Current status and future trends in seismic lithology and fluid prediction

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Summary

We present cutting edge techniques for lithology and pore fluid prediction from pre-stack seismic amplitudes, by combining statistical techniques, geological constraints and rock physics models. A promising tool for early exploration detection of reservoir lithologies and hydrocarbons is to do AVO classification constrained by depth trends. We show a blind-test from an offshore Brazil discovery where the method successfully predict the presence of oil.

Another rock physics tool for seismic reservoir prediction, useful for late stage exploration and production stage oil fields, is the rock physics template (RPT) technology. This technique can be used to classify elastic seismic inversion results.

Finally, we summerize what we foresee as the future trends in rock phyisics and seismic lithology and fluid prediction. There is a clear trend of more sophisticated inversion routines (3-term AVO and full-waveform inversions) as the computer intensivity increases. Also, there is a trend of more integration of disciplines like geology, statistics and physics both in modelling and interpretation. Attenuation and frequency attributes will be increasingly important especially in gas fields.

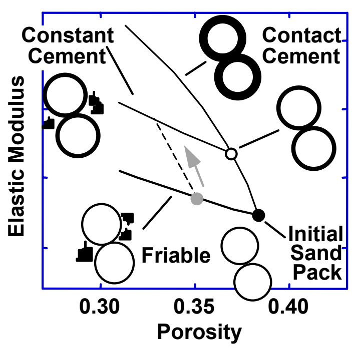

Figure 1: Rock physics models relating porosity and rock texture to seismic properties (from Avseth et al., 2005a).

Introduction

Every year finding new oil is harder, riskier, and more expensive – a natural consequence of its finiteness. As dictated by M. King Hubbert's "peak," declines in discoveries and production are inevitable. Yet, demand continues, forcing us to deeper water, more complex reservoirs, and smaller, more subtle oil fields. These trends in oil exploration have given rise to more quantitative seismic methods and improved understanding of 3-D seismic data, beyond the conventional geometric structural and stratigraphic interpretations. The quantitative information in seismic amplitudes opens up new gates for reservoir characterization including the predictability of pore fluid types, fluid saturation, lithologies, and pore pressure (e.g., Castagna et al., 1998; Ursin et al., 1996). In this paper, we give an overview and some extensions to cutting edge technologies developed by Avseth et al. (2005a), and show examples from offshore Brazil and the North Sea.

Fluid and lithology substitution

Gassmann theory

Undoubtedly, the Gassmann theory is the most important and most frequently applied theory in rock physics. The Gassmann's equations allow us to predict the seismic properties of hydrocarbons if we have only measured the properties of water saturated rocks. Seismic fluid sensitivity is determined by combination of porosity and pore space stiffness. A softer rock will have a larger sensitivity to fluids than a stiffer rock at the same porosity. Gassmann's relations simply and reliably describe these effects.

$$\frac{K_{sat}}{K_{mineral} - K_{sat}} = \frac{K_{dry}}{K_{mineral} - K_{dry}} + \frac{K_{fluid}}{\phi(K_{mineral} - K_{fluid})} \quad (1)$$

and the companion result

$$\mu_{sat} = \mu_{dry} \quad (2)$$

Gassmann's equations (1) and (2) predict that for an isotropic rock, the rock bulk modulus will change if the fluid changes, but the rock shear modulus will not.

These dry and saturated moduli, in turn, are related to P-wave velocity $V_P = \sqrt{(K + (4/3)\,\mu)/\rho}$ and S-wave velocity $V_S = \sqrt{\mu/\rho}$, where ρ is the bulk density given by

$$\rho = \phi\rho_{fluid} + (1 - \phi)\rho_{mineral} \quad (3)$$

For clean porous sands, the Gassmann theory has been proven to work very well. However, one should be aware that the formulation assumes an isotropic rock, with one mineral only. Most reservoir sands are somewhat shaly and may also be anisotropic. Berrymann and Milton (1995) extended Gassmann theory to include mixtures of two minerals, while Brown and Korringa (1975) extended it to include anisotropy.

