Geomechanics for Unconventionals Series, Vol XIV:

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

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Introduction

The petroleum industry has made great strides towards understanding the influence of rock fabric and geomechanics on the behavior of multi-cluster, multi-stage hydraulic fracturing along long horizontal laterals in fractured and near-fractured[1] formations. Nonetheless, we don't want to risk, per the cliché, a case of "missing the forest for the trees".

The bulk of what are now often called fracture-driven interactions (FDI's) are related to some form of pressure communication between offset wells during hydraulic fracturing operations, more commonly called Frac Hits. Other forms of fracture-driven interactions can and do occur, for example, even in a single well. If we limit ourselves solely to Frac Hits under the FDI umbrella, sometimes proppant is involved but, at the core, most FDI's involve unexpected pressure communication between wells. The first questions that should come to mind when considering this form of FDI's are "What's the big deal? ...Is this just an academic issue for a graduate study?". If the answer to this question is that it may be a big deal, then we have to go on to consider: 1) "Why/when does it happen?" and 2) "How do we predict or prevent them?".

The rest of this Part I article will provide an initial consideration of these questions.

Background Fundamentals

Like with most "in" things within the Oil & Gas industry, it is appropriate to approach the issue of FDI's with a healthy dose of skepticism. FDI's do not occur on every stage or, for that matter, on every well. More importantly, FDI's (again, primarily Frac Hits) occur for one or both of two fundamental reasons: 1) our horizontal laterals are simply too close together; and/or 2) we have "rogue"-length hydraulic fractures.

Coming back to our first question – "Should we be concerned about FDI's". Unfortunately, as with most similar questions, the correct answer is "It depends". Published works show that FDI's can sometimes have little or no effect, can actually have a positive effect (through, for example, a formation pressure increase), or can have a negative impact on production (or on operational issues such as casing deformations). The result is that, for the most part, it is difficult to know, *a priori*, when a given well or well pair will experience FDI impacts. With experience, we can come to know those formations or situations that are more prone to certain FDI's (like casing deformations

[1] "Near-fractured" in this context are formations that contain structural features like natural fractures, laminations and bedding planes that largely only come into play in their effect on hydraulic fracture propagation and production and often do not impact base reservoir performance away from a hydraulic fracture.

in the Montney Formation, for example, or Frac Hits associated with parent-child well pairs) but predicting FDI's for a given well or, perhaps more importantly, in a new development area is far from trivial.

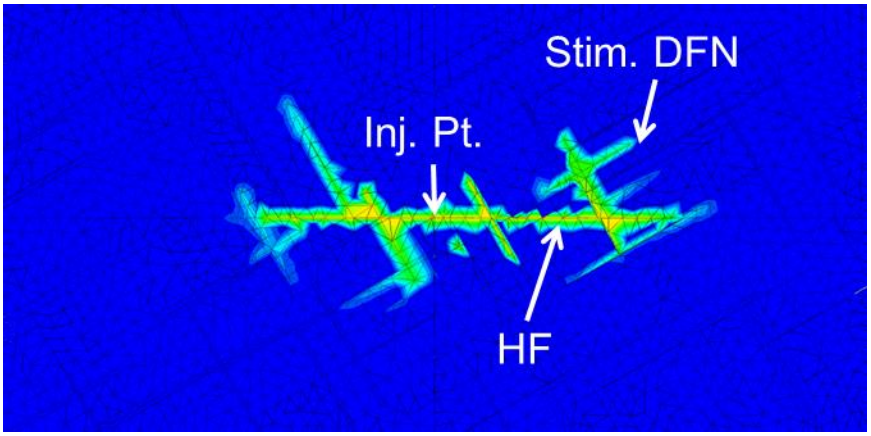

Figure 1: Simulation of irregular pressure pattern from hydraulic fracturing in Unconventionals. What are the implications of non-planar fluid flow?

