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Hydraulic Fracturing in Unconventionals: The Necessity of a New Geomechanics Paradigm

By Dr. Neal B. Nagel

Introduction

I had the pleasure of giving a presentation by this title at a workshop on "Geomechanics for the Unconventionals in China" held in association with China Rock 2019 and hosted by China University of Petroleum (Beijing) – CUPB – and the Chinese Society for Rock Mechanics and Engineering (CSRME). I have taken that presentation, expanded upon it, and drafted this paper.

I am more and more convinced that Unconventionals are potentially becoming the present-day version of coalbed methane (CBM). If you recall, in the late 1980s and early 1990s CBM was the "next big thing" in both the oil & gas business in general and within the hydraulic fracturing community in particular. Technical interest in the science of CBM stimulation and production peaked somewhere in the early 2000s and, today – at least in the United States – much fewer papers are written and fewer presentations are given about CBM production. US CBM production peaked in 2008 and, according to the US EIA, has seen a 50% decline since. Nonetheless, global CBM production, is potentially increasing (data is very scarce) with increased CBM production from Indonesia and China. While global CBM resources remain abundant, the decline in CBM production is likely attributable to several factors including: 1) most of the tier 1 CBM resources (at least in the US) have been developed and are on decline; and 2) the lack of interest means a lack of financial support for development and research.

Like CBM, Unconventional developments, particularly in the US, have, or are beginning to, exhaust tier 1 areas. Coupled with stagnant commodity prices and rapid well production declines, this has led many business analysts to become bearish on Unconventionals and this is reflected in the increased M&A activities and articles such as "***Peak Shale: How U.S. Oil Output Went From Explosive to Sluggish***" published in Bloomberg Business in October 2019.

One potential means to address the declining production from new Unconventional wells, one that is too often bandied about as the easy solution to declining production, is the application and development of new approaches and technologies. This paper focuses on one such approach regarding hydraulic fracturing in Unconventionals.

Background

If you are familiar with hydraulic fracturing – the process of pumping high pressure fluid containing a solid propping agent to first create a tensile crack in a rock formation and then fill it

with the propping agent to keep it open – then you are likely familiar with the history of hydraulic fracturing. However, as a brief reminder, I'll cover some key points.

Oilwell "shooting" (with an explosive such as nitroglycerin) was common in the eastern United States in the late 19th century to break and/or rubblize the rock around a well to increase production. Also, while pumping acid for well stimulation was fairly well known during the early portion of the 20th century and the concept of "parting pressure"[1] was familiar to stimulation personnel, it is widely accepted that hydraulic fracturing was birthed in 1947, when Stanolind Oil, based upon evaluations by Floyd Farris, conducted the first experimental frac in the Hugoton Field located in Southwestern Kansas. That first hydraulic fracturing treatment utilized Napalm (gelled gasoline) and sand from the Arkansas River. And in March 1949, after the process was licensed to Halliburton, the first two commercial hydraulic fracturing stimulations were conducted in Stephens County, Oklahoma and Archer County, Texas.

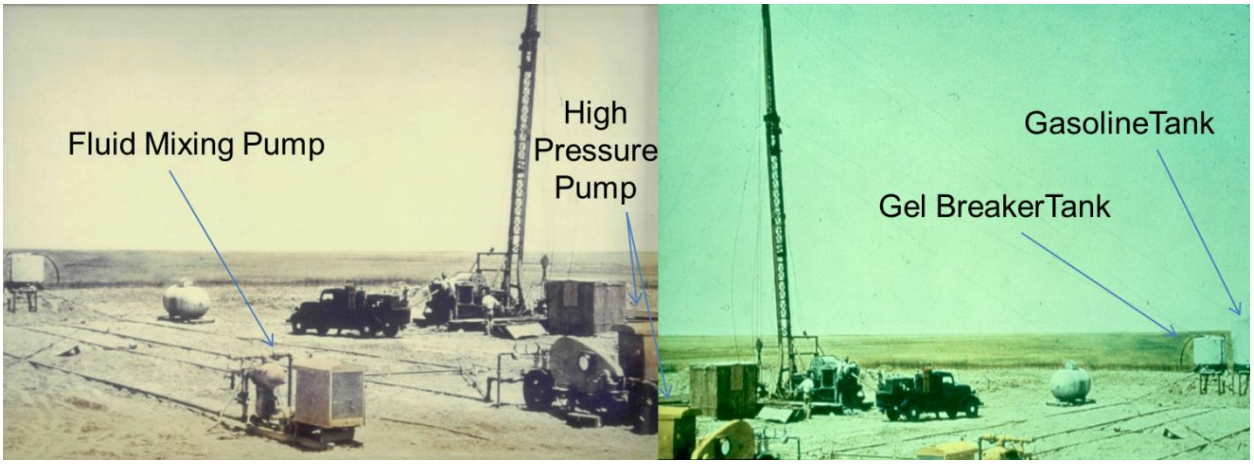


Figure 1: Photos from the experimental hydraulic fracture treatments conducted by Stanolind Oil in 1947 and 1948. Courtesy C.T. Montgomery.

The early milestones for hydraulic fracturing included the early technical papers on the fundamentals of hydraulic fracturing (e.g., Hubbert and Willis, "***Mechanics of Hydraulic Fracturing***", T.P. 4597, AIME Petroleum Transactions, Vol 210, 1957), development of the initial 2D analytical frac models by the likes of Perkins and Kern ("***Widths of Hydraulic Fractures***", JPT, 09/1961) and Geertsma and de Klerk ("***A Rapid Method of Predicting Width and Extent of Hydraulically Induced Fractures***", JPT, 12/1969) and the publication of the first hydraulic fracturing monograph by Howard and Fast ("***Hydraulic Fracturing***", SPE, Monograph 2, 1970).

These milestones, independent of their great significance, are based upon critical but largely overlooked assumptions. Consider this passage from Perkins and Kern: "*Consider an infinite*

[1] "Parting pressure" or "Pressure parting", which is a terminology not widely used today, was the term given to rock behavior wherein at reaching some high initial pressure level injection pressures were seen to decline (often significantly) before stabilizing at, typically, a near-constant level. This drop in pressure was believed to occur when the rock broke or "parted".

elastic medium containing a plane crack bounded by a circle-a penny-shaped crack. If fluid were injected into this pre-existing crack but at a pressure less than that necessary to extend the fracture in length, then the crack would be "inflated". For a perfectly elastic medium, the relationship between crack shape and pressure within the crack has been calculated by Sneddon." This reference to Sneddon is his 1946 paper "***The Distribution of Stress in the Neighbourhood of a Crack in an Elastic Solid***" (The Royal Society, V187, N1009, 22 Oct 1946). Figure 2 shows a slightly modified version of a figure from Sneddon's 1946 paper showing his calculation of the stress field (normalized stress) around a crack in an elastic medium.

Note that Sneddon's work – as well as Perkins and Kern's reference to this work – is based upon what is now commonly called Hooke's Law:

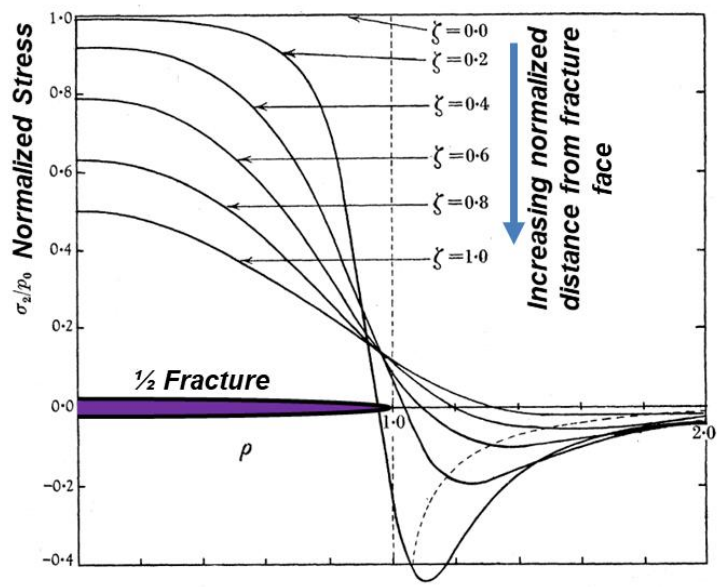


FIGURE 7. The variation of the normal component of stress, σ_z, with ρ and ζ. The broken curve shows the variation of σ_z in the plane of the crack ($z = 0$).