Nevertheless, the greatest uncertainty in Gassmann fluid substitution is not the mineralogy or the anisotropy, but the dry rock texture and the saturation pattern. The fluid sensitivity is not uniquely related to porosity, but to the rock stiffness (Mavko et al., 1998). Bear in mind that high-porosity sand can be much stiffer than low-porosity sand due to cementation. This is why lithology substitution is as important as fluid substitution.

Lithology substitution

We need to understand the expected changes in texture and lithology of the rocks on which we perform fluid substitution. For instance, diagenetic cement and clay lamination can have drastic effects on the dry rock frame as well as the fluid saturation pattern (see Avseth et al. 2005b). In particular, clay effects may be very important in turbidite systems, like offshore Brazil.

The most important reason for a rock physics – lithology link is to be able to calculate a correct dry background rock in the Gassmann modelling (i.e. the correct relationship between stiffness and porosity). Furthermore, such models can be used for porosity prediction and lithology substitution. If we observe one type of sand in Well A, we may want to ask "what if" we have a different type of sand in Well B.

In our attempt to link seismic properties to reservoir properties, we need to use rock physics models. However, without knowing the arrangement of porespace and minerals, we can at best predict the upper and lower bounds of seismic properties as a function of reservoir properties. The narrowest bounds possible to mix rock and pore space is given by the Hashin-Shtrikman models.

$$K^{HS\pm} = K_1 + \frac{f_2}{(K_2 - K_1)^{-1} + f_1\left(K_1 + \frac{4}{3}\mu_1\right)^{-1}} \qquad (4)$$

$$\mu^{HS\pm} = \mu_1 + \frac{f_2}{(\mu_2 - \mu_1)^{-1} + \dfrac{2f_1(K_1 + 2\mu_1)}{5\mu_1\left(K_1 + \frac{4}{3}\mu_1\right)}}$$

where

K_1, K_2 bulk moduli of individual phases
μ_1, μ_2 shear moduli of individual phases
f_1, f_2 volume fractions of individual phases

Upper and lower bounds are computed by interchanging which material is subscripted 1 and which is subscripted 2. Generally, the expressions give the upper bound when the *stiffest* material is subscripted 1 in the expressions above, and the lower bound when the *softest* material is subscripted 1.

This model serve as an excellent interpolator between the mineral point (i.e. zero porosity) and the high-porosity end member, normally given by the critical porosity (for sands equalling 0.4). The lower bound of this model is found to give a very good representation of friable sand with varying sorting, where the stiffest material (i.e. the grains) is located passively inside the softest material (i.e. the pore space). The upper bound is found to be more representative of diagenesis, where the stiffest material is added at grain contacts, causing a larger stiffening effect on the rock frame. However, for initial grain cement, the Dvorkin-Nur contact cement has been found to work better that the Modified Upper Hashin-Shtrikman model.

Figure 1 summarizes the diagnostic rock physics models which relate rock microstructure of sands to elastic properties. These models allow us to predict the geometrical arrangement of grains and pore space in sands. For more detailed descriptions of various rock models, see Avseth et al. (2005a).

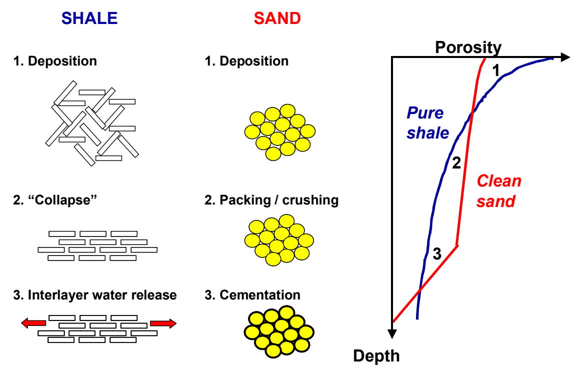

Figure 2: Schematic illustration of porosity-depth trends for sands and shales. There are a few rules of thumbs: 1. The depositional porosity of shales is normally higher than that of sands. 2. The porosity gradient with depth is steeper for shales than for sands during mechanical compaction (i.e. at shallow depths). 3. The porosity gradient with depth will be steeper for sands than for shales during chemical compaction (i.e. quartz cementation of sands normally occur at greater burial depth, beyond 2-3 km).

