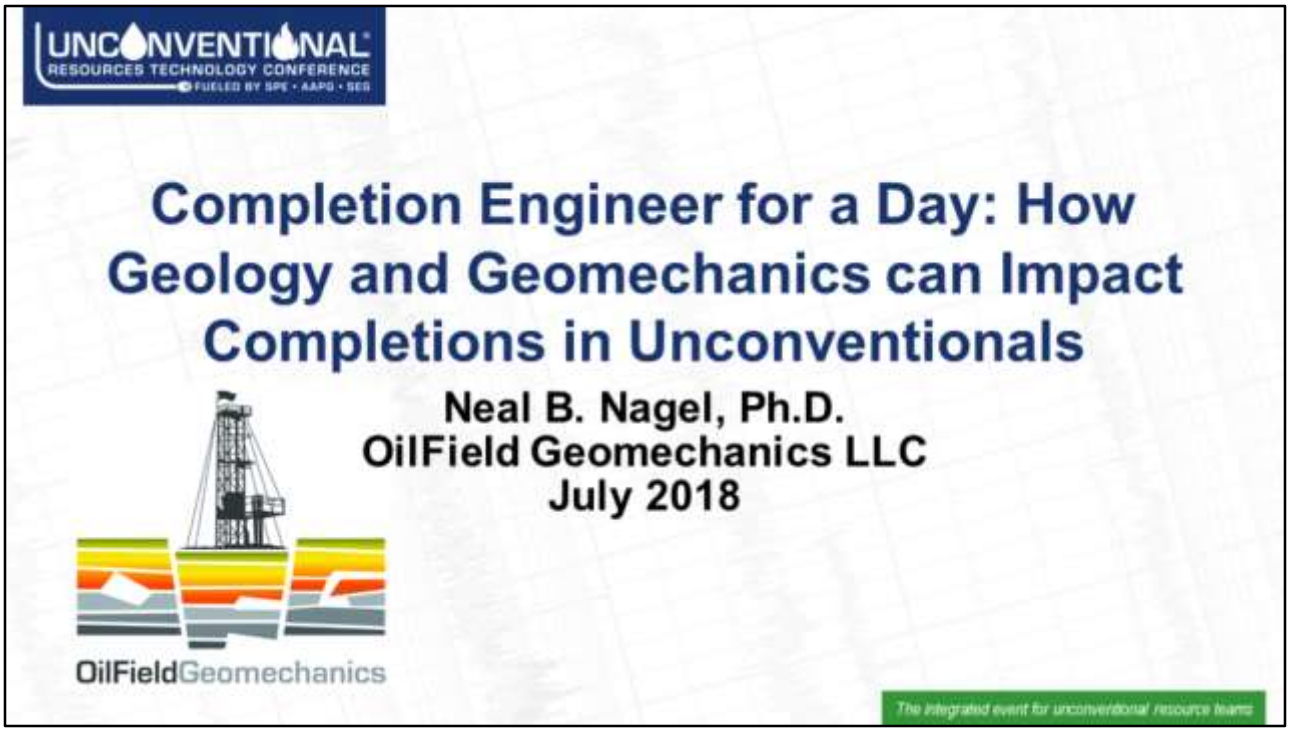


It is a pleasure to make my URTeC 2018 slides available. If you have not done so, please visit our website (www.ofgeomech.com) for training information as well as additional technical information.

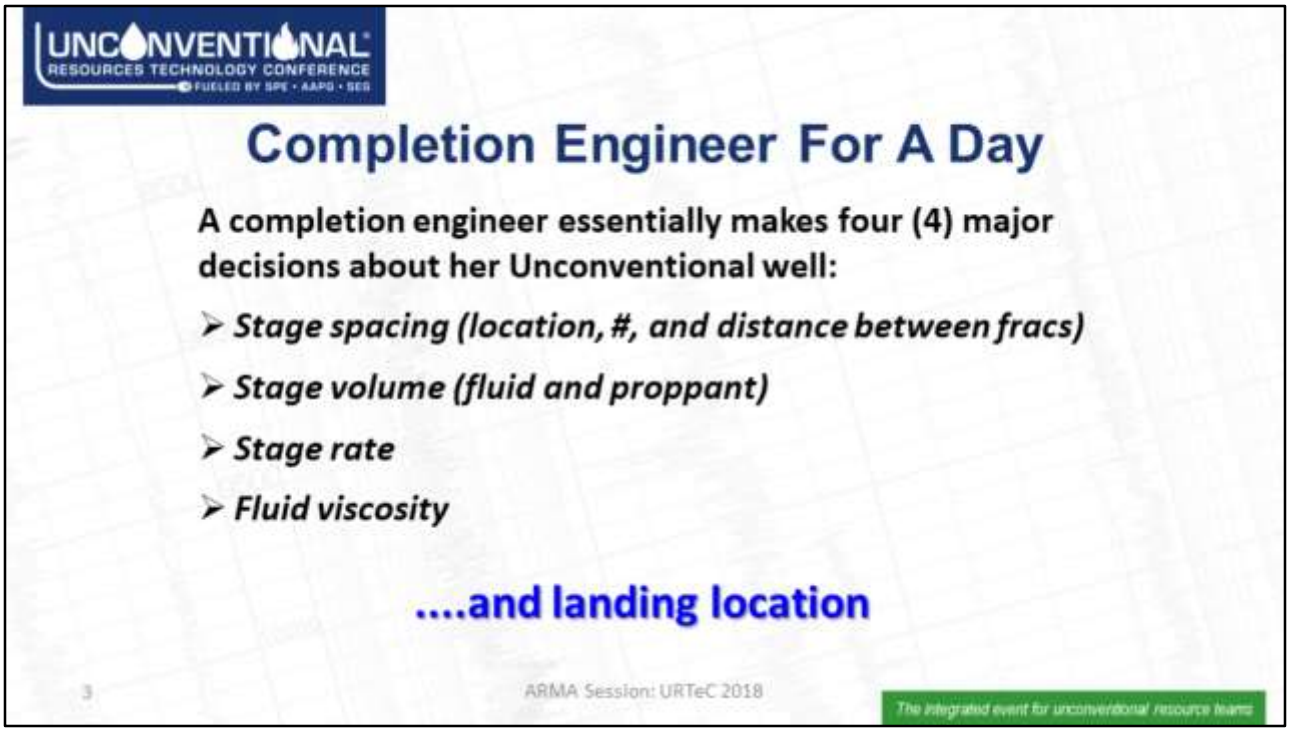
Should you have questions, drop me an email at nnagel@ofgeomech.com

OilField Geomechanics LLC is a small, independent geomechanics consulting company located near Houston, Texas, USA.

Enjoy!

Many in my family are involved in the oil and gas business. OilField Geomechanics was co-founded with my wife Marisela. In addition, I have an oldest son who is a drilling engineer with Anadarko, a daughter who is a reservoir engineer with Oxy, a youngest son who is a pipeline engineer with Plains, and a son-in-law who is a completions supervisor with ConocoPhillips.

When I asked them to review my presentation, my second grandson Noah refused to go to bed until he had reviewed and approved of my presentation. This kid has great potential!



The title for the presentation comes from our extensive experience providing geomechanics training for Unconventionals.

Invariably, sometime during a course – whether during it or immediately after – someone from an asset team will approach me or Marisela and ask:

"How do we help the completion engineers? What can we provide them and how do we speak their language?"

My title "Completion Engineer for a Day" is derived from the common refrain that, to fully understand someone, you need to "walk a mile in their shoes". So Completion Engineer for a Day is about focusing on what are the primary decisions a completion engineer is called upon to make when designing her/his stimulation.

In essence, there are four major decisions: 1) perforation location and spacing (cluster and stage); 2) volumes (fluid and proppant); 3) injection rate; and 4) fluid rheological properties – primarily viscosity.

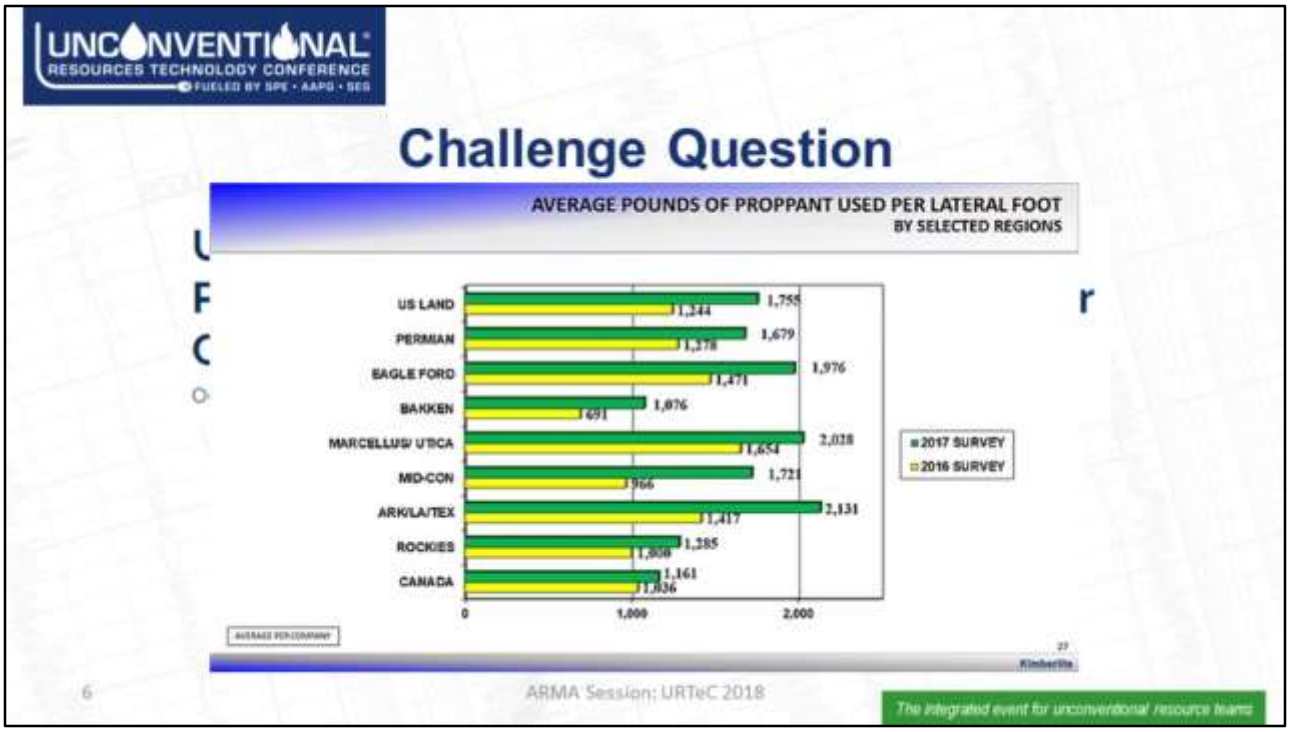
In addition, particularly for Unconventionals, it is very important that the completion engineer, as well as the drilling engineer, have a loud voice at the table when landing location is picked. Thankfully, we are slowly moving away from the paradigm that the lateral must always be landed in the highest porosity/permeability zone!

Critically, taking the Completion Engineer for a Day concept to its logical conclusion, from a Value of Information perspective, if the asset team is intent on influencing completion designs, they need to focus on providing information, data, and insight that influence the decisions a completion engineer is called on to make.

I had an interesting conversation with a marketing friend. He related that studies done after the last national economic downturn showed that overall, as expected, sales agents and account manager really suffered due to the slow down in activity. They simply couldn't make sales. No one was buying. However, one group of sales agents and account managers DID continue to find success. These were described as "Challenge Sellers".

A Challenge Seller was defined as a individual who did not focus solely on making friends with his/her buyers by getting to know the family or providing game tickets or the like. Rather, the Challenge Sellers asked their buyers to consider potential outcomes and the impact on their companies. They would ask "What would you do if XYZ occurred? Would you be prepared?" By using a bit of the Socratic method, the sales agent led the buyer to conclude, by themselves, the value of the product the sales agent was marketing.

In a similar vain, I begin this presentation with a Challenge Question. Basically, as you are confronted with a particular trend in the industry – in this case the significant increase in sand volumes pumped in stimulation treatments across all major plays – how might this be understood from a geology/geomechanics perspective?



There are a significant number of reports and papers on the increased usage of proppant. This chart comes from a Kimberlite Research article from October 2017.

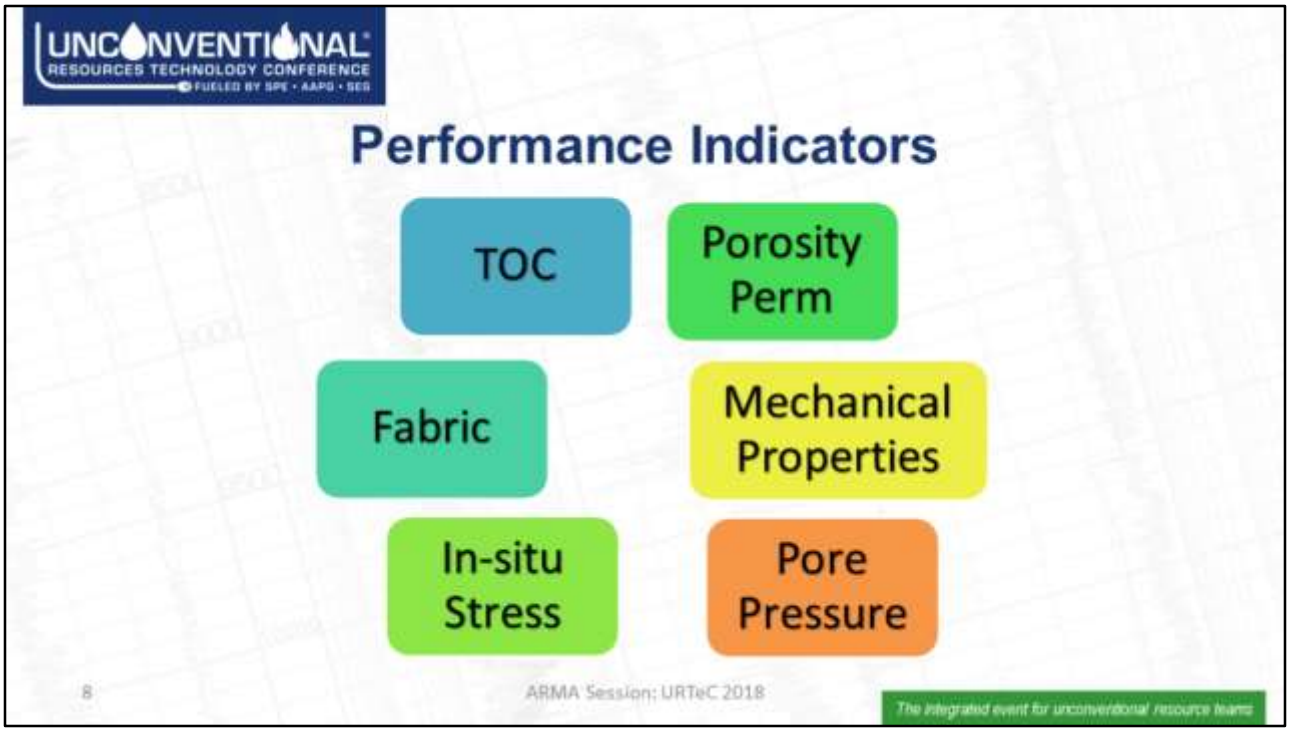
As shown, in a single year – from 2016 to 2017 – sand volumes per foot of lateral increased from 30% to 50%!! Other authors have shown something similar as well as the associated increase in production.

Why is this? What does this say about our stimulation designs and, most importantly, how do we incorporate this in future designs.

As we strive to achieve the optimal stimulation design (whether or not we ever get there is another question, but we do strive to get there), we have to ask some tough questions:

- After nearly 20 years of working Unconventionals in the United States (and to a lesser extent Internationally), how do we explain such a change in completion design over a single year?
- More importantly, when the completion engineer comes back to the asset team and asks "Why am I seeing significant production improvements with increased sand volumes? And, how do I incorporate this finding into further optimized designs" how does the asset team respond?

