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The Geomechanics Of A Shale Play: What Makes A Shale Prospective!

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Abstract

Many shale plays are being successfully developed throughout North America. These shale plays are being evaluated based on a number of criteria, but primarily through typical unconventional and tight formation gas reservoir characteristics. Prospective shale plays share several interesting characteristics such as mineralogy, rock mechanics, and geomechanics. It is the intent of this paper to highlight and demonstrate the interrelationship of these characteristics, and to show their importance on completion and stimulation design and more importantly to the very prospectivity of an unconventional shale play.

This paper will first show, through an analysis of the mineralogy, that shale plays are made up of mostly silica and carbonate material and have few clay constituents. In other words, the prospective shales are actually fine-grained clastics and not shale!Second, prospective shales tend to be brittle, with the static Young's Modulus generally in excess of 3.5 x 10^6 psi. Of course, this brittleness is related to the lack of clay constituents that make up these rocks. In addition, prospective shales tend to satisfy clastic correlations of dynamic to static Young's Modulus. They do not behave like typical shales, but more like fine-grained isotropic (on a core scale) clastics!

Finally, gas can flow through induced fractures or natural fissures under effective stress conditions in these shale plays. As a result, water-frac treatments are the stimulation of choice! However, proppant is still necessary in at least the near wellbore vicinity to provide a conductive pathway to the wellbore.This paper focuses on three key elements (mineralogy, rock mechanics, and geomechanics) of prospective shale plays and benefits the petroleum industry by:

1. Integrating the laboratory core work with multi-disciplinary data to develop a shale and unconventional reservoir prospectivity evaluation tool,
2. Illustrating how this multi-disciplinary dataset influences completion and stimulation design, execution, and well performance, and
3. Demonstrating how this multi-discipline dataset can be used to identify and mitigate well completion and stimulation risks in these unconventional reservoirs.

Introduction

There are a number of important parameters and technical disciplines that need to be addressed to understand the viability of an unconventional gas reservoir. Unconventional gas reservoirs are somewhat unique, in that they require "good" reservoir, completion, and fracture stimulation for success. Failure of any one of these key disciplines means a marginal or uneconomic well, and success in all three may not guarantee a successful well as they are extremely price/cost sensitive.

On the reservoir side, Gunter[1-2] and Newsham and Rushing[3-4] correctly tied the geology, petrophysics, and reservoir engineering to develop an integrated work flow for tight and unconventional gas reservoirs. The four stage model included: (1) large scale geologic architecture, (2) description of the rock and fluid systems, (3) definition of flow units through formation evaluation, and (4) calibration of the geologic and petrophysical models through reservoir simulation. Geomechanics was addressed throughout their workflow. Stage 1 of their work addressed the large scale structural components of the geologic model such as faults, in-situ stresses, and fissures, Stage 2 addressed the stress dependent properties and anisotropy of the rocks, and stages 3 and 4 addressed the hydraulic fracture and natural fissure orientations and effects on well performance.

Slatt[5] et al. developed a workflow for unconventional gas shales that included (1) characterization of multi-scale sedimentology and sequence stratigraphy, (2) relating stratigraphy to log response, (3) seismic response, (4) petrophysical and geomechanical properties, and (5) organic geochemistry. In this work, the geomechanics of the prospect are brought in through step 4 and, although not discussed in any great detail, a relationship between mineralogy and geomechanics is suggested. Further, the authors recommend that additional attention be given to the lithologic properties of the shale and the brittleness or ductility.

Shanley[6] et al. described the relationship between capillary pressure and relative permeability in unconventional gas reservoirs where a “permeability jail” can occur. In this work, the permeability jail concept (after Byrnes) is described as the area between the critical gas saturation and critical water saturation where, potentially, no fluid or gas can flow. In conventional reservoirs the difference between the irreducible and critical water saturations can be quite small, while in an unconventional gas reservoir this area can be quite large. In an unconventional gas reservoir, this understanding is extremely important to the reservoir and petrophysical assessment of resource quality.

Franz[7] et al. uses an integrated approach to analyze production data from the Barnett shale. Their integrated modeling approach incorporates the geology and geophysics with reservoir characterization, reservoir simulation, and completion and stimulation design. Their estimate of relevant data to collect includes geology, geophysics, and geomechanics and core analyses for mineralogy, porosity and permeability, saturations, organic content, and adsorbtion isotherms.

