Seismic reservoir characterization in unconventional shale plays

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Summary

Surface seismic data has proven to be an invaluable asset for organizations producing hydrocarbons from unconventional resource plays. Initially, one of the primary benefits of surface seismic was the ability to locate and avoid drilling into zones with faults, fractures and karsting which adversely affected the ability to complete the well successfully. More recent advances in pre-stack seismic data analysis yield attributes that appear to be correlated to formation lithology, rock strength and stress fields. Knowledge and proper utilization of these attributes may prove valuable in the optimization of drilling and completion activities. In this article we show an integrated seismic approach based on pre-stack azimuthal seismic data analysis and well log information to identify "sweet spots", estimate geomechanical properties and in-situ principal stresses.

Properties such as Young's Modulus and Poisson's Ratio provide valuable information for facies identification, mineral content, and rock strength. From these, we may infer preferential drilling locations or "sweet spots". Additionally, analysis of differential horizontal stress may be calibrated to field observations yielding stress field predictions such as fracture initiation pressure and closure pressure which are valuable during the completion stage of the fracture stimulation process. The reliability of these estimates has been addressed by incorporating triaxial core measurements (Jaeger J et al., 2007; Warpinski, N. and Smith, M.,1989). Relative production estimates can be derived by combining geomechanical and stress properties by estimating porosity, volume of shale, carbonate content, and water saturation. The goal is to ultimately use these volumes in a predictive mode for proper well placement and completion practices.

Stress Analysis Methodology

Traditionally, isotropic pre-stack seismic data assists with valuable rock properties via detailed reservoir-oriented gather conditioning, followed by pre-stack seismic inversion and multi-attribute analysis. This analysis provides quantitative understanding of host rock geomechanical properties such as acoustic impedance, Poisson's Ratio, and Young's Modulus (Goodway, W. et al., 1997). These properties are in turn related to quantitative reservoir properties such as porosity, mineral and TOC content.

Understanding fracture behavior in shales requires azimuthal anisotropic analysis and interpretation. The preservation of azimuths from the processed seismic gathers through azimuthal velocity and AVO analysis, in combination with geomechanical properties derived from isotropic methods, can be used to predict in-situ stresses acting on shale reservoirs. Such stresses, when oriented, would yield oriented fracture patterns during well completion. Optimal completion fracture patterns would be non-oriented, so that a maximum volume of reservoir can be accessed from the fracture origin.

The relationship between stress and strain is controlled by the elastic properties of the rock and is given by Hooke's Law. Therefore, it represents the fundamentals of hydraulic fracturing, that is, the deformation and fracturing of rock is caused by stressing it with hydraulic pressure in the borehole. Gray et al. (2010) uses Linear Slip Theory following Iverson (2010) to estimate these properties from seismic data . Principal stresses are estimated by combining elastic rock properties derived from seismic inversion with azimuthal velocity and AVO analysis of conventional 3D seismic data (Gray 2011). An important parameter for prediction of hydraulic fractures, the Differential Horizontal Stress Ratio (DHSR), can be estimated solely from the seismic parameters, without any knowledge of the stress state of the reservoir. These estimated stresses should be calibrated to the stress state of the reservoir derived from drilling and completion data, microseismic analysis and regional information.

In the study area, optimal targets exhibit relatively high values of isotropic Young's Modulus (more brittle) and low differential horizontal stress ratio (no preferential orientation). Such zones are more prone to fracturing in a complex pattern leading to a greater stimulated volume and production (Rich and Ammerman, 2010). The optimal workflow is shown in Figure 1.

Haynesville Case Study

The Haynesville Shale is a black, organic-rich shale of Upper Jurassic age that underlies much of the Gulf Coast area of the United States. The Haynesville Formation overlies the Smackover Formation and is overlain by rocks of the Cotton Valley Group. Its economic viability has primarily been a result of advancement in horizontal well drilling and hydraulic fracturing technologies. Drilling and completion costs vary with an average well cost of about US$7.5 million. Average drilling time ranges from 35 to 50 days.

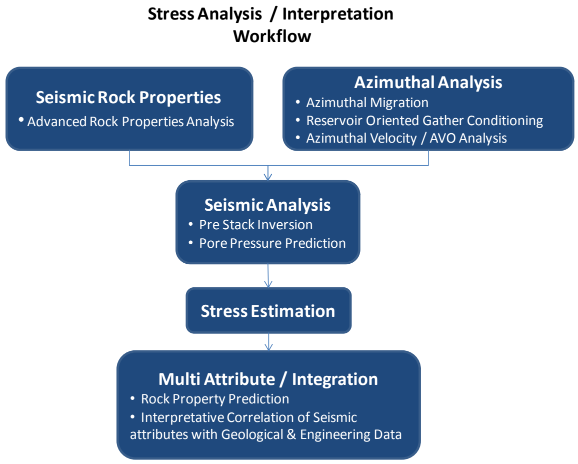

Figure 1: *Reservoir characterization workflow*

Using the workflow described in the previous section, we present the results from a Haynesville study in northwest Louisiana, USA (Figure 2). Potentially brittle zones have been identified based on elastic properties (Goodway et al., 2007) and their associated differential horizontal stress ratio, fracture initiation pressure and closure stress have been estimated. These findings are calibrated with existing production and well test data to determine optimal zones for drilling and completion.

