# Seismic Attributes Characterize Shales

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and Satinder Chopra

CALGARY–Seismic characterization of shale reservoir formations is an important goal in developing unconventional resource plays across North America. Well logging carried out in shale formations yields some of the measured parameters necessary to understand their properties. Resistivity and velocity are two such parameters, indicating the presence of organic material or kerogen in these rocks. Porosity and brittleness are also key parameters in characterizing shale formations.

Unlike well logging techniques that are applicable in a vertical sense at well locations, the goal in shale plays usually is to characterize the formation laterally rather than vertically using surface seismic data. While it is challenging to extract resistivity information from seismic, it is feasible to extract velocity, porosity and brittleness information from seismic data using inversion processes. Different workflows have been adopted for characterizing shale formations using 3-D surface seismic data.

To more accurately characterize unconventional reservoirs using conventional tools, an integrated workflow has been developed and applied to characterize the Montney Shale to obtain brittleness as well as total organic content (TOC) information. The higher the TOC, generally the higher the potential for hydrocarbon generation. In addition, extended elastic impedance (EEI) inversion was implemented to compute a porosity volume.

The organic content as measured by TOC ratings influences the compressional and shear velocities as well as the density and anisotropy in shale formations. Consequently, it should be possible to detect changes in TOC from the surface seismic response. In conjunction with high TOC, high porosity is prerequisite for better reservoir quality. Therefore, the computation of porosity volume from seismic data would allow the lateral mapping of high-porosity pockets within the formation.

Brittle rocks fracture much better than ductile rocks for enhanced permeability, so shale reservoir rocks must exhibit high brittleness for optimum production. Such information can be extracted from the seismic data through Young's modulus and Poisson's ratio.

## Measuring TOC, Brittleness

Well log curve-based techniques for measuring TOC in shale gas formations use the porosity/resistivity overlay to locate hydrocarbon-bearing shale pockets. Usually, the sonic log is used as the porosity indicator. The transit time curve and the resistivity curves are scaled in such a way that the sonic curve lies on top of the resistivity curve over a large depth range, except for organic-rich intervals, where they would show crossover. The limitation is that this approach is applicable only at well locations, and does not map sweet spots laterally. For that purpose, seismic data are beneficial.

However, it is difficult to extract TOC information directly from seismic data. But the effect of its changes on compressional and shear velocities ($V_p$ and $V_s$), density and anisotropy allows it to be detected in the seismic response using different workflows.

The brittleness of a rock formation can be estimated from the computed Poisson's ratio and Young's modulus well log curves. This suggests a workflow for estimating brittleness from 3-D seismic data. For executing this workflow, simultaneous prestack inversion was used to facilitate estimating compression (P) impedance, shear (S) impedance and density attributes from prestack data. The process began with a low-frequency impedance model to generate synthetic traces using angle-dependent wavelets. These synthetic traces were compared with the equivalent real-angle traces, and the difference between them was minimized in a least-squares sense by iteratively perturbing the modeled impedance values.

Once the P- and S-impedance volumes are obtained, it is possible to compute Young's modulus and Poisson's ratio volumes that can be treated as brittleness indicators. Although density estimation from seismic data requires the far-offset information, its quality and fidelity can deteriorate significantly

