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Characterizing reservoirs from play to plug scale: A case study on Vindhyan basin, India

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Abstract:
Understanding the reservoir character through a multidisciplinary approach integrating data from different sources, seismic, well log (petrophysics), image logs, laboratory based petrophysical measurements, petrographic study and process sedimentology was attempted for the Lower Vindhyan succession. At bigger scale, play level characterization is achieved through facies analysis, interpretation of depositional environment and sequence stratiraphic framework building and thereby predicting the reservoir architecture, their lateral continuity and vertical connectivity, reservoir facies are found to be fairly continuous. Reservoir properties such as porosity and permeability are quantified through cross-plotting of well logs RHOB vs. NPHI colluding with GR and through the application of laboratory techniques to measure these properties. Reservoirs are found to be ultratight (both the clastic and carbonates), often the primary porosity approaching zero. Petrography of the potential reservoir facies reveals multi-phase diagenetic affects, which has deteriorated the reservoir properties. Secondary porosity characterized through image log analysis led to the establishment of three genetic types of fractures, low frequency, low aperture fractures related to regional tectonics, high frequency, high aperture fractures concentrated along the fault damage zones and the lithology controlled high frequency fractures in thinly laminated intervals. To produce from this type of unconventional reservoir will require placement of well bore trajectory along the potentially fractured intervals as well as hydro fracturing.

Key words: Reservoir characterization, cross-plotting, image log, secondary porosity, hydro fracturing.

Introduction:
Reservoir characterization is a very important aspect throughout the hydrocarbon exploration –production cycle and the scope of the same also varies from frontier areas with scanty data to mature producing basins with multiple datasets. The present study deals with the reservoir characterization of lower part of Meso-Neoproterozoic Vindhyan basin, central India through integration of insights from different disciplines such as sedimentology, sequence stratigraphy, rock-physics, petrography and image log analysis. This basin has been under exploration for last two decades and so far given mixed bag of results, gas was struck at different stratigraphic levels in number of exploratory wells, but the commerciality of the same is yet to be established. Efforts are underway to develop these fields commercially, therefore detailed understanding of the reservoir properties from play to plug level is vital. To optimise a development plan, the characteristics of the reservoir must be well defined, in terms of size, vertical connectivity and lateral continuity, quantity of in-place hydrocarbon and its producibility.

Geological set-up:
The arcuate shaped Vindhyan basin of central India has developed over the Archaen-Paleoproterozoic basement consisting of highly deformed metamorphics and granitic rocks. As seen today Vindhyan rocks are present in two sectors, Son valley and Chambal valley (Figure 1). The major tectonic elements in and around the Vindhyan basin are Narmada-Son lineament to the south, Great Boundary Fault to the north-west and number of interbasinal faults cutting across the basin such as Kota-Dholpur, Ratlam-Sivpuri, Basoda-Barsingarh, Kannod-Damoh-Bansipur-Rewa and Mukundra fault. Bundelkhand gneissic complex is situated in the north-central part and imparted a dominant control on the evolution of Vindhyan basin. Son-Narmada lineament is considered as the southern basin boundary fault which defines the Son valley vindhyan basin. There are different tectonic models suggested for this basin such as intracratonic basin (Biswas et al., 1993), foreland basin (Chakraborty, 1996), rift basin with well-defined syn-rift and post-rift phases (Ram et al., 1996; Bose et al., 2001). The current study demonstrate that Vindhyan basin

initiation took place under an extensional regime with complex extensional fault system defining horsts and grabens with pronounced along-strike variation in morphology and style. Overall the Vindhyan succession is mildly deformed except in basin margin areas where the lower Vindhyans are moderate to strongly deformed and thrusted over by the older rocks. Son valley Vindhyans has an ENE-WSW trending regional synclinal disposition with minor westerly plunge.