Figure 2: Figure from Sneddon (1946) capturing his evaluation of stresses around a crack in an elastic medium.

$$\sigma = E \times \epsilon \qquad \textbf{(1)}$$

Which for hydraulic fracturing relates the stress change around the fracture to fracture width:

$$\Delta\sigma \propto E \times w(x) \qquad \textbf{(2)}$$

Where: σ = Stress (or stress change)

E = Young's modulus

ε = strain

w(x) = fracture width as a function of distance X from the wellbore

As an aside, note that Eq. 2 is the foundational equation for evaluating the changes in the in-situ stresses imparted by a hydraulic fracture (which is colloquially called Stress Shadows) where the stress changes, both in time and place, are controlled by the fracture width.

Coming back to Perkins and Kern, they also wrote: "*Crack width is not particularly sensitive to rock properties. Young's moduli of rocks have a range of about ten- or twenty-fold. However, crack width is inversely proportional to the fourth root of Young's modulus; therefore, only about a twofold variation in crack width should be expected from this range of moduli.*"

Later, Geertsma and de Klerk wrote that "*To keep the problem tractable, a number of simplifying assumptions have had to be made: 1. The formation is homogeneous and isotropic as regards those of its properties that influence the fracture-propagation process; 2. The deformations of the formation during fracture propagation can be derived from linear elastic stress-strain relations.*" In addition, they added: "*With the design charts presented here, and nothing more elaborate than a slide rule, it is possible to predict the dimensions of either a linearly or a radially propagating, hydraulically induced fracture around a wellbore.*"

In keeping with these comments from Perkins and Kern and Geertsma and de Klerk, as well as from the fracturing monograph from Howard and Fast, the nomograph shown in Figure 3 was used on-location to evaluate and design hydraulic fractures.

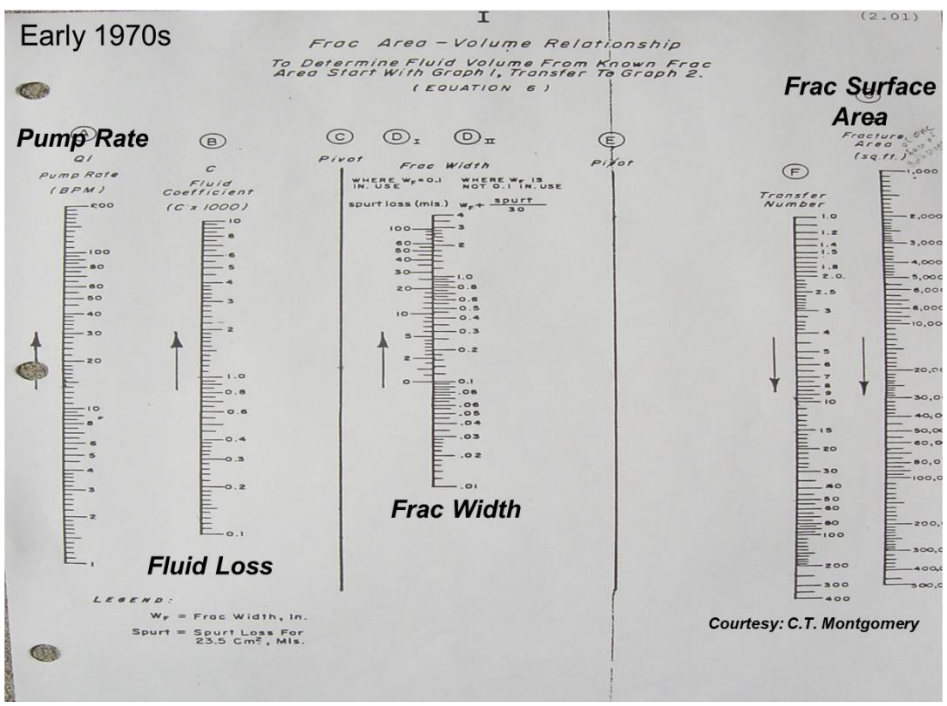


Figure 3: Field nomograph for hydraulic fracture evaluation and design.

I would suggest that four critical factors from these early works need to be remembered:

1. All the early analytical models (and later, most of the numerical models) are based upon the creation of a crack in an infinite, homogeneous, elastic continuum;
2. This infinite elastic continuum has a constant stress;
3. As Geertsma and de Klerk highlighted, the mechanical properties of the elastic medium have a minimal impact on hydraulic fracture dimensions; and
4. With these assumptions, and reflected in the comments of Geertsma and de Klerk as well as the field nomograph in Figure 3, the evaluation (and design) of hydraulic fractures is straightforward and – *my words* – largely trivial.

The Golden Age of Hydraulic Fracturing

Through the 1970s and early 1980s as field experience with hydraulic fracturing grew, it became obvious that the original 2D analytical frac models (PKN and GDK models after Perkins, Kern and Nordgren and Geertma and de Klerk, respectively), while useful, were also easily misused. Because in these models the height of the hydraulic fracture is an input to the model, one could achieve any frac length by simply reducing the frac height for a given injection volume. This gave rise to the development of what became known as Pseudo-3D frac models (or P3D models) so that frac height was an output of the model as opposed to an input.

While perhaps not doing justice to the actual mathematics involved, the core of the P3D frac models, essentially, is the solution of the original 2D analytical equations for both length and height. Consequently, the P3D models, some of which are in use today, carry all the benefits and limitations of the original 2D models plus additional assumptions and limitations to allow for a numerical solution (one common assumption/limitation is that the hydraulic fracture is elliptical in shape in both horizontal and vertical cross-sections).

Once frac height was no longer an input value to the frac model, but was, in fact, a calculated output, the field evaluation and consideration of what controlled hydraulic fracture height became paramount. As it was largely understood that fractures would propagate in a path-of-least-resistance process, then it became obvious that variations of the in-situ stresses in reservoir formations would impact fracture propagation, particularly frac height growth. This is where the "Frac Log" initiated what I call the Golden Age of Hydraulic Fracturing.

A primary (likely the primary) input into P3D frac models is the vertical profile of Shmin. Specifically, the difference in the minimum horizontal stress (based on the assumption that the stress field was either normal faulting: Sv > SHmax > Shmin or strike slip: SHmax > Sv > Shmin such that a vertical hydraulic fracture was created that opened against the least principal stress, Shmin) between flat-lying formations both above and below the well perforations. The challenge, however, was where to get this stress data. The classic "mini-frac" technique had been developed to directly evaluate Shmin (by evaluating the closure of created hydraulic fractures) but these were often costly and time-consuming. More importantly, it was not practical to perform a mini-frac in both the reservoir and the overlying and underlying bounding formations in order to develop a profile of Shmin for input to a P3D frac model.

While acoustic logging tools were first developed in the 1950s, it was the development of digital array sonic tools in the 1980s[2] that led to a true log-based evaluation of the vertical profile of Shmin. Unlike the early acoustic logging tools that only provided an evaluation of the compressional wave velocity in formations of interest, the development of array sonic tools ushered in the era of the independent log evaluation of both compressional and shear wave velocities. From the determination of compressional and shear velocities, and based upon elastic theory, dynamic values of Young's modulus and Poisson's ratio could be estimated from sonic log data.

