An integrated approach for reservoir characterisation in deep-water Krishna-Godavari basin, India: a case study

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Abstract

The Miocene reservoirs in prolific Krishna-Godavari basin are mostly fluvial deposits and laminated or blocky in nature. The type of reservoir quality depends on associated geological environments. Due to several lateral variations in reservoir properties, a similar kind of workflow for reservoir characterisation does not work. Customised workflow needs to be applied in this area for estimation of petrophysical properties or rock physical analysis for reservoir quality prediction. As the major input of rock physical analysis is petrophysical properties, it is crucial to estimate these properties accurately. Meanwhile, it is also important to check the seismic sensitivity to change in fluid saturation in the reservoir characterisation process. The analysis assures the presence of reservoir and hydrocarbon contact in seismic sensitivity, which is essential for removing risk. Integrating the geological model with rock physical analysis for reservoir characterisation at the drilled well, the reservoir quality at undrilled prospects is predicted. In this study, the comprehensive study for reservoir characterisation of Miocene reservoirs consists of three different steps: calculation of petrophysical properties for mixed of thick and laminated sequence, rock physical analysis for identification of hydrocarbon reservoir and corresponding seismic sensitivity for change in saturation and finally the rock physics template for prediction of reservoir quality away from the drilled well. Results from the study have added significant value in de-risking the number of undrilled prospects in this area.

Keywords: laminated reservoir, reservoir properties, extended elastic impedance, rock physics template, elastic properties

1. Introduction

Estimation of petrophysical properties for laminated/thin bedded reservoirs have always been a challenge for geoscientists. Furthermore, reservoir characterisation faces similar challenges as the input depends on petrophysical properties such as porosity, shaliness and saturation. It has been suggested by many studies (Poupon et al. 1954; Bateman 1990; Popta et al. 2004; Alao et al. 2013; Pradhan et al. 2015) that, most of the time, conventional methods for petrophysical evaluation (e.g. porosity and saturation calculation) in this kind of reservoir do not work properly. This occurs because the conventional approaches are based on assumptions such as clean sand, uniform porosity distribution and so on. There are possibilities of underestimating reservoir properties even over a great extent. As mentioned, the results add significant error in further reservoir characterisation, which uses the derived properties from petrophysical analysis. The study area used here is located in the deep-water
Krishna-Godavari basin (figure 1) where the water depths vary in the range of 1000 to 1200 m. The Miocene reservoirs in this area are mostly fluvial deposits within a channelised fan-lobe system. The overburden thickness above the reservoir sequence is approximately 2700 m at Well A. The reservoirs are laminated and blocky based on the location within the fan-lobe set up. In some reservoirs, the bed thicknesses are even less than the resolution of the resistivity imaging tool (Bastia et al. 2007; Yadav et al. 2010, 2012). Different approaches have been taken (Saxena & Klimentos 2004; Guha et al. 2006; Voleti et al. 2012) to estimate petrophysical properties to mitigate the challenges such as the thin bed, low resistive pay and induced fracture presence. The accuracy in estimation of those petrophysical properties ensures the best outcome in reservoir characterisation. This study focuses on accurate estimation of reservoir properties at well location and then the use of those results in reservoir characterisation for the entire study area to predict the quality of possible reservoirs at undrilled locations.

Reservoir characterisation primarily aims to define the reservoir in terms of rock and reservoir properties. In this regard, integration of petrophysical and rock elastic properties with a depositional environment is crucial to define and predict reservoir quality away from the drilled location (Mauricio 2005; Mondal et al. 2018, 2020; Singha & Chatterjee 2017; Das et al. 2018). The objective of this study is to predict reservoir quality away from the drilled Well A where there is evidence of significant lateral variation in reservoir quality. In addition, seismic sensitivity to change in fluid type reduces due to higher compaction in a deeper reservoir. In this study, the comprehensive approach of reservoir characterisation consists of three different steps: calculation of petrophysical properties for a mixture of thick and laminated sequences, rock physical analysis for identifying a hydrocarbon reservoir, corresponding seismic sensitivity for a change in saturation and finally rock physics template analysis for prediction of reservoir quality at undrilled locations. The workflow for this case study is discussed in section 2.