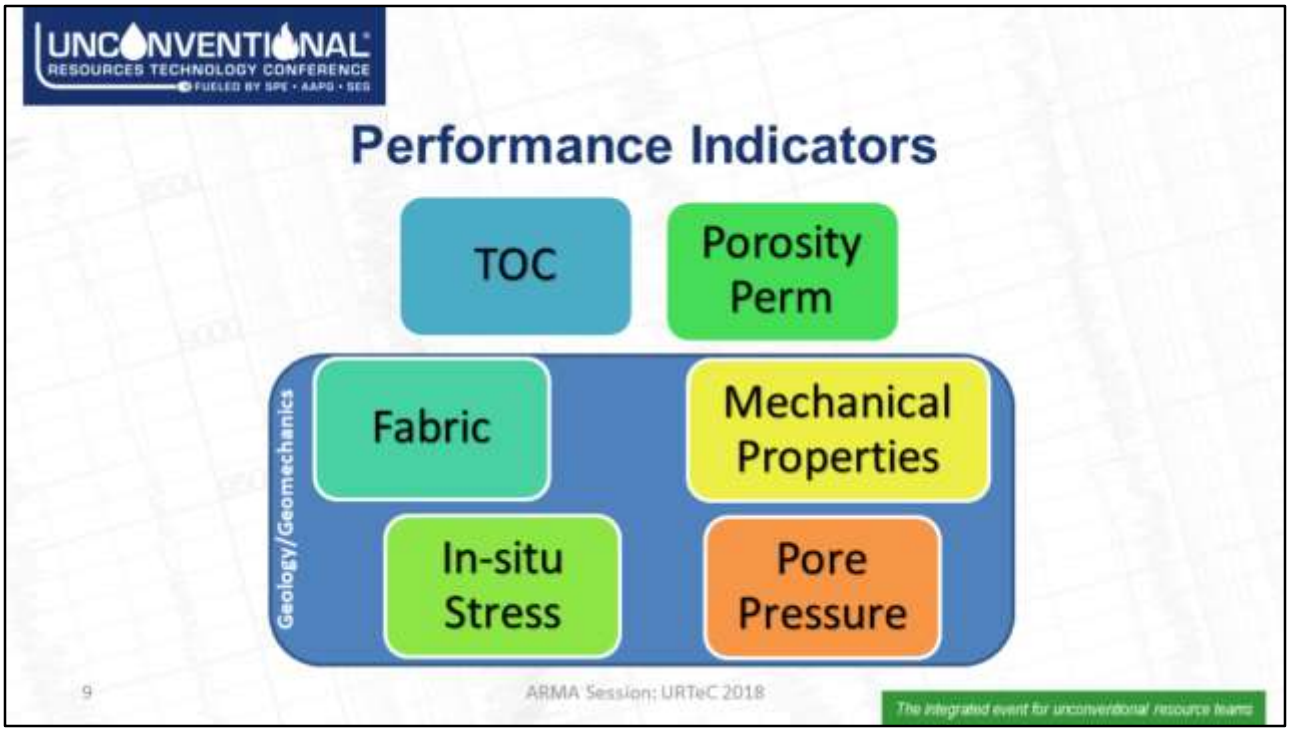
You might not want to be a "Completions Engineer for a Day" after trying to answer this question!



So lets take a few slides to investigate some of the common performance drivers for Unconventionals and see if, after some reflection on these, we might be able to answer the questions that the Completion Engineer has posed after seeing the production improvements with increased sand volumes.

Here I show a number of common performance indicators. Various companies have slightly different versions of this or may have a greater or lesser granularity to them. Nonetheless, this is good starting point for considering the performance improvements with increased sand volumes.

TOC and porosity/permeability are beyond the scope of this presentation and will not be discussed any further.



For this particular set of performance indicators, note that the bottom four (2/3rds of the indicators) are geology or geomechanics related. We'll focus on these.

First, let me discuss the issue of Mechanical Properties. Via the Brittleness concept, this factor has largely been front and center for many asset teams. However, though brittleness is the proverbial cat with nine lives, I think it is finally on its ninth and final life.

Let's play petroleum Jeopardy for a moment:

"Alex, I would like petroleum geomechanics for $500, please."

ALEX: "And the answer is 'brittleness'". Buzzer rings off camera.

"Alex, what is an ill-defined parameter that has likely cost the industry millions of dollars chasing after?"

ALEX: "No, I'm sorry. That is not correct". Though Alex whispers under his breath "but it isn't too far from the truth…"

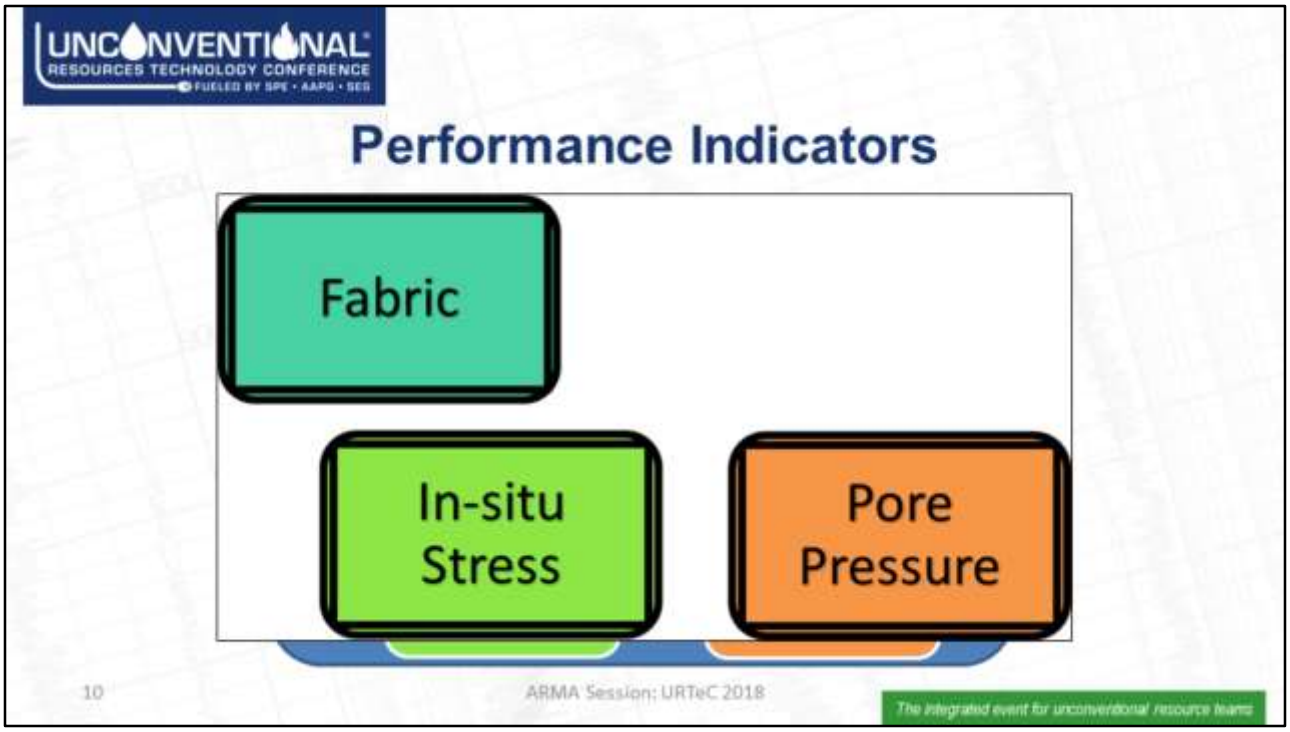
Neither of the other contestants buzz in. This is how many folks view brittleness.

Fundamentally, what was brittleness about? Picking perforation locations? What does Young's modulus or Poisson's ratio – elastic mechanical properties – have to do with production? The original Halliburton paper that really started the brittleness craze was: 1)

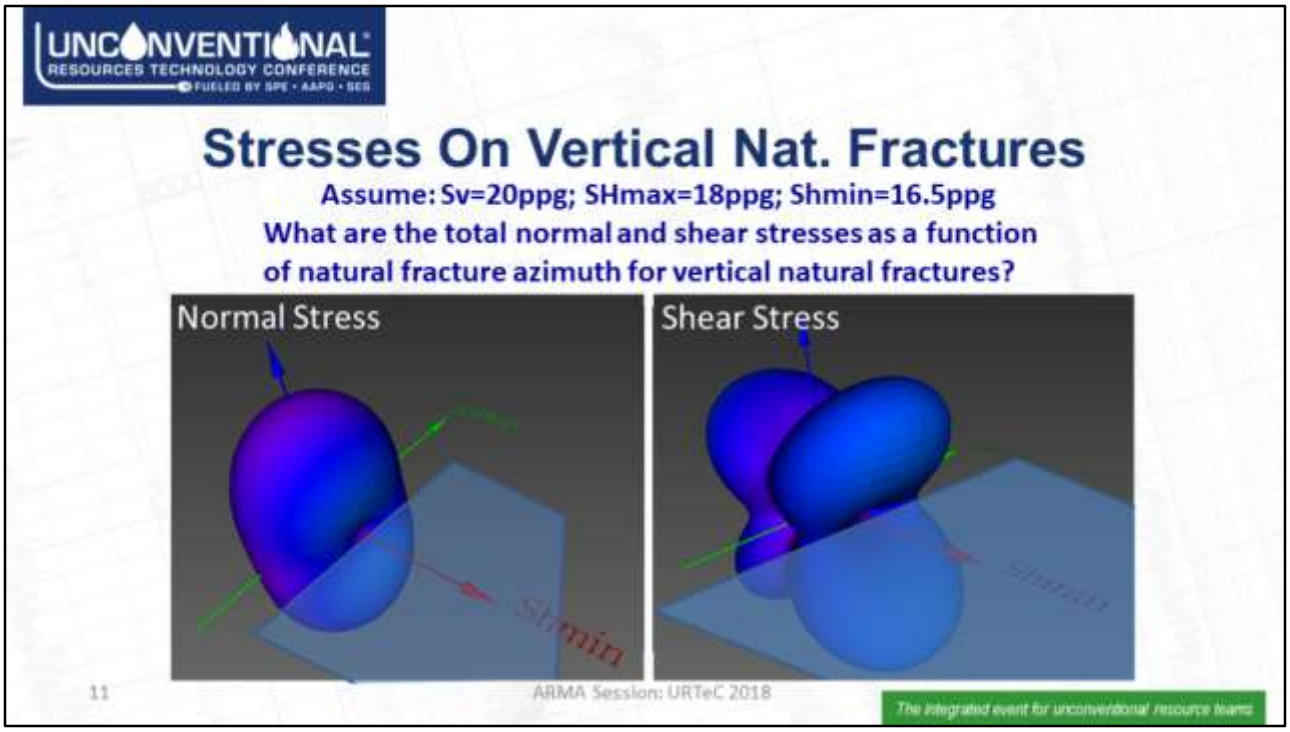
based solely on Barnett data; 2) was just an unexplained correlation drawn between these elastic parameters and production (no causation); and 3) the paper actually explains that, really, production was dependent upon the existence of and production from natural fractures.

Young's modulus and Poisson's ratio do play a role in hydraulic fracture width, stress magnitudes, and even the generation of rock fabric. Largely, however, these are 2nd order effects on stimulation design.

Nonetheless, I think mechanical properties are particularly important when we look at inelastic behavior. Not just because this helps us improve the estimation of in-situ stress, but also because most of the commercial hydraulic fracturing codes are based upon linear elastic fracture mechanics (LEFM) and inelastic behavior will tend to invalidate the results from these models. M. Zoback and his students at Stanford have done excellent work looking at the inelastic behavior of many Unconventional formations.



In the next few slides, I will discuss, albeit way too briefly, the impacts of pressure, stress, and fabric on production in Unconventionals.



With the advent of dipole sonic and similar logging tools in the 1970s and 1980s, the industry became able to measure both compressional and shear wave velocities downhole. By having both wave velocities, the value of Poisson's ratio could be computed based upon elastic theory. And with Poisson's ratio, and using the "Eaton Equation" (or the plane strain equation), the value of the minimum horizontal stress, Shmin, could be evaluated, which gave rise to the "frac log".

As it was known that a hydraulic fracture opened against the minimum horizontal stress and Shmin exerted significant control on fracture height growth (which is an important factor because, due to volume balance, if the frac fluid was going to create fracture height, it was not creating length and fracture surface area for production in the pay zone), Shmin was the primary (and, often, sole stress) input to fracturing codes. As such, the other principal stresses, the vertical stress, Sv, and the maximum horizontal stress, Shmax, were ignored by many completion engineers.

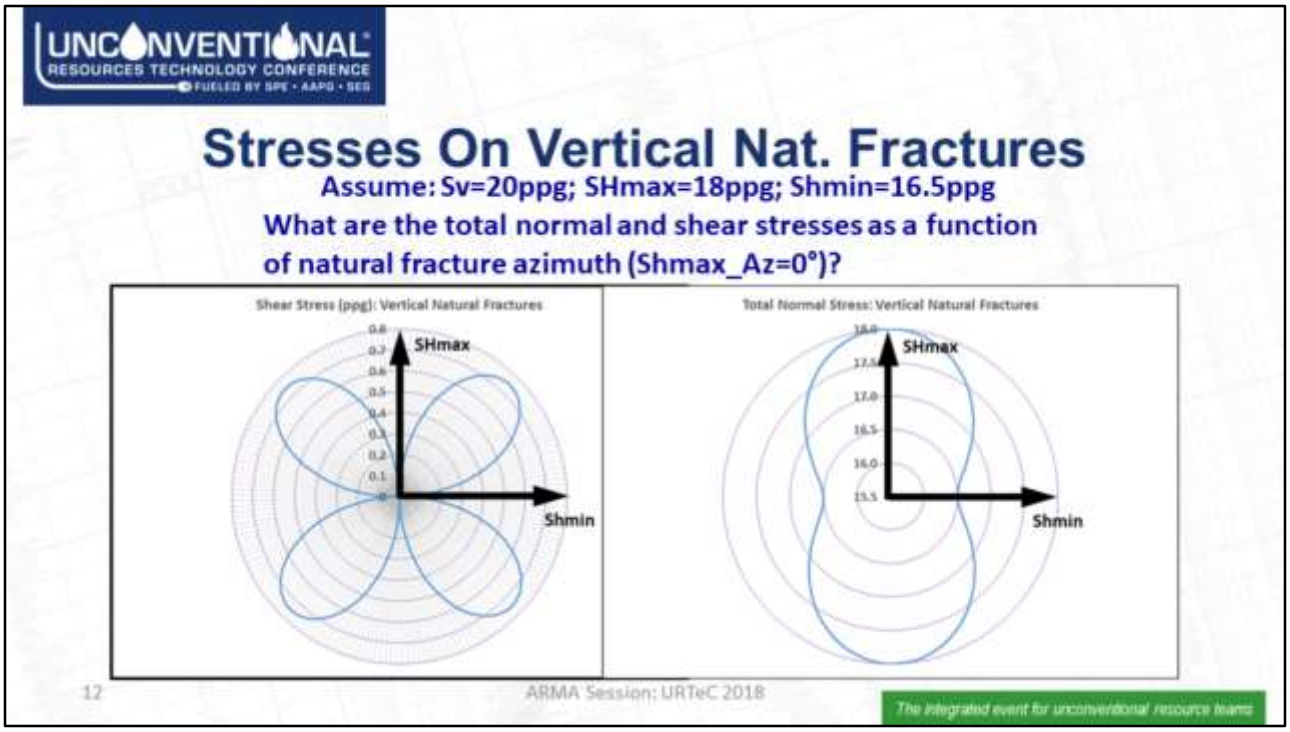
Particularly for Unconventionals, knowing the full stress tensor (which can be fully defined at a given point by three principals stresses and an orientation), provides significant power towards understanding the potential interactions between a hydraulic fracture and existing rock fabric (including natural fractures).

