Benefits by Integrating Core, Image and NMR Data for Shale Reservoir Characterization - A Case Study in Cambay Basin, India

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Abstract

The petrophysical evaluation of low resistivity pay zones in shale of Cambay basin poses multiple challenges. The primary cause for complexities include: big uncertainty in estimation of total and effective porosity through conventional methods in small scale sequence of fine silt laminations within shale and fluid typing. Pay zones are not amenable to conventional log techniques. There is no contrast between resistivity values of pay zones and shale. Perforation intervals are generally firmed up based on typical log motifs coupled with oil/gas shows during drilling. An attempt has been made to carry out the integrated study by acquiring conventional cores and advanced log data including borehole imaging, NMR in recently drilled well, helping to better characterize the reservoir.

Knowledge of the rock through detailed core analysis has helped immensely to understand Image and NMR log motif thus characterizing the reservoir which was otherwise difficult. Examination of slabbed conventional cores indicates that lithology of Cambay shale pay zones is shale with silt laminae. SEM micrographs confirms lamination, characterized by very thin continuous or discontinuous laminae. Also flattened lenses are observed. Lamination is given by different concentration of disseminated organic matter coloring the laminae with more or less intensity. Other laminae are distinguished by its sideritic replacement. Silt-sized siderite crystals are concentrated in laminae or disseminated in the matrix. The silt laminae were showing faint fluorescence when 2/3rd section of the core was immediately photographed under UV light. The presence of silt laminae explain the feeble oil signal observed in NMR 2D display. High grain density of the order of 3.5 g/cc is observed in the samples taken against sideritic streaks with very low porosity of the order of 3 pu. The grain density and total porosity is in the range of 2.4 to 2.9 g/cc and 18.8 to 26.8 pu. Clayey micro porosity, intraparticle and intercrystalline pores are observed in SEM study. Dean and Stark analyses shows oil saturation ranging from 0.03 to 11.49% BV. In general, samples with high grain density possess low porosity and oil saturation. X-ray diffraction analysis revealed that the quartz, siderite, kaolinite, chlorite, and smectite are the major mineral constituents of the formation under study.

Image data was recorded in the study well and processed in the zones of interest. Processed data covers the static and dynamic imagery, which yielded bed dip angles and azimuth, along with fracture and fault angles and strike direction through manually fitted Sin curves. Processed interval contains clay/claystone, shale and silt layers. Presence of high density siderite streaks are clearly seen on the imagery at places, suggesting reducing depositional environment. Clasts of different sizes have been noted at number of places suggests wide spread digenetic influence. Many fine laminated features are seen, which translates to low angle dips 5 – 10 degree and azimuth varying in between NW to SW direction. The red patterns all apparently suggest presence of channel having axis orientation in NW – SE direction. The presence of fractures are observed at places. The fine silt laminations seen on the image are well corroborated by the slabbed core data under CT scan.

NMR have been proved for enhancing more value to understanding Cambay shale reservoir and the fluids within. NMR is unique among logging measurements. It responds exclusively to hydrogen nuclei that is part of the fluids (water, gas or oil) present in the reservoir. There is no contribution from the matrix materials. This unique property is extremely helpful in evaluation of the complex formation under study. Total volume of fluids, their distribution among different pore sizes, and the fraction that is likely to be producible was determined from the logged NMR data. Furthermore, 2D NMR Map is able to distinguish between different fluids and say something about the associated properties. 2D NMR fluid typing analysis is based on the

fact that different fluids have differing NMR relaxation times and diffusivity. But problem lies in the interpretation of feeble hydrocarbon NMR signal against thinly laminated reservoirs. The integration of full diameter core photo showing golden yellow fluorescence against silt laminae within shale is found useful while interpreting NMR 2D display, enhancing the confidence that the chances of missing the pay zones now appear remote, within the NMR logged interval. NMR job pre-planning is performed in order to select an acquisition mode to meet objectives for logging. The reservoirs under present study have light oil with 35-37 degrees API and formation type as medium-tight. Based on such information, simultaneous multi-echo spacing T_2 data with sufficient wait time was acquired for oil identification. 2D NMR processing was carried out by 2D inversion of acquired data. The primary output from the analysis is a 2D map of $T_{2Intrinsic}$ and diffusion distributions, providing information for the presence of oil, as well as volumetric estimate of near-wellbore oil, independent of formation water resistivity. NMR porosity measurements, free from mineralogical effects have provided a very good estimate of formation porosity along with movable and bound fractional fluid porosities.

The integrated study reveals that the Cambay shale reservoir possesses thinly laminated silt. The laminations are replaced by siderite due to prevalence of digenetic influence at places well identified by conventional logs and imagery resulting into non-reservoir. The silt laminations are continuous, and sometimes discontinuous. The matrix is clayey in composition, with disseminated discrete organic matter particles. The silt laminae shows fluorescence under UV light. These are well identified by dynamic imagery, possess low density, feeble oil signal in 2D NMR display, oil saturation through Dean and Stark study making the reservoir volume of complex Cambay shale. Few fractures are clearly observed on conventional cores and image data helping for the oil production. The prospective zones are well identified for oil production.

