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A Practical Use of Shale Petrophysics for Stimulation Design Optimization: All Shale Plays Are Not Clones of the Barnett Shale

Rick Rickman, Mike Mullen, Erik Petre, Bill Grieser, and Donald Kundert, SPE, Halliburton

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Abstract

The most common fallacy in the quest for the optimum stimulation treatment in shale plays across the country is to treat them all just like the Barnett Shale. There is no doubt that the Barnett Shale play in the Ft. Worth Basin is the “granddaddy” of shale plays and everyone wants their shale play to be “just like the Barnett Shale.” The reality is that shale plays are similar to any other coalbed methane or tight sand play; each reservoir is unique and the stimulation and completion method should be determined based on its individual petrophysical attributes. The journey of selecting the completion style for an emerging shale play begins in the laboratory.

An understanding of the mechanical rock properties and mineralogy is essential to help understand how the shale reservoir should be completed. Actual measurements of absorption-desorption isotherm, kerogen type, and volume are also critical pieces of information needed to find productive shale reservoirs. With this type of data available, significant correlations can be drawn by integrating the wireline log data as a tool to estimate the geochemical analysis. Thus, the wireline log analysis, once calibrated with core measurements, is a very useful tool in extending the reservoir understanding and stimulation design as one moves away from the wellbore where actual lab data was measured. A recent study was conducted to review a laboratory database representing principal shale mineralogy and wireline log data from many of the major shale plays. The results of this study revealed some statistically significant correlations between the wireline log analysis and measured mineralogy, acid solubility, and capillary suction time test results for shale reservoirs. A method was also derived to calculate mechanical rock properties from mineralogy. Understanding mineralogy and fluid sensitivity, especially for shale reservoirs, is essential in optimizing the completion and stimulation treatment for the unique attributes of each shale play. The results of this study have been in petrophysical models driven by wireline logs that are common in the industry to classify the shale by lithofacies, brittleness, and to emulate the lab measurement of acid solubility and capillary suction time test. This is the first step in determining if a particular shale is a viable resource, and which stimulation method will provide a stimulation treatment development and design.

A systematic approach of validating the wireline log calculations with specialized core analysis and a little “tribal” knowledge can help move a play from concept to reality by minimizing the failures and shortening the learning cycle time associated with a commercially successful project.

Introduction

Producing methane from shale has been practiced in North America for more than 180 years. The first known well in the U.S. drilled to produce natural gas for commercial purposes was in 1821 outside of Fredonia, N.Y. (2008 www.britannica.com). This well produced from a fractured organic-rich shale through a hand dug well. It was produced for more than 75 years. Production from the Antrim shale in the Michigan Basin started in 1936. Today, there are more than 9,000 wells producing, most of which were drilled after 1987. The Barnett Shale, discovered in 1981, is being produced from more than 8,000 wells today (Wang 2008). **Fig. 1** represents the growth of the Barnett Shale play in the Newark, East field in the Ft. Worth basin. The cumulative gas production from this field is more than 4 Tcf. One could characterize the success of this play as: the right market, the right people, and the right technology (Wang 2008). The key technologies for the Barnett Shale success revolve around horizontal drilling and hydraulic fracture stimulation.

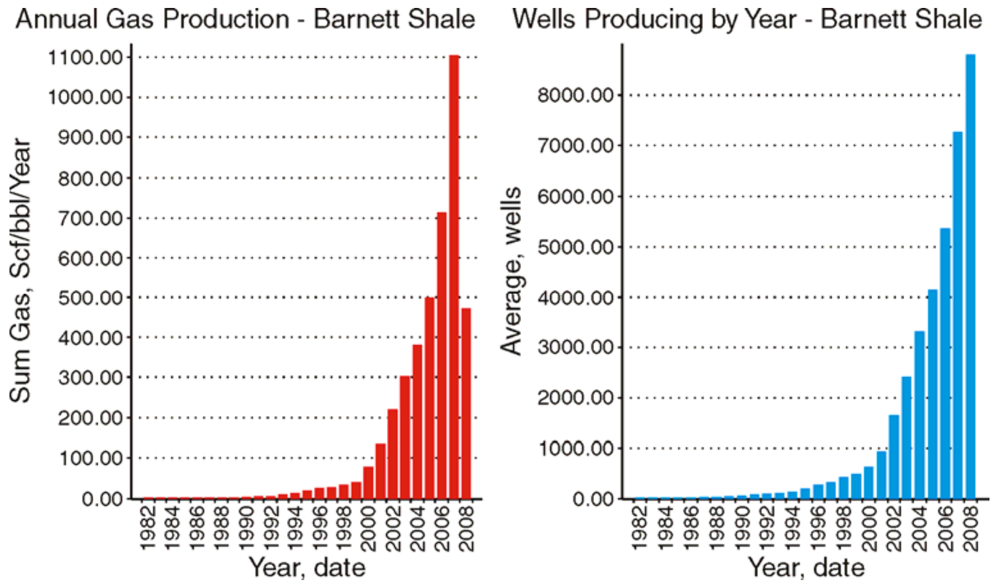

Fig. 1—History of the Barnett Shale Play annual gas production and number of wells (HPDI. Note: 2008 data only for first quarter).

The simple answer to the question of how to duplicate the Barnett Shale success in the emerging shale plays around the world would be to treat all shales like the Barnett Shale. If that technology works in the Barnett Shale, it should be the technology of choice for all other shales. Perhaps this understanding is oversimplifying the complexity of shale reservoirs. The objective of this paper is to investigate uniqueness of each shale play, especially the stimulation fluid selection and mapping out of a path using the laboratory measurements to calibrate the petrophysical model that will be used as a practical guide for stimulation design optimization.

