Petrophysical Properties and Its Efficacy in Maintaining Linkages to Co-Laterals – A Case Study in an Indian Offshore Carbonate Field

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ABSTRACT: Petrophysical properties play a key role in calibrating 3D seismic attributes. This has been displayed in Carbonate reservoir in Indian Western Offshore. ELAN processing was first carried out in wells covering the entire boundary of reservoir. Mudstone, Packstone/Wackestone and Montmorillonite (main clay) have been used as matrix components in processing. Support from core data was taken in establishing the parameters for realistic results. Property maps were then generated to visualize the variations in space. The properties were superimposed over seismic structure and attribute maps for correlation. The relevant log properties (porosity, clay volume, oil saturation, net pay thickness, Net/Gross ratio and IHM) and seismic attributes were compared to establish correlation between them over gross thickness of reservoir. A gross correlation of IHM with Cosine of phase attribute was found relevant in defining the reservoir boundary. Likewise, IHM values are found corroborating with Seismic amplitude, and three types of reservoir facies (good, moderate and poor) have been identified fully satisfying geological concepts. The study shows the good quality reservoir extent suitable for drilling. FMI image has been helpful in identifying thin intervening shale layers within the reservoir, indicating fluctuation of sea levels during deposition. The image also depicts effect of diagenesis (presence of vugs, cemented vugs and few cemented vertical/sub vertical fractures). A New porosity-permeability relationship has been developed. The estimated permeability matches with the core derived permeability and also matches reasonably well with well test permeability except in regions indicating fractures. High permeability streaks within layers have also been mapped, which have caused injection water break through. Spatial variations of the permeability in the field helped in tracking direction of water movement in dynamic studies. There is a good semblance between petrophysical properties and productivity. Better reservoir facies developed in up-dip part have contributed the most. The paper signifies the contribution of petrophysics to characterize the reservoir in conjunction with seismic, geological and dynamic studies.

INTRODUCTION

The offshore XX-2 field is located in the Arabian Sea to the west of Mumbai, India. The structure is an anticline bounded towards east by NNW-SSE trending fault. The reservoir is essentially a bio-Micritic limestone as evident from core data and higher values of calculated Bulk volume of water (BVW). Figure-1 shows higher value of BVW calculated in one of the wells. The limestone was deposited in middle Miocene period with frequent fluctuation of sea level, which created maximum heterogeneity in the reservoir. Thick clastic sediments of Post Middle Miocene to recent provide the main seal for the reservoir. The reservoir has a small gas-cap, followed by an oil column and aquifer at the edges. The new fault pattern emerged from 3D seismic study has considerable impact on the fluid contacts. The reservoir is divided into six layers (A, B, C, D, E and F) starting from top. This is based on intervening shale layers depicted on well log data. The intervening shale/Mudstone bands are very thin in crestal area and are revealed clearly only in FMI images [9], as could be seen in well C-11H (Figure-2). The FMI image also indicates about post depositional activities like diagenesis in the form of solution Vugs, cemented Vugs and few cemented vertical/
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variation of reservoir properties. These attributes were compared with seismic attributes to establish correlation between them. Based on this correlation, area for infill drilling was identified. A new relationship between porosity and permeability was developed to visualize the fluid flow behavior. Permeability log was generated in each well and layer wise permeability maps showed distinct trend in space, helping in tracking water movement within the reservoir.

LOG QUANTITATIVE INTERPRETATION

The study includes interpretation of log data of 101 wells, covering the entire boundary of XX-2 reservoir. Using available logs a quantitative estimation was made using ELAN (Elemental Log Analysis). The analysis is carried out considering the model comprising clay & clay bound water, Calcite-1 (Mudstone), Calcite-2 (Wackestone & Packstone) as the matrix component and fluid as gas, oil & water. Indonesia saturation equation was employed to derive the saturation results.

Mudstone character in well logs is reflected similar to shale, representing wide separation on density-neutron overlay, and relatively low resistivity [3]. On evaluation, they reveal high porosity, high water saturation and low permeability. There is a gradual increase in mudstone volume as one approaches towards flank.

