Certified organic - Including the effects of TOC in rock-physics modelling and classification of the Duvernay

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Summary

Rock-physics modelling is a useful tool to translate between geological and elastic properties. The elastic properties obtained from seismic inversion require such translations to assign geological meaning. Here we show that the complexities of the Duvernay, with variable mineralogy, porosity, TOC, and even fracture density, can be incorporated into rock-physics models. When applied to the elastic log data as calibration, the resulting classification closely matches the petrophysical curves and the application to seismic data shows valuable trends in the lithology distribution.

Introduction

The Duvernay Formation in Alberta exhibits vertical and lateral variability in mineralogy. On top of this mineral variability, the variations in total organic carbon (TOC) and the presence of fractures make reservoir characterization a complex, yet important, process. This study looks at an undeveloped area with minimal well control, making it difficult from well data alone to get a complete understanding of the link between elastic properties, obtainable from seismic data, and geological variability.

Rock-physics models, calibrated to petrophysical data, show the link between geological and elastic properties. Systematic changes are introduced into the models with the purpose of creating crossplot templates to guide reservoir characterization from elastic properties. This process is described in detail by Avseth et al. (2005).

Models were created investigating changes in porosity, mineralogy, and TOC content. These factors have a non-unique response in some elastic attributes but can be distinguished on others. A careful examination of the different properties is shown, and a classification scheme for reservoir characterization is presented and applied to log and seismic data.

Method

A rock-physics model calculates the elastic properties of a rock based on its constituent minerals, the architecture of the rock frame, its saturating fluids and the reservoir conditions under which they exist, and the combined response of each part. The data required for constructing these models came from reservoir monitoring data, core analysis, thin sections, and petrophysical logs.

The first step in creating a complex Duvernay model is to start with a simple model that can be calibrated to known data, typically log and core measurements. The composition of this calibration model was chosen to represent the best reservoir potential, that is, high quartz and low clay content, with mineral fractions obtained from XRD data and petrophysical calculations. Mineral moduli and densities were obtained from Mavko et al. (1998). Elastic properties of the fluid were determined using the Batzle and Wang (1992) equations, where the reservoir hydrocarbons were assumed to be in a single liquid phase with a high gas-oil ratio. The Duvernay is low porosity (4-12%) containing calcite cement (Figure 1). A cemented granular model (Dvorkin & Nur, 1996) was therefore used for the dry-frame properties of the model. The dry model was then taken to saturated conditions using Gassmann fluid substitution (Mavko et al., 1998).

The observed well data were used for calibration of the model after being filtered to the mineralogy ranges used. The log data suggest that 1.6% cement, when distributed around the grains, is most appropriate for the model. Both P- and S-wave velocities were used in the calibration, as well as points with porosity measurement from core analysis.

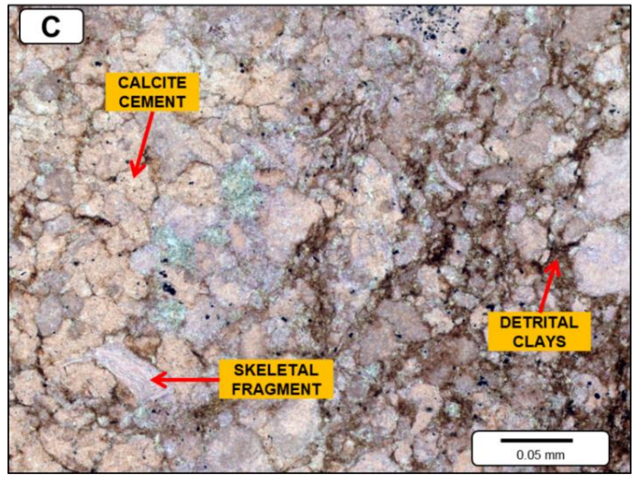

Figure 1. *Thin section photo showing the low-porosity, calcite-cemented, nature of the Duvernay. The calcite cement occupys the space between and surrounding the grains.*

The model used for calibration was then altered to allow for changes in the mineralogy, with variations in calcite (20-95%), quartz (0-50%), and clay (0-75%). Calcite and quartz were inversely related in log and XRD data and were therefore treated as dependant variables.