Using log-derived Poisson's ratio and assuming elastic behavior and fixed boundary conditions, an estimation of Shmin – solely from log data – could be developed using what is often called Eaton's equation:

$$\sigma_{hmin} = \left(\frac{\nu}{1-\nu}\right)(\sigma_v - \alpha Pp) + \alpha Pp \qquad \textbf{(3)}$$

Where: σ_{hmin} = Minimum horizontal stress

ν = Poisson's ratio (from the "frac log")

σ_v = Vertical stress (estimated from rock density)

α = Biot's coefficient (often assumed equal to 1.0)

P_p = Formation pore pressure (measured or estimated)

Figure 4 shows an example of "Frac Log" data for input into a P3D frac model.

With the availability of the "frac log", the industry was provided a quick, relatively inexpensive means to generate the main data input for a P3D frac model. This led to a "golden age" where there was a consensus that the physics of hydraulic fracturing were largely understood, numerical tools existed for hydraulic fracture design, and, with the "frac log", the main input to the design models were readily available.

[2] "**State of the Art on EVA Data Processing: An Improvement in Subsurface Imaging**", P.C. Arditty, et al., SEG Technical Program Exp. Abstract, 1982

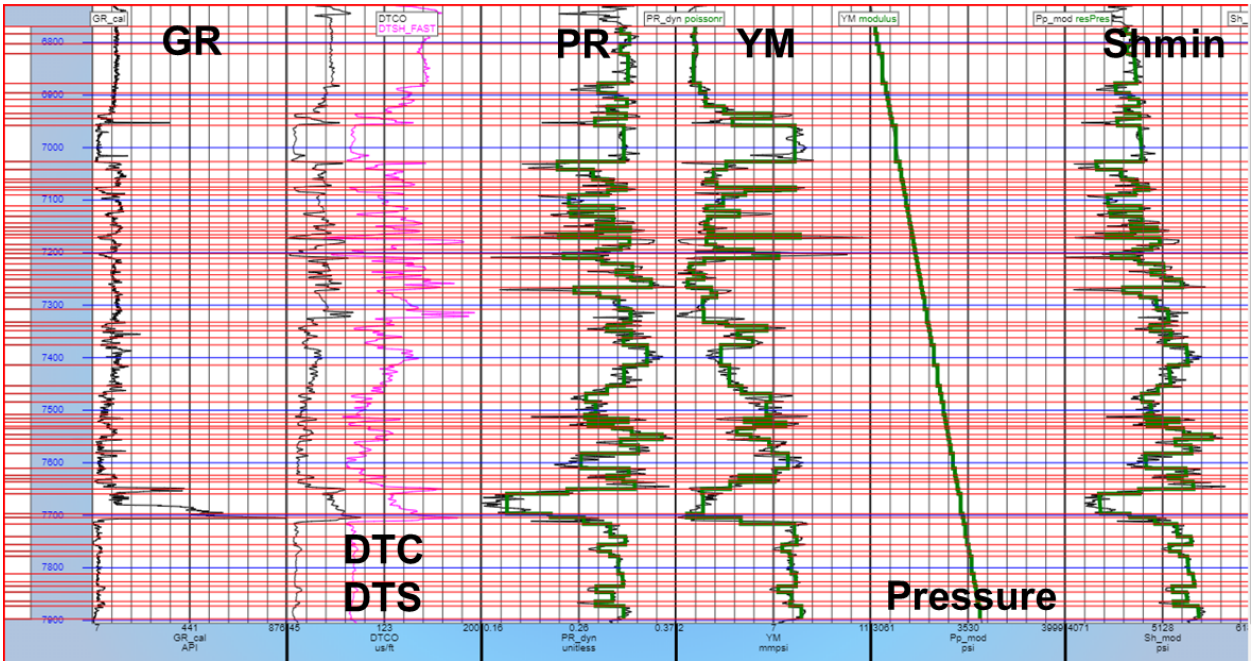


Figure 4: Array or dipole sonic output for a P3D frac model. Colloquially called a "frac log".

Figure 5 shows a graph of five-year total publications (sum over 5 years plotted at the end of a 5-year period) referencing hydraulic fracturing in the SPE One Petro system through the early 2000s. The constant slope from 1980 to 2002 suggests an evolutionary increase in hydraulic fracturing publications likely associated with an increasing world-wide application of the technology as opposed to a revolutionary change in the technology.

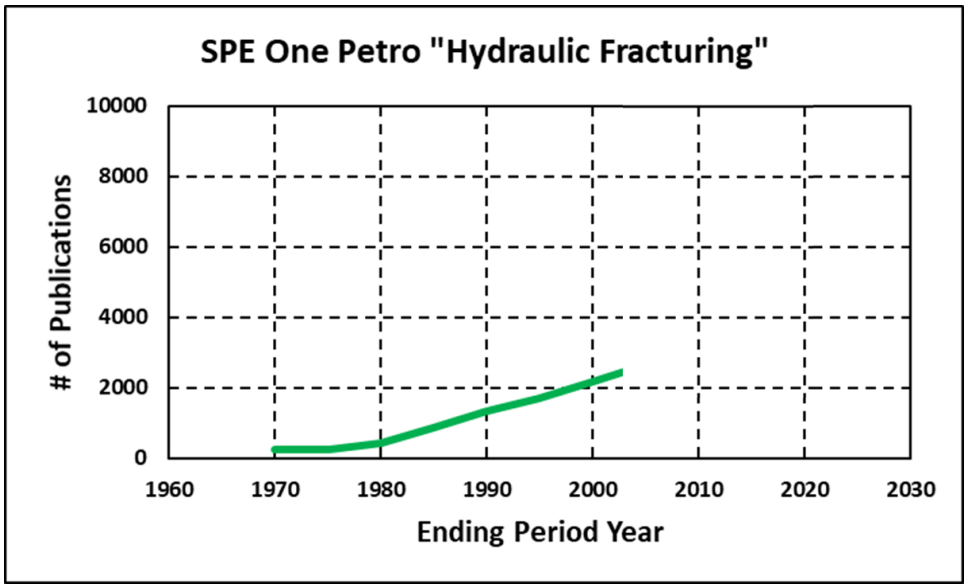


Figure 5: References to 'hydraulic fracturing" in SPE One Petro.

The More Things Change – The More They Stay the Same

The lack of revolutionary changes in hydraulic fracturing technology has been noted throughout its history. In a paper in the Journal of Canadian Petroleum Technology (JCPT, 04/04/1963) titled "***The Engineering Design of Well Stimulation Treatments***" by D. Flickinger and C.R. Fast, the authors wrote "*The unusually high (80%) success ratio achieved using this process (HF) is probably the major reason that many operators devote little thought and planning to the hydraulic and mechanical factors involved in a successful treatment"*. Note that this, again, was written only 14 years after the first commercial application of hydraulic fracturing.

Unfortunately, if anything Flickinger and Fast were prescient. As part of the original draft of their article "***Hydraulic Fracturing: History of an Enduring Technology***" written by C.T. Montgomery and M.B. Smith with NSI Technologies (and later published by SPE in 2010), the authors wrote "*At times it appears that hydraulic fracturing, as a "technology", is a victim of its own success in that "It works!", so well that the fact that it could work much better is lost. Unlike drilling technology which has made huge improvements in the technology over the last decade, fracturing technology still resides in the arena of technologies that were, for the most part, developed in the 50's and 60's."*

I would argue that not only are the early comments of Flickinger and Fast, as well as the comments from nearly 50 years later by Montgomery and Smith, accurate but they also portent the significant challenges hydraulic fracturing in Unconventionals has faced and continue to face today.