Jacobi[8] et al. proposes an integrated approach to petrophysical evaluation of unconventional shale gas reservoirs using only logging data. Density, neutron, acoustic, nuclear magnetic resonance, and geochemical logging data are used to provide lithology, stratigraphy, and mineralogy. The approach further differentiates source rock intervals, classifies depositional facies by their petrophysical and geomechanical properties, and quantifies total organic carbon. One of the objectives of this work was to identify the optimal completion intervals.

Parker[9] et al. conducted a petrophysical evaluation on the Haynesville shale using both core and log data. Their work describes the starting point for the completion and hydraulic stimulation design as (1) identification of free gas zones, (2) identification of rock types and lithology, (3) total organic content, (4) quantification of effective shale porosity, (5) estimates of shale permeability, (6) mechanical stress measurement for fracture design, and (7) fissure identification. This work incorporates core analysis to validate log measurements and also includes the completion and fracture stimulation design and post-appraisal process into the work flow where they belong.

Rickman and Mullen[10] et al. showed the use of a petrophysical analysis for stimulation design optimization. This work ties together the rock mechanics, mineralogy, completion, and stimulation design strategy. Their work showed a correlation between wireline log analysis, petrology, acid solubility, and capillary suction time tests for shale reservoirs. These tests of mineralogy and fluid sensitivity have proven essential for optimizing completion and stimulation(s) in shale reservoirs. The authors further demonstrated through mineralogical analysis that all shales are not alike, and in particular, that all shales are not the Barnett Formation. It further showed that even within the Barnett vertical section there are subtle geomechanical and mineralogical differences that can make for poor or marginal completions and fracture stimulations.

This paper takes the Rickman and Mullen[10] view that mineralogy and brittleness are important to successful shale plays. More importantly, this work will show the interrelationship between mineralogy, rock mechanics, and geomechanics and how it can be used to optimally complete and fracture stimulate any unconventional shale reservoir. This work proposes the view that the standard petrophysical properties expoused in the prior works[1-10] are important, but that the key to a successful unconventional gas play is the integration of the mineralogy, rock mechanics, and geomechanics to the completion and fracture stimulation design and post-appraisal. There are numerous shales that are producing commercial quantities of gas that have substandard petrophysical properties such as thermal maturity, organic content, or organic richness, but there aren’t very many that have poor rock and geomechanics, and those that do have significant questions about their long term economic viability.

Discussion:

The Integrated Approach To Understanding Shale Prospectivity:

The integrated approach to understanding shale prospectivity involves, as a first step, conducting some core laboratory tests to relate and integrate the mineralogy, rock mechanics, and geomechanics. The basic suite of core tests recommended by this work includes:

1. Fourier Transform Infrared (FTIR) Spectroscopy tests for determining the mineral constituents of the core sample,
2. Fluid sensitivity testing to determine the clay sensitivity to salt concentration and frac fluid. A capillary suction test also provides insight into this phenomenon, as described by Rickman and Mullen[10],
3. Triaxial compression testing to determine the static rock properties (Young’s Modulus and Poissons Ratio),
4. Ultrasonic velocity testing to determine dynamic rock properties and shear anisotropy,
5. Embedment testing to determine the conductivity lost due to embedment in ductile shales, and
6. Unpropped crack testsing to determine the flow capacity of an un-propped crack under confining conditions.

The results of these tests can then be used to determine shale prospectivity, and more importantly, design completions and fracture stimulation(s) to maximize the well performance. This is especially true for horizontal well completions and water-fracs in unconventional gas reservoirs. The importance of rock and geomechanics to horizontal completions is reviewed in depth in a paper by Britt and Smith[11]. The importance of the geomechanical impact of unpropped crack tests to the design, placement and post-appraisal of water-fracs is documented in a paper by Britt and Smith[12] et al. with the underlying theoretical work done by Bennett[13].

This paper supports the following conclusions regarding shale play prospectivity. Prospective shales have:

1. Limited clay constituents- generally less than forty percent,

2. Static Young's modulus in excess of 3.5 x 10^6 psi,
3. Dynamic to Static Young's modulus correlations consistent with clastic reservoirs (not shales),
4. Fairly isotropic on the core plug scale (not many/any laminations evident), and
5. Gas flow at effective confining conditions through an un-propped crack.

