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Permeability Modelling: Problems and Limitations in a Multi-Layered Carbonate Reservoir

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Summary

Reservoir characterization is a continuous process, from field discovery to abandonment and involves a number of geological, geophysical and engineering techniques for realistic performance predictions through reservoir simulation. Permeability modeling of an oil and gas field is a significant part of reservoir characterization and reservoir simulation, particularly, in carbonates where it is still a challenge due to their complex faulting and fracture behaviour and complicated reservoir architecture. Additional complexity is added in carbonates due to the interaction between fractures and matrix rock and the diagenetic processes. These rocks usually have diverse pore types and heterogeneity, their porosity is dominated by micro intra-granular porosity, and vugs or macro intergranular pores usually enhance permeability.

A set of permeability values estimated on grid blocks are needed for any reservoir simulation study. Permeability data obtained from laboratory measurements or pressure transient tests are usually approximative. It is already known that in the permeability estimates derived from the pressure response during pressure build-up testing, the radius of investigation can be several thousand feet, and the volume tested normally contains more than one petro-physical zone. The other problem is that core data are laboratory measurements, while pressure data are in-situ data. Core measurements are not representative of the in-situ conditions. Although permeability from pressure build-up analysis is representative of the in-situ conditions, some assumptions are still needed to be made about the thickness of the production interval, and about the nature of the flow.

In the present paper, core, log and well test data is studied for permeability modeling in a multi-layered carbonate reservoir of an Indian Offshore Field. It was found difficult to establish any relationship between core porosity and permeability based on either geological facies types or log parameters due to the highly heterogeneous nature of the reservoir. Porosity-permeability cross-plots were analysed for all the eleven geological layers and then layerwise relationships were established for predicting the permeability in the non-cored wells and hence for permeability modelling in the reservoir simulation model. Upscaling and validation of core derived permeability could not be done due to non-avalability of core and well test permeability data in the same layers/wells.

Introduction

Permeability is a measure of the ability of a porous material to transmit fluid. Environmental and depositional factors influencing porosity, also influence permeability. Therefore, fundamentally, a correlation between porosity and permeability is expected in all type of reservoirs. The relationship varies with formation and rock type and reflects the variety of pore geometry present. Typically, increased permeability is accompanied by increased porosity. Many earlier workers [1-6] plotted permeability versus porosity and established reservoir specific relationships between them. Sometimes, the porosity-permeability cross-plots were rationalised by grouping the data according to depositional environment and/or rock types. According to their findings, constant permeability accompanied by increased porosity indicates the presence of more numerous but smaller pores. Post depositional processes in sands including compaction and cementation result in a shift to the left of the porosity-permeability trend line. On the other hand, dolomitization of limestones tends to shift the porosity-permeability trend lines to the right.

In a sequential approach to understand permeability profiles in non-cored wells, the core data was analysed after classifying it using geological, log derived and layerwise approaches in a multilayered carbonate reservoir of an Indian Offshore field and presented in this paper. The reservoir under consideration is heterogeneous, inter-bedded by thin shale bands and argillaceous limestones. The top of this reservoir is easily identifiable on logs due to the presence of a thick over-lying shale. The shallowest litho-stratigraphic reservoir unit is designated as the A1 layer. It has total 11 number of geologcal layers A1, A2I A2II, A2III, A2IV, A2V, A2VI, A2VII, B, C and D from top to bottom separated by interbedded shales.

Analysis of Core data using Geological Approach

After the wellwise core log depth matching, a total number of 355 core samples gathered from 15 wells were classified into three macro-facies type namely Mudstone, Packstone and Wackstone. **Fig.1** shows the core porosity versus core permeability cross-plot for these different type of facies present in the reservoir.

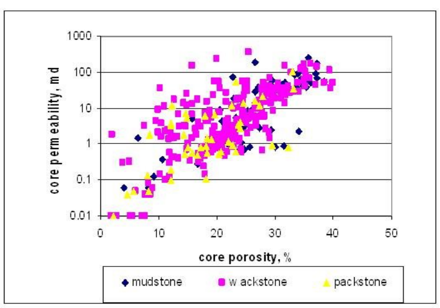

Figure 1: Microfacies Classification in Mumbai High Field

It is found that out of the total 355 core samples, wackstone is predominantly present in 243 samples followed by mudstone (68 samples) and packstone (44 samples). The core porosity and permeability values in these three facies type varies as depicted below;

	Mudstone		Wackstone		Packstone	
	Φ %	K md	Φ %	K md	Φ %	K md
Min	4.1	0.01	1.75	0.01	2.25	0.01
Max	38.4	251.6	40.0	350	33.0	105.8
Avg	25.9	33.4	21.3	18.5	18.4	7.87

It is seen that although wackstone has maximum value of porosity and permeability, mudstone has their maximum average values. However, lowest maximum and average values of porosity and permeability are found in Packstone. The variation of permeability with depth for these 3 facies type is shown in **Fig.2**. It is seen that wackstone is present throughout the reservoir from top to bottom with higher permeability values towards bottom.

