Modelling for interpreting the effects of thin beds on inverted elastic properties

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Summary

From a seismic perspective, thin beds are those which cannot be resolved by separate reflections with non-interfering amplitudes. Even in thick formations, the presence of alternating sand-shale layers or coal beds introduces thin-bed considerations between a well-defined top and base reflection. However, despite the inability of these layers to be imaged properly, there is still information to be found by backing out how thin layers have changed the bulk properties of the overall seismic response, specifically for the elastic properties obtained through AVO inversion.

I give examples from three scenarios where rock-physics modelling is used to extract useful reservoir information in the presence of thin beds: 1) A thin sandstone reservoir of variable thickness in a shale background; 2) Multiple sandstone reservoirs interbedded with shales layers; and 3) A thick sandstone reservoir with multiple thin coal layers.

Theory and Methodology

Rock-physics modelling (Avseth et al., 2005) is a powerful tool to determine the elastic properties of different rock compositions. Typically, a single model would be built to describe a specific combination of mineralogy, fluid content, and rock structure. This model would be representative of the elastic properties measured by seismic inversion for a well-resolved layer. Systematic changes to the model help interpret changes in the observed seismic properties.

The same changes modelled for thin beds do not represent the magnitude of change that would be observed by the seismic estimates. In these circumstances, the bulk properties resolved by the seismic observation will be affected by the thin beds, but not to the full extent. Figure 1 shows conceptually how thin layers are observed by seismic as an equivalent single thicker layer (Backus, 1962). Here we look at how the measurements from this equivalent layer may be interpreted to infer data about the reservoir layers of interest.

To accommodate the presence of thin beds of variable proportions in the rock-physics models, I use the methodology outlined by Avseth et al. (2009). In the three scenarios I show, the equivalent medium has non-reservoir component of fixed elastic properties (e.g. shale or coal) and a reservoir component with variable properties. The interpretive question that needs to be solved is: given an observed seismic response, what is the proportion of reservoir layers present, and what are their expected properties?

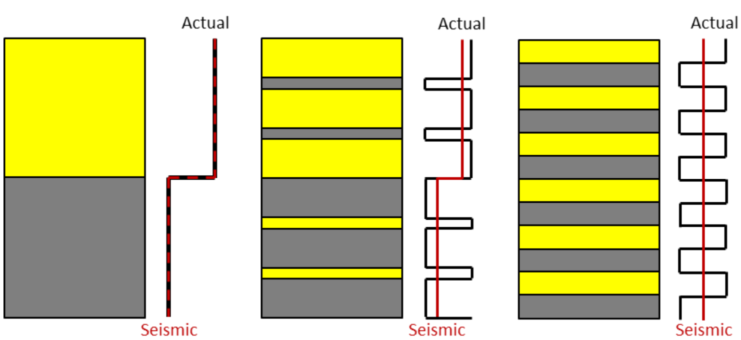

***Figure 1**. The observed elastic properties from seismic data match the properties of the individual layers when fully resolved (left). When thin layers, below seismic resolution, are introduced, the observed response is affected by a predictable amount (centre/right).*

The methodology first looks at rock-physics modelling of the reservoir component. This procedure follows the steps of: 1) log quality control and editing, 2) selection of log data for a specific lithology that is suitable for model calibration, 3) checking and refining model parameters through calibration with the log data, and 4) applying systematic variations to the models to cover the range of expected scenarios. The properties of the non-reservoir component are obtained from statistical analysis of the log response, or lacking reliable data, from rock-physics relationships. With the properties of both components available, the two are mixed at various net-to-gross (N:G) proportions from 0.0 - 1.0 using Backus averaging (Backus, 1962).

The resulting models can then be used to identify elastic properties that are significant for the interpretation goals, either classifying the inverted seismic or determining the feasibility of observing different conditions. For classification, a rock-physics template is formed by the models of different rock properties (e.g. porosity) of the thin reservoir layers and the N:G of the two layers.

