An integrated petrophysical and rock physics modelling for characterization of Early Miocene reservoir in Kesanapalli West field of Krishna Godavari Basin, India

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Keywords

Petrophysics, Rock physics modelling, Miocene Sands, Kesanapalli West, Krishna Godavari Basin

Abstract

Petrophysical evaluation of well log data has always been crucial for identification and assessment of hydrocarbon bearing zones. In present paper, petrophysical evaluation of well log data from cluster of 35 wells in the study area is carried out in combination with rock physics modeling of 7 wells for qualitative and quantitative characterization of Early Miocene reservoir in Kesanapalli West oil field of Krishna Godavari Basin India. Petrophysical evaluation has provided the estimation of fluid and mineral types, rock/pore fabric type and fluid and mineral volumes for invaded and virgin zones. Calibrations are made where cutting and testing data were available.

Rock physics study is carried out for analyzing the influence of porosity, mineral compositions and saturation variations on the elastic properties of the subsurface. The rock physics modeling allowed quantitative prediction of relationship between porosity, saturation (gas, oil and water), clay volume and the elastic properties. Cross-plots of different elastic parameters are generated to identify the lithology variability and pore-fluid type, and to establish likely distinction between the hydrocarbon bearing sands, brine sands and shale.

The Early Miocene reservoirs are found to be primarily sandstone intermixed with incidental clay matrix and some calcareous cementation. Sands are interpreted to be continuous in most of the blocks. The effective porosity for these sands varies from 15 to 25%, with minor clay content ranging from 5% to 25%, and water saturation ranging from 30% to 55%.

Finally, a numerical rock physics model based on Xu-White methodology is prepared to predict the elastic properties of the rock from petrophysical properties. Rock physics attributes such as acoustic impedance and Vp/Vs ratio and lambda-rho ($\lambda\rho$), mu-rho ($\mu\rho$) based on the Lame's parameter of incompressibility(λ), rigidity (μ) and density(ρ) have been combined to discriminate lithology and fluid types.

The modelled elastic properties inferred that acoustic impedance (Zp) values for range from 16500 to 34000 ft/s*g/cc sand facie, while the Vp/Vs ratio for gas, oil, and water sands ranges from 1.50 to 1.55, 1.55 to 1.65, and 1.65 to 2.20, respectively. Non-reservoir facies, including shale/silts, exhibit P-Impedance values of 15000 to 35000 ft/s*g/cc and Vp/Vs ratios of 1.70 to 2.80. The study concludes that gas sand, oil sand, and water sands are distinguishable on P-Impedance (Zp)-Vp/Vs ratio cross-plot.

Introduction

Petrophysical evaluation is a crucial component of reservoir characterization as it plays a significant role in distinguishing between hydrocarbon-bearing and non-hydrocarbon-bearing zones. Several techniques have been proposed in the literature for fluid and lithology discrimination, including those suggested by Castagna and Swan (1997). The primary objective of petrophysical analysis is to convert wireline log data into reservoir properties such as shale volume, porosity, permeability, and water and hydrocarbon saturation. Accurate analysis of these reservoir properties enhances the ability to differentiate between hydrocarbon-bearing and non-hydrocarbon-bearing zones. However, petrophysical results can be influenced by adverse borehole conditions and missing logs, temperature, pressure, and salinity. Moreover, petrophysical models are typically established for specific intervals of interest based on single-well data. Consequently, these models may be consistent within the given interval but may fail to yield satisfactory results when applied to wells in close proximity (Bisht et al., 2013).

To address these limitations, integrated workflows combining petrophysics and rock physics are employed to develop consistent rock physics models that encompass the entire area of interest. The establishment of a consistent rock physics model enables the synthesis of elastic logs, identification of inconsistencies in well logs, rapid well data analysis, and improved seismic-to-well tie, ultimately enhancing reservoir characterization and reducing uncertainty risks (Bisht et al., 2013). Calibrated models also enable accurate predictions of lithology and fluid saturation variations (Odegaard and Avseth, 2004). Integrated rock physics models establish more accurate and reliable connections between petrophysics, seismic data, and reservoir properties. Numerous rock physics models have been proposed by researchers. Avseth et al. (2005) classified these models into different categories, including inclusion models, contact models, transformations, bounds and computational models.

