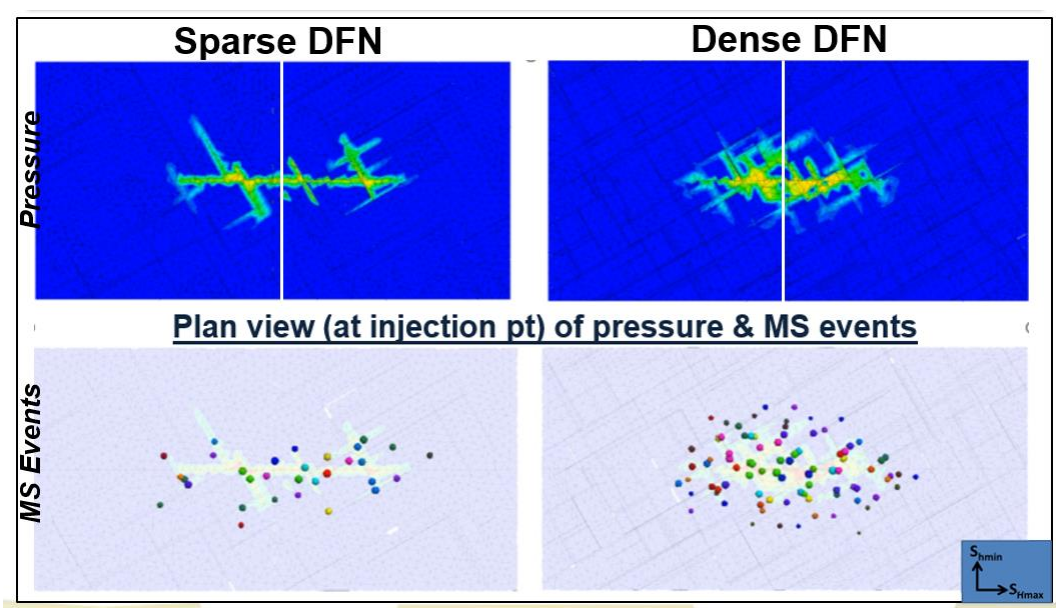

Figure 7: Stimulated rock fabric for a sparse DFN (left) and a dense DFN (right). Note the longer hydraulic fracture (warm colored pressure region) in the sparse case due to less leakoff into the fabric.

Where the variable flow capacity of the rock fabric can lead to rogue-length hydraulic fractures is when the rock fabric – and associated flow capacity – varies along the wellbore naturally and/or because of dynamic effects including Stress Shadows and pressure diffusion. Particularly if the stage pump volume was based upon rock fabric with greater flow capacity and the particular stage does not have this rock fabric flow capacity, enhanced hydraulic fracture dimensions may result. Consider the case mentioned before of "pressure capture" wherein a client reported better stimulation results when frac stages were pumped as quickly as possible after each other in order that subsequent stages took advantage of the pressure supercharge from the preceding stage. In this scenario, the additional shear on the rock fabric due to the increased pressure (actually due to the lower effective normal stresses) results in additional leakoff from the hydraulic fracture and, therefore, smaller hydraulic fracture dimensions. Assume for a moment that, due to equipment problems, the well is shut-in between stages and the subsequent stage is pumped into the rock fabric without the pressure supercharge. In this case, there will be less leakoff and greater fracture dimensions.

Recall the role of minimum horizontal stress on fracture propagation discussed previously. Where stresses are higher, propagation is disfavored, where stresses are lower, propagation is favored. However, in order to propagate, the fracture must break the rock, which requires energy (in linear elastic fracture theory this is the fracture toughness}. Consider a propagating fracture that propagates towards a structural feature that I'll call an interface. This interface has mechanical properties and it has flow capacity. As the hydraulic fracture tip approaches, rather than translate the stresses from the tip across the interface, the interface slips (and this slippage is enhanced by fluid flow and increased pressure within the interface itself). As a result, the fracture propagation is blunted or impeded at the interface. When this happens, the frac fluid is force to propagate the hydraulic fracture in another direction thereby increasing its dimension in that direction.

