Evaluation of thin laminated unconsolidated reservoirs of 98/2 area in KG offshore

Amitha Boindala[1], Akancha Dalania, Soma Chatterjee, VLN Avadhani
[1]Email:amitha_b@ongc.co.in, Oil and Natural Gas Corporation Limited

Abstract

The KG deep offshore depositional environment is known for its heterogeneity in terms of lithology, reservoir property and many other parameters. The rapid changes in energy and sea level dictate the degree of heterogeneity. The overall laminations reflect multiple cycles of deposition under a dual flow regime, characterized by fluctuations in energy levels. The present study deals with the petrophysical evaluation of these complex reservoirs to derive the realistic net to gross ratio.

There are a number of different techniques available to the petrophysicist for evaluating thin beds, including conventional “bulk volume” techniques, various types of high-resolution modeling, and different low-resolution modeling techniques, both with and without triaxial resistivity measurements. There is no single best technique to use. Instead, the most appropriate method is dependent on the formation complexity and the types of data available. Generally, it is very useful to have triaxial resistivity measurements to understand the formation anisotropy better. In other cases, complex formation modeling is required to provide the best results with low uncertainty.

Introduction

The major problem with thin-laminated reservoirs is finding out the realistic net pays and making reliable assessment of hydrocarbon reserves. The main difficulty arises from the low vertical resolution of standard logging tools. In many layered formations, there are both conductive and resistive beds. In a laminated shaly-sand reservoir, the hydrocarbons are generally stored in and flow through the sand layers, making them resistive, while the shales tend to be more conductive. If there are conductive layers, the current from a conventional resistivity tool will preferentially pass through these paths of least resistance, meaning that the sand layers will have little impact on the measurement. More specifically, the apparent resistivity is significantly reduced in laminated formations leading to high water saturation computation, while the thin-bedded reservoirs are known to produce water-free hydrocarbons.

The 98/2 area (Figure-1) in KG offshore is a proved hydrocarbon area from laminated reservoirs. Their sequence with beds of sand and shales ranging from the centimeter to meter scale commonly constitute the main reservoir. Laminar clays are distributed in a reservoir thin layers of shale deposited between clean layers of sand. These shale layers within the laminations do not affect the porosity or permeability of the surrounding sand layers, making them the Darcy level reservoirs with high production rates.

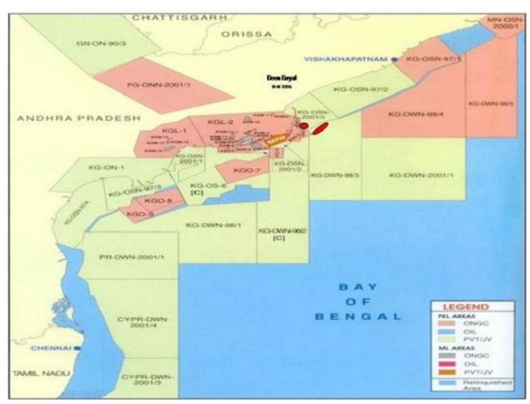


Figure1: Location of study area in KG

Due to younger age of deposition, i.e; Plio-Pleistocene age, the sequences have very little compaction and remain poorly cemented or unconsolidated. This may lead to sand cut problems during production, enhancing the difficulties to exploit the Godavari Clay formation in 98/2 area. Core recovery in unconsolidated reservoirs can be challenging due to the formation’s limited cohesive strength. In addition to careful well-site preservation and stabilization, the most critical steps are the plugging and handling of such delicate materials. The cores are highly sensitive to the external environment and deterioration takes place over time if not preserved properly. The core tends to break along the plane of lamination and the massive sand turns into loose sand.

Unconsolidated laminated reservoir cores

The shale layers within the laminations are mostly smectite rich with high water absorption tendency. The wells in 98/2 area drilled with SOBM system which ensures no swelling in shale layers. The conventional coring in this area is successful with moderate to good recovery rates. Around 16 wells have been cored in this area.

In Well-A, the conventional core CC#1 was cut in the interval X065.0 – X074.2 m with 100% recovery. The coring was carried out in October 2018. The Figure-2 below shows the picture of core at the time of recovery.

