Identification of Fragility in Unconventional Reservoirs, through the estimation of mineralogy in pre-stacked seismic data and micro-seismic events

Roderick Perez Altamar, Independent Consultant

Abstract

Fragility is a key characteristic for the effective stimulation of unconventional deposits and is mainly controlled by the mineralogy of the rocks. The objective of this work is to evaluate the most popular techniques for estimation of fragility in rocks, which were then used to estimate the properties geomechanics and the productivity of an unconventional training located in Texas. Using specialized well logging tools, which were calibrated with core descriptions, it was possible to create a BI template, as well as a template in the domain of Lamé parameters ($\lambda\rho$ - $\mu\rho$), which was used to predict BI in the reservoir calculated from surface seismic data. This workflow was applied to a set of 3D seismic data acquired in a area, resulting in a 3D volume in which the areas with the highest content could be highlighted of quartz, and of greater fragility, using a template based on the well register and the core data. By extracting $\lambda\rho$ - $\mu\rho$ values from micro seismic event locations acquired in the area, the results showed that most micro-seismic events occurred in the most fragile part of the reservoir. The methodology used in this study was replicated in the analysis of training not in Colombia, with the objective of increasing the production of resources and select the best areas (higher quartz content and high fragility) and decrease the rates of fluids injected into the rock during hydraulic fractures.

Introduction

Shales are described as organic-rich, fine-grained reservoirs and are typically dominated by clays. The mineral composition and the presence of organic matter can influence not only the distribution of pores and fluid saturation, but also the effectiveness of stimulation.

The Fort Worth Basin is a shallow north–south elongated foreland basin, encompassing roughly 15,000 mi^2 in North Texas, formed during the late Paleozoic Ouachita Orogeny" (Walper, 1982). Paleotectonic collision events in the Fort Worth Basin resulted in a northwest–southeast main stress field orientation at the time of the Barnett Shale deposition. However, the present day regional maximum stress direction in the basin is northeast–southwest, with local deviations in intensity and direction about the mineral wells and other minor.

The Barnett Shale is an organically rich and thermally mature rock deposited during Mississippian time (≈340 Ma) in the Fort Worth Basin, characterized by low average permeability (70 nD) and porosity (6%) distributed in a variety of depositional facies (Deacon, 2011). The Viola, Forestburg, and Marble Falls Limestones are hydraulic fracture barriers and are not considered production targets because they are water bearing. The Viola Formation deposited on top of the karsted Ellenburger Formation (Loucks, 2008) presents a potential risk of water production. In the area of study, the Forestburg Limestone divides the Upper Barnett and the Lower Barnett shales into two members, which must be treated and fractured separately.

Singh (2008) and Perez (2009) describe three distinctive gamma ray (GR) log patterns: upward-increasing, upward-decreasing, and constant. These GR log patterns are correlated to lithofacies using cored wells in the Barnett Shale representing unique deposition environments. Singh (2008) defines the upward-increasing GR parasequence (GRP) to be composed of upward increasing amounts of clay accompanied by a decrease in calcite content.

Conventional logs such as GR, neutron porosity, and resistivity are useful to stratigraphically characterize a reservoir. However, these logs do not fully provide the information needed to characterize organic shales in terms of their geomechanical behavior. This additional information can come from the integration of sequence stratigraphy, special analysis techniques, specialized logging tools, and core lab measurements. Recent availability of mineralogy logs such as elemental capture spectroscopy (ECS) and dipole sonic logs enable characterization of a reservoir in terms of its mineral content and elastic properties, providing a means to differentiate lithology types by their completion response.

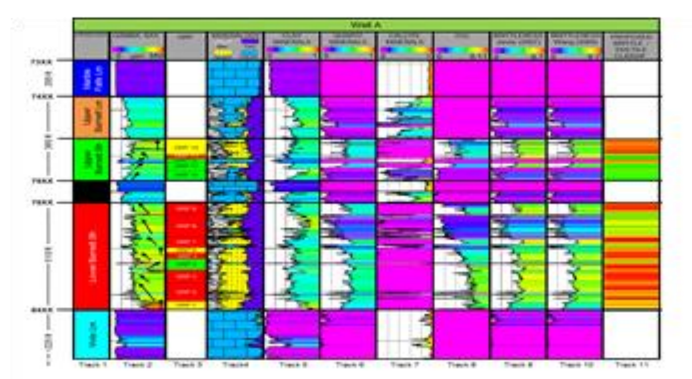

Figure 1.