The Conventional Hydraulic Fracturing Paradigm (CHFP)

Through the late 1990s and into the early 2000s, some basic assumptions about hydraulic fracturing – supported by 50 years of empirical knowledge – were taken for granted:

1. Hydraulic fractures were bi-wing, symmetrical, and planar around a wellbore and elliptical in shape.
2. Fracture propagation was dominated by the vertical differences in formation minimum horizontal stress (Shmin). Where Shmin was higher in bounding formations, long hydraulic fractures could be developed. Where there was no contrast in Shmin, radial or large height-growth fractures were created.
3. Formation stress and pressure were laterally homogeneous.
4. Reservoir and bounding formations were laterally homogeneous in all rock properties and flat-lying (with vertical layering).
5. Reservoir and bounding formations exhibited elastic behavior and, largely, neither Young's modulus or fracture toughness were sensitive parameters.

Other important assumptions or "conventional wisdom" were also common:

- Leakoff was avoided as this reduced fracture length, and 100 mesh proppant was almost exclusively used for leakoff control.

- Pump rates were typically less than 60 bpm as the cost of the stimulation was tied directly to required horsepower (and higher pump rates simply drove friction pressures and wasted cost).
- Viscosity was typically around 500 cp or higher via a cross-linked fluid for proppant transport.
- The key design points were a) fracture half-length, X_f,in pay; and b) proper proppant conductivity via dimensionless fracture conductivity, FCD.
- "Stress Shadows" either did not exist or did not matter.
- Fracture design variations (like changing proppant to optimize FCD) were cost-driven and evaluated by comparing a numerical production forecast against the cost of the design changes.
- Fracture dimension evaluations were conducted primarily for height growth with near-wellbore evaluations like temperature logs or radioactive tracers.
- It was known that surface pressures could not be used to infer bottomhole pressures so real-time monitoring, when it was performed, employed bottomhole pressure (from gauges or a dead-string) with a Nolte-Smith plot analysis.

Most critically, the elemental basis of the CHFP was, essentially, that the rock did not matter for frac design. Different formations had different levels of stress or, perhaps, different values for leakoff, but it was assumed that the rock was homogeneous and exhibited elastic behavior that had very little impact on a hydraulic fracture. The key for proper design was to obtain or improve the vertical profile of Shmin.

With the development of Unconventionals, the industry discovered, at great cost, that the CHFP was fatally flawed. This is reflected in Figure 6, which, like Figure 5, looks at the references to hydraulic fracturing within SPE's One Petro system. The great upturn in references to hydraulic fracturing after 2005 suggest a revolutionary change in either or both the interest in hydraulic fracturing or the underlying technology.

Flaws in The Conventional Hydraulic Fracturing Paradigm (CHFP)

The chief flaws in the CHFP are the assumptions that the mechanical behavior of the reservoir formations and bounding layers do not matter to hydraulic fracturing and that major design inputs, like Shmin, pore pressure and rock properties, are laterally homogeneous around a wellbore.

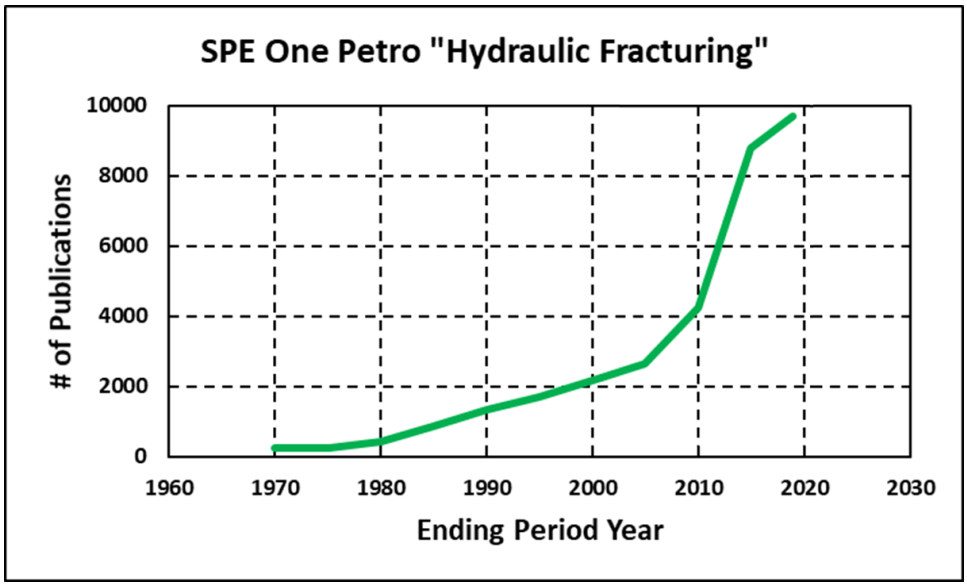


Figure 6: References to 'hydraulic fracturing" in SPE One Petro

More specifically:

The assumption that a hydraulic fracture is bi-wing and symmetrical around the wellbore is based both on the faulty assumption that the stress field, pore pressure, and rock properties are laterally homogeneous around the wellbore and the resulting assumption that fracture propagation is then solely controlled by the delta pressure due to friction from the perforations to the tip of the hydraulic fracture, which, itself, becomes symmetric around the wellbore. In essence, with homogeneity in stress, pressure and mechanical properties, a fracture will grow to one side of the wellbore (likely randomly), increasing the delta pressure in that wing, which then causes an equal growth in the other wing (until the delta pressure in the two wings, and the resulting wing lengths, are equalized). This behavior, wherein lateral fracture propagation is controlled solely by fluid-drive friction pressure is called "viscosity-dominated" behavior[3].

The fundamental debate then is whether or not stress, pressure, and mechanical properties are laterally homogenous. The answer to this should be a bit of a "no-brainer". 3D seismic as well as log data along horizontal laterals continue to show the significant heterogeneity in the reservoir formations we produce from whether it be stress, pressure or mechanical properties. More importantly, two major factors often dominate this heterogeneity.

First, as more wells are in-filled or otherwise influenced by offset production effects, the non-uniformity in the pressure field (i.e., depletion or injection effects as in a waterflow) causes a non-uniformity in the stress field. As such, one wing of a potentially bi-wing hydraulic fracture will

[3] In classical hydraulic fracturing behavior, a fracture is considered to be "viscosity-dominated" when propagation is largely controlled by fluid-driven friction pressures as opposed to "toughness-dominated" behavior wherein fracture propagation is largely controlled by the rock's resistance to fracturing called fracture toughness (a strength property of a rock commonly related to, but not equal to, the tensile strength of the rock).

propagate in a lower stress area leading to asymmetric wing lengths. A second, and equally important, factor is the influence of rock fabric. Because reservoir formations are neither homogeneous in elastic properties or in strength properties, it is no longer simply a question of equal delta pressure in both wings of a potential bi-wing fracture solely due to length-induced friction but delta pressure will vary based upon variations in fracture width (due to changes in elastic properties) and due to variations in mechanical behavior and strength associated with rock fabric such as bedding or natural fractures[4].

Another major factor controlling asymmetric hydraulic fracture growth is the influence of Stress Shadows. Stress Shadows is the colloquial name given to the changes in the stress field imparted by a hydraulic fracture (both during propagation and after closed on proppant). Like the influence of depletion which can create asymmetric stress around a wellbore, Stress Shadows also create non-homogeneous and often asymmetric changes in the stress field. And the resulting asymmetric stress field can lead to asymmetric fracture wing growth (both laterally and vertically).