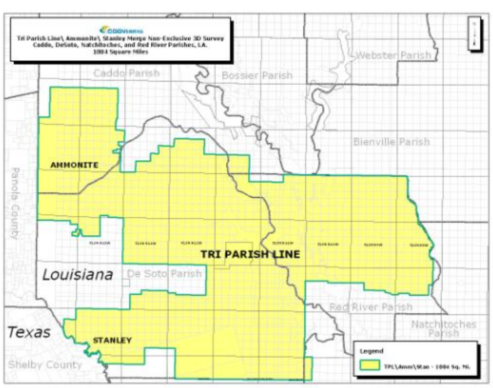

Figure 2. *Haynesville* ***s****eismic survey, NW Louisiana, USA.*

An elevated well-calibrated value of Young's Modulus is a key property to isolate brittle areas within the shale. However, interpretation of Young's Modulus alone is insufficient to identify optimum targets for hydraulic fracturing (Gray et al., 2010). It is also necessary to understand stress field distribution characterized by the DHSR. Areas that display both low differential horizontal stress ratios and elevated Young's Modulus values characterize ideal areas for hydraulic fracturing, as indicated in Figure 3.

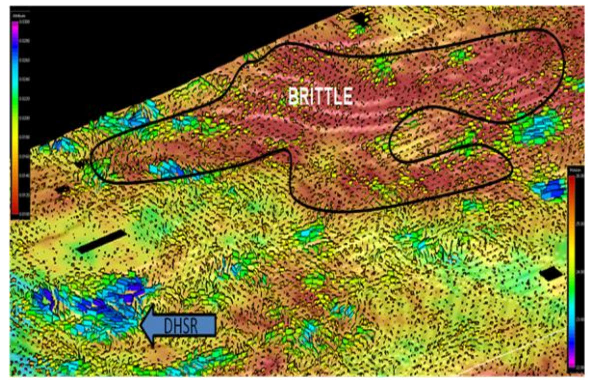

Figure 3. *Surface showing stress plates overlaying brittleness values for Haynesville shale. The color indicates brittleness. Plate orientation represents the direction of maximum horizontal stress. Plate magnitude represents the Differential Horizontal Stress Ratio (DHSR).*

Fractures will propagate without a preferential horizontal orientation in brittle areas such as those described above. Figure 4A displays a cross plot of these properties in the Haynesville within the study area. Figure 4B shows a map of the most probable optimal hydraulic fracturing zones in the lower Haynesville.

Analysis of the data suggests preferential development locations are found in areas that have a combination of certain key rock properties. Specifically, optimal well placement should target areas of better porosity development, high siliceous mineralogical content, and high values of TOC.

A detailed rock property analysis shows that properties such as Poisson's Ratio and Lambda-Rho (incompressibility) bring valuable information in identifying these areas. The bulk volume of gas can be estimated by combining these elastic properties via multi-attribute analysis (Figure 5).

Predictive models of fracture initiation pressure and closure stress add value in the development of well completion programs. Fracture initiation pressure is interpreted to be pressure above which injection of fluids will cause the rock formation to fracture hydraulically. Similarly, the closure stress is the pressure at which fractures will effectively close without proppant in place (Iverson, W., 1995). These parameters can be estimated via the stress formulation presented in the previous section. In Figure 6 we show a cross section of these stress related properties for a horizontal well in the

Haynesville. These properties must be calibrated to well measurements to increase their reliability.

4A.

4B.

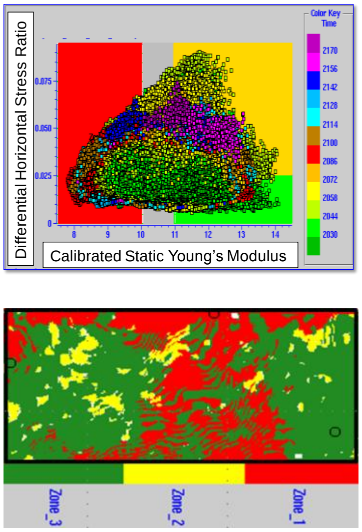

Figure 4. A. *Cross plot of calibrated static Young's Modulus against Differential Horizontal Stress Ratio, Haynesville shale: The green rectangle highlights the region where swarms of fractures will occur in a brittle environment, the yellow rectangle shows areas where aligned fractures will form and the red rectangle indicates the ductile areas.* ***B****. Map showing the color overlay from the zones in Figure 4A on the lower Haynesville.*