Several cross plots were generated to fix the most reliable matrix, fluid and clay parameters (Figure-3). NGS cross plots [4] identifies Montmorillonite as the main clay type within the reservoir (Figure-4). Pickett plot indicates coordinator and exponent values as a=1 and m=2, the formation water resistivity (Rw) set at 0.12 at formation temperature and the saturation exponent is set at 2 (Figure-5).
FLUID CONTACTS

XX-2 reservoir shows a gas cap in the crestal part of the field at –940m. OWC shows reasonably a large variation, in the north, it is close to –974m, in the central part, it is close to –983 m and in the southern part, it can be extended down to –989m. This confirms that at least some of the faults brought out from 3-D seismic interpretation are of sealing nature and have divided the field into blocks, controlling fluid flow.

Mudstone facies have created difficulty in petrophysical evaluation. This creates difficulty in placing oil-water contact distinctly, and some time even mask the ‘gas effect’ in top part of reservoir, when mud stone volume reaches a critical level. High percentage of Mudstone facies in the reservoir volume leads to lower accumulation of hydrocarbons even in situations when wells are located within oil limit.

PERMEABILITY EVALUATION

Permeability is an indicator of production rate and is one of the important engineering properties required for design, prediction and other investment purposes to manage production. An assessment of permeability and its variation in vertical and lateral direction in the field is always desired in reservoir characterization activities to link reservoir properties to production, and diagnose the causes of reservoir ailment. Timur type equation was tried and new permeability-porosity transforms were developed as indicated below:

\[ K^{1/2} = 66 \times \frac{\phi^{2.5}}{Sw} \quad \text{(for oil)} \]
\[ K^{1/2} = 33 \times \frac{\phi^{2.5}}{Sw} \quad \text{(for gas)} \]

The estimated permeability values derived through above transforms matches well within the permissible limit to core-derived permeability values (Figure-6), and also with well test permeability values, where the reservoir is devoid of fractures. In the crestal area (R, B & A platforms), the well test derived permeability and productivity index values are often higher due to presence of fractures. There is lot of variation (vertical as well as lateral) in log derived permeability as one approaches from periphery to up-dip area (Figure-7).

VALIDATION OF ESTIMATED PERMEABILITY WITH PLT DATA

PLT results indicate that all hydrocarbon production is from a selected interval (Figure-8). Similarly maximum intake
of fluid in injectors is indicated in selected interval out of total perforated interval. The production and intake of fluids generally take place in intervals having high permeability. Permeability values derived through the Timur type transform described above are found validating PLT results qualitatively. However, in few injector wells (converted from producers after producing for few years), maximum intake is now noted in less permeable zones. This anomalous behavior may be due to chocking of the big pores, which may be a later phenomenon.

**MAPPING OF PETROPHYSICAL PROPERTIES**

The computed parameters from ELAN processing include PIGN, Sw, Sxo, rock and fluid volumes, clay volume, and permeability (Figure-9). GeoQuest software ‘RESUM’ was used to calculate gross and layer-wise average reservoir properties for 101 processed wells. These elemental scale properties were used for spatial mapping using CPS-3, enabling use of petrophysical data as a complementary and / or supplementary connect to seismic, geology and reservoir engineering for value creation and competitive advantage in production optimisation and recovery process. Figure-10 to 15 show some of the bubble maps describing spatial variation of petrophysical properties.

**LINKAGE WITH 3D SEISMIC INTERPRETATION**

A number of log properties and seismic attributes were superposed to investigate the possibility of tangible correlation between the independent (seismic) and the
dependant (Well logs) parameters over gross thickness of reservoir, and look for a possible extension to use seismic attributes to determine the extent and quality of reservoir, required to target for recovery improvement. The study shows that reservoir characteristics derived through this integration can be extended to “pre-drill” areas with competitive advantage and employ the results as input in early reservoir simulations, and stretch it further to economic evaluation. This activity has the potential to facilitate optimize facilities and resources, and reduce production and drilling costs.
High amplitude is found corroborating with poor petrophysical properties outside the periphery of bulk producible reservoir, and relatively low amplitude is seen in the crestal part with local variations, correlating with good petrophysical properties. Good amount of hydrocarbon accumulation in better reservoir facies appears to be the probably cause for the enhancement of negative acoustic impedance contrast, resulting in relatively low amplitude [5 & 7]. The hydrocarbon saturation appears primarily responsible for this kind of feature. No correlation is found between amplitude and porosity, however good correlation exists between amplitude and IHM when there is not much variation in porosity (Figure-19-21). The local variations in seismic amplitude within the crestal part are apparently due to change in fluid content (Figure-17). The higher amplitude in fractured area of the crestal part probably represents water flooding, and low amplitude to higher oil saturation. Based on this correlation, area for infill drilling has been identified (north of C platform wells) for recovery improvement.

