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Identification and Evaluation of the Thin Bedded Reservoir Potential in the East Coast Deep Water Basins of India

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Summary

Thin beds characterization in a deep water channel over bank system is always a challenging job. In the typical case of sand inter-bedded with shale, the logs reflect an average of sand-and shale properties. Direct interpretation of the log readings therefore results in a significant underestimation of reservoir quality and it's potential.

The potential of these thin sand shale sequence may depend on many factors like thickness of sands-shale sequence, mineralogy, sediment compaction and resistivity of pays. One of the main reasons for low resistivity is the result of the electric current shorting due the presence of conductive clays in between the resistive hydrocarbon sands.

With the discovery of the many Gas / Oil fields, in the East coast of Indian deep water, it is important to estimate the Prospective Resource available within the different blocks. Worldwide 30-40% of the in-place resources are confined within thin beds; therefore, it is important to find their true potential with minimum uncertainty.

With the introduction of the Tri-axial resistivity tools and its wider acceptance in the industry, the vertical and horizontal resistivities plays important role in finding the correct hydrocarbon saturation associated with these beds. The technique use the resistivity anisotropy approach coupled with the modified Thomas-Stiber technique for the estimation of porosity and saturation. The results were calibrated with core data and testing results. The results were compared with another technique using the borehole Image Logs and results were found to be good..

Introduction

In a deep water channel over bank system, there lie a lot of uncertainties, due to presence of thin beds. In a Petrophysical sense, thin beds can be defined as beds that are thinner than the resolution of the logging tools used to characterize them. This implies that the direct log values do not represent the true bed-or layer properties, but an average of multiple beds. Therefore, there is a need to find out a way to properly characterize the beds and to find its true potentials by integrating the different tools and techniques.

Worldwide, awareness about the thin bedded reservoir is increasing. Companies are worried about the true potential of the fields. Gulf of Mexico has more or less the similar settings. The example (Fig. 1) shows how the thin beds can be identified using the Image logs, whereas the same were not detectable on the conventional resistivity and Neutron and Density Logs. The increase in the Vertical resistivity also indicates the presence of resistivity anisotropy caused due to thin hydrocarbon bearing beds. On testing, these have produced large quantities of hydrocarbon. There are many reservoirs having thin beds been put on production and are producing for long time.

The current study deals with the deep water of Indian East Coast, which represents a passive continental margin with presence of heterogeneous continental lithosphere, i.e., Archean basement. Tectonically, the region evolved with the initiation of rifting during the Permo-Triassic period (Early Rift) prior to continental splitting of the super continent Gondwana land. This resulted in the development of a series of NE-SW trending broad, elongated troughs termed as Gondwana Graben Trend. These events followed an older set of Archean fault lineaments - the Eastern Ghats Trend. Rift initiation was in the form of linked rift-rift-rift triple junctions; the main arms being floored with continental lithosphere.

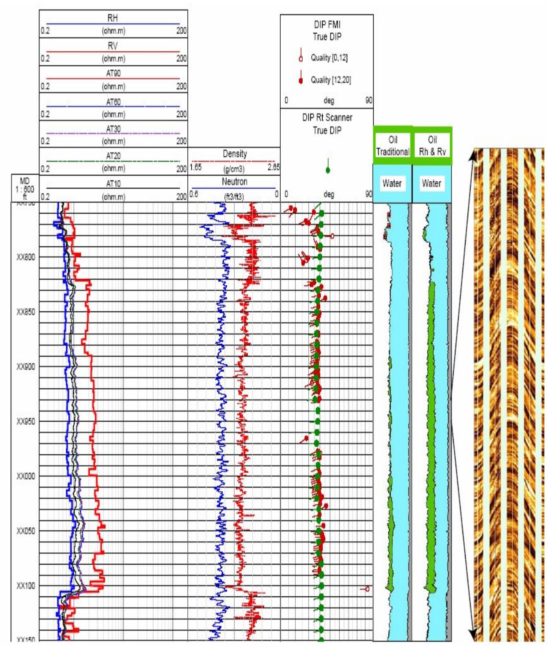


Fig 1: Thin bedded reservoir example from GOM

the failed arms of these rifts forming aulacogens represented a favorable location for the development of fluvial systems, which provided large-scale drainage basins for the progressive unroofing of the cratonic hinterland.

