Integrated multipronged reservoir characterization and fluid discrimination of thin and discrete oligocene clastic reservoirs of tidal regime in C-39 field, Tapti-Daman sector, Western offshore basin, India: A case study

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Reservoir characterization, Depositional environment, Prestack geostatistical inversion, Fluid facies probability volumes.

Summary

The present study pertains to Oligocene clastic reservoir of C-39 field, spread over an area of 1250SKM, on the western continental margin of India. Owing to thin and discrete nature of sands, the field has faced optimal development challenges. The major challenges for this includes predicting the microenvironments, mapping thin and discontinuous sands, explaining the charging and entrapment mechanism and identification of gas charged sands.

Considering the complexity of the area, quality of seismic data, skewed distribution of well control, ***a four stage reservoir characterization work flow and strategy was adopted***. To bring out the sand geometry, fairway maps for each stratigraphic unit was prepared, & integrated with seismic attributes to prepare sand isolith. The P-impedance slices generated from pre-stack inversion results for windows corresponding to pay units were used to further fine tune the probable geometry of sandy fairways. From Prestack deterministic inversion volume Vp/Vs maps were generated to separate pay and non-pays. To capture the model uncertainty and improve upon the results of deterministic inversion, prestack geostatistical inversion was carried out. Different probability volumes of pay sands were generated; analyzed and finally fluid facies prediction map for each unit was prepared. This led to identification of upside potential beyond estimated reservoir limits and helped mitigate development risk.

Introduction

The study pertains to clastic gas reservoirs of C-39 field located in the northern part of Tapti- Daman block of Mumbai offshore basin on the western continental margin of Indian subcontinent. The field, located along the NNE-SSW trending synclinal low flanked on the NW by UMRAT structure and along the east by the steeply rising flank, has encountered gas and condensate within thin discrete sands of Upper Mahuva and Daman formations of Oligocene age. The entrapment is mainly strati-structural in nature.

Twenty exploratory and eight development wells from two platforms have been drilled so far in this field (Figure 1). The field has faces optimal development challenges; hence the major challenge was to delineate and map accurate distribution of gas bearing pays by predicting the occurrence of thin- gas charged reservoirs below the resolution of conventional seismic methods.

For this horizons and faults were mapped and a high frequency sequence stratigraphic framework was developed. Within this framework integrated analysis of seismic attributes and well data with results of Pre-stack inversion were carried out and pay sand geobodies were identified and finally Pre-stack Geostatistical inversion was carried out to generate different probability volumes of gas charged geobodies.

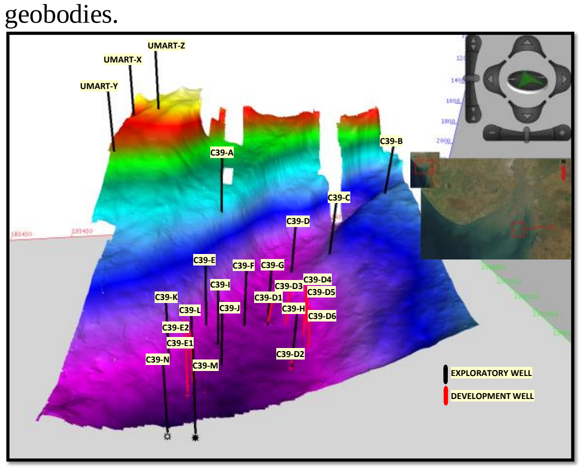

Figure 1: C39 field and distribution of exploratory and development wells. Inset: Approximate location of study on the western continental margin of India

Interpretation & Volume based Visualization Interpretation

Methodology

High Frequency Cycle Mapping

Regionally, five stratigraphic markers corresponding to tops of Lower Mahuva, Upper Mahuva, Daman, Miocene Basal Sand (MBS) and Mahim were identified on the basis of log signatures and biostratigraphic age boundaries (Figure2*)*. Since Upper Mahuva formation holds the maximum reserves as can be seen in figure 2 (dots indicating tested hydrocarbon) ***it was subdivided into lower order stratigraphic units*** (Figure 3) ***to capture the reservoir heterogeneity as well as spatio-temporal variations of sand geometries.*** Within Upper Mahuva Formation five pays are encountered which are mostly discontinuous in nature and the pools are discretely located all over the field. The petroleum system is undercharged in which even the thin sands are not fully charged and exhibit water contact.

