Gassmann's fluid substitution on thinly bedded sand-shale sequences offshore Angola

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Summary

The most common technique used for modeling and estimating the elastic properties of rocks under various fluid scenarios is Gassmann's method (Gassmann 1951). However there is always a risk of making a human error when applying this method, especially on heterogeneous media. One example for such media is a thinly bedded sand-shale sequence, in which laminations are often if not always ignored, especially in industry software. In this paper we will discuss three different fluid substitution approaches based on Gassmann's method performed on well log data from a deep water turbidite offshore Angola and how each of them yields a different outcome despite the fact that the underlying relationships are the same. They key message here highlights the significant difference we observed on the Gassmann fluid substitution results when sand-shale laminations are ignored compared to when they are properly handled.

Introduction

Gassmann's equation which relates the bulk modulus of a rock to its pore frame and fluid properties assumes a homogeneous mineral modulus and statistical isotropy of the pore space but free of assumptions about the pore geometry. Most importantly, it is valid only at sufficiently low frequencies such that the induced pore pressures are equilibrated throughout the pore space. Violating any of these basic assumptions will lead to errors in the fluid substitution results. One example of such violations is ignoring sand-shale laminations when applying the Gassmann method on a thinly bedded sand-shale sequence, which does not have a homogeneous mineral modulus and a statistical isotropy of its pore space. This means, applying the Gassmann fluid substitution method as a black box, without understanding its basic assumptions and limitations will definitely lead to erroneous results. Therefore the main objective of this paper is to discuss the workflow which should be followed when using Gassmann in thinly bedded sand–shale sequences presented by Dejtrakulwong and Mavko (2011). Well log data used for this fluid substitution study is from deepwater turbidites offshore Angola on which laminations (highlighted by the green color) seen in Figure 1 and in blue given a range of shale volumes as in Figure 2 using the Thomas-Stieber (1975) Analysis. Therefore we will concentrate only on those intervals of the well data. However, detailed analysis of this log data using the Thomas-Steiber and Yin-Marion Models can be found in Nasser 2011.

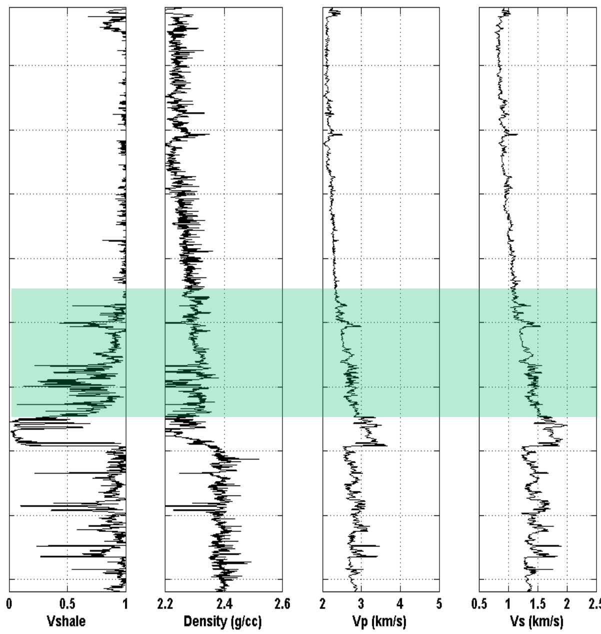

Figure 1. (a) From the left to the right: Vshale, density, Vp and Vs for Well 1.

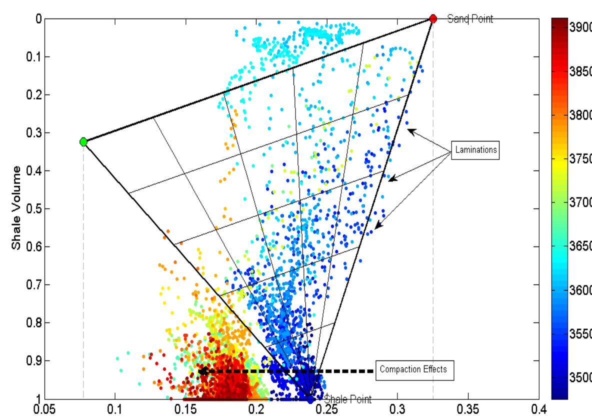

Figure 2. Shale volume against porosity cross-plot with the Thomas–Stieber model super-imposed on the data from well 1. Compaction effects is highlighted by the dashed line.