2. Workflow

The workflow starts with petrophysical analysis and ends with predictive reservoir characterisation (figure 2). The part of the workflow for petrophysical analysis can be applied to both laminated and thick reservoir sequences. The Thomas–Stieber (TS) model (Thomas & Stieber 1975) is used to inspect the type of reservoir. The model shows how the porosity of the reservoir is affected by the presence of different types of shale. If the reservoir has a thick and clean sand sequence, the porosity of the reservoir is equivalent to clean sand porosity ($\phi_s$) and total water saturation is calculated using Archie’s equation. However, if the reservoir has a laminated sequence, volumes of laminated and dispersed shale (if present) are estimated using the TS and resistivity tensor models. The tensor model is also useful to estimate resistivity of sand lamina, especially in the case of a thin and laminated reservoir. Once the different shale volumes are estimated, effective porosity is calculated. The Waxman–Smith (Waxman & Smiths 1968; Juhasz 1981) saturation equation is used to calculate the total water saturation. The model for estimating water saturation has been effective as the reservoirs in the study area have laminated sequences and there is evidence of a minor volume of dispersed shale presence (Mondal et al. 2018). Effective and total porosity, shale
volume and water saturation output have further been used in reservoir characterisation. When the reservoir has a thick sequence, Gassmann’s fluid substitution technique (Gassmann 1951) is applied to replace and model the reservoir for other fluid scenarios. However, in the case of a laminated sequence, a modified Gassmann’s fluid substitution method (Dejtrakulwong & Mavko 2011) is used, where the ratio of effective to total porosity measures the shale content within the reservoir. A rock physics crossplot has been performed to differentiate the reservoir from non-reservoir zone. Based on the crossplot, extended elastic impedance attributes have been identified for fluid and lithology. Consequential synthetic gather analysis represents the seismic sensitivity at gas–water contact. Similar seismic attributes have been generated using intercept and gradient volume and possibilities of hydrocarbon contact have been analysed. Finally, the rock physics template (RPT) analysis has been performed to predict the quality of reservoirs at undrilled locations. The detailed petrophysical analysis is discussed in section 3.

3. Petrophysical analysis

A comprehensive approach has been followed to estimate petrophysical properties of both thick and laminated sequences. As mentioned earlier, both types of reservoir are present in the study area. The volume of shale ($V_{sh}$) has been calculated from the gamma ray log. Total porosity ($\varphi_t$) has been estimated from a neutron (NPHI)-density (RHOB) crossplot. To calculate laminated and dispersed shale presence in $V_{sh}$, the TS model has been used. In laminated reservoirs, where the bed thickness is even below well log resolution, TS model has worked successfully in estimating shale volumes and porosities (Pedersen & Nordahl 1999). The total porosity in a laminated sequence is given by Mollison et al. (2001) as:

$$\varphi_t = \varphi_{ss} - V_{lam} (\varphi_{ss} - \varphi_{sh}),$$

(1)

where $\varphi_{ss}$ and $\varphi_{sh}$ are the porosities of clean sand and pure shale, respectively, and $V_{lam}$ and $V_{dis}$ are the volume fraction of laminated and dispersed shale where,

$$V_{sh} = V_{dis} + V_{lam}.$$  

(2)

Using total porosity input from a neutron-density crossplot and clean sand/shale porosity values, the volume of laminated and dispersed shale can be estimated from the model. In the case of authigenic clay deposition (dispersed shale), porosity decreases drastically and is described as

$$\varphi_t = \varphi_{ss} - V_{dis} (1 - \varphi_{sh}).$$

(3)

Figure 2. Comprehensive workflow for reservoir characterisation.
So, corresponding total ($\varphi_{t\_Sand}$) and effective ($\varphi_{e\_Sand}$) porosity for laminated sand from the model is given as

$$\varphi_{t\_Sand} = (\varphi_t - \varphi_{sh} \cdot V_{lam}) / (1 - V_{lam}),$$  \hspace{1cm} (4)

$$\varphi_{e\_Sand} = \varphi_{t\_Sand} - \varphi_{sh} \cdot V_{dis} / (1 - V_{lam}),$$  \hspace{1cm} (5)

where volumes of laminated ($V_{lam}$) and dispersed shale ($V_{dis}$) have been calculated for Well A using the TS model. The tensor resistivity model has also been used in this study, which includes two orthogonal resistivity measurements ($R_v$ and $R_h$ are the measured resistivity perpendicular and parallel to the bedding plane, respectively). Mollison et al. (2001) and Hayden et al. (2009) demonstrated this model in the following form

$$R_v = R_{sand} (1 - V_{lam}) + R_{shale\_vertical} V_{lam},$$  \hspace{1cm} (6)

$$\frac{1}{R_h} = \frac{(1 - V_{lam})}{R_{sand}} + \frac{V_{lam}}{R_{shale\_horizontal}},$$  \hspace{1cm} (7)

where $R_{shale\_vertical}$ and $R_{shale\_horizontal}$ are selected from the values of $R_v$ and $R_h$ in the pure shale section and $R_{sand}$ is resistivity of the sand layer. This model is effective in determining true laminar sand-fraction resistivity and laminar shale volume, where individual bed thickness is less than the resolution of the resistivity measuring tool (Klein et al. 1993, 1995; Hagiwara 1996; Gupta et al. 1998).