When a rock is subjected to increasing stress, it passes through three successive stages of deformation: elastic, ductile, and fracture. Based on these behaviors, it is possible to classify the rocks into two classes: ductile and brittle. If the rock has a smaller region of elastic behavior and a larger region of ductile behavior, absorbing much energy before failure, it is considered ductile. In contrast, if the material under stress has a larger region of elastic behavior but only a smaller region of ductile behavior, the rock is considered brittle.

Several of the more commonly used brittleness definitions neglect geologic factors such as the rock composition and the origin and habit of mineral rock components (such as quartz and calcite, and/or the type of cement in the rock). To estimate a reliable and robust reservoir brittleness measurement, it is necessary therefore to combine conventional well logs with direct measurements of geomechanical properties, such as Young's modulus E and Poisson's ratio v (Grieser and Bray, 2007; Rickman et al., 2008).

Jarvie et al. (2007) and Wang and Gale (2009) propose BI definitions based on the mineral composition of the rock, dividing the most brittle minerals by the sum of the constituent minerals in the rock sample, considering quartz (and dolomite, in the case of Wang and Gale, 2009) as the more brittle minerals.

I calculated the BI using Jarvie et al.'s (2007) and Wang and Gale's (2009) equations using the ECS log data points and show the results in Figure 1, tracks 9 and 10, respectively. Comparing both BI indices with the mineralogy logs (Figure 2 track 4), we observe that the zones with high quartz and calcite content are more brittle than the regions with high clay content, which are less brittle (ductile).

Then, I crossploted GR versus BI for all the formations in showing that the shale formations (Upper and Lower Barnett Shale) exhibit moderate to high GR and BI values. Exceptionally high-GR values (>200 API) correspond to thin layers containing highly radioactive phosphatic nodules and concretions (Singh, 2008). Counterintuitively, this crossplot shows a positive correlation between GR and BI. As expected, limestone formations (Marble Falls Limestone, Forestburg Limestone, and Viola Limestone) show low-GR and low BI values. Notice that the Viola Limestone formation (light blue) exhibits a subtle positive variation in BI related to clay content in the limestone formation.

In Figure 2, I divided the data population into four equal petrotypes, setting the BI between 0 and 0.16 a ductile (green), between 0.16 and 0.32 as less ductile (yellow), between 0.32 and 0.48 as less brittle (orange), and greater than 0.48 as brittle (red). Examining the GR log along with the ductile/brittle classification results based on BI, we observe that the mid-lower part of the Lower Barnett Shale and the middle section of the Upper Barnett are the more brittle zones because of their higher quartz content in the vertical section. Also, we identify from the log several thin ductile layers (green) within the shale formation related to high clay mineral content.

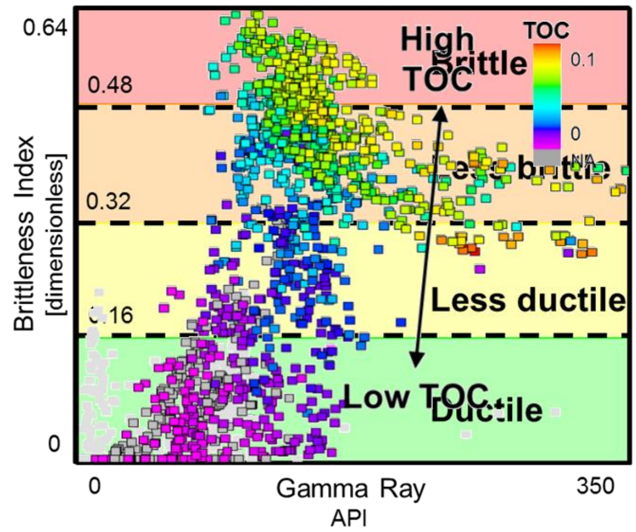

Figure 2.