Vindhyan succession represents a thick sedimentary pile, about 6000m belonging to Meso–Neoproterozoic age. The entire succession belongs to two distinct depositional cycles. The older one dominantly calcareous and argillaceous with volcaniclastics, referred to as Semri or Lower Vindhyan. The younger cycle, is dominantly siliciclastic with minor proportion of carbonates, commonly known as Upper Vindhyan comprising of Kaimur, Rewa and Bhander Subgroups. The upper Vindhyan succession unconformably overlies the lower Vindhyans. The stratigraphic succession of Vindhyan Supergroup is presented in (Table 1).

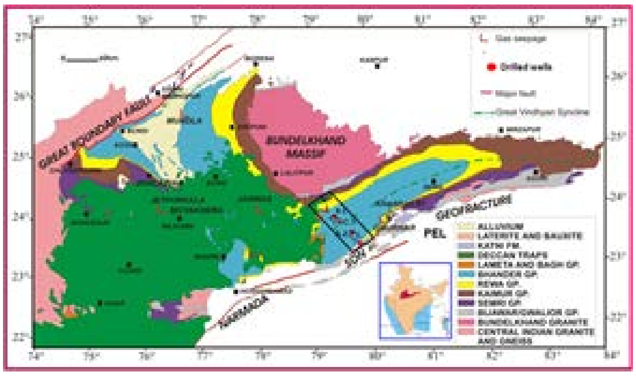


Figure 1: Geological map of the basin covering both the Son and Chambal valley sectors. Study area is shown with a rectangle, along with the drilled wells and approximate position of the seismic line and the accompanied facies model marked with arrow heads (X-X').

Upper Vindhyan	
Unconformity	
Lower Vindhyan	Rohtas Limestone
	Basuhari Glauconitic Sandstone/Rampur Shale
	Mohana (Fawn) Limestone
	Chorhat Sandstone
	Charkaria Shale/Koldaha Shale
	Jardepahar Porcellanite
	Kajrahat Formation
	Arangi Formation
	Deoland Formation
Unconformity	
Basement	Bijawar/Mahakoshal Group/Bundelkhand

Table1: Generalized stratigraphy of the Son valley sector, Vindhyan basin. Details of only Lower Vindhyans is given.

Methodology:

For the reservoir characterization multidisciplinary approach has been adopted, in order to understand the play scale reservoir property especially lateral continuity/lateral facies variation and vertical connectivity a 2D facies model across the basin was prepared using seismic, well log, core and cutting data. Reflection seismic data was relied upon to understand the basin configuration and stratal pattern; well logs, cutting and core data was used to construct the facies stacking pattern. Well logs are tied to the seismic data and different formation tops are picked up and correlated across the basin. A NW-SE seismic section across the Son valley sector of the Vindhyan basin is used to demonstrate the basin architecture and the well data is used to understand the facies distribution along this section (Figure 2a). This seismic section is flattened at the Charkaria Shale top, which is a continuous reflector to remove the effect of tectonic overprinting (Figure 2b). Lithologies of the total drilled section of all the three wells considered in this study are plotted and attempt was made to correlate different facies across the basin. The 2D facies model (Figure 3), is used for the visualization of the paleogeography through different time slices. Higher order sequence stratigraphic surfaces are identified from seismic stratal pattern whereas the lower order surfaces are identified from the well log/depositional trend. For the sake of brevity Sequence stratigraphic framework is also demonstrated in the composite facies model (Figure 3). Porosity is quantified through cross-plotting of well logs RHOB vs. NPHI and the laboratory measurement from the core plug offered real sample values of porosity and permeability. Mineralogical and textural analysis was carried out using polarising petrographic microscope, to understand the diagenetic evolution and porosity development. Secondary/fracture porosity was characterized through the analysis of image logs.