Information Necessary for Successful Hydraulic Fracturing of a Shale Formation

There is a rather short list of items that need to be known about the reservoir before a stimulation treatment is designed for a shale reservoir. This list, which has two components, is common for conventional reservoirs as well as for shale reservoirs (**Table 1**).

Table 1—Necessary Information for Design of Stimulation Treatment

Geomechanical Considerations	**Important For**	**Determined By**
How brittle is the shale?	Fluid type selection	Petrophysical model
What is the closure pressure?	Proppant type selection	Petrophysical model
What proppant size and volume?	Avoid screenouts	Petrophysical model/tribal knowledge
Where should the frac be initiated?	Avoid screenouts	Petrophysical model/tribal knowledge
Geochemical Considerations	**Important For**	**Determined By**
What is the mineralogy?	Fluid selection	XRD/LIBS/petrophysical model
Fluid water sensitivity?	Base fluid salinity	CST/BHN/Immersion Test
Can acid be used if necessary?	Initiation issues—etching	AST
Does proppant or shale flow back?	Production issues	Tribal knowledge
Are surfactants beneficial?	Conductivity endurance	Flow test/tribal knowledge

The majority of geomechanical considerations can be answered through a calibrated petrophysical analysis (Mullen et al. 1997). Most of the geochemical considerations can be addressed using a series of lab measurements. Addressing these considerations can greatly increase the possibilities of success in placing the treatment and identifying the issues that arise along the way. Ignoring these issues can be referred to as relying strictly on “tribal” knowledge, or trial and error. Combining the two can help obtain the best of both worlds. For this study, there is the basic assumption that the shale in question meets some basic screening criteria as a potential target. The screening test for potential organic- and silica-rich shale targets would have a cumulative total organic content (TOC-FT) > 30, gas content of 40 scf/ton, and a thickness greater than 30 ft (Russum 2005). The screening criteria mentioned here is not the primary objective of this paper.

The geochemical considerations can be determined using some common laboratory measurements. The tests mentioned in Table 1 are: acid solubility test (AST), capillary suction time test (CST), X-Ray defraction (XRD), or chemostratigraphy, a laser induced breakdown spectral (LIBS), and hardness number (BHN). More specialized tests can be run to determine the optimal amount of salts needed to minimize the effects of the frac fluid on the clay minerals. These tests are: the clay glycolation test, methylene blue, specific surface area, and ensilin tests, which can accurately predict shale swelling and dispersion so that the fracturing fluid will be optimal for that specific formation. The practical use of these test results is the subject of this paper, not the specific details of each test.

A universal petrophysical model that does not need any external calibration would be ideal. Any petrophysical model will need lab measurements to help ensure accuracy in the estimates of mechanical rock properties, Young's Modulus and Poisson's Ratio, mineralogy, and TOC, etc. Because the petrophysical model is not the main topic of this study, only the relationships used to derive brittleness, acid solubility, and closure stress will be discussed.

Brittleness

The concept of rock brittleness combines both Poisson's Ratio and Young's Modulus. These two components are combined to reflect the rocks ability to fail under stress (Poisson's Ratio) and maintain a fracture (Young's Modulus) once the rock fractures. Ductile shale is not a good reservoir because the formation will want to heal any natural or hydraulic fractures. Ductile shale however, makes a good seal, trapping the hydrocarbons from migrating out of the more brittle shale below. Brittle shale is more likely to be naturally fractured and will also be more likely to respond well to hydraulic fracturing treatments. There is a need to quantify the brittleness factor in a way that combines both rock mechanical properties in shale. This method differs from other mineralogy based methods of determining brittleness that are based mainly on core measurements (Wang 2008). The advantage of using the petrophysical interpretation over the core method is that it is much more common to have a log across the zone of interest that covers the shale as well as the bounding rock layers than it is to have core data covering the entire interval that will be hydraulically fractured.

Fig. 2 is a graphical representation of this concept. 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. 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.

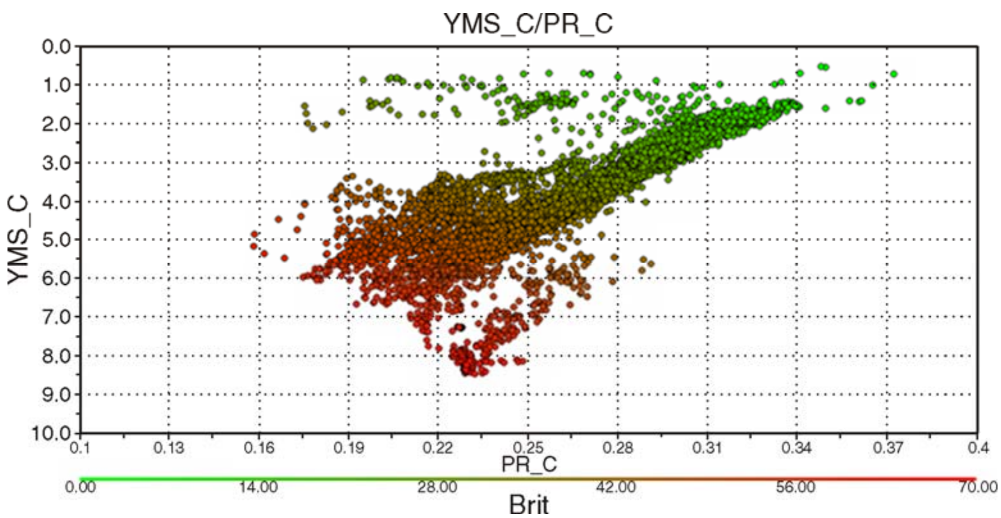

Fig. 2—A cross plot of Young's Modulus and Poisson's Ratio showing the brittleness percentage increasing to the southwest corner of the plot.