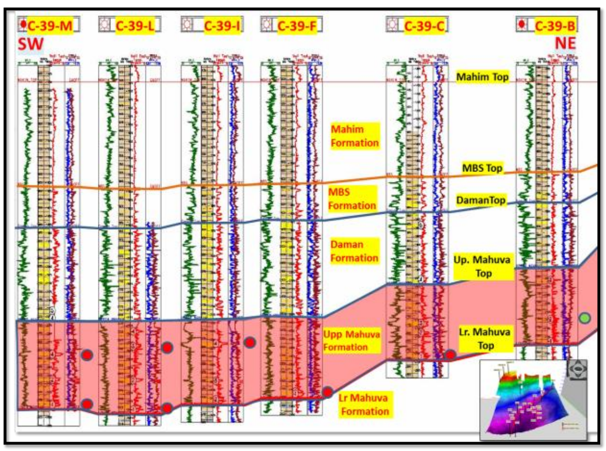

Figure 2: Correlation of sequences across the study area.

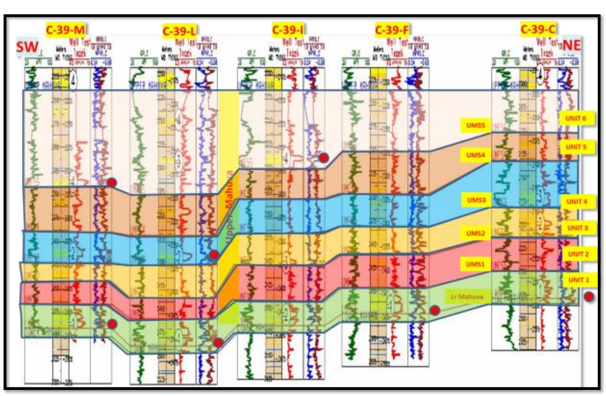

Figure 3: High frequency cycle correlation within Upper Mahuva Formation

High frequency sequence stratigraphic analysis was undertaken to further subdivide the Upper Mahuva Formation into five subunits viz, Upper Mahuva Sequences 1 to 5 -UMS1, UMS2, UMS3, UMS4 and UMS5 (Figure 3). The main hydrocarbon bearing units encountered in C39-G and C39-H (UMS20 and UMS30) are contained in UMS1 and the shallower gas sands of C39-L are from part of Sand unit UMS3-UMS4.

Depositional Environment:

Core-log integration, Clay mineral analysis

To bring out the depositional cycles in transgressive–regressive setting and to delineate approximate paleo-coastline, sedimentological data was integrated with clay mineral analysis by generating cross plots of NGS logs viz. Thorium Vs Potassium(Figure 4), PEF Vs thorium/potassium ratios, PEF Vs Potassium concentration. Based on the relative dominance of clay minerals, Kaolinite, Smectite, Chlorite and glauconite, a conceptual depositional map for the lower sand of Upper Mahuva Formation was prepared which demarcated various sub-environments like sub-tidal, inter-tidal, supratidal and fluvial zones. The study brought out the dominant influence of fluvial regime in the NE part whereas marine influence gradually increases towards SW direction.