Reservoir characterization:

Play scale reservoir characterization through facies analysis and sequence stratigraphic study:

Detailed facies analysis was carried out for three wells drilled in different physiographic positions in the

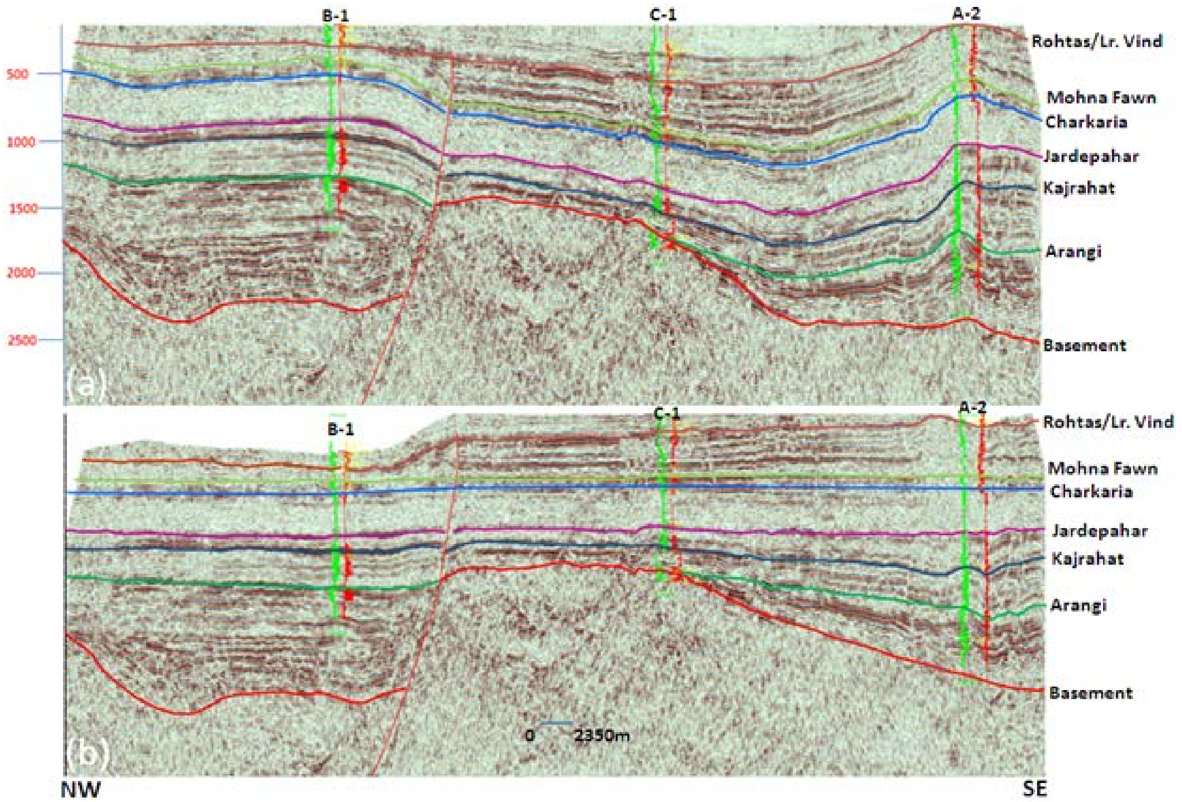


Figure 2: NW-SE trending seismic section (PSTM) passing across the Son valley sector of the Vindhyan basin which captures the basin architecture and connects wells drilled at different physiographic position in the basin (a), formation tops are given alongside. This seismic section is flattened at the Charkaria Top, which is a continuous reflector to remove the effect of tectonic overprinting (b). Well A-2 is located in Jabera area, B-1 in Damoh and C-1 in Nohta area respectively.

