The 2nd South Asain Geoscience Conference and Exhibition,GEOIndia2011,
12-14th Jan,2011,Gearter Noida,New Delhi,India

GEO India 2011

GEO India Conference in Greater Noida, UP, January 12-14, 2011

PAPER ID 489

Integration of Laboratory Measurements and Well Log Data for Reservoir Characterization of Carbonate Field, India: A Case Study

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ABSTRACT

The Mukta field is located in the north-western part of Heera-Bassein block in Bombay Offshore Basin, India. The field is situated in the western vicinity of Panna field with syncline in between and is around 25 km east of giant Bombay High field. The Mukta field was discovered in 1981 by drilling first well in the eastern culmination of the structure and produced oil and gas from Bassein limestones of Eocene to early Oligocene in age. The field has subsequently been delineated by drilling more E & A wells. Currently, the field is producing from a single wellhead platform.

The present paper focuses on the understanding of reservoir characteristics using well log data in conjunction with lab measurements. The study has been carried out in one part of the field that is currently under development phase. The Thin section Petrography, Core NMR and Mercury Intrusion Capillary Pressure (MICP), and well log data shows that the dominant lithology is clean limestone having all three type of porosity (Micro, Meso, and Macro) with dominance of Meso porosity system. The presence of multi-layered reservoirs is explained through the texture analysis along with capillary pressure data. The petrophysical evaluation shows that the water saturation in the reservoir zones is governed by height from FWL and porosity development. The study also depicts that the reservoir zones are under transition due to insufficient height above Free Water Level (FWL).

A Single Well Predictive Model (SWPM) study has been carried out and results were compared with those of the Drill Stem Tests (DSTs) carried out in the well. A good match between both SWPM and DST results (Kh, Radius of Investigation, and PI) was seen. The study is helpful in decision making for future development of the area.

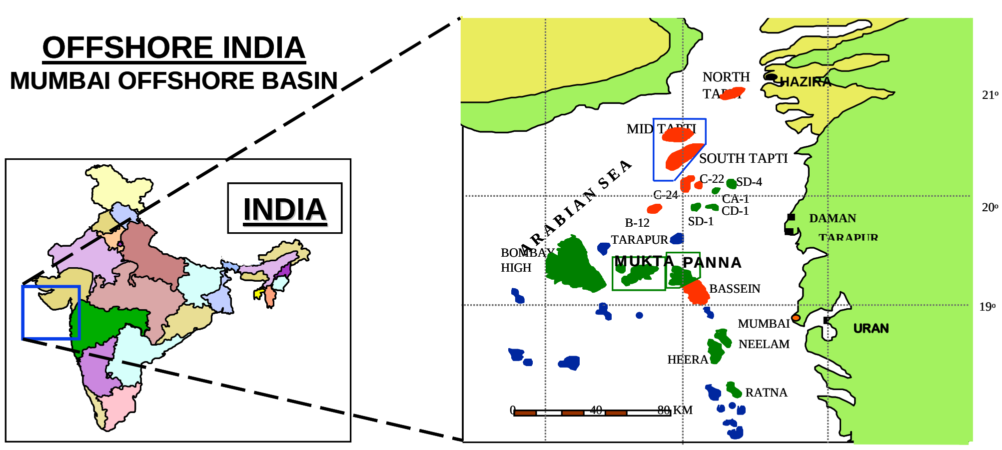

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Figure 1: Location of the Mukta Field, offshore Western India.

INTRODUCTION

The Mukta field was discovered by ONGC in 1981 by drilling first well B-57-1 in the eastern culmination of the structure. It produced oil and gas from various zones of Middle Eocene-Oligocene carbonate called Bassein limestone. The field has been since delineated later on by drilling more E & A wells.

A generalised structural section of Mukta Field is shown in Figure 2. The Bassein formation is the main reservoir in the area. Locally, seals in Mukta area include a tight limestone with a thin shale layer at the top of Bassein B-Upper, tight limestone in the TZ-3 zone between the Bassein B-Upper and B-Middle, the TZ-2 zone between the Bassein B-Middle and B-Lower and regional shale between Bassein B-Lower and Panna Formation. Unlike the Panna area, Mukta does not appear to have any collapse features (Breccia pipe or sink hole) which provide linkage between the different Bassein Limestone reservoir layers in Panna field. As a result, there is presence of multi-layered reservoir zones as B-Upper, B-Middle, and B-Lower respectively. The field is segmented in to different blocks and the present study is focused in Bassein B limestone of adjoining part of MA area (Figure 3).

