P-55

Rock Physics Template (RPT) Analysis of Well Logs for Lithology and Fluid Classification

Nabajyoti Boruah
Final Year, M.Sc.Tech. (Applied Geophysics)
Department of Applied Geophysics, Indian School of Mines, Dhanbad

Summary

Rock Physics Templates (RPTs) are geologically constrained rock physics models that serve as tools for lithology and fluid prediction (Avseth et al., 2005). Rock physics diagnostic models and Gassmann fluid substitution relations are essential ingredients in generating the templates for a reservoir. RPT analysis of well log data is necessary to calibrate the templates to local geology before applying them on seismic data. RPT can serve as a powerful tool in validating hydrocarbon anomalies and mitigating exploration risks. The success of RPT analysis depends on the choice of proper model and correct geological information of the reservoir.

RPT analysis is carried out on three wells of a North Sea field. Oil sands are encountered in two wells. A qualitative prediction of the nature of reservoir and cap rocks, along with a quantitative assessment of cement volume, porosity and saturation of the oil sands are attempted using the templates.

Introduction

Rock Physics establishes a link between the elastic properties and the reservoir properties such as porosity, water saturation and clay content. As seismic signatures are directly governed by these elastic parameters, rock physics template (RPT) provides a methodology to infer the geology of the reservoir, both qualitatively and quantitatively from these signatures. The template is a crossplot of elastic parameters obtained theoretically from rock physics models, constrained by local geology. When the field data (well logs or seismic inversion results) are superimposed on the template, different geologic trends can be identified in the dataset (Fig. 1) and accordingly different clusters or populations are classified.

The common form of RPT is between acoustic impedance (AI) and Vp/Vs ratio , as combination of these two elastic properties is a good lithology and fluid indicator (Avseth et al., 2005, Chi and Han, 2009). Other forms of RPT include combination of shear impedance (SI) and AI, elastic impedance (EI) and AI and Lame's parameter (λ) and shear modulus (μ).

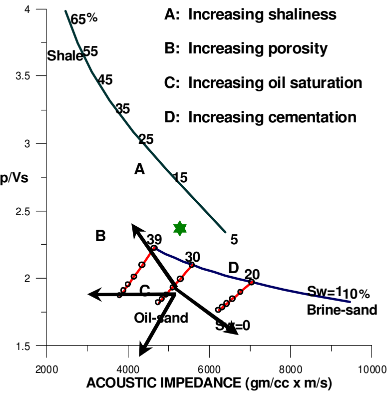


Fig. 1: Illustration of geologic trends in a RPT. 1% Constant Cement Model is used.

R.N. 201-D, Sapphire Hostel, Indian School of Mines, Dhanbad, Jharkhand-826004, India
email: naba.ismu@gmail.com

Rock Physics models

a. *The friable-sand model or HMHS model* (Dvorkin and Nur, 1996).

This model for unconsolidated sediments assumes porosity reduction from the initial sand pack value (critical porosity) due to the deposition of solid matter away from the grain contacts that result in gradual stiffening of the rock. This porosity reduction for clean sandstone is caused by depositional sorting and packing. The elastic moduli at the critical porosity end point (Φ_c) are given by Hertz-Mindlin (HM) theory. The zero porosity point represents the mineral point. These two points are connected by the unconsolidated line represented mathematically by the modified lower Hashin-Shtrikman (MLHS) bound.

b. *The contact cement model* (Dvorkin and Nur, 1996).

During burial of sandstones, cementation by diagenetic quartz, calcite or other minerals results in a strong stiffening because of welding of the grain contacts. The contact cement model describes the porosity reduction from initial sand pack due to uniform deposition of cement layers on the surface of grains that results in a sharp increase in velocity with decreasing porosity.

c. *The constant cement model* (Avseth, 2000).

This model is a combination of the *friable-sand model* and *the contact cement model*. It assumes that the sands of varying porosity all have the same amount of contact cement , and variation within this group is due to non contact pore filling (e.g. sorting). Porosity initially decreases from critical limit, Φ_c to Φ_b (cemented porosity) solely due to cementation. From Φ_b, porosity decreases as in the case of friable sand model. Since the amount of cement is often related to depth, this model is also called '*the constant cement depth model*'. On the other hand, sorting is related to lateral variation in flow energy during sediment deposition (Avseth, 2000).

