Integrating surface seismic, microseismic, rock properties and mineralogy in the Haynesville shale play

Gabino Castillo[1*], Simon Voisey[1], Kevin Chesser[1], Norbert van de Coevering[1], Antoine Bouziat[1], Guy Oliver[1], Chi Vinh Ly[1] and Lih Kuo[2] **illustrate a workflow integrating reservoir and geomechanical properties obtained from pre-stack seismic inversion and incorporating stress and fracture information extracted from azimuthal analysis of the seismic data.**

Although drilling has slowed substantially from its peak in 2010, steadily improving natural gas prices coupled with the promise of demand from liquefied natural gas and gas to liquids facilities have renewed interest in the prolific Haynesville shale gas play in NW Louisiana. A consensus of opinion among operators in the field will agree that only a fraction of the Haynesville potential has been developed to date.

As is the case in most shale plays, production from wells has been highly variable, leading to the use of 3D seismic reservoir characterization studies for the determination of sweet spots, well placement and completion strategies where seismic anisotropy has been proven to be an important factor in understanding the shale plays.

This paper illustrates a workflow (Figure 1) integrating reservoir and geomechanical properties obtained from pre-stack seismic inversion and incorporating stress and fracture information extracted from azimuthal analysis of the seismic data. Eight wells in the area targeting the Haynesville and Mid-Bossier reservoirs were used for calibration of surface seismic measurements of reservoir and geomechanical properties. A variety of seismically derived attributes are used to estimate production potential in the field. This paper shows the application of global azimuthal inversion, a technology for extracting the azimuthal anisotropy. Above all, the workflow makes quantitative use of microseismic and SEM (Scanning Electron Microscope) derived mineralogy data to validate the seismic-derived attributes.

Study area

The area of study (Figure 2) is located in northwest Louisiana. The Haynesville Formation is an organic-rich Upper Jurassic shale overlying the Smackover Formation and overlain by the Cotton Valley Group. The Haynesville is dominated by calcareous and micro-laminated, argillaceous mudstones. Organic-rich and siliceous lithofacies, which favour gas-recovery, contain both quartz and calcite in excess of 20–30%.

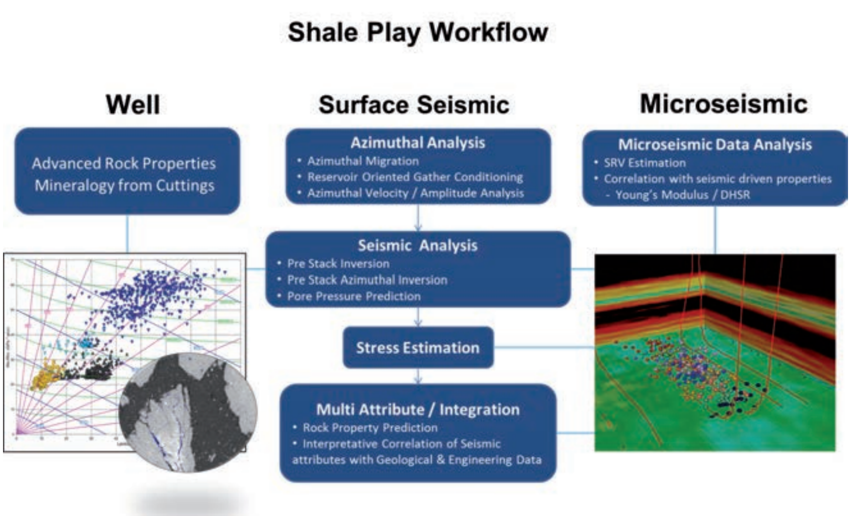

Figure 1 Integrated geoscience workflow for a shale play, incorporating numerous disciplines to high-grade the survey area to identify 'sweet spots' and optimize drilling locations and completions.

