AN INTEGRATED APPROACH FOR IDENTIFYING RESERVOIR FLUIDS AND CONTACTS IN DEEP WATER THINLY LAMINATED SEDIMENTS*

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The X field is a part of a multi-billion-dollar project undertaken by State Owned Oil and Natural Gas Corporation (ONGC). The paper highlights the application of multi-component induction logging, formation pressure testing and sampling for determining hydrocarbon column in a deep-water Pliocene turbidite formation composed of thin sand inter-bedded with shale. The shale distribution and porosity are computed by applying the Thomas-Stieber analysis. Laminated Sandy Shale Analysis (LSSA) has been used to identify the pay interval. Carrying out formation pressure tests and sampling based on these results helped in determining Gas down to (GDT) from fluid identification tests and pressure gradient analysis.

Key words: laminated, deep water, unconsolidated, shaly sand, hydrocarbon.

INTRODUCTION

The latest hydrocarbon discovery in the East Coast Basin of India was made based on appraisal wells drilled in the study area to confirm the geological and geographical continuity of discoveries made earlier. The target sands belong to the post-rift tectonic stage of evolution with hydrocarbon occurring in the structurally and stratigraphically controlled traps deposited under marine condition, making reservoir evaluation challenging due to the expected high shale contents of the formations. In such cases, conventional petrophysical analysis based on induction and bulk density logging may lead to an underestimation of the reserves or, at times, completely miss a potential hydrocarbon bearing zone. The presence of synthetic oil based mud filtrate in the invaded near-wellbore flushed zone and unconsolidated formation makes fluid identification challenging during log analysis and (wireline) formation testing. Conventional bulk volume analysis gives a very pessimistic estimate of the pay interval compared to LSSA. Carrying out formation pressure tests and sampling based on LSSA results helped in determining Gas down to (GDT) from fluid identification tests and pressure gradient analysis. Clean formation gas samples were collected, thereby successfully meeting the objective of confirming pay intervals in a challenging unconsolidated environment (Fig. 1a), by integrating conventional triple combo runs with tensor induction and full wave sonic logging, and complemented with LSSA guided formation pressure testing and sampling.

GEOLOGICAL SETTING

Hydrocarbon prospectivity for the Plio-Pleistocene sequence has been established in the northern block of Krishna Godavari (KG) basin, where the youngest petroleum system, *i.e.*, Vadaparru–Ravva–Godavari is established. The XYZ and ABC reservoirs of Pliocene–Pleistocene in the study area are complex and highly heterogeneous across the field. The primary targets for exploration in the XXX contract area are Plio-Pleistocene sands in submarine slope, fan-channel-levee complexes. These sands are sourced from the Godavari River system, and deposited on the mid slope to lower slope. The KG basin was a major intercratonic rift basin during Gondwana until it

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changed to syn-rift basin. A series of NE–SW en-echelon horsts and grabens were formed between India and NW Australia. The grabens were filled with middle Jurassic to Early cretaceous clastics. The horst-graben topography was buried and passive margin progradation commenced during the late Cretaceous. The deposition of thick tertiary sediment cover over the basin was aided by the SE tilt during early Paleocene. In addition, complex fluid distributions from specific reservoir fluid geodynamics processes have also been identified in these reservoirs and they can have significant impact on development strategies, as there can be different reservoir realizations.