The NE-SW grabens were filled with thick Middle Jurassic to Early Cretaceous clastics. Rifting ceased and widespread Late Cretaceous clastics buried the horst-and-graben topography. Onset of passive margin progradation towards the south-east commenced during the Late Cretaceous, and palaeo-shelf breaks have been recognized in the sub-surface. During the latest Cretaceous to earliest Palaeocene, the Indian sub-plate was tilted down towards the south-east. This event was caused by the uplift of north-western India as it drifted northwards over the Deccan "hot spot", culminating in collision of the Indian plate with the Eurasian plate and leading to the evolution of Himalayas. Cretaceous volcanic highs, trending NE-SW are present in the basin, and are considered to represent extensive magmatism along an Archaean weakness just prior to the early drift phase.

The coastal sedimentary basins to the west of the deep-water area were formed during the late Jurassic time. These basins are composed of several grabens separated by subsurface ridges mainly trending NE-SW and parallel to Eastern Ghat trend. The pre-Tertiary sediments are moderately thick in the depressions and almost absent or very thin over the ridges. The most widespread unconformity between Mesozoic and Tertiary is prevalent both in the onshore and in the offshore areas. Paleogene clastics in the coastal basins were sourced predominantly from the Indian craton. In the offshore area, particularly in deep water, the Neogene sequences are reasonably thick and their deposition was governed mainly by the sediment supply coming from the north (Himalayan) fan system.

The tilting caused a major transgression, and increased the depositional energy of the proto-Krishna and Godavari Rivers. The resultant influx of coarse clastics caused vigorous passive margin progradation to the southeast.

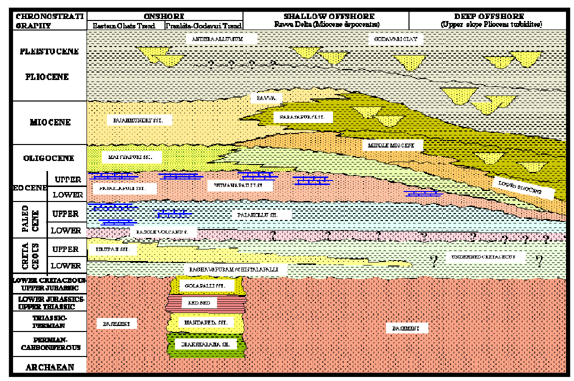


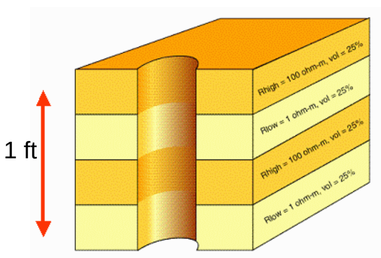
Fig.2: Generalised sratigraphy of the East Coast of India

Sediment input in this area has been dominated by the Krishna and Godavari River systems since the Cretaceous. The two present-day delta promontories became established in their present positions in the early Miocene Fig. 2).

The thick Tertiary passive margin system is the primary focus for the exploration activities in the east coast Area. The overall sequence thickens basin-ward, away from the present day coastline. The offshore portion of the Tertiary includes depositional systems ranging from shore face through to deep-water submarine channels and fan sandstones. The primary targets for exploration are Miocene to Pleistocene submarine intra-rift meandering river channels and submarine fan sandstones. These sandstones were sourced from the Godavari River system, and deposited on the mid to lower slope. The sediments are loose and unconsolidated, coarse grained having very good reservoir property. The thickness of the sand varies from few millimeters to 40-50 m. The current study aimed to identify and characterize the thin beds along with the thick sand packs.