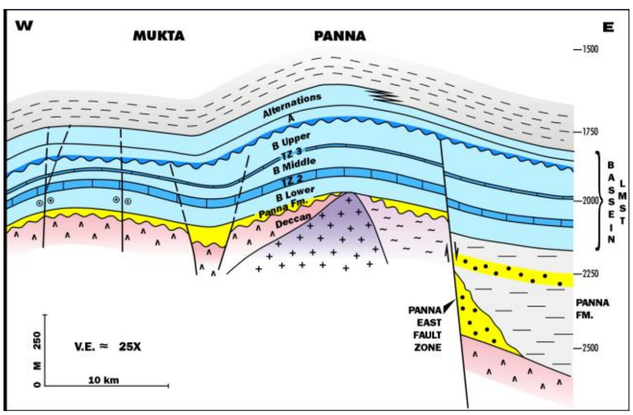

Figure 2: Generalized Structural Section for Mukta Field.

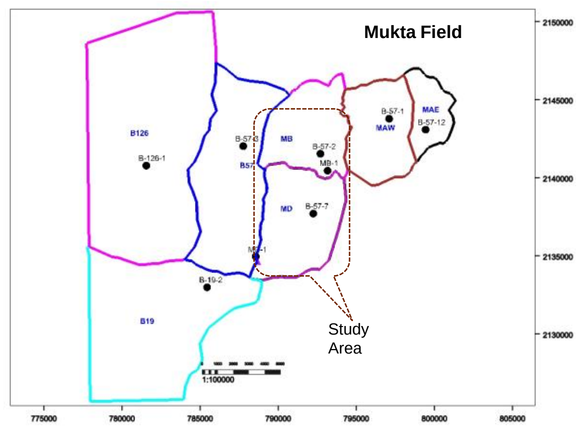

Figure 3: Different Blocks in Mukta Field and the study area.

Porosity Partition Using Laboratory Data

The porosity of the samples from one of the well under study area was characterized using a system built upon Mercury Porosimetry: Micropores are defined as pores with throats less than 0.5 µm; Mesopores are defined as pores with throats between 0.5 and 5 µm; and Macropores are defined as pores with throats in excess of 5 µm. The three pore types are identified by the lab studies on the core samples of well MD-1.

The Bassein B Limestone is a low porosity reservoir having all three types of porosity. Figure 4 depicts the Mercury Porosimetry plot and it is seen clearly that dominant porosity type is **Meso**. The porosity is further characterized by the integration of core NMR, Thin section Petrography, and Mercury Porosimetry data. Figures 5 to 7 demonstrate all three types of porosity: **Micro, Meso, and Macro** respectively.

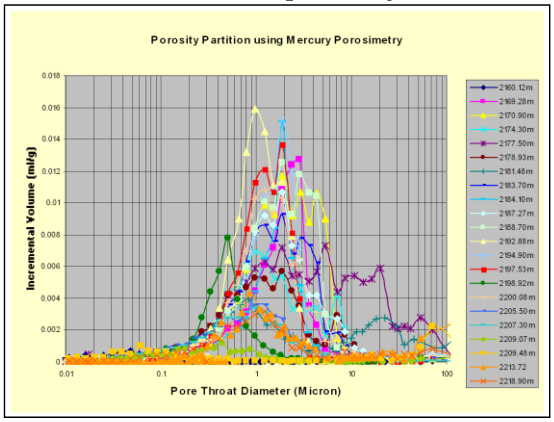

Figure 4: Mercury Porosimetry plot for Bassein B Reservoir (Well under study area).

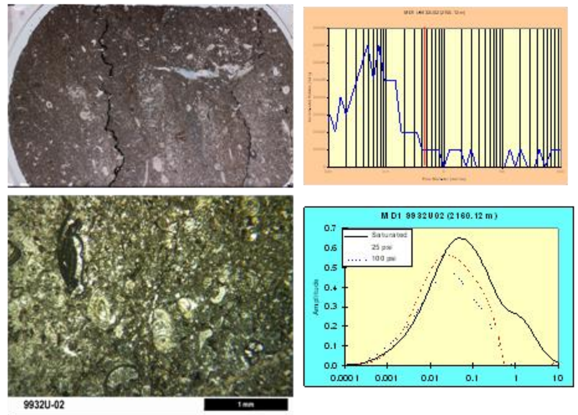

Figure5: Data from a plug consisting entirely of Microporosity (pore throat diameter less than 0.5 μm).