With the full stress tensor, shown in this slide in gradient (ppg), the shear and normal stresses acting on any orientation can be computed, including, for example, a fault or fracture surface. In the left of the figures, the blue "glyph" represents the normal stress on a plane in 3D at any dip and dip direction. In a similar fashion, the "glyph" in the right figure shows the

shear stress acting on any plane (any dip and dip direction) in 3D.

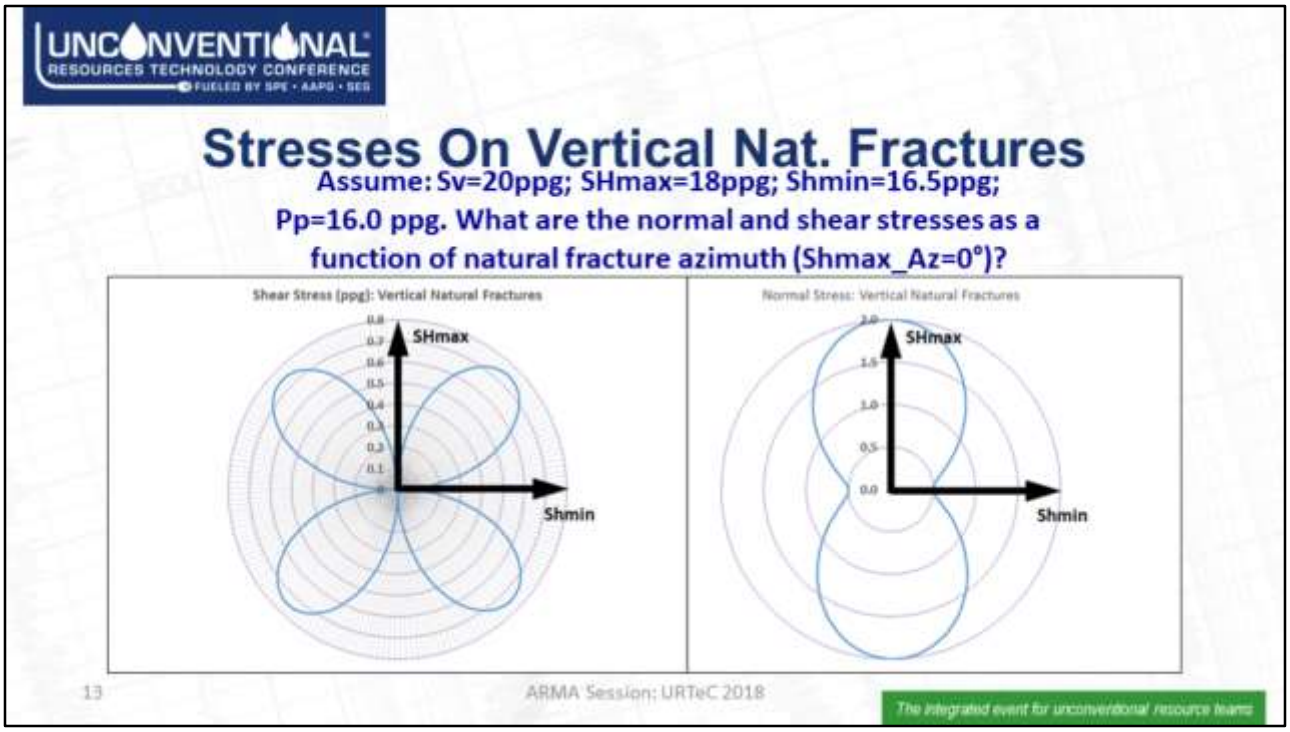
For this case, the ranking of the stresses (Sv, Shmax, and Shmin – which are considered to be principal stresses) reflect a normal faulting environment (in Andersonian terminology). The glyphs could easily be generated for a strike-slip or thrust stress environment.

Let's take each of the normal and shear stress glyphs and cut them horizontally to look at the case of vertical surfaces (natural fractures).

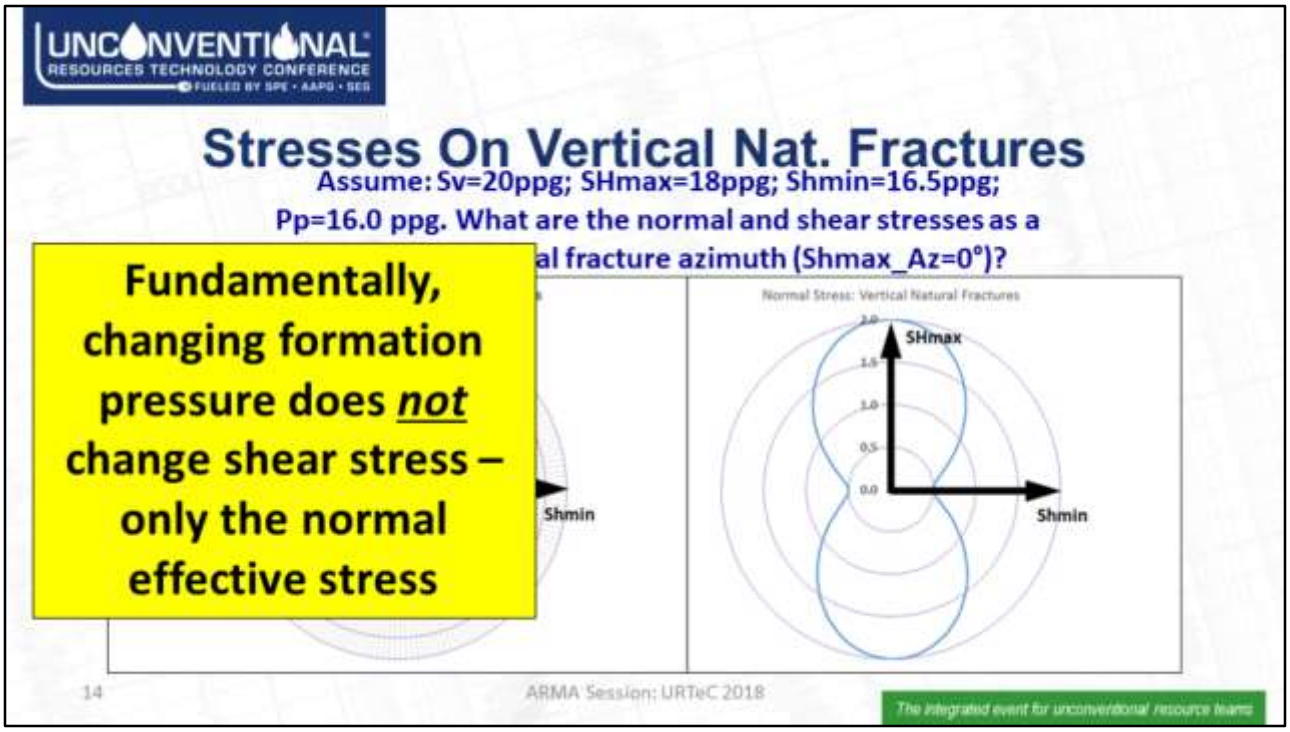


These two figures represent the 2D results of cutting both the normal and shear stress glyphs from the previous slide. They represent the stresses (normal and shear) acting on a vertical plane (natural fracture) for any dip direction from 0 to 360 degrees. Note that there is no shear stress at a dip direction of 0, 90, 180 or 360 degrees (which follows from the definition of principal stresses). Note also that the maximum shear stress is at 45 degrees between the direction of SHmax and Shmin.

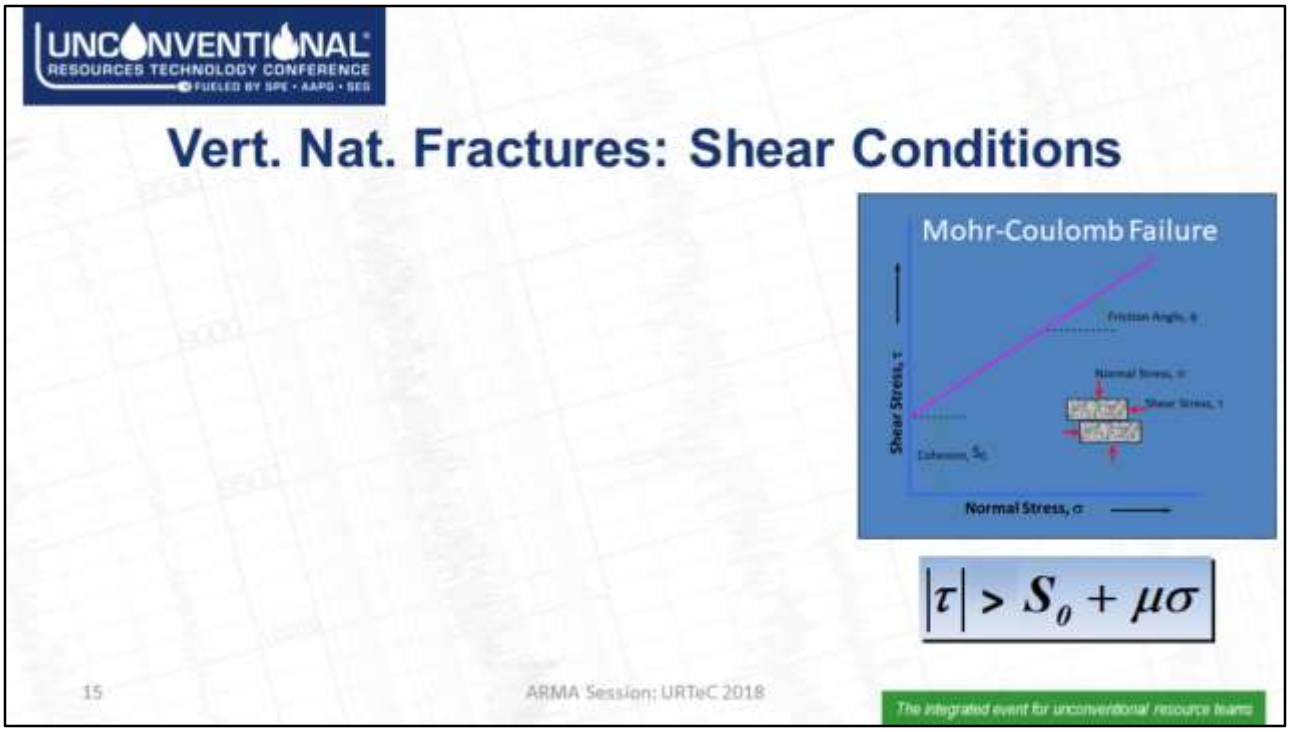
The right figure shows the normal (total) stresses for any dip direction. At 0 degrees, the magnitude is 18.0 ppg, which matches with the value of SHmax. And at 90 degrees it is 16.5 ppg, which matches with the value of Shmin as expected.



Adding formation pore pressure changes the figures. Or, more correctly, changes the normal (effective) stress figure on the right. Note that the magnitude of the shear stresses in the left figure are unchanged from the previous slide. However, the magnitude of the normal (now effective) stress is greatly reduced (and reduced by the value of the pore pressure).



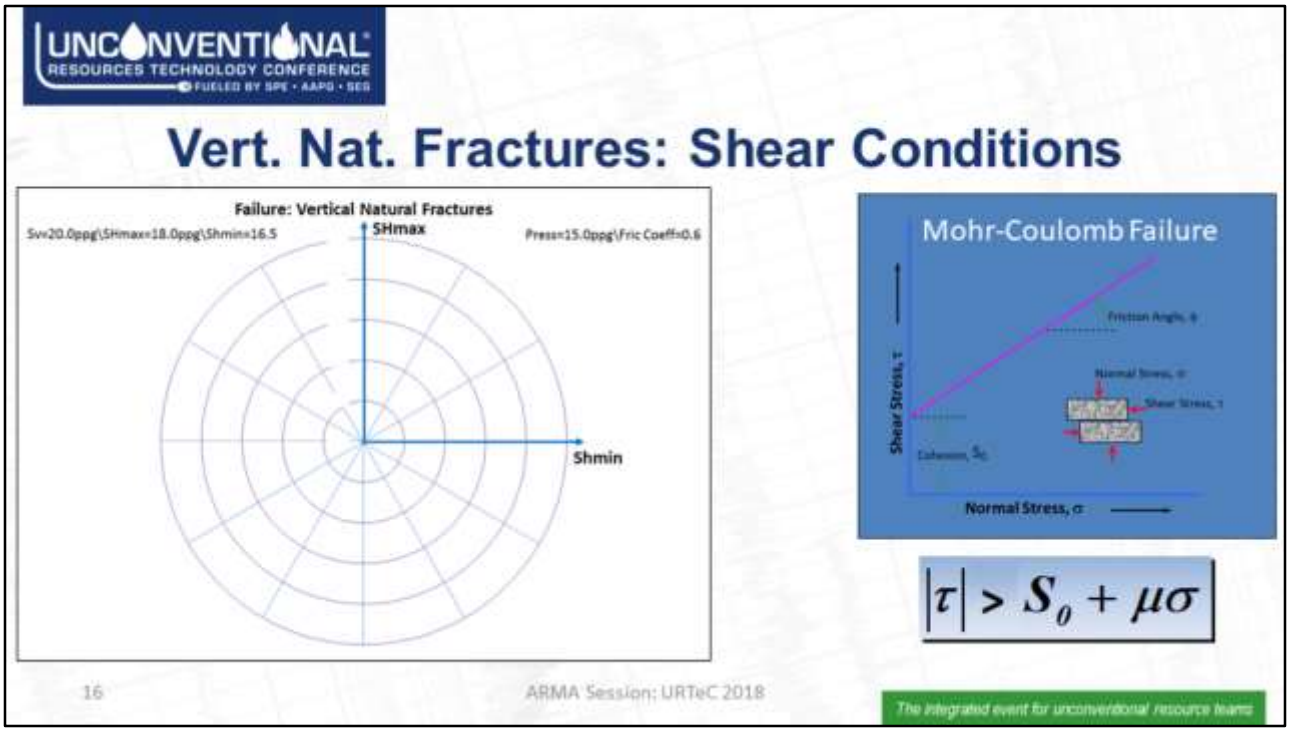
The behavior noted between the two previously slides points us towards a fundamental geomechanics principle: Changes in formation pressure WILL change the normal (effective) stress but WILL NOT change the shear stress. This is especially critical when we consider the role of pressure on rock shear failure – and shear stimulation.



One of the simplest failure criterion (i.e., equation to define failure) we use is the Mohr-Coulomb failure. In the figure in blue, normal (effective) stress is plotted on the X-axis and shear stress is plotted on the Y-axis. The red/purple line in the figure represents the failure surface (which simply separates normal/shear stress pairs that leave stable rock from those that cause the rock to fail). Stress conditions above and to the left of the red/purple line are not permissible (the rock would fail), while stress conditions below allow for a stable rock.