Theory

“Thin beds” are beds thinner than the vertical resolution of logging devices. Thin beds of clay, silt and fine-grained sand distributed within a hydrocarbon bearing sand significantly reduce the apparent resistivity measured by a conventional induction or lateralog tool. Moreover, the fine-grained layers frequently have high irreducible water saturation and therefore the reservoir can produce oil or gas with zero water-cut.



When thin laminae of sand and shale are intersected by a wellbore, electrical current from the resistivity tool is shorted due to the high conductivity of the shale laminae. Consequently, the hydrocarbon-bearing sand layers, although being more resistive may not be detected. When producing thin-bedded reservoirs, the contributions of many laminae will be cumulated together.
For the purpose of reservoir characterization two different approaches were used to verify the effect of the thin beds. It is important to understand the two approaches as the data processing concept is entirely different. The two approaches are:

1. Thin bed analysis using the Resistivity Image tool
2. Resistivity Anisotropy approach using 3D-resistivity tools

Thin Bed Analysis Using Resistivity Image Tools

Shallow resistivity tools with high vertical resolution are used for the identification of the thin beds. The vertical resolution varies from a centimetre to 1.2 inches. Conventionally these tools were utilised for the dip and orientation of sedimentation and also for stratigraphic studies. Their integration with the normal logs for thin bed analysis has proved to be a boom for quantitative interpretation. The technique follows the basic process of sharpening the logs. It is assumed that a volumetric analysis has been already completed with standard-resolution logs and an attempt is being made to sharpen the results.

High-resolution shallow resistivity logs are used to create a scaled synthetic resistivity curve. This curve is used to create a lithofacies model of sand, shale, silt and wet sand and tight facies (cal. Sand). Standard input logs are squared, and then the squared SRES is used to generate an initial set of modelled square logs for all the input logs with same vertical resolution at that of SRES curve. A new sets value for each curve for each facies are then assigned, but the facies transitions are determined by the squared SRES curve.

In the next step, the depth matched model curves are processed in a constrained optimiser. This optimisation process iteratively calculates the difference between the squared model convolution and the original logs then adjusts the square model curve and recalculates the convolution/log difference. The square log adjustment is constrained by lower and upper limits for each facies. In addition, the optimisation is constrained by V_{clay} value computed through the normal processing of the standard logs.

Finally optimised squared logs are re-optimised with no macro-facies constraints. One can also restrict the optimisation process for a certain facies if he feels that the synthetic/convolved logs are matching significantly over the certain facies. This in an effort to clean up the model and assures that the convolved square logs match the original depth matched logs.

The process is Limited to five lithofacies and the squaring and convolutions limited to Rt, RHOB, NPHI and GR. Bed boundaries are driven by SRES.

For each facies, one has to set the minimum and maximum values for constrained optimisation. This allows the enhancement for the square logs. Typically, the resistivity extremes are set varied for each facies like shale, silt and sand. The whole point of optimisation with constraints is that sand laminae have log values typical of thick pay sands and shale laminae have log values typical of thick shale sections. Using the sharpened optimized data processing was run using the core derived parameters. Clay volume was recomputed using the new petrophysical parameters, which has gone as an input to the processing. The model was calibrated at another well for the validation purpose and it matched very well in this well. The fig. 3 shows the calibration of the porosity, clay volume and grain density over the processed interval. The match obtained is of very good quality. The porosity used was total porosity as the core derived porosities are near total porosities.