Figure 3 parts a and b show tensor resistivity and TS plots, respectively, for gas bearing intervals. For a gas bearing interval, clean sand porosity is approximately 30%, which has decreased linearly to 15% in pure shale. The percentages of dispersed shale are negligible. The tensor model shows the maximum resistivity of laminated sand layer is approximately 75 $\Omega$ m$^{-1}$. Sand total porosity ($\varphi_{t\_Sand}$) from this analysis has further been used for calculation of water saturation in a laminated reservoir. Comparison of laminated shale volumes derived from the models is shown in figure 4a.

As discussed, the present reservoirs have both thick and laminated thin-bedded sequences, so a similar saturation equation for entire zone will not work properly. Studies suggest that modified versions of Archie’s equation (Archie 1942) need to be developed and implemented (Juhasz 1981; Worthington 1995; Onovughe & Sofolabo 2016) for laminated sequences. $V_{sh}$ cut off (<5% for clean sand) has been applied to differentiate between clean and laminated sequences. In this study, Archie’s equation (for thick and clean sand) and the Waxman–Smith (for laminated sequence with dispersed clay) saturation model have been used for calculating water saturation. As mentioned earlier, the reservoirs in the study area have experienced the presence of minor dispersed clay, the Waxman–Smith model has been applied in this area to calculate the saturation in a laminated sequence. However, in the case where the dispersed clay is not present, other saturation equations such as Simandoux (Simandoux 1963) and Indonesia (Poupon & Leveaux 1971) can be applied for calculation of water saturation in this type of reservoir.

The estimated petrophysical properties for an entire interval in study Well A are shown in figure 4a. The plot shows the gross reservoir intervals containing hydrocarbon (3880–3898 m) and brine (4000–4043 m) fluids. Total porosity within the gross gas reservoir interval is approximately 30% where the brine interval has approximately 24% porosity. $V_{lam}$ Curves from the TS and tensor models show a significant match within the reservoir intervals. Figure 4b shows the comparison plot of saturation output from Archie’s equation (SWT_Archie) and the Waxman–Smith (SWT_WST) equation. A deep resistivity log ($R_d$) was taken as the resistivity input in the saturation calculation from Archie’s equation, whereas the Waxman–Smith equation used the bed parallel and perpendicular resistivity ($R_v$ and $R_h$) values. It can be seen from the plot that conventional Archie’s equation underestimated gas saturation values in
Figure 4. (a) Log motif of Well A. Track 3 shows gamma ray log, track 4 shows the neutron–density log. Track 5 shows total and effective porosity, track 6 shows laminated shale volume from the tensor resistivity model ($V_{sh\_Tensor}$) and Thomas–Stieber model ($V_{sh\_TS}$), track 7 shows total water saturation. (b) Comparison plot of the saturation log from Archie’s (black) and Waxman–Smith equations (red) for the interval (3880–3898 m), which contains gas-bearing reservoirs.
laminated shaly-sand intervals. In section 4, rock physics analysis for reservoir characterisation is discussed in detail.

4. Rock physics crossplot for reservoir characterisation

In reservoir characterisation, rock physics crossplots are used to differentiate litho-facies (Dutta 2009) within a gross reservoir interval. In this section, different crossplots are used to identify and characterise the reservoir from the log. Meanwhile, selected impedance attributes from crossplots have been generated to interpret gas–water contact in seismic sequences. The input of petrophysical properties for analysis is taken from the output of section 3.