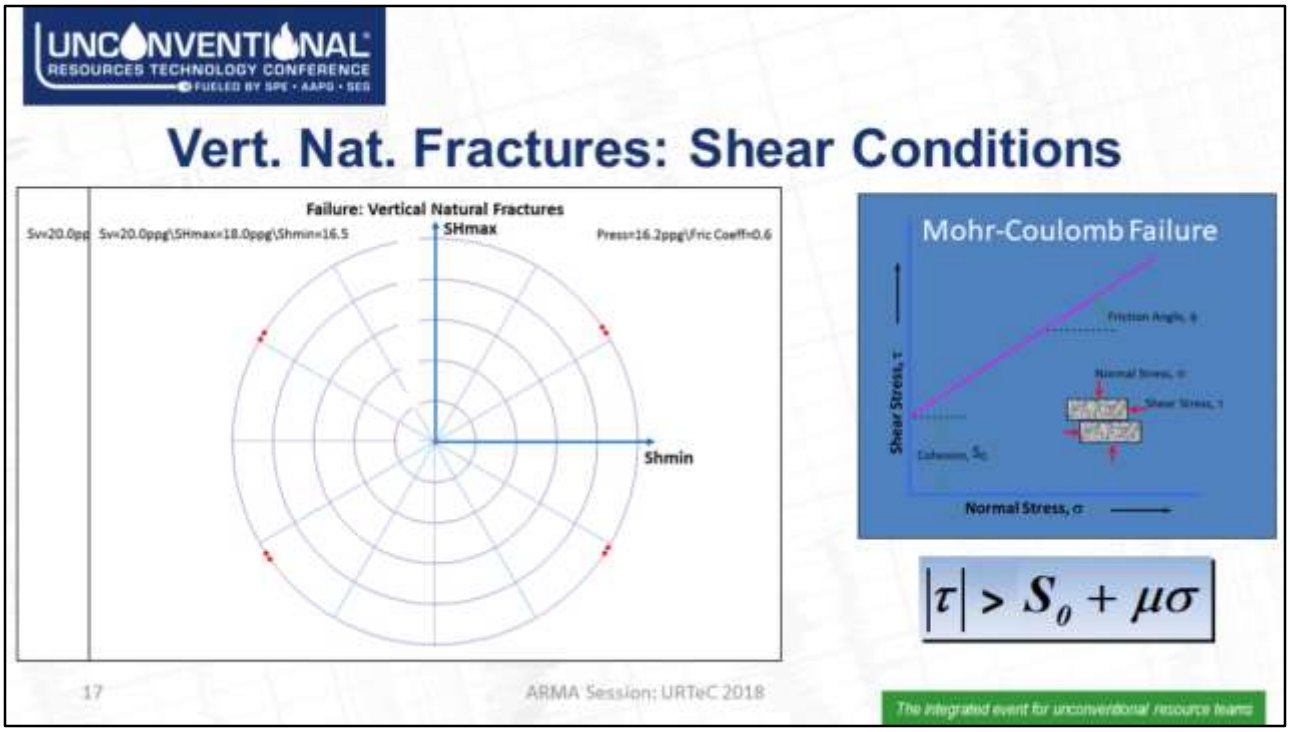
The equation of the red/purple line is shown below the figure. When the shear stress (tau) is greater than the resistance force (cohesion plus normal effective stress times friction), the rock will fail.

At some distance from the hydraulic fracture, where the stress field is unperturbed (i.e., the field shear stress is unaltered), the shear stress is a given value, cohesion is set, the friction is set and only the pressure (which reduces the normal effective stress) can change. As such, rock failure (as, for example, evidenced by microseismic data) will only occur due to a change in formation pressure.



In this figure, rather than look at stresses, the rose diagram reflects the dip direction of shear failure. Under the conditions shown (Sv=20ppg, etc) and a formation pressure of 15ppg and a friction coefficient for our natural fractures of 0.6 (friction coefficient is the tangent of the friction angle), no orientation of vertical natural fractures is at a shear condition.

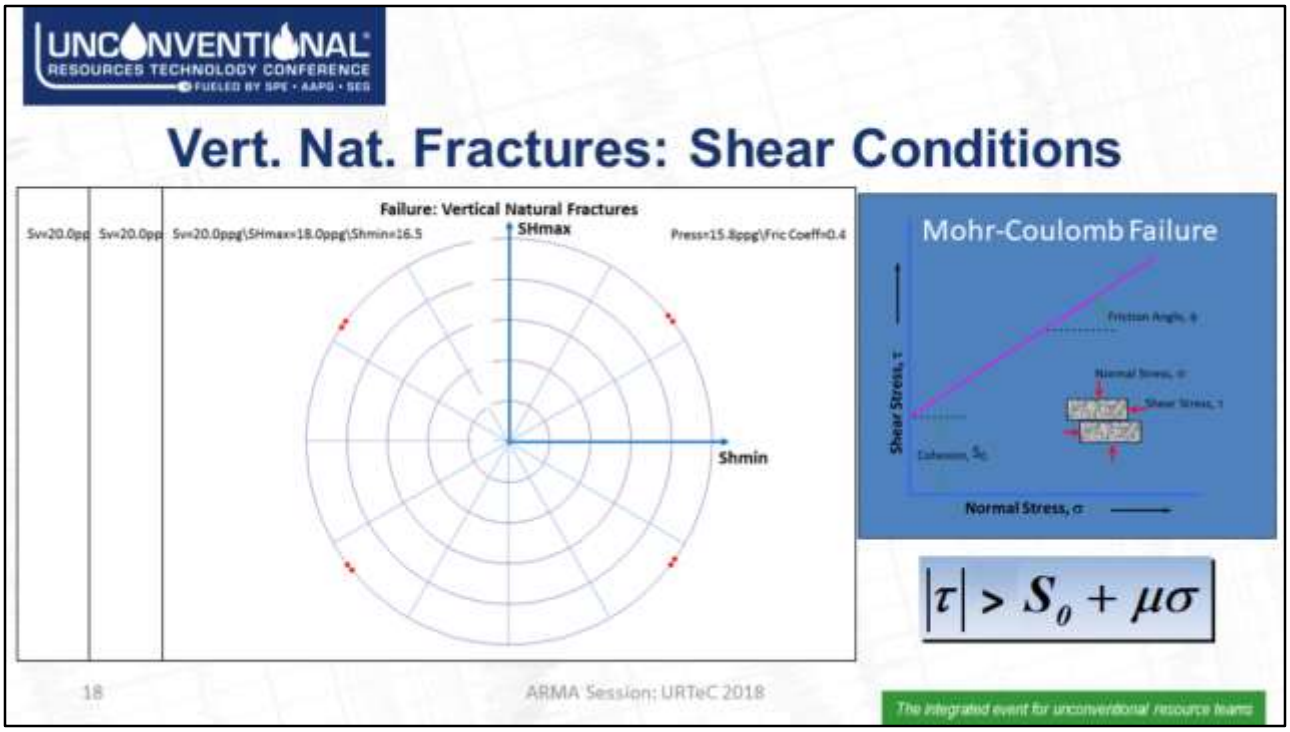
If a microseismic survey was to be run under these conditions, nothing would be picked up on the sensor array.



If the formation pressure was increased to 16.2 ppg (from the 15 ppg on the previous slide), shear failure is seen to occur on vertical natural fractures at a dip direction of about 58 degrees. No other orientation of vertical natural fractures would be at a shear condition.

Can we get the formation pressure to 16.2 ppg? How?

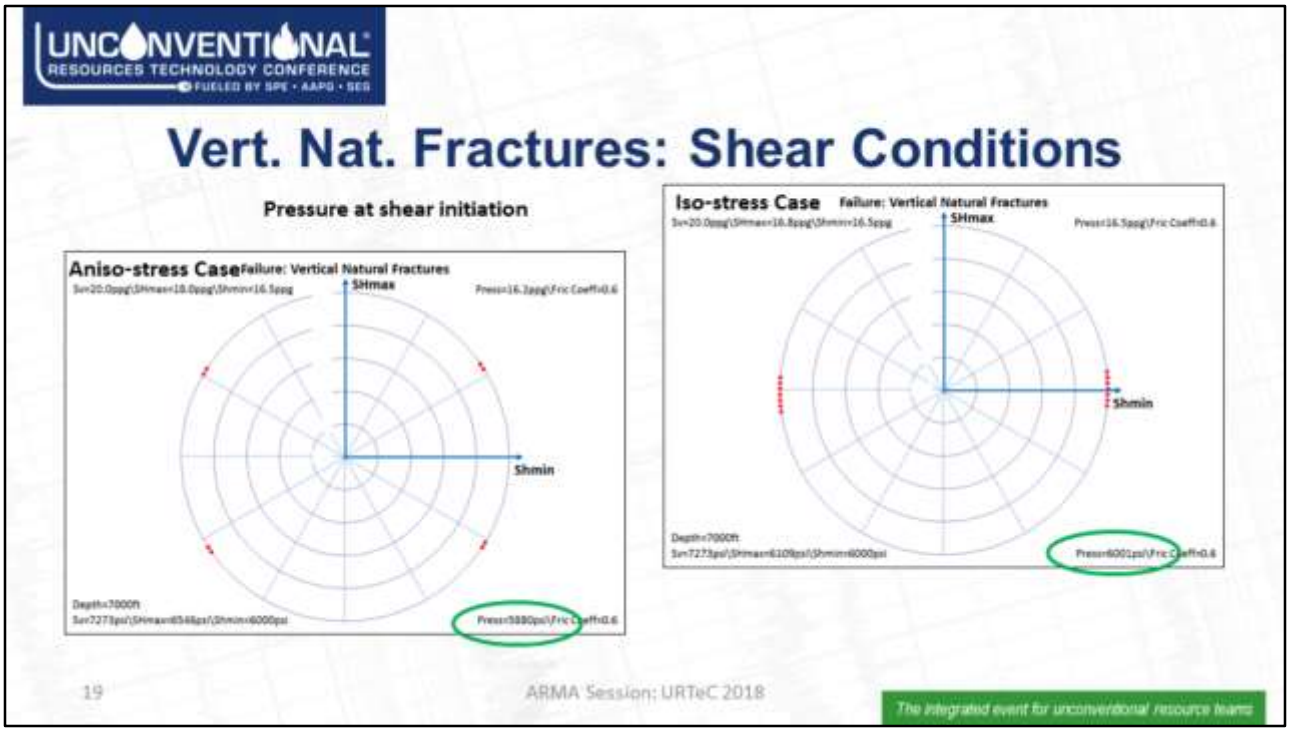
To create a hydraulic fracture, the pressure in the fracture itself must be equal to Shmin plus net pressure (defining net pressure is beyond our discussion here), which means the pressure in the hydraulic fracture is equal to 16.5 ppg plus maybe 0.1 to 0.2 ppg or ~16.7 ppg. If this pressure can be pushed into the natural fractures within the rock, then it is clearly possible that we could achieve a pressure of 16.2 ppg in the rock some distance away from the hydraulic fracture and generate shear slippage (and microseismicity).



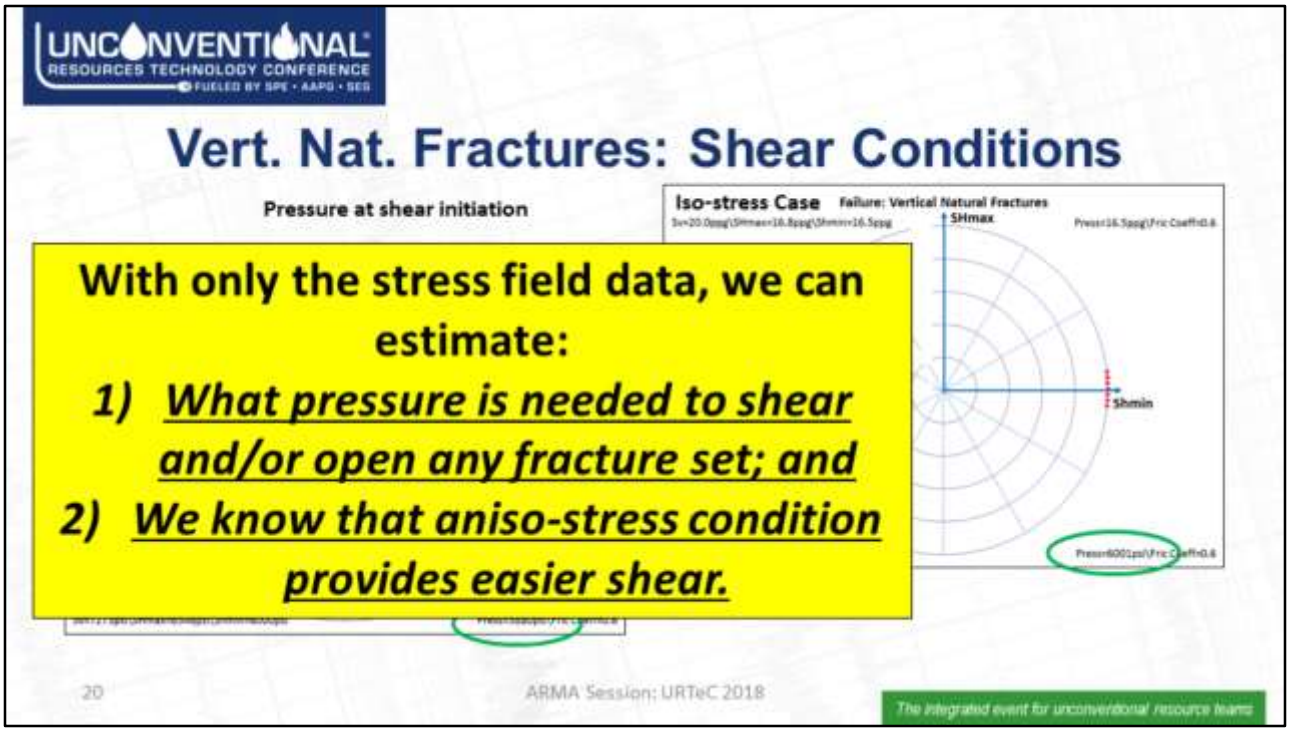
What if the friction on the natural fractures was lower? In that case (a coefficient of friction of 0.4 is shown here), then the pressure to achieve shear slippage of a vertical natural fracture at a dip direction of 56-57 degrees is reduced to 15.8 ppg.

Critically then:

- Having a measure of the full stress tensor allows for simple computation of stresses acting on any orientation of surfaces, planes or features in 3D (i.e,, fractures, bedding planes, and faults).
- With simple assumptions about the mechanical properties of the surfaces or planes involved, we can predict which will tend to shear slip first and, likely, when (under which pressure).



There remains much debate about the role of stress anisotropy in Unconventional stimulations. Largely, this discussion revolves around whether or not a better stimulation is achieved when the values of SHmax and Shmin are similar (iso-stress) or significantly different (aniso-stress). For shear stimulation (that is shear stimulation in the far-field NOT that created by a propagating hydraulic fracture), the better field stress condition is anisotropic stress. Why? Because the aniso-stress condition starts with more shear stress on every orientation of natural fracture – and more shear stress means a lesser normal effective stress change (lesser pore pressure change) is required to achieve shear failure and shear stimulation. This, in turn, means that, for a given net pressure and pumping time, a larger volume of rock will reach shear conditions with anisotropic stresses.



We have looked at stress at a single point – obviously stresses change within a 3D volume. So the analyses represented here would need to be conducted within a 3D stress model and with input on the major orientation of features and planes.

This is actually fairly commonly done – and is called a critically stressed fault analysis.