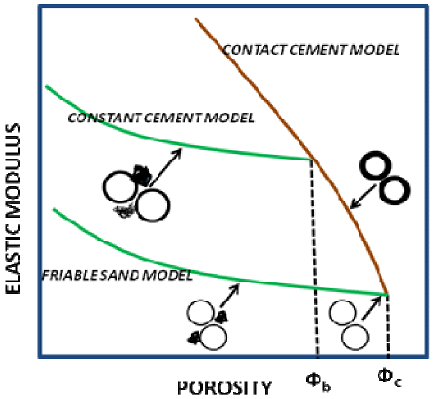


Fig 2: Schematic diagram of the three rock physics models.

Fluid substitution: Gassmann equations

Gassmann's relations (Mavko et al., 1998) are applied to estimate the elastic moduli of the fluid saturated rocks.

$$K_{sat} = K_{dry} + \frac{(1 - \frac{K_{dry}}{K_{\mathrm{min}eral}})^2}{\frac{\varphi}{K_{fluid}} + \frac{1 - \varphi}{K_{\mathrm{min}eral}} + \frac{K_{dry}}{K_{\mathrm{min}eral}^{\;2}}}$$

$$\mu_{sat} = \mu_{dry}$$

Where,

K_{dry} is the dry bulk modulus and μ_{dry} is the dry shear modulus obtained from the rock physics model.

φ is the porosity.

And density of the saturated rock,

$$\rho = (1 - \phi)\rho_{\mathrm{min}eral} + \phi\rho_{fluid}$$

Estimating average mineral and fluid properties

Gassmann equations are applicable for monomineralic rocks. For a mixture of minerals, elastic moduli of the average mineral are calculated by using Voigt-Hill-Reuss (VRH) average (Mavko et al., 1998).

$$M_{VRH} = \frac{M_V + M_R}{2}$$

Voigt Average, $M_V = \sum_i f_i M_i$

Reuss Average, $\frac{1}{M_R} = \sum_i \frac{f_i}{M_i}$

f_i and M_i are respectively volume fraction and modulus (K or μ)of the ith mineral.

And for mixed fluid saturation, average bulk modulus and density of the effective fluid is estimated by using the following relations (Domenico, 1971).

$$\frac{1}{K_{fluid\_avg}} = \frac{S_{brine}}{K_{brine}} + \frac{S_{oil}}{K_{oil}} + \frac{S_{gas}}{K_{gas}}$$

$$\rho_{fluid\_avg} = S_{brine}\rho_{brine} + S_{oil}\rho_{oil} + S_{gas}\rho_{gas}$$

$S_{brine}, S_{oil}, S_{gas}$ are the saturations, $K_{brine}, K_{oil}, K_{gas}$ are the bulk moduli and $\rho_{brine}, \rho_{oil}, \rho_{gas}$ are the densities of the brine, oil and gas phases respectively.

The fluid properties at the reservoir conditions are calculated using the *Batzle-Wang relations* (Batzle and Wang, 1992).

Temperature: 77°C Effective Pressure: 20 MPa

Brine properties:

Salinity:	80,000 ppm*
Density:	1.06 gm/cc
Bulk Modulus:	2.48 GPa

Oil properties:

Oil gravity:	32*	GOR:	64*
Gas gravity:	0.6	Density:	0.80 gm/cc
Bulk Modulus:	0.93 GPa		

*(Avseth et al., 2005)

Table: Mineral properties (Mavko et al., 1998, Avseth, 2000**):

Mineral	Bulk Modulus (GPa)	Shear Modulus (GPa)	Density (gm/cc)
Quartz	36.6	45.0	2.65
Feldspar	75.6	25.6	2.63
Clay**	17.5	7.5	2.30

RPT analysis of well logs from a North Sea field

RPT analysis is performed on three wells of a North Sea field, namely well-2, well-3 and well-5 (Avseth et al., 2005). Oil sands are encountered in well-2 and well-5. The depth zones between 2000m to 2300m are focussed in all the three wells. Missing shear wave data in well-3 is predicted using Vp-Vs relation obtained from well-2 and well-5.