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Although the Mid-Bossier Formation proved successful in certain wells in the study area, the Lower Haynesville is the main target for shale gas production for this study. Geological structure in the area can be complex with numerous faults bisecting the study area. Generally, wells are positioned on the plateaus of the geological structures and between major faults. Laterals are generally oriented North-South perpendicular with the regional stress field.

Rock properties from seismic

Well log data provides calibration for all subsequent seismic analysis, including interpretation of elastic properties, HTI anisotropy and stress analysis. The study integrates eight wells targeting the Haynesville and Mid-Bossier reservoirs. Information from core (Figure 3), cuttings, and DFIT (Diagnostic Fracture Injection Test) analysis complements the well, surface, seismic and microseismic data.

Properties associated with gas-bearing rocks in the Haynesville and Mid-Bossier (free gas mingled with absorbed gas and TOC – Total Organic Carbon) are similar to those associated with free gas in conventional reservoirs, including correlation of increasing gas volume with decreasing Poisson's ratio and Lambda-Rho. In the target intervals, subtle contrasts attributed to gas are somewhat larger than those attributed to minor lithology variation, but smaller than contrasts observed between different zones marked by dramatic changes in lithology and porosity (Figure 3), such as the transition from lower Haynesville to Smackover.

In this study, pre-stack simultaneous inversion was applied to conditioned angle gathers to derive P-impedance, S-impedance and density. Commonly used descriptive reservoir attributes (i.e., mineral volumetrics, TOC, porosity, water saturation and lithofacies) were estimated with multi-linear regression prediction techniques. This analysis suggests P-impedance is mainly inversely related to porosity. Density and TOC also have an inverse relationship. Additionally, Lambda-Rho (product of Lamé's parameter and bulk density) appears to be directly related to Haynesville zones with high volumes of gas that are estimated from log data (Figure 4).

Figure 2 *Location of the study area, northwest Louisiana. Map and seismic data courtesy of CGG Land Multi-Client Data Library.*

Rocks with higher clay content have been demonstrated to be more ductile and difficult to frac. Zones with high quartz volumes are stiffer and more likely to fracture when under hydraulic stress. Mineral fractions of quartz, calcite and clay were used in conjunction with Young's modulus (the ability to maintain a fracture) and Poisson's ratio (the ability of the rock to resist failure under stress) to provide insight into how brittle or ductile the rock may be.

Petrophysically-derived lithofacies were created and applied to each well in the study. A supervised Bayesian classification methodology was applied with well control to generate probability cubes of lithofacies. This analysis is based on Probability Distribution Functions (PDFs) associ-

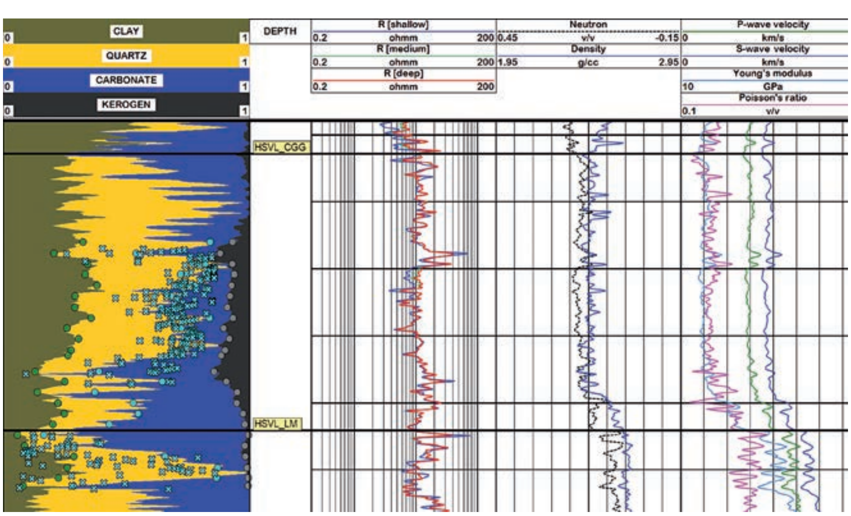

Figure 3 *Haynesville section with well log lithology fractions matched to up-scaled and normalized carbonate fraction / volume – mineralogy from cuttings (left track; cross shapes) and up-scaled XRD (X-ray diffraction) core data (left track; round shapes).*