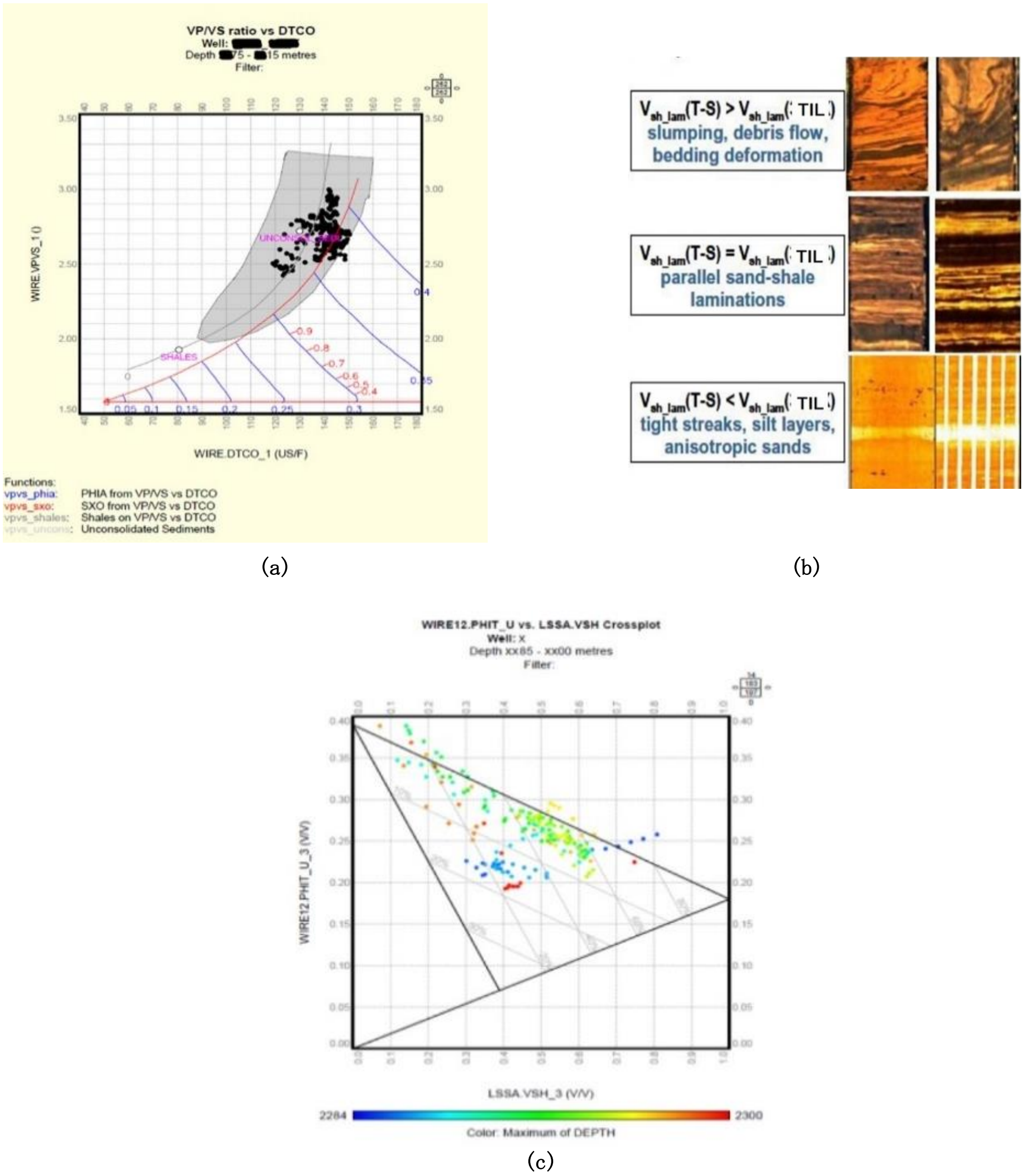

Fig. 1 – (a) Banana plot showing unconsolidation in sands, (b) Comparision of Vsh-lam for T–S and Tensor models, (c) Thomas–Stieber plot for Well-X.

MULTICOMPONENT INDUCTION TOOL

The multicomponent induction tool is a tri-axial induction instrument consisting each of three mutually orthogonal transmitter and receiver coils. Like conventional induction tools, it measures the components of the magnetic induction tensor parallel to the borehole axis, ZZ, to provide the horizontal formation resistivity. In addition, two magnetic induction tensor components perpendicular to the borehole axis, XX and YY, induce currents that flow transversely across the laminated shale sand sequences, thus providing the vertical formation resistivity. For thin bedded hydrocarbon bearing reservoirs with high shale fractions, the horizontal resistivity is dominated by the lowest resistivity (shale) and does not provide the highest resistivity measurement (sand). Determination of hydrocarbon saturation in this case will be inaccurate and under called. In a multi-component induction tool, in the same formation, the resistivity components in both the horizontal (Rh) and vertical (Rv) directions are measured, therefore providing better accuracy of hydrocarbon saturations, as the vertical component is closer to hydrocarbon bearing sand resistivity which is dominant. Against formations where there are laminated shale sand sequences, it is found that the vertical and horizontal resistivity components differ. A critical measurement provided by the tri-axial induction tool is the formation electrical anisotropy (Rh/Rv). The electrical anisotropy provided by the tool can be used to determine the sand resistivity in thin bed environments.

PETRO-PHYSICAL MODELS

For the tensor measurements (vertical and horizontal) made by the multicomponent induction tool, the thinly laminated shale sand sequence acts as a network of resistors connected in series and parallel within the tool response volume (Hagiwara *et al.*, 1994). The horizontal resistivity can be represented by Eq. 1,

$$R_h = 1/\ (V_{sh}/R_{sh} + V_{sd}/R_{sd}) \qquad (1)$$

$$R_v = (V_{sh}R_{sh} + V_{sd}R_{sd}) \qquad (2)$$

When resistivity is measured vertically to the borehole, the measurement will encounter the thin sands and will be dominated by the highest resistivity component. This measurement will be closer to the true resistivity of the formation and will provide better fluid saturation results. The vertical measurement can be represented by Eq. 2 above.