Vs = 0.808Vp-988.6 (Vp and Vs are in m/s).

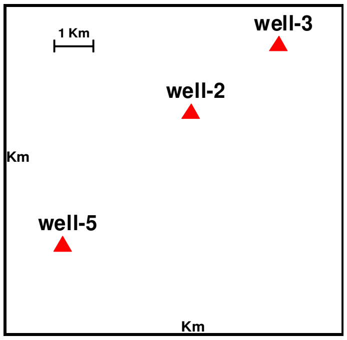


Fig. 3: Relative locations of the three wells.

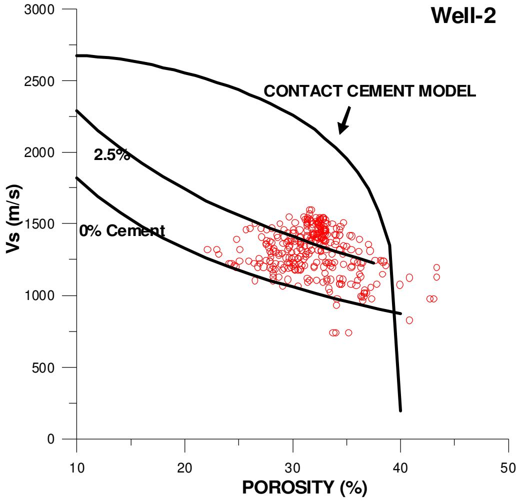
Rock Physics diagnostic (Avseth et al., 2005) approach is adopted to infer the sedimentology (cementation) of the reservoir rocks in all the three wells. This is carried out in the Vs-porosity domain (Fig. 4) in order to minimize pore fluid effects (Avseth et al., 2009). Porosity is obtained from the density logs. The following rock physics models are chosen for generating templates for respective wells:

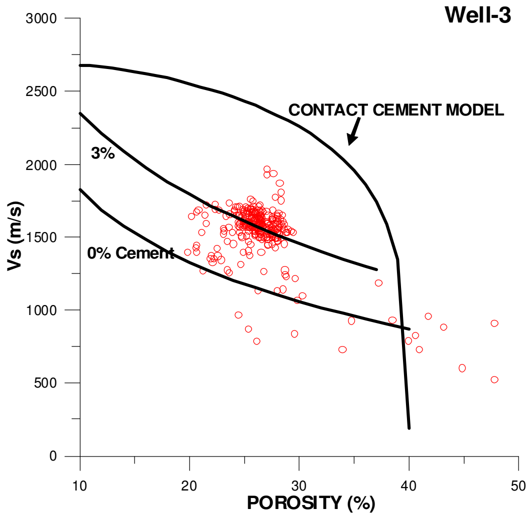
Well 2: 2.5% Constant Cement Model
Well 3: 3.0% Constant Cement Model
Well 5: 2.0% Constant Cement Model

Shales are composed of soft clay minerals and are normally not cemented (Avseth et al., 2005). Thus the HMHS model is used for the shale line.

Before applying the well log data on the templates, the logs are corrected for mud invasion effects in the hydrocarbon bearing zones using Gassmann fluid substitution (Mavko et al., 1998). From the resistivity curves available in well-5, water saturation in the oil sands is calculated to be approximately 20%. The same value is assumed in case of well-2 due to unavailability of resistivity logs. The location of the oil sands in well-2 is known a priori.