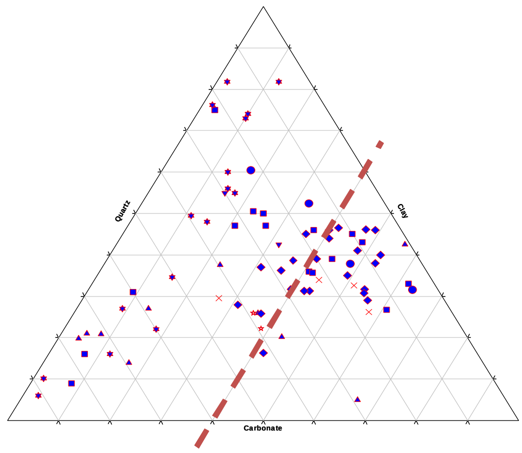
The subsequent sections will present data that support these five conclusions. Exceptions will also be presented with implications on the completion and well stimulation highlighted.

Petrology or Mineralogy of Prospective Shales:

One of our favorite petrophysicists describes unconventional gas shale reservoirs as either "shilts or shands." I can't think of a better way to characterize the mineralogy of shale reservoirs than that. First, these reservoirs all have clay constituents- they just don't have all that much. If they do, they are not very prospective. Based on this work, clay content in excess of thirty five to forty percent is too high to be considered widely prospective.

Figure 1 shows a ternary diagram of the mineralogy of samples from eight different shales in North America. As shown, most of the samples are to the left of the red dashed line representing forty percent clay constituents. Of the samples to the right of the line, only two shales have significant representation. Both of those shales (represented by diamonds and boxes) produce some gas, but no viable economic play has been made in either (at least with gas prices less than $6-$7 per mcfd).

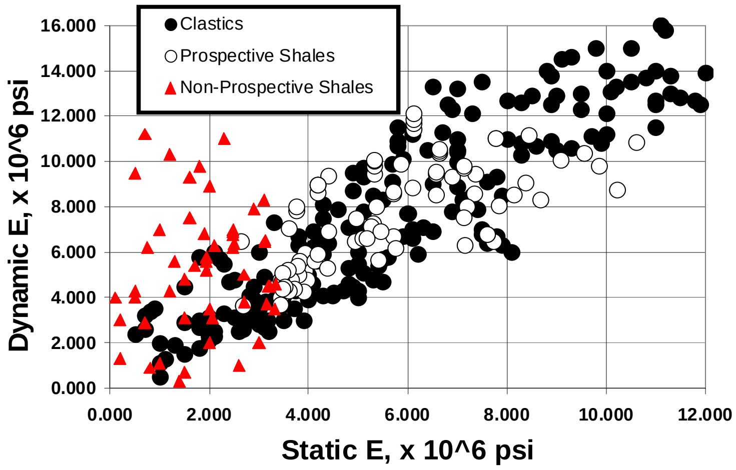
Figure 1: Ternary Diagram of the Mineralogy of Shales



Is this because the pore throats are so small that water and gas are trapped in "permeability jail?" Is it because the abundant clay mineralogy makes the shale too ductile to maintain either an induced fracture or natural fissure under confining conditions? We understand the relative "permeability jail" concept; unfortunately, it is hard to measure in these unconventional sediments. On the other hand, we can and have tested what happens to the rock mechanics and geomechanics when a sample has "too much" clay. The Haynesville Formation, for example, has elevated clay content approaching the forty percent level. And although it has more clay than most of the prospective shales tested, it is still prospective, although the fracture stimulation design is affected as will be discussed later.

Both the "permeability jail" concept and excess ductility may occur and likely do, but one solution to the geomechanical effect of shale ductility is to pump gelled fracture stimulations with higher proppant concentrations. This has worked in many tight gas formations but hasn't been widely effective in unconventional shale reservoirs. In these reservoirs, water-fracs have been the stimulation of choice. The use of a clean, non-damaging fissure dilating fluid, like water, has distinct advantages over the use of gelled fluids. After all, water-fracs have been the stimulation of choice in naturally fissured reservoirs for nearly sixty years for a reason!

Figure 2: Dynamic to Static Young's Modulus Correlation



Rock Mechanics of Prospective Shales:

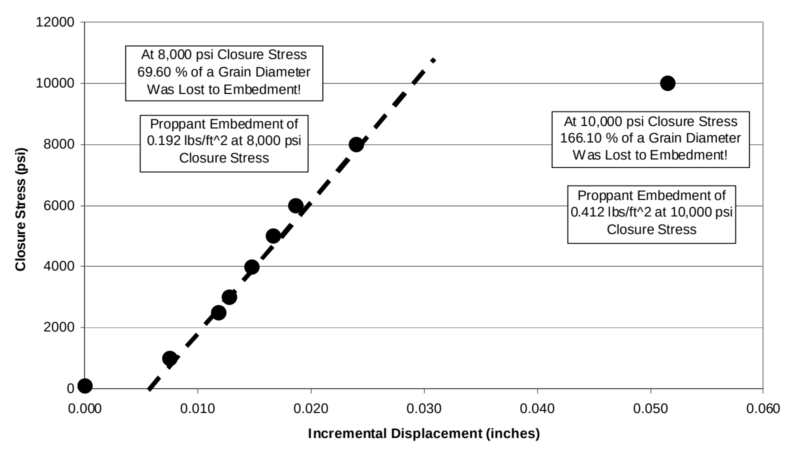
Triaxial compression tests and ultrasonic velocity tests are important core tests to be used in the evaluation of shale prospectivity. Tri-axial compression tests are used to determine static Young's modulus and Poisson's Ratio, while ultrasonic velocity tests are used to determine the dynamic Young's modulus and Poisson's Ratio. Rickman and Mullen[10] suggest these are important to establish the brittleness or ductility of the shale. Low modulus and high Poisson's Ratio shales are generally too ductile to be prospective. Our view is that there is another important use of these static and dynamic tests. As an industry, we have a long history of developing dynamic to static

Young's modulus correlations[14-19]. Most of these correlations are for clastic rocks. We have found that prospective shales tend to fit the dynamic-to-static clastic correlations of Young's Modulus. Figure 2 shows a plot of the dynamic Young's Modulus versus static Young's Modulus for clastics, prospective shales and non-prospective shales.

As shown on this figure, the prospective shales have a dynamic-to-static Young's modulus correlation constistent with the clastic rocks tested. The non-prospective shales are a group of tests conducted on various "true shales" that presented various drilling problems in several basins in the Mid-Continent and South Texas. These shales were characterized as having very high clay content and generally exhibited visible laminations to the naked eye. Also note that there are very few tests in prospective shales that have a Young's Modulus less than 3 x 10^6 psi or in non-prospective shales with a Young's Modulus in excess of 3 x 10^6 psi.

Several of the lower modulus data points are from the Haynesville Shale Formation. The Haynesville shale is a relatively high clay content shale found in East Texas and Northern Louisiana. In such a shale with low modulus, the ductility of the formation is an issue. As a result, in such a shale an embedment test is recommended to determine the extent of the conductivity lost to embedment. Figure 3 shows a plot of closure pressure versus displacement. As shown, as the load was applied from 1,000 to 8,000 psi, the incremental displacement was linear. Once the load was increased to 10,000 psi, however, the incremental displacement (embedment) increased dramatically. For example, at 4,000 and 8,000 psi closure stresses, proppant embedments of 0.118 lb/ft^2 and 0.192 lb/ft^2 or 42.6 and 69.6 percent of a grain diameter (20/40 mesh in this case) were recorded, respectively. At 10,000 psi closure stress, the embedment recorded was 0.412 lb/ft^2 (166.1%), or over twice the embedment seen at 8,000 psi. It should be noted that this dramatic increase in displacement was due to the ductility of the formation at high closure stresses and not failure of either the core sample or proppant.

Figure 3: Haynesville Shale Embedment Test



Another comment regarding the ultrasonic velocity testing is that not only is data obtained for determination of a dynamic Young's modulus, but shear data parallel and perpendicular to the core plug axis is also determined. Such shear travel time information can be used to assess the anisotropy of the core sample. Many of the prospective shales with Young's modulus in excess of 3.5 x 10^6 psi exhibit little shear anisotropy on the core plug level. Thus, it would appear that many of the shales on this scale are isotropic. For example, data indicates that the anisotropy exhibited by samples with a static Young's Modulus greater than 3.5 x 10^6 psi (minimum shale prospectivity criterion) averages less than 6 percent, while the samples with a static Young's Modulus less than 3.5 x 10^6 psi exhibits nearly four times the anisotropy.

One final point regarding the isotropic nature of the prospective shale plugs is that if they are isotropic on this level and laminations are not visible, core plug orientation may not be important. That is, either vertical plugs from whole core or horizontal plugs from rotary sidewall cores may be useable for determining the rock mechanics[19]. Several studies of sample orientation have been conducted to support this conclusion, although conduct a fluoroscopic inspection of the plugs prior to testing in an attempt to detect internal flaws or laminations in the plugs is always recommended!