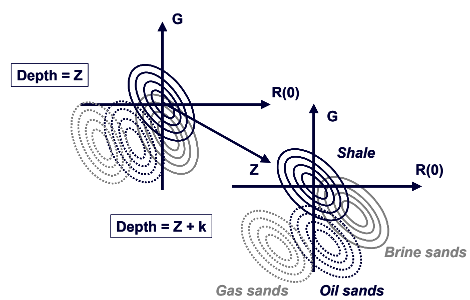

Figure 3: Schematic illustration of AVO depth trends. The elastic contrasts between sands and shale will change with depth and diagenesis. Hence, the expected AVO response of hydrocarbon saturated sands will vary with depth. Rock physics depth trend models can be applied to create depth-dependent training data for AVO classification (see Avseth et al., 2005).

Rock physics and AVO depth trends

Existing empirical porosity-depth trends for sands and shales can be used as input to rock physics models of Vp, Vs and density (Figure 2). We use Hertz-Mindlin theory (Mavko et al., 1998) to calculate the velocity-depth trends for unconsolidated sands and shales, whereas Dvorkin-Nur's contact-cement model (Dvorkin and Nur, 1996) is used for cemented sands. The modeling results provide estimates of the parameters needed to calculate expected seismic response with depth for sand-shale interfaces. Hence, the depth-trends allow us to study the ability to discriminate between pore fluids and lithologies at different depths (Figure 3).

Example from Brazil

Figure 4 (upper) shows a post-stack seismic section of an offshore Brazilian oil field. The data are from Stovas et al. (2004). The reservoir target is located around 3070ms (TWT) and represents Oligocene age turbidite sands with relatively high porosity.

First, we establish local rock physics depth-trends as described above. Expected values of Vp, Vs and density for brine saturated shales and sands are picked from these depth-trends at the given reservoir depth. Gassmann modeling is performed to include hydrocarbon saturated reservoir sands in the training data. Using Monte Carlo simulations, we account for natural variability and uncertainty in the parameters (for details on the methodology, see Avseth et al., 2005a). From pre-stack seismic data we extract AVO attributes around the target zone (including intercept (R0) and AVO gradient (G)) and these are calibrated to the simulated AVO training data. After the calibration we perform a bivariate classification of the AVO attributes into most likely lithology and fluid category. Figure 4 (lower) shows the resulting AVO classification result, and we can observe the predicted oil zone at the target level. These results match nicely with the AVO prediction results of Stovas et al (2004).

Rock physics templates (RPTs)

The Gassmann theory, the rock texture and lithology models and the depth trend models can be combined all together into so-called rock physics templates (RPTs). These are useful tools for interpretation of lithology and pore fluids from well log and seismic data. This technology was introduced by Ødegaard and Avseth (2004).

Figure 5 shows an example where we apply RPT analysis to well log data from a North Sea well. The well penetrate different types of shales, and sands filled with gas, oil and brine. The various lithologies and fluid types are easily separated in the RPT plot. The same RPT plot can be used to classify elastic seismic inversion results from the same field.

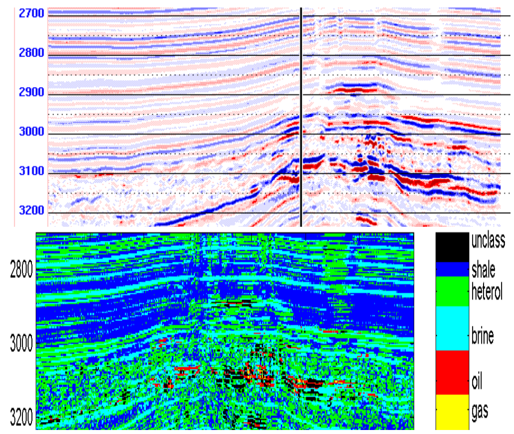

Figure 4: Post-stack seismic section (upper) intersecting a turbidite oil field offshore Brazil. The AVO classification results (below) confirm the presence of oil at the target level (seen in red).