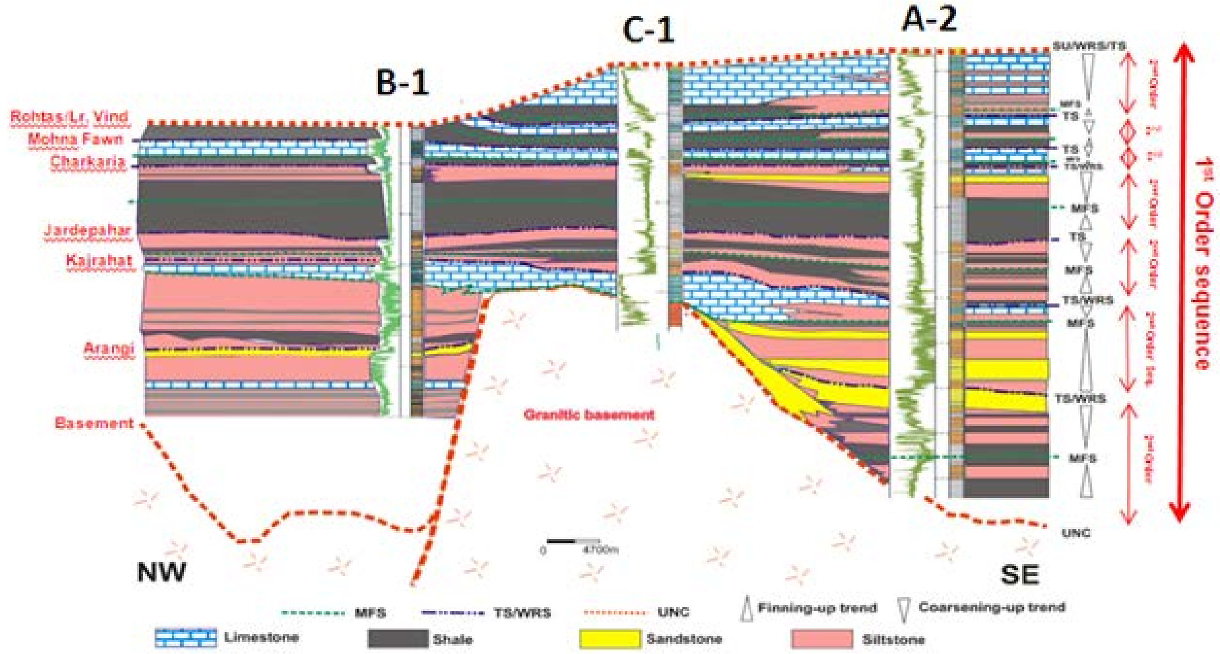


Figure 3: 2D facies model across the Son Valley sector, representing the vertical facies stacking pattern and lateral facies variation. The whole stratigraphic section is bounded at the top and bottom by subaerial unconformities, nesting seven T-R sequences.

basin and the 2D facies model across the basin is prepared which reflects the play scale reservoir geometry (lateral facies variation as well as vertical compartmentalization/connectivity). Sequence stratigraphic framework is also presented. Seven T-R sequences are identified within the lower Vindhyan, (Figure 3). For detailed discussion on facies analysis readers are referred to Paul et al., (2013). Lower Vindhyan succession is bounder at the bottom and top by Subaerial Unconformities (SU), the basal one is basement-sediment cover interface and the upper boundary is the contact between Lower and Upper Vindhyan. As per the hierarchy 2nd Order T-R sequences are nested within the 1st order sequences. Each of the 2nd order sequences contains two Systems tracts i.e. Transgressive Systems Tracts (TST) and Regressive Systems Tracts (RST). Sequence stratigraphic approach fundamentally addresses the spatio-temporal facies variations in response to changing base level and sediment supply. Play scale reservoir development is well predictable within a sequence stratigraphic framework. Clastic reservoirs are better developed in the southern part of the Jabera graben and northern part of the Damoh graben at all the stratigraphic levels because of proximity to provenance, shaleness increases as we move towards the basinal part. Clean carbonate reservoirs are observed at Kajrahat level topping the intrabasinal horst blocks and its strike continuity, at all the levels Kajrahat, Mohna (Fawn) and Rohtas carbonate reservoirs are dirtier in the proximal and cleaner in the distal areas. Carbonate reservoirs are laterally extensive and developed throughout the basin.