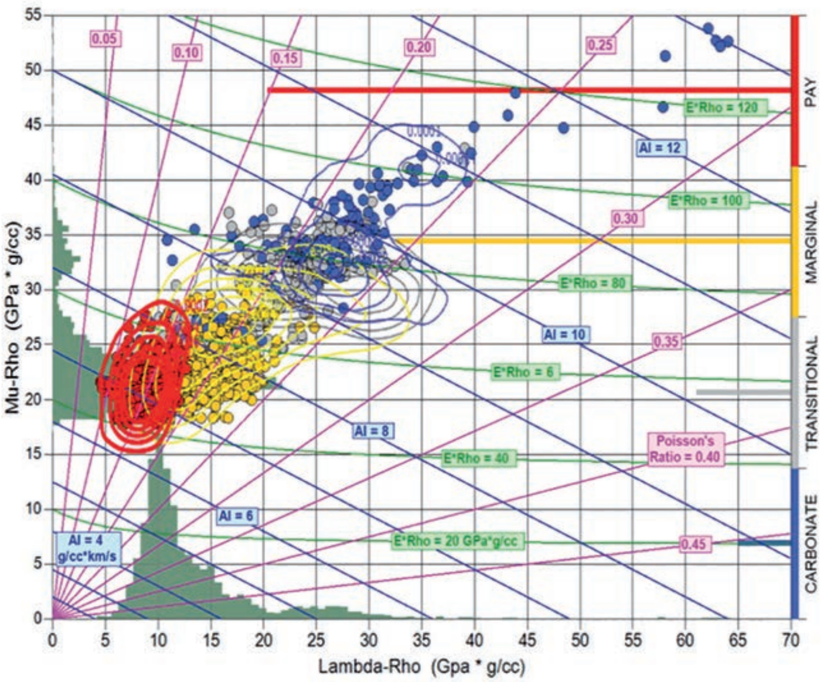

*Figure 4 Scatter of lithofacies data from multiple wells in the Haynesville. Red and yellow samples have < 30% total carbonate; red samples have > 70% gas saturation, while yellow samples have < 70% gas saturation. Blue points have > 40% carbonate by volume. Grey points, which do not fall into any of these classes, are transitional between lithofacies. The gas-rich (red) lithofacies is associated with high levels of TOC. Contours represent probability distribution functions for each lithofacies. Horizontal bar lengths give relative frequency of each lithofacies. Additionally, LRM crossplot space shows constant lines of acoustic impedance (AI = blue), Poisson's ratio (PR = magenta), and product of Young's modulus*density (ERho = green).*

ated with classes of pay (red), marginal gas-bearing zones (yellow), transitional 'shoulder' facies (grey), and carbonate (cyan) (Figure 4). The resulting seismic volumes of most probable lithofacies (Figure 5a) and probability of each lithofacies class (Figure 5b) provided encouraging results for mapping. Indicative attributes in the identification of sweet spots could be compared directly and analyzed based on probabilities.

Azimuthal inversion – stress estimation from seismic

In-situ stress, present in the earth prior to drilling, affects propagation of induced fractures and the long-term productivity of wells. Therefore, understanding the stress regime in the subsurface is important when planning the orientation of laterals. Further inspection of the seismic gathers will illuminate the amount of HTI anisotropy in the data and Azimuthal AVO and Azimuthal elastic inversion (Castillo and Van de Coevering, 2013) techniques will give insights into in-situ stress and fracture parameters in the area.