Future trends

There are some clear trends in quantitative seismic interpretation; more rigorous modeling and inversion of the wave propagation phenomena; combining sedimentologic and diagenetic modeling with rock physics modeling to obtain more realistic predictions of seismic properties; probabilistic Monte Carlo simulations to capture uncertainties in both rock physics and inversion results; and incorporation of geostatistical methods to account for spatial correlations in reservoir properties. Representation of quantitative seismic interpretation in terms of probabilities allows the results to be more easily incorporated in to economic risk analysis.

Today, two-term AVO analysis is still the most common means to estimate elastic properties from prestack seismic data. However, higher order, ultra-far AVO analysis, though immature, is a technology, which can potentially provide us with additional information about reservoir properties from seismic data. Furthermore, full waveform prestack inversions will become more common as computer power increases. Bachrach et al. (2004) quantified uncertainties in reservoir prediction using full waveform prestack inversion combined with rock physics analysis and mapped the estimated probabilities of different lithologies in deep-water Gulf of Mexico. Not only will we see inversions of the elastic seismic properties, but also increased use of attributes related to attenuation. Attenuation has always been difficult to estimate reliably from seismic data. However, recent techniques give us hope that it will become more common to use Qp and Qs in addition to Vp, Vs and density for reservoir characterization.

Finally, integration of geologic processes, by numerical modeling, will open up new doors in quantitative seismic interpretation. Helset et al. (2004) combined numerical modeling of diagenetic processes with rock physics models, to predict quantitative depth trends in seismic properties.

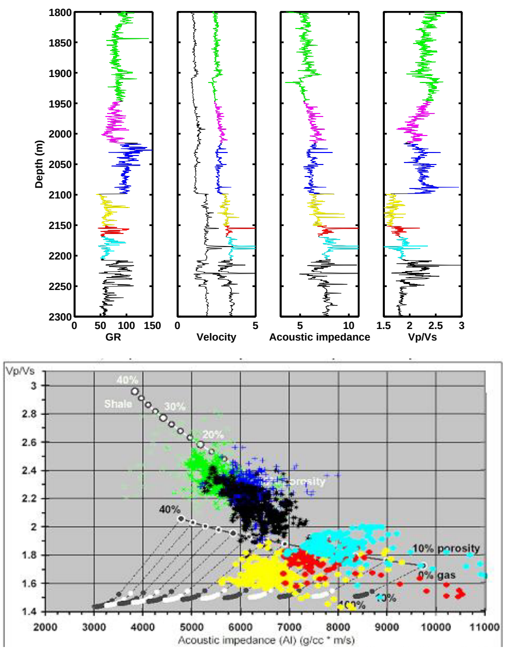

Figure 5: RPT analysis of a North Sea well. The various zones in the well logs plot in different areas of the RPT. The upper three zones (shales and tuff) plot between the shale model and the clean sand model. The yellow, red and cyan coloured zones are Heimdal sands filled with gas, oil and brine, respectively. The hydrocarbon zones are easily detected by the RPT plot. The plot indicates that AVO must be applied to discriminate gas sands from shales, since these have overlapping AI values but different Vp/Vs values.

Conclusions

1. Gassmann fluid substitution should be used with caution in shaly sands. Be aware of, mineralogy, reduced stiffness of rock frame, as well as heterogeneity effects.
2. Lithology substitution is equally important as fluid substitution. Various "what if " scenarios should be included in rock physics modeling of different depositional and diagenetic factors.
3. Rock physics depth trends allow us to predict expected AVO responses at different target depths even in areas with sparse or no well control.
4. RPT (Rock physics template) analysis represent a user-friendly and fast means of interpreting sonic well log data as well as elastic inversion results.
5. Quantitative seismic interpretation represents a necessary paradigme change in the way we explore 3-D seismic amplitudes for increasingly subtle hydrocarbon traps and allows us to characterize reservoirs in terms of lithology, porosity, fluid type, saturation, and pore pressure.

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