Introduction

Indrora field is situated in the Cambay Basin, which is situated in the western part of India, in the state of Gujarat and one of the prolific hydrocarbon basin of India. Cambay Basin, is a narrow, elongated, intra-cratonic rift graben, came into existence at the close of cretaceous. The basin is subdivided into five tectonic blocks (Figure 1): Patan – Sanchor, Mehsana – Ahmedabad, Cambay –Tarapur, Jambusar – Broach, and Narmada – Tapti. The basin is further sub-divided into two parts as North Cambay Basin and South Cambay Basin, separated by Mahi river. The Indrora field is located Mehsana – Ahmedabad block (North Cambay Basin). It is located at about 40 Km NW of Ahmedabad.

Massive eruption of lava flowed covering almost the whole of the Cambay basin forms the tectonic basement i.e. the Deccan Trap of late Cretaceous-Paleocene age over which the rift sedimentation took place. Olpad formation overlies the Deccan Trap. The Olpad formation was deposited in alluvial fans, alluvial fan deltas, over bank and lacustrine environments, characterized by trap wacke, sandstone, siltstone, wash, clay stone which have generated substantial hydrocarbons. The syn-rift stage continued to early Eocene time in which a thick sequence of Cambay shale was deposited, predominantly black-to-dark gray shale with superseding sand and silts in the main source of hydrocarbon generation in Cambay basin. The Cambay basin is further divided into the older Cambay shale (OCS) and the Younger Cambay shale (YCS) formations. The overlying Kalol formation of Middle Eocene age is characterized by intercalations of the sandstone and siltstone, shale and coals. The generalized stratigraphy of the Cambay Basin is given in Figure 2. Indrora oil field was discovered by ONGC in 1971 by striking oil in first exploratory well Indrora-1. Main oil bearing pays are Indrora Pays within Cambay Shale. Indrora oilfield with block area of 130 km2 was awarded to Selan Exploration Technology Limited in March 1995 under a production sharing contract (PSC).

Till date 16 wells have been drilled. Recently drilled wells Indrora-X1, Indrora-X2 & Indrora-X3 are producing hydrocarbons from Indrora Pay (YCS-1), however, optimal production has not been achieved due to lack of good understanding of the reservoirs. Their character and distribution are not completely ascertained. On electro log, the section equivalent to Indrora Pay is characterized by high gamma, low resistivity and low density values. Pay zones are not amenable to conventional log techniques. There is no contrast between resistivity values of Indrora Pay. The resistivity is in the range of 0.75 -1.5 Ohm-m which is less than the resistivity observed in the shale section. Perforation intervals are generally firmed up based on

typical log motifs coupled with oil/gas shows during drilling. An attempt has been made to better characterize the reservoirs by integrating wireline conventional log, advanced log, mud log, cutting and core data. This paper presents the results of integrated study carried out using core, NMR, and image and conventional data.

Figure 1 Different tectonic blocks of Cambay rift basin.