It should go without saying that the goal of our wellbores and hydraulic fractures is to optimize production and recovery (i.e., optimized on an economic basis). Imagine you exactly know the porosity, permeability, water saturation and pressure within an entire reservoir. Also assume you could accurately predict hydraulic fracture dimensions (primarily length within the reservoir). With this information (as well as, obviously, costs versus production efforts) you could design the perfect hydraulic fracture spacing along a given lateral as well as the perfect spacing between laterals so that two hydraulic fractures within a lateral, or hydraulic fractures in two separate laterals, do not steal production or reserves from each other yet maximize, in particular, recovery on an economic basis.

The challenge is that we simply do not have an accurate handle on the spatial variation of porosity (especially dual porosity – i.e., including porosity in structural features like open natural fractures), permeability (especially dual permeability – i.e., matrix perms and overall effective perms), water saturation and pressures. Equally important, we do not have an accurate handle on the geomechanical factors controlling fracture growth, especially near-wellbore issues (i.e., cluster efficiency), three-dimensional stress variations and Stress Shadow effects, and the interaction between the hydraulic fracture and rock fabric. In fact, I would argue that the real underlying cause of FDI occurrence is that we do not know these parameters accurately enough to predict FDI's.

So, again, our first question has to be whether or not FDI's are of sufficient concern to invest the time, effort and money to understand and, hopefully, predict them. In consideration of this, it is clear that FDI's have become a central focus of a growing number of technical articles, which suggests that the Oil & Gas industry believes FDI's are important. And I can say, at least qualitatively from first-hand experience, our (OilField Geomechanics') focus on rock fabric characterization and hydraulic fracture-rock fabric interactions in our Unconventional

Geomechanics training courses has been very well received, also reflecting the interest in FDI's within the industry.

If we assume that we have "crossed the Rubicon" with regards to FDI's, that is, we have committed to the value proposition that we cannot ignore FDI's and need to invest in understanding and predicting FDI's in order to either take advantage of possible positive effects or remediate against negative effects, then there are two primary scenarios – simply having too close a well spacing or having rogue-length hydraulic fractures – that need to be considered.

Anecdotally, we are seeing increasing reports of FDI's. I say anecdotally because, while there is a likely real increase in FDI's being experienced, we have to acknowledge a sort of "bandwagon" effect whereby the more FDI's are talked about, the more FDI events are found. Nonetheless, there is a fairly clear overall trend, evident within technical publications and such, that more FDI's are being experienced. However, this should not come as much of a surprise given the clear trends in decreasing well spacing in nearly all major Unconventional plays. That is to say, it is critical to accept that, for given in-situ conditions and frac volumes, *there is a minimum well spacing below which FDI's are all but guaranteed to occur regardless of reservoir parameters*. As a result, as again published in numerous technical articles, some operators have accepted this fundamental truth and responded by increasing well spacing in order to reduce or eliminate FDI occurrences.

FDI Geomechanics

So where does geomechanics come into this picture? To answer this question, we need to go back to our two scenarios for FDI occurrent – too close of a well spacing and rogue-length hydraulic fractures.

Too-Close Well Spacing

Many technical papers over the last couple of decades (way, way too many technical papers) start with – and often end with – the idea that the hydraulic fractures created within a horizontal lateral are: 1) equally spaced along the lateral; 2) equal length from wellbore to tip; and 3) symmetric around the wellbore. It is rare that any of these assumptions actually holds for actual wellbores, but the underlying key assumption/belief here is that our created hydraulic fractures have a constant, predictable length (from wellbore to tip) from the toe to heel stages of the well. If this belief is correct (i.e., constant-length hydraulic fractures from toe to heel along the lateral), then determining the optimal well spacing becomes a straight-forward reservoir flow modeling exercise with given hydraulic fracture input (e.g., length and conductivity).

In this too-close well spacing scenario, the geomechanics is dominated by accurately predicting hydraulic fracture length, which, if we ignore the role of rock fabric, is dominated by correctly capturing the values of the minimum horizontal stress (Shmin) by formation, since changes in Shmin by formation will control hydraulic fracture height growth which ultimately controls hydraulic fracture length (for a given injection volume). This central and nearly-sole focus on the vertical changes in Shmin as the dominant geomechanics input to hydraulic fracturing is what I call the Conventional Hydraulic Fracturing Paradigm (CHFP).