Figure 2: CC#1 in Well-A at the time of recovery

The picture shows the recovered sand is highly laminated with sand shale sequences of centimeter range. Some of the massive sands are also embedded within the sequence. Over a time period of 8 months, the condition of the core is shown in the picture Figure-3. The core is seen to be broken along the plane of the lamination and the massive sands have been turned out to be loose sand.

The shale layers are all fractured due to evaporation of the clay bound water. The core plugging was not amenable due to the core condition. The shales are swelling with high absorption of water by normal plugging method. So the plugging must be carried out in oil emulsion to have a successful collection of core plug.

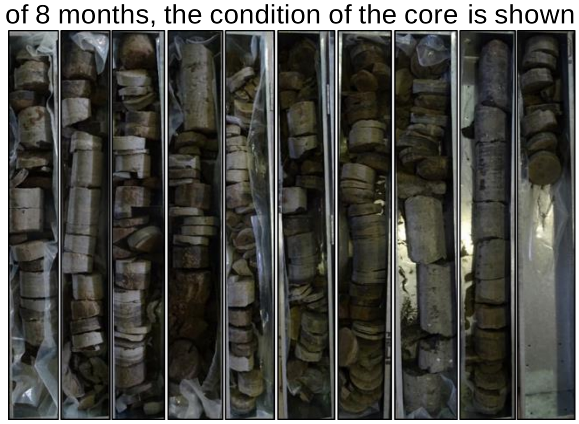


Figure 3: CC#1 in Well-A over a time span of 8 months.

Core data provides the most representative and relevant data for the interpretation and understanding of the sub-surface. As the offshore drilling and coring costs are very high, proper preservation techniques are to be used in 98/2 core preservation. Few preservation methods are coating the cores with hot wax, freezing core technique which increases the localized formation strength by increasing shear resistance and consolidation.

Study Approach & Methodology:

Evaluation of Laminated reservoirs

To better understand the impact of shale on a resistivity log, it is useful to know the distribution of the shale through the formation, whether it is in continuous laminations or dispersed throughout the pore space or a mix of both. The most common method for this is the Thomas-Stieber shale distribution model. Thomas and Stieber (1975) provided a model for understanding porosity variations with shale volume depending on the configuration of shale in the sand-shale sequences (e.g. laminated, dispersed or structural). The assumption of the model is that there are only two types of rocks alternating within the lamination. In other words, the interpretation is limited only to sand and shale. However, laminations consisting of only two alternating elements may not always be present. For example, both the sand and shale properties within the interval of interest can vary due to variations in amount of clay content present in each.

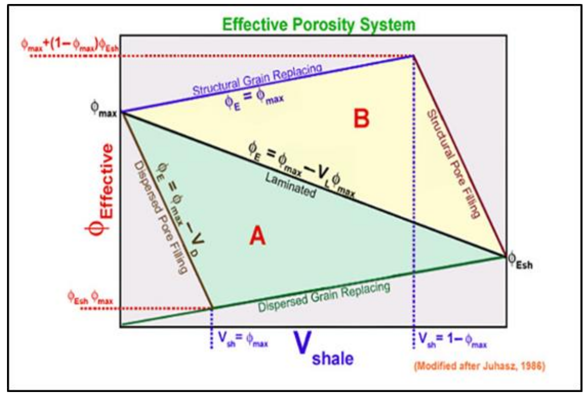


Figure 4: Thomas Steiber Plot showing the shale distribution variations.

Resistivity Anisotropy

Anisotropy is prevalent in shales as well as in the parallel bedding planes of laminated sand-shale sequences. When the beds are thinner than the vertical resolution of the induction logging tool, the measurement becomes a weighted average of the properties of the individual layers, dominated by the elements with the lowest resistivities. This phenomenon may mask the presence of hydrocarbons. Transverse anisotropy detected in triaxial measurements generally indicates that the laminations and thin beds are laterally extensive, at least across the volume of the formation being measured by the tool.