The concept is that the ductile shale points will fall to the northeast quadrant, and the more brittle shale to the southwest quadrant. Ductile shale makes a good frac barrier as well as a good seal for a reservoir.

To calculate brittleness from Poisson's Ratio and Young's Modulus, the following equations are used:

YM_BRIT = ((YMS_C - 1)/(8- 1)) * 100 ……………………………………………………………………….(1)
PR_BRIT = ((PR_C- 0.4)/ (0.15 - 0.4)) * 100 …..(2)
BRIT = (YM_BRIT + PR_BRIT) / 2 ....(3)

The static Young's Modulus and Poisson's Ratio used in this model are derived using the process described in Mullen et al. 2007. The way to interpret the brittleness curve is two-fold. The first use is to distinguish between ductile and brittle shale. This is usually done as color shading on the petrophyscial analysis (**Fig. 3**). The second use is to overlay the closure stress gradient to look for hydraulic fracture barriers. To distinguish the ductile from the brittle shale, a brittleness cutoff is selected as the brittleness value in clay-rich shale. The higher the values of brittleness above this 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 stimulation.

Closure Stress Determination

The closure stress determination used in this model is modeled after Barree (2002), and shown in a simplified form below.

Closure Stress = PR_C / (1 – PR_C) * (Po – V_Biots * Pp) + Pp + Strain * YMS_C + Ptech ………………. (4)

Where,
PR_C = composite determination of Poisson's Ratio
Po = oberburden pressure, PSI
V_Biots = vertical Biots coefficient
Pp = pore pressure, PSI
Strain = strain coefficient
YMS_C = composite determination of Young's Modulus

Fracture Width Determination

With a reasonable estimation of the mechanical rock properties, the hydraulic fracture width can be calculated. This calculation is important in determining the proppant sieve-size. As described in the equations below, the fracture width calculation is a function of the fluid pump rate, fluid viscosity, fracture half length, and shear modulus of the formation.

G = YMS_C / 3*(1-2*PR_C) * 1000000 ....(5)
Xw = .3 *(((PumpRate * FluidVisc* (1-PR_C) * Xf) / G)^(1/4)) * (3.414/4) * BRIT)))) ....(6)

Where,
G = Shear modulus
PR_C = composite determination of Poisson's Ratio
YMS_C = composite determination of Young's Modulus
Xw = fracture width
Xf = designed fracture half length
PumpRate = anticipated stimulation treatment pump rate, bbl/min
FluidVisc = frac fluid viscosity, cp
BRIT = the degree of brittleness

The Practical Use of Petrophysical Analysis

The practical considerations of using the brittleness, closure stress, and fracture width calculated from the petrophysical model (Fig. 3 and **Table 2**) will help determine the frac fluid type, the fracture height for volume considerations, and the proppant size and type that should be used. First, consider the proppant to be used. **Fig. 4** represents the recommended proppant type as a function of closure stress. As the stress is applied to the proppant, the permeability of the proppant pack is reduced because of proppant crushing. The proppant size is generally selected by the minimum fracture width generated by frac fluid viscosity and pump rate (**Fig. 5**). Using the brittleness computation as a general guideline to fluid type selection is demonstrated in **Table 3**. As brittleness increases, the fracture geometry becomes more complex. In high-brittleness shales, the proppant may act more as a wedge, providing a high-conductivity flow path for hydrocarbons to migrate to the wellbore. As the shale becomes more ductile (lower values of brittleness), the fracture becomes more like conventional bi-wing fracture geometry.