APPROACH

It is utmost difficult to identify oil bearing zones by conventional logs due to their low resistivity (Figure 3) and thus resulting in high water saturation. It was decided to acquire conventional cores and advanced log data including Image and NMR for better understanding of these complex reservoirs. In total, 32.59 meters of conventional core was cut in younger and older Cambay shale formation. After slabbing the plug samples were selected for routine core analysis (RCA) and special core analysis (SCAL). Immediately after slabbing, the core was viewed under UV light to observe any oil shows. The samples were selected for measuring grain density, porosity, and permeability. Samples were also taken up for residual saturation determination by Dean and Stark analysis. Thin section preparation was done for analysis of pore system geometry. Samples are analyzed under the SEM in order to study reservoir characteristics. Qualitative and semi
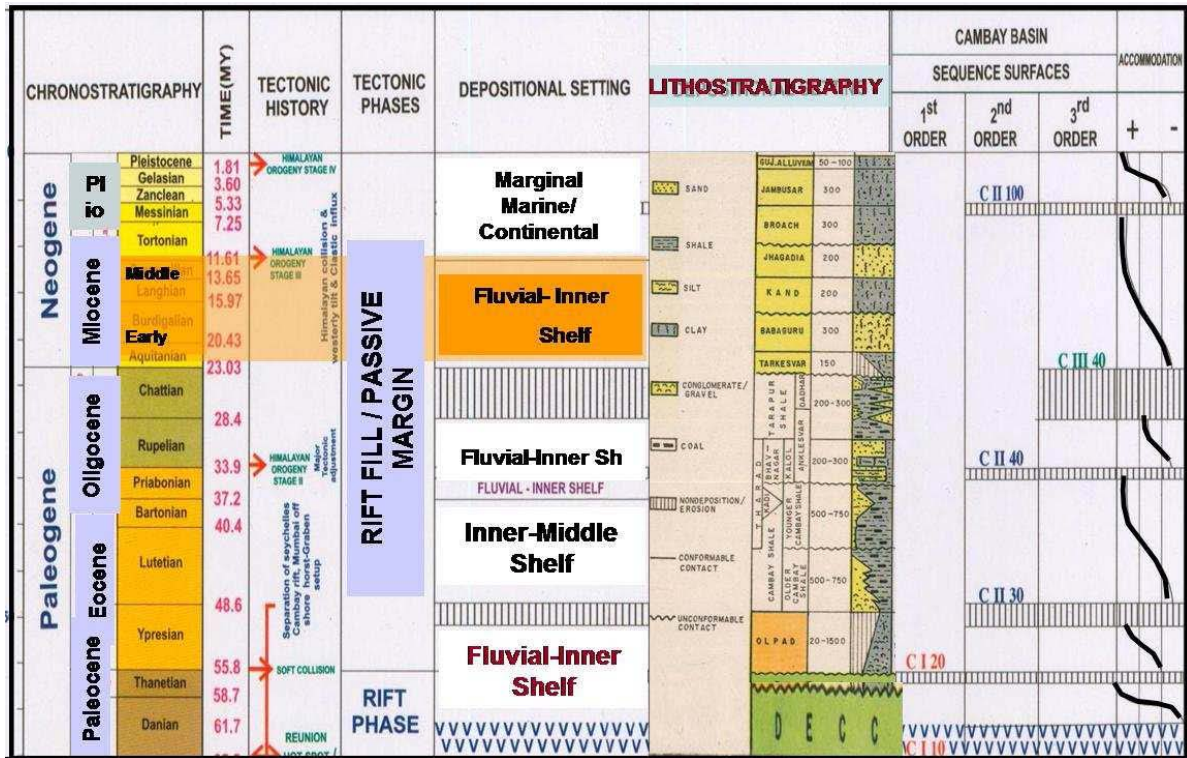
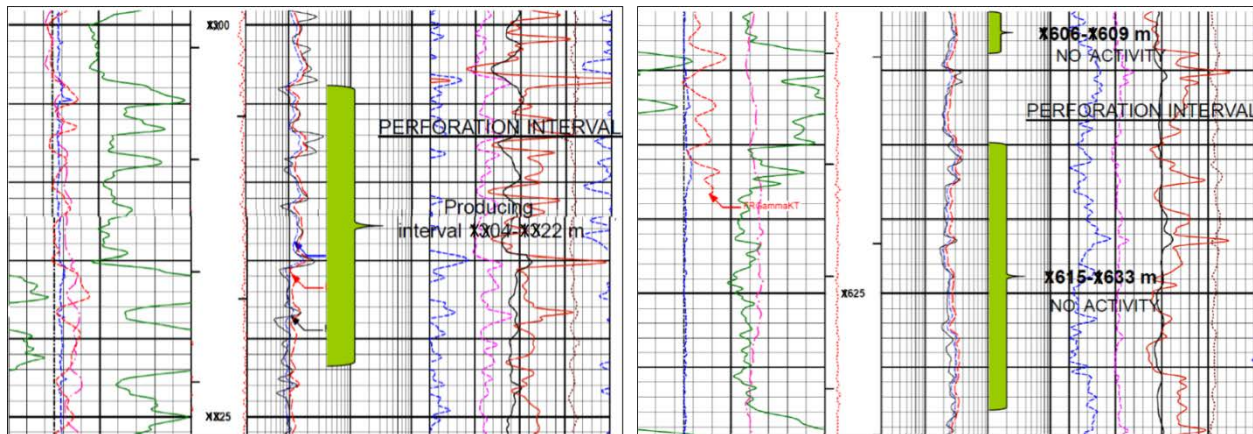Figure 2: Generalized Stratigraphy of Cambay Basin.

Figure 3: Conventional log data depicting producing interval (left), no activity (right). Resistivity log is plotted in Track 2.

-quantitative determination of all mineral components including clays and zeolites are obtained by means of X-ray diffraction analysis.

Image data was recorded in the study well and processed in the zones of interest. Processed data covers the static and dynamic imagery, which yielded bed dip angles and azimuth, along with fracture and fault angles and strike direction through manually fitted Sin curves. For creating static image, a histogram of the total data set is equalized providing the color range over the whole logged interval so that similar lithologies/ facies appear as same color. This is good for an overview and relatively large-scale comparison in different sequences. Static images, however, shall miss some minor details. For creating dynamic image, dynamic

equalization was performed using a histogram generated from a rolling 1 m window of data. A dynamic image gives a more detailed characterization in finer scale within similar lithologies / facies.

NMR data was acquired in porosity and fluid typing mode in a single pass. NMR is unique among logging measurements. It responds exclusively to hydrogen nuclei that is part of the fluids (water, gas or oil) present in the reservoir. There is no contribution from the matrix materials. More than that, NMR can also provide a discrimination of the porosity in terms of the amount associated to clay-bound water, capillary-bound water, and movable fluid. Further, there is more information than the porosity that can be extracted from NMR data, e.g., it is possible to identify which type of fluid is filling the pore space. This unique property is extremely helpful in evaluation of complex formation under study.