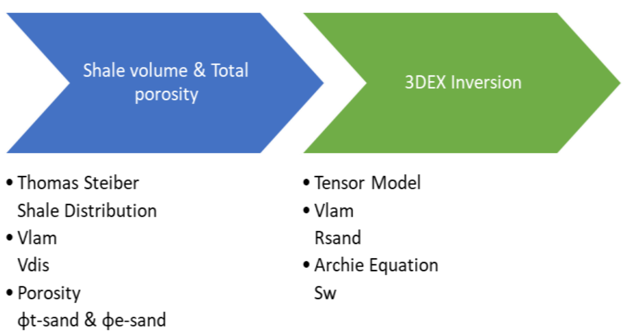


Figure 5: Thomas Steiber & Tensor Model workflow

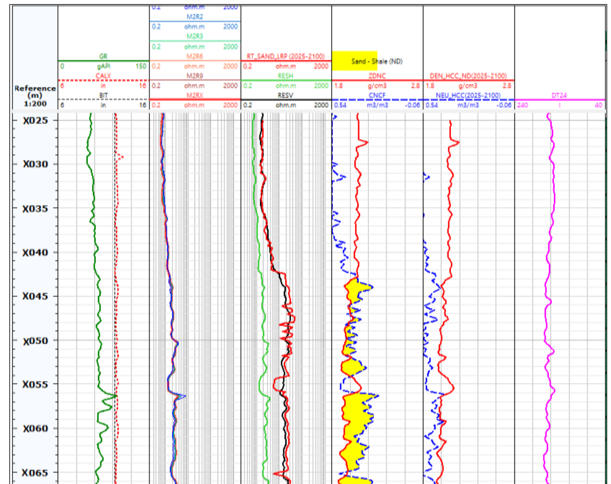
The accurate laminar shale volume can be derived from the Thomas-Steiber model and the true resistivity may be modelled from tri-axial resistivity. So there is need to link these two methods to estimate the true water saturation. This is done by using the Thomas-Steiber and Tensor models for shale volume estimations and deriving the Rtsand from Tensor model for saturation estimations.

In the Thomas Stieber model, laminar shale is both grain and porosity replacing material. On the other hand in the tensor model, the laminations must be laterally extensive, over the depth of investigation of the measurements. The convergence of the two models in laminated intervals can be used by the analyst as a check that the shale resistivity values are valid. Once the volume of shale is computed and calibrated by both the models, the laminated sequence can be treated as a simple Archie reservoir for saturation estimation with Rtsand computed as the true resistivity.

Methodology adopted for Evaluation

The Well-B was drilled as a development well to a depth 2182 m at a bathymetry of 1003 m. The objective of the well was to exploit gas from the pay zone-8 & 9 of the structure. The objective sand is found to be encountered in the interval X035 – X089 m. The log motif of the objective sand is shown in Figure-6.

The sand is gas bearing with a gas-shale contact at 2089 m. The recorded neutron density logs indicate the sand to be a massive sand due to the hydrocarbon effect (Track-4 in Figure-6). The hydrocarbon correction has been applied and the points are shifted as shown in the Density-Neutron crossplot (Figure-6).



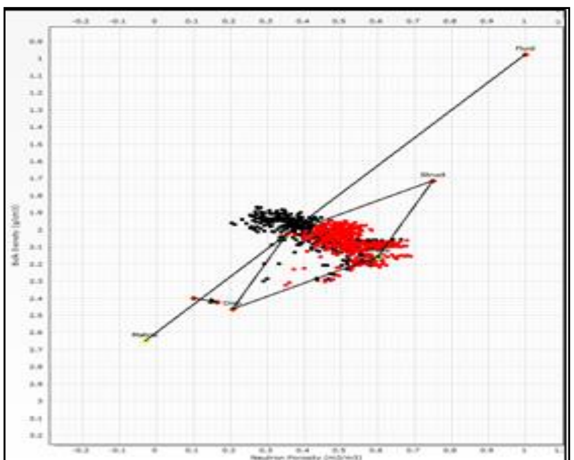


Figure 7: HC correction on Neutron density log

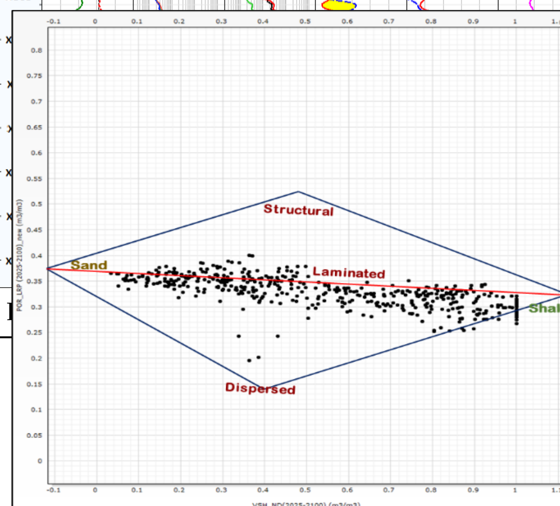


Figure 8: Thomas-Steiber Plot showing laminated reservoir.