Finally, it is also important to address the assumption of elastic behavior of reservoir formations. While the matrix of most formations will dominantly act elastically, two factors need to be recalled. In formations with significant fabric (particularly, for example, open natural fractures), the elastic behavior of the rock mass may be more influence by the fabric than the matrix. This effect is well-known, for example, in the mining community where modifiers for rock mass stiffness as a function of fabric or rock strength as a function of rock fabric are common.

$$\frac{E_m}{E_i} = \frac{1}{0.726\, F_k^{0.618} + 1} \qquad \textbf{(4)}^{5}$$

Where: E_m = Rock mass deformation modulus

E_i = Intact rock Young's modulus

F_k = Oda's Fracture Tensor

Furthermore, it also now clear that, primarily as a function of TOC and/or clay content[6], many of the reservoir formations in Unconventionals do not act purely elastically but also exhibit various combinations of plastic and time-dependent behavior. Given that the common fracturing equations are based upon linear elastic fracture mechanics and few, if any, operators conduct laboratory testing to capture either plastic or time-dependent behavior, the inability to account for inelastic reservoir behavior is another failure of the CHFP.

[4] This implies fracture behavior is, effectively, more toughness-dominated than viscosity-dominated as would be expected for PKN-type fractures.

[5] From "*Scale Effects on the Deformability of Jointed Rock at the 3D Level*" by Kulatilake, Wang and Stephansson in **Scale Effects in Rock Masses 93**, A.A. Balkema, 1993

[6] "**Mechanical Properties of Shale-gas Reservoir Rocks — Part 2: Ductile Creep, Brittle Strength, and Their Relation to the Elastic Modulus**", Sone and Zoback, Geophysics, V78N5, 2013

Summarizing, I will argue here that there have been two primary drivers for the bi-wing assumption. First, it is a left-over artifact from the original 2D analytical models, which were based upon the assumption of a homogenous elastic medium. I would secondly argue that is also a bit of wishful thinking. Trying to account for heterogeneity away from the wellbore is often a daunting undertaking – and it is much easier to overlook this possibility than deal with it.

A New Hydraulic Fracturing Paradigm: False Starts

Three major pseudo-geomechanical concepts have driven hydraulic fracturing in Unconventionals for more than a decade. Unfortunately, each of these has seriously mislead, and likely cost, the industry seriously. These are the concepts of brittleness, stimulated-reservoir-volume, SRV, and complexity.

Brittleness. The word "brittleness" has existed in the geomechanics community for decades (and is an important concept in the behavior of ceramics). Primarily, a "brittle" rock is one in which, post-failure, the built-up strain energy in a rock is released quickly. This was typically reflected in a very rapid drop in rock stress post-failure in a traditional stress-strain diagram. A less brittle, more "ductile" rock does not release built-up strain energy rapidly but rather shows a more gradual reduction in maximum stress post-failure.

Given this understanding, I approach the discussion of brittleness this way. Particularly in a training course, I will ask the attendees to play a game of "Petroleum Jeopardy". "Alex, may I have Petroleum Geomechanics for $500" and Alex reads aloud "Brittleness – and please remember to answer in the form of a question". Few – very few in hundreds of course attendees – can explain what brittleness was really supposed to be. Eventually, with some coaxing, someone will offer "What is a parameter to guide us where to perforate in a lateral?" or perhaps "What is a parameter to indicate rock that will fracture better than other rock".

This general lack of understanding what brittleness was supposed to represent is very important. From a simple value-of-information exercise, if we don't know the "value" of a piece of information (i.e., we don't know what decision will be altered by the information), then the information has no value (and we shouldn't waste time and effort obtaining said information).

To appreciate brittleness – and the 30 or more different equations used to quantify brittleness (which then led to the lesser-known concept of "fracability") – it is worthwhile to revisit the original Halliburton paper that birthed the brittleness concept.

In the 2008 paper titled "***Practical Use of Shale Petrophysics for Stimulation Design***", SPE 115258 by R. Rickman et al., the authors created the quantitative brittleness value as a ratio of normalized Young's modulus to normalized Poisson's ratio of the rock matrix in order to "*reflect the rock's ability to fail under stress (Poisson's ratio) and maintain a fracture (Young's modulus)".* However, what is likely more interesting than the equation for brittleness from the paper are the conclusions:

1. *"Ductile shale is not a good reservoir because the formation will want to heal any natural or hydraulic fractures.*
2. *Brittle shale is more likely to be naturally fractured and respond favorably to hydraulic fracturing treatments.*
3. *There is a need to quantify the brittleness factor in a way that combines both rock mechanical properties in shale.*
4. *In terms of Poisson's ratio, the lower the value, the more brittle the rock, and as values of Young's modulus increase, the more brittle the rock will be.*
5. *Because the units of Poisson's ratio and Young's modulus are very different, the brittleness caused by each component is unitized, and then averaged to yield the brittleness coefficient as a percentage.*
6. *To distinguish ductile from brittle shale, a brittleness cutoff. The higher the values of brittleness above the cutoff value, the more likely the shale will be brittle. This means there may be natural fractures present and the shale should respond well to hydraulic fracturing."*

Reviewing these conclusions suggests the following:

- A central goal of the paper was to sell logging services.
- Part of the brittleness concept was to identify inelastic ("ductile") behavior. But this begs the question of how elastic parameters can infer inelastic behavior.
- The real key was not brittleness but rock fabric – and the concept was that somehow the ratio of normalize Young's modulus to normalized Poisson's ratio could predict both the existence and degree of fracturing (as part of rock fabric).

Note also that this initial paper was based solely upon Barnett data – a play in which the role of natural fractures is absolutely key.

Since 2008, the brittleness concept – and all its incarnations – has mostly faded away (though some 3D seismic companies continue to offer 3D brittleness cubes from seismic data). Fundamentally this is because brittleness – some function of the elastic behavior of the matrix – does not tell us anything directly about rock fabric. And rock fabric is the key to stimulation design in Unconventionals.

<u>*SRV.*</u> Stimulated Reservoir Volume, much like brittleness, was often portrayed as the "answer" to completion design and evaluation questions. And like brittleness, it chiefly was intended to sell services, in this case microseismic services.

Very early on, I recall perhaps it was at a Calgary conference, I spoke with Mike Conway of Stim-Lab. Mike helped establish the Stim-Lab Consortium and for decades has been one of the (if not the) technical brains behind the Stim-Lab company. Mike and I spoke briefly about the conference and then we talked a bit about new things, like the increasing use of microseismics. One of the main sales pitches at the time about microseismics (MS) was that MS was "proof of the pressure front". This idea being used to sell MS services was that MS events <u>only</u> occurred in association with a reduced normal effective stress along a fault or fracture in association with a pressure

increase as pressure moved from a hydraulic fracture into the rock mass. However, as Mike Conway queried me, he was seeing MS events only a minute or two into a stimulation that were 1000 or even 2000 feet away from the perforations and, often, in the direction of Shmin rather than SHmax. Obviously, these could not be pressure related since pressure diffusion cannot move that fast through a rock mass.

I told Mike at the time – and he encouraged me to write a paper showing this – that MS events could be caused by either a pressure change or a total stress change and, as such, some MS events could occur long distances from the perforations in a short period of time because a stress pulse moves through the rock at the compressional wave velocity. With several engineers who worked for me at the time, we published a number of papers on this and even wrote, in 2012, about the concept of "wet" (associated with a pressure change) and "dry" (related to a stress change) MS events[7].