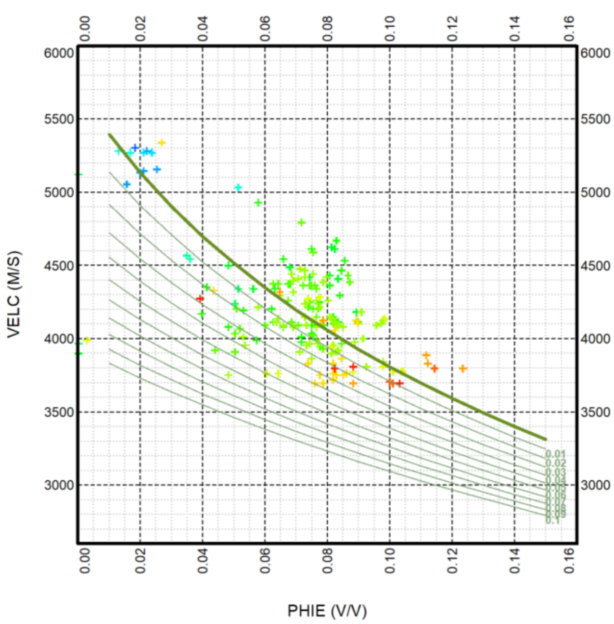

Figure 2. *The effects of TOC content on P-wave velocity compared to well data.*

While the mineralogy is important for determining the completions potential of the reservoir, TOC is significant to indicate the resource present. The method by which TOC is introduced into the model is significant for the final results. Models were compared that either include TOC as part of the matrix or to introduce it in the pore space using solid substitution (Ciz & Shapiro, 2007). Figure 2 shows a range of TOC fractions introduced into the calibration model using the preferred solid-substitution method.

The properties of the TOC were modelled using the methodology proposed by Zhao et al. (2016), who show the influence of kerogen maturity on its elastic properties, as well as the methodology for calculating the properties of the kerogen-fluid mixture. Vitrinite reflectance data indicates that the kerogen in this reservoir is mature. For mature kerogen, pores within the kerogen background are filled with the

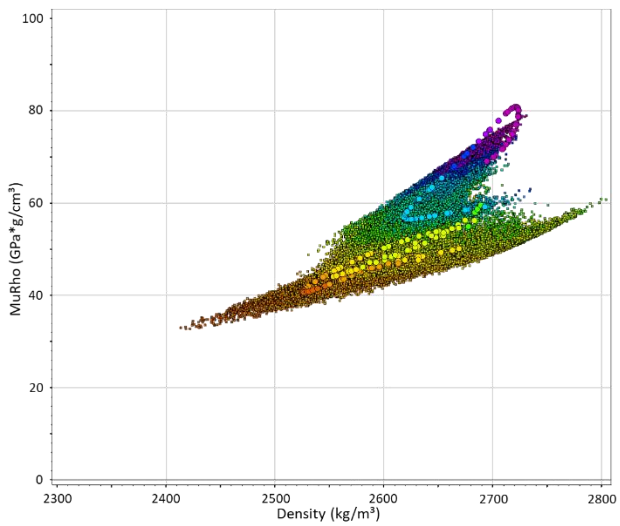

Figure 3. *A crossplot showing both the seismic points (small squares) and the filtered log data (large circles). The data are coincident and support the use of the rock-physics templates on seismic data.*

generated fluids. These fluid inclusions are introduced using a DEM approach. A TOC component of 3% was found to best match the range of lithology found in the data.

To check the validity of the interpretation potential, the rock-physics templates were applied to elastic well logs to predict variations in porosity and mineralogy. These predictions were compared to independent petrophysical measurements of these geological properties. The same interpretation scheme was then applied to inverted 3D seismic data. Seismic resolution is lower than that of the well data, and the range of interpreted properties is therefore expected to be smaller. Nevertheless, the two data sets cover the same space in the elastic crossplots, reinforcing the value of the templates for seismic interpretation. Figure 3 shows the well data, filtered to seismic frequencies, overlain on the seismic data.

Results

Seismic inversion has the ability to provide estimates of three independent parameters, often P-impedance, S-impedance, and density, or various transforms of these. Because of this, there is a limit of three independent geological attributes that can be interpreted from these elastic properties in a unique manner.

Density shows a strong response due to changes in porosity, while only having minimal influence from the mineralogy or TOC content. Conversely, an investigation of MuRho shows that lithology has a significant effect, while the porosity effects are only moderate. Figure 4 shows the first two crossplots of a classification scheme that takes advantage of these differences.