Another petrophysical model is the Thomas Strieber shale distribution model (Fig. 1c). The model is based on a cross-plot method and can distinguish between dispersed shales which replace porosity in the sand, structural shale grains which replace sand grains of equal size and laminated shale layers which replace both sand grains and sand porosity (Thomas *et al.*, 1975).

The Laminated Shaly Sand Analysis (LSSA) petrophysical model is an approach of volumetric evaluation using sand-shale-fluid components along with vertical and horizontal resistivities. The vertical and horizontal resistivities derived from multicomponent induction tool along with user defined vertical and horizontal shale resistivities compute laminar sand resistivity (R_{sand}) and laminar shale volume (V_{lam}). Another laminar shale volume and sand porosity computed from Thomas Stieber cross plot methods in conjunction with tensor resistivity model is used to provide additional information about the laminar shale. If laminated intervals are known, the two methods should complement each other and validate the model as illustrated in Figure 1(b) below.

A typical challenge faced during this study was the unconsolidated nature of the formation. This is confirmed by the Banana cross-plot between Compressional velocity (DTCO) and the Vp/Vs ratio (Fig. 1a). Also sanding was observed during the formation tester logging and choked the probe on multiple occasions.

CROSS PLOT FOR SHALE DISTRIBUTION

The shale distribution and porosity are computed from Thomas–Stieber cross-plot (Fig. 1c), in which volume of shale is plotted on X-axis and total porosity on Y-axis. Based on the position of data points in this cross-plot, laminar (V_l), dispersed (V_d), structural (V_s) shale volumes and porosity are calculated. Depending on the local geological setup it is assumed that amount of structural shale is too small. Since the laminar shale volume can be isolated after T–S analysis, saturation computation can be done by using Archie's equation over sand intervals using R_{sand} and Phi_{sand}. In the current study we have used Archie's equation since minimum amount of dispersed shale is present and laminar shale volume can be isolated.

METHOD

A laminated shaly sand analysis (LSSA) for petrophysical evaluation is carried out for Well X. The following methodology is used:

- Assuming a thick clean sand interval is present in the interval of interest, total shale volume (V_{sh}) and total porosities are computed from one or more conventional method, *e.g.*, Gamma ray, spectral log, density-neutron cross plot.
- From Thomas Stieber cross-plot, the laminar and dispersed shale volumes are determined.
- From the tensor resistivity data (R_v and R_h), resistivity of the sand layers and laminar shale volume is determined.
- The total and effective porosities are computed for the sand laminae.
- Fluid saturations within the sand fraction (Fig. 2) are computed using Archie or Waxman-Smits method. In this case, however, Archie method was used for computation of fluid saturations. This is because the thin shale-sand intervals were found to have little dispersed shale component.