Reservoir characterization through petrophysical study:

Cross plotting of compatible logs (those measuring the same parameter), such as RHOB and NPHI is a standard practice for reservoir characterization. Here the cross plots of RHOB and NPHI of selected reservoir facies intervals are analyzed. RHOB-NPHI cross-plots of important carbonate facies encountered in the well C-1 are shown in (Figure 4) and clastic reservoir facies encountered in A-2 are shown in (Figure 5). Figure 4A represent the Upper Rohtas Limestone, RHOB-NPHI values are plotted within a very narrow range, having very poor porosity, limestone is very clean in character, resistivity of this interval is very high in the range of 7000-20000 ohm-m. Figure 4B represents Lower Rohtas Limestone, RHOB-NPHI values are plotted within a very narrow range in this interval as well and the NPHI value approaching zero and, RHOB 2.75, resistivity is also very high. Figure 4C represents the Kajrahat Limestone sitting right above the granitic basement rocks, RHOB-NPHI values are plotted within a very narrow range, RHOB values vary between 2.7 to greater than 2.9 and NPHI in the range of zero to 0.03. Gamma count in this interval is very less and consistent, giving blocky appearance, resistivity of this interval is very high around 40,000 ohm-m. Figure 4D represents Mohna (Fawn) Limestone, RHOB-NPHI values are plotted within a rather broad range, with the warmer colour points representing higher gamma values because of the presence of thin intercalation of shaley interbeds, resistivity of this interval is also very high. Figure 5A represents the RHOB-NPHI cross plots of Chorhat Sandstone, Figure 5B is for the upper part of the Jardepahar Formation, Figure 5C and Figure 5D are for the uppar and lower clastic units of Kajrahat Formation, sample position of each analysis is shown by the arrow against the well column, Gamma ray character of the intervals are also colour coded to discern the lithology. Gamma ray scale of individual interval is adjusted according to the range of Gamma ray count recorded for a particular interval. None of these intervals posses good reservoir character, because the rocks are extremely compacted and underwent multiphase diagenetic effect pushing the RHOB and resistivity log values close to the pure mineral endpoints values.

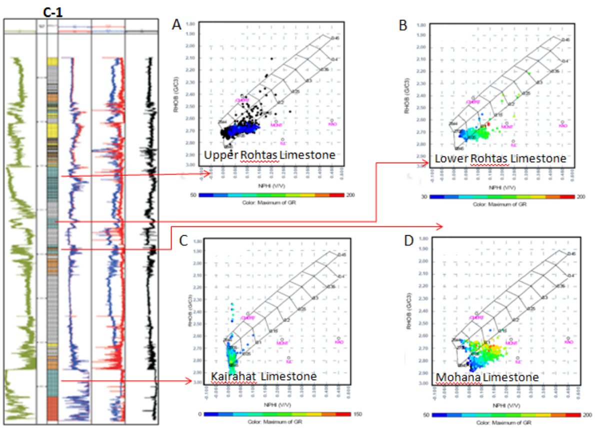


Figure 4: RHOB-NPHI cross plots of important limestone reservoir facies of C-1, GR values are also colour coded to discern the lithology.

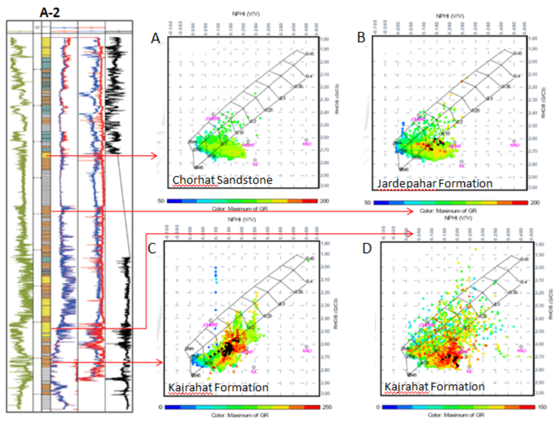


Figure 5: RHOB-NPHI cross plots of important sandstone reservoir facies of A-2, GR values are also colour coded to discern the lithology.