In this study, the stress state was estimated by employing a global inversion of pre-stack 'azimuthal' seismic data using Fourier Coefficients (Downton and Roure, 2010) to derive fracture properties and eventually local in-situ stress fields. Figure 6 shows the resulting azimuthal anisotropy plates generated from attribute volumes; (i) direction and (ii) height plus colour. Direction, in this example, is the isotropy plane (orthogonal to symmetry axis) while height and colour represent the magnitude of Differential Horizontal Stress Ratio (DHSR), calculated using azimuthal inversion. DHSR gives information about fracture orientation and style. The data slice (colour of base horizon) is Young's modulus (approximates the ability to maintain a fracture).

Minimum (σh) and maximum (σH) horizontal stress can be viewed and interpreted independently; σh, or closure stress, represents the minimum amount of stress required to maintain open fractures. DHSR is the normalized difference between σh and σH and is an indicator of the stress regime.

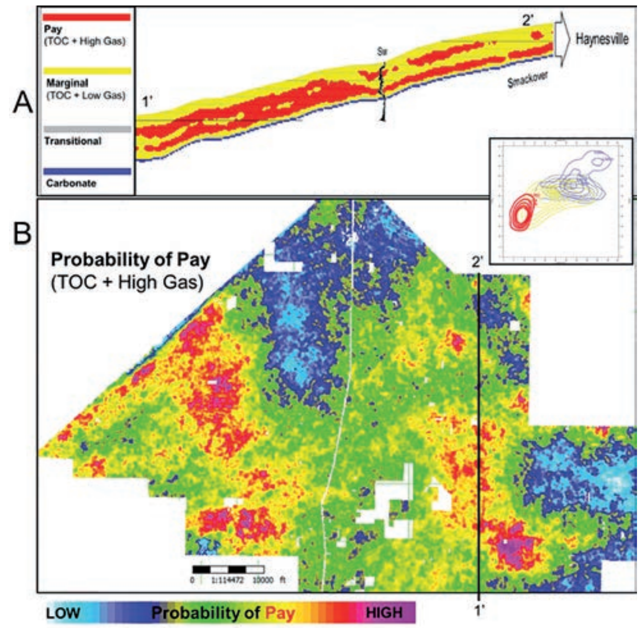

Figure 5 a) Most Probable Lithofacies Section and b) Pay Probability Map at Lower Haynesville level based on Lambda-Rho vs. Mu-Rho (LMR) crossplot. The PDF's which are applied to inverted seismic volumes honour the distribution of well log data in the LMR crossplot space (Figure 4).

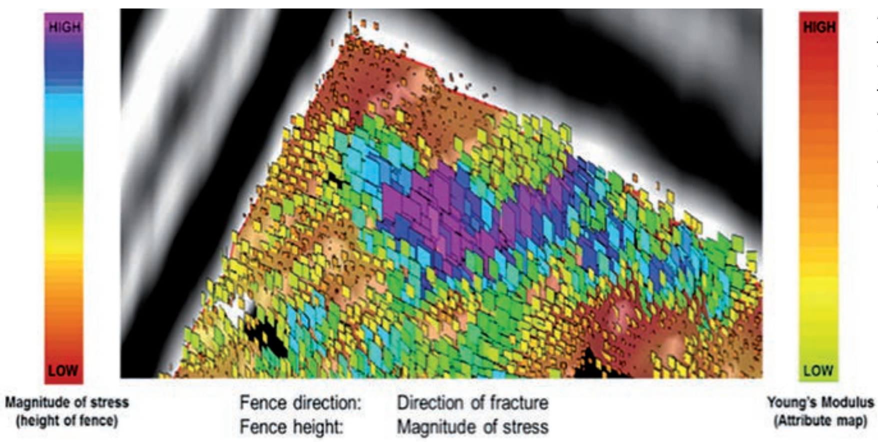

***Figure 6** Azimuthal Inversion results – surface showing DHSR overlaying Young's Modulus (ability to maintain the fractures) for the Haynesville shale. The background colour indicates Young's modulus. Plate orientation represents the direction of maximum horizontal stress. Plate height represents DHSR (derived from the azimuthal inversion). Seismic stack is also shown in density display (B&W).*

In the Haynesville it has been suggested that with respect to hydraulic fracturing, low DHSR favours fractures with random orientation, while high DHSR favours fractures that are more aligned (Sena et al., 2011). Therefore, in this example, low DHSR may be more desirable if natural, open fractures are absent, because the area stimulated (and hence production) can be maximized when the induced fracture pattern is more random.