Resistivity Anisotropy Approach

There are some sand beds which are still thinner than the resolution of the image logs. Therefore, further

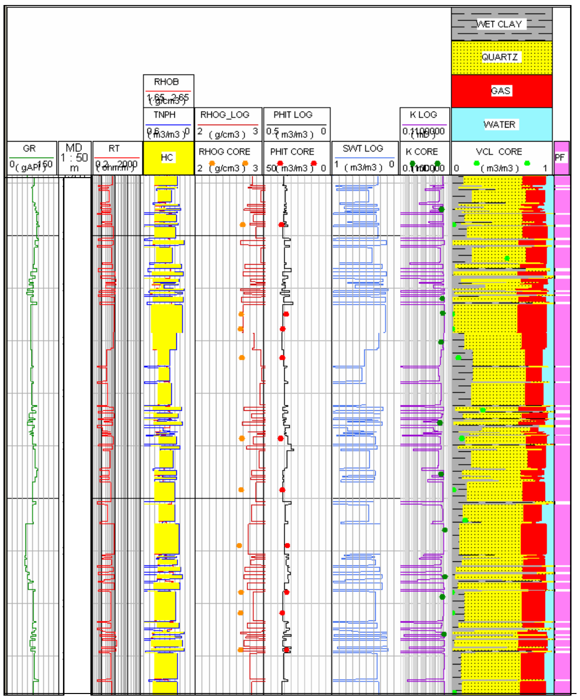


Fig. 3: Processed volumetric data using the Image and Normal log data after sharpening.

development led to the innovation of the triaxial resistivity tools. The tool measures all the nine possible component of the resistivity. The triaxial array induction tool measure formation resistivity both perpendicular and parallel to the direction of the shale-sand layers, i.e., Rv and Rh, respectively.

The vertical resistivity measures the reservoir and shale-silt laminations in series; thus, it keeps its sensitivity to reservoir laminae, by reducing the low resistivity phenomenon observed in thinly-bedded formations. Using Rh and Rv as inputs in a bimodal sand-shale laminar model, as shown in Figure below, we can then solve for the two unknowns: R_{shale} and R_{sand}.

- The horizontal resistivity data (Rh) measures the horizontal shale resistivity (Rh_{shale}) and sand resistivity (R_{sand}) in parallel:
  $(1/ Rh)= (V_{shale} / Rh_{shale}) + (V_{sand} / R_{sand})$ (1)
- The vertical resistivity data (Rv) measures the vertical shale resistivity (Rv_{shale}) and sand resistivity (R_{sand}) in series:
  $Rv = (V_{shale} \times Rv_{shale}) + (V_{sand} \times R_{sand})$ (2)
- The sum of the fractional volumes of the two constituents (i.e., sand and shale are the only two components of the model) is equal to one:
  $V_{sand} + V_{shale} = 1$ (3)

The above system of three equations contains five variables; R_{sand}, Rh_{shale}, Rv_{shale}, V_{shale} and V_{res}. To solve this system we assume that the shale micro-anisotropy coefficient, lambda = Rv_{shale} / Rh_{shale} is constant throughout the evaluated interval and Rh_{shale} is allowed to vary. The interpreter selects the micro-anisotropy coefficient; this reduces the number of variables to four. Moreover, the fractional volume of the laminated shale, i.e., fV_{shale} may be computed from standard log interpretation. Water saturation can then be computed using a bimodal approach used for resistivity evaluation, i.e., the formation is split into its two constituents, sand reservoir with structural shale, and shale/silt laminae.

Workflow

- Determination of Rv, Rh, formation dip and azimuth using inversion.
- Estimation of reservoir true resistivity (R_{sand}) and shale true resistivity (Rt_{shale}) from Rv and Rh.
- Estimation of laminated/ dispersed shale fraction and sand porosity estimation using the Thomas-Stiber method (Fig. 4).
- Calculation of water saturation (S_w) using reservoir true resistivity (R_{sand}) and sand porosity as inputs.
- Normalisation of porosity with respect to total volume
- Estimation of gas saturation using sand porosity and R_{sand}
- Net pay and volumetric estimation

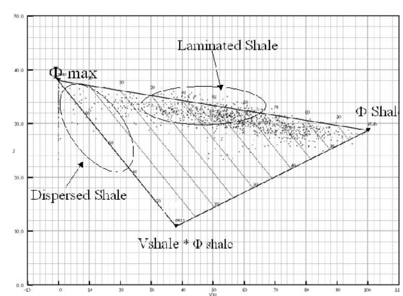


Fig.4: Thomas Stiber cross plot indicating that most of the shale is laminar

Hydrocarbon saturation of the sand laminae

The critical parameters for the estimation of the hydrocarbon saturation are sand porosity and its resistivity.