The primary flaws behind the concept of SRV – where you draw an ellipse around the full extent of MS events to establish the stimulated volume as proposed by Mayerhofer, Warpinski, and others[8] - include:

- Field MS events are almost exclusively evidence of rock shear failure and no causal link between rock shear failure and well production was ever proven. Rather, Warpinski postulated the concept of "Shear Stimulation", that being an increase in permeability of a natural fracture, after slippage, due to dilation of the fracture when creating a mis-match between the two fracture surfaces. Obviously, even if the Shear Stimulation concept held (and, admittedly, there is ample evidence field and theoretical evidence to support it), it applied at the point of the MS event and NOT along the entire path from the event to the wellbore.
- As I explained to Mike Conway, shear events can be driven by pressure, which does suggest a hydraulic connection between the event location and the wellbore, or stress changes, which may or may not be hydraulically connected to the wellbore. Consequently, at the very least "dry" event locations should be excluded from consideration of production contribution.
- SRV, as a concept, overlooked basic reservoir engineering. That is, what counts is the drainage area and not some stimulated region. In fact, this point led to two major developments. First, field evidence made it clear that the farthest extents of the SRV contributed, at best, for only a relatively short period of time. This was attributed to the closure of unpropped fabric and led to efforts to consider how to get proppant into the rock fabric. A second development is the heavy, largely empirical filtering that MS service providers are currently doing to their MS data. Instead of considering all MS events as contributing to production as the industry was told for more than a decade, current practice is to use empirical filtering techniques to eliminate those events farther

[7] "Understanding "SRV": A Numerical Investigation of "Wet" vs. "Dry" Microseismicity During Hydrualic Fracturing", N.B. Nagel, et al., paper SPE 159791, SPE Ann Tech Conf and Ex, San Antonio, TX, 2012

[8] "**What is Stimulated Reservoir Volume**", M.J. Mayerhofer, et al., paper SPE 119890, SPE Shale Gas Production Conference, Fort Worth, TX, 2008

away from the wellbore that are either unlikely to contribute to production or do so for only a short period of time (and this filtering is often severe).

While operators continue to occasionally use MS surveys to evaluate hydraulic fracturing behavior, and the MS service companies continue to refine their services in order to actually develop a service to predict drainage area, the industry has gradually come to understand the failings of SRV as a concept and the limitation of MS surveys for understanding and predicting well performance.

Complexity. Complexity was a term that was largely developed to explain the visual appearance of MS events during the stimulation of many Unconventional wells. In most part birthed with the 2010 paper "***The Relationship Between Fracture Complexity, Reservoir Properties, and Fracture-Treatment Design***" paper SPE 115769 by Cipolla et al., the authors introduced the Frac Complexity Index which was simply a measure of the symmetry of the MS event cloud from a stimulation (where the more symmetric the cloud of events, the greater the complexity index, and, apparently, the greater the production).

Ignoring for a moment the assumption that a symmetric MS event cloud led to more production than an asymmetric one, the FCI concept naturally led to the stimulation goal of achieving symmetric or near-symmetric MS event clouds as well as the unfounded belief that complexity could be created (recall all the presentations and publications with pictures of fractured glass to show the concept of rock complexity).

Again, after a number of years of failed priorities, the industry now largely understands that "complexity", as exemplified by symmetric or near-symmetric MS event data, is actually a fundamental behavior of rock fabric – the variations in mechanical properties and strength inherent within most rock formations. What MS events actually reflect is whether or not the well stimulation accessed and potentially stimulated this rock fabric.

A New Hydraulic Fracturing Paradigm: Potential Keys

By dint of basic statistics, the trial-and-error approach to hydraulic fracturing in Unconventionals was bound to reveal concepts and procedures that worked better than previous concepts and procedures (i.e., eventually you run out of poor choices and are left only with better ones). Basically, an evolutionary process, even if completely random, will almost always result in improvements due to a survival-of-the-fittest type process. Some of the industry concepts that have had staying power, though perhaps for the wrong reason(s), include:

1. *Low viscosity/high rate*
2. *100 mesh (and smaller) proppants*
3. *Perforation clusters*
4. *Reduced cluster spacing*
5. *Well sequencing*

Low viscosity/high rate. A widely accepted principle of the CHFP was that frac fluid viscosity, while increasing friction pressures and associated pumping horsepower charges for the stimulation, was generally a good thing. Viscosity was needed to provide proppant transport and, if the friction pressure was within the hydraulic fracture itself, viscosity promoted hydraulic fracture width and increased fracture proppant conductivity. Of course, it was also known that the polymers used to generate viscosity also left a degree of damage to the proppant conductivity since the concentrated polymer (concentrated because the polymer was too big to move into the matrix as base filtrate from the frac fluid leaked off) did not fully break down.

Industry concerns about field proppant conductivity, which largely led to the creation of the Stim-Lab consortium, reached a peak in the early 2000s with the publication of detailed papers considering all the sources of proppant damage such as the 2007 paper "***Determining Realistic Fracture Conductivity and Understanding its Impact on Well Performance - Theory and Field Examples***" paper SPE 106301 by Palisch et al. in which proppant conductivity, including all effects, could be reduced by as much as 99%.

As a principal source of conductivity damage was gel damage, there began a significant movement in the industry to reduce gel loadings, first from the common 40#/1000 gal to 30#/1000 gal and so on until eventually the lowest gel-containing fluid was arrived at – slickwater (slickwater, which is essentially water with a very small amount of polymer in order to prevent the water from entering high-friction, turbulent flow, is a common oilfield fluid for non-stimulation well work). The challenge of a low gel concentration fluid (i.e., low viscosity) like slickwater was that it would not carry proppant – one of the two principal purposes of a frac fluid.

The natural and obvious solution to poor proppant transport was to increase pump rate. And later, when it was determined that increasing pump rate did not significantly overcome the proppant transport issues with slickwater, high rate became important for fluid diversion.

While low viscosity fluid was bad for proppant transport, it did have the advantage that it appeared to "generate" more complexity as represented by MS events. As compared to cross-linked fluids which tended to create very asymmetric MS event clouds, slickwater treatments appeared to create more symmetric MS event clouds (which, as presented, were considered an indication of a good stimulation). The reason for this is that both the equation for fluid flow in natural fractures as well as the equation for pressure diffusion in rock fabric are inversely proportional to viscosity. The common "cubic equation" for flow in parallel plates, for example, which has been empirically shown to apply in natural fractures[9], is shown in Eq. 5

$$Q = \frac{\gamma_w}{12\mu} G a^3 \Delta h \qquad \textbf{(5)}$$

[9] "**Validity of Cubic Law for Fluid Flow in a Deformable Rock Fracture**", P.A. Witherspoon, et al., Water Resources Research, V16N6, 1980

Where: Q = Flow rate

γ_w = Fluid density

μ = Fluid viscosity

G = Geometry constant

a = Fracture aperture

Δh = Pressure drop

Based upon the equations, the lower the frac fluid viscosity, the farther fluid pressure is driven into the rock fabric leading to a more symmetric MS event cloud. As a result, while slickwater is detrimental to proppant transport, it is favorable with regard to increasing the area potentially influenced by shear stimulation.

High pump rates, however, are not favorable for shear stimulation. As pressure diffusion into rock fabric is inversely proportional to viscosity, it is also proportional to time (i.e., time of the application of driving pressure for diffusion). At higher pump rates, for a fixed fluid volume, there is less total time for pressure diffusion to occur. The evidence and importance of pressure diffusion on generating shear stimulation is reflected in the near-universal observation of MS events after injection pumps have been shut-down but pressure diffusion is still moving through the rock fabric.

100 mesh (and smaller) proppants. It is well established that proppant permeability is proportional to proppant size. As proppant mesh size goes up, both proppant porosity and permeability increase. 20/40 proppant (i.e., a proppant mixture that passes through a 20 mesh filter but will be retained on a 40 mesh pan) was a very common proppant in most conventional plays in the 1980s and 1990s and this carried forward into the early years of Unconventionals. 100 mesh proppant was available and common to the industry, but due to its low conductivity as well as low strength (as a natural sand), it was not commonly used as a proppant but was often used for leakoff control.

The use of 40/70 and even 100 mesh sand as proppant started early in the development of the Barnett and other Unconventional plays both to address the concern over proppant transport and because it was thought that even the low conductivity of these smaller proppants was sufficient for potentially nano-darcy permeability formations. However, it was the reported successes of EOG and similar operators in the early 2010s using mostly, and later totally, 100 mesh sand that led to the large-scale shift towards the use of 100 mesh proppant. In fact, estimates[10] of the percentage of frac sand that is 100 mesh or finer exceeds 50% for 2019 and beyond.