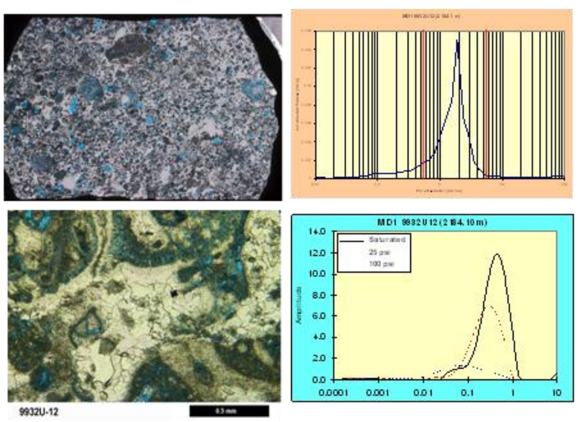

Figure 6: Data from a plug consisting entirely of Mesoporosity (pore throat diameter between 0.5 and 5 μm).

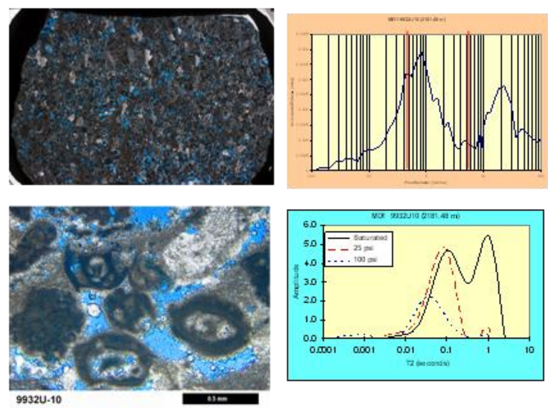

Figure 7: Data from a plug consisting Micro, Meso and Macroporosity (pore throat diameter between < 0.5 and >5 μm).

It was observed that the proportion of Microporosity increases up to 80% in tight limestone for example in TZ3 which is acting as a barrier in the field. It can be concluded that in Mukta field, low porosity limestone (< 7 p.u.) will likely has bigger volume of Microporosity and thus acting as a barrier for flow of fluids unless there are presence of fractures.

Saturation-Height Function

There are various practical techniques for correlating capillary pressure curves according to rock type for a heterogeneous formation and generating field wide saturation-height function that relates capillary pressure curves to porosity, permeability or rock type in general. The classic method is based on Leverett's J-function approach and this has been adapted to in estimating field saturation distribution. Leverett combined the pressure scaling and the rock quality parameter into "J" as given below:

dynes/cm

$$J = 0.2166 * Pc * (K/\phi)^{0.5} / \sigma \ \mathrm{Cos}\ \theta \quad \text{----1}$$