Mud properties (Avseth et al., 2005):
Bulk Modulus: 2.80 GPa
Density: 1.06 gm/cc





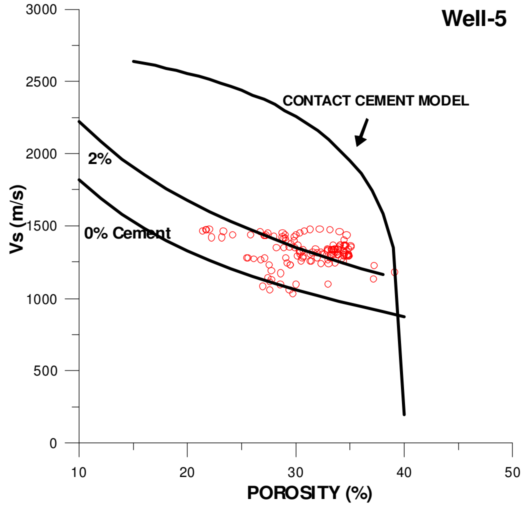
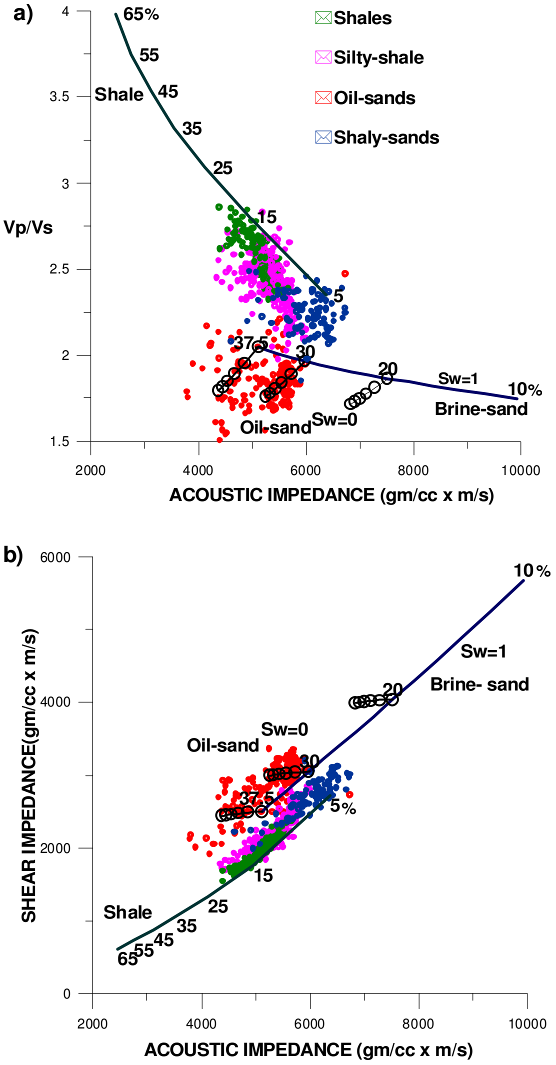


Fig. 4: Vs versus density-porosity from the three wells superimposed on the rock physics models to quantify the cement volume in the reservoir rocks.



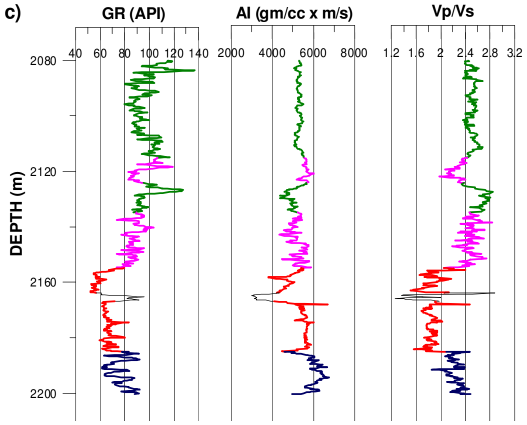
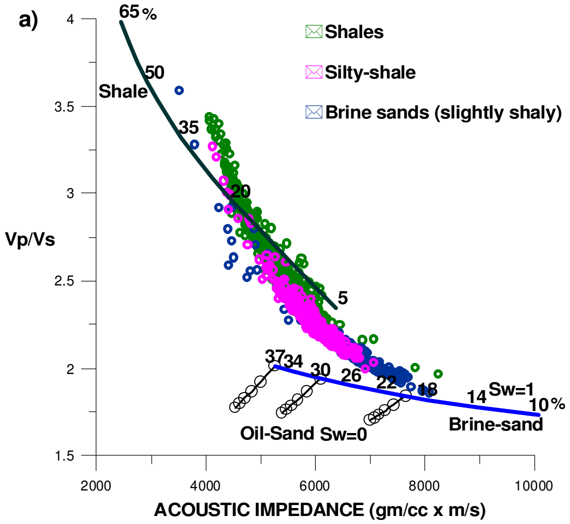


Fig. 5: RPT analysis of well-2. a) Vp/Vs versus AI; b) SI versus AI; c) Corresponding well logs. Constant Cement Model (2.5% cement) is used.