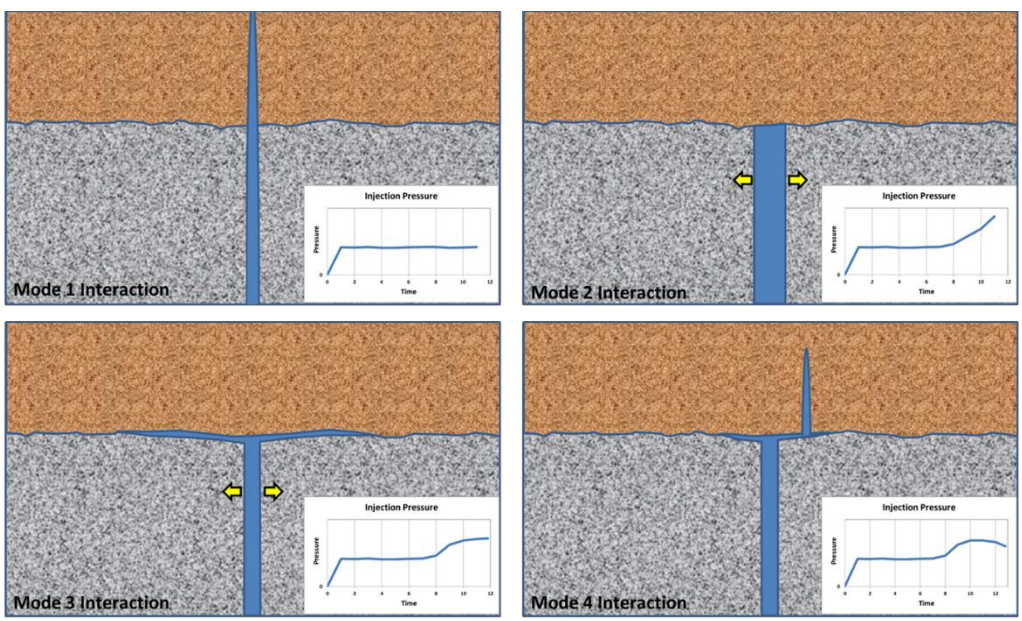

Figure 8: Possible hydraulic fracture interactions with an interface showing: crossing, full blunting (no crossing), T-shape (no crossing), T-shape (offset crossing).

This situation is fairly common in several plays where, like the Niobrara, there are bentonite layers that impeded vertical hydraulic fracture growth resulting in greater fracture lengths.

The third rock fabric consideration related to the formation of FDI's, *and likely the most important direct cause of FDI's*, is the existence of open rock fabric, filled with fluid, that provides a preferential pathway for fracture propagation to follow and that serves, in some cases, as a high transmissibility communication conduit between wellbores.

This third rock fabric consideration itself can be broken into two components. The first is when the rock fabric provides an easier, preferential pathway for a hydraulic fracture to follow for some distance. This distance is related to the underlying structure of the fabric (e.g., planar fabric nearly aligned with the current maximum stress orientation or multiple, crossing natural fracture sets). By following open or partially open pathways through the fabric (without, essentially, having to break rock to make the pathway), and particularly nearly aligned with the current SHmax orientation, the fracture propagation pathway can and will dominate over the stress field, which can lead to unexpectedly long, rogue-length hydraulic fractures.