There are two primary reasons for the widely reported improvements in well productivity using 100 mesh and smaller proppants. First, if the proppant were transported down the hydraulic fracture, the smaller proppants are far more favorably sized relative to the evaluated kinematic apertures of rock fabric as reported, for example, by Gale, et al., from the UT Bureau of Economic Geology ("***Natural Fractures in Shale: A Review and New Observations***", 2014, AAPG Bulletin, V98 N11). However, the more likely of the two reasons is the greatly improved proppant transport

[10] Rystad Energy Presentation at Enercom Dallas 2019

with smaller diameter proppant both due to reduced settling velocities but also due to a reduced critical shear stress for saltation[11] to occur.

Nonetheless, conductivity still matters in hydraulic fracturing ("***Is Conductivity Still Important in Unconventional Reservoirs? A Field Data Review***", URTEC 2898429, 2018, by R. Shelley, et al.) and while 100 mesh and smaller proppants may increase the effective length of the hydraulic fractures, they most often do not possess enough conductivity, particularly near-wellbore where the flow stream converges to the perforations.

Perforation clusters. While the "old-timers" may recall that the use of multiple perforation clusters per stage is actually an old technique used even in vertical wells, the basic premise of the concept remains the same: it is too expensive to individually stimulate each perforation cluster individually, so they are grouped into a single stage and stimulated together. In order to provide some means of fluid distribution, since the breakdown pressure will likely be slightly different for each cluster, a variant of limited entry perforating[12] is used.

Since the initial development of limited entry perforating, the results have shown that the technique has significant shortcomings and often leaves a significant number of clusters unstimulated. Various reasons have been proposed for this, including perforation erosion, but a significant shortcoming of the process is that it builds delta pressure only at the perforations and assumes that the delta pressure within the hydraulic fractures are the same, which is demonstrably false. When the delta pressure of the hydraulic fractures varies from cluster to cluster, independent of perforation delta pressure, some clusters will not be stimulated even with limited entry perforating.

Until a cost-effective technique is developed to stimulate every perforation cluster independently, cluster stimulations, using limited entry perforation designs and diverters and such, will remain a functional part of hydraulic fracturing in long horizontals.

Reduced cluster spacing. There simply is no magic cluster spacing length. Whether the industry trends towards smaller spacing or larger spacing, this decision needs to be based upon the reservoir characterization performed to justify each well design and each well economics.

The current industry trend towards smaller cluster spacing (with a commensurate increase in both fluid and proppant volumes) is largely an artifact of 1) the historically misleading results of MS event data and SRV interpretations and 2) a lack of proper characterization of the drainage area around a given hydraulic fracture. Like the trend toward reduced well spacings in most Unconventional plays, the reduction in cluster spacing, which is dominantly a result of trial-and-

[11] There is a whole field of study on solids transport in flowing fluids. A central focus of this has been, for example, sediment flow in rivers and streams. Saltation is one of several recognized mechanisms for solids transport in moving fluid. In particular, saltation is the process when a particle is dropped from suspension but later picked back up and carried further downstream.

[12] Limited entry perforating is intended to promote diversion amongst perforation clusters by limiting the size and quantity of perforations in order to induce excess pressure drop for the cluster, which results in an increase of pressure in the wellbore and promotes breakdown and diversion to other perforation clusters.

error improvements in production, reflects poorly on many of the original assumptions and theories about production in Unconventionals (such as the meaning of SRV and the efficacy of shear stimulation).

When asked in one of our training courses about the correct cluster spacing, my response is that this is a reservoir engineering question – what are the flow properties of the reservoir rock (e.g., permeability and porosity) and what is the drainage area (or, more properly, the economic drainage area accounting for the time-value of production). Only once this has been properly determined can the operational impacts on cluster spacing – including the very critical impact of Stress Shadows on hydraulic fracture development under close spacing – be considered in order to reach an optimized cluster spacing length.

Cluster spacing, like well spacing, is a reservoir characterization issue (then economically optimized) and will vary from well-to-well and play-to-play.

Well sequencing. The issue of well sequencing, captured in concepts like "Cube" development as in the Permian Basin, is, again, not particularly new. The idea of timing the completion of a well, relative to offset wells, is ingrained in most large field developments, particularly those offshore or with a known waterflood phase.

What makes well sequencing more of a challenge in Unconventionals is, first, that the sequencing is dynamic or time-dependent. For example, years ago we were told about the concept of "Stress Capture"[13] wherein better production was seen if the subsequent frac stage was stimulated as soon as possible after the initial frac stage. Rather than really be a stress function, this was, in fact, related to the increase in pressure within the rock fabric due to a previous stage. And, as previously mentioned, pressure diffusion is time-dependent and the benefit of fracturing into a region overcharged from a previous frac stage decreases with time as pressure bleeds off into the rock mass.

Not only is completion sequencing time-dependent, it is highly dependent upon where the pressure field has changed as well as the magnitude of the pressure change. Geomechanically-speaking, the evaluation of injection or depletion effects on the stress field is trivial (i.e., the equations for doing so are robust and well-known); however, the knowledge of where and how much the pressure has changed – the root cause of the stress change – is highly uncertain.

The sequencing issue is, in large measure, an effort to address the challenges faced with parent-child well relationships and the common knowledge that child wells often produce at a 20% discount (or more) to the parent. Again, to understand and predict (with the emphasis on prediction) this dynamic behavior requires a proper and detailed reservoir characterization effort.

[13] I will attribute my learning of the concept of "Stress Capture" from BHP.

The Unconventional Hydraulic Fracturing Paradigm (UHFP)

Finally, we have come to the central issue of this paper – what is the geomechanics paradigm for hydraulic fracturing in Unconventionals?

First, let's avoid the obvious trap. If a central failing of the CHFP is that it assumed homogeneity in rock properties, stress, and pressure away from a wellbore, it would likely be an equal mistake to assume all sorts of heterogeneity in properties, stress and pressure when, in some cases and perhaps in most, these parameters are essentially homogeneous around a wellbore. Consequently, our new paradigm must acknowledge the range of possible rock formation scenarios as, for example, reflected in Figure 7.

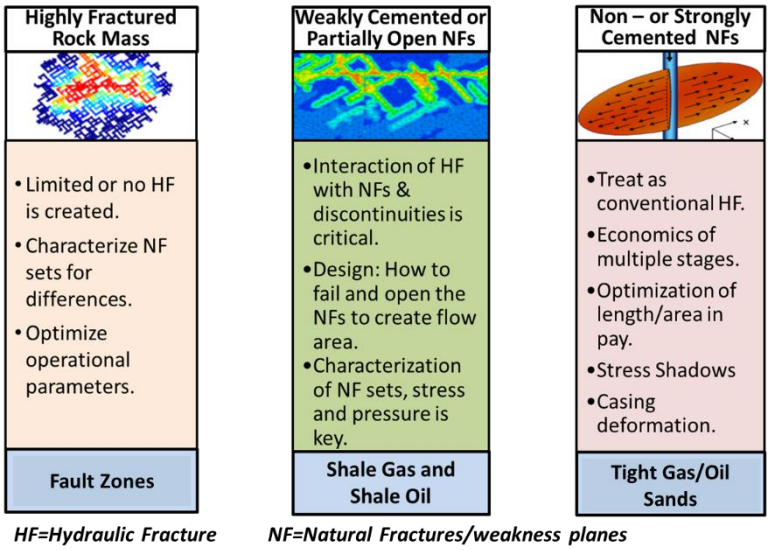


Figure 7: Simplified consideration of rock fabric in the UHFP.