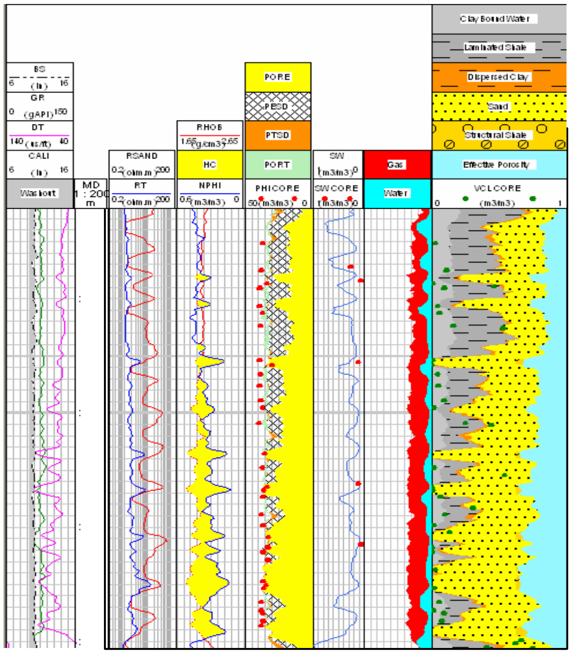


Fig. 5: Volumetric presentation of the processed output from Resistivity Anisotropy approach.

In a laminated sand shale sequence, modified Thomas Stiber (TS) technique is used to find the distribution of shale in the form of structural, laminated or dispersed shale. Laminated shale does not affect the reservoir property and the sands are as clean as thick sands. Since GR is affected due to the presence of orthoclase, Singa curve was used for Vclay estimation. A more realistic model uses different rules for finding the rock properties, usually based on shale volume or constants based on core analysis. The average porosity from the T-S method is a porosity of the sand fraction only and was used for hydrocarbon saturation estimation. Since there is anisotropy within the shale also, the process was constrained to sand intervals only by integrating the image logs. Porosity, clay volume and saturation were calibrated to core measurement and then same model was used where there is no core data.

Sums and averages for reservoir properties are determined in the usual way. The conventional model may fail to find any net reservoir unless cutoffs, especially shale cutoffs, are very liberal. Even if net reservoir is found, it will be smaller than the true net reservoir and rock properties are likely to be pessimistic.

It is considered that the shale laminations do not contain any hydrocarbons. All hydrocarbons must thus be accommodated in the 'sand' portion of the gross interval (which may be absolutely clean or contain certain amount of dispersed and structural clay). The following equality must then be valid:

$$h\phi_T S_{hT} = (1-V_L)h\phi_{TS} S_{hTs} \quad \Lambda\,\Lambda\ (1)$$

Hence the hydrocarbon saturation in the sand portion is:

$$S_{hTs} = \phi_T S_{hT} / (1-V_L)\phi_{Ts} \quad \Lambda\,\Lambda\,\Lambda\ (2)$$

This saturation in the sand laminae together with the sand laminae porosity (ϕ_{Ts}) and the thickness [(1 - V_L^2) h] should provide a more realistic basis for productivity estimates.

Net Pay Estimation

As discussed above, two different approaches have been used for the estimation of net reservoir parameters. It is important to understand the strengths and limitations of both the approaches. On the one end Sharp analysis can be very useful in identifying the zones of thin beds and can delineate the beds up to a certain scale. This scale may be coarser than the core but still provide a very good resolution for the purpose of reservoir characterization and well placement. On the other end Anisotropy approach is very good for volumetric estimation as measurement is based on the three dimensional resistivity measurements, which looks on the reservoir as a whole. Through data has been processed using both the approaches, but net pay estimation has been carried out based on Anisotropy approach. Fig.6 shows that the Vsh is very critical parameter for net pay calculation. It shows that in the case of laminated reservoirs, Vsh cutoff can be as high as 85%. The intervals with Vsh upto 85% Vsh has produced on open hole formation pressure Tester (MDT).

