De-risking Hydrocarbon Exploration by Leveraging Rock Physics Modelling – A Success Story from Western Onshore basin: India

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Summary

The primary objective of rock physics modelling is to establish a link between various rock properties viz. porosity, lithology and fluid saturation, with elastic attributes like Vp/Vs and/or impedances. These linkages play a crucial role in both qualitative and quantitative seismic interpretation and reservoir characterization. Rock physics modelling entails the utilization of mathematical and physical models to replicate the behaviour of rocks and fluids under diverse geological conditions. By integrating rock physics modelling into seismic interpretation workflows, geoscientists can enhance their comprehension of subsurface geology, forecast reservoir properties, and make well-informed decisions for hydrocarbon exploration.

The current study is a successful case study of the integration of petrophysics, rock-physics and seismic inversion techniques to identify exploratory locations in the Linch field of the Western Onshore Basin, India. Six strategically selected wells within the study area underwent log data conditioning to mitigate environmental influences, adjust for depth variations and account for the impact of borehole irregularities on the well logs. The development of a consistent petrophysics-rock physics model is indispensable for achieving desired modelling results. Following the log conditioning process, all pertinent data viz. lab derived Archie's parameters, formation water resistivity, petrographic studies (XRD, SEM, photomicrographs), hi-tech logs (NMR porosity) etc. have been integrated to build an apt multi-mineral model for petrophysical evaluation. Three out of six wells had shear log data recorded against formation of interest which was used to build, calibrate and validate the rock physics model. The Xu-White rock physics model (Xu, S. and White, R.E., 1995) have been employed to simulate the elastic logs, considering the clastic nature of the target formation. The moduli of solid minerals were modelled using the Voigt-Reuss-Hill average. To determine the moduli of the dry rock, the Kuster-Toksoz algorithm (Kuster-Toksoz, 1974) have been applied which was followed by fluid substitution using Gassman's equation. Using the calibrated model, elastic logs (Vp, Vs and density) were modelled for the Older Cambay Shale (OCS) formation in all six wells. Despite the fact that sands developed in OCS formation are thin, their high porosity renders the elastic properties of the reservoirs extremely sensitive to variations in fluid content.

Pre-stack seismic inversion was carried out using the rock physics modelled elastic logs. Based on seismic inversion, a drilling location was proposed. Post-drilling, the location proved to be successful as it yielded hydrocarbon production from the targeted sands.

Introduction

Elastic properties such as density, P-wave and S-wave velocities, along with their relationship to various rock properties such as lithology, porosity or fluid content plays a crucial role in reservoir characterization. P-wave and S-wave velocities could be of immense help in identifying fluid-type in porous reservoir rocks (Mavko, G et al., 2009). However, in numerous cases there is sparse availability of shear information in the field. Rock-physics modelling is widely used as an aid to supplement the missing shear information in rest part of the field or in the same well where data has been affected due to borehole rugosity / invasion.

For clastic sedimentary rocks, Xu-White (1995) model has been employed which attributes the effect of clay content and differences in pore aspect ratio between shale and sandstone pores on sonic velocity. Aspect ratio refers to the ratio between the minor and major axes of an ellipsoidal pore.

A consistent petrophysical model and rock physics model is key for successful rock physics modelling. The foundation of a robust petrophysical model lies in the integration of core and log data, enabling the generation of accurate mineral volumes. These mineral volumes are subsequently used as an input for reliable modelling of elastic properties of the medium.

The current study (Fig.1) is focussed for Linch pays developed within OCS formation of Linch field in Western Onshore basin, India. Linch field is located on the western rising flank of Warosan low in south-east part of Mehsana sub-block in the Mehsana-Ahmedabad block of Cambay Basin. Various arenaceous units within OCS, designated as Linch pays occur as discreet lensoid sand bodies having limited aerial extent.