2D-NMR technique is used for fluid typing. This enhances the capability to discern different fluid phases by mapping proton density as a function of the T2 relaxation time in the first parameter dimension and diffusion constant in the second parameter. The D-T_{2int} maps take advantage of both T2 intrinsic and Diffusivity contrast for fluid typing purposes. It allows differentiating between CBW, BVI, BVWM, oil and gas. The basic principle behind the D-T_{2int} maps is the fact that fluids can be differentiated not only due to their relaxation time T2, or T2int, but also due to contrast in the Diffusivity value. Because of that, water, oil or gas normally appears at different zones on the map. The maps overcome the drawback of the 1D spectra, where overlapping of fluids contributions to one-dimensional T2 or Diffusivity can easily happen. Similar to the 1D-T2 spectrum, the 2D-NMR technique requires no prior knowledge of the fluid properties. The fluid typing is based on parameter separation in the Diffusivity and T2int domains, presented in the form of a two-dimensional map.

The integrated study was performed using core, Image, and NMR data resulting in better understanding of the formation.

RESULTS

Inspection of conventional cores indicates Indrora Pay is shale with silt laminae and occasionally intercalated with siltstone bands. The presence of fractures is visible. The silt laminae were showing faint fluorescence when 2/3rd section of the core was immediately photographed under UV light. The grain densities were measured twice to make sure that the density values are correct. The Shaly samples were subjected to Dean and Stark process. The data collected for fluid volumes extracted and the weight loss during the process are comparable. Water saturation extracted is a combination of pore water and clay bound water. The grain density and porosity of the formation is determined in the range of 2.40 to 2.97 gm/cc and 18.8 to 26.8% respectively. The SEM analysis describes the texture of the formation as illustrated in Figure 5 to 8.
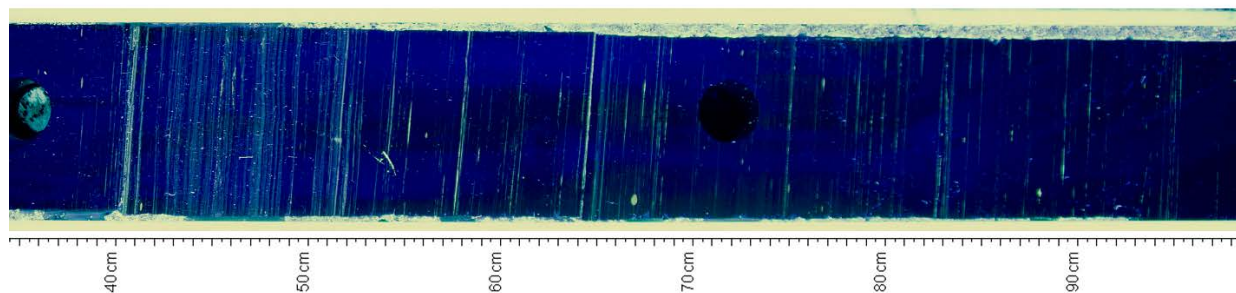

Figure 4 Slabbed section of full diameter core under UV light. The silt laminae within shale section showing fluorescence.
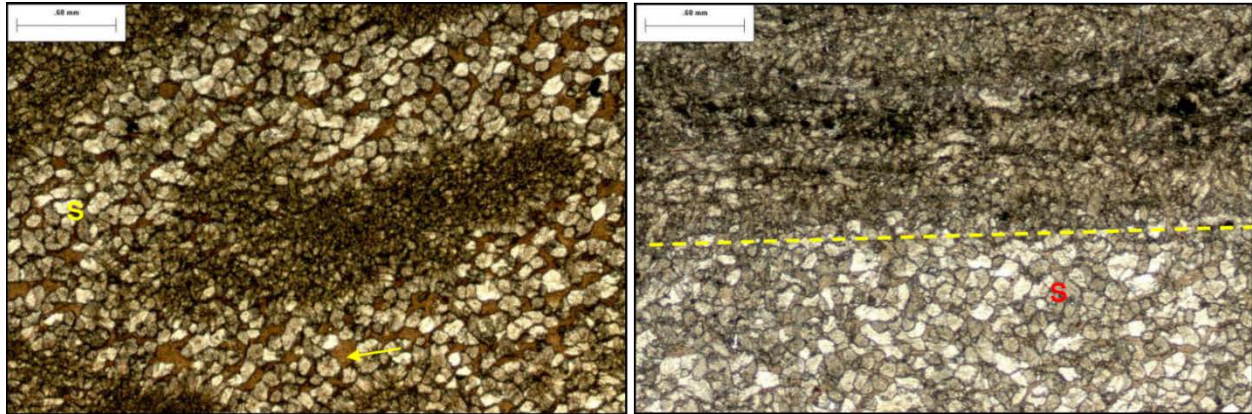
Figure 5 Rock replaced by a siderite mosaic. Heterogeneities given by differences in crystal size (left). The laminated rock completely replaced by a siderite mosaic (right). Lamination is given by differences in crystal size (dashed line).
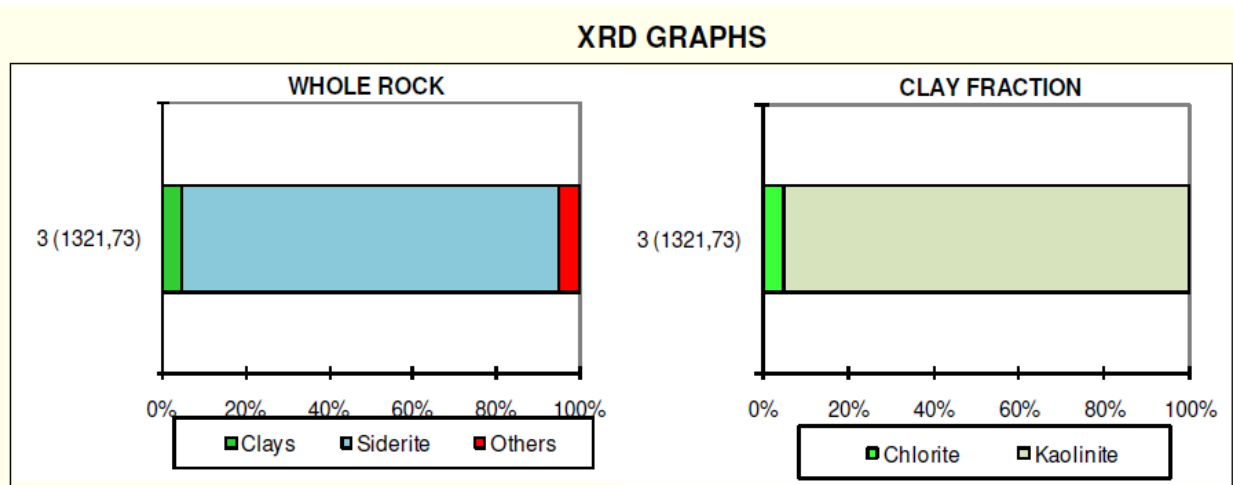