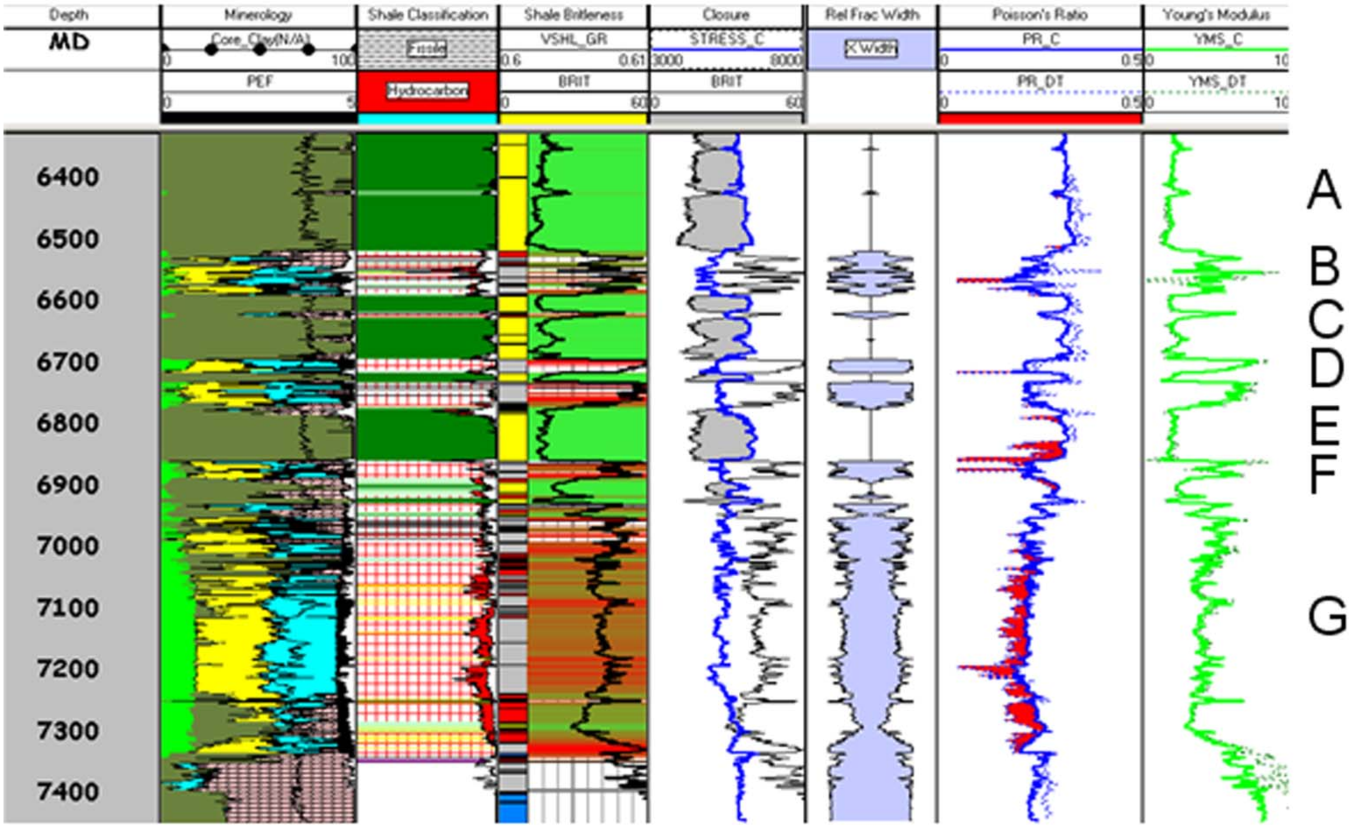

Fig. 3—The geomechanical portion of the petrophysical analysis showing mineralogy, shale classification, shale brittleness, closure stress, frac barriers, frac width, Poisson's Ratio and Young's Modulus.

Gas effect is observed as the difference between the composite determined Poisson's Ratio and the Poisson's Ratio calculated only from the dipole sonic measurements.

Table 2—Analysis and Recommendations for Stimulation Design Based on Data Shown in Fig. 3

Zone	Brittleness, %	Thickness, ft	Closure Stress, psi	Frac Barrier, Y/N	Frac Width at 100 bbl/min, in.	Recommendations			
						Fluid Type	Proppant Size	Proppant Type	Frac ?
A	15.3	400	6,134	Y	0	—	—	—	N
B	56	82	4,650	N	0.038	Slick Water	30/50	Sand	Y
C	18	103	6,261	Y	0	—	—	—	N
D	59	91	5,150	N	0.038	Slick Water	30/50	Sand	Y
E	18	85	6,350	Y	0	—	—	—	N
F	22	40	6,040	Y	0	—	—	—	N
G	45	350	5,600	N	0.038	Slick Water	30/50	Sand	Y

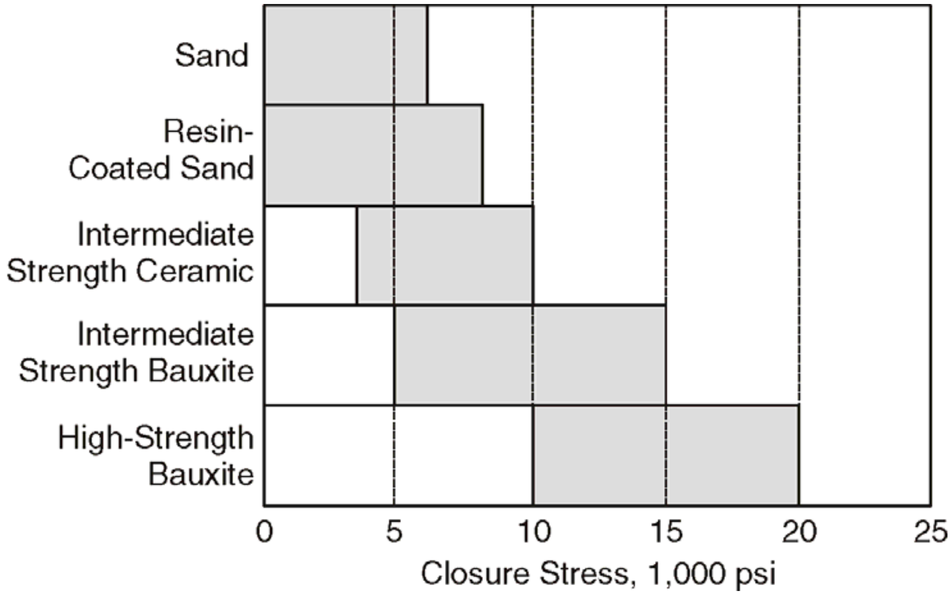

Fig. 4—The recommendations of proppant type based on closure stress the proppant will be subjected to during the life of the well. Taken from Economides et al. (1998).