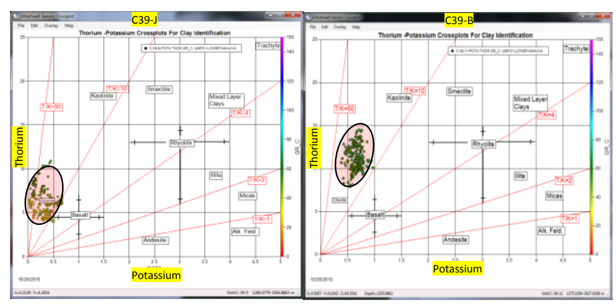

Figure 4: Thorium-Potassium CrossPlot for Clay typing. Representative well from southern part of study area C39-J, showing dominance of chlorite as clay, while C39-B from northern part of study area shows dominance of kaolinite.

The Upper Mahuva sediments were deposited in High Stand System within an overall tidal regime, in which shallowing of bathymetry, and prograding sand lobes are observed. ***The tidal signatures are evident in the form of cross laminations, flaser beddings, mud drapes, bimodal distribution of grains, rhythmites, extensive presence of burrows etc*** (Figure 5). Burrows are both inclined and horizontal and have obliterated the laminae at many places, with evidence of biotic activities pointing to episodes of low energy and low bathymetry in a ***locale proximal to upper tide line.***

The sands deposited at the base of the Upper Mahuva Formation overlying the, MFS have maximum thickness of 5 to 10m and spread across the entire study area. These sands were probably deposited within the ***drowned distributaries (estuaries)*** at the end of transgressive phase, and fed by first clastic influx and ***subsequently reshaped by tidal action filling the maximum available accommodation*** space.

The vertico-lateral discontinuity caused by interplay of sediment influx and tidal action has resulted in thin and discrete sand development often below seismic resolution. The sands are thin, discontinuous, laterally grading into siltstone and shale and vertically compartmentalized by shale flasers.

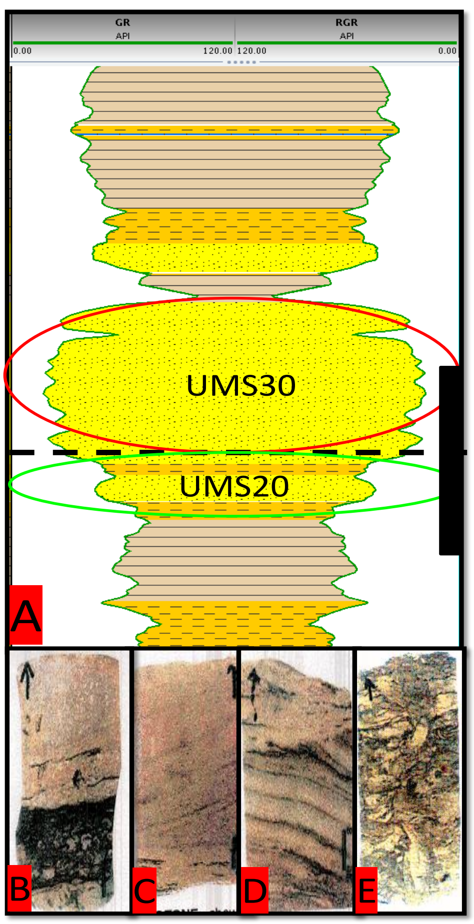

Figure 5:

A) Log motif of of well C39-G (Lower Mahuava-UMS1 Unit). Core analysis[1] of the sand shows that it is **Bioturbated Sandstone**: Light grey, fine to medium grained. Burrows are both inclined & horizontal & have obliterated the laminae at many places. Clay matrix is dominantly composed of kaolinite & chlorite. FMI analysis[2] suggests multiple cycle of sand deposition. UMS30 is interpreted as flank dip of SW prograding sand body with evidence of tidal reworking noticed as conjugate dips (NE-SW). UMS20 is Interpreted as tidally reworked bar with a gradational contact from underlying silt. These are episodes of low energy & low bathymetry encouraging intense biotic activity & indicate the locale as proximal to upper tide line.

B) Sandstone: Bimodal, showing sharp contact with burrowed shale.

C) Sandstone showing thin cross laminations.

D) Cross laminated sandstone with scouring at the top. Lower part shows planar cross laminations while the upper scour and fill portion shows trough cross lamination.