Figure 6 Clayey material (arrows shown in figure 5 (left) is identified as kaolinite by XRD.
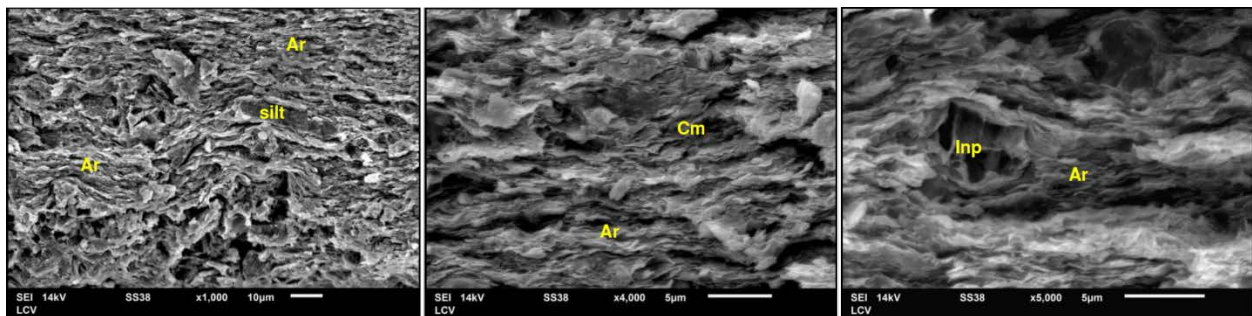