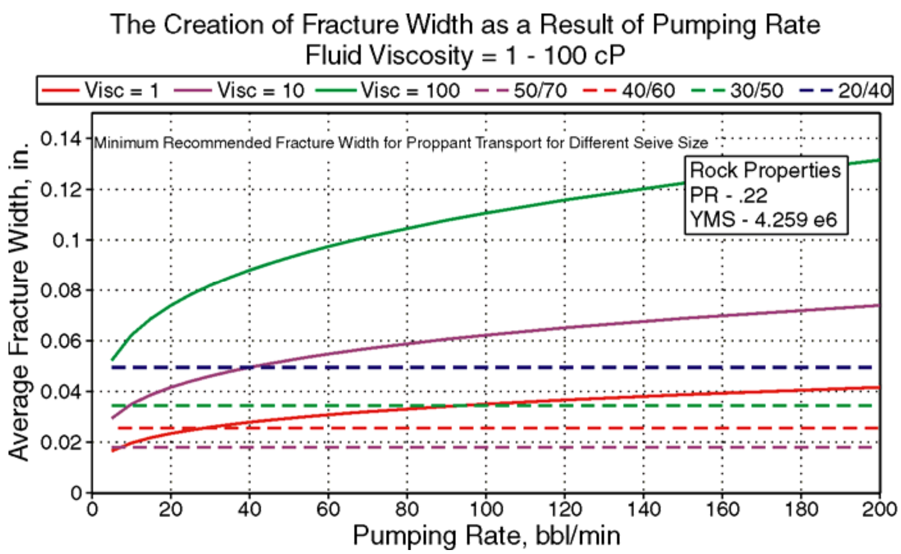

Fig. 5—Proppant size selection is based upon the minimum recommended fracture width for common proppant sizes.

Table 3—Fluid System Recommendations Based on the Brittleness Calculation

Brittleness	Fluid System	Fracture Geometry	Fracture Width Closure Profile	Proppant Concentration	Fluid Volume	Proppant Volume
70%	Slick Water			Low	High	Low
60%	Slick Water					
50%	Hybrid					
40%	Linear					
30%	Foam					
20%	X-Linked					
10%	X-Linked			High	Low	High

Geochemical Considerations

The next step in stimulation design is looking at the laboratory measurements on cuttings or core samples. The objective here is to provide a mineral composition of the shale, acid solubility, and an idea of the fluid sensitivity of the shale. If the shale exhibits a high degree of sensitivity to fluid, more advanced testing is recommended to help find the optimal base fluid salinity to minimize any damage that might occur because of incompatible fluid systems.

The mineral composition determined by XRD is used to calibrate the mineral composition in the petrophysical model. It is not practical to measure a sample every half-foot of shale, so incorporating this data into the petrophysical model is a way of extending the core data to the entire formation.

X-Ray Diffraction/Chemostratigraphy—a Laser-Induced Breakdown Spectral

To adequately characterize the shale, the mineral components must be known. For this study, the XRD/LIBS analysis was grouped into three categories: quartz, carbonates, and clays. The quartz group included quartz, feldspars, and pyrites. The carbonate group included calcite, dolomite, and siderite. The clay group included the total clay. Also recorded in the database was the volume of mixed layer clay for use in comparing with the CST data and the total nonsoluble minerals like pyrite, siderite, kaolonite, and chlorite. This summation was used in conjunction with the AST as a test for the possibility of creating movable fines, should acid be used in the stimulation treatment. A ternary diagram was used to display the mineral makeup of each shale investigated in this study. While this is a rather simplistic view of the full power for XRD or LIBS analysis, the goal of this study was to be more of a practical guide in comparing shale reservoirs. The determination of brittleness using the XRD mineralogy is based on a modified technique developed by Barree (2002). This technique estimates the Young's Modulus and the Poisson's Ratio based on the mineral percentages of quartz, carbonate, and clay. These values are then used as inputs to Equations 1–5.

Acid Solubility Testing

Acid solubility is a test that measures the volume of rock dissolved as the sample is immersed in acid. There is a very strong correlation between the percentage of carbonate material in the sample and the acid solubility (See **Figs. 6** and **7**). Low to moderate acid solubility can be used as a caution flag because there likely will be a significant generation of fines causing plugging of the proppant pack and damage around the perforations. In most shales, acid is frequently used as a breakdown fluid or used to reduce near-wellbore friction during the frac job. If acid is needed, it is recommended to use a blend of weak acids and surfactants to etch low AST shales. This gives a benefit of roughing the surfaces of the fracture plane contacting more surface area without releasing nonsoluble minerals in the shale. The reactive fluids are usually used in shales to reduce high treating pressure at low pumping pressure rates, helping the fluid find its way into the fracture network in the formation.

Capillary Suction Time Test

Shale and clay stability has been an ongoing problem for both the service sector and operating companies in our industry. The capillary suction time test is simple and easy to use, and hence is applied as a reliable but rapid method for screening large numbers of formation samples including cuttings, full core pieces, core plug ends, and rotary sidewall coring tools (RSCT) samples. On the drilling side, operators use the CST method to conduct the test at the rig-site while drilling. However, because of sample preparation variation, the test should be used only qualitatively as a "yes" or "no" indicator of clay swelling and dispersion related to cation exchange. In fracturing applications, samples are normally sent to a lab rather than evaluated at rig-site, but it is not uncommon for confirmation testing to be needed quickly. This is when CST can be used to its greatest benefit. Typically, comparison is made with a given sample by comparing the CST time of DI water and a fixed concentration of KCl (i.e. 3%). If the difference is insignificant, then it can be quickly concluded that minimum swelling and dispersion potential exists, and the KCl requirement is minimal, if needed at all. When running XRD, conversely, CST is run to quickly confirm the presence or absence of swelling potential when mixed-layer, illite/smectite clays are identified. XRD alone cannot answer that question. Often, a composite sample can be used in the CST test as a low-cost rapid-turnaround indication or confirmation test before a frac job. When translating to a fluid recommendation, sufficient sample distribution and density is required to represent the rock package contacted by the frac fluid. Less KCl is often the rule in the gas shales and tight gas formations. Conversely, if unusually high CST numbers are observed (in the 70-sec range) in the stratigraphy, then more KCl protection and consequently, more evaluation testing should be considered. More sophisticated testing such as the Brinell hardness number (BHN) test can provide indications of the effects of fluids on the softening of the fracture face. Salinity can be optimized to reduce the frac face softening effect. In summary, CST is a useful tool in our testing arsenal. However, it should be used *qualitatively*, not quantitatively. As a practical guide, the CST ratio of deionized water to 2 or 3% KCL serves as a good indicator of fluid sensitivity. A CST(di)/CST(KCl) ratio less than 1 has no fluid sensitivity, a ratio between 1 and 1.5 is moderately sensitive, and greater than 1.5 is sensitive to fresh water, **Table 4**.