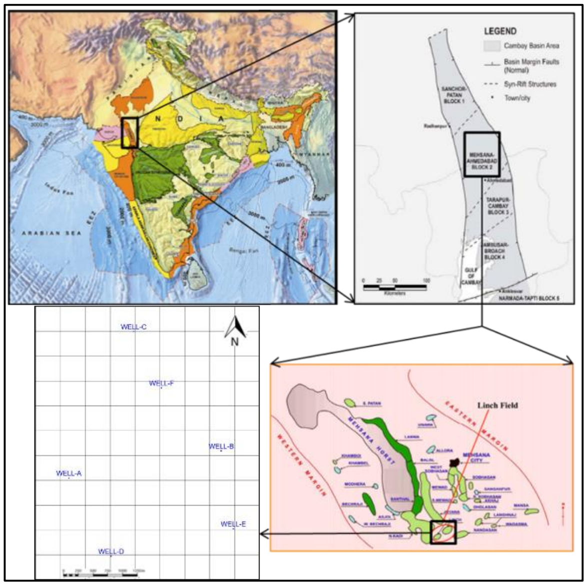

Figure 1: Location Map of Cambay basin (left top), tectonic blocks of Cambay basin (right top), Linch Field within Mehsana-Ahmedabad Block (right bottom) and Wells in Study Area (left bottom)

In the study area, a meticulous selection process was employed to choose six key wells for the study. Shear log data was recorded in three (wells: A, B & C) out of six wells (wells: A, B, C, D, E & F). Log data conditioning and petrophysical evaluation was carried out in all the six wells. Rock Physics Model (RPM) was built, calibrated and validated using shear log data recorded in three wells. The calibrated rock physics model was then used to model elastic logs in remaining three wells of the study area to facilitate pre-stack seismic inversion.

Theory and Method

All six shortlisted wells initially underwent log data conditioning to address various factors like mitigating the environmental impact, compensating for depth variations, and accounting for the influence of borehole irregularities on the well logs.

Petrophysical Evaluation:
To ensure the reliability of the rock physics model, it was crucial to develop a coherent petrophysics-rock physics framework. After the log conditioning procedures, all relevant data, such as laboratory-derived Archie's parameters, formation water salinity (measured as 12-13gpl), petrographic studies (XRD, SEM, photomicrographs) and advanced logging techniques (NMR porosity) were integrated. This comprehensive dataset was utilized to build a multi-mineral model for petrophysical evaluation.

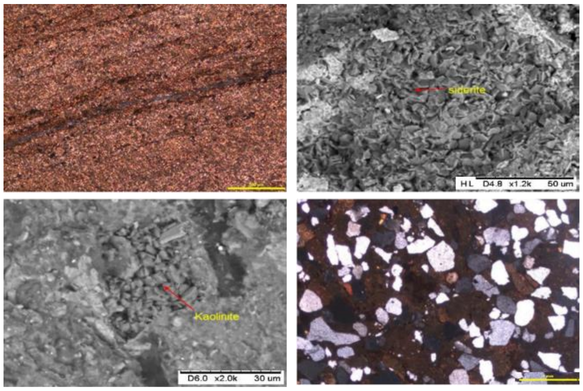

Figure 2: Left Top & Right Top: Presence of sideritic shale composed mainly of detrital clays and little quartz. Left Bottom: SEM image shows Kaolinite in the cavities. Right Bottom: Dominantly sandstone lithology composed of moderately sorted medium grained, sub angular quartz (OCS, Well A)

Fig. 2 illustrates presence of quartz, kaolinite clay mineral and siderite in petrographic study (SEM, photomicrograph and thin section) which was carried out on core samples from OCS formation of Well: A. XRD study carried out for core samples of well A further bolsters the minerals observed in SEM and thin section. Fig. 3 depicts XRD analysis of representative samples revealing that clay (Kaolinite and chlorite) is the most abundant mineral followed by quartz and siderite.

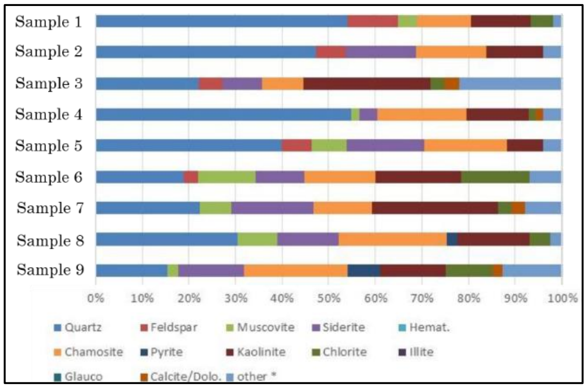

Figure 3: XRD analysis (Well A, OCS) showing dominant presence of kaolinite, chlorite, quartz and siderite. Minor amount of muscovite, feldspar, pyrite and calcite/dolomite is also observed.