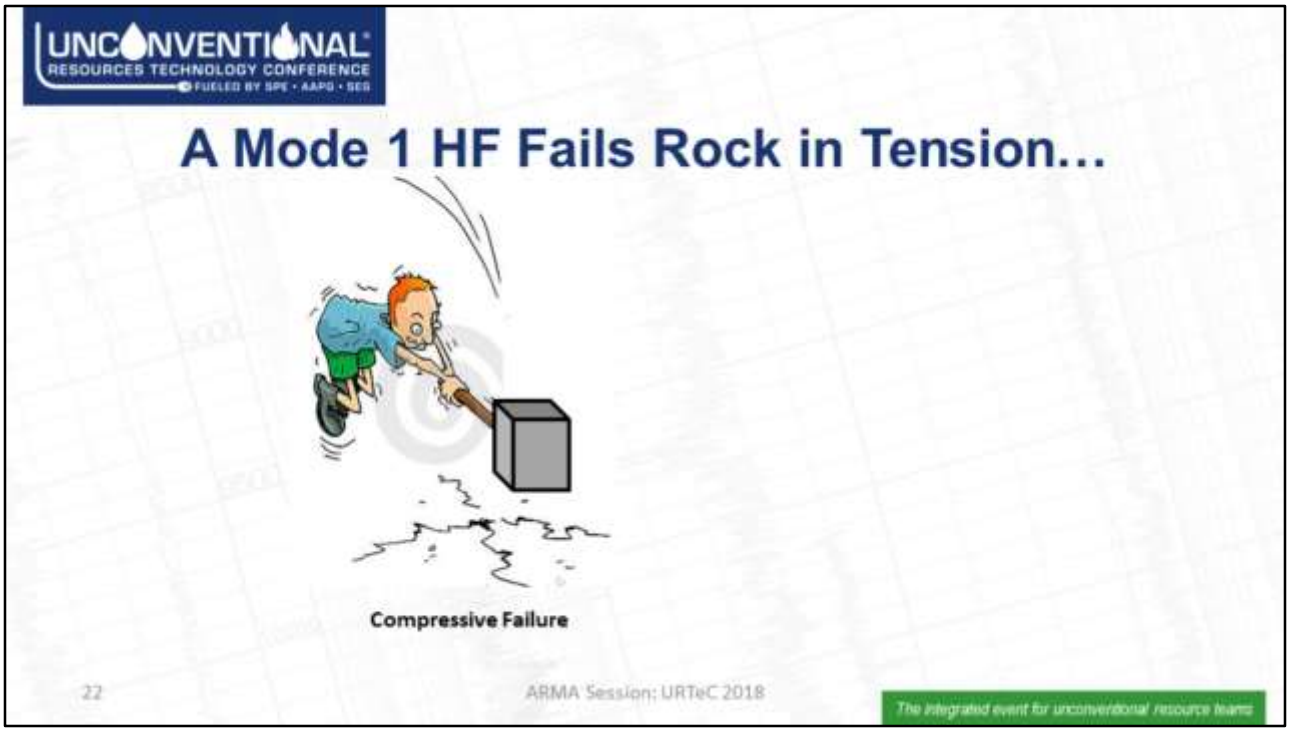
The last of the three performance indicators I want to present is the concept of rock fabric.

I use the concept of “fabric” because it can be easier to understand and, perhaps more importantly, gets us away from a strict discussion of the presence or absence of natural fractures. “Fabric” also allows me to talk about natural fractures (whether opened or closed or cemented or not) and bedding planes generically.

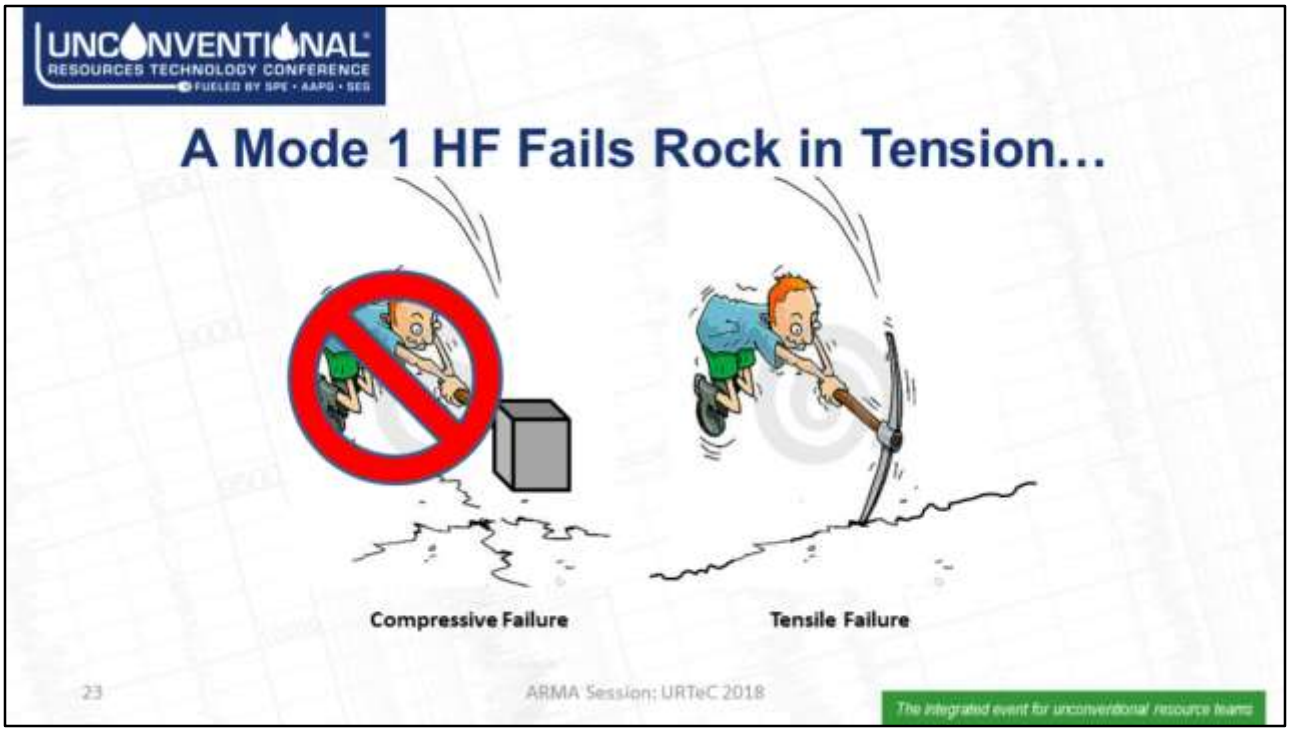
For this discussion of fabric (let’s call it geomechanical fabric), let’s define fabric as heterogeneity in rock mechanical properties (elastic, inelastic, and strength properties). Other effects may also be present (i.e., changes in permeability).

In the right figure, you are looking at the surface of a big block (1-meter cube) hydraulic fracture experiment. Note the roughness. This roughness is due to the propagation of the hydraulic fracture wiggling a little to the left or a little to the right due to local strength variations.

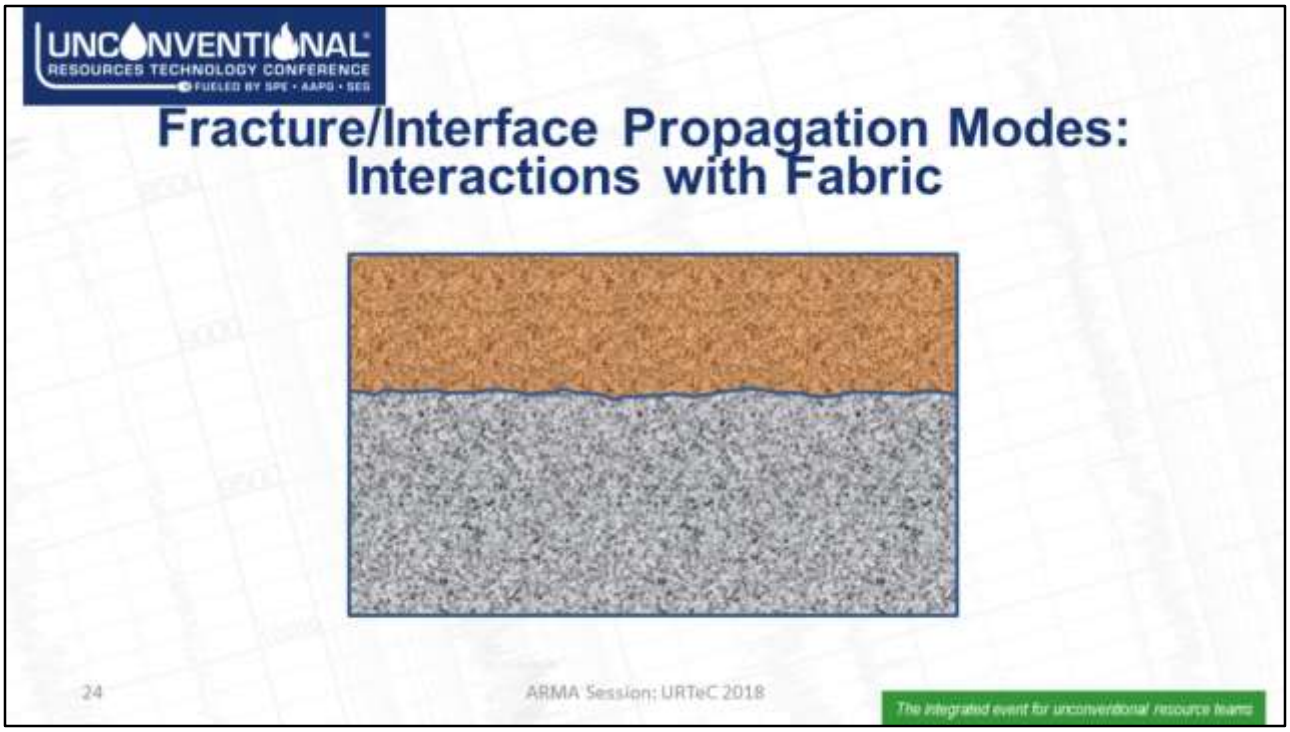
In the left figure, a chunk of shale from China, the variations in geomechanical fabric are evident by how the shale has broken and fractured.



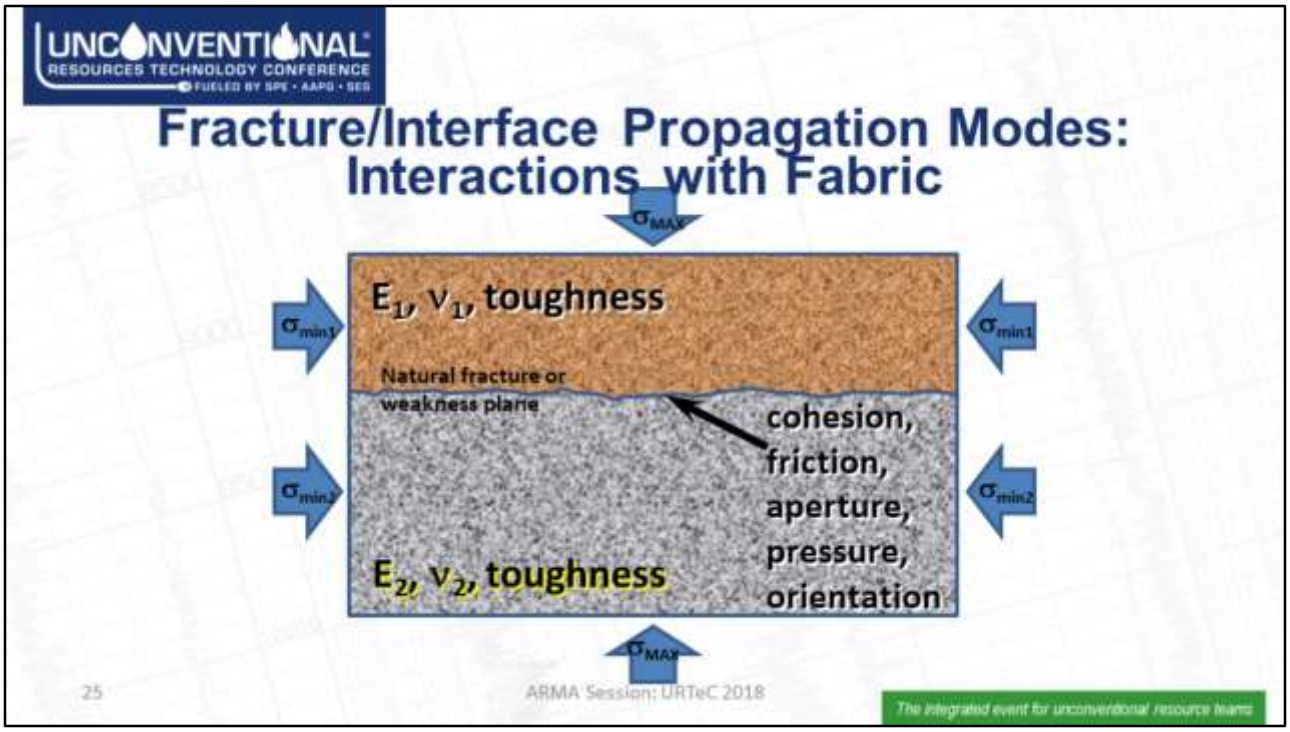
Thankfully, the concept of “complexity”, wherein we wholesale broke up the matrix of the rock formation by hammering on it from our hydraulic fracture stimulation (recall all the pictures of fractured glass that people have shown over the years), has also outlived itself. Simply put, with few exceptions, the net pressures seen in most stimulations are not large enough to fail the matrix of the rock in shear. failure.



Because of the nature of hydraulic fracturing, wherein the volume creation for the injected fluid is controlled by the least or easiest rock failure, a mode 1 (tensile) hydraulic fracture is created rather than a large network of shear fractures. This is because the tensile strength of rock is often 10% or less than the shear strength of rock. Consequently, our focus on rock behavior during hydraulic fracturing needs to be on the interaction between the created mode 1 (hydraulic) fracture and rock fabric.

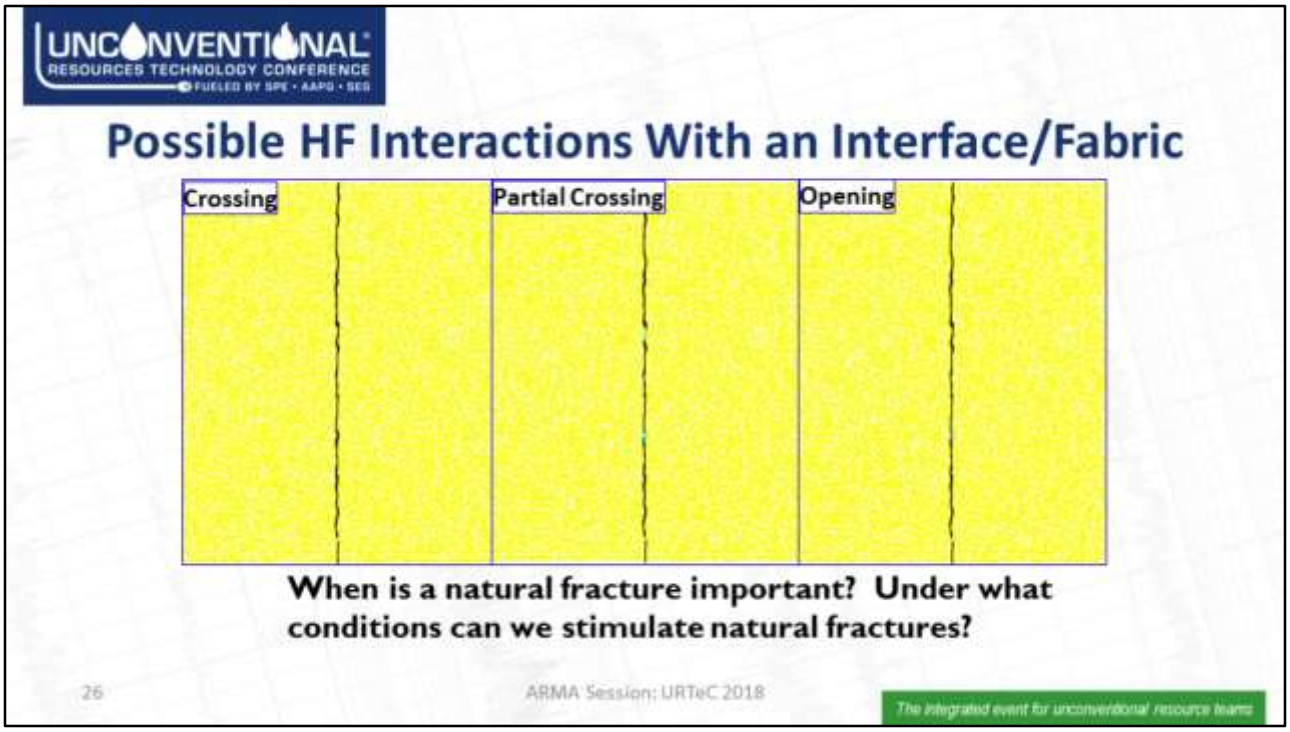


As we have defined fabric as heterogeneity in mechanical properties, we need to consider these from a geomechanical perspective. Mechanical properties will vary within a layer, between layers, and even within the region separating two layers themselves (which I will call and “interface”).