Figure 4: BRML Built for Purpose Crack Test Equipment

Geomechanics of Prospective Shales:

In addition to the petrological and rock mechanical testing, a series of geomechanical tests are recommended to evaluate whether an un-propped hydraulic fracture could retain conductivity. Residual fracture width has been observed both in the laboratory and in field experiments. Surface asperities, or roughness at the fracture face, may account for this residual width. A laboratory study by Schlumberger[20] investigated this aspect of treated water fracture stimulations. Their work showed that fracture displacement and surface asperities were required to provide adequate fracture conductivity in the absence of proppants and suggested that high strength proppants and higher, more conventional concentrations of proppant were required to mitigate the need for the fracture displacement and surface asperities' effect on fracture conductivity. This work was extended further by conducting additional laboratory tests. These results showed that an un-propped induced fracture under effective confining pressure conditions in excess of what is anticipated in most shale formations could be expected to have at least 0.1 to 1 mdft of fracture conductivity.

To conduct this work, the cracked core was placed in our "built for purpose" equipment and confining pressure was applied. Figure 4 shows a picture of the equipment that was built and used in this study. This equipment consists of a test cell that can handle confining pressures from 0 to 10,000 psi and temperatures up to 300^{o}F. A piston head is used to apply confining pressure and includes inlet electronic and flow ports. In the induced crack testing, the piston is actuated to apply confining pressure and emulate flow and shut-in conditions. While confined at pressure and temperature, flow is established through the inlet ports and the permeability of the core and induced crack measured. Figure 5 displays the head of the test cell. Shown in this figure is the piston head for applying confining pressure and inlet electronic and flow ports. During most studies, effective confining pressures (i.e, difference between minimum horizontal stress and reservoir pressure) up to 2,000 to 2,500 psi are applied to emulate the field conditions of most shale formations.

Flow ports exist both in the core direction and perpendicular to the core, as shown in Figure 6. In these studies, we attempt to measure the retained permeability of the core in the direction of the induced crack as a function of confining pressure.

A series of retained permeability experiments have been performed for shale core plugs prepared as described in the previous paragraphs. These tests were designed to determine the retained permeability of the crack while flowing wet nitrogen as the confining pressure was increased to effective confinement conditions. Results of the testing show that for prospective shales the retained permeability measured at effective confinement conditions can be significant, but for all prospective shales gas flow was maintained. Conversely, for the non-prospective shales tested (primarily Atoka and Wilcox shales), the flow of wet nitrogen ceased long before effective confining pressure was reached. Further, it has been found for several shales near the limit of clay constituents (approximately forty percent) that although gas flow was maintained at effective confining conditions, the measured permeability in these cases was at least an order of magnitude less than the more prospective shales. In other words, it would appear that the clay mineralogy and rock mechanics (brittleness and ductility) play a role in the results of the un-propped crack test.

Figure 7 shows a plot of Normalized Permeability versus Normalized Stress. Shown are crack test results for five different shales in North America. As shown, the upper datasets in black (prospective shales) have a normalized permeability that is more than an order of magnitude greater than the lower data in red (marginal to non-prospective shale). From hundreds of such tests coupled with a review of well performance, a geomechanical schematic has

Figure 5: Test Cell Head With Piston and Inlet Ports

Figure 6: Schematic of Test Procedures

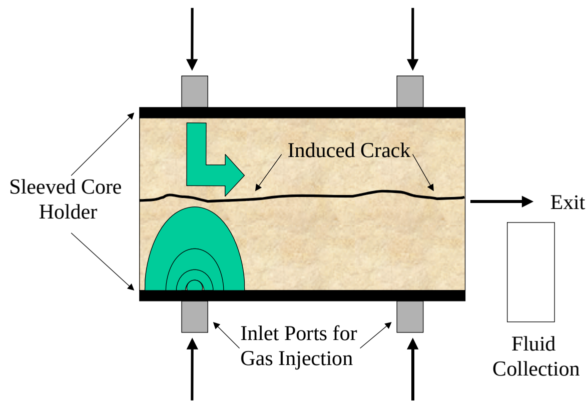
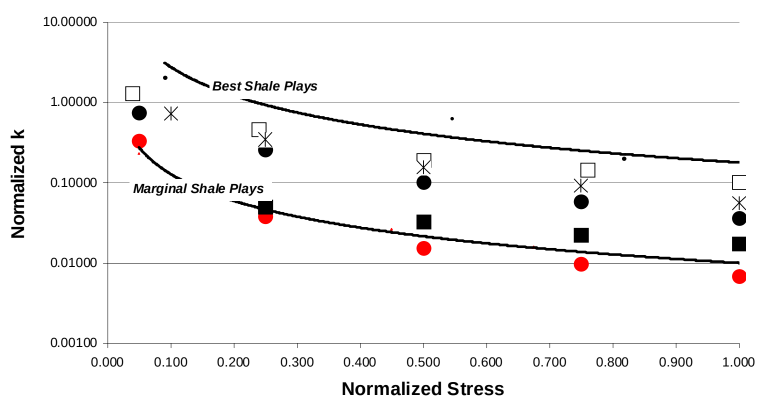