Scenario 1 - Thin Reservoir in Background Shale

The first scenario occurs frequently, where the reservoir interval is below seismic resolution and is contained in a background of relatively homogeneous material. In both the examples shown, the sandstone reservoirs are found in a background with a much higher clay content.

The first example is from Colombia, where the reservoir thickness is around 10-15 m, but where the seismic data has resolution closer to 25 m. The log data show that immediately outside of the reservoir intervals, the background is relatively constant. The elastic properties of the background were obtained through log analysis, where the clay fraction was greater than 0.60.

The porosity of the sandstone was determined to be a key property, and was modelled for a range of values. The sandstone models were then combined with the properties of the background in proportions from 0.0 - 1.0. To test the appropriateness of the N:G model, the well logs were upscaled with a length of 25 m. The upscaled points, and the interpreted N:G and average porosity are shown with the rock-physics template in Figure 2. The petrophysical values of N:G and reservoir porosity are close to the interpreted results from the upscaled elastic properties.

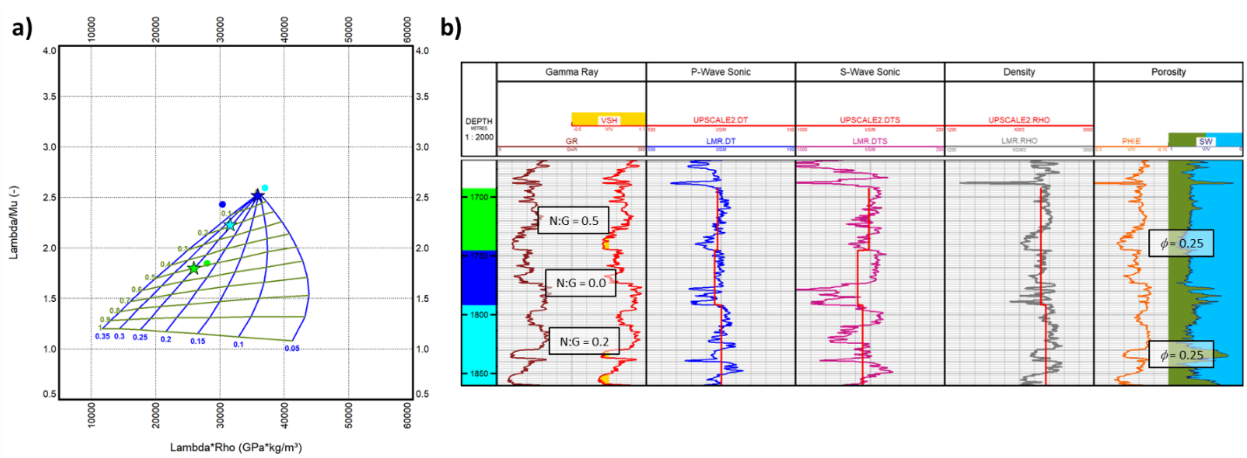

***Figure 2**. a) Rock-physics template with petrophysical values of N:G and porosity (stars) compared to the upscaled elastic properties (circles) showing close agreement. b) Log data showing petrophysical interpretations and upscaled elastic logs. The logs are upscaled into three zones.*