Reservoir characterization at plug scale:

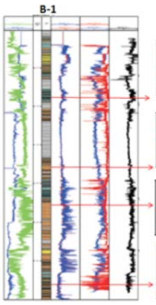
Laboratory based measurements of porosity, permeability, transmissibility, bulk density etc from cored plugs are obtained to understand the reservoir characters of different reservoir intervals. These types of studies are also important because they are used to calibrate the wire line logs. Laboratory based petrophysical studies of the well B-1 are given in (Figure 6), measurements are shown beside the well column for four cored intervals from different formations. Porosity of the studied intervals ranges from

0.45 to 4.39 % and the saturated bulk density ranges from 2.84 to 3.01 gram/cc, log based NPHI and RHOB values for the corresponding units are also shown for comparison. Over all reservoir properties for all the studied intervals indicates the reservoirs are ultra tight.

Reservoir characterization through Petrographic study:

Petrographic study was carried out to understand the diagenetic history and characterize the reservoirs of the drilled wells. Hydrocarbon bearing carbonate reservoirs of well C-1, from Rohtas Formation (Figure 7A), is dolomitic limestone formed due to dolomitization of micritic limestone, development of rhombohedral dolomite crystal can be seen within the micritic matrix. Porosity development due to dolomitization process is miniscule. Figure 7B is micritic limestone/lime mudstone from the same formation which has undergone sparitization, development of micro fracture is seen, which are however filled with secondary silica. Important clastic intervals encountered in the well A-2 were analyzed (Figure 8A) is from Chorhat Sandstone; (i.e. the regressive unit at the top of Charkaria Shale). It is a medium to fine grained sandstone with shaley interlayers and the framework grains are tightly held by the silicious cement, intensive silicification of this interval had taken place, which points towards deep burial diagenesis. Porosity is negligible due to diagenetic effects. Grading from quartz arenite to wacke fabric is observed in photomicrograph**.** Figure 8B is from Jardepahar Formation shows inter-locking texture produced by quartz and feldspar, margins of the individual grains are serrated, and enclose a large volcanic rock fragment, intensive silica cementation has taken place which had caused the deterioration of the primary porosity.

During this study it was found that the whole Lower Vindhyan succession lacks compositional (relative abundance of stable vs. unstable minerals) as well as textural maturity (relative abundance of matrix vs. framework grains and the degree of roundness and sorting of framework grains), evident from the preponderance of rock fragments, feldspars and angular to sub-angular clastic grains respectively. Pervasive diagenesis and intense silicification/ silica-cementation have been observed. Carbonate intervals had also undergone pervasive diagenesis and dolomitization.



Cored interval 818-820.5m	Porosity (%) from Plug (Lab)	NPHI values	Sat. Bulk density(g/cc) from Lab	RHOB g/cc
	1.67-2.37	5-6	3.01-2.85	2.73-2.75

Cored interval 1983-1984.5m	Porosity (%) from Plug (Lab)	NPHI values	Sat. Bulk density(g/cc) from Lab	RHOB g/cc
	0.45	6-8	2.84	2.71-2.73

Cored interval 2257-2259.6m	Porosity (%) from Plug (Lab)	NPHI values	Sat. Bulk density(g/cc) from Lab	RHOB g/cc
	2.03	11	2.86	2.68

Cored interval 3252-3254m	Porosity (%) from Plug (Lab)	NPHI values	Sat. Bulk density(g/cc) from Lab	RHOB g/cc
	1.47-4.39	18	2.90	2.83

Figure 6: Reservoir characterization through laboratory based measurements for well B-1.

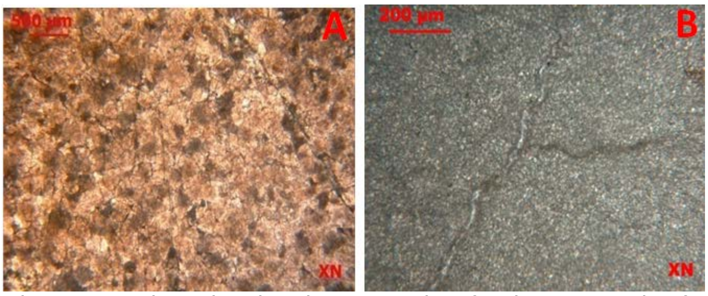


Figure 7: Hydrocarbon bearing reservoirs of Rohtas Formation from well C-1; dolomitic limestone (A) and micritic limestone (B).

