



# Application of hydraulic flow unit for prediction of flow zone in carbonate reservoir

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Received: 23 December 2020 / Accepted: 30 March 2021 / Published online: 7 April 2021  
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## Abstract

The feasibility of oil production in any reservoir depends on the porosity and the permeability of that reservoir. Particularly, the permeability in the reservoir allows the ease of flow of fluid through it. High permeability is always desirable for the successful production of oil in any reservoir. The porosity and permeability depend on the reservoir rock. In general, the higher value of porosity and permeability makes limestone a suitable reservoir. Therefore, it is very important to characterize the reservoir in terms of porosity and permeability for the feasibility of oil production. In this investigation, reservoir characterization was carried out to determine the porosity and permeability of limestone reservoirs obtained from four different basins of Oilmax Mumbai. A total of 32 core samples of NX size were tested for characterization and determined porosity and permeability values. The variation in porosity and permeability was observed from 0.3 to 20.5% and 0.002 to 1.484 mD at the burial depth from 1618.86 to 1634.14 m, respectively. The normalized porosity and reservoir quality index were determined using the experimentally obtained porosity and permeability values. Normalized porosity values were used to calculate the flow zone indicator (FZI), which varied from 0.071971 to 6.024804. The least-square regression method was used to determine the hydraulic flow units (HFU) for different limestone samples. The porosity range indicates the highly porous reservoir, while the lower permeability was observed due to the non-linearity between porosity and permeability correlations. The results showed the consistent flow regime in five different hydraulic flow units in wellbore A. The consistent fluid regime in the other wellbore is only possible by increasing the reservoir's permeability. Hence, hydraulic fracturing is highly recommended before the establishment of a production well.

**Keywords** Porosity · Permeability · Flow zone indicator · Hydraulic flow units (HFU)

## Introduction

The simulation of a reservoir and prediction of its performance requires an accurate description of the reservoir is necessary. The characteristics parameters like porosity and permeability are essential for determining the hydraulic flow unit (HFU) and the prediction of the reservoir performance. The concept of HFU has been developed to estimate permeability in the cored zone and then use their result in the un-cored zone. Depending upon the nature and availability of data, various

methods are utilized to estimate HFU. Some of these are gamma-ray, flow zone indicator, cumulative flow and storage capacity curve, stratigraphic modified Lorenz plot, etc. (Zargari et al. 2013). Carbonate reservoirs are as crucial as sandstone since they contribute 60% of the world's hydrocarbon containment. Characterization of carbonates is a challenging task owing to their composition. Calcite is composed of calcium carbonate, and it is chemically reactive and more prone to diagenesis than silica. Carbonates in their early stage of deposition exhibit high porosity and permeability. Dissolution and re-precipitation are often seen in carbonates with time. Due to this reason, carbonates mostly exhibit secondary porosity and permeability (Abdulelah et al. 2018). Diagenesis caused heterogeneities in carbonate reservoirs, which makes it tough to characterize carbonate reservoirs (Bagci and Akbas 2007). Thus, making it challenging to comprehend the storage and flow capacity. This heterogeneity resulted from depositional setting and post-depositional diagenesis. Apart from causing the problem in characterization, it also causes variation in pore

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Responsible Editor: Santanu Banerjee