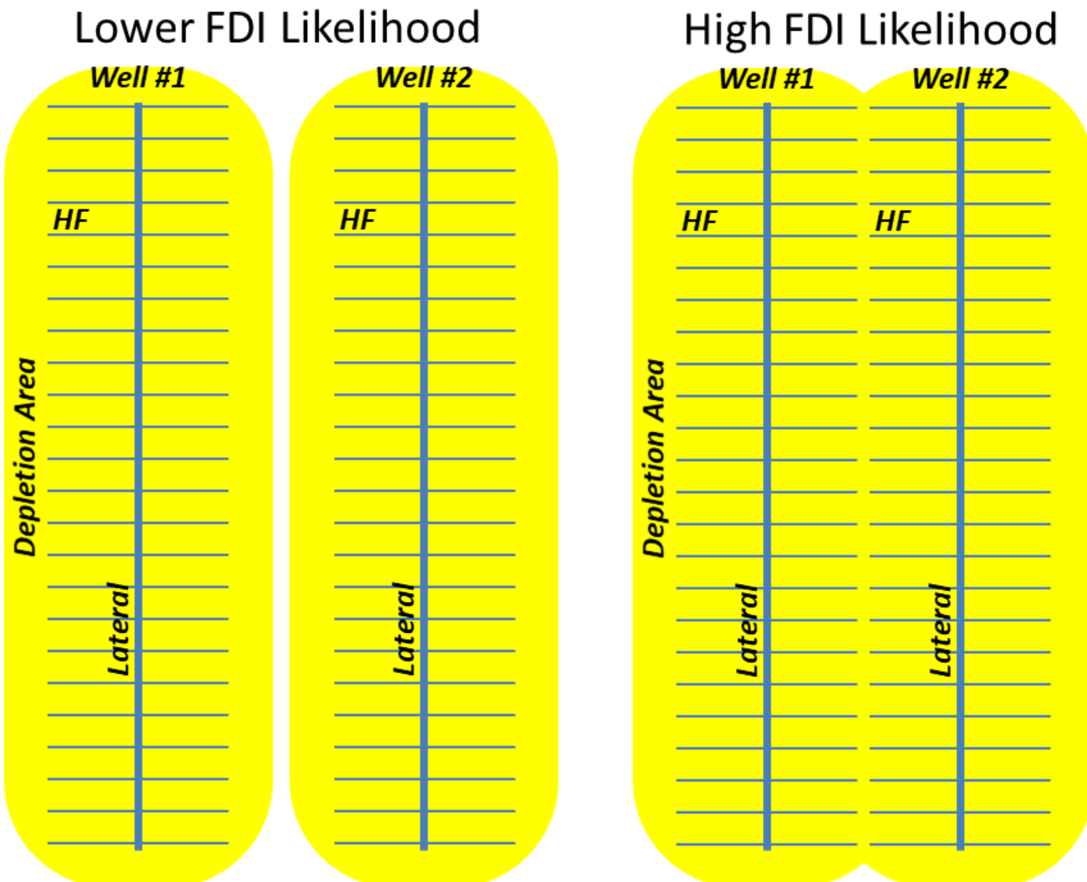

Figure 2: Assuming constant-length hydraulic fractures, left is near-optimal spacing with low risk of FDI's. Right reflects high risk of FDI's as hydraulic fractures may connect.

How might we know, from field data, if we are experiencing the too-close well spacing scenario (with the underlying assumption of constant length hydraulic fractures from toe to heel)? Consider a 10,000 ft lateral with 75 frac stages in each of two parallel laterals. How many FDI's would be expected if the well spacing was too small under the too-close well spacing scenario? If the assumptions are correct (particularly, again, constant length hydraulic fractures from toe to heel along the lateral), then we should see lots of FDI's (essentially one per stage) within this well pair.