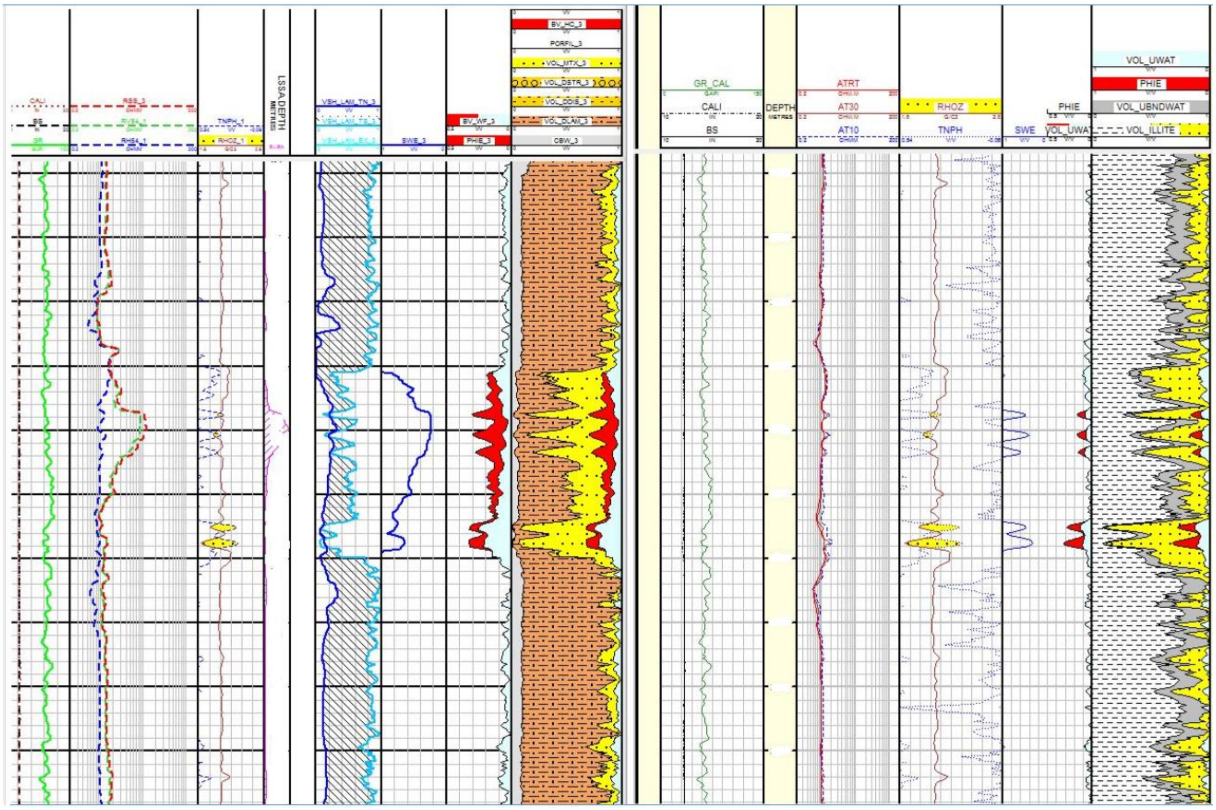

Fig. 2 – Comparison between processed log parameters derived from conventional resistivity & multi-component induction log of Well X.

FORMATION PRESSURE TEST RESULTS, MOBILITIES AND FLUID IDENTIFICATION

A total of 47 pressure tests were performed. Out of 47 tests, 16 good tests, 31 tight tests. Computed draw-down mobilities are observed to be in the range of 3.23 mD/Cp to 3949.8 mD/cP for the entire test data. Depth levels of pressure tests were chosen based on results from electrical anisotropy measured from the multicomponent. Based on test results, it was planned to carry out fluid identification during pump out (Fig. 3) and acquire clean reservoir fluid samples. Three pressure tests were recorded across the zone and on all three occasions repeatability was ensured by conducting multiple pressure tests and varying the drawdown volumes and pump rate of withdrawal based on real time pressure observations. Fluid gradient was then established by using these three stable and repeatable formation pressures from XX80m TVD to XX15m TVD which provide a gradient value of 0.1 psi/ft which indicated gas.

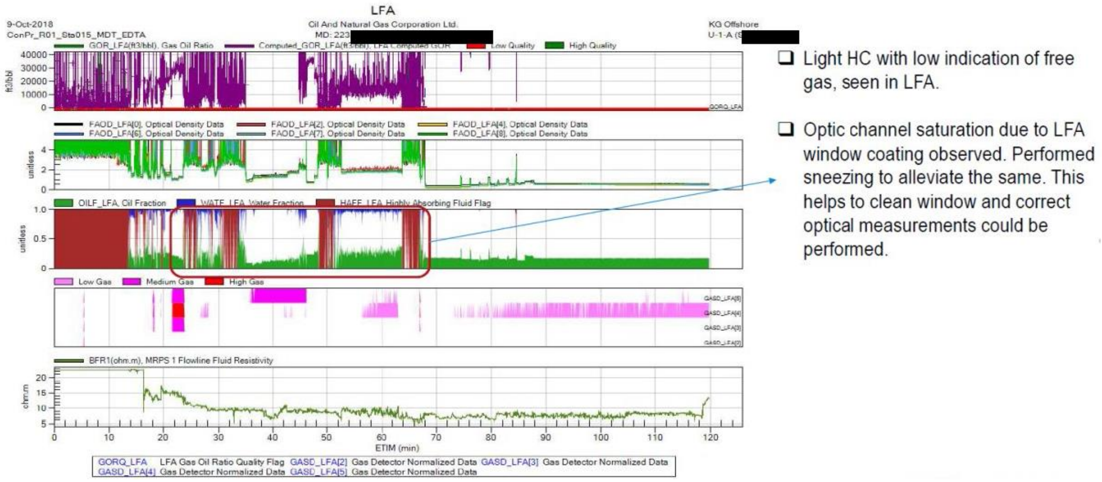

Fig. 3 – Clean-up Monitoring curves during the formation at a station in Well X.

CONCLUSIONS

1. Formation pressure testing and sampling intervals were successfully identified on the basis of electrical anisotropy and the intervals were found to be gas bearing.
2. Problems associated with petrophysical evaluation through conventional logging methods could be clearly identified and mitigated using LSSA.
3. This paper describes integrated approach to estimate the sand laminae resistivity and hence hydrocarbon saturation in laminated sand shale formation.
4. The resulting water saturation from the laminar sand resistivity and sand porosity provides better characterization of the laminar sand fraction reservoir properties (Fig. 2).

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