Figure 7 The SEM analysis shows that the sample corresponds to a claystone made up of clays and scarce silt-sized siliciclasts. Presence of organic matter and siderite replacement is seen (left). The enlarged observations allow to visualize clayey minerals (Ar), determined by XRD as kaolinite, smectite, scarce chlorite and illite/smectite interlayers (middle). Clayey microporosity (Cm) and subordinate intraparticle (Inp) pores are observed (right).
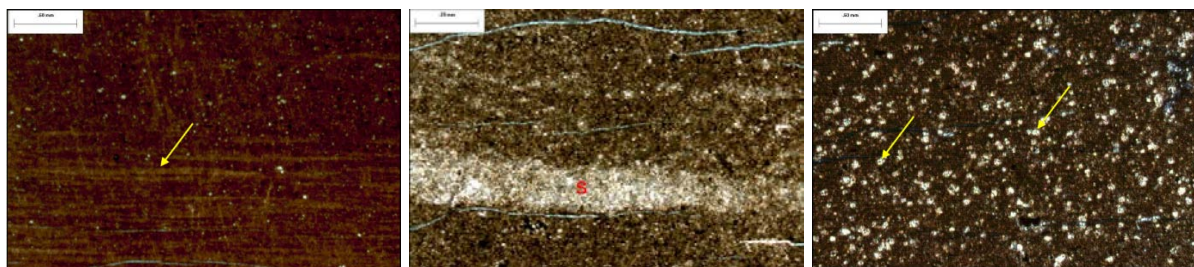
Figure 8: SEM analysis: Sample corresponds to a claystone with scarce scattered silt-sized clasts. Lamination is seen and is characterized by very thin continuous or discontinuous laminae, 0.01 to 0.02 mm thick. Also flattened lenses are observed (arrows), (left). Sample corresponds to a claystone with very scarce scattered silt-sized clasts. Parallel and ripple lamination is seen and is characterized by thin continuous or discontinuous irregular laminae, 0.01 to 0.25 mm thick (middle). Sample corresponds to a massive claystone with abundant scattered foraminifers and very scarce scattered silt-sized clasts (right).
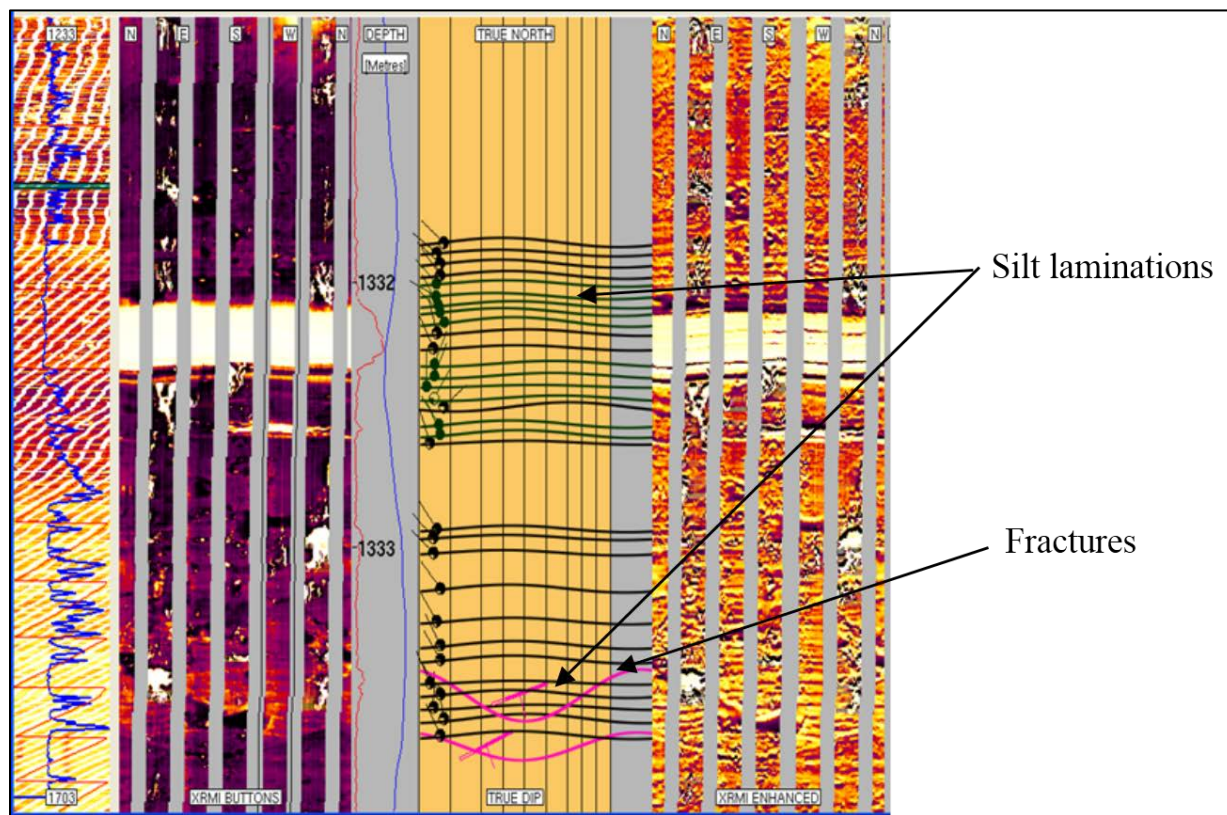

Figure 9: Imagery data showing silt laminations, fractures and tight sideritic streak.

Detailed core analysis has helped immensely understand borehole Image and NMR log motifs and eventually in characterizing flow behavior of the reservoir fluid. SEM micrographs confirm laminations, some of which are very thin, continuous and sometime discontinuous, and in some cases, associated with flattened lenses. Laminations are represented by different concentration of disseminated organic matter coloring, some with more intensity and some with less intensity. Some laminae are distinguished by siderite replacement. Silt-sized siderite crystals are concentrated in laminae or disseminated in the matrix. Clayey microporosity, intraparticle and intercrystalline pores are also observed in SEM study. X-ray diffraction analysis revealed that the quartz, siderite, kaolinite, chlorite, and smectite are the major mineral constituents

of the formation under study. Dean and Stark analyses shows oil saturation ranging from 0.03 to 11.49% BV. In general, samples with high grain density possess low oil saturation.