Rogue-Length Hydraulic Fractures

The reality is that most often we do not see lots of FDI's in a given well. In the case where we see some FDI's in a well pair but far fewer than the number of stages, then the rogue-length hydraulic fracture scenario comes into play. In the rogue-length scenario, we experience FDI's not because the laterals themselves are necessarily too closely spaced but because, at intervals along a given lateral, we get longer-than-expected, much longer-than-average, rogue hydraulic fracture lengths.

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.

1. Cluster Efficiency. Fundamentally, the reason that cluster efficiency has an impact on rogue-length hydraulic fractures is because the frac design for a given stage most often assumes that an equal share of stage volume goes into each perforation cluster. With 10 clusters, for example, only $1/10^{th}$ of the stage volume is expected to go into any cluster and the length of the hydraulic fracture is then based upon $1/10^{th}$ the stage volume. However, if cluster efficiency is only 50% for example, then each of the five clusters taking fluid actually receives twice the fluid volume, with a likely corresponding increase in frac length.

Cluster efficiency really comes down to diversion. The goal, per our 10-cluster case above, is for our frac fluid to evenly divide into 10 formation entry points, yet we know, from our high school science class, that fluid will flow to the path of least resistance. If we had a garden hose with two holes in it, one big and one small, we would intuitively know that more fluid would escape the hose from the larger hole than the smaller one – because it is easier (the path of least resistance) to flow through the larger hole. The same phenomenon occurs across our perforation clusters where some clusters offer a lower resistance to flow and therefore take more of the frac fluid.

Limited entry perforation design is an attempt to control the path of least resistance within a set of perforation clusters by controlling the number and diameter of the perforations. The diameter of the perforation, in particular, controls the pressure drop across the perforation and therefore the resistance to fluid flow for that perforation cluster.

Geomechanics plays a role in cluster efficiency through several avenues. First, it is well-known that stress around a wellbore is not constant, making it easier to perforate in some directions than others, which leads to variable perforation behavior (e.g., size, length and flow capacity). These stresses are also influenced by the Stress Shadow effect. In addition, perforation performance is also controlled by the strength and stiffness of the formation, both key geomechanical parameters.

The other, and likely more important, role that geomechanics plays in cluster efficiency, is that, once hydraulic fractures begin to propagate away from the wellbore, the resistance to fluid flow for a given perforation cluster becomes a combination of perforation resistance as well as fracturing pressure. Critically, fracturing pressure is controlled by the stress field, variations in the stress field (like Stress Shadows or pressure depletion effects), fluid friction pressures (including proppant effects), and resistance to fracturing at both the matrix scale (i.e., fracture toughness) and the formation scale (propagation in and/or through rock fabric, leading to a pseudo fracture toughness). Basically, where it becomes more difficult to hydraulically fracture (i.e., requires greater energy), the fluid for that perforation cluster will divert into other, lower resistance perforation clusters.

2. Stress Field and Stress Field Heterogeneity. In what I labelled the CHFP before, hydraulic fracture propagation is nearly completely controlled by the stress field with little or no impact from rock fabric. The CHFP is further premised on the assumption that Shmin, in particular, is constant

away from the wellbore and symmetric on both sides of the wellbore. When these assumptions – little or no impact from rock fabric and laterally constant Shmin away from the wellbore - fail, as they often do in Unconventional reservoirs, we get rogue-length hydraulic fractures.

If you were to use nearly any hydraulic fracture simulator developed from the mid-1970s through the mid-2000s, you would find that: 1) the sole stress input into the simulator was a vertical profile of Shmin, and 2) the simulator only modeled one wing of a bi-wing hydraulic fracture. Why? Because the simulator was built on the assumption that Shmin is laterally constant away from the wellbore on both sides. As a result: 1) the hydraulic fracture wings are symmetric and only one side needs to be shown; and 2) the value of Shmin at the wellbore, for a given formation, defines the value of Shmin within the formation regardless of how far away from the wellbore the fracture propagates.