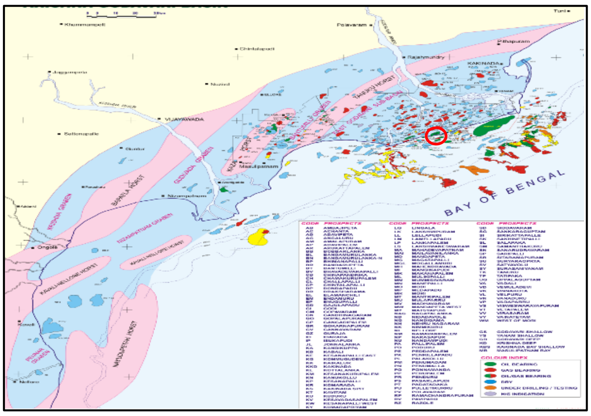

Figure-1. Location of the study area, Kesanapalli West field, located west of Vainateyam River in coastal tract of island area.

Inclusion models treat rocks as elastic blocks composed of minerals and pore spaces, yielding better consistency with measured well log data. Xu and White (1995) proposed a clay-sand mixture model based on the inclusion model by Kuster and Toksoz (1974), supplemented by the Gassmann (1951) and effective medium theories (Zhang, 2008). This model accounts for the impact of clay content on seismic velocities and proves valuable for estimating shear wave velocity. The combination of shear and acoustic velocities has been widely utilized as a seismic attribute in reservoir.

The Matsyapuri sandstone formation of the Early Miocene age is a proven reservoir in Kesanapalli West field of Krishna Godavari Basin, India. The sand intervals of this formation are composed of quartz, feldspar, Kaolinite, clay, mica, and minor amounts of heavy minerals.

The aim of this study is to use an integrated approach based on petrophysical analysis and a rock physics model to characterize the Early Miocene play on seismic properties such as velocities and elastic moduli of the sand intervals. The rock physics model proposed by Xu and White (1995) is calibrated using wireline logs for the study area.

Study area

The present study Early Miocene play of Matsyapuri sandstone formation of Kesanapalli West field of Krishna Godavari Basin, India. The location map of study area is shown in Figure-1. Kesanapalli West field falls west of Vainateyam River in the coastal tract of island area and discovered in 1996. The structure trending ENE-WSW extends further into offshore. Litho-stratigraphic units of Eocene to Younger age in Kesanapalli West field are comprised of Vadaparru shale, Matsyapuri sandstone and Godavari clay formations (Figure-2). Matsyapuri sandstone comprising of sand/sandstone with minor claystone has been deposited in middle shelf environment. The sands within Matsyapuri sandstone unit form the main reservoirs in this field. Pay sands have both structural and as well as stratigraphic entrapment conditions.

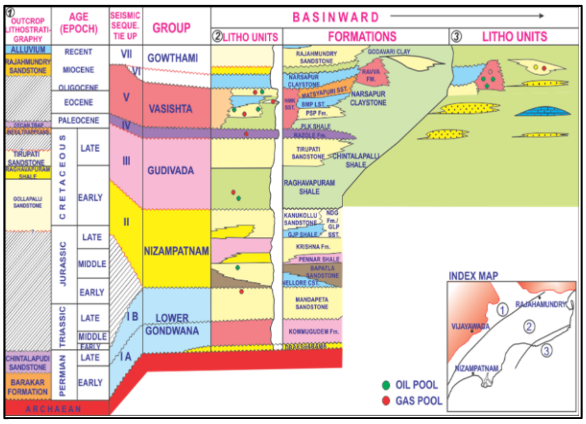

Figure-2. Litho-stratigraphic units of Eocene to younger age in Kesanapalli West field are comprised of Vadaparru (Eocene), Matsyapuri (Early-Miocene) and Godavari (Plio-Pliestocene).

Materials and Methodology

In the present study log data of 35 wells have been included for petrophysical evaluation. The conventional logs like, gamma-ray (GR), neutron porosity (NPHI), bulk density (RHOB), compressional -sonic (DT), shallow resistivity (LLS), and deep resistivity (LLD) well logs were is available in all 35 wells. Shear-sonic (DTS) was available in 4 wells. In other wells, shear log is either missing or not recorded. Rock-physics modelling was performed in seven wells of the area. The workflow of the methodology is shown in figure 3.