As mentioned before, the preliminary objective of the crossplot is to differentiate between reservoir and non-reservoir facies. The lamda-rho ($\lambda\rho$) versus Mu-rho ($\mu\rho$) crossplot has been done for a depth range of 3875–4060 m (Figure 5). Mu-rho ($\mu\rho$) represents rigidity related to rock matrix values, which are higher for sand and lower for shale due to the higher rigidity of spherical sand grains. On the other hand, Lamda-rho ($\lambda\rho$) is measurement of incompressibility and the $\lambda\rho - \mu\rho$ crossplot is extensively used to identify fluid and lithology (Gray & Anderson 2000; Ekwe et al. 2011; Rasaq et al. 2015). The Lame' parameters ($\lambda, \mu$) are described as (Goodway 2010):

$$\lambda = (\alpha^2 - 2\beta^2)\rho, \quad (8)$$

$$\mu = \beta^2\rho, \quad (9)$$

where $\alpha$, $\beta$ and $\rho$ are compressional velocity, shear velocity and density of the layer, respectively. It can be seen in the crossplot that reservoir zones are differentiated from non-reservoir zones; the data from brine and gas bearing sands are separated due to the difference in porosity and saturation.

In this context, the acoustic and gradient impedance (AI and GI, respectively) crossplot (figure 6) has been found to be an effective way of visualising AVO behaviour and tying rock properties to seismic data (Whitcombe & Fletcher 2001). Along different projection angles in AI-GI crossplot, the maximum changes of the reservoir and rock properties can be measured. Whitcombe et al. (2000) introduced extended elastic impedance (EEI) as the generalisation of elastic impedance (Connolly 1999), which allows elastic seismic inversions to be carried out for various reservoir properties. Whitcombe & Fletcher (2001) describes EEI for a specific angle $\chi$ as

$$EEI(\chi) = \alpha_0\rho_0 \left[ \left(\frac{\alpha}{\alpha_0}\right)^p \left(\frac{\beta}{\beta_0}\right)^q \left(\frac{\rho}{\rho_0}\right)^r \right], \quad (10)$$

where

Acoustic impedance (AI) = $\alpha\rho$, \quad (11)

Gradient impedance (GI) = $\alpha\beta^{-6k}\rho^{-4k}$, \quad (12)

where $p = (\cos \chi + \sin \chi)$, $q = -8k \sin \chi$, $r = (\cos \chi - 4k \sin \chi)$ and $k = (\frac{2}{\rho})^2$. The suffix 0 (e.g. $\alpha_0, \beta_0$ and $\gamma_0$) indicates the average values between two consecutive layers. The projection angle is chi ($\chi$). EEI equivalent to $\chi = 0^\circ$ is acoustic impedance and at $\chi = 90^\circ$ is GI (Whitcombe & Fletcher 2001).

From figure 6, along fluid projection angle, maximum variations related to saturation will be captured. On the other hand, orthogonal to fluid projection, variations in lithology will be seen. EEI correlations for different rocks require further investigation.
and reservoirs are shown in figure 7. From the Al-GI cross-plot, chi (\(\chi\)) angle 20° has been selected as fluid indicator. At chi angle 20°, the maximum correlation for Lamda-rho (\(\lambda\rho\)) is observed. At this angle, the projection will optimally enhance fluid contacts. On the other hand, a projection angle of -70° has been shown to be insensitive to changes in pore fluid but potentially sensitive to changes in lithologies and has been used as a lithology indicator. The change in synthetic responses to change in fluid saturation will be discussed in the next part, which is crucial for detecting hydrocarbon contact in seismic sensitivity.

To generate EEI volumes using seismic values, reflectivity volume for specific \(\chi\) angle can be expressed as

\[
R(\text{EEI}\chi) = (A \cos \chi + B \sin \chi),
\]

where \(A\) and \(B\) are the intercept and gradient, respectively.

The extended elastic impedance (EEI20) volume has been also used in this study to check seismic sensitivity at fluid contact.

Figure 8 shows a synthetic gather analysis for the entire depth interval (3840–4085 m MD). The gas bearing zone shows class-II AVO response and is correlated with the trough in seismic sensitivity. Derived petrophysical properties from the previous section (porosity, saturation and shale volume) have been used in a modified Gassmann fluid substitute model (Dejtrakulwong & Mavko 2011) to calculate bulk modulus and density of the reservoir for different fluid scenarios. In this case, total gas saturation has been replaced by water and so we expect to observe a weak class-II AVO response. For a brine saturated zone, both seismic and synthetic responses show a pick response. In this case, the zone would have been filled with gas and a class-II AVO response should have been seen. The synthetic gathers and consecutive impedance logs for gas and brine are the integrated outcome of the petrophysical and rock physics crossplot for
seismic sensitivity analysis. As mentioned, EEI20 correlates with fluid saturation, so hydrocarbon saturated geo-bodies should be boosted from background shale compared to a reservoir with less gas saturation.