Estimation of maximum vertical stress (σV) and σh is derived from pore pressure estimation using Eaton's equation (Eaton, 1975) modified for unconventional reservoirs. All elements of pore pressure prediction are verified by independent measurements which include DFIT tests and mud weights used while drilling. Additionally, σH is taken from tri-axial measurements of oriented core plugs. Conventional pore pressure methods assume low P-wave velocity in shale occurs whenever pore pressure is greater than hydrostatic pressure. Because high gas content and TOC can mimic pressure changes, this assumption was tested by running parallel calculations based on S-wave velocity and Mu-Rho. Where calibration data is available, P-wave velocity gives results closest to known pressures in the Mid-Bossier and Haynesville.

Mapping sweet spots

The previous mention of rock property attributes alluded to manipulation of pre-stack inversion volumes through regression techniques. Multi-attribute linear regression finds a relationship among attributes in multi-dimensional space leading to a 'best-fit' seismic volume of a given target attribute. Target attributes tend to be volumetric well logs, such as total porosity, mineralogy or water saturation. The process creates links between multiple seismic attributes and petrophysical data, in three dimensions (x, y, and time or depth).

In this study, multi-attribute linear regression was applied to generate a 2D map of productivity index or a 'sweet spot' map. The link is built between production data and maps extracted from the seismic attributes at the target level (Figure 7).

Multi-attribute analysis is statistically driven; the method has no prior information or biases regarding which attributes are 'best'. The optimal number of attributes and rank of each is determined during the analysis by validating the prediction at each production sample using the remaining control points. In our case, the closure stress has the highest correlation with the production index.

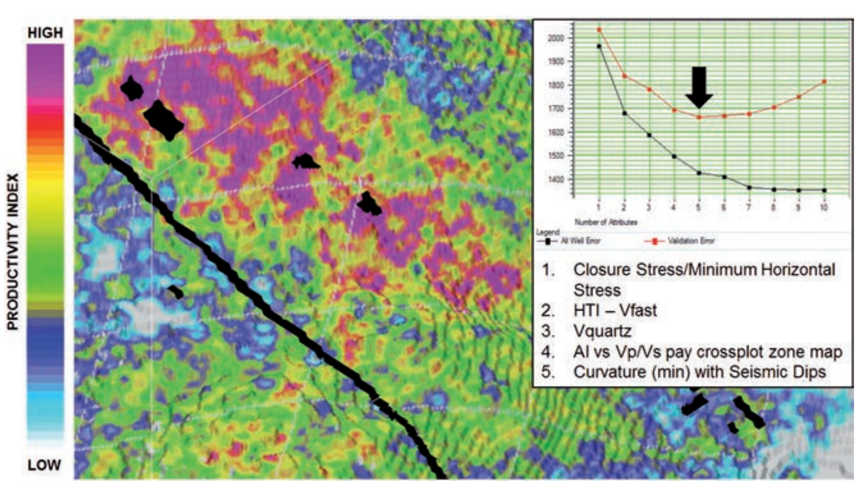

***Figure 7** Productivity Index. The result utilizes multi-attribute analysis to build a relationship between seismic attribute maps and production data from producing wells in the survey area. The graph shows that the 'validation error' (red curve) is minimized with the five attributes listed, ranked in order of contribution to the overall correlation.*

Integrating microseismic

As shown, elastic and geomechanical attributes derived from surface seismic reflection data have proven to be very useful in shale gas reservoir management by (1) delineating reservoir sweet spots where formation properties make the rock matrix more fracture-prone under hydraulic stimulation and (2) predicting reservoir stress anisotropy which may affect the orientation of hydraulic fractures. The impact of rock properties and spatial stress distribution on the success of hydraulic fracturing treatments may be evaluated by integrating data from hydraulically-induced microseismic events. Spatial correlation of microseismic events with specific seismic attributes implies that both are governed by the same in-situ properties of the rock.