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First, we will discuss the application of the Gassmann fluid substitution method where laminations are ignored, followed by the case where they are properly handled and then compare the two.

Gassmann fluid substitution

Gassmann's equation relates the saturated bulk modulus of the rock (K_{sat}) to its porous frame properties and the properties of the pore-filling fluid:

$$K_{sat} = K_{dry} + \frac{\left(1 - \frac{K_{dry}}{K_o}\right)^2}{\frac{\phi}{K_{fl}} + \frac{(1-\phi)}{K_o} - \frac{K_{dry}}{{K_o}^2}} \tag{1}$$

where K_{sat} is the saturated rock bulk modulus, K_{fl} is the bulk modulus of the fluid that occupies the pore space, ϕ is porosity, K_o is the bulk modulus of the mineral matrix and K_{dry} is the bulk modulus of the dry porous frame. All of these four parameters can be computed from well log data or laboratory measurements on core samples. This equation is applied in two parts, whereby we first determine the dry frame bulk modulus followed by the calculation of the bulk modulus of the rock saturated with a fluid.

Fluid substitution while ignoring laminations

In this case we will discuss the impact of ignoring shale laminations on the fluid substitution results. We assume that the original fluid (K_{fl_1}) has been computed by harmonic average (Reuss) using the saturation data from the well logs assuming two fluid phases in the reservoir: water and oil. We then calculate K_{dry} from equation (1), and compute K_{sat_2} with K_{fl_2} as 100% brine or 90% oil assuming the rest is 10% brine. Figure 3 shows the result of applying the Gassmann fluid substitution method (equation 2) on thinly bedded sands and shales with laminations being ignored (i.e. treated as part of the rock frame). This clearly demonstrates that the implementation of this workflow creates significant differences in P-wave velocity observed for the laminated sand-shale interval highlighted by the red arrows a.1 and b.1 for Well 1 and Well 2 compared to the relatively clean sand interval a.2 and b.2 for Well 1 and Well 2. This is predominantly the case at high shale volumes and low porosities, in which the presence of clay minerals lowers the incompressibility of the mineral mix and as a result exaggerates the fluid response.

Next we will discuss the application of the Gassmann equation in the P-wave modulus domain (Mavko 1995) and not in the Bulk modulus domain we discussed earlier, and what implications this may have on the fluid substitution results in a laminated sand-shale environment. This method becomes handy in the case where shear logs are not available. However, in the case of heavy oil, this method should not be used due to the fact that the shear modulus of the fluid is no longer zero. The main idea here is to replace the bulk modulus (K) with the compressional modulus (M), without including shear modulus (μ):