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size, grain size, and cementation, thereby damaging the direct relationship between porosity and permeability. Carbonate reservoirs exhibit a high level of heterogeneity at every scale, from core to field. The formation's discretization is essential in terms of similar flow properties to manage heterogeneity in reservoir modeling. Recently, the interest in extending the rock-typing approaches is increasing, intending to identify the potential layers in complex lithology like carbonates. The hydraulic flow unit is also described as a reservoir section where the factors controlling the fluid flow are different from the rest of the reservoir. The factors that influence fluid flow are pore-throat geometrical attributes like mineralogy and texture (Amaefule et al. 1993). Various combinations of these factors lead to distinct rock flow units having similar fluid transport properties. Therefore, an HFU is included in several rock facies, depending on their depositional environment and mineralogical content. The hydraulic flow unit is an interval with specific specified properties, which has noticeable development in the reservoir. This property is considered a practical tool for grouping reservoir rocks and characterizing heterogeneity using porosity and permeability relationships (Masoud et al. 2020). Many attempts were made to describe carbonates using both geological and petrophysical properties in the recent past. The most appropriate and widely used method is the hydraulic flow unit (HFU). The classification of carbonate reservoirs into various HFUs helps in delineating distinct reservoir zones where its unique petrophysical parameter characterizes each flow zone. These flow zones help for a better understanding of the heterogeneity of the carbonate reservoir. HFU focuses on clustering similar fluid pathways in the reservoir where the lithofacies' concept works on the distribution of various lithologies (Ebanks 1987). HFU is generally determined using rock quality index (RQI), flow zone indicator (FZI), and the void ratio (Abed 2014a; Bize-Forest et al. 2014). Flow zone indicator is dependent on the geological framework, characteristic of rock type, and pore-throat geometry of the rock. FZI is determined by reservoir quality index (RQI) and normalized porosity ( $\phi z$ ) (Fujii and Fujimoto 1996). One of the parameters for estimating the thickness of the pay zone is permeability. In wells, where core data is unavailable, well logs are used to estimate rock mass permeability (Abed 2014b). The hydraulic flow unit methodology is a modification of the Kozeny-Carmen equation and the concept of mean hydraulic radius (Bize-Forest et al. 2014). In this method, it was considered that the reservoir rock to be made of a stack of capillary tubes. Poiseuille's and Darcy's Laws provide a relationship between porosity and permeability (Fahad and Holditch 2000).

The literature survey's summary indicated significant importance and influence of characteristic parameters for the prediction of hydraulic flow in the carbonate reservoir. Therefore, in this investigation, the porosity, permeability, and grain density of the carbonate reservoir in Oilmax

Mumbai, India, were determined. Based on the porosity and permeability values, the normalized porosity or pore volume-to-grain volume ratio infraction ( $\phi z$ ), hydraulic flow unit (HFU), flow zone indicator (FZI), and reservoir quality index (RQI) were calculated to predict the hydraulic flow and feasibility of oil production in the study area.

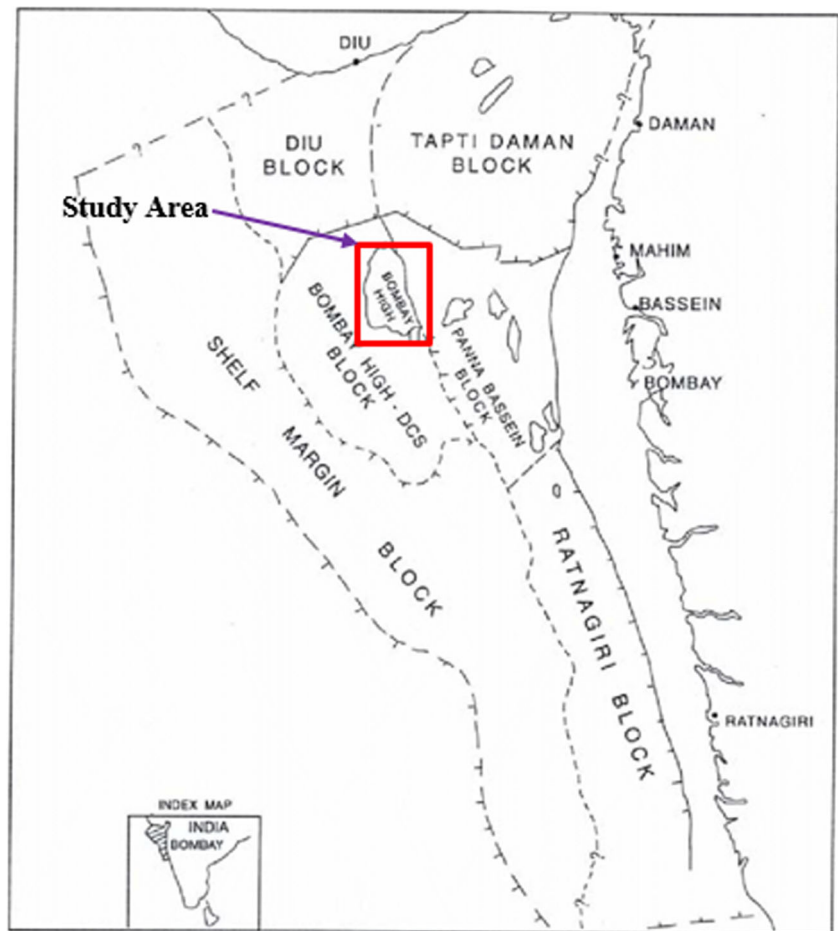
## Methodology

A total of thirty-two core samples data was collected from well A at the burial depth varied from 1618.86 to 1634.14 m from the Oilmax, Mumbai, India (Tables 2 and 3). The data in Tables 2 and 3 represents the average value of the