The study reveals physically meaningful statistical correlations between microseismic event density with estimates of Young's modulus and DHSR from azimuthal analysis (Figures 8a and 8c). The size of the Stimulated Reservoir Volume (SRV) and Stimulated Reservoir Area (SRA, i.e., 2D SRV) is directly proportional to average Young's Modulus and inversely proportional to DHSR, implying SRV and SRA are maximized in areas of high Young's modulus and low differential horizontal stress.

Figure 8b shows SRA with Young's modulus (colour axis). The time-evolution of the SRA was also calculated to gain insight into the fracture growth process and to better understand the spatial and temporal correlation of microseismic events with the spatial distribution of seismic-derived rock properties. The seismic-to-microseismic correlation is enhanced by relating the calculated size of the SRA with seismic attributes spatially averaged over the computed SRA for each stage.

Integrating scanning electron microscope mineralogy

Macro-effects sensed by surface seismic and microseismic observations span a much broader area than the relatively small volumes of rock sensed by well logs, yet both are ultimately controlled by the rock fabric at scales beyond even the well log measurements. To access this scale, cuttings and core chippings were analyzed at high resolution (in both vertical and lateral wells) using a Scanning Electron Microscope (SEM) fitted with energy-dispersive X-ray detectors. This provides measured quantitative data on elemental and mineralogical composition, rock texture, porosity and pore aspect ratio (Ashton et al., 2013). The dataset complements older, but less extensive, X-ray diffraction (XRD) data. SEM data is consistent with XRD results for mineral fractions (such as 'total carbonate') and also match lithology estimates from conventional well logs (Figure 3).

Textural and mineralogical data are combined to produce a brittleness/ductility estimate as well as other indices useful for characterization of well completions.