Thus a multi-mineral model comprising quartz, mixed clay and siderite was built for carrying out petrophysical evaluation for OCS formation in the study area.

Porosity plays a critical role in determining the elastic properties of the reservoir. To ensure realistic computations, the porosity derived from a multi-mineral model was compared and validated against NMR porosity. Fig. 4 shows the complimentary nature of total and effective porosity obtained from NMR and multi-mineral model for Well: E.

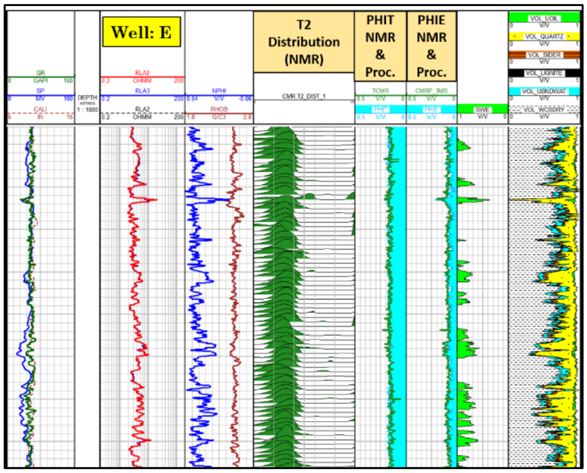

Figure 4: Comparison showing Total and Effective Porosity from NMR log and multi-mineral model are consistent (Well: E)

A representative paralog of the area is shown in Fig. 5 highlighting the thin and clean sands developed in OCS formation with ~25% effective porosity and 8-10% water satutaion.

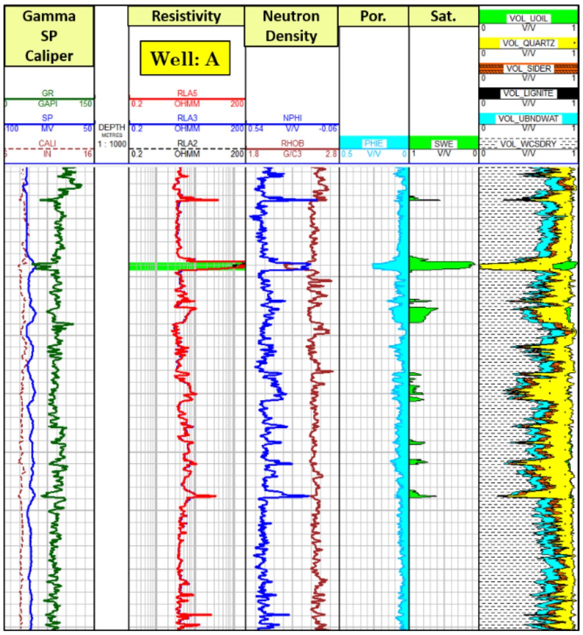

Figure 5: Representative well: A, showing conditioned logs and processed logs. Clean and porous thin sands are developed within OCS

Rock Physics Modelling:

There are many rock physics models that allow for the modelling of the elastic properties of rocks based on the volumes and the elastic properties of the component minerals and fluids. The elastic properties of the rock, other than density, are dependent on the micro-structure of the rock. Inclusion-based rock physics models account for the micro-structure mainly by assigning shapes to the pore space, and sometimes to the minerals. Rock physics modelling encompasses four key steps, including solid mineral-mixing, dry framework modelling, fluid mixing and substitution and computation of saturated elastic parameters.