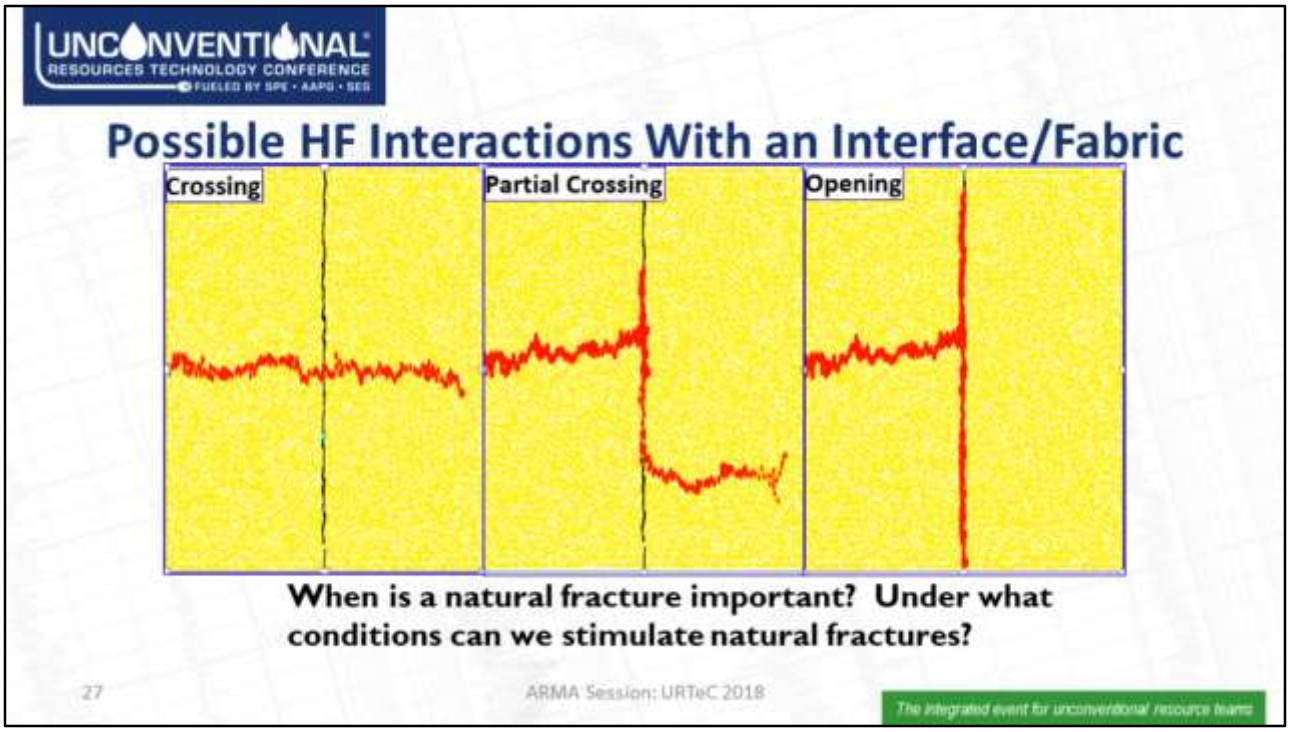
What happens when a propagating HF intersects an interface (whether that be an open or closed natural fracture or a bedding plane, etc.)? Does it cross? Stop? Does injection pressure change?

The interaction between an HF and an interface is controlled by a variety of parameters including: 1) the stress field; 2) matrix mechanical properties; 3) interface mechanical properties; 4) interface orientation; and 5) interface aperture (and pressure) if it is open. The figure graphically represents these possible variation in mechanical properties and stress.



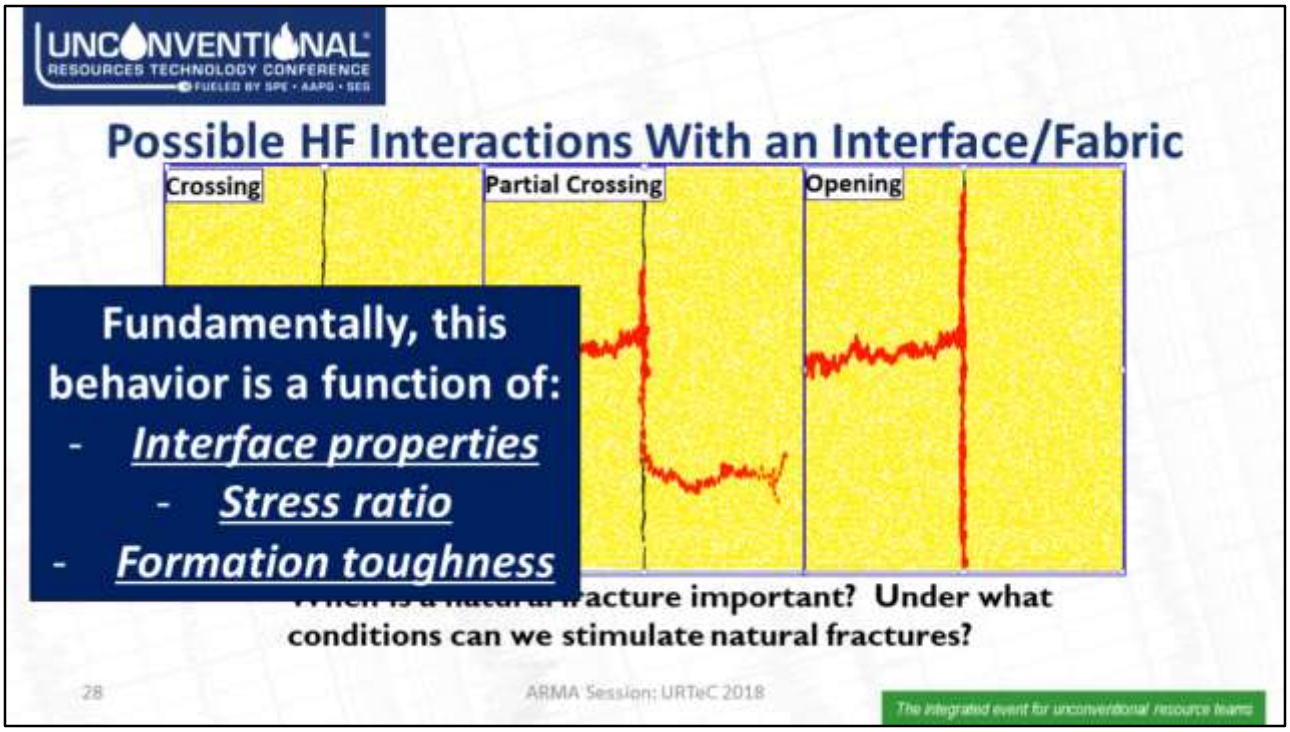
Some of the best and early work on the interaction of a propagating fracture and an interface (here "interface" is heterogeneity in mechanical properties and may simply be the contact between to formations, or a natural fracture, or a bedding plane or similar) was conducted by Renshaw and Pollard from Stanford.

In their work, they defined three crossing behaviors.

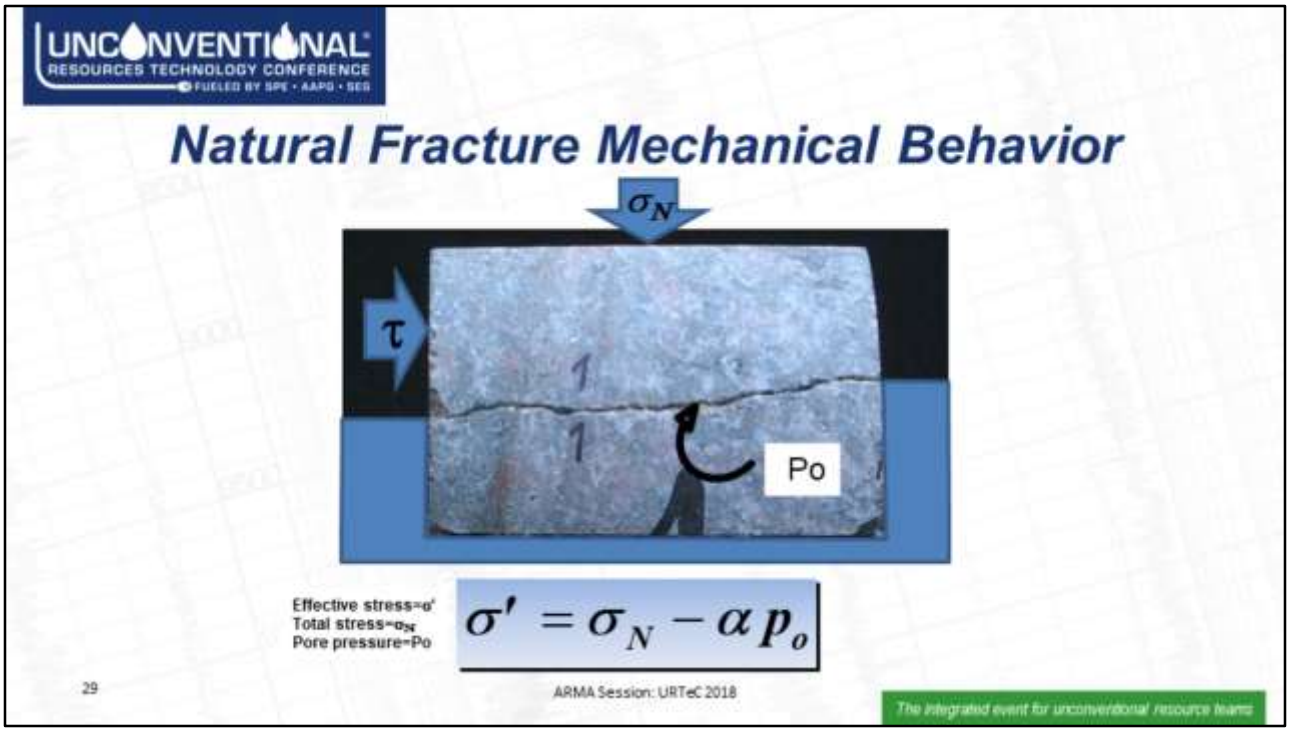


In the crossing patterns shown by Renshaw and Pollard, they found a “crossing” behavior where the hydraulic fracture (in red) propagated through the interface without effect; a “partial crossing” behavior where the interface stopped the fracture propagation for a time but propagation started up again with an offset; and “opening” wherein the hydraulic fracture was stopped and then propagated along the interface.

Image these three crossing behaviors on: 1) hydraulic fracture growth – both vertically and laterally; 2) proppant transport – and whether the proppant can turn corners; and 3) net pressures within the hydraulic fracture.

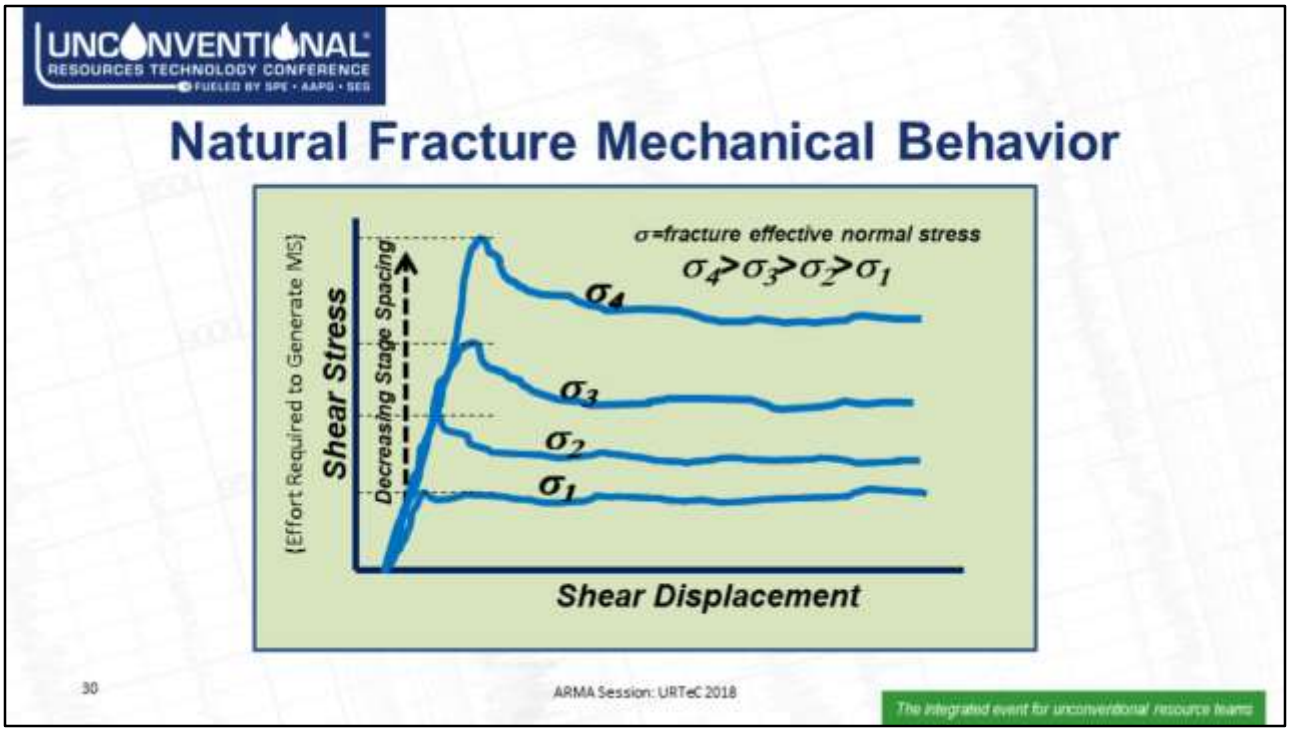


Crossing behavior is controlled mainly by the mechanical properties of the interface, the stress contrast on either side of the interface and the fracture toughness on either side of the interface, amongst other parameters.



So what about the mechanical properties of the interface? Do we have these? Can we measure these?

Here, as an example, is a chunk of granite from nuclear waste site testing in Sweden. We have potted the lower portion of the sample (below the shown natural fracture) and applied stress and pressure on the sample. This is done in what is called a Direct Shear Test Frame. We will then apply a shear stress in an attempt to obtain slip along the natural fracture.

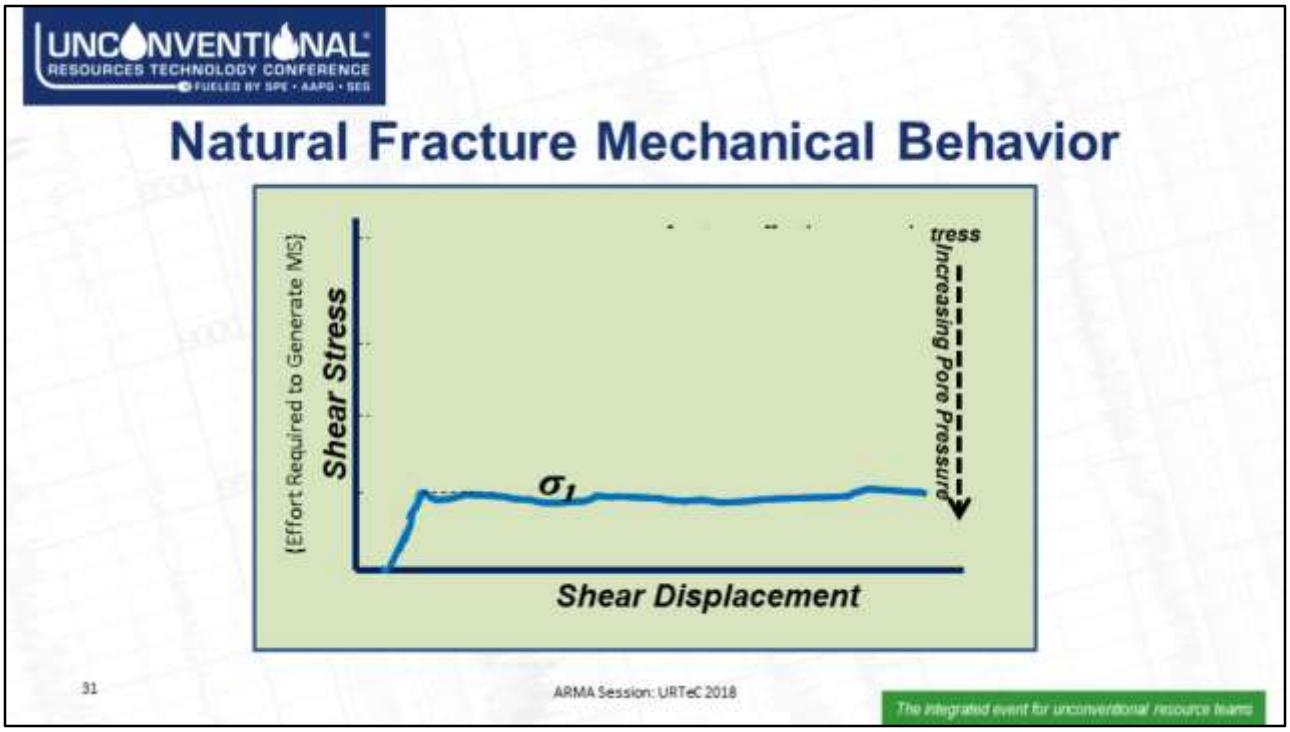


Mechanical natural fracture behavior is a function of the normal effective stress and the applied shear stress.