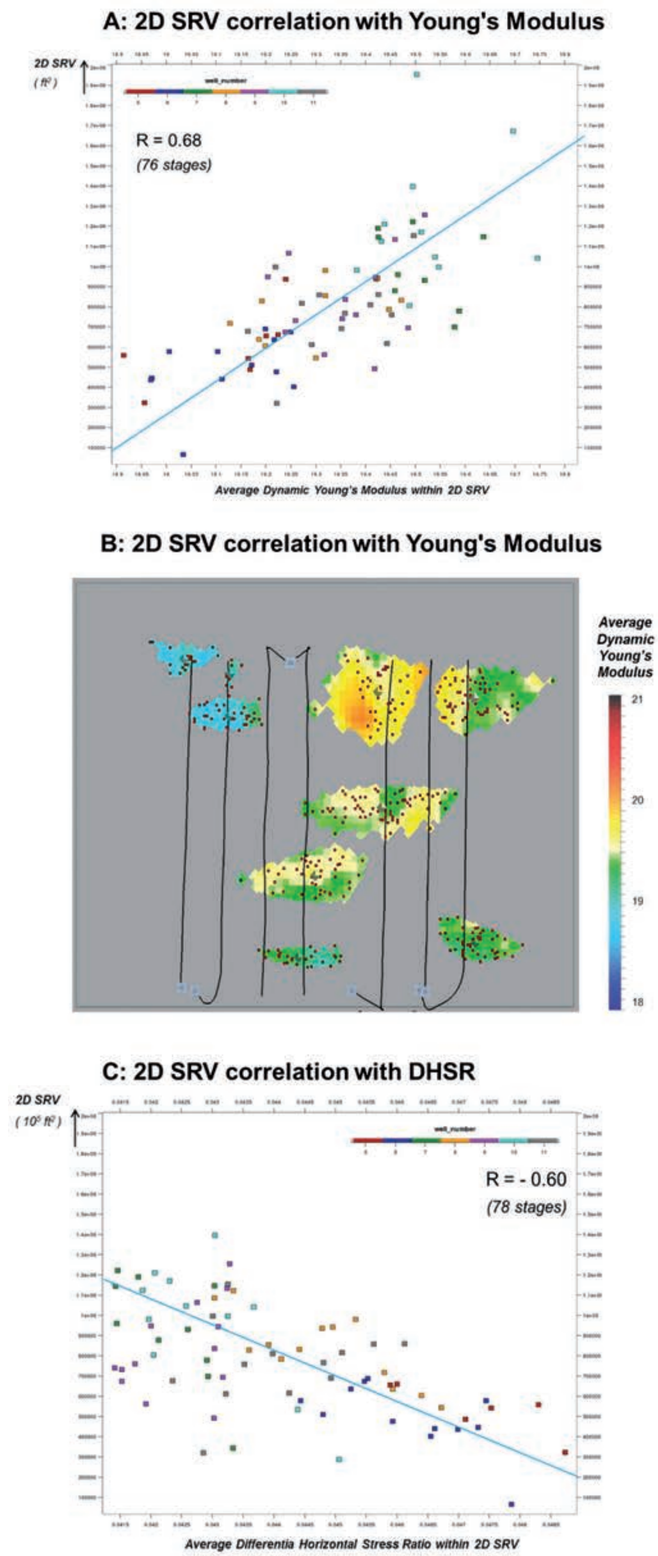

Figure 8 a) 2D SRV (SRA) correlation with Young's Modulus (positive slope), b) Map view. SRA associated with hydraulic fracturing stages, Young's Modulus is shown in colour inside the associated 2D SRV, black lines are the horizontal well paths, c) 2D SRV correlation with DHSR (negative slope). Note: 2D SRV (Stimulated Reservoir Volume) = SRA (Stimulated Reservoir Area).

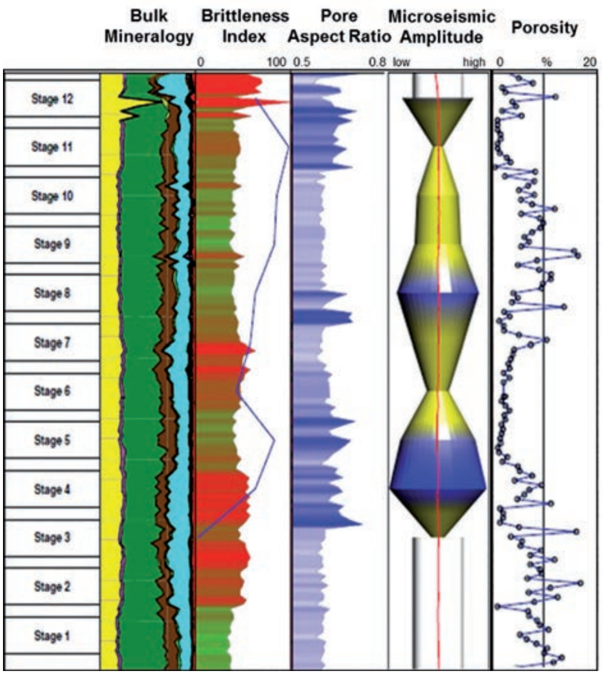

Figure 9 *Scanning Electron Microscope X-ray analysis of mineralogy from cuttings, brittleness index, pore aspect ratio and porosity, shown with amplitude of microseismic events and frac stages (stages 1 and 2 planned but not executed) in a lateral well. The displays show correlations among variables, as detailed in the text.*