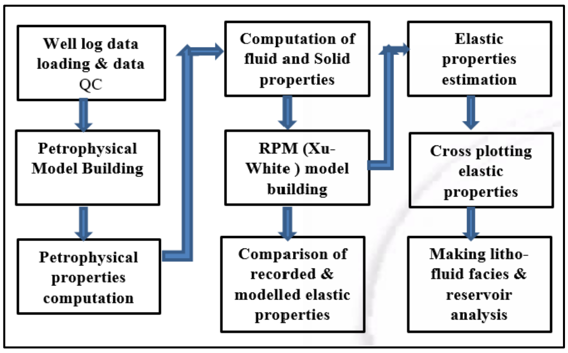

Figure- 3. Schematic diagram of workflow and methodology adopted for integrated reservoir characterization.

Results and discussion

The methodology proposed in the previous section is applied on the wireline logs of all the wells under study. In this section, the petrophysical study of reservoir intervals is presented firstly. Then the results of rock physics modelling are thoroughly discussed. The calibrated rock physics model and petrophysical analysis are used for reservoir characterization in the reservoir intervals encountered in the seven wells of the study area.

Petrophysical Evaluation

Petrophysical analysis fills a gap between core and seismic data and plays an important role in reservoir characterization. The estimation of various petrophysical parameters from wireline logs with accuracy can significantly enhance the ability to interpret the lithology and reservoir characterization

The quality checked of logs has been performed before data processing and the conditioned logs are taken as input for processing of log data for mineral and fluid volumes computation through petrophysical model.

Petrophysical Model

Processing of log data of 35 wells has been carried out using the Multimin Module of Geolog Software. Multimin is a mineral (or rock) and fluid modeling tool. An initial petrophysical model is built using lithology and fluids knowledge from nearby wells, mud logs and cuttings, core descriptions, core analysis and cross-plot analysis. The Multimin analysis uses the model mineral and fluid responses to calculate pseudo-logs (or predicted logs). The extent of matching of the generated logs with recorded logs is an indication of how close the model is with the reality. The model can be adjusted in terms of minerals and fluids and their responses to improve the match.

Cross plots of Neutron porosity vs. bulk density (Figure-4) and Potassium vs. Thorium concentration (Figure-5) have been generated to identify matrix and clay mineral constituents of the formation.

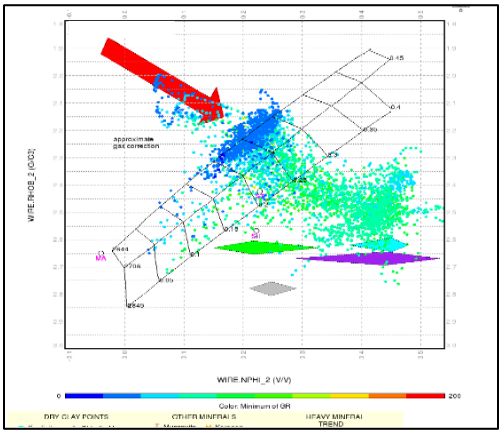

Figure- 4. Cross plot of Neutron porosity versus bulk density cross-plot for lithology identification.

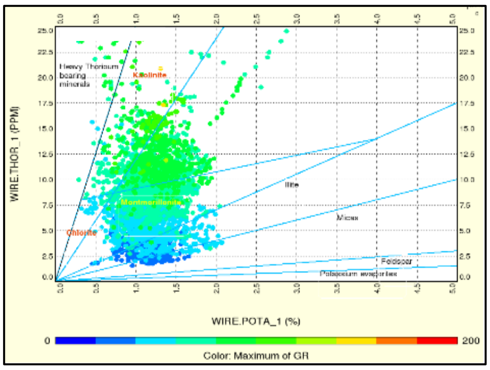

Figure-5 Potassium-Thorium Cross-plot for clay mineralogy

Based on well logs characteristics, ditched sample description and well testing details a robust petrophysical model comprising of Quartz, feldspar, Silt, Mica and SM1 (heavy mineral) were developed. The model also encompasses clay mineral Kaolinite and Illite-Smectite. Oil, Gas and Water have been taken as fluids in the model. Based on produced formation water salinity 11.8 gpl and 11.5 gpl. formation water resistivity Rw~ 0.15-0.18 ohm-m at formation temperature with standard Archie's parameters ('a=0.62', 'm=2.15', 'n=2') were taken for processing of well log data.