psi md fraction degrees

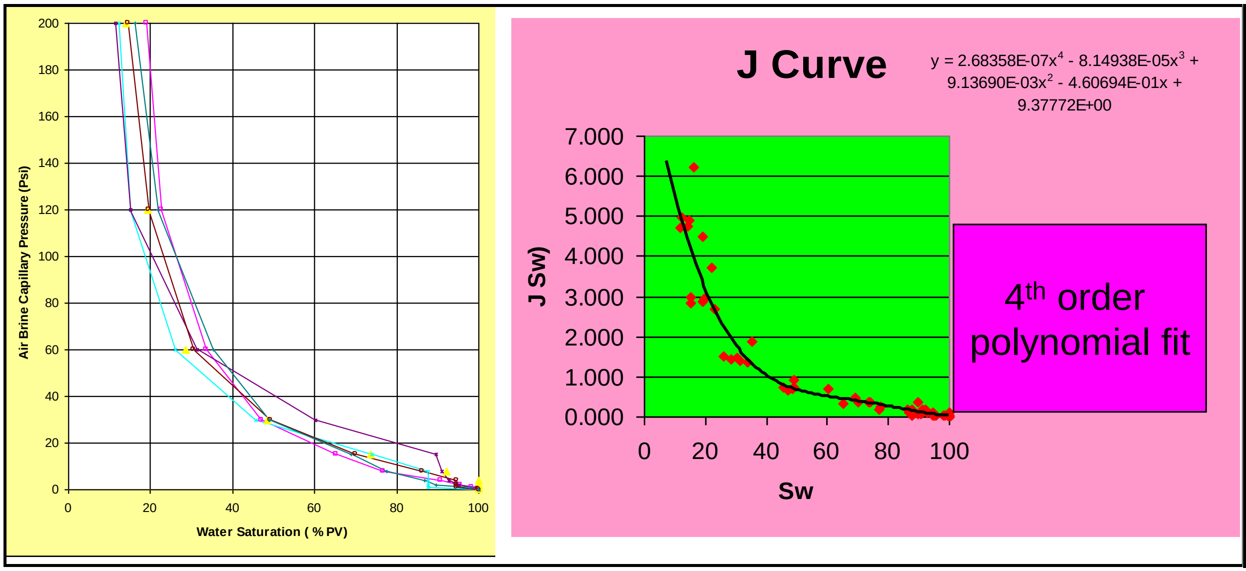

Figure 8: Air-Brine capillary pressure data (left), J function (right).

The J function was used to predict saturation trends in well MB-1. Capillary pressure measurements (SCAL) are performed on each core plug (Figure 8, left) and, after conversion to reservoir conditions, are then converted to J values for each sample and plotted against saturation (Figure 8, right).

$$P_C = (\rho_w - \rho_o) * h/144 \text{-----------------2}$$

ρ_w and ρ_o are in lb/ft3

h is height from free water level in ft. Pc was estimated in the example well and again J values were estimated using equation 1 to derive the water saturation. Permeability (K) was estimated through pero-perm relationship using core data. Φ was estimated through log data.

The example well data (MB-1) were also used to derive hydrocarbon saturation. These were then used to gauge how close the estimates from the saturation-height function could get to the log-derived values (Figure 9).

Mukta field under Transition

Air-brine (drainage) capillary pressure tests, at the maximum 200 psi capillary pressure, yielded immobile water saturation (Swi) values between 11.6 and 33.8 percent pore volume in well MB-1. On inspection of saturation profile in B-Upper and B-Middle reservoir of MB-1 (Figure 9), It can clearly be seen that zones are in transition as Sw is of the order of 50% even at the top part of reservoir which is due to insufficient height from free water level. It is also to be noted that

TZ3 is as a barrier between two zones results in lower oil saturation in BU zone as a result of smaller height above the FWL.

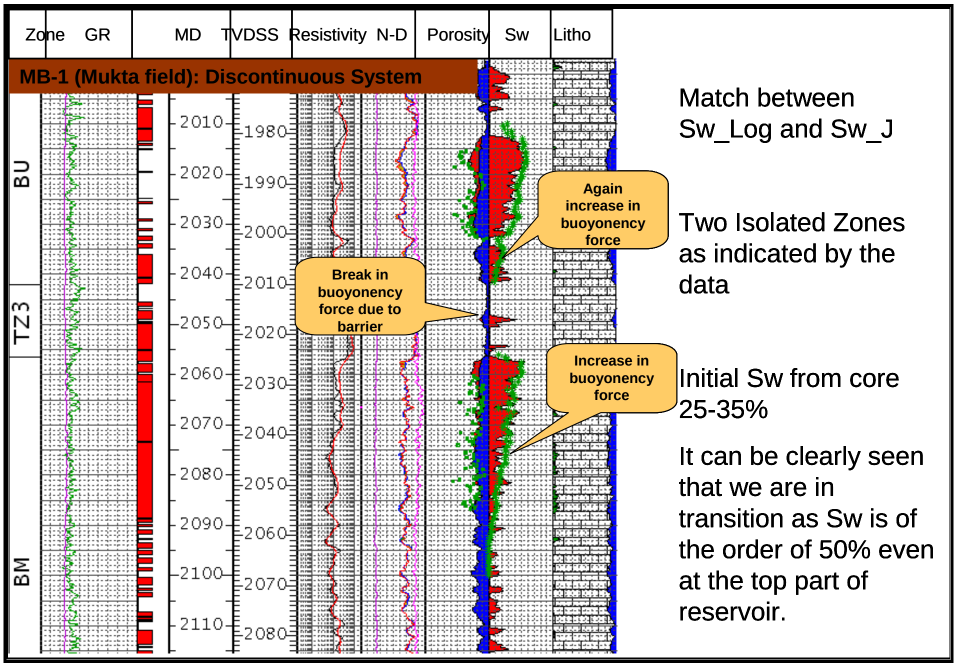

Figure 9: Saturation profile in B-Upper and B-Middle of well MB-1.

Single Well Predictive Model

A Single Well Predictive Model (SWPM) study has been carried out for MB-1 and results have been compared with those of the Drill Stem Tests (DSTs) carried out in this well.