Is the assumption of lateral constancy in stress, within a given formation, a reasonable one? Basic principles suggest that it has some merit. Consider three, constant-diameter, circular rods constructed of steel, cement and wood. When we apply the same, constant stress on one end of each of these cylinders, what is the stress on the other end? For this case, known as a constant stress boundary condition, the full stress is transmitted through the rod regardless of material. That is, if a unit of stress was applied to one end of any of the three rods, a unit of stress would be measured at the other end of said rod, which implies a constant lateral stress throughout the rod. On the other hand, what if we considered what is called a displacement boundary condition in which a given displacement (deformation) amount is applied to one end of each of our circular rods. Is the stress at the other end of each rod, under the displacement boundary condition, the same? No, it is not. In this case, the magnitude of the generated stress is a function of the displacement amount and the stiffness (think Young's modulus) of the material. The wood would likely have the smaller stiffness with a corresponding smaller stress measured at the end of the rod. The steel would likely have the largest stiff with a corresponding largest stress.

So, is the earth around our wellbores under a stress boundary condition or a displacement boundary condition? The general answer is that field data suggests a combination of both; however, the exact answer for a given situation is both challenging to develop and beyond the discussion here. Nonetheless, there is some basis for assuming a constancy in lateral stress, but with some significant caveats.

Amongst myriad caveats to the assumption of lateral stress constancy, two standout (more so from an ease of awareness rather than a true ranking of importance). The first of these is related to faults and the well-known perturbation of the stress field around an active or recently active fault. Again, it is well-known that hydraulic fracturing in or near a fault zone can lead to unexpected fracture propagation and rotation associated with local variations in the stress field. The second caveat, and a prime topic of FDI's in Unconventionals, is the parent-child relationship wherein the parent well has been on production (with formation pressure depletion) before the child well is hydraulically fractured. In this scenario, the depletion field from the parent well may cause both a rotation in the stress field and a reduction in the stress magnitude that often encourages or draws, the hydraulic fractures from the child well towards the parent (leading to, at best, asymmetric hydraulic fracture length around the child lateral, with the hydraulic fractures being longer on the parent side of the child well).