With small normal stresses, it is easier (i.e., lower shear stress) to shear the fractures (which could generate microseismicity). As normal stresses increase, it is more and more difficult to shear the natural fracture.

In a horizontal lateral will multiple hydraulic fractures, the increase in normal stress can occur due to Stress Shadows as the distance between hydraulic fractures (stage or cluster spacing) decreases.

This would suggest that obtaining shear slippage would increasing more difficult from toe to heel in the well….or with decreasing fracture spacing. However, this is not seen in field microseismic data.

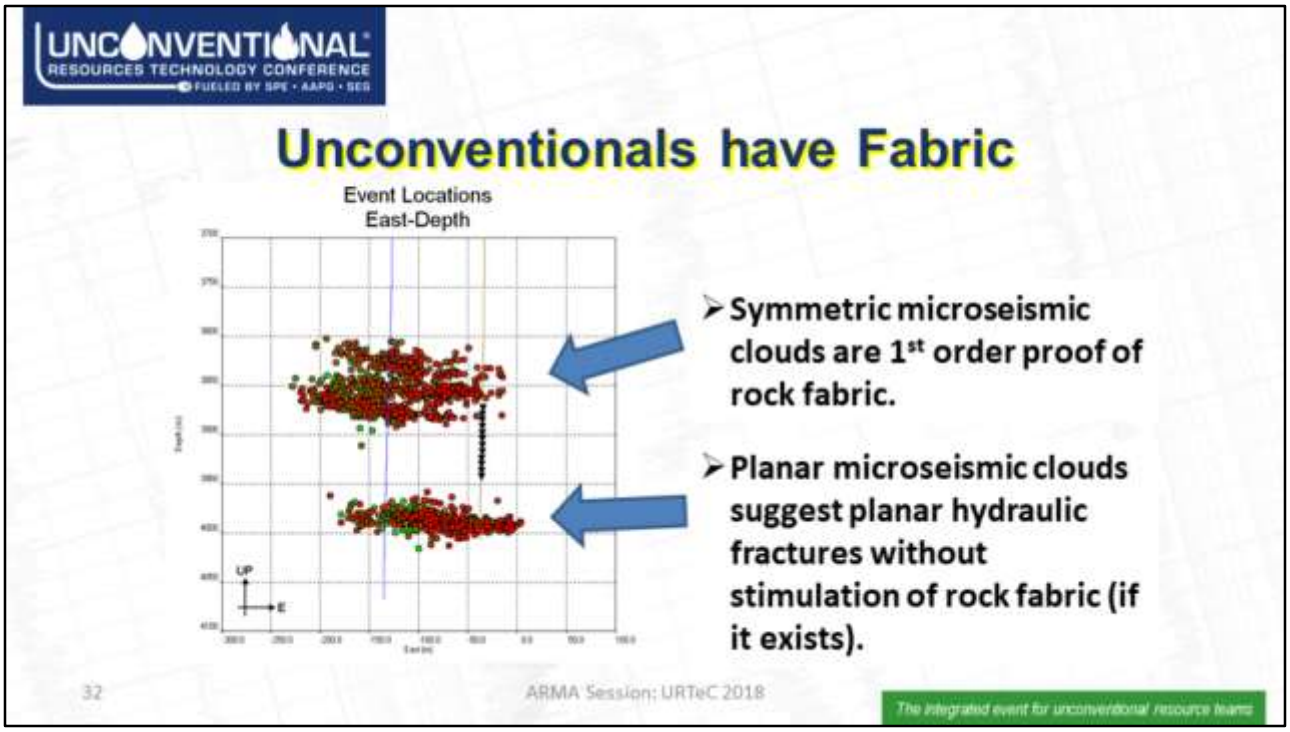


Whereas decreasing stage spacing means greater shear stress is required to shear stimulate natural fractures, increasing pore pressure causes the normal effective stresses to decrease and fractures become easier to shear. As such, if pressure can be increased in the rock fabric, then the effects of Stress Shadows can be offset.

Note also that changes in total stresses (due to rock deformation) can cause some fractures to shear.

Two mechanisms, then, affect natural fracture shear, one related to pore pressure and the other related to rock deformation and total stress changes. Both effects may occur together but may act at different distances from the wellbore.

In order to understand shear stimulation (and microseismicity), we need to consider fracture mechanical and flow properties and we need to use the proper models to simulate this problem.



The old idea of "complexity" was given legs by microseismic data; however, rather than reflect that we hammered the rock and generated complexity, microseismic data actually is a reflection of our ability to drive pressure into the rock fabric.

A planar microseismic cloud reflects a LACK of stimulation of the fabric; however, it does not conclusively show that there is no fabric.

Conversely, a more symmetric cloud of microseismicity is both proof of rock fabric AND proof that we have driven pressure some distance into the fabric.

The importance of this is simple: even if there are no evident natural fractures in cores or outcrops, a large, symmetric cloud of microseismicity is 1st order proof that fabric does exist in the rock.

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Importance of Fabric in Shale Plays

1. Reserves are proportional to the tributary drainage volumes which are related to the geometry of hydraulically induced fractures and the existing or stimulated natural fracture network. (SRV)
2. Depending on the geometry, intensity, mechanical and hydraulic properties of the natural fracture system, different completion schemes are required to optimize hydraulic fracture propagation and proppant placement.
3. Joint frequency and distribution is greatly dependent on shale and associated facies characteristics.
4. The relationship between the present day stress field and joint orientation is an important consideration for well trajectory and stimulation design.
5. Pore Pressure plays an important role in the ability to stimulate the natural fractures.

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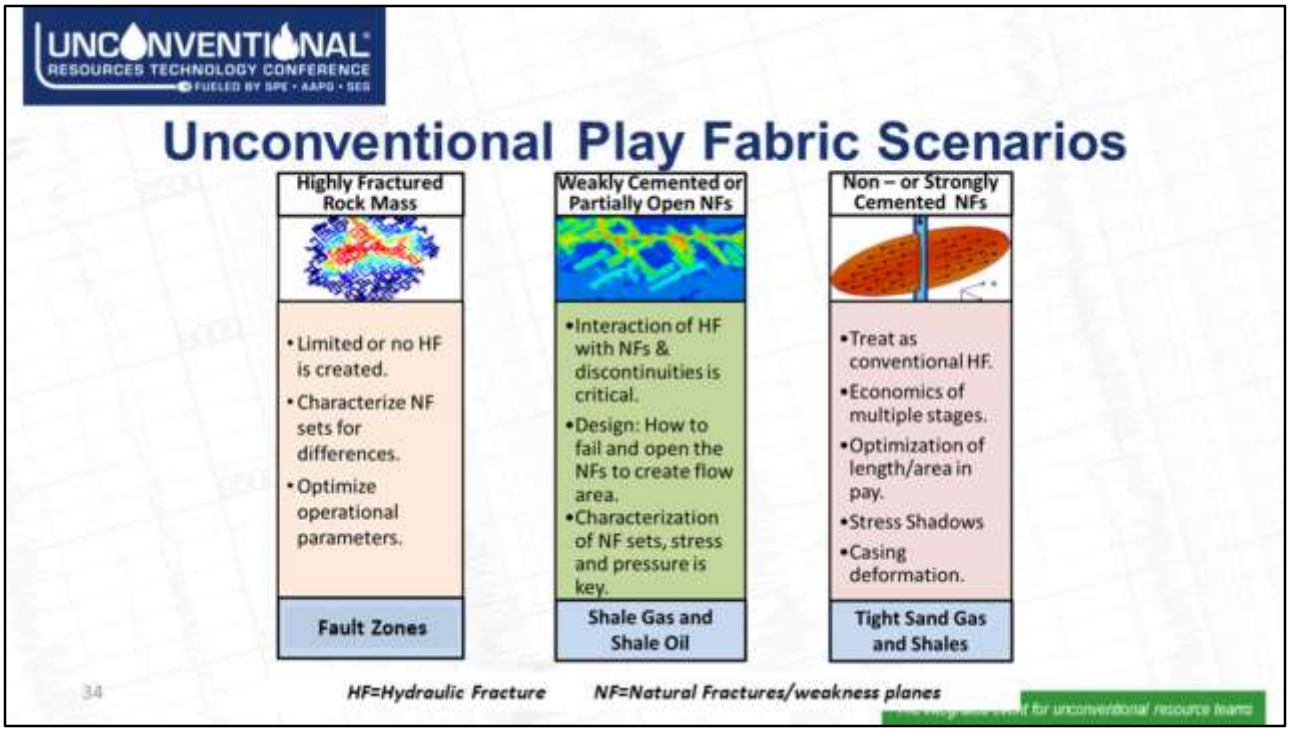
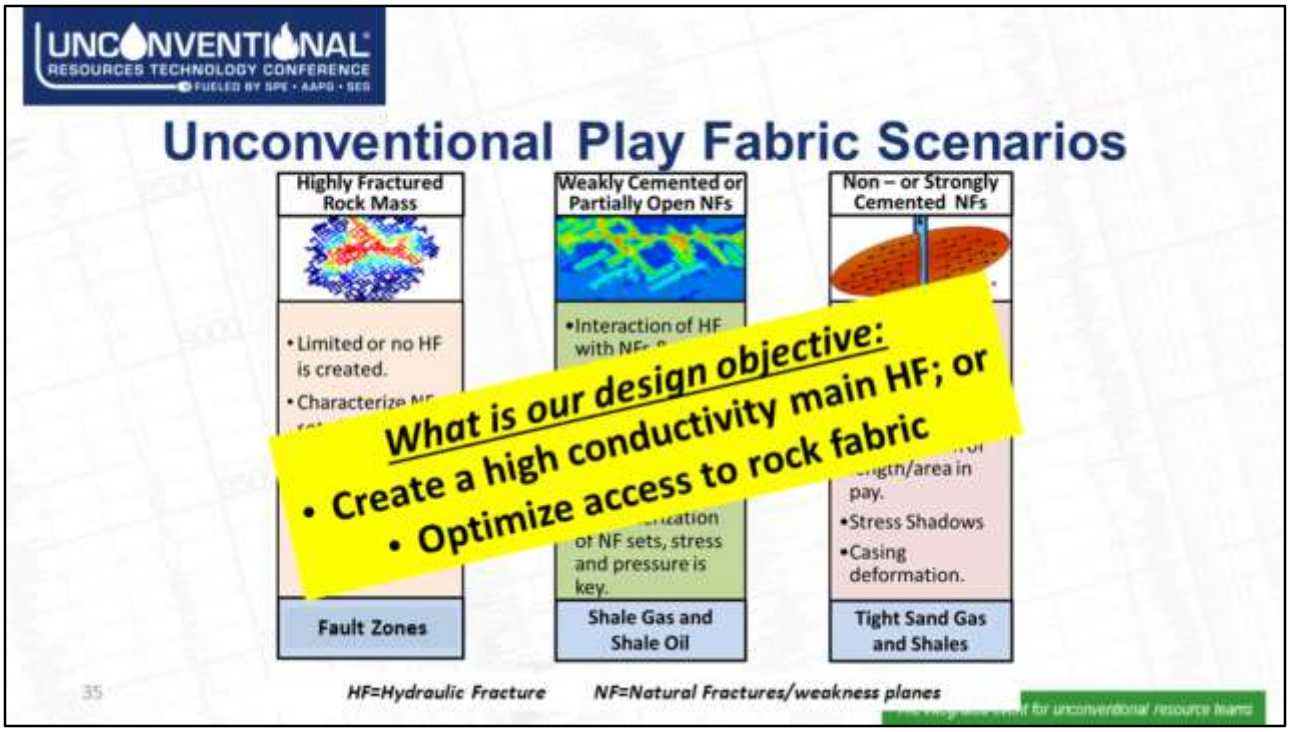
So….fabric is a very, very critical performance indicator and plays a major role in determining the drainage area as well as the hydraulic fracture design to achieve this drainage area.



In order to move towards an optimized stimulation design, it is necessary to understand which fabric scenario we have.

In the figure, we classify fabric along three broad scenarios: a) on the left extreme – a highly fractured rock mass (as seen in a fault zone, for example); or b) at the right extreme (very few natural fractures and weak planes or strong mineralized natural fractures and tending toward a traditional bi-wing fracture stimulation); or c) in the middle… weakly cemented or partially open natural fractures creating complex hydraulic fracture patterns. Obviously, intermediate situations can also occur.

The HF design strategy in each case can be very different (as well as the production response). Let's focus on the middle case; the main question is how we can generate enough shear strain so we can fail these mineralized natural fractures and weak planes to be able to open and stimulate these.



The decisions made during stimulation design – rates, volumes, viscosities, etc – affect the response of the formation and the interaction of the formation with the stimulation. Consequently, these design decisions must consider whether flow into the fabric is a net negative or positive to well production.

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Key Geomechanical Issues

- **Formation Fabric** - Related to flow area additional to the main HF.
  - Need to understand intensity and initial hydraulic conductivity (apertures), type of cement. Where are fabric corridors (associated to faults, salt/intrusion bodies…??). What defines the mechanical layers (properties associated to fabric intensity).
  - Geometry (dip, dip direction, respect to the in-situ principal stress orientation) – Related to the ease of stimulating the fabric and the range of orientation of fabric that could be stimulated.
- **High Pore Pressure** – related to reservoir energy, but also to the effective stresses in the fabric: higher pore pressure = lower initial effective stress = easier for the fabric to slip and open.
- **Stress Anisotropy** - a) horizontal (difference between SHmax and Shmin); and b) vertical (difference between Sv and Shmin); c) Shmin contrast between layers. Related to the tendency to create vertical fractures vs. horizontal ones; related also with initiation pressure.

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Recall our geology/geomechanics performance indicators (fabric, in-situ stress, and pressure). In this slide, the importance of these is summarized.