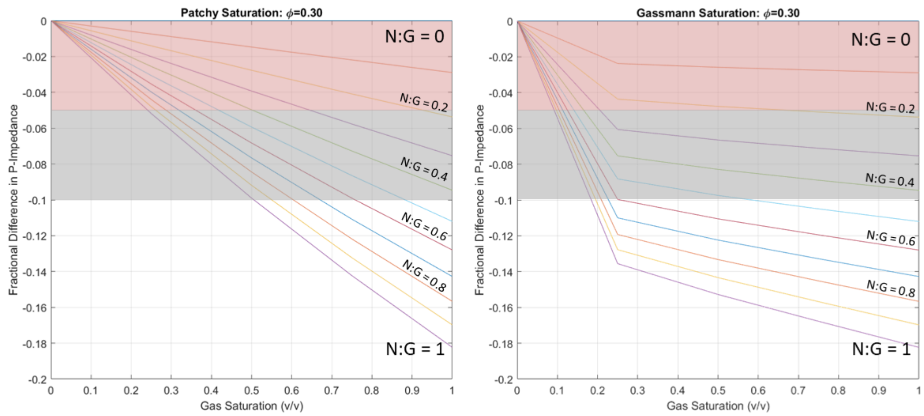

***Figure 3**. Difference in I_P from the wet case versus gas saturation. Each line corresponds to a different N:G, and the shaded areas indicate potential uncertainty in the inversion results.*

The second example for this scenario is from the Waarre sandstone reservoir in the Otway Basin, offshore Southeast Australia. In addition to determining the response of different reservoir thicknesses in the background lithology, it is important to know the degree of gas saturation that can be distinguished from brine saturation. This distinction is made more difficult by the potential for thin reservoir units (5 - 10 m) relative to the seismic resolution (15 - 20 m). In this case, the rock-physics modelling of the reservoir uses a fixed porosity, while various gas saturations were applied. The reservoir was combined with a uniform background, whose properties came from log analysis, and together were modelled for N:G values from 0.0 - 1.0 (Figure 3).

This analysis provides the feasibility of accurately interpreting the presence of gas from an AVO inversion. For the anticipated quality of the seismic, uncertainty in P-impedance (I_P) may be as high as ±10%. At these levels, a N:G of at least 0.5 is required to produce a significant I_P difference from the wet-reservoir case. Higher N:G allow for lower gas saturations to be detected.

Scenario 2 - Interbedded Sands and Shales

The second scenario considered is for stacked sandstone reservoir layers interbedded with shale intervals. The example shown is from the Doba Basin in Chad (Reine et al., 2016). The thickness of both lithologies varies both vertically and laterally, and the variability in their proportions makes accurate characterization important for field development.

The lithology does not show a continuous transition in mineralogy between sand and shale layers, but rather exists as a binary system of two rock types. The variation in sand properties is mainly limited to porosity variations. At bed thicknesses less than 10 m, the resolution of the seismic (~30 m) is insufficient to distinguish these layers uniquely.

Log analysis shows a large shift between the velocities and v_P:v_S values of sandstone versus shale intervals. The sandstone properties were modelled for a range of porosities, and the shale properties were taken from log data where V_{shale} = 1. Trends of both N:G and porosity are evident on crossplots of P-impedance versus v_P:v_S. These trends are roughly orthogonal, meaning that the two properties may be interpreted with some independence.

Here, the resulting rock-physics template was used to classify the inverted seismic data. Figure 4 shows the resulting classified volume, where the highest classified N:G is further subdivided by