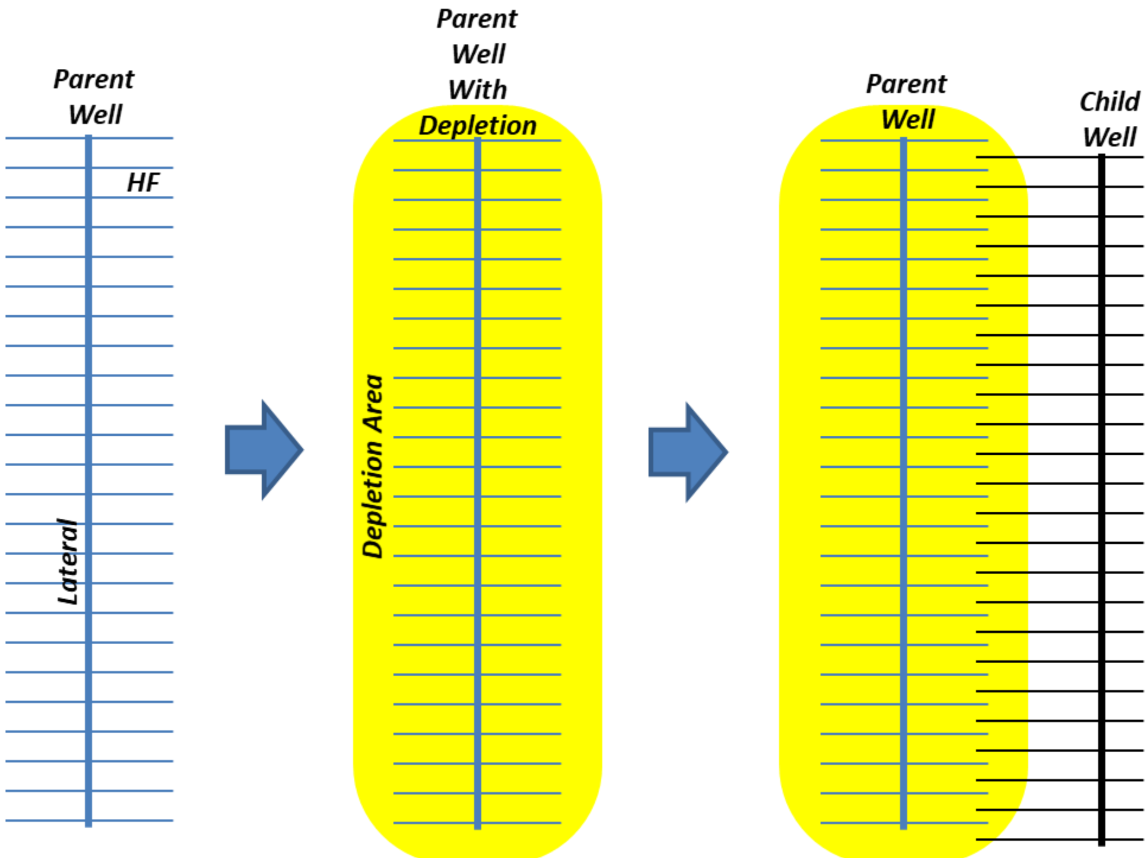

Figure 3: Asymmetric, rogue-length hydraulic fractures from a child well (right) due to the attraction of the lower stress around the depletion field from the parent well. Constant-length HFs are assumed.

Note, however, that the issue of stress field heterogeneity on creating rogue-length hydraulic fractures in the parent-child relationship is not simply that there is a pressure depletion effect in the stress field as suggested in Figure 3. Rather, a likely more critical issue is that the stress field heterogeneity (affecting hydraulic fracture propagation from the child) is related to the depletion field of the parent well, which, amongst other factors, is related to rogue-length hydraulic fractures in the parent well itself. This is, admittedly, perhaps, a difficult concept to grasp, so consider this: any rogue-length hydraulic fracture behavior in the parent lateral, due to the factors cluster efficiency, stress heterogeneity, Stress Shadows and/or rock fabric, leads to a heterogenous depletion field around the parent well, which creates an even more heterogeneous stress field for hydraulic fractures from the child well to propagate within. More simply, heterogeneity in fracture lengths in the parent leads to heterogeneity in the parent depletion field that leads to further heterogeneity in the stress field around the parent, which tends to enhance rogue-length hydraulic fractures from the child well.

3. Stress Shadows. Generically, Stress Shadows encompass all the changes in the in-situ stress field – in both principal stresses and shear stresses – induced by the formation deformations resulting from a hydraulic fracture, though the primary focus of Stress Shadows is the increase in Shmin around a hydraulic fracture. There are numerous technical papers that review and explain Stress Shadows in detail, so I'll not go into greater detail on how or why Stress Shadows occur. Nonetheless, since Stress Shadows result in a change in Shmin (an increase in Shmin) and, in the absence of rock fabric hydraulic fracture propagation is dominated by the Shmin stress, it stands to reason that Stress Shadow have the potential to influence hydraulic fracture propagation and cause rogue-length hydraulic fractures.

Consider a four cluster frac stage. The four perforation clusters have been designed with limited entry principles and we even use oriented perforating such that each perforation for the clusters is placed in a similar stress area around the wellbore. Regardless, whether owing to a slight eccentricity in the perf gun position within the lateral, a slight variation in the cement around the lateral, or even a slight variation in the formation along the lateral across the four perforation clusters, two of the perforation clusters initially offer a lower path of resistance to fluid flow and initially take the bulk of the frac fluid for the stage. As hydraulic fractures grow from these two clusters (of the four total), they generate Stress Shadows (i.e., they increase the magnitude of Shmin). Then, as the fluid friction pressure drop in the two clusters with propagating hydraulic fractures increases with frac length, and wellbore pressure rises, growth of hydraulic fractures from the original two clusters that did not initially take fluid is encouraged (due to the rising wellbore pressure); however, hydraulic fractures from these two clusters are blunted because of the increased propagation pressure associated with the increase in local Shmin due to the Stress Shadows from the hydraulic fractures already propagating from the original two perforation clusters.