E) Bioturbated Sandstone.

Reservoir characterization

After establishing depositional setup, in the next stage the amplitude and frequency based attributes like sweetness (Figure 6), RMS (Figure 7a), maximum negative amplitude (Figure 7b), ***were used to bring out the plan-form geometry of reservoir distribution*** which integrated with well log and core studies has brought out the environment of deposition in a high stand estuarine setup within a tidal regime.

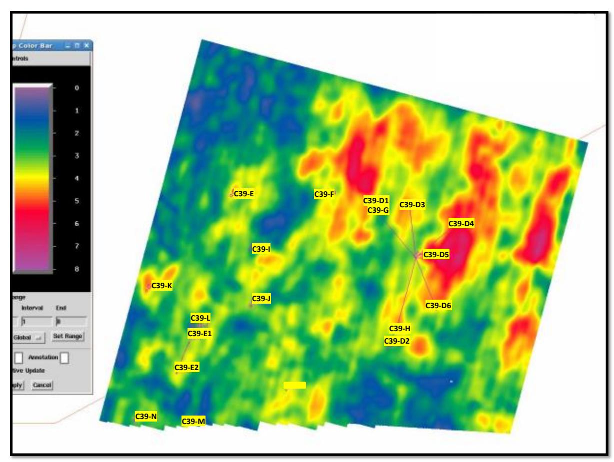

Figure 6: Sweetness map for Lower Mahuva to UMS1 window suggesting probable extension of gas charged sands.

The **sand appears** to be deposited in three major **discrete lobes, instead of a continuous sand body**

reshaped by tidal reworking with maximum thickness in wells C39-G, F, H, D4 and C39-D5.

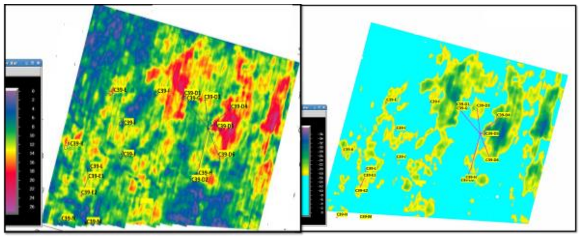

Figure 7a (Left): RMS amplitude map and Figure 7b (Right): MNA (Maximum negative amplitude) map for Lower Mahuva to UMS1 window showing the likely extension of sand bodies.

In the next stage of reservoir characterization the P-impedance slices were generated for windows corresponding to pay units (Figure 8). Pay sands in the area show impedance in the range of about 8200 g/cc*m/s, hence to further fine tune the geometry of pay sand impedance map was blocked in the range of 7700 g/cc*m/s to 8650 g/cc*m/s based on PDF which brought out the likely configuration (Figure 9). The map largely discriminated reservoir and non-reservoir facies and brought out the probable extension of pay sands. This combined with seismic attributes (Figure 6-7) was used to prepare sand isolith (Figure 10) which explained the sand distribution. Though the sand isolith elucidated the sand dispersal pattern and lobe configuration, it was not able to explain the observed hydrocarbon distribution in the area. Since, this unit is composite of two sand units i.e. sand UMS20 & UMS30 (Figure 5 & 10), these sand units were studied separately in detail and individual sand isoliths of UMS20 and UMS30 **(**Figure 11 & 12) were prepared taking into account the well data, testing results *& gridded with trends from maximum negative amplitude and RMS amplitude attributes,* which largely explained the fluid distribution pattern in the area, illustrated with the help of geological cross section shown in Figure 13.

In the third stage Prestack deterministic inversion was carried out using petrophysical parameters like Sw, PHIE, and Vclay and elastic logs viz. Vp, Vs, RHOB, generated through rock physics modelling, has helped in separating pays from non-pays and a plausible hydrocarbon distribution pattern was prepared.