After generation of the static model, the 3D model was simulated in the prediction run. A BHP limit of 1100 psi was given and liquid rate was observed to match with DST results. The model was simulated with a 5 hr flow period followed by an 18 hr build up to history match the DST done earlier. Simulated pressures and rates are as shown in Figure 10.

The pressure-rate data of DST simulation was taken into well testing software, and the results infinite acting radial flow was identified on the log-log plot. The results of the log-log plot and semi-log plot were found to match with the results from the interpretation of DST (Figure 11).

Thus the DST was simulated accurately validating the reservoir properties. The analysis is useful for future development of part of the field under study.

CONCLUSION

The Bassein B reservoir has basically low porosity reservoir with dominance of Mesoporosity. It was observed that the proportion of Microporosity increases (50-80%) in tight limestone which is acting as a barrier. The Capillary pressure data explains the presence of Multi-layered reservoir

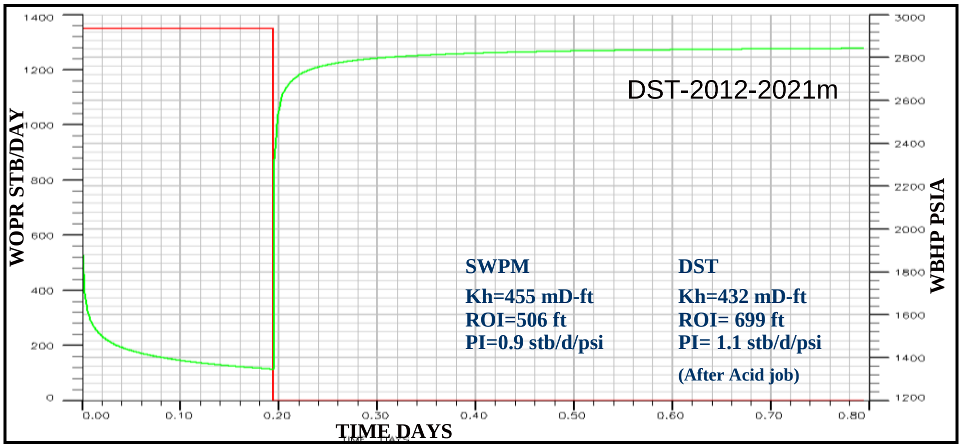

Figure 10: Simulation of DST

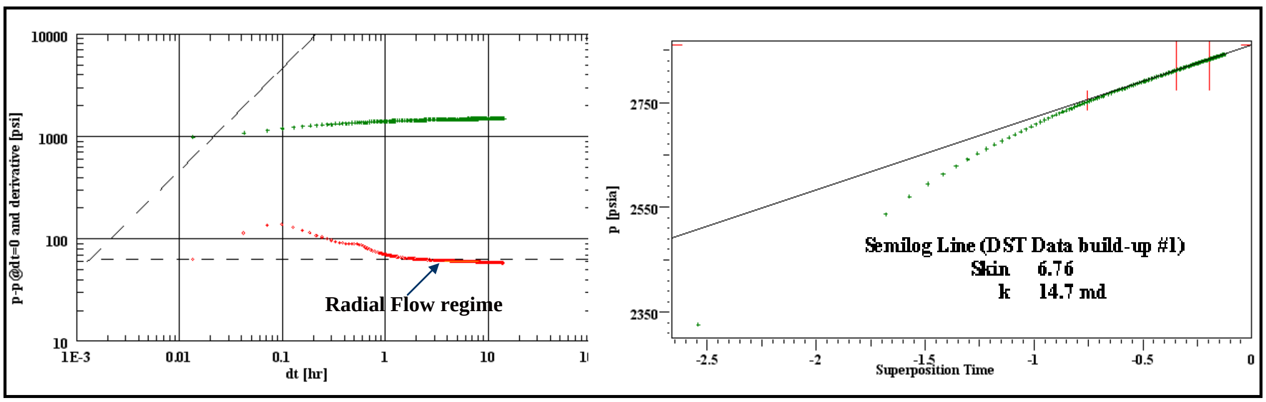

Figure 11: DST simulation- interpretation results Simulation of DST

zones as B-Upper, B-Middle, and B-Lower respectively. There is a good match between both SWPM and DST results (Kh, Radius of Investigation, and PI). The study is helpful in decision making for future development of the area.

Acknowledgments

The authors wish to thank BG Group and the Tapti JV Concession partners ONGC and Reliance Industries Ltd. for permission to publish this work.

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