Figure 7: Un-propped Crack Tests for Shales



been developed to identify prospective and non-prospective shales which are also shown on this plot as trendlines for “best shale plays” and “marginal shale plays.”

As another comment regarding these tests, both naturally fissured samples and mechanically cracked samples have been tested. Results indicate that the natural fissures in the samples are less stress sensitive but also have a smaller flow capacity than mechanically fractured samples. This relationship is especially evident when a naturally fissured sample is mechanically cracked and retested. The implication of this may show up when a dilating fracture fluid such as treated water connects with a natural fissure system and induces further mechanical failure of the system.

Finally, these tests are conducted to effective stress conditions to test the ability of gas to flow in the reservoir away from the wellbore. At the wellbore, the stress on either natural fissures or induced fractures is the minimum horizontal stress minus the bottom hole flowing pressure. Thus, for most gas wells, the stress on the natural or induced cracks near the wellbore is the fracture pressure. At these conditions, we have found no shales and few tight gas sands that can flow gas. As a result, some proppant is required in the near-wellbore area to maintain flow through the natural fissures and induced fractures. Proppantless fractures will likely and have failed in these formations in the past. In the Haynesville sample shown in Figure 3, for example, nearly five times the embedment was seen near wellbore (10,000 psi), as seen in the far field under effective confining conditions (2,000 psi).

Completion and Fracture Stimulation Design Impacts:

Our proposed methodology for identifying prospective unconventional gas plays originated as a means of understanding the viability of treated water as a fracturing fluid.[12] Water as a fracturing fluid has a long history[22-25] (as long as fracturing itself) but is a unique fracturing fluid due to its poor proppant transport characteristics. The poor transport characteristics result in a fracture with variable conductivity laterally and vertically. The lateral effects of conductivity have been well studied[13,26], but it is the effect of the vertical component of flow in a fracture where treated water fracture stimulations derive their benefits.[12,13]

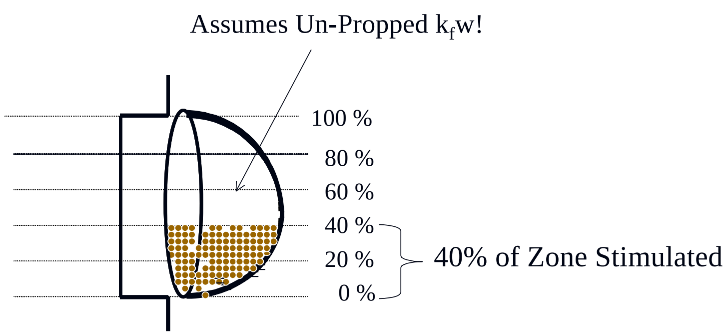
The primary aspect of this most recent work was coupling numerical simulation studies of fracture flow with a laboratory investigation to show that hydraulically cracked and un-propped fractures can retain fracture width sufficient to flow gas. Further, this work showed that as long as the vertical dimensionless fracture conductivity (F_{CDvert}) is in excess of 2, the treated water frac will act like a fully propped fracture. Should the fracture have an F_{CDvert} less than 2, the gas deliverability and reserve recovery will be lessened compared to a fully propped fracture. This work was the principal focus of a 2007-2008 SPE Distinguished Lecturer Tour[27] on “The Use of Low Viscosity Treated Water In Fracture Stimulations.”

In recent years, these laboratory results have been applied to shale plays in North America with some very interesting findings. The shale in these unconventional gas reservoirs, when cracked and subjected to confining pressure (effective stress), are brittle enough to retain conductivity and flow gas. More ductile shale fail to retain conductivity and as a result fail to flow gas un-propped. Such a shale is likely a poor water frac candidate and likely not prospective as an unconventional reservoir.