Analysis of Core data using Log derived Approach

After analysing the core porosity –permeability data using geological approach, it has been grouped based on two log parameters i.e. shale content (Vsh) and Gamma ray content (GRc). The core porosity versus core permeability plots based on four Vsh classes (0-10, 10-20, 20-30 and 30-40) and eight GRc classes (0-10, 10-20, 20-30, 30-40, 40-50, 50-60, 60-70 and >70) are depicted in **Fig.3** and **Fig.4** respectively.

No distinct trend between core porosity and permeability has been observed according to different Vsh classes (**Fig.3**). Out of 355 samples, 94 samples were falling in the Vsh range of 20-30, followed by 83 samples in 30-40, 75 samples in 10-20 and 30 samples in 0-10 range. However, the maximum permeability of 350 md has been observed at 25% porosity in the Vsh range of 10-20 whereas in the range of 20-30, maximum permeability of 251md has been found at 35% porosity.

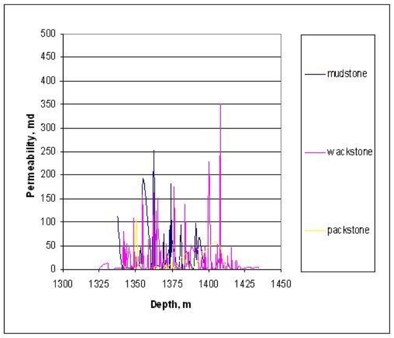

Figure 2: Microfacies wise variation in Permeability

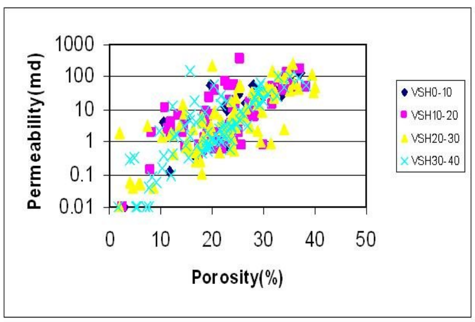

Figure 3: Variation of Porosity and Permeability with Vsh

Similarly, no distinct trend between core porosity and permeability has been observed according to different GRc classes (**Fig.4**). Out of 355 samples, maximum number of 171 samples were falling in the GRc range of 30-40, followed by 97 samples in 40-50, 40 samples in 20-30 and 32 samples in 50-60 range. However, the maximum permeability of 350 md has been observed at 25% porosity in the GRc range of 30-40.

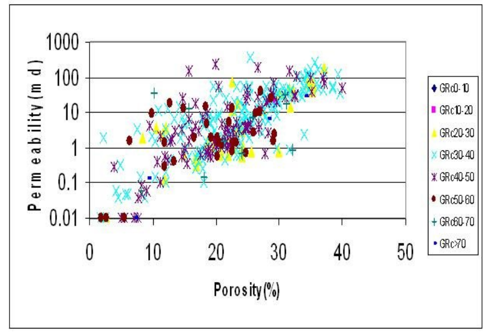

Figure 4: Variation of Porosity and Permeability with Grc

Layerwise classification of Core data

Based on total number of 434 core samples from 12 number of wells, layer-wise core porosity- core permeability plot is shown in **Fig.5**. It is seen that there is no distinct trend exists for different layers. The porosity and permeability values obtained in these layers have wide range as indicated below;

Layer	No. of wells	No. of samples	Φ,%	K, md
A1	5	60	12.2-36.6	1-135
A2I	7	34	3.9-33.8	0.01-63
A2II	6	47	5.3-40.7	0.05-486
A2III	5	28	1.5-34.3	0.01-111
A2IV	3	15	12.8-34.7	0.3-228
A2V	6	73	3.8-36.3	0.1-461
A2VI	2	20	6.5-36.0	0.06-122
A2VII	6	51	2.9-35.7	0.01-192
B	5	55	6.7-38.4	0.01-251
C	18	18	2.3-29.9	0.03-33
D	2	33	12.7-40	0.8-113

It is seen that layers A2II and A2V have large variation in porosity and permeability in comparison to other layers. In layers A2I and C, despite the presence of good porosity, comparatively low permeability values are obtained.