Using the $\lambda\rho - \mu\rho$ template for the three most common minerals in the area of study as a reference, the $\lambda\rho - \mu\rho$ well log results were crossplotted and color coded by the GR values, resulting in high-GR regions (shale) and low-GR values (limestone). As discussed previously, high-TOC zones are depositionally related to high quartz content and to high BI. We will use the template in Figure 8c to predict BI from $\lambda\rho - \mu\rho$ estimates made from surface seismic data.

Figure 3 shows the $\lambda\rho - \mu\rho$ crossplot (a) color coded by GR, (b) color coded by TOC, (c) color coded by BI (extracted from mineralogy) overplotted by a proposed brittle/ductile classification, and (d) the proposed BI classification.

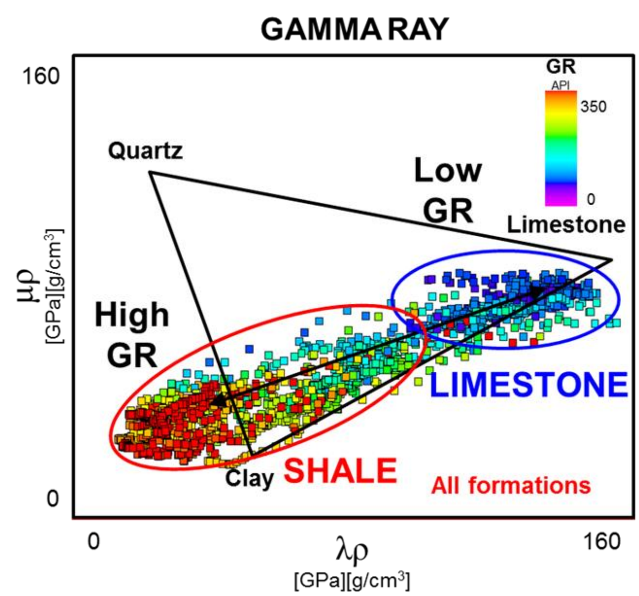

Figure 3.

Seismic inversion

In an isotropic, linear elastic medium, only two elastic constants (such as Lamé parameters λ and μ) are necessary to completely specify the stress-strain relation. Calibrated by mineralogy logs, these elastic parameters can be used empirically to predict whether a reservoir will deform plastically (for a “ductile” rock) or cataclastically (for a “brittle” rock).

Lamé’s incompressibility parameter λ relates uniaxial and lateral strain to uniaxial stress. The λ is primarily a longitudinal measure and hence orthogonal” to Lamé’s rigidity parameter μ a quantity that relates shearing stress to strain. Dipole sonic coupled with P-wave sonic and density logs provide a direct measure of Lamé’s parameters λ and μ.

Figures 4 and 5 show a representative vertical slice (north–south) through $\lambda\rho$ and $\mu\rho$ seismic volumes shows the difference between shale and limestone formations. Limestone formations exhibit a higher $\lambda\rho$ (related to incompressibility) and $\mu\rho$ (related to rigidity) than the shale formations, which show low $\lambda\rho$ and low $\mu\rho$.

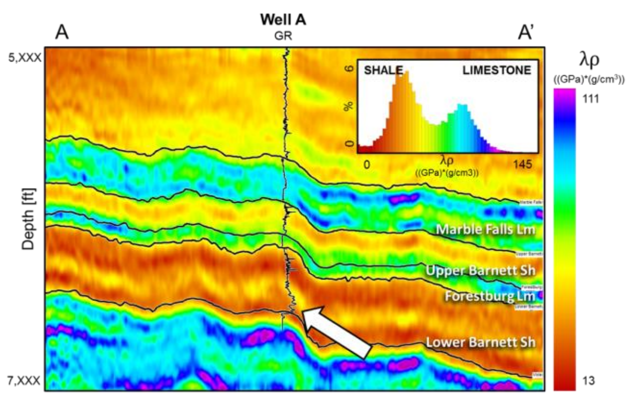

Figure 4.