**FIGURE 1**

**Integrated Workflow for Characterizing Unconventional Reservoirs Using Conventional Tools**

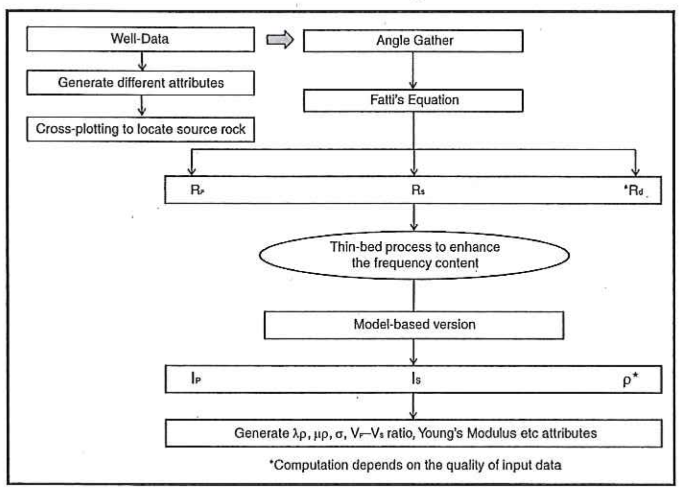
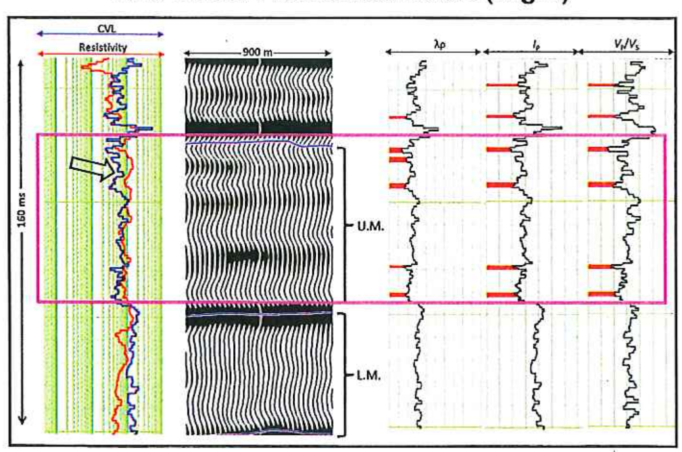



**FIGURE 2**

**Overlaid Resistivity and Sonic Curves (Left) And Cross-Plotted Attributes (Right)**



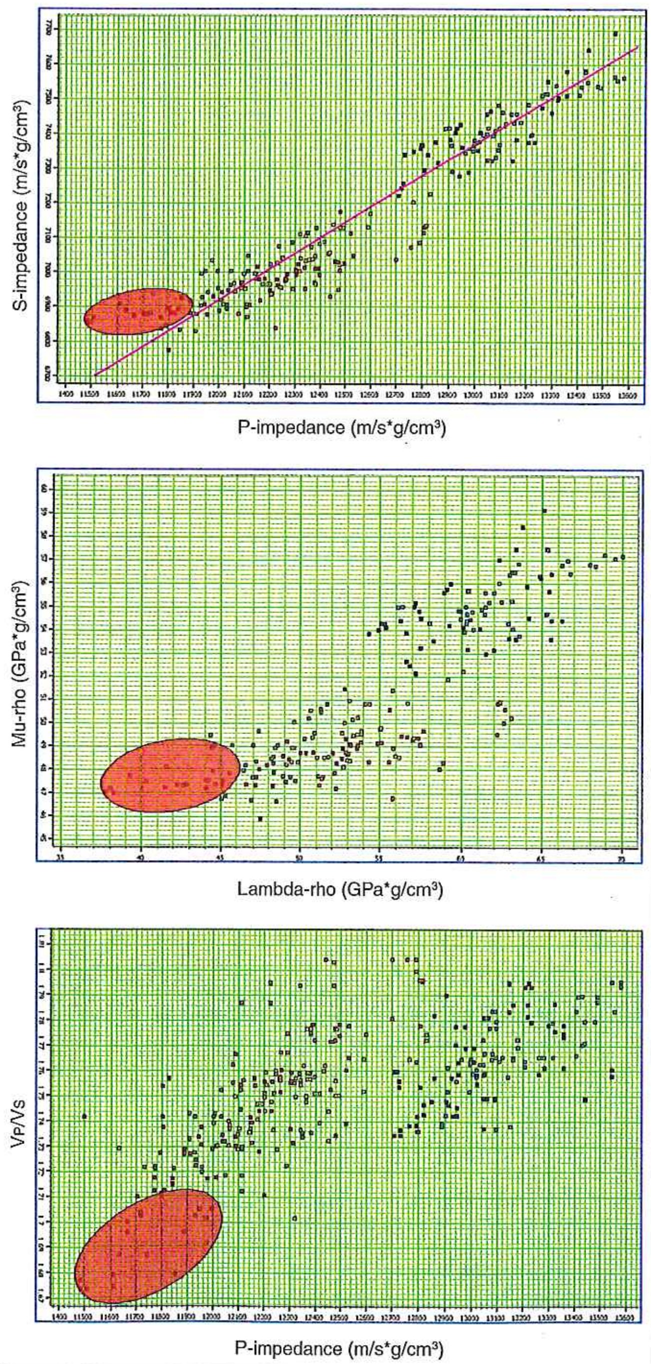
at large angles of incidence. Therefore, in the absence of density attribute, estimating Young's modulus is difficult.