Processed interval of the imagery data (Figure 9 and 10) shows clay/claystone, shale and silt layers. Presence of high density siderite streaks are clearly seen on the imagery at places, suggesting reducing depositional environment. Clasts of different sizes have been noted at number of places suggests wide spread digenetic influence. Many fine laminated features are also seen, which translates to low angle dips 5 – 10 degree and azimuth varying in between NW to SW direction. The red patterns apparently suggest presence of channel having axis orientation in NW – SE direction. The presence of fractures is observed at places. The fine silt laminations seen on the borehole image are well corroborated by the slabbed core data under CT scan.
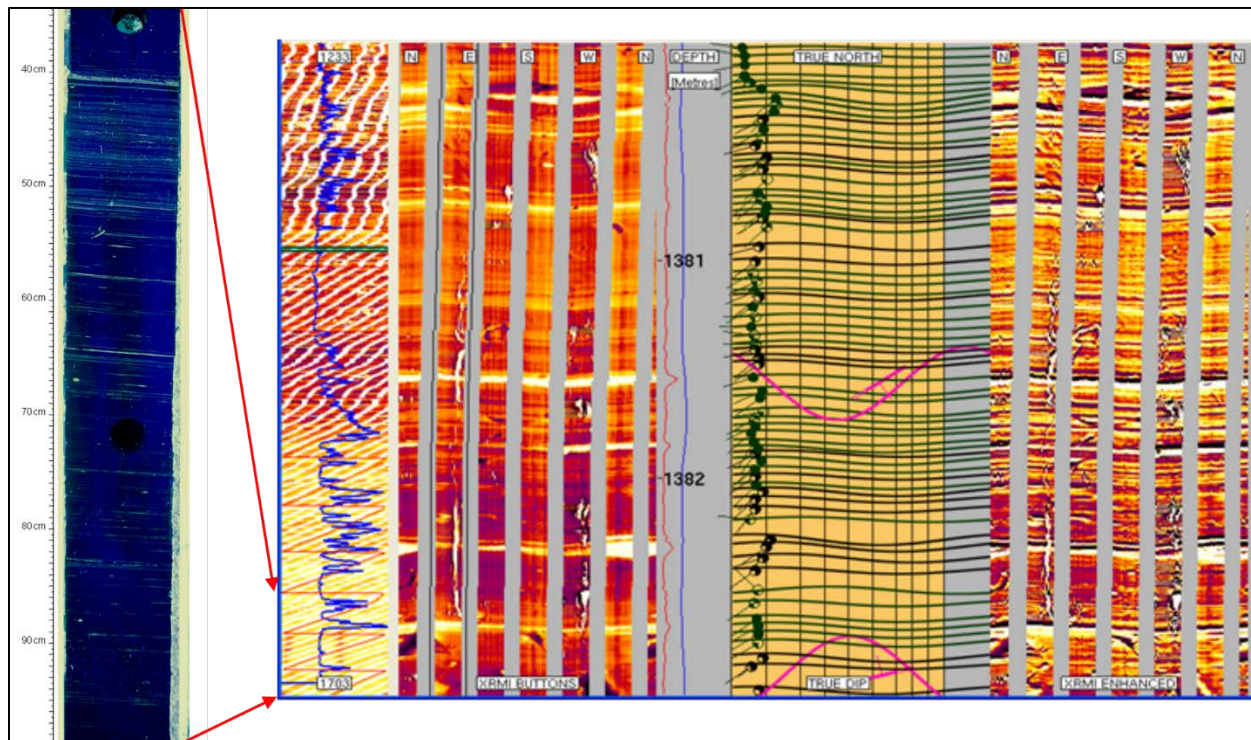

Figure 10: 2/3rd portion of full diameter slabbed core under UV light showing thin laminae with fluorescence (left), Static and dynamic imagery showing thin laminae and fracture (right).