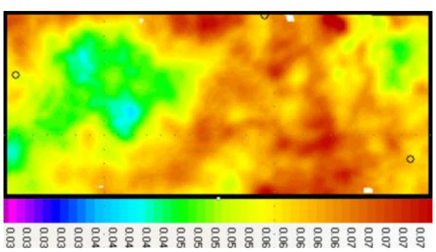

Figure 5. *Haynesville bulk volume gas estimated from total porosity and water saturation.*

From the several correlation methods applied in this study, we found that no single attribute provides enough information to correlate seismic data to production. By correlating multiple elastic and stress-related attributes to average production and horizontal well length at well locations, a predicted production map can be generated (Figure 7). The map show several undrilled areas with potentially high predicted productivity.

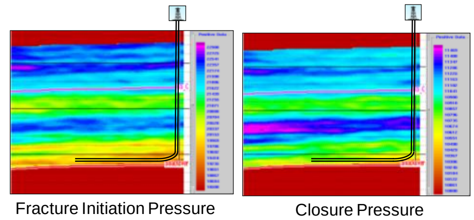

Figure 6. *Fracture Initiation Pressure (left) and Closure Pressure (right), in psi units, for a horizontal well in the Haynesville.*

7A.

7B.

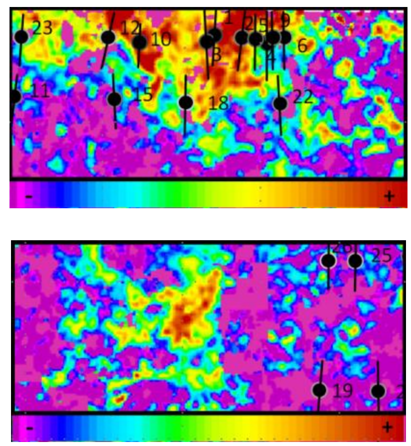

Figure 7. A*. Predicted average production calibrated to horizontal well length.* ***B.*** *Potentially high productivity areas that have yet to be drilled.*

Validation

Calibration and validation play a critical role in this study (Jaeger J. et al., 2007). A seismically derived prediction of the stress regime must be calibrated to core plug measurements. Figure 8 shows that the orientation of the maximum horizontal stress over the Haynesville area is regionally west to east. This agrees with historical fracture stimulation patterns with horizontal wells drilled in a north-south direction. However, the lateral variability of the direction of maximum horizontal stress, as indicated in Figure 3, shows that the local stress field is variable. The understanding of this variation is critical for optimal completions.

In order to validate the use of multi-azimuth seismic data to predict local stress environments, we compared the predicted local stress fields to triaxial measurements from core samples at two locations. The full strain tensor and the principal stress directions were measured from these core samples, which then served as baseline values to which seismic predictions were correlated. We found that the direction of maximum horizontal stress, predicted from seismic observations, matched within 5% of the corresponding core stress measurements.

Conclusions

We have presented an integrated seismic approach based on pre-stack azimuthal seismic data analysis and well log information to estimate geomechanical properties, predict in-situ principal stresses, and identify preferential drilling locations. Parameters such as Young's Modulus and Poisson's Ratio prove to be valuable for target discrimination.

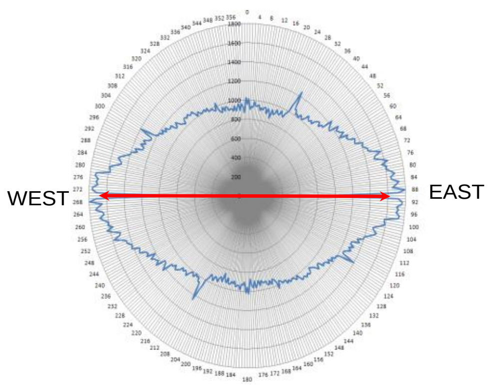

Figure 8. *Regional Haynesville validation: Orientation of the maximum horizontal stress across the entire study area.*

Stress related parameters such as Differential Horizontal Stress Ratio, fracture initiation pressure and closure pressure were also estimated. These parameters are critical at the completion stage of the fracture stimulation process. The reliability of these estimates has been addressed by calibrating to triaxial measurements from core samples. Additional calibration, however, is needed to increase confidence in the results of this study. Relative production estimates were also derived from combining geomechanical and stress properties to estimate porosity, shale and carbonate content, and water saturation.

The goal is to use these volumes to predict from seismic optimal well placement and completion strategy. The main benefits of this approach are:

- Better definition of reservoir drainage geometry
- Better well placement for field development
- Prediction of fracture behavior
- Grouping of reservoir intervals with similar stress profiles for optimal stage zoning in hydraulic fracture stimulation
- Avoidance of drilling hazards

With similar input data sets, the analysis and interpretation of shale production development can easily be extended to analogous environments with minimal modifications.

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