Any formation can be a viable water frac target, but some lend themselves to the use of treated water as a fracturing fluid better than others. Low permeability naturally fissured formations, for example, make excellent water-frac candidates. This is because water-frac stimulations differ from more conventional fracture stimulations, as water is a cleaner fluid than conventional gels and does little damage to any natural fissures present. In addition, water is a poor fluid for transport of the proppant within the fracture. This latter issue (poor transport fluid) is the basis for our water-frac designs. The resulting fracture after a water-frac has two distinct components. The first part of the fracture is the bottom, where all of the proppant settles during the treatment. The second part of the fracture is the upper part that has little or no proppant, as it has all settled to the bottom of the fracture.

Figure 8 shows a schematic of a water-frac where forty percent of the fracture is filled with proppant and sixty percent of the fracture is un-propped. Reservoir simulations of such a fracture provide the basis of design for a water-frac treatment. These simulations show that a water-frac stimulation performs like a fully propped fracture, provided that the ratio of the unpropped conductivity of the fracture to the product of the reservoir permeability and the height of the un-propped part of the fracture is in excess of 2. If this ratio is less than a value of 2, it indicates that the retained conductivity of the unpropped part of the fracture is too small for the reservoir permeability and un-propped fracture height. In this scenario, the only thing that can be done to improve the situation is to reduce the unpropped fracture height by pumping more proppant and filling up more of the fracture.

Figure 8: Schematic Of A Water-Frac



Common stimulation questions being asked today are: How much treated water? How do we treat the water? How much proppant? These aren't new questions, but they are important, and the results of the laboratory testing in the first part of the paper lay the foundation to help answer these and other questions. Prior work[12] showed that an F_{CDvert} of at least 2 is required to maximize well performance from water fracs.

$$F_{CDvert} = k_f w_{upf} / k * H_{upf} \qquad \text{(1)}$$

where $k_f w_{upf}$ is the un-propped fracture conductivity (lab tests), k is the reservoir permeability, and H_{upf} is the un-propped fracture height.

By setting equation 1 equal to 2 and varying permeability and un-propped conductivity (lab results), we can estimate the height of an acceptable un-propped fracture. Figure 9 shows a plot of un-propped fracture height versus reservoir permeability.[27] This figure shows several interesting things. First, water-fracs are truly for use in tight and unconventional gas reservoirs. In higher permeability (conventional) reservoirs, the acceptable un-propped fracture height is potentially less than a foot (un-propped conductivity of 1 mdft). Second, the acceptable un-propped fracture height in a 0.0001 md reservoir may be hundreds of feet, as shown. Therefore, treated water should be the stimulation fluid of choice in unconventional gas reservoirs, provided there is enough brittleness to maintain an un-propped fracture width under confining conditions. Even so, some proppant will always be required, as the effective stress near the wellbore is always greater than that in the reservoir. The effective stress (stress acting to close un-propped induced or natural fractures) in the reservoir is the fracture pressure minus the reservoir pressure, while at the wellbore it is fracture pressure minus the bottom hole flowing pressure. In most U. S. reservoirs the effective stress in the reservoir approaches 0.2 psi/ft (Salz) while the effective stress at the wellbore approaches 0.6 psi/ft. As a result, proppant will always be needed to prop the fracture in the near-wellbore area, but how much proppant is needed depends on the un-propped conductivity and the reservoir permeability, as previously shown. Therefore, water-frac design is strongly related to the results of the laboratory testing described in the first part of this paper.

Figure 10 shows this effect very well. This figure is a bar chart of Initial Potential (IP) as a function of East Texas Cotton Valley area[28]. Shown is a comparison of treated water fracs versus gel fracs for eight Cotton Valley areas. As shown, the IP for the water fracs was near that for gelled treatments (six month gas cumulative recoveries were nearly identical) in all but areas 4, 5, and 7. In areas 4, 5, and 7 the Initial Potential of the water fracs significantly underperformed those of the gel fracs. It should be noted that areas 4, 5, and 7 represent the Woodlawn and Blocker Fields of East Texas where the Taylor sand is not 50 feet thick, as it is in each of the other areas studied, but 100 to 150 feet thick instead. The answer to this problem is not that water fracs do not work in areas 4, 5, and 7, but rather that one can't use the same water-frac design without considering the reservoir, rock mechanics, and geomechanics. And, in fact, the water frac treatments in these areas were modified (more sand pumped to reduce the un-propped fracture height and increase the F_{CDvert}) and the well performance results were greatly improved as a result.