The corrected neutron density log shows the objective sand to be highly laminated (Track-5 in Figure-7). The Thomas-Steiber plot also indicates laminated nature of the reservoir (Figure-8).

The sand has been evaluated using the Thin Bed Analysis (TBA) module combining both Tensor and Thomas-Steiber model. The output result has been shown in Figure-9. The hydrocarbon saturation shown in Track-7 of Figure-9 shows total sand thickness as pay. However, this may not be true from both resistivity image data and conventional core observations. So the net pay thickness estimation from this could be over-estimated. For realistic estimation of pay thickness, resistivity image data has been incorporated.

The six dynamic pad images of STAR data have been calibrated using shallow resistivity data which generates individual calibrated dynamic pad images. These six calibrated pad images were oriented to North and scaled dynamic image data was generated which is used to derive a lithology flag curve by segregating sand & shale from resistivity image. The image data is flattened prior to computation of sand count, which ensures sand count along the bedding direction and not across multiple beds if the bedding is inclined.

The conventional output of sand counting is a blocky curve showing conductive and resistive patches. The sand distribution array has been used in the present study to extract the volume of Quartz from the image data. The effective porosity has been computed using this volume of quartz.

$$Phie = (1 - Vsh) * Total\ porosity$$

$$Phie = Vol\_Quartz\ IMG\_SC * Total\ porosity$$

Now the resultant effective porosity is having the vertical resolution similar to that of the image data. The water saturation has been estimated using simple Archie's equation with Rtsand from TBA and effective porosity computed from image derived volume of quartz. The water saturation is presented in last track of Figure-10.

$$S_w = \left(\frac{a * R_w}{Phie^m * Rt_{sand}}\right)^{1/n}$$

The computed water saturations are at par with the vertical resolution as image data. The water saturation computed from Archie is also in agreement with the TBA results. The comparison of pay thickness estimation with conventional resistivity, TBA and using the image data is compared as shown in the below table. The pay thickness estimation using conventional resistivity is pessimistic due to low contrast in resistivity because of laminations. While the TBA generated output leads to over-estimation of the thickness as the method is majorly reliant on the Rt sand derived from tria-axial resistivity. The Rt sand/Rv resistivity curves does not reflect any major shale layers within the sand pack. However, the method incorporating the resistivity image data provides the near to realistic estimations as the image derived sand count curve discriminates the sand shale distribution in the laminated sequence.

The cutoffs considered for the computation are $Volume_{shale} \leq 0.5$, $\emptyset_{effective} \geq 0.05$ and $S_{water} \leq 0.7$.

Estimation Method	Well	Gross (m)	Net (m)	Net to Gross	Av_Phie (m3/m3)	Av_SH (m3/m3)	HC-POR-THK
Conventional	ANP-B	57.00	**17.069**	0.298	0.219	0.358	1.34
TBA		57.00	**52.883**	0.927	0.205	0.703	7.62
Sand count + TBA		57.00	**34.412**	0.6037	0.202	0.650	4.52

Conclusions

The deep-water depositions in KG offshore 98/2 area is having established laminated reservoir pay sands. These sands are highly unconsolidated due to little or no compaction. The core plugging could not be done due to the deteriorated state of conventional cores. The core studies would have strengthened the model with core derived porosity, permeability and petrophysical parameters.

The conventional cores are to be preserved with precise methods like freezing or hot wax coating to keep them intact. The tri-axial resistivity in these reservoirs is highly helpful in estimating the water saturation. The near to realistic estimations could only be possible with tri-axial resistivity along with the incorporation of resistivity image.