### New Seismic Attribute

However, a new attribute (Eρ) can be used in such a scenario for obtaining brittleness information. The attribute is the product of Young's modulus (E) and density (ρ). Zones with high Young's modulus and low Poisson's ratio would be brittle and have better reservoir quality (higher TOC and higher porosity).

**FIGURE 3**

**$I_p$-$I_S$ (Top), λρ-μρ (Middle) And $I_p$-$V_p/V_S$ (Bottom) Attributes**




This workflow works well for high-quality data.

The proposed integrated workflow uses well data and seismic data to characterize hydrocarbon-bearing shales (Figure 1). First, different attributes are generated from the well log curves. Then, using the cross-plots of these attributes, the interpreter looks for hydrocarbon-bearing shale zones. Once this analysis is done at well locations, seismic data analysis is picked up for computing appropriate attributes. Seismically, prestack data are essentially the starting point. After generating angle gathers from the conditioned offset gathers, Fatti's equation is used to compute P-reflectivity, S-reflectivity, and density, which depends on the quality of input data as well as the presence of long offsets.

Because of the band-limited nature of acquired seismic data, any attribute extracted from it will be band-limited also and have a limited resolution. While shale formations may be thick, some high-TOC shale units may be thin. So it is desirable to enhance the resolution of the seismic data. An appropriate solution is thin-bed reflectivity inversion. Following this process, the wavelet effect is removed from the data and the output of the inversion process can be viewed as spectrally broadened seismic data and retrieved in the form of broadband reflectivity data that can be filtered back to any bandwidth. This usually represents useful information for interpretation purposes.

Thin-bed reflectivity serves to provide the reflection character that can be studied by convolving the reflectivity with a wavelet of a known frequency band pass. This not only provides an op-