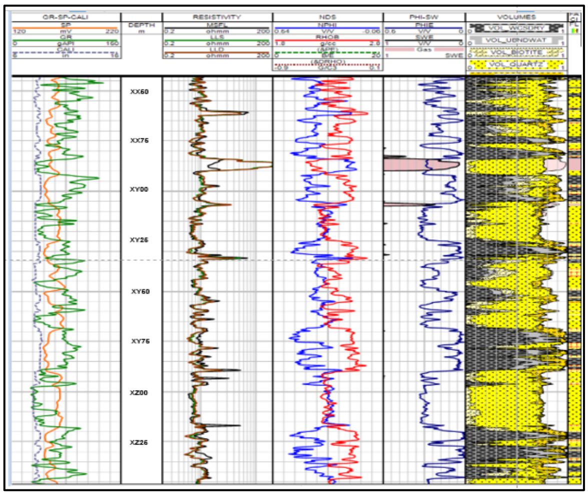

Figure-6. Well log plot showing log curves and computed petrophysical properties using developed petrophysical model

Water saturation

As the presence of shale also affects the water saturation, we compensate for the effect of shale by applying the Indonesian model (Poupon and Levaux 1971). This model improves the results reliability in shaly formations. The mathematical form of this model is

$$S_w = \left[\left\{\left(\frac{V_{sh}^{2-V_{sh}}}{R_{sh}}\right)^{1/2} + \left(\frac{\phi_e^m}{R_w}\right)^{1/2}\right\}^2 R_t\right]^{-1/2}, \qquad (1)$$

Where S_w represents water saturation; R_{sh}, R_w, and R_t are the shale, water, and true resistivities, respectively; These estimated petrophysical parameters (volume of shale, porosity, and water saturation) and mineralogical volumes are shown in figure-6.

Rock physics modelling

Rock physics modelling is a process of finding an appropriate model that shows good consistency with the available well log data. The proposed Xu–White (1995) clay–sand mixing model is based on the Kuster and Toksoz (1974) model supplemented by the Gassmann (1951) and pore aspect ratio theories. This model has the ability to separate the sand- and clay-related pores by assigning them different aspect ratios. If α_s and α_c are the aspect ratios of sand- and clay-related pores, Φ_s and Φ_c are porosities of sand grains and clay content, respectively. Then these sand and clay grains can be mixed through clay content in order to calculate the elastic properties of dry rock porous media, as shown in equations (2)–(4):

$$\frac{K_d - K_m}{3K_d + 4\mu_m} = \frac{1}{3}\left(\frac{K_f - K_m}{3K_m + 4\mu_m}\right)\sum_{l=s,c}\Phi_l T_{iijj}(\alpha_l), \tag{2}$$

$$\frac{\mu_d - \mu_m}{6\mu_d(K_m + 2\mu_m) + \mu_m(9K_m + 8\mu_m)} = \frac{\mu_f - \mu_m}{25\mu_m(3K_m + 4\mu_m)}\sum_{l=s,c}\Phi_l F(\alpha_l), \tag{3}$$

$$F(\alpha_l) = T_{ijij}(\alpha_l) - \frac{T_{iijj}(\alpha_l)}{3}, \tag{4}$$

where K_d, K_m, and K_f represent bulk modulus of dry rock frame, solid matrix, and pore fluid respectively, and μ_d, μ_m, and μ_f represent the corresponding shear modulus. Φ is the porosity, while $T_{iijj(\alpha l)}$ and $T_{ijij(\alpha l)}$ are the scalar functions of the aspect ratio, which have been calculated using the Eshelby (1957) approach.