Nature mixes two constituents of rock within two limits which is understood by effective medium theory. For any given volume fraction of constituents the effective modulus of the mixture will fall between the bounds (Voigt. W, 1889 and Reuss A., 1929) but its precise value depends on the geometric details. In

this study, for mineral-mixing Voigt-Reuss-Hill average method was adopted.
Pore space is introduced using inclusion theory of Kuster-Toksoz, 1974 algorithm. Fluids are then introduced using Gassmann's equations (Gassmann F, 1951)

The bulk modulus K_f of a fluid mixture can be calculated using Wood's equation:
$\frac{1}{K_f} = \frac{S_w}{K_w} + \frac{S_o}{K_o} + \frac{S_g}{K_g},$ where K_w, K_o, and K_g are the bulk moduli of water, oil, and gas, respectively; S_w, S_o, and S_g are the water, oil, and gas saturations, respectively, expressed as volume fractions of the pore space; and $S_w + S_o + S_g = 1$. Equation also implies that the pore fluid is uniformly distributed in the pores.

The bulk density of the fluid mixture is calculated by

$$\rho_f = S_w\rho_w + S_o\rho_o + S_g\rho_g,$$

where ρ_w, ρ_o and ρ_g are the bulk densities of water, oil, and gas, respectively.

The Gassmann equation has been used for calculating the effect of fluid substitution on seismic properties using the frame properties. It calculates the bulk modulus of a fluid saturated porous medium using the known bulk moduli of the solid matrix, the frame, and the pore fluid. For a rock, the solid matrix consists of the rock-forming minerals, the frame refers to the skeleton rock sample, and the pore fluid can be a gas, oil, water, or a mixture of all three:

$$K^* = K_d + \frac{(1 - K_d/K_m)^2}{\frac{\phi}{K_f} + \frac{1-\phi}{K_m} - \frac{K_d}{K_m^2}},$$

where K^* is the bulk modulus of a rock saturated with a fluid of bulk modulus K_f (Batzle-Wang, 1992). K_d is the frame bulk modulus, K_m is the matrix (grain) bulk modulus, and Φ is porosity. The shear modulus G^* of the rock is not affected by fluid saturation, so that $G^* = G_d$, where G_d is the frame shear modulus of the rock. The density of the saturated rock is volume weighted average.

The computed saturated bulk moduli (K^*), shear moduli (G^*) and density (ρ^*) are then used to derive compressional velocity, shear velocity and bulk density.

The most commonly used Xu & White (Xu White, 1995) rock physics model (based upon inclusion theory of Kuster-Toksoz ,1974 have been applied for building and calibrating rock physics model using elastic logs from well: A, B and C. The essential feature of the Xu & White model is the assumption that pore-geometry associated with sand grains is significantly different from that associated with clays. In present study, aspect ratio of the sand-related pore are 0.13-0.14 and clay-related pores are 0.03-0.04 used in the Xu-White model. Then Gassmann model is used to simulate the effect of the fluid relaxation. The model was used for prediction of compressional and shear velocities of Older Cambay Shale formation in all 6 wells viz. well: A, B, C, D, E and F.

Results & Discussions

Ødegaard and Avseth, 2004 had proposed a technique where rock physics template (RPT) was used to estimate fluid and mineralogical content of a reservoir using cross plot of Vp/Vs ratio against acoustic impedance. Fig 6 shows a RPT which describes the effect of clay content, porosity, saturation, cementation and pressure.

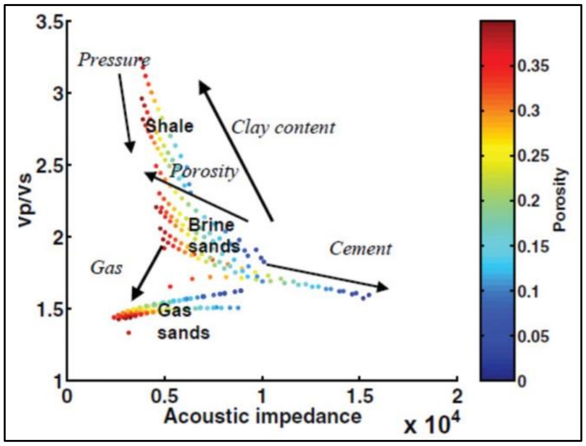

Figure 6: Rock Physics Template (after Odegaard and Avseth, 2004)

The modelled elastic logs have been analyzed both in log display as well as on crossplots to comprehend the behavior of reservoir (both hydrocarbon and water bearing) and non-reservoir zones. The P-Impedance (x-axis) and Vp/Vs (y-axis), highlighting the discrimination of various fluid-litho facies, from recorded and modelled logs for well: A, B & C is shown in Fig. 7.