The synthetic response shows the change in amplitude in the range of 10–12% for gas sand zone. So, in case gas–water contact is present, the seismic sensitivity should show a change in amplitude. Figure 9 shows acoustic impedance and the EEI20 section in time along Well A in the dip direction. The gas-saturated interval (top approximately at 4680 ms) does not show a significant change in amplitude (<5%) along the down-dip direction in both acoustic impedance and EEI20 sections. This analysis assures absence of the gas–water contact across the geobody, until the available data shows in the down-dip. The pressure data analysis at Well A (Mondal & Chakraborty 2018) also shows the absence of gas–water contact at the well location that validates this sensitivity analysis.

5. Rock Physics Template (RPT) for reservoir characterisation

The RPT (Ødegaard & Avseth 2003, 2004; Avseth et al. 2007) has been an excellent tool to integrate petrophysical analysis, geologic interpretation and rock physics analysis. Studies have shown the importance of the RPT in performing effective reservoir characterisation for different geological set ups (Andersen & Wijngaarden 2007; Avseth et al. 2009; Chi & Han 2009). Figure 9b shows an RPT plot for the Well A reservoir (3800–3960 m). The rock physics
modelling of the reservoir has been accomplished using a constant cement model. Most of the gas-saturated points are located within the total porosity lines at 25 to 30%. Gas-saturated zone is characterised as a laminated sheet sand with lesser variability in terms of porosity within the reservoir. Now the challenge arises to use seismic data in the RPT, which can be useful to predict a reservoir away from Well A. Elastic seismic inversion was performed using three angle stacks (near: 5°–15°, mid: 15°–25° and far: 25°–40°) and the absolute values of AI and velocity ratio for reservoir zones at Well A were extracted and scaled to log values. The response of scaled inverted seismic is plotted in figure 9b along with log data. Similar seismic volumes were used to extract the data at undrilled locations.

Pseudo locations were selected from the geological model. Based on RMS amplitude interpretation, a possible channel and levee are marked in figure 10a. Pseudo Well B is located in the levee part and Well C is located along the axis of the channel but further in the down-dip. The AI and velocity ratio along the well path were extracted from inverted seismic data and plotted in RPT. As discussed earlier, the study Well A is located on the channel with a higher net-to-gross (NTG) ratio and good porosity (figure 10b). According to RPT analysis, pseudo Well B, which is located at the levee part, has a porosity of approximately 22% (figure 10c). The seismic data falls in between the 20 and 30% porosity lines. The thickness of overlying sediments above the pseudo location B is similar to Well A. The differences in porosity are mainly due to an increase in lamination and overall shale content of the reservoirs. Along the axis of the channel, we have encountered blocky and stacked sheet sand, whereas the levee part has more laminated reservoir sequences. Pseudo Well C shows a similar porosity range to Well A (~27%). Well C is located in the distal part of the lobe and the predicted reservoir has approximately 150 m of extra overburden sequence compared to Well A. The amplitude map interpretation suggests that the location of Well C is along the axis of the same channel. The retention of porosity at Well C could be due to higher NTG within the reservoir.

6. Conclusions

The study discussed an integrated approach for predictive reservoir characterisation of the Miocene reservoir in the deep-water Krishna-Godavari basin. The comprehensive workflow started with analysis of petrophysical properties, which were used in the rock physics crossplot, seismic sensitivity analysis at hydrocarbon contact and RPT analysis for characterising the reservoirs away from the drilled well. The workflow is applicable for both laminated and thick reservoir sequences, irrespective of depth or stratigraphy. The accuracy of petrophysical properties assured the quality output of the reservoir characterisation.

Different rock physics cross plots were used to differentiate the reservoir-non-reservoir and gas-water zones. From the AI-GI crossplot, chi angles (χ) were identified to calculate EEI logs as attributes for fluid and lithology. The EEI section for fluid equivalent chi angle (20°) was generated using various angle stacks, which showed the absence of gas-water contact at the well as well as along the reservoir interval further in the down-dip.
Outputs from absolute elastic inversion were plotted in the RPT to characterise the reservoirs in undrilled locations. The results were verified at Well A. Pseudo Well C along the channel showed good porosity, which was indicative of a higher NTG value. Pseudo Well B is located in the levee part and has less porosity due to higher salinity. The RPT analysis was also in agreement with the existing geological model in this area.

The study gives a holistic approach, which integrates cross-functional output to characterise a reservoir at a drilled location and away in a channelised fan-lobe depositional system. This kind of work adds substantial value in resource estimation and reduces the uncertainty in drilling for appraisal and development prospects.

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