The elastic properties of clay are not well established in this area and vary dramatically for different clay types. At the initial stage of this model, we used the typical solid mineral values for clay and sand as proposed in literature. The Wyllie et al (1956) time average equation was used as a mixing algorithm to get the solid matrix properties. Batzle and Wang (1992) proposed relationships were used to compute in situ fluid temperature and pressure. These fluid properties have been mixed using the Brie et al (1995) mixing algorithm as shown in equation (5):

$$K_{Brie} = (K_b - K_g)(S_w)^e + K_g, \tag{5}$$

Where S_w represents water saturation; K_b and K_g are the bulk modulus of brine and gas, respectively, K_{Brie} represents the bulk modulus of fluid calculated using Brie's approach, and e is the exponent of fluid mixing whose value varies from 1 to 40. When e=1, the mixing is Voigt's average and when e=40, the mixing results are very near to wood's average (Brie et al 1995).

The elastic moduli of saturated rocks were calculated using the Gassmann (1951) fluid substitution model, which gives the relationship between bulk modulus of saturated rock, dry rock modulus, pore fluid, and solid matrix (equations (6) and (7)):

$$K_{sat} - K_d = \frac{\left(1 - \frac{K_d}{K_m}\right)^2}{\frac{\Phi}{K_f} + \frac{(1-\Phi)}{K_m} - \frac{K_d}{K_m^2}} \tag{6}$$

$$\mu_{sat} = \mu_d. \tag{7}$$

Density of saturated rock was calculated using equation (8):

$$\rho_{sat} = \Phi\rho_f + (1 - \Phi)\rho_m. \tag{8}$$

Here, K_{sat} and μ_{sat} are the bulk and shear modulus of the saturated rocks, respectively, whereas ρ_{sat}, ρ_f, and ρ_m represent the densities of the saturated rock, pore fluid, and solid matrix, respectively. Finally, we substitute K_{sat}, μ_{sat}, and ρ_{sat} values in equations (9) and (10) to obtain the elastic velocities

$$V_P = \sqrt{\frac{K_{sat} + \frac{4\mu_{sat}}{3}}{\rho_{sat}}} \tag{9}$$

$$V_S = \sqrt{\frac{\mu_{sat}}{\rho_{sat}}}. \tag{10}$$

After building a rock physics model, the most important task is to adjust the input parameters for the specific reservoir. Most of the default parameters failed to properly match the modelled logs with the measured logs, as elastic properties of clay have not been clearly defined. Therefore, it is necessary to adjust the elastic parameters (density, P and S wave velocities) of clay to achieve an optimal fit with the measured logs within the target interval. For this purpose, we constructed a series of models to adjust the elastic values of clay and aspect ratios. The typical values for sand and clay related pores are 0.12–0.15 and 0.02–0.05, respectively (Xu and White 1995) which were tested in the calibration process. After trial and error, the final values of aspect ratios and elastic parameters were selected. At these selected values, the modelled velocities show very good consistency with the measured velocities (figure-8)

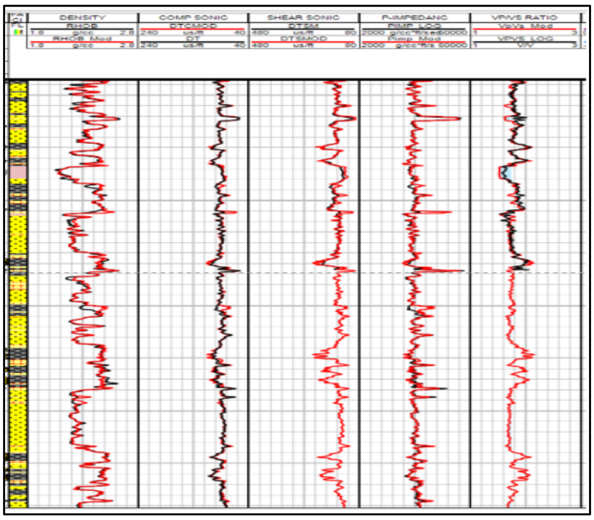

Figure-8. Log plot between recorded (black) and modelled (red) elastic logs (bulk density, Compressional Sonic -DT, Shear Sonic-DTSM, Acoustic Impedance-PIMP and Vp/Vs ratio).

Reservoir characterization

Rock physics models are utilized as an important tool in reservoir characterization. They create the bridge between elastic properties (P-wave velocity, S-wave velocity, density, impedance, and VP/VS ratio) and reservoir properties (porosity, permeability, and saturation) (Avseth 2000, Chi and Han 2009).

The calibrated rock physics model has been utilized to estimate the elastic properties of reservoir interval encountered in each well.