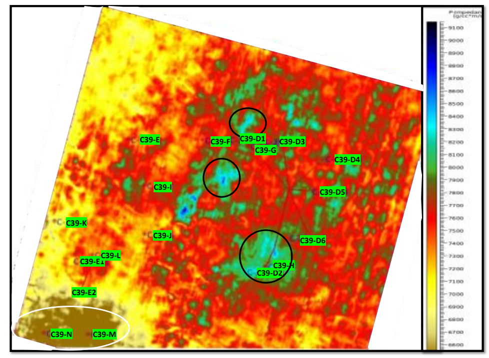

Figure 8: P-impedance map of Lower Mahuva to UMS1 window.

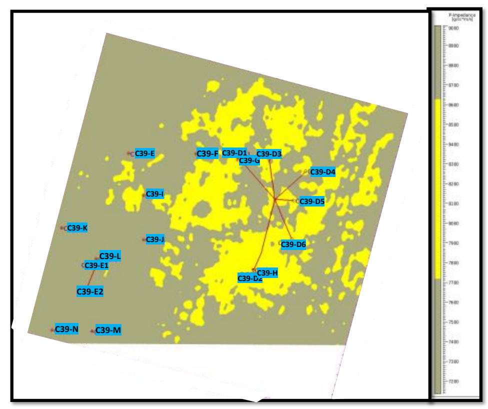

Figure 9: P-impedance map of Lower Mahuva to UMS1 window coloured yellow in the range of 7700-8650 g/cc*m/s showing the likely extension of sand bodies.

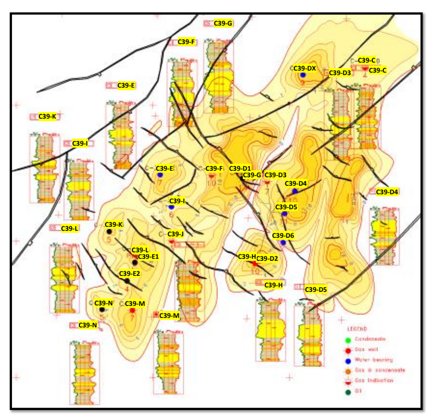

Figure 10: Sand isolith of Lower Mahuva to UMS1 unit with log motifs of well showing the unit is a composite of two sand units namely UMS20 and UMS30.

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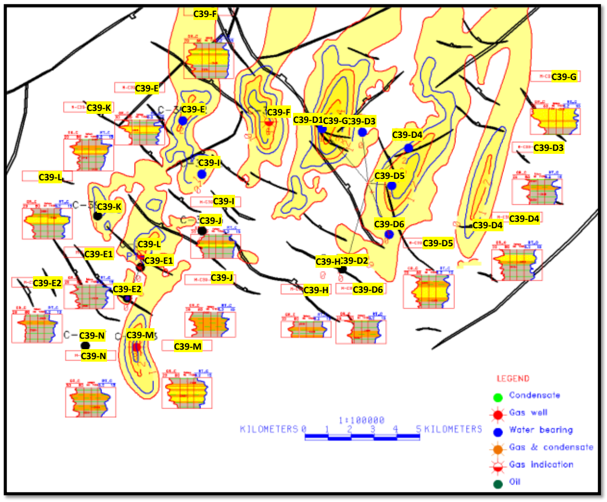

Figure 11: Sand isolith of UMS20.