**FIGURE 4**

**λρ Sections from Poisson's Ratio/Young's Modulus Curves (Top) And New Workflow (Bottom)Curves**

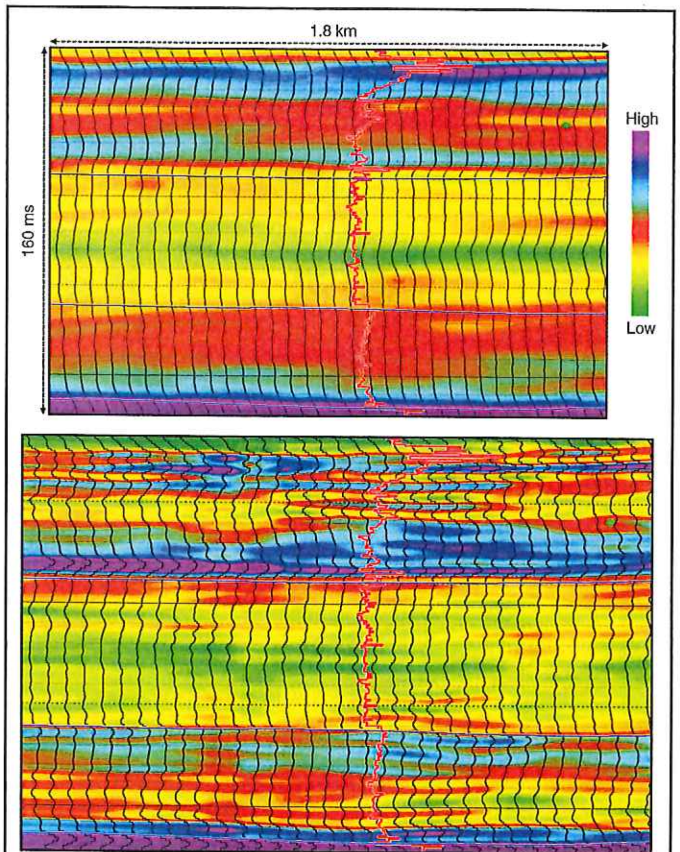


**FIGURE 5**

**Cross-Plots of Lambda-Rho and Mu-Rho Attributes**

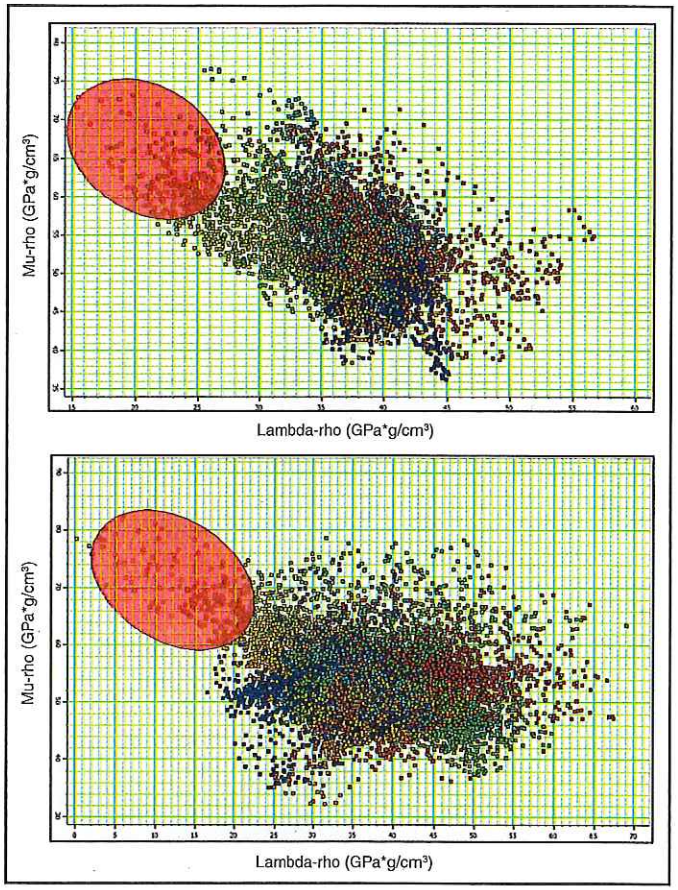
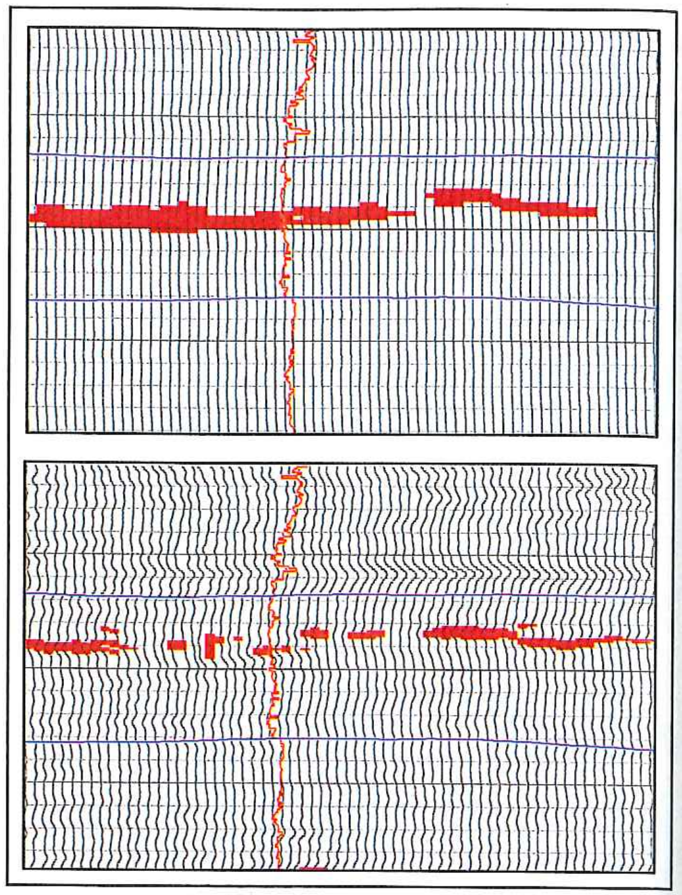



**FIGURE 6**

**Back Projections of Points in Red Polygons in Figure 5**



portunity to study reflection character associated with features of interest, but also serves to confirm its close match with the original data.

Furthermore, the filtered thin-bed reflectivity inversion is considered as the input for the model-based inversion to compute P-impedance, S-impedance and density. Once impedances are obtained, other relevant attributes can be computed, such as lambda-rho ($\lambda\rho$), mu-rho ($\mu\rho$) and P-wave velocity to S-wave velocity ($V_p/V_s$). These are used to measure the pore space properties and get information about the rock skeleton. Young's modulus can be treated as a brittleness indicators and Poisson's ratio as a TOC indicator.