Elastic attributes (VP/VS ratio) has the ability to discriminate between different type of lithology and payable sand in the target. However, a combination of P-impedance and VP/VS ratio can be utilized to efficiently predict the lithology and fluid saturation (Odegaard and Avseth 2004,). Based on P-impedance and VP/VS ratio response, these data clusters is classified into five different lithologies/facies and a fluid and lithology discriminator (FLD) flag is created. The FLD flag has a defined value and colour for each lithologies/facies (Table-1). To verify the effectiveness of the model, calculated and measured elastic impedance is cross-plotted against VP/VS ratio for Well: X-1 in figure-7 and for Well: X-2 in figure-8. The data points are colour coded using fluid and lithology discriminator (FLD) flag.

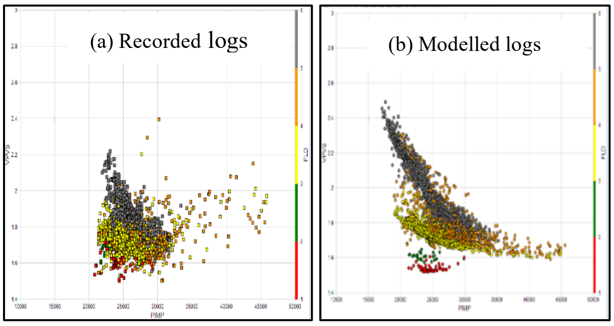

Figure-7. Well: X-1, Comparison between recorded and modelled elastic properties. (a) Recorded acoustic impedance versus VP/VS ratio. (b) Modelled acoustic impedance versus VP/VS ratio.

In Well: X-1 and X-2, the cross plot between modelled parameters (figure 7(b), 8(b)) clearly separates the different types of facies whereas cross plot between recorded (logs) parameters (figure 7(a), 8(a)) fails to separate these facies. Since the measured log data is affected by different parameters and environmental conditions, it is difficult to discriminate fluid contents or lithology from log data. However, in modelled data, we have more control over the input parameters, so it is more suitable and effective for differentiating different type of facies.

Table-1, Fluid lithology discriminator (FLD) flag

Lithology/facies	FLD Code	Colour
Gas Sand	1	Red
Oil Sand	2	Green
Water Sand	3	Yellow
Tight/Slity Sand	4	Orange
Shale	5	Gray

Keeping in mind the effectiveness of the model, cross plots between VP/VS ratio and acoustic impedance (figure 9) have been developed in order to discriminate between the different types of facies in all wells.

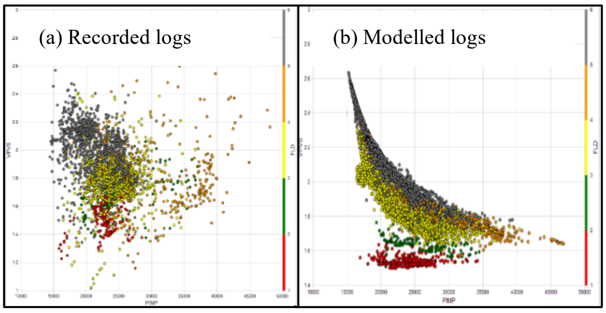

Figure-8. Well: X-1, Comparison between recorded and modelled elastic properties. (a) Recorded acoustic impedance versus VP/VS ratio. (b) Modelled acoustic impedance versus VP/VS ratio.

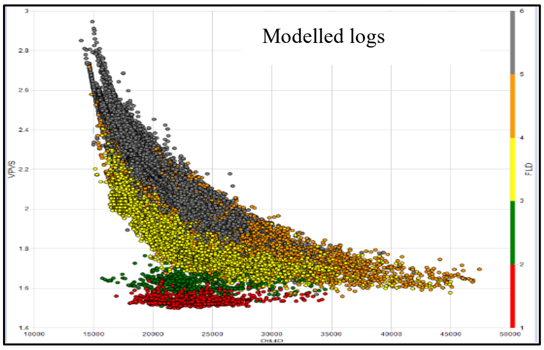

Figure 9. Modelled acoustic impedance versus VP/VS ratio for all the wells. Data is colour coded with FLD flag, to demarcate the different litho-facies and fluid types.