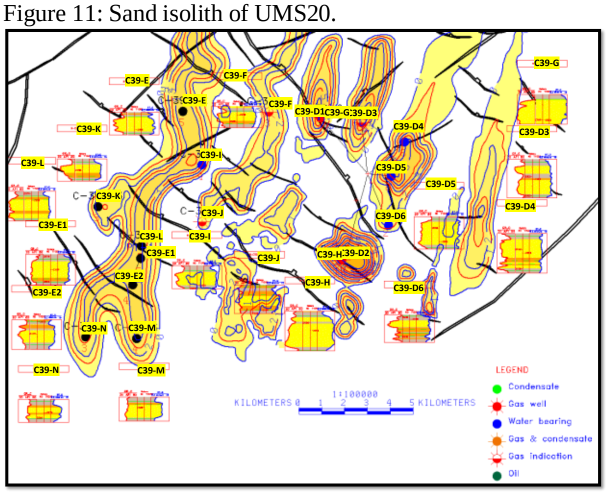

Figure 12: Sand isolith of UMS30

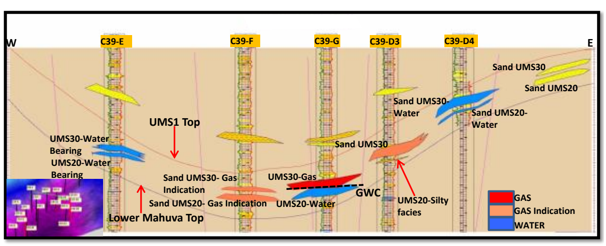

Figure 13: W-E crossection through wells C39-E, C39-F, C39-G, C39-D3, and C39-D4. It shows the distribution of sands UMS20 and UMS30 with corresponding hydrocarbon occurrence in Upper Mahuva. The lower sand unit is UMS20 and Upper sand unit is UMS30. The sands are thin and discontinuous and the reservoirs are undercharged. In C39-E, sand UMS20 & UMS30 are water bearing, the equivalent facies eastwards in well C-39-F has shown gas indication. In C39-G, lower sand UMS20 which is a bar facies, is water bearing and has become thin and silty in updip well C39-D3, further updip the sand is water bearing and falls on a different sand lobe. Sand UMS30 is gas bearing in well C39-G, but further updip has shown gas indication only. In the eastern periphery the equivalent sand facies are likely to be present on a different sand lobe as brought out by different seismic attributes.

The pay sands in the northern part of study area, under normal pressure regime exhibited Vp/Vs ratio in the range of 1.65-1.695 whereas those in the southern part in high pressure regime indicated high Vp/Vs in the range of 2.0 to 2.20. Geobodies in the respective range of Vp/Vs were extracted to map the extent of pay sands (Figure 14). The map clearly discriminated dry and hydrocarbon bearing wells except C39-D5 which falls in the transitional area of Pay and non-pay also illustrated with the help of a random line along exploratory and development wells through Vp/Vs volume (Figure 15).

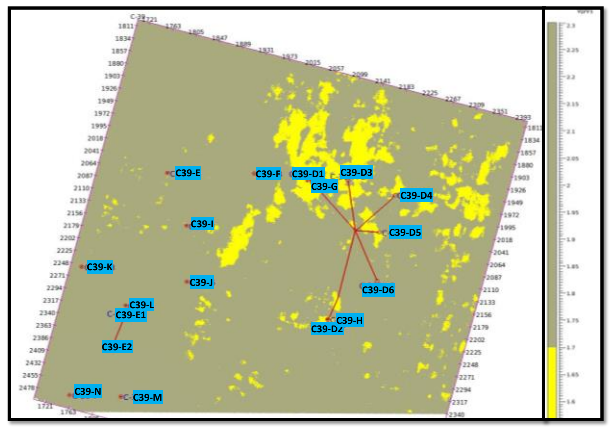

Figure 14: Vp/Vs map showing the extension of pay. All the wells are discriminated except for well C39-D5 which falls in transitional area.

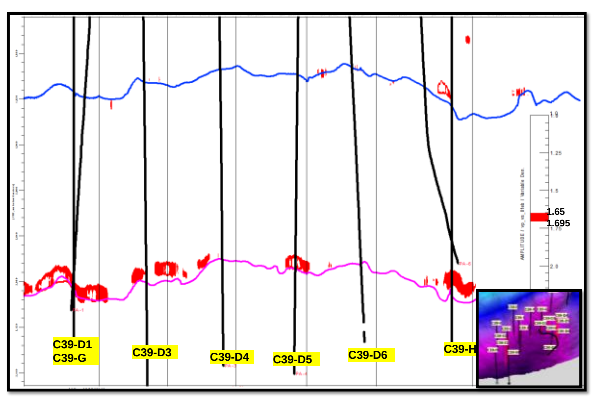

Figure 15: RC through Vp/Vs volume passing through wells C39-D1, C39-G, C39-D3, C39-D4, C39-D5, C39-D6, and C39-H