SEISMIC PHASE ANALYSIS FOR IDENTIFYING RESERVOIR BOUNDARY

Keeping in view the encouraging results of amplitude analysis and established linkages with hydrocarbon saturation, the cosine of phase attribute was studied to reaffirm hydrocarbon boundary, as hydrocarbons often cause local phasing.

A phase boundary from Cosine of phase was generated from 3D seismic data. Petrophysical properties when analyzed in conjunction with the phase boundary imply the phase boundary as reservoir boundary, interpreted as being caused due to hydrocarbon presence, which is at a low

Figure 15: Trend of log derived permeability supports direction of water movement (D-layer)

Figure 16: Dynamic study indicating water movement from well B-1 to D wells

Figure 17: IHM Vs. Seismic amplitude – identifying good, moderate and poor reservoir facies. Range of IHM: 0.01-4.5
saturation level beyond the boundary. A gross correlation of petrophysical properties (IHM) with phase boundary is shown in Figure-18.

The contour of oil water contact is found located in the proximity of this boundary, which explains that a certain critical % of hydrocarbon saturation has created the appreciable phase change appear as boundary.

**PALEO ENVIRONMENT AND BATHYMETRY INFORMATION IN LAYER DESCRIPTION**

**Layer ‘F’**

The deposition of lower most layer-F marks the beginning of XX-2 limestone deposition. The limestone is characterized by wackestone facies in crestal part, switching over to mudstone facies towards basinal part, because of low energy owing to relatively deep bathymetry. The layer is overlain by shale, which is present almost in entire field. The layer is oil bearing in crestal part. The gross thickness varies from 2-5 m and average porosity from as low as 12 % in E area to 28 % towards crest. Good permeability values are seen only in crestal part.

**Layer ‘E’**

The layer shows a low potassium and thorium content and high uranium value. The high uranium content could be due to the presence of organic material (syndepositional), which could be linked to a reducing environment. The presence of pyrite also suggests probable reducing conditions. Conventional core cut in well H-1 suggests facies as packstone with abundant corals and wackestone. Towards basinal part, limestone is represented by wackestone /mudstone. The layer is overlain by thin
carbonaceous shale and is oil bearing in up dip part. The thickness varies from 12 m to 2.5 m. The average porosity ranges from 27% in H-1 to 13% in H-4. Area around A, C & R posses very high permeability values.

**Layer ‘D’**

The layer is represented by packstone / wackestone facies followed by mudstone facies (recrystallized with sparite cemented vugs) at top. It consists of larger foraminifers (Gypsinidae and Nummulitidae family), big gastropods and algae. The presence of larger foraminifers suggests shallow bathymetry and abundant food supply in the form of algae. Core data of H-1 and H-2 suggests presence of micro fractures, which could be due to the post middle Miocene activity, resulting into development of secondary porosity. FMI image of well C-11H shows presence of solution vugs (Figure-22). The porosity map shows good development of porosity of the order of 17% to 27% that holds good amount of liquid hydrocarbons above the OWC through out the field. Wells of A, B, C, D, R and some wells of E, T, P, N7, Q and S platforms are the good examples. The average thickness of this unit varies from 4-7m. In T platform area the thickness reduces to 2-3m. The highest potential of this unit is seen in D platform area with very high permeability values. However, towards basinal part facies variations (towards wackestone / mudstone) are seen.