From figures 9, it can be clearly seen that acoustic impedance value for sand facie ranges from 16500-34000 (ft/s*g/cc) and Vp/Vs ratio ranges from 2.20 to 1.60. Shale shows acoustic impedance of 15000-35000 (ft/s*g/cc) and a Vp/Vs ratio of 1.70-2.80. Gas Sands are characterize by Vp/Vs ratio of 1.51-1.55 while for oil sands Vp/Vs ratio ranges from 1.68 to 1.55.

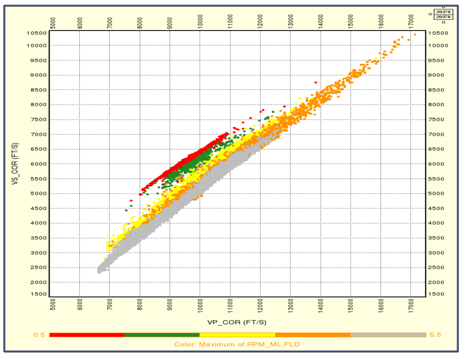

Figure 10. Cross-plot of modelled compressional velocity versus shear velocity for all the wells.

The cross plots of modelled compressional velocity versus shear velocity (figure-10) and Lambda-rho and mu-rho (figure 11) based on the Lame's parameter of incompressibility(λ), rigidity (μ) and density(ρ), as described by Goodway et al., (1997) have also been combined to discriminate lithology and fluid types.

The cross-plotting results show that our calibrated model effectively predicts the lithology and fluid content in the

Early Miocene play of Matsyapuri formation of Kesanapalli West field of Krishna Godavari Basin, India.

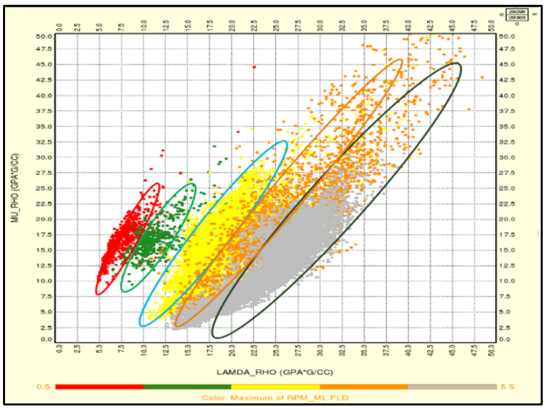

Figure 11. Cross plot of rock physics attributes λρ (GPa*g/cc) versus μρ (GPa*g/cc) clearly demarcates the different litho-facies and fluid types.

Conclusions

In this study, an integrated petrophysical and rock physics modelling approach is adopted to understand the reservoir characterization of Early Miocene play of Matsyapuri formation of Kesanapalli West field of Krishna Godavari Basin, India. The developed methodology helped us to build up an accurate and consistent rock physics model. The calibrated model shows good consistency between measured and modelled velocities. The good consistency of the model laid a significant foundation for improved reservoir characterization in the study area. The calibrated model has also proven helpful in accurately estimating the elastic parameters (density, P and S wave velocities) even in those wells where shear logs were missing in the target zones. Rock physics attributes such as acoustic impedance and Vp/Vs ratio and lambda-rho (λρ), mu-rho (μρ) have been combined to successfully discriminate lithology and fluid types. Cross plots of these modelled parameters clearly delineate the lithology and fluid content. On the basis of these cross plots, the quantitative values of elastic parameters have been defined in order to discriminate between the gas-bearing, oil bearing, water bearing sand, shale, and shaly/silty sand zones. It is found that the VP/VS ratio is more sensitive to gas-bearing sand followed by acoustic impedance. The proposed model allows for accurate discrimination between different types of facies and provides quick results. It can also be effectively utilized in seismic inversion to improve seismic reservoir characterization.

Acknowledgements

The authors are indebted to Shri Vishal Shastri, ED-HOI-GEOPIC, ONGC, Dehradun, India for providing the technical input and guidance for writing this paper. Thanks are due to Shri Kishori Lal, Head-INTEG, GEOPIC, ONGC, Dehradun, India for providing all kind of support for this work. We thank ONGC management for allowing this paper to submit in SPG 2023 14th International Conference and Exposition.

The views expressed in this paper are solely of the authors and do not necessarily reflect the views of ONGC.

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