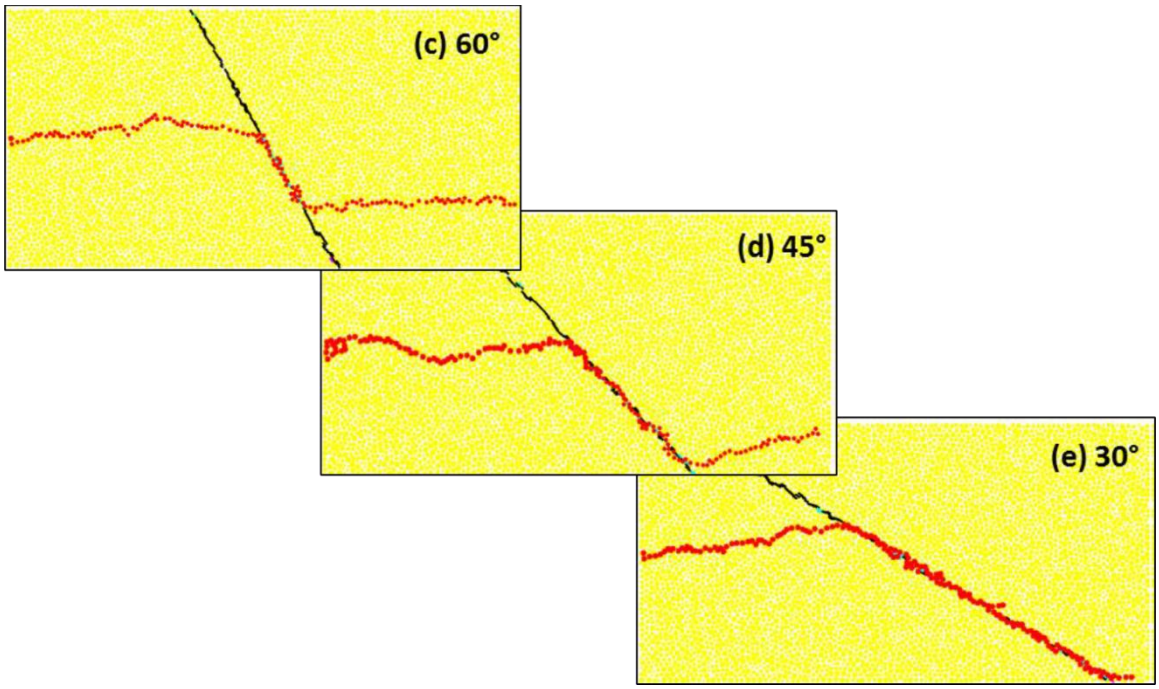

Figure 9: Hydraulic fracture propagation (red) being influenced by rock fabric (black) (top and middle) and becoming trapped in the rock fabric (lower).

The second component of open rock fabric is the ready transmission of pressure and fluid volume over long distances. In a homogenous rock mass (without structural features), pressure movement through the rock matrix follows Darcy's law. On the other hand, flow in, for example, open natural fractures, follows a cubic flow equation (assuming Navier-Stokes, laminar flow) in which the flow rate goes as the cube of the natural fracture aperture. Clearly with the presence of open channels, both fluid and pressure can be transmitted over long distances, very quickly. Particularly for FDI's

reported over very long distances (and often fairly early during a stage pumping schedule), the existence of open fabric is clearly suggested.

How do we know if these subsurface "superhighways" exist, and where they are, and over what length they act? That is a critical question and one to consider for another day!

In summary

- *Our conventional hydraulic fracturing paradigm essentially ignores rock fabric and fracture propagation is (nearly) solely determined by the stress field. However, rock fabric can have: 1) no impact on propagation; 2) impede propagation; or 3) create preferential propagation coupled with but separate from the stress field.*
- *Particularly where rock fabric creates an "easier", preferential flow path for the frac fluid, this pathway can dominant over the stress field effects we expect of fracture propagation and lead to rogue-length hydraulic fractures and FDI events over very long distances.*

FDI Geomechanics, Part 2 Summary

Thanks for reading and apologies for the length. Sometimes it just takes more words to convey your thoughts!

In this article, I've presented a more detailed geomechanical look at the causes of FDI's, based upon the concept of rogue-length hydraulic fractures. I focused on the three main drivers – stress and stress changes, pressure and pressure changes, and rock fabric.

Thanks again. Constructive comments are always welcome!

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Be Safe!