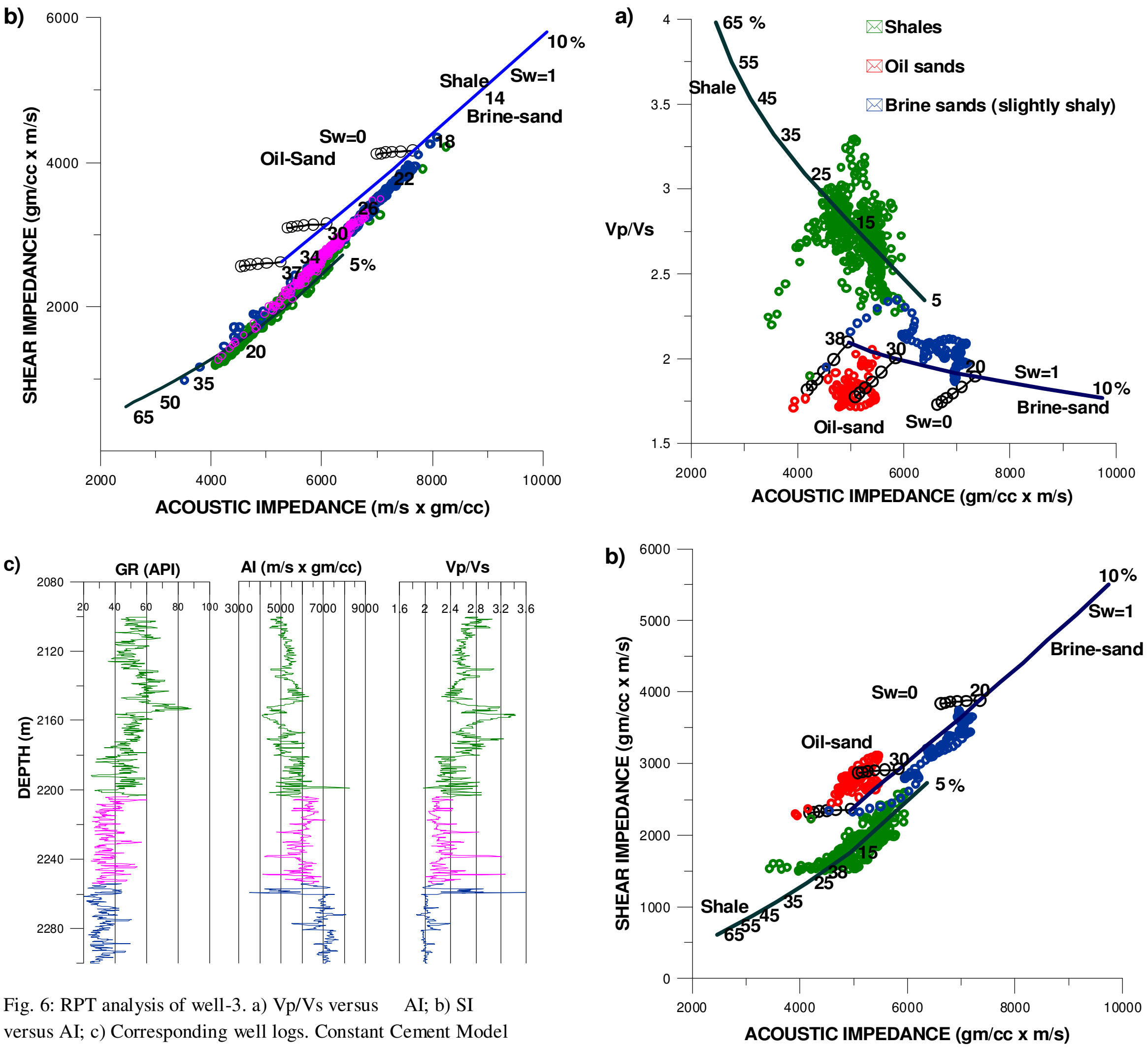


Fig. 6: RPT analysis of well-3. a) Vp/Vs versus AI; b) SI versus AI; c) Corresponding well logs. Constant Cement Model (3.0% cement) is used.