By using three elastic properties, or three dimensions, the Duvernay is subdivided by it’s reservoir potential. In the first crossplot, MuRho vs. density, the rock-physics template is used to isolate only the reservoir points above a given porosity threshold. These high-porosity data are then passed to a second crossplot of MuRho vs. LambdaRho. The rock-physics template here is based on mineralogy for a fixed high-porosity, and can be represented as combinations of clay and either quartz or calcite. This scheme is applied to the elastic well logs, and the match to independent petrophysical measurements is confirmed. Figure 5 shows the classification of the seismic data. Here, a slice through the reservoir is displayed showing the

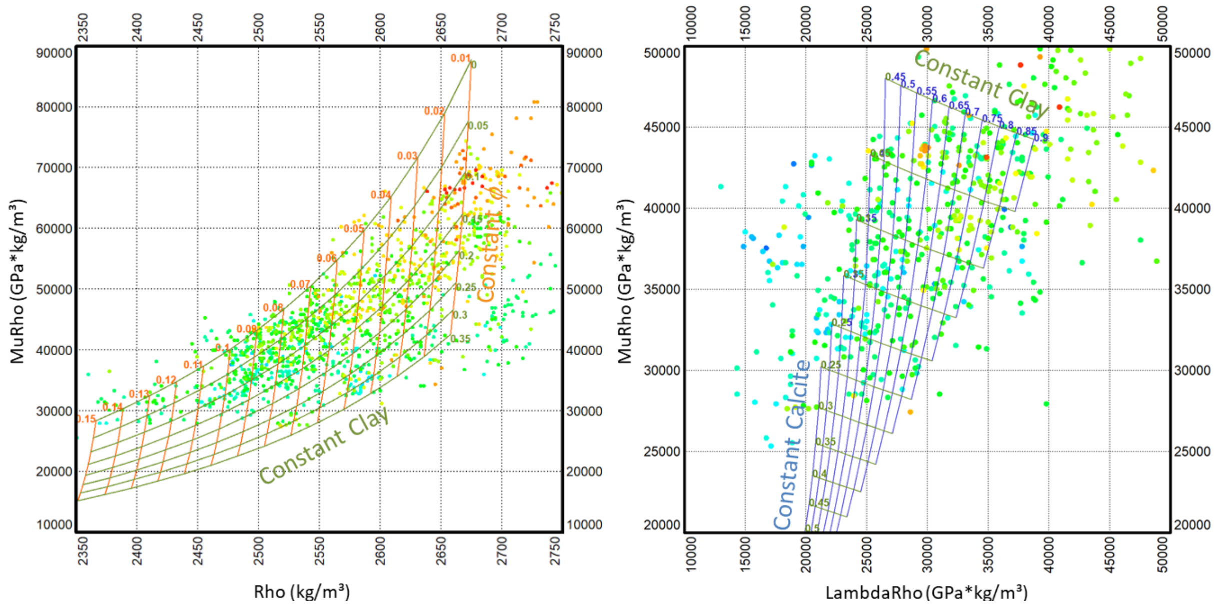

Figure 4. *A two crossplot scheme for identifying reservoir potential in the Duvernay. Three independent elastic properties are used, MuRho, LambdaRho, and density. The high-porosity points from the first crossplot are passed to the second crossplot for mineralogical classification.*

quartz content of the reservoir. This is consistent with the geological setting, in which a carbonate reef is present closest to the low-quartz (high-calcite) region of the seismic survey.

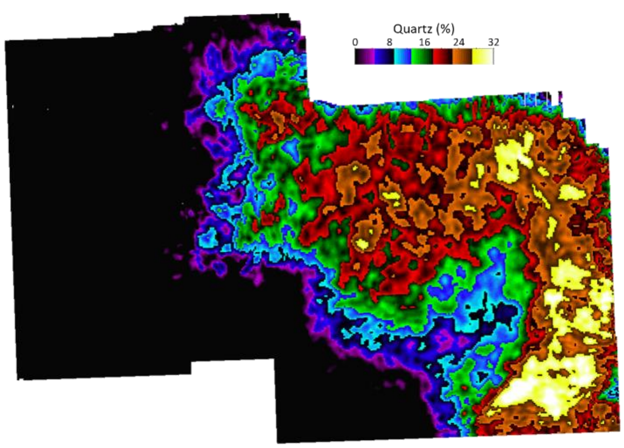

Figure 5. *A slice through the reservoir showing interpreted quartz content. The low quartz content (black) is consistent with the proximity to a carbonate reef.*

Conclusions

Reservoir characterization using seismic data needs a geological foundation for assigning meaning to elastic attributes. Rock-physics modelling is an ideal way to build this translation and works for the geological complexities of the Duvernay, incorporating changes in porosity, mineralogy, and TOC. The combination of rock-physics templates using multiple elastic properties shows a valuable scheme that can be applied to the equivalent seismic inversion results.

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