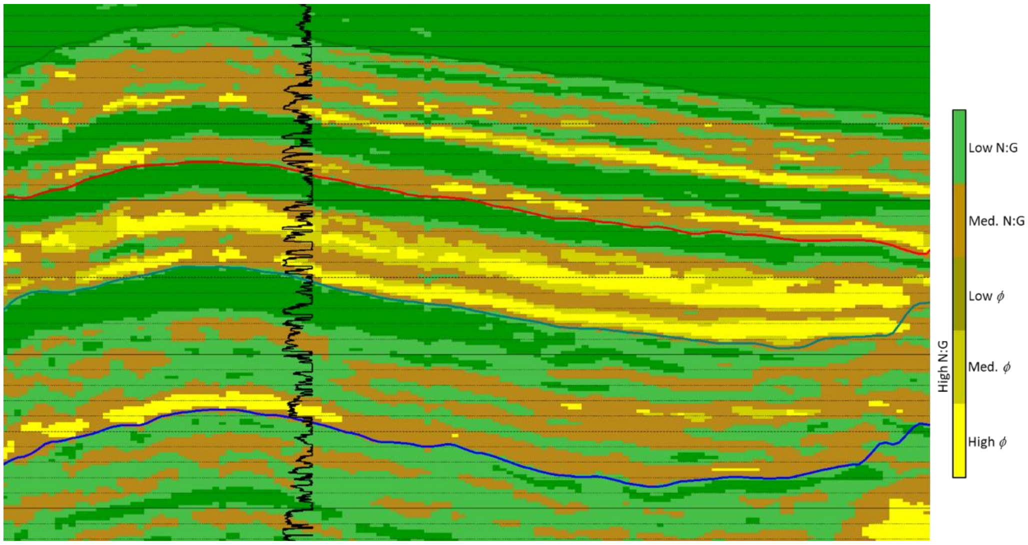

***Figure 4**. Seismic volume classified by N:G and porosity of reservoir sands. The V_{shale} log indicates an excellent agreement with the assigned classes.*

the porosity of the sandstone present. The N:G classification does an excellent job of matching with the V_{shale} log data.

Scenario 3 - Reservoir with Non-Prospective Layers

The final scenario investigated is for a thick reservoir that is well resolved by seismic data, but with thin non-prospective layers. In this situation, the reservoir itself is effectively the background; however, the principle is the same for combining the elastic properties of the two components.

The example for this scenario is for the Toolachee and Patchawarra sandstones in East-central Australia. The reservoir units can contain thin coal layers that reduce the viability of the reservoir when found in in large proportions. Rock-physics models were created for the sandstone at various porosities. The shear properties of the coals in this case were difficult to accurately identify directly from the log data due to their low values and the associated difficulties with log-data acquisition. Instead, elastic relationships for coal from lab data (Morcote et al., 2010) were used along with the measured P-wave velocities and densities.

Figure 5 shows a rock-physics template along with upscaled well data for two reservoir types: sandstone with abundant coal layers and sandstone with very limited coal layers. The separation of the elastic properties measured from the upscaled logs is consistent with the N:G division on the template, indicating that interpretation of the proportion of coals is feasible.

Conclusions

It is not uncommon for thin layers to be present in a formation, either as the reservoir itself, or as layers reducing the reservoir's effectiveness. Despite best efforts to boost frequency bandwidth of the data or the use of other inversion techniques, it is not always possible to directly measure properties from these thin layers. Nevertheless, the thin layers affect the measured seismic response, and through appropriate modelling, it is possible to understand these effects and infer information about the proportion and properties of these layers.

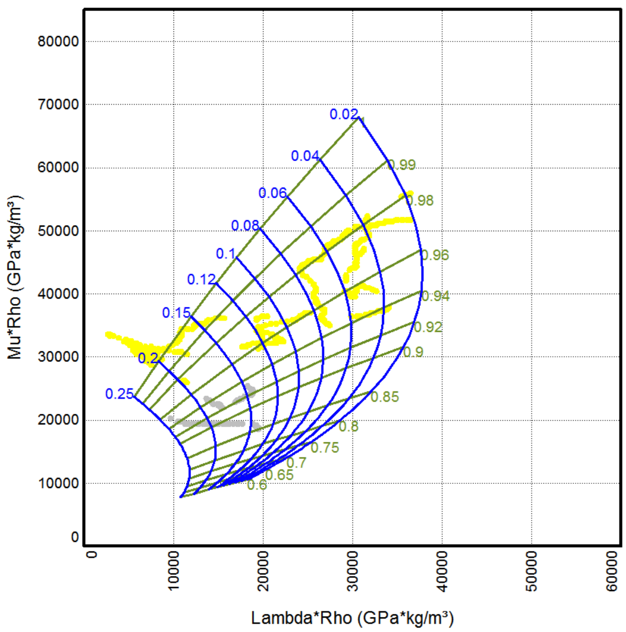

***Figure 5**. Rock-physics template for constant N:G and constant porosity along with upscaled log data. The log data in yellow has very few coal layers, while the data in grey has more. These proportions are consistent with the template lines of constant N:G (green).*

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