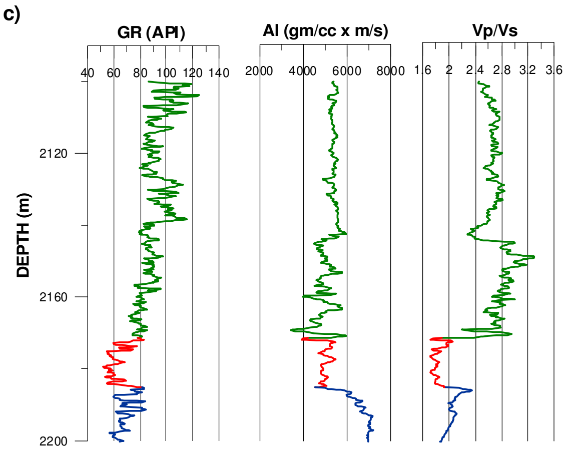


Fig. 7: RPT analysis of well-5. a) Vp/Vs versus AI; b) SI versus AI; c) Corresponding well logs. Constant Cement Model (2.0% cement) is used.

Results

Well-2: Oil-sands are encountered beneath a cap rock which is silty-shale. Average porosity of the sands is about 30%, with hydrocarbon saturation varying from 20% to nearly 100%.

Well-2: No hydrocarbon bearing zone is observed. The average cement volume in the brine saturated sand zone (~2260m-2300m) is about 3%.

Well-3: The oil-sands have an average porosity of about 32%, with oil saturation varying from 50% to nearly 100%. The cap rock is composed of relatively cleaner shales compared to well-2.

The results are subjected to possible errors in fluid substitution in the invaded zone, uncertainties in the mineral and fluid properties, their composition and the model applied.

Conclusions

RPT analysis of well logs is necessary to validate the templates for the reservoir, before applying them on seismic data. The analysis can also aid in petrophysical interpretation and in understanding the elastic properties of the reservoir rocks for seismic interpretation like AVO.

RPT provides a quick and efficient way of interpreting seismic inversion results and predicts reservoir properties where there is no well control. With the assumption that the undrilled area has the same depositional environment, quantitative estimation of reservoir parameters like porosity, saturation, cement volume, etc. can be made. However the success of such extrapolation depends on the accuracy of the rock physics models and the knowledge of the reservoir geology.

References

Avseth, P., 2000, Combining rock physics and sedimentology for seismic reservoir characterization of North Sea turbidite systems, PhD. thesis, Stanford University.

Avseth, P., Jørstad, A., Wijngaarden, A. V., and Mavko, G., 2009, Rock Physics estimation of cement volume, sorting, and net-to-gross in North Sea sandstones, The Leading Edge, 98-108.

Avseth, P., Mukerji, T. and Mavko, G., 2005, Quantitative Seismic Interpretation: Applying rock physics to reduce interpretation risk, Cambridge University Press, Cambridge, U.K.

Batzle, M. and Wang, Z., 1992, Seismic properties of pore fluids, Geophysics, 42, 1369-1383.

Domenico, S.N., 1976, Effect of brine-gas mixture on velocity in an unconsolidated sand reservoir, Geophysics, 41, 882-894.

Dræge, A., 2009, Constrained rock physics modeling, The Leading Edge, 28, 76-80.

Dvorkin, J. and Nur, A., 1996, Elasticity of high porosity sandstones: Theory of two North Sea data sets, Geophysics, 61, 1363-1370.

Mavko, G., Mukerji, T. and Dvorkin, J., 1998, The Rock Physics Hand Book: Tools for Seismic analysis in a porous media, Cambridge University Press, Cambridge, U.K.

Ødegaard, E. and Avseth, P., 2004, Well log and seismic data analysis using rock physics templates, First Break, 23, 37-43.

Xin, G. and Han, D., 2009, Lithology and fluid differentiation using rock physics templates, The Leading Edge, 28, 60-65.

Acknowledgement

I deeply acknowledge Dr. Rima Chatterjee, (Indian School of Mines, Dhanbad) for her guidance and constant encouragement. I also pay my gratitude to Ashok Yadav (RIL, Mumbai) for his sincere help and suggestions.