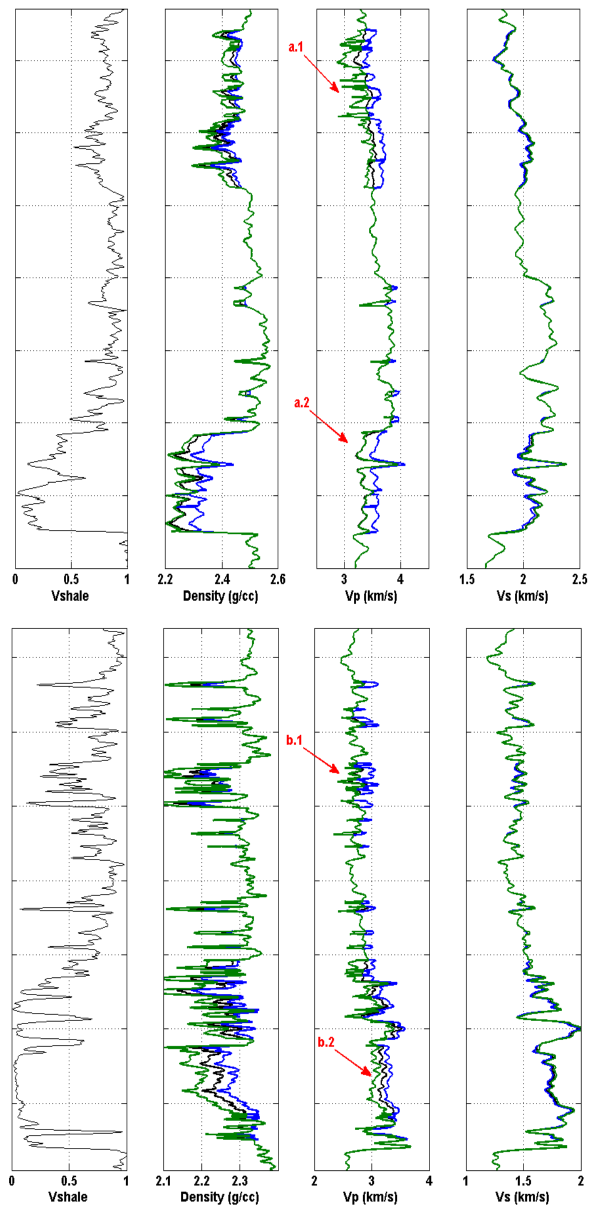

Figure 3. Gassmann. (a) From the left to the right: Vshale, density, Vp and Vs for Well 1 (b) The same order for Well 2. On subplot 2 (density), subplot 3 (Vp) and subplot 4 (Vs). Black curves are in-situ logs, green curves are 90% oil saturation and blue curves are 100% water saturation.

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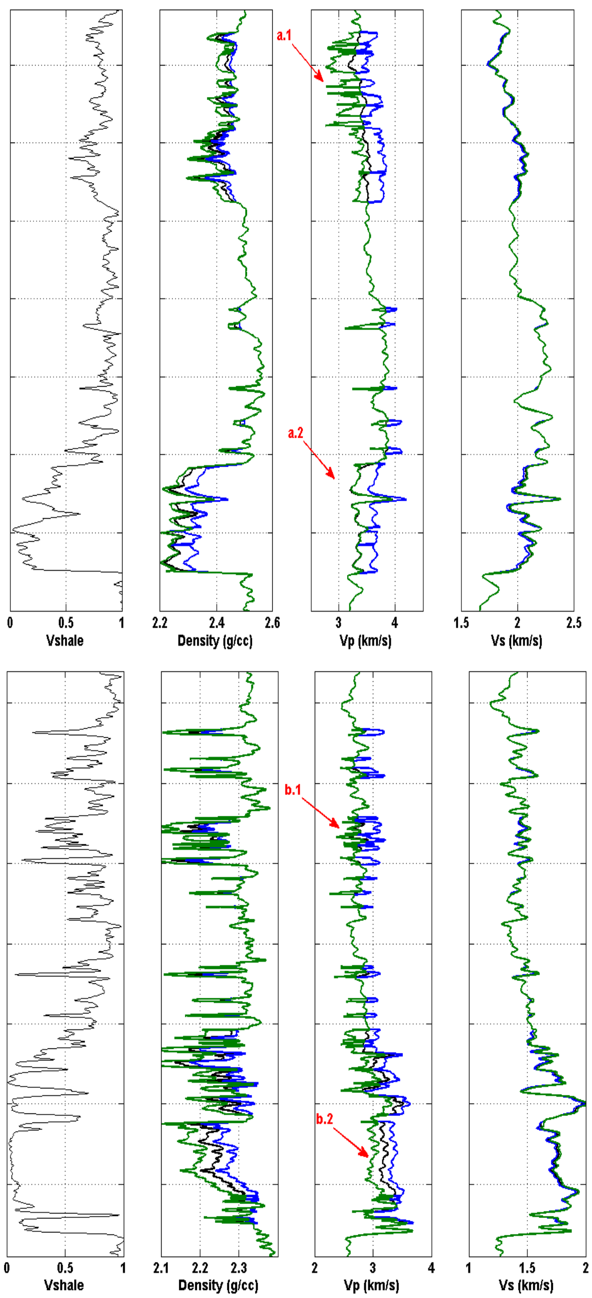