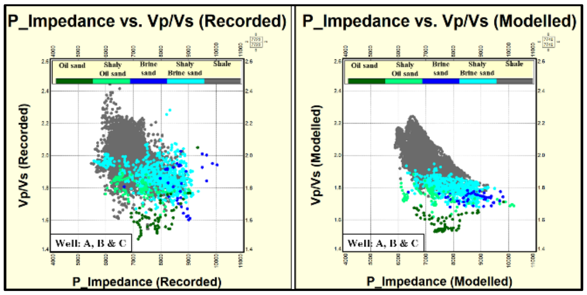

Figure 7: Recorded (left) and Modelled (right) xplot of P-Impedance vs. Vp/Vs colored with Fluid-Lithology log for well: A, B & C.

The calibrated rock physics model was applied on all 6 wells for which the crossplot is shown in Fig. 8. Various fluid-litho facies viz. oil sand, shaly oil sand, brine sand, shaly brine sand and shale are very well segregated on the crossplot thus allowing discrimination of these facies using the elastic logs.

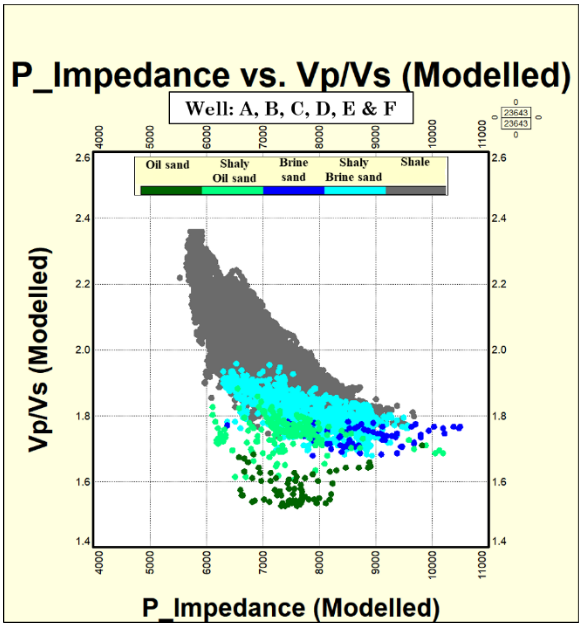

Figure 8: Crossplot of P-Impedance (modelled) vs. Vp/Vs (modelled) colored with Fluid-Lithology log for well: A, B, C, D, E & F.

To check the efficacy of the model, crossplots of recorded and modelled slowness and density were also analyzed. A high correlation coefficient of 0.92, 0.91 and 0.95 was observed between recorded and modelled compressional sonic, shear sonic and density log respectively (Fig 9).

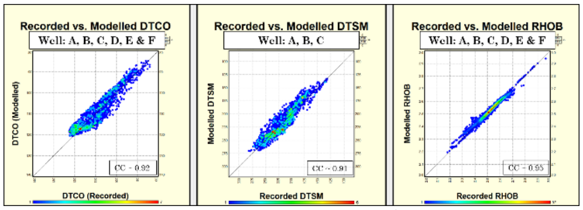

Figure 9: Recorded vs Modelled DTCO (left), DTSM (mid) and Density (right) data showing high correlation coefficient.

A representative paralog and crossplot (well: C) is shown in Fig. 10 to compare the recorded and rock physics modelled logs. A satisfactory match is observed between the recorded and modelled elastic logs for both pays and non-pays (last four tracks). The fluid and lithology are well discriminated for recorded as well as modelled data on RPT (xplot). The sensitivity of Vp/Vs log against pay zone may be attributed to the high porous nature of reservoir.