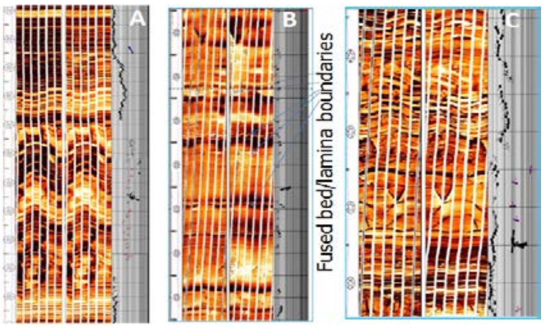


Figure 9: High density, high aperture fractures in the fault damage zone (A) low density fracture in thicker beds (B) and high density fractures in thinly laminated beds (C).

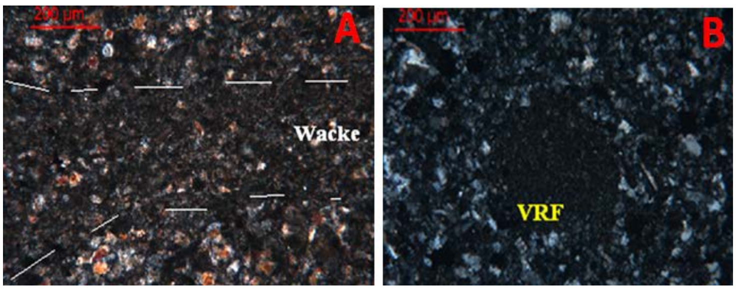


Figure 8: Clastic reservoirs from well A-2; Chorhat Sandstone (A) Jardepahar Formation (B).

Reservoir characterization (fracture porosity) through Image log analysis:

Since the primary porosity of most of the reservoir sections were found poor image logs of the drilled wells were analyzed to understand the mode of fracture development which directly contributes to the secondary porosity. Two genetic types of fractures were identified.

A) Fractures related with fault damage zone: Large aperture, high density (Figure 9A)
B) Related to regional tectonics: Small aperture, low densityfractures developed away from the fault damage zone

Lithology has a dominant control in the localization of fractures, especially in the areas away from the fault damage zone, thicker and cleaner sandstone and limestone beds which are highly compacted are associated with low density (Figure 9B), on the other hand thinner beds, sandstones-siltstones and dirtier limestones (limestone- siltstone-shale intercalations) are associated with high density fractures (Figure 9C).

Discussion:

More oil and gas could be extracted from reservoirs if the geology of the reservoir is properly understood, in our endeavour the same has been achieved through multi-dataset analysis. Sequence stratigraphic approach has allowed us to characterize reservoirs at play level for their lateral continuity and vertical connectivity. Genetically good reservoir facies (depositional facies) could be located both for the clastic and carbonate reservoirs, however in most of the cases their primary porosity were found to lost. Deterioration of the reservoir properties has taken place due to deep burial and pervasive diagenesis, as seen through the petrographic study. Petrophysical analysis of the well logs and laboratory measurements confirmed the same. Secondary porosity characterized through image log analysis revealed that high aperture, high density fractures are associated with the fault damage zones and the lithology has dominant control on the fracture distribution and density. Thicker and cleaner reservoir units have poor reservoir properties in comparison to thinner units both for clastic and carbonates. In reservoir stimulation point of view thicker units (thick sandstone and limestone beds) are less prone to hydro-fracturing than their thinner counterparts (thin siltstones and limestone with shale-siltstone intercalations).

Conclusion:

Vindhyan basin has known hydrocarbon occurrences at multiple stratigraphic levels, however their commercial viability is yet to be established. Reservoir characterization through multidisciplinary approach led to the better realization of the reservoir properties (both the qualitative and the quantitative aspects). Most of the reservoir facies were found ultra tight and the bulk of the porosity is contributed by the fracture network. Mapping of the fracture zones in 3D space is required so that the well bore trajectory can be placed along such zones to harness the hydrocarbon resources. In addition multi stage hydro fracturing will allow better flow rate.

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