The image data quality is a limitation in OBM systems due to acquisition constraints. The sonic image data in OBM can be attempted for better quality image logs. The volume of sand is estimation is purely based on the image data. The quality of image data needs to be examined before using it for the estimations. The image quality in many wells found to be affected due to OBM systems constraining the application of this method.

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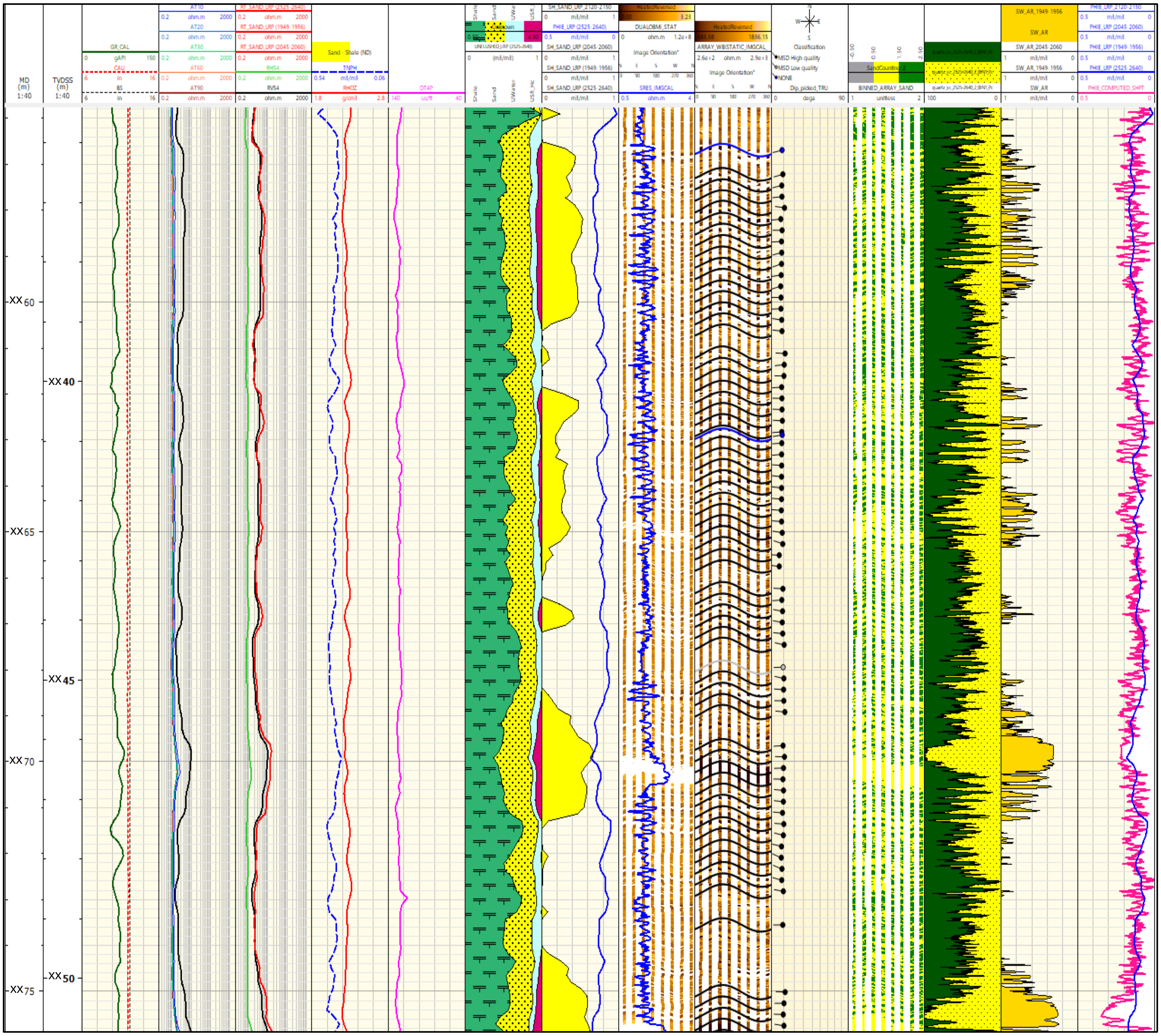

Figure 9: The output results of TBA analysis & results after incorporating the resistivity image data.