Figure 4. Mavko. (a) From the left to the right: Vshale, density, Vp and Vs for Well 1 (b) The same order for Well 2. Here on subplot 2 (density), subplot 3 (Vp) and subplot 4 (Vs). Black curves are insitu logs, green curves are 90% oil saturation and blue curves are 100% water saturation.

$$M_{fl} = K_{fl} + {}^{4}/_{3}\,\mu_{fl}$$
$$\mu_{fl} = 0; \rightarrow\ M_{fl} = K_{fl}$$

and $\mu_{sat} = \mu_{dry}$ therefore $M_{sat} \approx K_{sat}$
Therefore, we can rewrite the Gassmann's equation in the P-wave modulus domain as follows:

$$\frac{M_{sat}}{M_g - M_{sat}} = \frac{M_{dry}}{M_g - M_{dry}} + \frac{M_{fl}}{\phi(M_g - M_{fl})} \qquad (3)$$

Figure 4 shows the result of applying Mavko's approximation (1995) on the same wells as in Figure 3, which shows that Mavko's approximation gives even larger differences than the previous case (bulk modulus domain) in the thinly bedded sand–shale sequences as well as the clean sand intervals in both wells.

Dejtrakulwong's method

Applying Gassmann's fluid substitution method on log data without accounting for sub-resolution sand-shale laminations will result in erroneous predictions as demonstrated in Figure 3 and 4. Such discrepancy arises because fluid substitution should occur in permeable layers only and should not be applied to shale layers for consistency with Gassmann's assumptions. One solution that Dejtrakulwong and Mavko (2011) proposed was to first downscale for the sand and shale end-members' properties, apply either Gassmann's equation or Mavko's approximation to sand layers only, and then upscale the layers back using the Backcus average (Katahara, 2004; Skelt, 2004; Dvorkin et al., 2007). This method honors the rock-physics models for dispersed sand-shale systems, the Thomas-Stieber model and the Gassmann's fluid substitution method, such that it can automatically model laminations without having to explicitly identify them. Dejtrakulwong and Mavko (2011) obtained an expression for the compliance ($\boldsymbol{C_{sat}}$) of a thinly bedded sand-shale sample with a new fluid.

$$C_{sat_2} = C_{sat_1} - \left(\frac{\phi_{eff}}{\phi_s}\right)\left(C_{sand\,fl1} - C_{sand\,fl2}\right) \qquad (4)$$

where $C_{sat_1} = 1/M_{sat_1}$ is the inverse compressional moduli of an arbitrary point representing laminations between shaly-sand and shale, with its effective porosity saturated with fluid 1. M_{sat_1} is obtained from P-wave velocity from the original well log dat $M = \rho V_p^2$, ϕ_{eff} is effective porosity and ϕ_s is porosity of the sand. $\Delta C_{sand} = C_{sand\,fl1} - C_{sand\,fl2}$ is the change in the inverse compressional moduli for clean sand when fluid 1 is substituted by fluid 2 using either Gassmann's equation or Mavko's approximation. This however means that the change in P-compliance after fluid substitution for a laminated sand-shale sequence is directly proportional to the change in P-compliance of the clean sand. Moreover, the

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magnitude of this change is approximately equal to the ratio of the effective porosity of the laminated sand-shale sequence to the clean sand porosity. Finally, in this study we assume that the fluid substitution occurs only in effective porosity, thus the shale and sandy-shale intervals remain unchanged under fluid substitution because of their zero effective porosity.