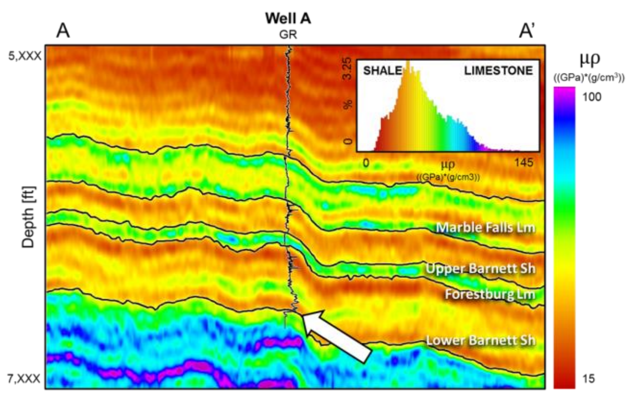

Figure 5.

Figure 6a and 6b shows representative slices (east–west) through $\lambda\rho$ and $\mu\rho$ seismic volume, respectively. Figure 6c shows the same vertical slice through crossplotted λρ versus $\mu\rho$ seismic volumes using the 2D color bar as shown in Figure 6d.

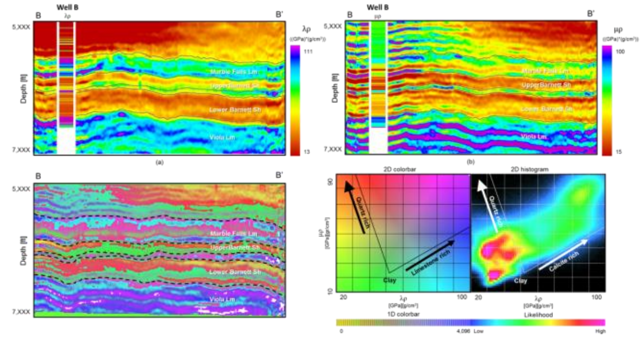

Figure 6.

Then, isolating the $\lambda\rho$ and $\mu\rho$ values corresponding to the Lower Barnett Shale section and generate a specific 2D color bar and histogram. This clipped color bar is used to display four stratal slices corresponding to different layers in the Lower Barnett (Figure 7). Clipping the color bar enhances the horizontal and vertical mineralogy variation of the formation. In the upper section of stratal slice A exhibits a higher quartz content than in the south, and at the same time, slice D exhibits a higher limestone content because it is close to the Viola Limestone.

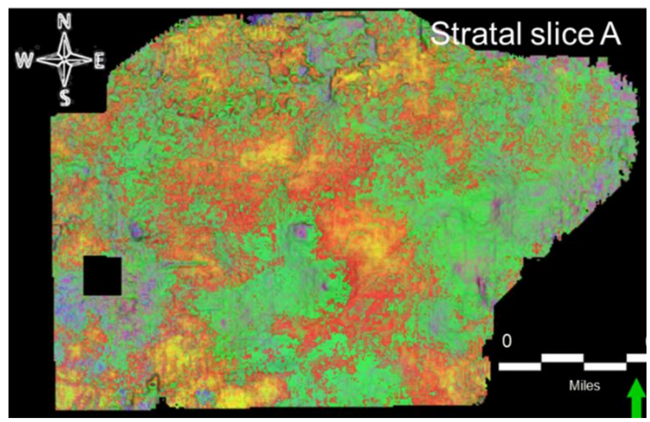

Figure 7.

Microseismic event analysis

Microseismic monitoring techniques are based on the same principles as earthquake seismology. A complete analysis includes the detection, location, and estimation of magnitude and moments of the microearthquakes induced by hydraulic fracturing and reservoir depletion processes (Warpinski et al., 2005). Microseismic data can be used to evaluate effectiveness of completion designs and map the development of fracture patterns in the reservoir.

During the hydraulic fracturing process, water and any other injected materials (usually sand) are pumped into the wellbore and into the formation through holes that have been perforated through the well-bore casing. The water and other injectables squeeze into the available spaces in the rock until the rock fails. This failure state is reached quicker when the rock is considered brittle (commonly rocks with a high quartz content), resulting in a more effective hydraulic fracture job.

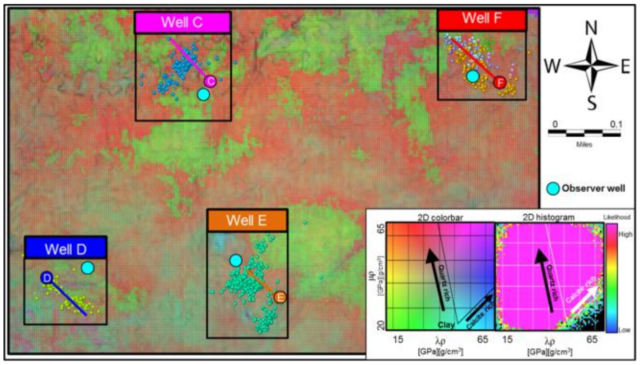

Figure 8.