Interpretation & Volume based Visualization Interpretation

Prestack Geostatistical inversion was carried out to improve inversion details and assess model uncertainty and finally to bring out different fluid facies probability volumes (P10, P50, P90). Multiple realizations of facies and elastic properties were generated and from these realizations different probability volumes were generated and analyzed, for instance the ambiguity around well C39-D5 has been completed resolved as it falling lowest probability area of less than 10% as depicted in Figure 16.

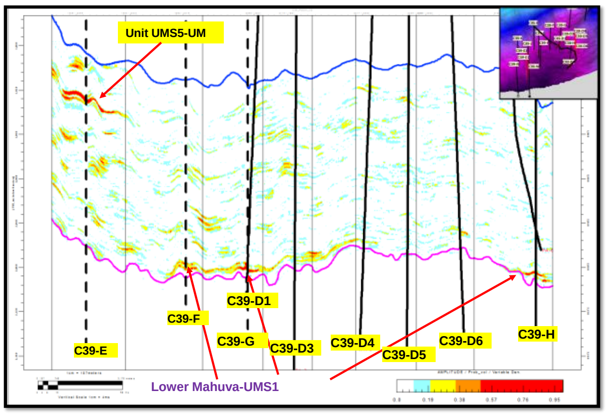

Figure 16: RC through probability volume volume passing through wells C39-E, C39-F, C39-D1, C39-G, C39-D3, C39-D4, C39-D5, C39-D6, and C39-H.

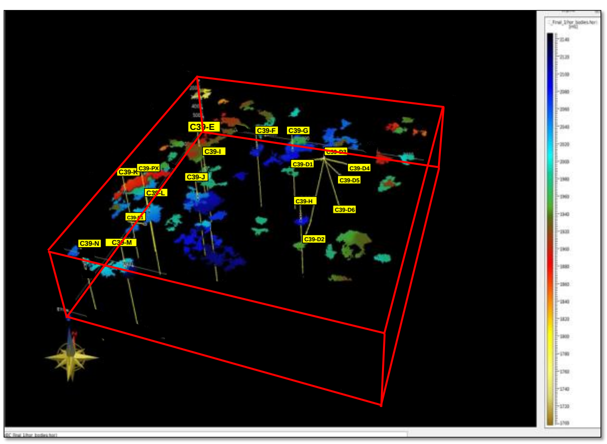

Figure 17: P50 probablity geobodies rendered in time.

Similarly well C39-E, which is prolific producer from UMS5-UM unit, is falling in high probability area of more than 90% and the same well tested dry at lower stratigraphic level is falling in low probability area. It was observed that probability percentage was in exact consonance with the testing results of wells The Geobodies representing the most likely distribution of hydrocarbon bearing sands, extracted from most likely volume (Figure 17) depict a good match with the Vp/Vs maps, thus indicating the areas of hydrocarbon charge.

Conclusions

The present study has brought out the distribution of pay sands based on prestack deterministic and geostatistical inversion which clearly explains the hydrocarbon distribution in the area. This has enhanced confidence level of identifying thin gas bearing reservoirs, which are otherwise below seismic resolution, thereby mitigating significant exploratory and development risk in the area. It has also brought out the distribution of pay sands based on stochastic inversion, which clearly explains the fluid distribution in the field. Based on the study two trends of high probability gas charged geobodies one on the east and one towards west have been identified. The limitations of data quality notwithstanding, the Vp/Vs and P10, P50 and P90 probability volumes may be used to plan future development wells.

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Views expressed here are author’s own and do not represent views of the organisation they belong to.

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