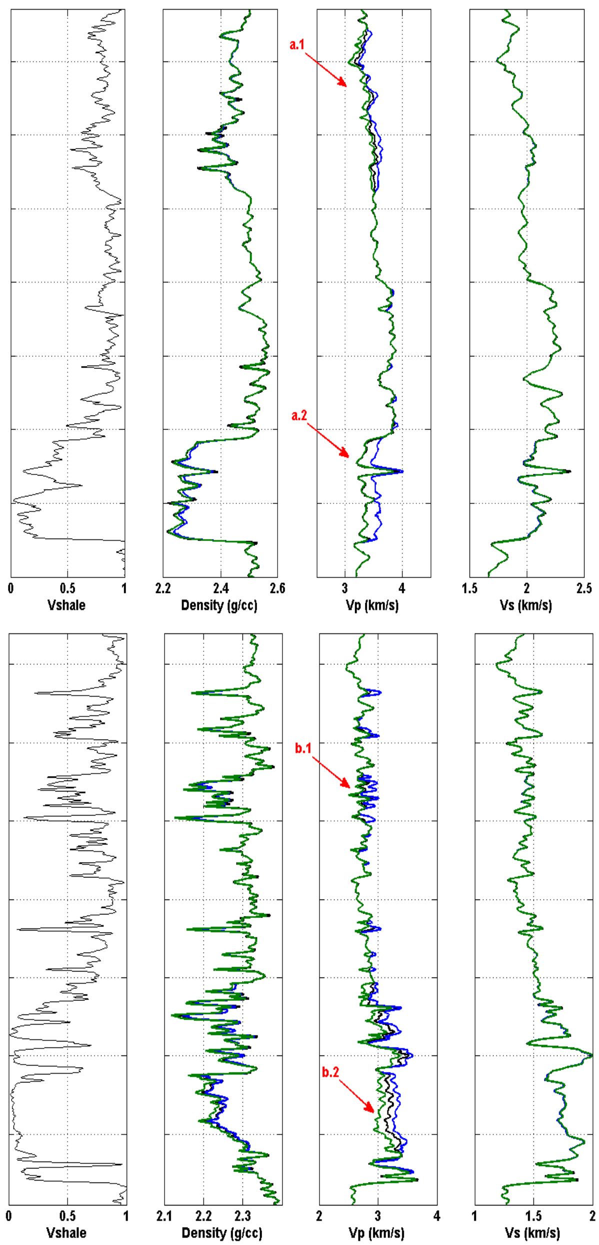

Figure 5. Dejtrakulwong. (a) From the left to the right: Vshale, density, Vp and Vs for Well 1 (b) The same order for Well 2.

In Figure 5 we show the fluid substitution results when using Dejtrakulwong and Mavko (2011) method for well 1 and 2. These results are now consistent with the original dataset, especially the intervals with sand-shale laminations. The difference between the in-situ logs (black) and the substituted logs (green is oil and blue is water) in a.1 and a.2 for well 1 and b.1 and b.2 for well 2 is compatible with the difference observed between thinly bedded sand-shale sequences and clean sand intervals.

Conclusions

We have performed fluid substitution (water and oil) using the Gassmann equation on a laminated sand-shale sequence by following three different approaches to the application of the fluid substitution method. The first was ignoring laminations, followed by Mavko's approximation (avoiding S-wave velocity) and finally Dejtrakulwong's method where laminations are properly handled. We have also demonstrated that when thin laminations are not accounted for, the fluid substitution results are over-predicted and hence small sand fractions will show a fluid response at least twice as much as large sand fractions, which is incorrect.

Dejtrakulwong and Mavko (2011) method for fluid substitution in thinly bedded sand-shale sequences has the following characteristics:

- Performing fluid substitution on sands thinly bedded with shales or shaly-sands thinly bedded with shales can be done by applying Gassmann's fluid substitution on clean sands only. For other compositions in between, calculation of elastic properties is done by scaling it to the clean sand response.

- For clean sands thinly bedded with shales, this method gives results similar to that from previous work (e.g., Katahara, 2004)

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EDITED REFERENCES

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