Some of the suggested keys to a UHFP would be:

1. Until the reservoir characterization data shows otherwise, the starting assumption should be that created hydraulic fractures may be highly asymmetric, non-planar, and non-elliptical. This needs to be considered in the stimulation design (and design software) as well as field development including well spacing.
2. Rock has fabric that is often very heterogeneous in 3D away from the wellbore. This needs to be properly characterized in order to evaluate the drainage volume around each hydraulic fracture, to consider hydraulic fracture design changes that may promote the stimulation and possible placement of proppant in the rock fabric, and, ultimately, help optimize both cluster/stage spacing and well spacing.
3. The complete stress tensor is needed in order to evaluate fracture propagation and the impact of rock fabric. Most importantly, the magnitude of horizontal stress anisotropy is important to evaluating the role of rock fabric on generating drainage volume.

4. 3D variations in pore pressure and stress away from the wellbore need to be properly characterized (under both initial and dynamic/infill conditions) and accounted for in hydraulic fracture design.
5. Inelastic rock behavior may dominate rock fabric behavior and must be considered in stress tensor evaluations, frac design efforts (particularly fracture toughness) and potential proppant embedment.
6. Matrix, elastic behavior is a lower priority, 2nd-order effect, which should be taken into account when developing a geomechanics program in support of completion optimization. The mechanical properties and strength of rock fabric are likely a higher priority than matrix, elastic behavior.
7. As a function of rock fabric, leakoff may be a prime contributor to achieving "complexity" (shear stimulation) and drainage area. Whether leakoff should be actively reduced versus actively promoted must be a fundamental decision of the hydraulic fracture design, which is optimized to account for the presence (or lack thereof) of rock fabric.
8. Fluid viscosity and proppant size should be selected relative to the characterization of the rock fabric. Where pressure diffusion into the rock fabric will increase drainage volume, a lower viscosity frac fluid is favored. Where fabric is non-existent or closed and cemented, then a higher viscosity fluid, which will promote proppant transport and additional shear failure at the propagating hydraulic fracture tip, is favored.
9. Where a thin frac fluid is favored, smaller proppants are suggested in order to promote both better proppant transport along the main hydraulic fracture as well as possibly into the rock fabric. Where a higher viscosity fluid is called for, larger proppant is suggested. The larger proppant will provide better proppant conductivity and will clean-up better from potential gel damage.
10. "Stress Shadow" effects must be considered in optimized hydraulic fracture design and cluster/stage spacing along horizontal laterals. Dynamic "Stress Shadows" both from stage-to-stage within a single lateral and during multi-well completions should also be accounted for.

Short-comings Of the Unconventional Hydraulic Fracturing Paradigm (UHFP)

If moving to a new geomechanics paradigm for hydraulic fracturing was easy, it would have already been implemented and widely accepted. As that is not the case, the short-comings behind the UHFP need to be discussed:

- There is no simple log or log suite to populate a UHFP approach. The equivalent to the old "frac log" for the UHFP does not exist and is unlikely to exist since a key to the UHFP is that near-wellbore data cannot necessarily be extrapolated in 3D away from the wellbore.
- Rock fabric can be highly variable, and we will never know the exact details of rock fabric (position, orientation, properties). Consequently, characterizing rock fabric may be too difficult, time consuming and/or costly for some companies.
- Rock fabric cannot be defined by simple uniaxial or triaxial geomechanics tests (i.e., elastic PR and YM are 2nd-order). Detailed efforts are required to evaluate and test the variations

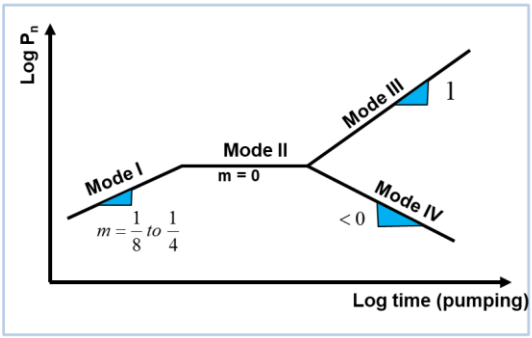
in the mechanical properties and strength of rock fabric and these efforts are not part of traditional, common, core-based geomechanical evaluations.

- The full stress tensor is not easy to obtain and stress varies in 3D (sometimes rapidly). Again, the evaluation of the full stress tensor within a 3D domain is far from trivial – and when it is influenced by depletion or injection operations, success in evaluating the stress tensor is entirely dependent on being able to evaluate the extent and magnitude of pressure changes.
- Given the variations in rock fabric and stress, a one-size stimulation design for a given lateral is likely not optimal. Stimulation programs must be flexible depending upon the results of reservoir characterization efforts within and between laterals.
- Many (most?) simulators do not accurately account for the proper geomechanics of rock fabric and other heterogeneities influencing hydraulic fracture propagation and the resulting drainage volume. These codes are also very computationally intensive. As a result, this creates a chicken-and-egg situation – without the proper reservoir characterization data, there is no driver to improve and streamline optimized hydraulic fracture simulators for the UHFP, while the absence of proven models to utilize UHFP characterization data precludes the optimized collection and evaluation of this characterization data.

Final Thoughts and a Possible Path Forwards

Figure 8 shows a representation of the Nolte-Smith plot[14] developed by Ken Nolte and Mike Smith to evaluate the propagation behavior of hydraulic fractures. Recall that net pressure is the excess pressure inside a hydraulic fracture, above the local value of the minimum principal stress (often Shmin), which is a proxy for the work being done on the rock and largely represents the ease or difficulty of fracture propagation. Particularly with slickwater frac fluids, net pressures should only be several hundred psi for PKN-type fractures and these fractures should be viscosity-dominated. Deviations from these values, as used in the original Nolte-Smith plot, might serve to provide information about rock fabric and help optimize hydraulic fracture design.

[14] "**Interpretation of Fracturing Pressures**", K.G. Nolte and M.B. Smith, paper SPE 8297, J Pet Technology, V33N9, 1981.



Slopes of Fracturing Pressures and Their Interpretation		
Type	Approximate log-log Slope Value	Interpretation
1	1/8 to ¼	Restricted Height and Unrestricted Extension
2	0	Stable Height Growth / Fissure Opening
3A	1	Restricted Extension (Two Active Wings)
3B	2	Restricted Extension (One Active Wing)
4	Negative	Unrestricted Height Growth

Figure 8: Diagram and interpretation of net pressure to evaluate hydraulic fracture propagation.

Two factors must be considered. First, as confirmed with ISIP pressure data, it appears that net pressure increases from toe to heel. While part of this may be related to rock fabric, a significant portion is related to Stress Shadows. What appears to be an increase in net pressure is actually a real increase in the minimum principle stress caused by the Stress Shadow effect and the proper evaluation of net pressure requires an evaluation of the change in the minimum principle stress along a lateral (which is subtracted from bottomhole pressure to obtain net pressure). Second, both laboratory data and numerical simulation results show that net pressure increases when a fracture is impeded from propagating by rock fabric. This behavior suggests that net pressure could be used to evaluate rock fabric.

In order to consider this possible path, several steps are needed:

- The evaluation of net pressure requires accurate bottomhole pressure. This requires a commitment to obtain high quality, bottomhole pressures along the lateral.
- The Stress Shadow effect influences bottomhole pressures through a change in the stress field (and apparent net pressure). The Stress Shadow influence on the minimum principle stress must be accounted for before evaluating treating pressures to determine net pressures.
- A base-line expectation of net pressures without Stress Shadows and rock fabric must be established. These can then be compared to field data in order to consider rock fabric effects.
- Additionally, and likely most significantly, research (via laboratory and simulation) must be conducted to evaluate the magnitude of net pressure (per fluid type) in the presence of rock fabric and the type of interaction between a propagating hydraulic fracture and the fabric.

Thanks for reading! Ciao!

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