Figure 9: Un-Propped Height as a Function of Permeability

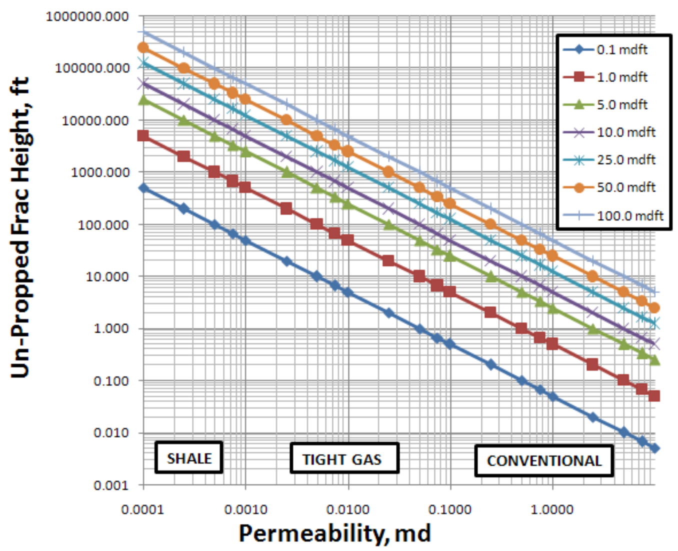
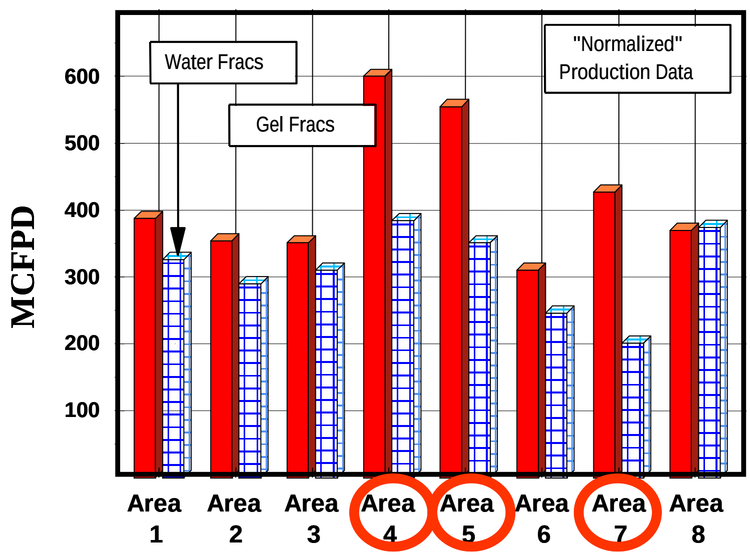


Figure 10: Effect Of Treatment Design On Productivity



Summary and Conclusions:

This paper clearly shows the importance of linking the mineralogy, rock mechanics, and geomechanics to determine an unconventional shale play's prospectivity. Further, through understanding of the laboratory results, the basis of fracture design can be developed to improve and optimize the completion and stimulation designs. Based on this work, we conclude:

1. Prospective shales have
    a. Limited clay constituents generally less than forty percent,
    b. Static Young's modulus in excess of 3.5 x 10^6 psi,
    c. Dynamic-to-static Young's modulus correlations consistent with clastic reservoirs (not shales),
    d. Fairly isotropic on the core plug scale (not many/any laminations evident), and
    e. Flow gas at effective confining conditions through an un-propped crack.
2. Therefore, laboratory core tests of mineralogy, rock mechanics, and geomechanics should be conducted on every potentially viable shale.
3. Results of these laboratory tests can be used to develop optimum water-frac designs for unconventional shale plays.

Acknowledgements

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Nomenclature

σ_v = Vertical stress
σ_{Hmax} = Maximum horizontal stress
σ_{hmin} = Minimum horizontal stress
Effective Stress = $\sigma_{hmin} - p_i$
Proppant Stress = σ_{hmin} – BHFP
F_{CDvert} = Dimensionless Fracture Capacity to vertical flow
$k_f w_{upf}$ = Un-propped fracture conductivity, mdft
H_{upf} = Un-propped fracture height, feet
x_f = Fracture half-length, feet
$k_f w$ = Fracture Conductivity, mdft
k = Reservoir permeability, md
H = Fracture height, feet
E = Young's modulus, psi
E' = Plain strain modulus, psi
$E_{dynamic}$ = Young's Modulus determined through sonic or ultrasonic measurements
E_{static} = Young's Modulus determined through tri-axial compression measurements (Hydraulic fracturing is a static process)
p_i = Reservoir pressure, psi
BHFP = Bottomhole flowing pressure, psi
Normalized k = Normalized permeability

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