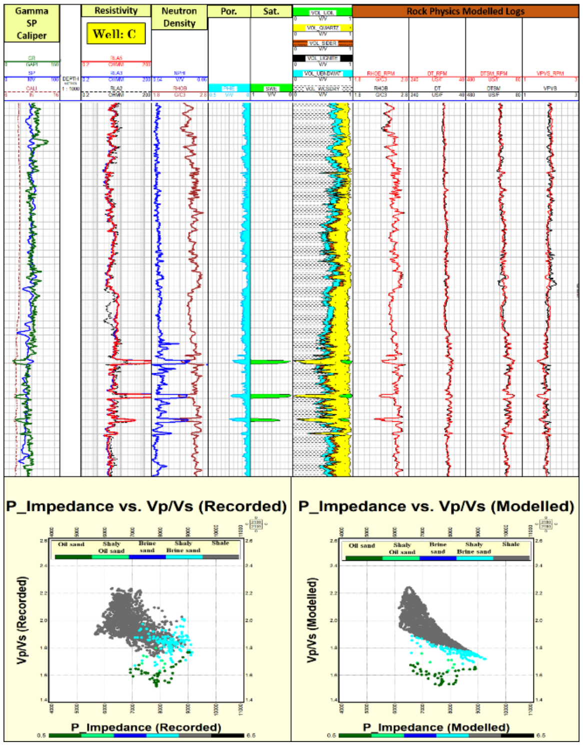

Figure 10: Paralog and crossplots showing good match between recorded and modelled elastic logs (well: C).

Vp/Vs and P-impedance estimated by the present study at well level has been upscaled to seismic bandwidth and used to generate seismic inversion volumes in 3D-space. Based on the inversion results, a new well (well: G) was proposed shown in Fig 11 along with its adjacent wells. The proposed well turned out to be a success as it produced oil@88.8m3/d and gas@14,040m3/d from the objective sands. This proves the efficacy of the modelling technique and its usefulness in seismic reservoir characterization.

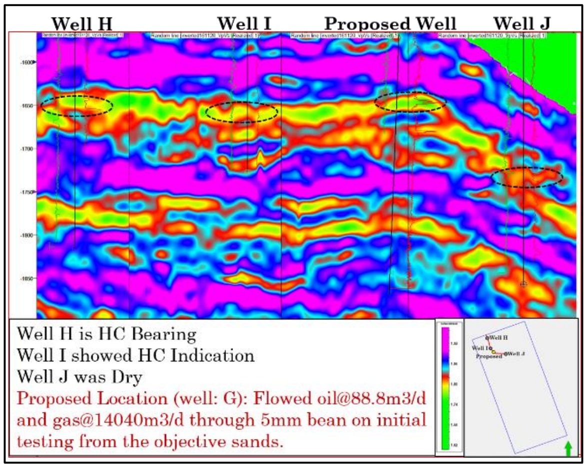

Figure 11: Vp/Vs section from pre-stack seismic inversion showing proposed exploratory location with low Vp/Vs value.

Like any other scientific tool, rock physics modelling has its own limitations. Rock physics modelling and its interpretation is seriously impeded by challenges such as oversimplified assumptions, uncertainty in model-parameters, limited data, non-uniqueness, limited model applicability, geological complexities and validation. Consequently, this necessitates the interpreters to not only meticulously carry out pre-modelling feasibility study but also maintain an awareness of the likelihood of success. Despite these limitations, rock physics modelling remains a valuable tool for understanding and predicting subsurface properties.

Conclusions

The present study has brought out a multi mineral log interpretation model based upon integration of logs and core-studies. Inclusion theory based Xu-White rock physics model suits rock physics modelling to predict elastic logs in six wells across Linch area. Rock Physics Modelling has differentiated various litho-facies on rock physics template. The values of Vp/Vs in oil, water and shale were found to be 1.53-1.7, 1.7-1.85 and 1.75-2.35 respectively. The study facilitated pre stack inversion to identify hydrocarbon bearing geo-bodies based on which an exploratory location was proposed that turned out to be a success by yielding hydrocarbon from the targeted sands. Despite the potency of rock physics modeling, it is imperative to be aware of its limitations when interpreting the results.

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