**Layer ‘C’**

It is essentially a wackestone facies, recrystallized with larger Forams (Gypsinidae and Nummulitidae), Miliolids, big Pelecypod tests (Core data of H-2). The layer is well developed throughout the field. The lower part of the unit is relatively clean, whereas the upper part represents mudstone facies with some Echinoderms and Pelecypods. Numerous sparite-cemented vugs can be seen in the interval. Thin layer of packstone is also present in the interval. The quality of reservoir is better in updip area and deteriorates towards flank. Porosity values vary from more than 22% in crestal part to around 18% towards flank with increase in argillaceous matter. Good permeability values are seen in crestal part.

**Layer ‘B’**

This layer is represented by wackestone facies followed by packstone facies at top in the crestal part (A, B, C & R area. The bottom part is argillaceous and GR counts decreases towards top. The thickness varies from 5 m in crestal part (H-2) to 12m (O-5) towards flank. The top part is highly porous in crestal area, but porosity is destroyed towards flank. Based on high porosity & permeability values this layer is again subdivided in two sub layers ‘B1’ and ‘B2’. Layer ‘B1’ possesses very high values of permeability in B, R & D area whereas ‘B2’ possesses good permeability values in A, B, C & R area.

**Layer ‘A’**

The layer contains a wackestone / packstone facies in the lower part followed by mudstone facies in upper part. Gross thickness varies from 4-5 m in peripheral wells like I-2 to 6-8 m in wells located in the crestal part. The average porosity varies from 23% in the crestal part to 14% in the T area. Porosity has been destroyed towards periphery due to diagenesis. Good permeability values are seen in A, C & K8 area.

Overall, better facies are observed in updip area. Facies are deteriorating towards basinal part. Core data indicates presence of Packstone / wackestone in updip area,
and Mudstones / wackestone facies towards periphery. The effect of facies variations is well reflected in permeability and productivity values.

In reservoir, Sparitic cementation of solution vugs, together with recrystallization has often been observed, which is probably a reprecipitation effect of the dissolved calcite during post depositional diagenesis in precipitation phase of vedose zone. This phenomenon has resulted the limestone loosing its original porosity. FMI image of well C-11H clearly shows presence of cemented vugs.

Similarly, solution vugs are well present, which can be expected as a result of sub-aerial exposure at the end of cycle where the sediment is exposed to meteoric water (fresh water vedose zone). FMI image of well C-11H confirms presence of vugs.

**LINKAGE WITH PRODUCTIVITY AND WELL POTENTIAL**

The well productivity in general is good in the up-dip area (R, B, D, A), moderate in peripheral area (P, S) and poor in T, E area. The productivity represents a good semblance with petrophysical properties map (Porosity, oil saturation, net pay thickness, IHM and \( V_{clay} \)). These maps indicate better reservoir facies in the up-dip portion than peripheral area. In B-R area, higher productivity could also be due to presence of fractures. The permeability estimated from Build up is varying in different part of the field; R: 50-500md, S: 10-80md; A: 10-150md (less towards A-3, more in A-5); D-9: 170md; P: 5-20md; Q: 10-80md. The permeability estimated from Timur type relation matches well in the periphery, but in up-dip the well test permeability is higher in few wells, which is indicative of the fractures. The presence of fractures has been validated by Curvature analysis carried out on 3D seismic data.

The high water cut is the main problem of the reservoir. Studies comprising Tracer survey, Diagnostic plots, Event analysis and water tracking through OFM were carried out. Integration of these studies with faults and permeability mapping show the possible water paths. For example, the dynamic study indicates high water cut in D area from injector B-1 (Figure-16). The estimated log derived permeability values are very high in layer ‘D’ in D area (Figure-15). The high permeability streaks have acted as conduits from injector to producers.

**CONCLUSION**

- Extensive well log database has been used to calibrate 3D seismic derived attributes, to establish the possible use of this independent data in reservoir delineation and exploitation purposes. The correlation has been established between petrophysical attributes and seismic amplitude & cosine of phase attribute.
- Well log signatures and quantitative values together with core description have successfully been used in geological descriptions of the various layers.
- The Permeability values derived from newly developed porosity-permeability relationships have shown semblance to dynamic studies, and have helped in tracking water movements within the reservoir.
- Results emerged from above study have developed linkages of petrophysics with seismic, geological & dynamic studies.

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