Since the higher the porosity, the better the quality of a reservoir, porosity is one of the desirable properties for mapping sweet spots in shale formations. Generally, porosity information is extracted from the impedance inversion in an indirect way by considering that increases in porosity decreases the impedance. However, EEI inversion allows porosity to be determined directly from seismic data. By analyzing the calculated EEI log curves and the recorded porosity log curves, a high correlation between any pair of such curves yields an optimum angle that can be used to predict rock physics parameters from the seismic data.

### Case Study Example

The Montney formation characterization work began by overlaying the resistivity and sonic curves (left track of Figure 2). Identifying the cross-over between these curves in the Upper Montney, it was concluded that this interval was the potential reservoir rock. Since the resistivity volume could not be extracted from seismic, cross-plots of pairs of different relevant attributes was undertaken to characterize the formation. These attribute pairs included compressional and shear impedance ($I_P$-$I_S$), $\lambda\rho$-$\mu\rho$ and $I_P$-$V_P/V_S$ ratio (Figure 3). The points enclosed by the red polygons on the cross-plots show the characteristics of the hydrocarbon-bearing zone.

The back projection of the red polygons onto the log curves helps the interpreter understand where these points are coming from (right track of Figure 2). It was noticed that the anomalous points were coming from the Upper Montney, showing consistency with the interpretation of resistivity and sonic curves. Moreover, it showed that unconventional reservoirs could be characterized using conventional tools.

Irrespective of the workflow used for characterizing the shale play, estimating density is required to obtain the brittleness information since Young's modulus is a function of density. To determine whether density could be extracted from seismic data, angle information was overlaid on the conditioned gathers to define the maximum angle that could be considered in offset-to-angle domain conversion for the zone of interest. If the maximum acceptable angle was more than 45 degrees, density information likely could be extracted from the gathers. In this case, the maximum angle was 48-49 degrees, and the inverted density closely matched measured density at the well location, increasing confidence in using inverted density to compute

**FIGURE 7**

**Young's Modulus and Poisson's Ratio Cross-Plot (top) And Back Projections (Bottom)**

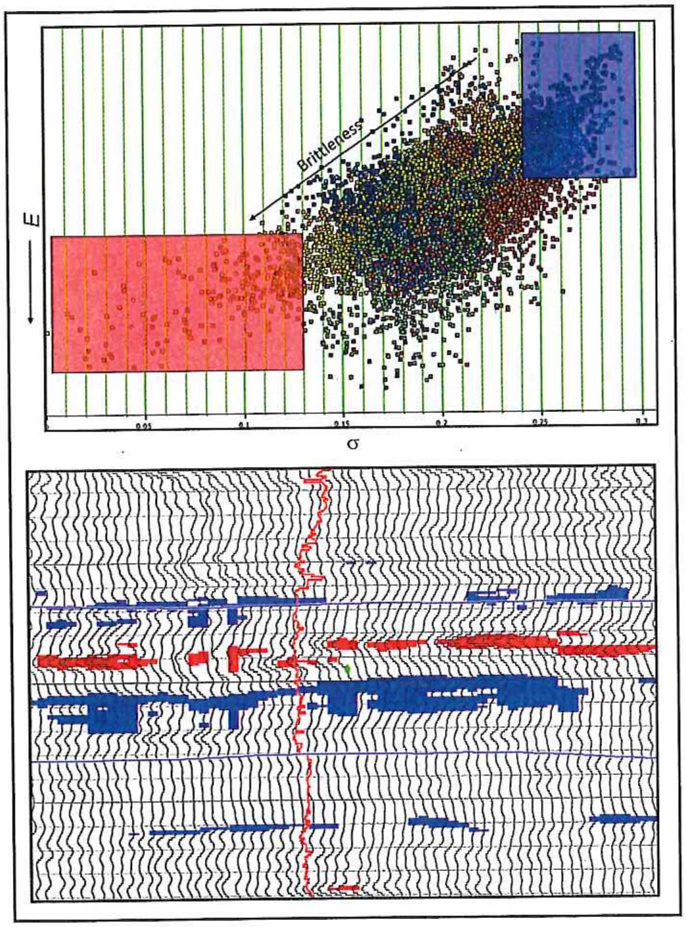
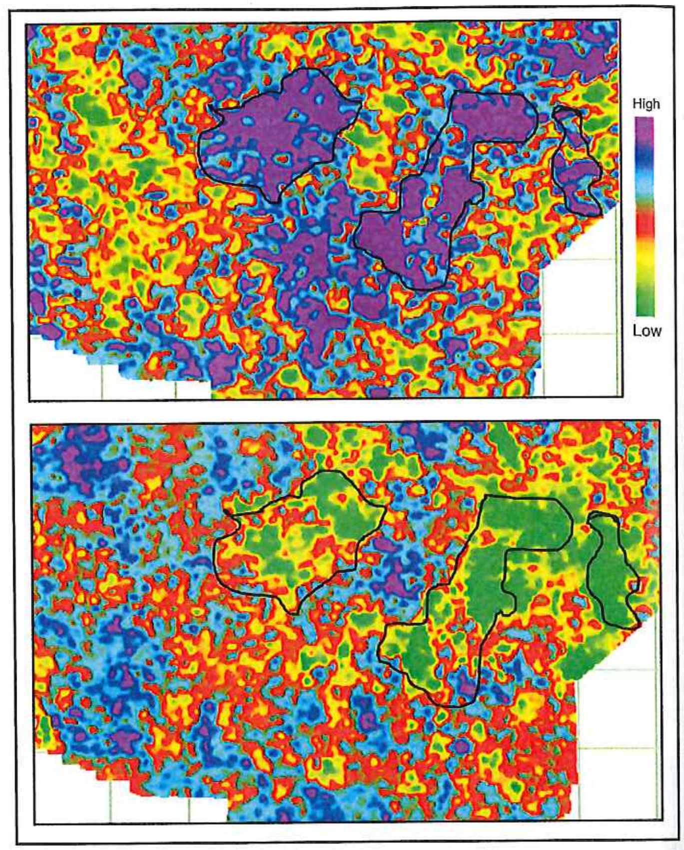