Acid Solubility and Capillary Suction to Mineralogy for the Barnett Shale

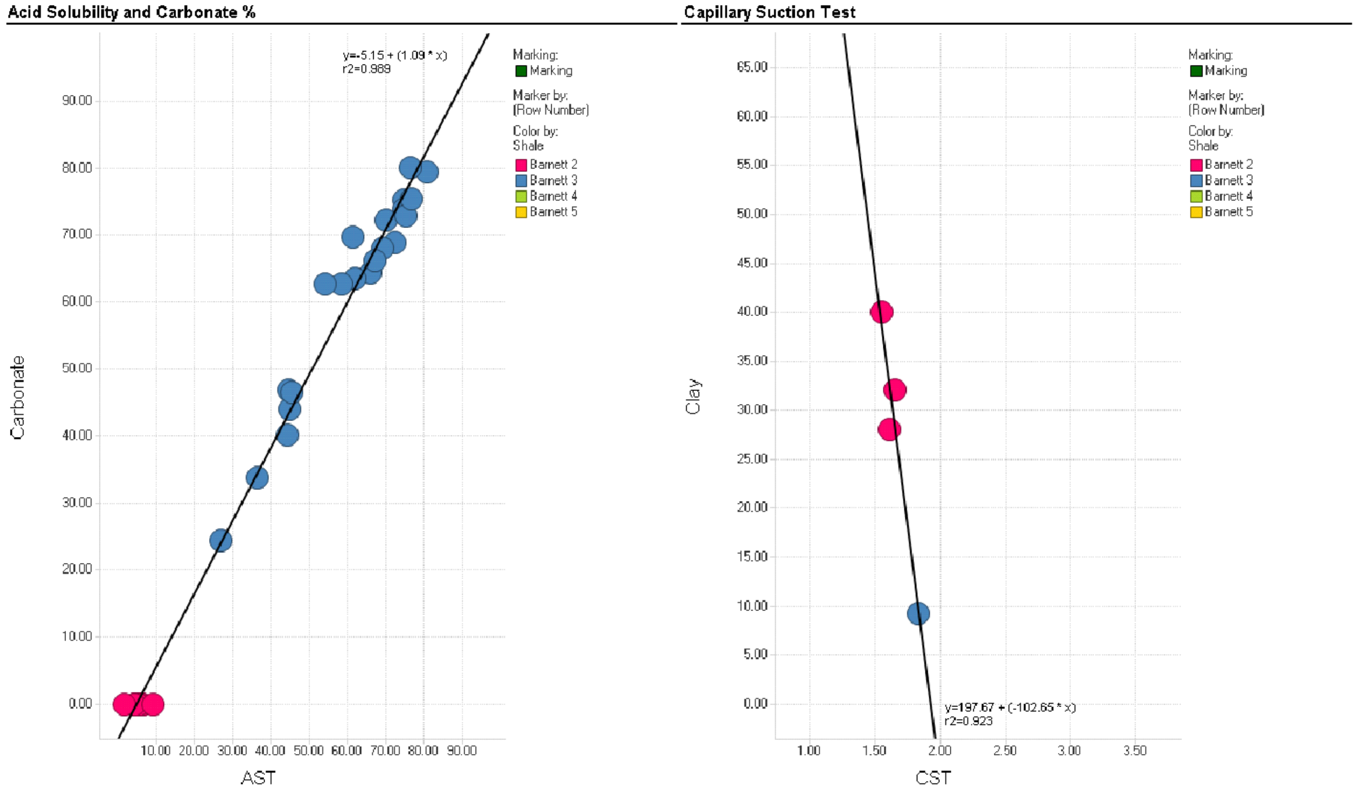

Fig. 6—Acid solubility and capillary suction to mineralogy for the Barnett shale.