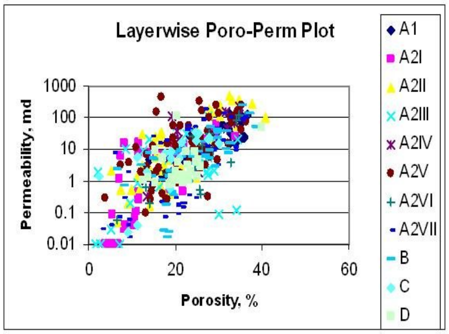

Figure 5: Layerwise variation of Porosity and Permeability

In order to predict the permeability values in non cored wells, layerwise core data based porosity and permeability correlations have been developed based on regression analysis as under;

K = a exp (b * Φ)

where K is permeability in md and Φ is porosity in percentage. The values of constants a and b for all the layers are given below;

Layer	a	b
A1	0.0058	0.2665
A2I	0.0081	0.2855
A2II	0.0588	0.2393
A2III	0.0426	0.2011
A2IV	0.1292	0.1998
A2V	0.0797	0.2032
A2VI	0.0230	0.2388
A2VII	0.0310	0.2212
B	0.2250	0.1467
C	1.0943	0.1035
D	0.0794	0.1469

Using layerwise coefficients so generated, the variation of permeability with porosity is shown in **Fig.6**. It is seen that in comparison to other layers, C layer has higher permeability values at low porosity and low permeability values at higher porosity and further, layer D is the least permeable layer. The very slow variation of permeability with increased porosity gives an indication of presence of more numerous but smaller pores in layer C. The increase in shift of permeability porosity trend lines to the right from top to bottom layer indicates that more dolomitesation of limestone has taken place in bottom layers in comparison to upper layers.

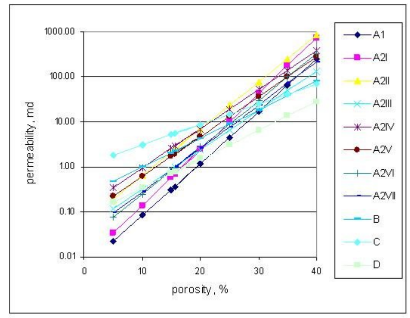

Figure 6: Layerwise Porosity and Permeability correlations

K-∅-Swi Correlation

In the redevelopment study of Mumbai High field, a K-∅-Swi relation was derived using both core and log data. Earlier, attempts were made to generate K-∅-relations for each layer separately for better characterisation. The cross plots, however, showed a lot of over lapping data from all of these layers. Subsequently, from the careful observation of the core and log data pertaining to L-IIII reservoir, a good trend was observed and a strong relationship could be derived.

$$\sqrt{K} = 138 \times \frac{\phi^3}{Swi}$$

The permeability estimated from this equation appeared to give better permeability estimation compared to standard equations such as the Timur equation. This equation was valid for the zones with irreducible water saturation levels only as it tends to under estimate the permeability values in the transition zones and the water bearing portions of the reservoir.

To compute the permeability values in the transition and water bearing zones it was decided to utilise the Bulk Volume Water (BVW) versus depth approach where BVW is the product of porosity (∅) and water saturation (Sw). For the purpose of estimating Swi in the transition and water-bearing zone, and thus the permeability levels in those zones, a constant BVW line was extended from the oil-bearing zone into these zones.Using this BVW value and the porosity computed from the logs at digital level, a Sw value was calculated and used in the above equation.

It was observed that the permeability levels estimated from K-∅- Swi relationship show far lower values than the permeability levels used during the history match stage of the reservoir simulation. This is probably due to the reason that there are no core samples to represent the very high permeability intervals. Secondary porosity in some of the formations has resulted in significant permeability enhancement. The K-∅- Swi relation derived from core plugs could not generate these levels of permeability.

Limitations in Comparison of Permeability determined from Core analysis and Pressure Transient Tests

Permeability values determined from pressure transient tests in 140 wells of this multi-layered carbonate reservoir were available for analysis. Most of the tests were carried out in multiple layers as the wells were completed in more than one layer. Permeability values ranging from 1.7 to 2169 md were observed in multiple layer completions. Out of 11 layers, single layer pressure transient test data was available only in 3 layers A1, B and C. But, even in these three layers, it was found that there is not a single well test permeability available in the same well in which core permeability was available. Therefore, it was not possible to compare the core derived permeability values and those derived from pressure transient tests in all the layers.

Conclusions

The core data was analysed using geological and log derived approaches. The core porosity-permeability cross-plots were made for three facies types e.g. wackstone, mudstone and packstone. The core porosity and permeability data was also analysed based on shale and gamma ray content. But, it was found difficult to establish any relationship between core porosity and permeability based on these facies types and log parameters. After the failure of these approaches, porosity-permeability cross- plots were analysed for all the eleven layers and layerwise relationships were established for predicting the permeability in the non cored wells and hence for permeability modelling in the reservoir simulation model. Since, most of the wells were completed in more than one layer and even in case of single layer completions, core and well test permeability was not available in the same well of this multi-layered carbonate reservoir, it could not be possible to compare permeability values obtained from core and pressure transient tests in all the layers.

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