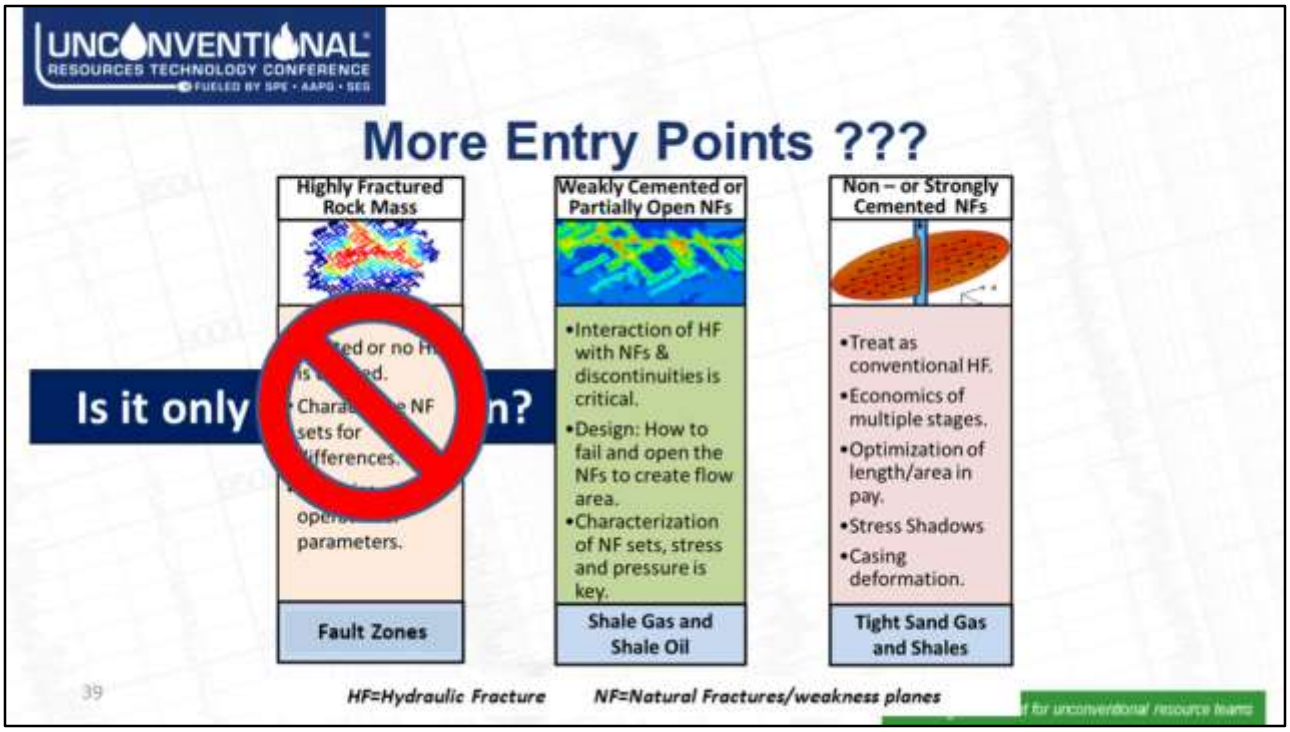
So, back to our Challenge Question.

Is there a geological/geomechanical foundation as to why increasing sand volumes (lbs/ft lateral) has led to a notable performance increase?

Basic hydraulic fracturing (for conventional plays) requires consideration of the question of whether or not a stimulation adds reserves or just accelerates these reserves (or a combination of the two). In the acceleration-only case, the stimulation increases well rates, providing more hydrocarbons sooner, but does not change ultimate reserves. In order to value the stimulation, you have to use economic metrics to determine the value of the stimulation.

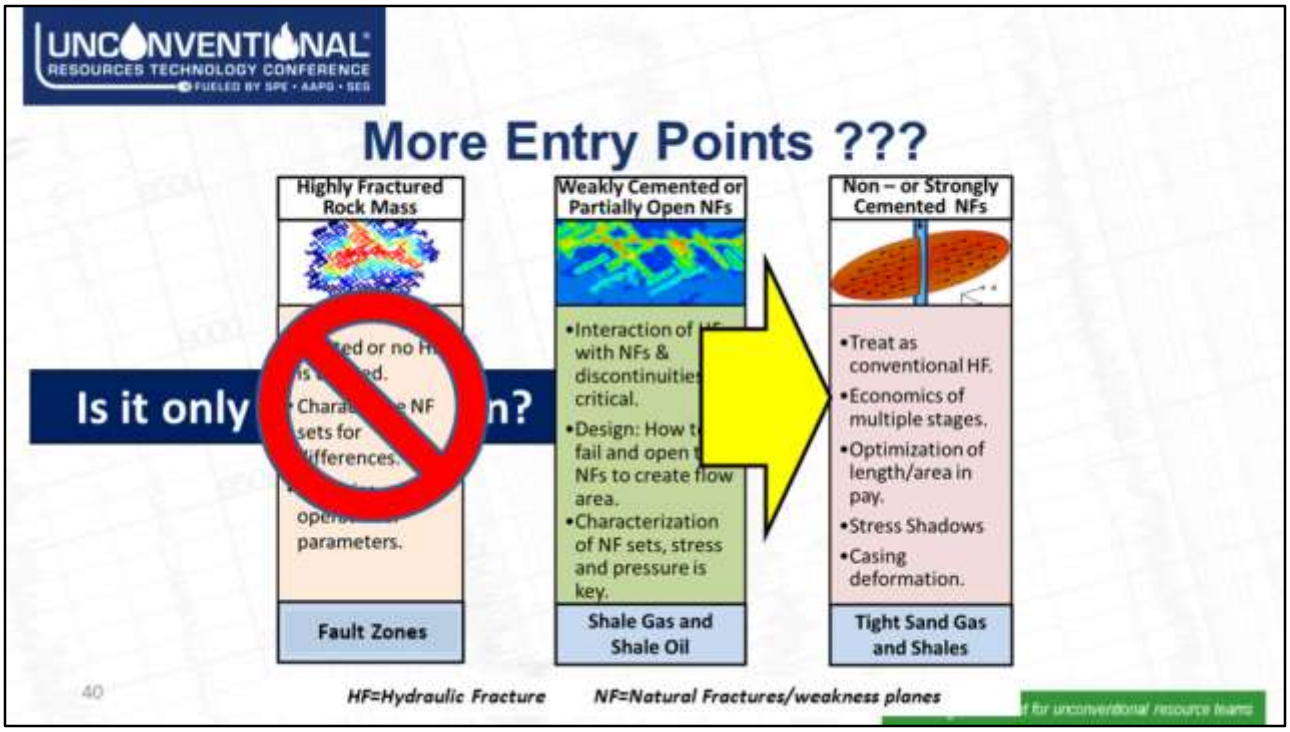
If the trend of increased production with increased sand volumes were to be due solely to acceleration, then we really cannot say too much about the geology or geomechanics of the situation.

If, however, we can conclude that the trend in increased production with increased sand volumes is an actual increase in ultimate well production, then…..



If no acceleration is involved, we can eliminate the far left fabric scenario. If the rock had this much hydraulic communication, then additional entry points would not add to ultimate production.

What about the other two cases: some fabric which can be stimulated to increase production (middle) and no fabric (or little to none) (right)?

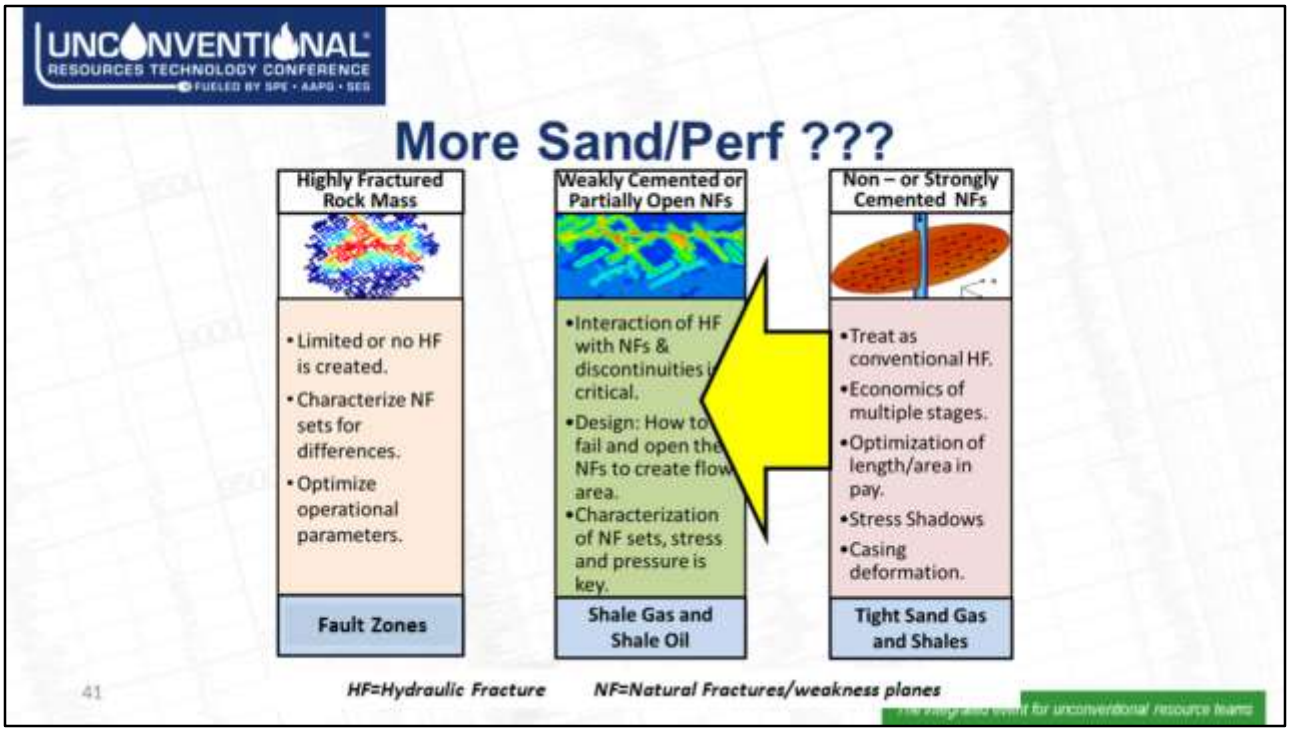


Consider for a moment that our rock was nano-darcy permeability AND had no fabric. Our stimulation would come only from the surface area created from our bi-wing (assumed) hydraulic fractures. What is the optimal hydraulic fracture spacing?

The optimal spacing (ignoring acceleration and focusing on reserves only) would be a function of permeability and, given that we have nano-perm, the optimal spacing could be 10 to 20 ft!!!

Given this, and that we are potentially seeing greater production due to reduced hydraulic fracture spacing, does this not – all other things being equal – basically say that on the average, fabric is not contributing (or not contributing enough) to offset the increased value of additional hydraulic fracture surface area on production for a given rock volume? IF we were draining the resource from the area of the fabric, why/how would additional entry points lead to an increase in reserves?

Note that this does NOT mean that we cannot use fabric to contribute to production but that the general, average case (assuming the increased production is due to additional entry points into the formation) suggests it is not contributing under current stimulation designs.



What if….

What if, even with more entry points along a wellbore, the reality is that the additional sand volumes are, largely, going into one or two main clusters for a given stage? In this case, the increases in production being observed as due to more sand into the main hydraulic fracture(s).

If this were the case, this suggests that fabric DOES play a significant role but that our average stimulation designs have left these (significantly?) under-stimulated.

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Success of Microproppants

- Entered Oil and Gas market in 2012 with micro proppant
- Millions of pounds shipped to date
- Used in over 200 wells, primarily in Texas and Oklahoma
- Productivity improvements of 10-50% reported. Supported by 3 SPE papers* and a March 2017 JPT cover story.

*SPE 167092, 174060, 184863

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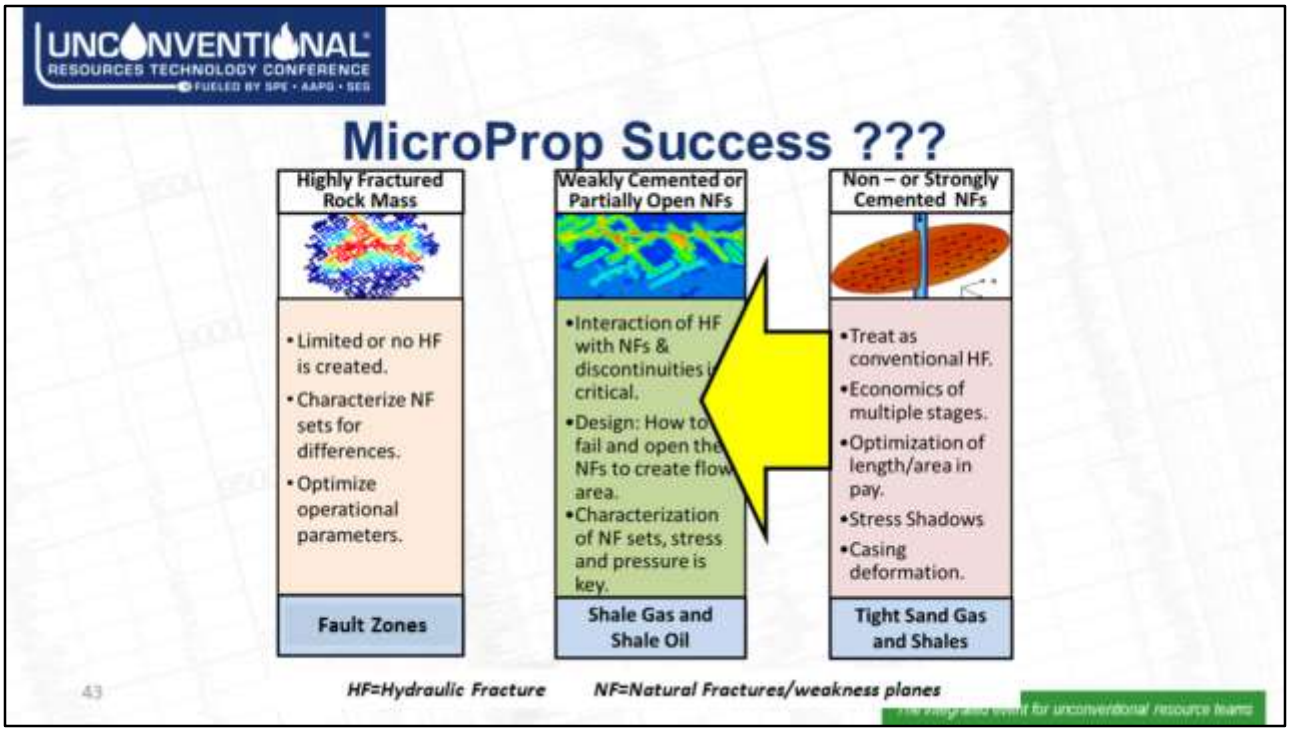
If we consider the results from 100-mesh and microproppants, what do these results suggest?



With 100-mesh and microproppants, a number of different effects are occurring simultaneously. First, reductions in treating pressures are often observed, which suggest a reduction in near-wellbore tortuosity. Second, smaller proppants are far more easily transported along a lateral, through perforations, and within the hydraulic fracture. So smaller proppants also suggest proppant has been displaced further along the main hydraulic fracture. Third, and perhaps most importantly, smaller proppants are carried better into the rock fabric and are small enough to potentially prop these open.

Again, this suggests that fabric DOES play a significant role but that our average stimulation designs have left fabric (significantly?) under-stimulated.

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Completion Engineer for a Day: What is Our Stimulation Objective?

30,000 ft View:

- **Maximize well value through optimized stimulations (hydraulic fracturing, HF)**

A Little Deeper:

- **Optimize fracture surface area and fracture conductivity (e.g., effective wellbore radius concept)**

Deeper Still:

- **Optimize HF creation vs. fabric access/drainage area (leakoff control; fabric stimulation); maintain access (proppant placement); and optimize HF flow capacity (proppant placement and conductivity)**

In conclusion, we need to consider our stimulation objective at the design level:

Our design parameters (volumes, rates, viscosities, spacing, etc.) ALL affect the interaction of the created hydraulic fracture and rock fabric. We need to make an engineering decision as to whether or not fabric is a negative (i.e., leakoff, thereby reducing main hydraulic fracture length) or positive (increased drainage area through stimulation of the fabric). From this, the design parameters are chosen (e.g., high versus low viscosity) to either focus on hydraulic fracture surface area or fabric stimulation.

This is the fundamental message:

Design parameters must be chosen to either: 1) stimulate the fabric; or 2) solely generate created hydraulic fracture surface area (length).