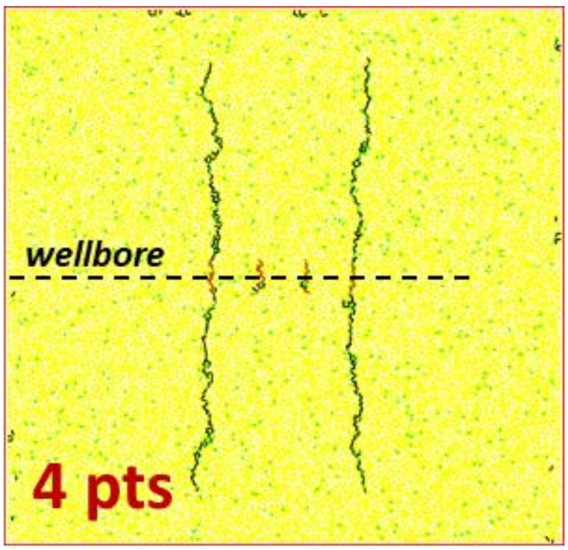

Figure 4: Hydraulic fracture growth from a four-cluster frac stage where Stress Shadows from the outer clusters have prevented inner-cluster frac growth.

A similar effect from Stress Shadows, to that at the wellbore described above, affects hydraulic fracture propagation away from the wellbore and within the three-dimensional formation (i.e., Stress Shadows affect both upward as well as outward hydraulic fracture propagation). Furthermore, Stress Shadows can result in hydraulic fracture rotation as well as longitudinal propagation when Stress Shadows cause the Shmin and SHmax principal stresses to swap directions.

These influences of Stress Shadow effects on hydraulic fracture propagation can impede some fractures while enhancing others, leading to rogue-length hydraulic fractures along a horizontal lateral.

4. Rock Fabric. Within what I called the Conventional Hydraulic Fracturing Paradigm (CHFP), mentioned before, rock fabric is essentially ignored. Yes, within the CHFP vertical, layered variations in Young's modulus, Poisson's ratio and fracture toughness matrix rock properties are allowed, similar to vertical variations in Shmin, but within a given formation, laterally away from the wellbore, geomechanical parameters, including deformation properties like Young's modulus and Poisson's ratio but also strength properties like cohesion and friction angle, are considered to be homogeneous. However, experience from Unconventional plays shows that these geomechanics parameters are not homogeneous within a given formation or laterally away from the wellbore, often due to rock fabric effects that include natural fractures, laminations, bedding planes and other structural features within the rock. In fact, the experience is that this heterogeneous behavior in geomechanical parameters can dominate hydraulic fracture propagation behavior even over the impact of the stress field.

Figure 5: Rock fabric expressed in a large shale sample.

There are a number of good technical papers addressing the role of rock fabric on hydraulic fracture propagation and I have written and presented on the topic numerous times. As such, I will not go way into the weeds on this topic in this article. However, understand that rock fabric can be a major contributor to rogue-length fractures whether through bedding plane slippage preventing upward hydraulic fracture growth that promotes length growth, laminations that lead to small-scale stress variations and act as stress boundaries, or natural fractures - either closed (hindering fracture propagation) or open (both potentially reducing propagation pressures and channeling the direction of propagation), that influence hydraulic fracture propagation.

FDI Geomechanics, Part 1 Summary

In this article, I've presented an introduction and overview of the two primary causes of FDI's – too close a well spacing and rogue-length hydraulic fractures. The field data tells me that rogue-length hydraulic fractures are the most common source of FDI's. The bad news to this is that if we cannot accurately predict rogue-length hydraulic fractures, then our only real mitigation tool is increasing well spacing, which ultimately will result in stranded reserves.

Thanks for reading. Constructive comments are always welcome!

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