NMR has given characteristic clue to fluid distribution in reservoir space. This has enhanced more value to Cambay shale reservoir characterization. 2D NMR fluid typing analysis is based on differing NMR relaxation times and diffusivity values for different fluids. In the present study, problem increased many fold due to laminated reservoirs and feeble hydrocarbon NMR signal response depicted against it. The integration of full diameter core photo shows golden yellow fluorescence against silt laminae within shale. This validates observed feeble oil signal in NMR 2D display (Figure 11), enhancing the interpretation confidence and minimizing the chances of missing the pay zones within the NMR logged interval. The perforated intervals with no activity also could effectively be explained with NMR data— by the absence of free fluid volume despite having good porosity. NMR porosity measurements, free from mineralogical effects have provided a very good estimate of formation porosity ranging from 18 to 30 pu along with movable and bound fractional fluid porosities. The producible and non- producible zones are well distinguished through T2 distribution in NMR response.
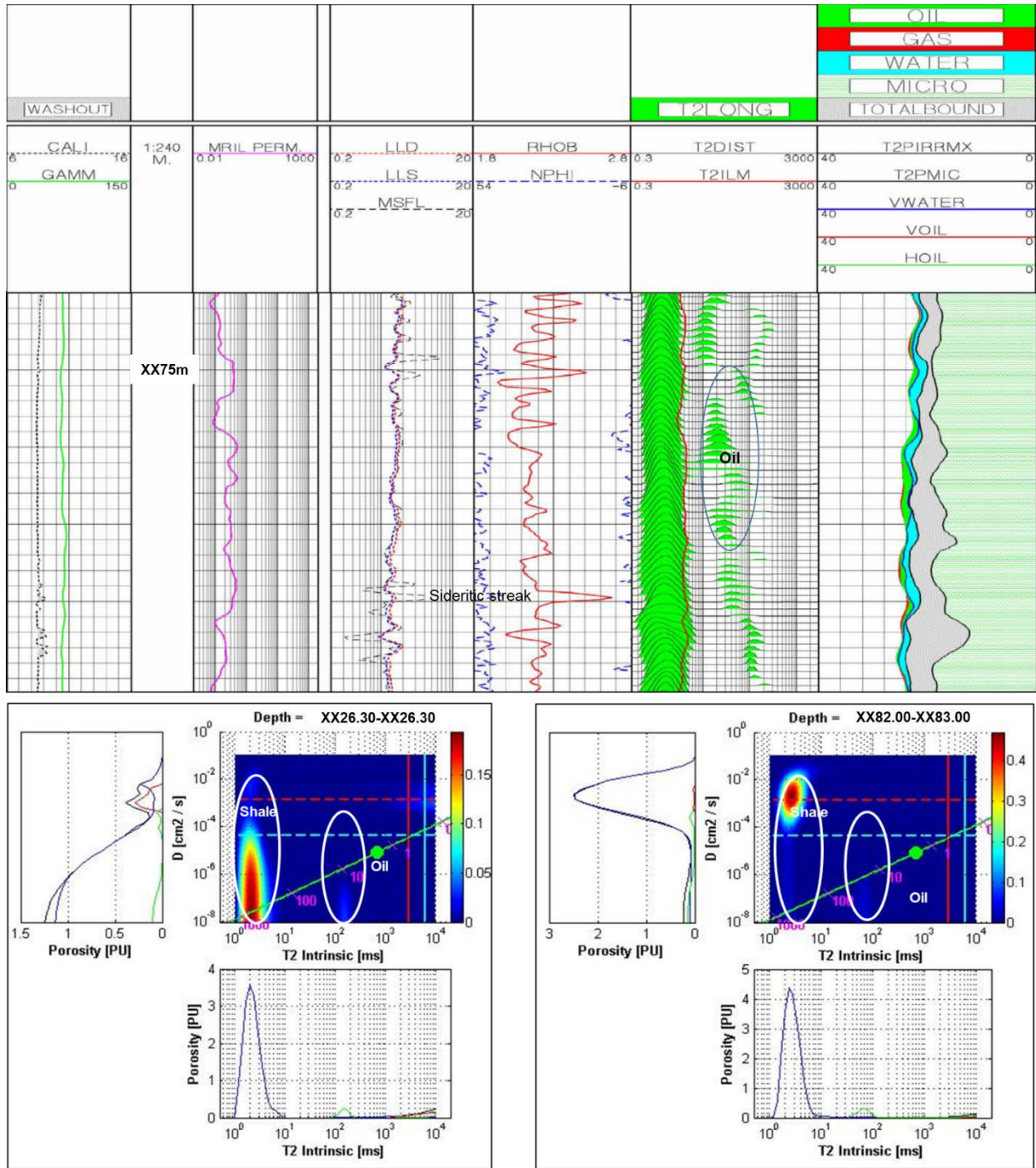
Figure 11: NMR T2 distribution showing free fluid volume against thin silt laminae (top), and 2D NMR plot showing feeble oil signal (bottom).

CONCLUSIONS

The integrated study reveals that the Cambay shale reservoir possesses thinly laminated silt. The laminations are sometime replaced by siderite due to prevalence of digenetic influence resulting to non-reservoir at places. These are well identified by imagery data. The silt laminations are continuous, and

sometimes discontinuous. The host of the silt laminations is clayey in composition, with disseminated discrete organic particles. The silt laminae shows: fluorescence under UV light, possess low density, good amount of oil saturation through Dean and Stark study and feeble oil signal in 2D NMR display. Few fractures are clearly observed on conventional cores and in image data. These fractures render help in oil production. The producible and non-producible zones are well distinguished through T2 distribution in NMR response.

Detailed core analysis has helped immensely understand borehole Image and NMR log motifs and eventually in characterizing flow behavior of the reservoir fluid.

ACKNOWLEDGMENT

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Ajay Kumar is a Petrophysicist with over 33 years of project and industry experience gained on oil & gas exploration and development. He has extensive exposure to clastic, carbonate and unconventional environments in Indian and Overseas sedimentary basins with the ability to integrate knowledge from different subsurface disciplines in formation evaluation for reservoir characterization. He has been responsible for technical evaluation and assurance of subsurface development projects, ensuring quality and functional excellence in technical studies. He has carried out several development projects including reservoir characterization work in Mumbai High, Heera, Panna, Mukta and Tapti fields that led infill drilling campaigns in these fields. He has performed due diligence and evaluation of acreages/blocks for ONGC-OVL, BG, and Petrofac leading to successful acquisition/farm-in or collaborative work. He worked in several ONGC locations including ONGC Schlumberger Wireline Research Centre, New Delhi. He is currently AVP & Head (Formation Evaluation Center) at HLS Asia and holds M. Tech degree in Electronics & Communication Engineering from university of Roorkee (Now IIT, Roorkee). He is a member of the Society of professional Well Log Analysts and the Association of Petroleum Geologists, India and participated in several papers as author or coauthor.

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