Most the horizontal wells were drilled along a northwest–southeast azimuth to generate a northeast–southwest-trending fracture pattern, using a different number of stages in each well. Figure 8 shows the direction of four horizontal wells with their microseismic events color coded by stage number. In general, microseismic data show that most of the area around the wellbore was stimulated. However, low activity around the toe of well C indicates that microseismic events are not distributed uniformly along the wellbore.

The majority of the advance in the unconventional reservoirs was heuristic and with low evidence about the specific mechanics that controls the geomechanical behavior of the reservoir. However, the following formulation is an evidence that the obtained results were correct since based on the criterion to initialize a fault we expect that the rocks with a higher quartz content will be more prone to fracture, compared with the calcite rich rocks.

$$S_2 = S_2 = \frac{\nu}{1-\nu} S_1.$$

CALCITE

$$S_2^{calcite} = \frac{0.32}{1-0.32} S_1 = 0.47 S_1$$

QUARTZ

$$S_2^{quartz} = \frac{0.1}{1-0.1} S_1 = 0.11 S_1$$

$$\boxed{p_{w,max}^{frac} = 3(S_3 - S_2) - p_{f0} + T_0}$$

Criterion to initialize a fracture

$$p_{w,max}^{frac-quartz} = 2(0.47 S_1) - p_{f0} + T_0.$$

$$\boxed{p_{w,max}^{frac-calcite} = 2(0.11 S_1) - p_{f0} + T_0}$$

Conclusions

Simultaneous inversion of surface seismic data not only differentiates shale from limestone but also brittle and ductile shale intervals. The change from brittle to ductile is transitional based on the mineralogy logs and calibrated with microseismic data.

In this specific case in the Barnett Shale, we are defining as brittle those rocks with high Poisson's ratio and ductile rocks with low Poisson's ratio which is contrary to the industry wide definitions for brittle and ductile rocks, which assume a low Poisson's ratio for brittle and high Poisson's ratio for ductile rocks because the calculated brittleness is based on the rock mineralogical content, and not on its geomechanical properties.

Acknowledgments

I would like to thank Devon Energy for providing the seismic and well data and for the financial support to complete this project.

References

Deacon, R. J., 2011, Barnett provides future returns: E&P Magazine, 7175, 71–75.

Jarvie, D. M., R. J. Hill, T. E. Ruble, and R. M. Pollastro, 2007, Unconventional shale gas systems: The Mississippian Barnett Shale of North-Central Texas as one model for thermogenic shale-gas assessment: AAPG Bulletin, 91, 475–499, doi: 10.1306/12190606068.Grieser and Bray, 2007;

Loucks, R. G., 2008, Origin and modification of Lower Ordovician Ellenburger Group paleokarst breccias and fractures in Central and West Texas, in I. D. Sasowsky, C. T. Feazel, J. E. Mylroie, A. N. Palmer, and M. V. Palmer, eds., Karst from recent to reservoirs: Karst Waters Institute, Special Publication, vol. 14, 130–135

Perez, R., 2009, Quantitative analysis of gamma ray parasequences in the Barnett Shale: M.S. thesis, ConocoPhillips School of Geology and Geophysics: The University of OklahomaRickman et al., 2008

Singh, P., 2008, Lithofacies and sequence stratigraphic framework of the Barnett Shale: Ph.D. dissertation, ConocoPhillips School of Geology and Geophysics: The University of Oklahoma.Walper, 1982

Wang, F. P., and J. F. W. Gale, 2009, Screening criteria for shale-gas systems: Gulf Coast Association of Geological Societies Transactions, 59, 779–793

Warpinski, N. R., R. C. Kramm, J. R. Heinze, and C. K. Waltman, 2005, Comparison of single- and dual-array microseismic mapping techniques in the Barnett Shale: Presented at SPE Annual Technical Conference and Exhibition, 95568