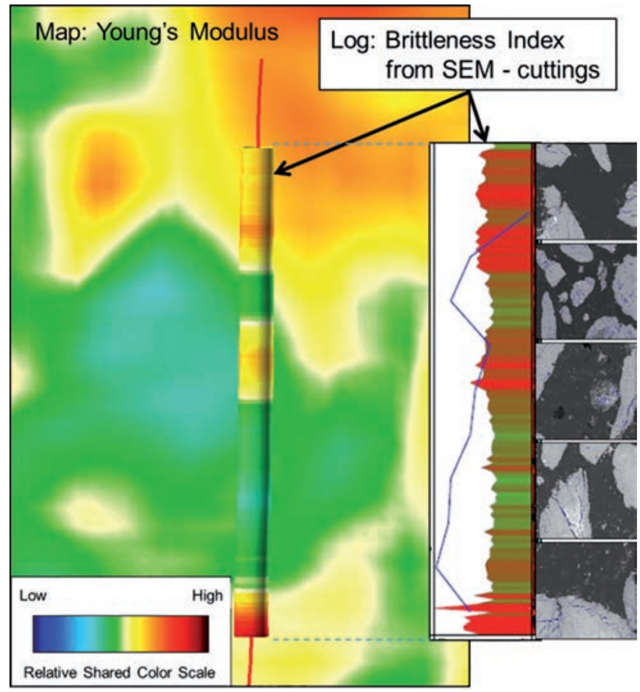

Figure 10 *Validation in a horizontal well. Correlation between dynamic Young's Modulus from seismic inversion (map view) and Brittleness Index from SEM data.*

Figure 9 shows several of these indices plotted with microseismic 'fracture amplitude' in the fourth track. Although qualitative, microseismic amplitude appears to be directly correlated with factors such as pore aspect ratio and number of pores larger than 200 microns. This is significant in that data shown in Figure 9 is collected from 172 cuttings samples from a horizontal well in which no conventional well logs or core data was acquired. The only other source of information about this particular lateral comes from pre-stack seismic inversion and azimuthal inversion analysis. Figure 10 suggests there is a strong correlation between the brittleness index from mineralogy/cuttings and the estimated Young's Modulus from pre-stack seismic inversion. The brittleness index log was not used in the inversion process for validation purposes.

Conclusion

In this paper, we discuss a workflow which integrates petrophysical well log analyses and seismically derived rock properties such as pore pressure and azimuthal stress-field analysis to produce maps and volumes of predicted pay. Geomechanical properties such as Young's Modulus provide estimates of relative brittleness/stiffness or ductility, which is important for completions and fracture stimulation designs. These estimates are clearly related to lithology, TOC, and rock texture.

The stress state is determined by the spatial distribution of elastic properties and strength properties, the structural framework and pore pressure, in addition to tectonic stresses acting in the subsurface. Observations of azimuthal variations of velocity and reflection coefficients were used to estimate the principal stresses.

To finalize the workflow, mineralogical and elemental data together with microseismic data have been integrated and used to validate the results of the seismically-derived properties. Interesting and perhaps significant correlations between the size of the stimulated area and key properties such as Young's modulus and DHSR exist. Low DHSR and high Young's Modulus, taken together, correlate with wide zones of microseismic activity. Low horizontal stresses and low stress bias represent one possible path to creating a wide network of induced fractures. However, a variety of combinations of stress state and existing fracture patterns allow the creation of a wide network (shear slip on pre-existing fractures). In addition, correlations between Young's modulus and brittleness/ductility estimate derived from cuttings-based mineralogy are apparent. This is important on long laterals where only limited well log data is available.

Technology is continually being enhanced to improve exploitation of shale plays, in part by quantitatively integrating and interpreting data from wells, surface seismic, and microseismic. Integration of disciplines and data types and sources (including at different scales) is a key element in efforts to improve drilling and completion strategies, by examining how these relate to well production. No single attribute by itself is conclusive; multi-attribute analysis is required to derive physically meaningful correlations.

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