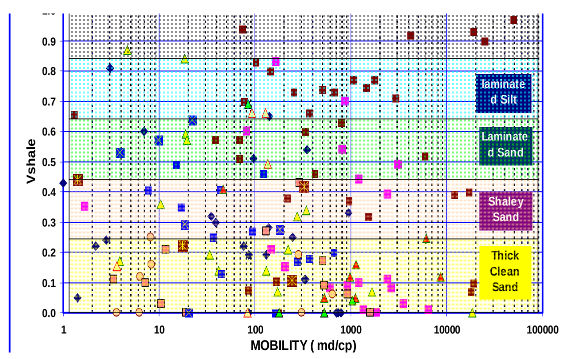


Fig.6: Plot showing the MDT mobility vs Vshale computed from the processing indicating Vshale cutoff as high as 85%.

Similarly Fig. 7 indicates that resistivity as low as 1-2 ohm can produce the hydrocarbon, which is low due the sand shale intercalations.

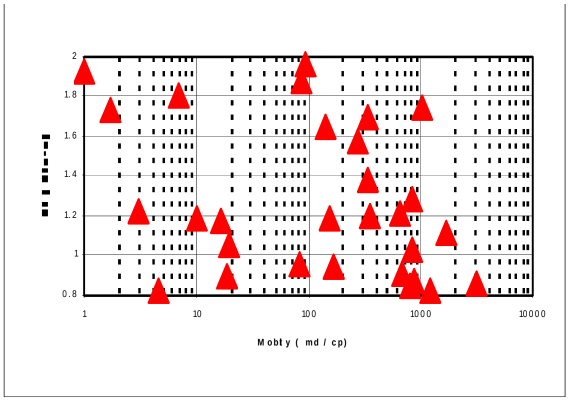


Fig.7: Plot showing the MDT mobility vs the formation Resistivity showing formation producing gas with 1-2 ohm-m resistivity

After petrophysical evaluation, it is important to integrate it with the seismic data. Since, seismic measures velocity of the formation. To calibrate logs with seismic, it is necessary to differentiate sand shale on the sonic logs and than carry forward the properties to the seismic cube. Fig. 8 shows that it is possible to distinguish between the thick sand from thin hydrocarbon bearing sands. Though there can be some overlap area, still it is possible to find the areas of the thick and thin sands and their hydrocarbon potential.

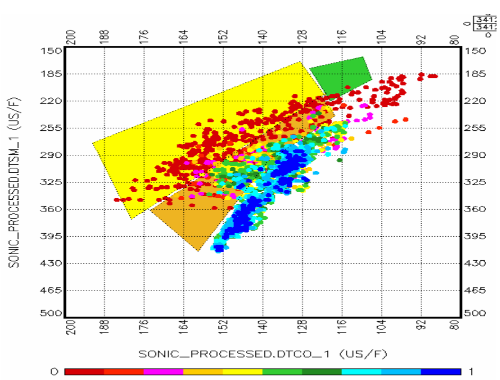


Fig. 8: Plot of Vp Vs, Vs to separate out the thin, thick sand and shale

Conclusions

1. Volumetric estimation in the well computed through the Image logs and Anisotropy matches well within the limits
2. Resistivity Anisotropy provides better results as it takes care of the beds thinner than the resolution of Image tools
3. Cutoffs are very sensitive parameters in any volumetric computation, may be different for different techniques
4. Identifying the thin zones on Image logs and than applying proper petrophysical parameters for resistivity anisotropy approach provides the best results.
5. Integration of data should be encouraged to minmise the uncertainty within the petrophysical processing and while integrating with seismic.

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