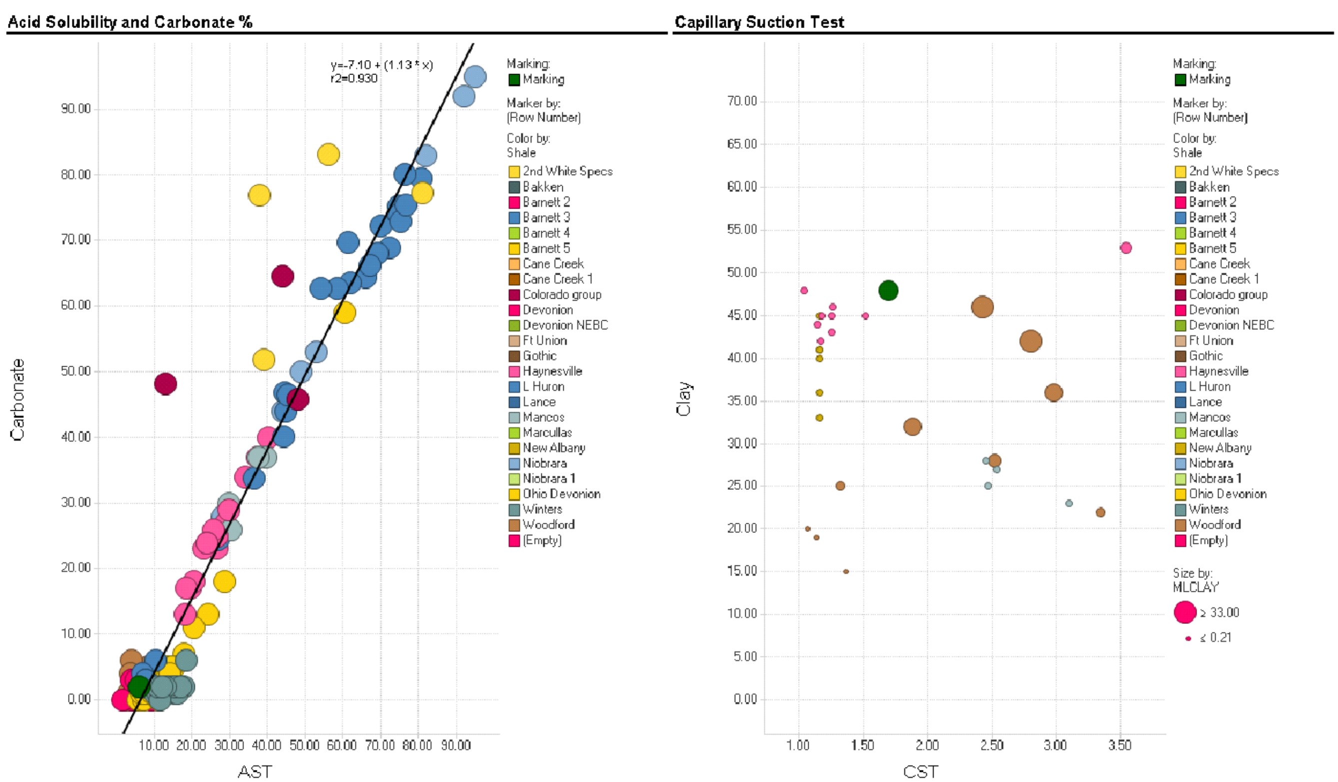

Fig. 7—AST and CST for all shales in the database. AST data shows a good correlation to AST. There does not appear to be a good correlation to CST.

Table 4—Practical Interpretation of CST Results

CST(di)/CST(KCl) ratio	Fluid Sensitivity	Mediation
<1	None	None needed
1 to 1.5	Moderately sensitive to fresh water	Take precaution, use KCl
>1.5	Very sensitive to fresh water	Strongly recommend further testing to find the appropriate KCl amount needed

There does not appear to be any good correlations observed that compare the CST data with outputs from the petrophysical data (Figs. 6 and 7).

The Fingerprint of the Barnett Shale

In the study, there were four Barnett Shale wells. Each well represents a unique mix of mineralogy. **Fig. 8** is the ternary diagram of the quartz, carbonate, and clay percentage summary from the XRD data for the Barnett Shale. Even the Barnett Shale itself is not consistent in its mineral composition. This data suggests four distinct lithotypes:

- Quartz-clay and no carbonate, Well 2
- Carbonate dominate with smaller portions of quartz and clay, Well 3
- Quartz dominate with smaller portions of carbonate and clay, Well 4
- Quartz-clay dominate with varying amounts of carbonate, Well 5

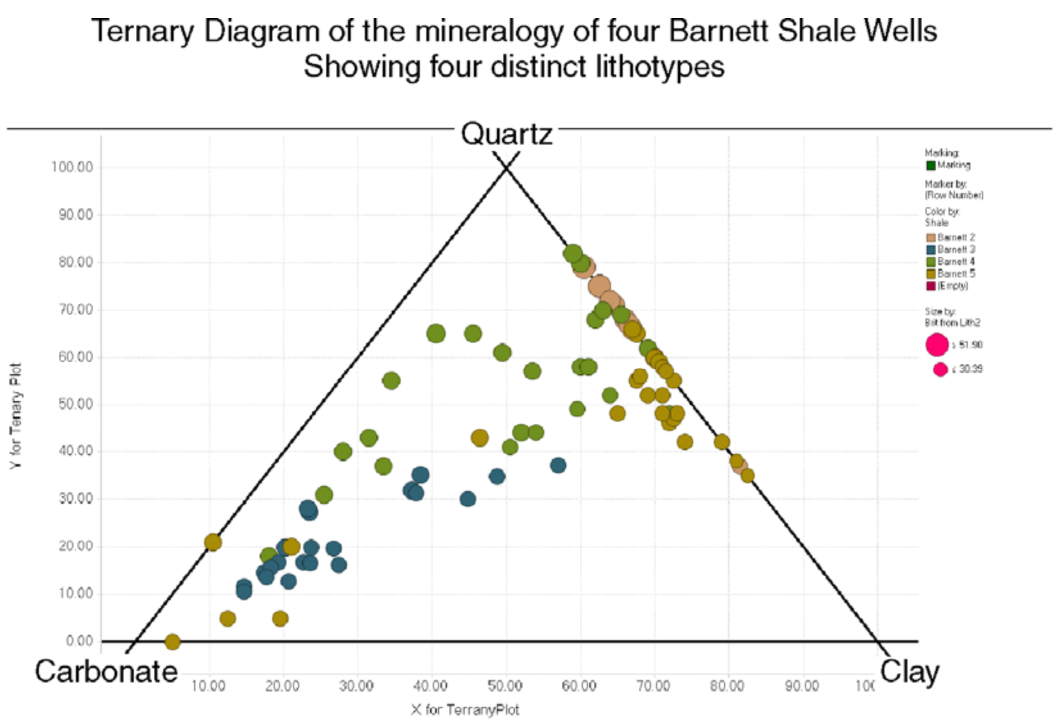

Fig. 8—Ternary diagram of four Barnett shale wells. The size of the markers indicates brittleness of the formation

Fig. 6 shows the variability of the reservoir of the Barnett Shale. By including the brittleness calculation as the size of the data points, one can see that as the clay percentage increases, (points toward the southeast corner of the diagram), the brittleness decreases. As the quartz percentages increase (toward the north point of the ternary diagram), brittleness increases, and as the points trend toward the carbonate end of the diagram (toward the southwest point of the ternary diagram), the brittleness is in a moderate range.