**FIGURE 8**

**Young's Modulus (Top) And Poisson's Ratio (Bottom) Horizon Slices**




Young's modulus.

Different attributes then were computed from the seismic data. The panel in the top of Figure 4 shows the $\lambda\rho$ section computed using estimates from the Poisson's ratio and Young's modulus well log curves, while the image at the bottom shows the same section computed using the new workflow. Note the higher resolution in the bottom image.

Figure 5 shows cross-plots of the $\lambda\rho$ and $\mu\rho$ attributes, with the image from the new workflow again shown on bottom. The red polygons highlight the points that have characteristics of hydrocarbon-bearing zones. These anomalous zones show greater separation in the bottom image. The back projections of the red polygons on the respective seismic sections in Figure 5 are shown in Figure 6. While a broad red paint-brush pattern is seen in the top image, more detailed information can be seen in the bottom image.

In the top image in Figure 7 is a cross-plot of Young's modulus and Poisson's ratio attributes, with brittleness increasing in the direction of the arrow. Ductile shale is expected to have low Young's modulus and high Poisson's ratio, while brittle shale shows the reverse behavior. The blue and red polygons correspond to ductile and brittle rock, respectively. The back projection of both polygons on the seismic section is shown in the bottom image. Hydrocarbon-bearing and brittle shale was noticed in the Upper Montney.

As shown in Figure 8, the next step was mapping the lateral extension of sweet spots using the horizon slices of Young's modulus (top) and Poisson's ratio (bottom) derived from the seismic data. Brittle and hydrocarbon-bearing shale was mapped by the black polygons.

Having the information of brittleness and TOC using different seismically derived attributes, extended elastic impedance was used to obtain porosity volume. This process began with a correlation analysis between EEI logs and available petrophysical porosity curves. Data from four wells were included in this analysis. Although all the wells showed a negative minimum over a range of angles from 2 to 18 degrees, two wells showed a maximum correlation of 92 percent at 18 degrees. This angle was used to compute an EEI log resembling the porosity curves at the well locations. A good correlation between the predicted porosity and the actual measured porosity curves lends confidence in the analysis.

Having optimal angle from well log analysis, seismic data corresponding to porosity was generated from intercept and gradient volumes. Considering this seismic as input data, model-based inversion was followed to obtain porosity volume. Furthermore, to map the sweet spots within the formation, horizon slices from Poisson's ratio, Young's modulus and porosity volumes were generated. Some pockets showed high Young's modulus and low Poisson's ratio, but not high porosity and vice versa. Therefore, it is always desirable to glean as much information from seismic attributes as possible to make the interpretation more robust. ☐

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