Fig. 7 demonstrates the results of acid solubility and capillary suction time test for the Barnett Shale wells in the data set. The CST data in the Barnett Shale does not make sense of increasing clay to decrease CST.

Discussion of the Results for the Barnett Shale

The combination of XRD, AST, and CST provide useful insight into the appropriate fluid systems the data would suggest for the different lithotypes found in the Barnett Shale. Lithotype 1, the quartz-clay lithotype, is rather insensitive to acid and moderately sensitive to fresh water. This suggests some small portion of the clay volume would be swelling clays. If needed, acid can be used as a breakdown fluid without causing much damage. The CST suggests moderate sensitivity to fresh water. This effect is probably overcome by the high degree of brittleness. This lithotype would be prone to creating the wide fracture networks created by large volume of low viscosity frac fluid. It would also be a good candidate for low-proppant-concentration frac jobs. A blend of weak acids and surfactants, called reactive etching fluids, could also be used in this reservoir without adverse results.

The analysis of Lithotype 2 suggests a high degree of acid solubility. In areas of formation of high carbonate volume, acid would be acceptable. But in the areas of 20–50% carbonate content, acid should be avoided because it could have unwanted side effects, the release of fines that would plug up the near-wellbore region of the perforations. The recommendation here would suggest avoiding acid and being aware of the base fluid. There is some damage likely occurring from fresh water, but is overcome by the brittleness of the rock. Lithotypes 3 and 4 did not have lab measurements in the data available for this study.

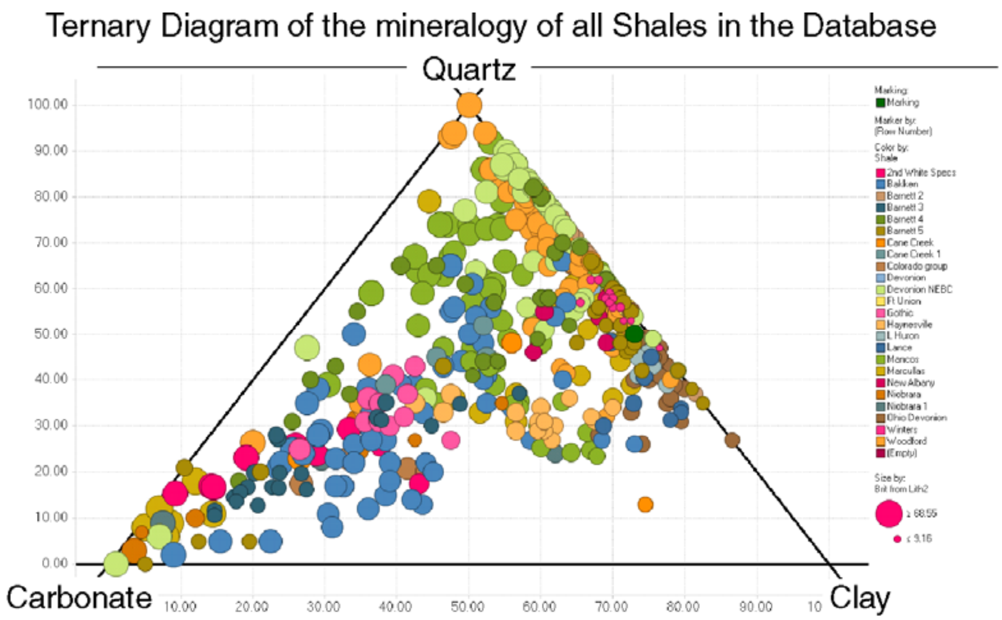

Fig. 9—Ternary diagram of all shales in the database. The color represents the individual shale and the size of the bubble represents the brittleness determined from the XRD data.

Comparison of the Barnett Shale with Other Shale Plays

Figs. 7 and **9** represent the same analysis shown above for the Barnett Shale with all the other shales in the database. Each shale should be considered based on its own mineralogy, CST, and petrophysical attributes. In general, there is a very good correlation between the carbonate content and AST. However, there has yet to be a good correlation between the CST measurement and the petrophysical calculations.

Conclusions and Recommendations

As demonstrated by this study, one can see that all shale plays are not clones of the Barnett Shale. There is still considerable variability, even within the Barnett Shale. One needs to be aware of these subtle changes in the geomechanical and geochemical properties for continued improvement in stimulation and completion practices. Using the systematic approach around the world will greatly shorten the tribal-learning cycle of trial and error. Capturing the available core data in the petrophysical model for use by close, offset wells is a cost effective way to gain reliable information without needing an extensive coring program. While XRD mineralogy and AST testing can be emulated through the petrophysical model, no substitute has been found to unlock capillary suction time test data for fluid sensitive shales. The CST data is the key indicator of when further lab testing needs to be done to find the starting point of the optimal frac system.

Acknowledgements
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