**Table 1** The data calculated based on the NORMSINV (probability) function

New sample no.	Cumulative	Inverse (Z values)
1	0.02	- 2.15
2	0.05	- 1.68
3	0.08	- 1.42
4	0.11	- 1.23
5	0.14	- 1.08
6	0.17	- 0.95
7	0.20	- 0.83
8	0.23	- 0.72
9	0.27	- 0.63
10	0.30	- 0.53
11	0.33	- 0.45
12	0.36	- 0.36
13	0.39	- 0.28
14	0.42	- 0.20
15	0.45	- 0.12
16	0.48	- 0.04
17	0.52	0.04
18	0.55	0.12
19	0.58	0.20
20	0.61	0.28
21	0.64	0.36
22	0.67	0.45
23	0.70	0.53
24	0.73	0.63
25	0.77	0.72
26	0.80	0.83
27	0.83	0.95
28	0.86	1.08
29	0.89	1.23
30	0.92	1.42
31	0.95	1.68
32	0.98	2.15

**Fig. 1** Location map showing study area (Kumar 2009)



characteristic parameters. The collected data were processed to determine the flow zone indicator (FZI), reservoir quality index (RQI), normalized porosity ( $\varphi_z$ ), and hydraulic flow unit (HFU). This paper focuses on determining the above parameters and understanding the flow zone in the carbonate reservoir based on the data collected from the Oilmax, Mumbai India; therefore, the testing images are not provided.

The flow characteristics of the reservoir were determined by the flow zone indicator (FZI). This is one of the critical parameters to establish the relationship between the reservoir’s petrophysical properties at well log level. The flow zone in the reservoir represented using the term FZI. The mathematical representation of FZI (Onuh et al. 2017) is:

$$FZI = \frac{RQI}{\varphi_z} \tag{1}$$

where FZI is the flow zone indicator, RQI is the reservoir quality index, and  $\varphi_z$  is the normalized porosity

The reservoir quality index (RQI) is an important parameter for quantifying the reservoir’s flow zone. The RQI (Awad and Saleh 2020) is generally determined with the help of FZI. The mathematical representation of FZI is:

$$RQI = 0.031 \sqrt{\left(\frac{K}{\varphi_e}\right)} \tag{2}$$

where RQI is the reservoir quality index,  $K$  is the permeability (mD), and  $\varphi_e$  is the effective porosity (%)

Normalized porosity ( $\varphi_z$ ) was calculated as (Enaworu et al. 2016):

$$\varphi_z = \frac{\varphi_e}{1 - \varphi_e} \tag{3}$$

The NORMSINV function ( $Z$  value) calculates the inverse of the standard normal cumulative distribution function for a supplied probability value. The syntax of the function is NORMSINV (probability). The supplied probability is the probability value (between 0 and 1), at which the inverse of the standard normal cumulative distribution function is calculated (ExcelFunctions.net 2008-2021). The normal distribution is a continuous probability function that is given by the formula (ExcelFunctions.net 2008-2021):

$$f(x, \mu, \sigma) = \frac{1}{\sqrt{2\pi}\sigma} e^{-\frac{(x-\mu)^2}{2\sigma^2}} \tag{4}$$

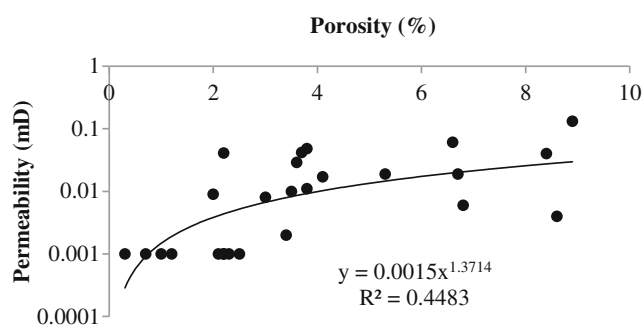
**Table 2** Characterization results of carbonate reservoir in Oilmax, Mumbai

Sample no.	Depth (m)	Porosity (%)	Permeability (md)	Grain density (g/cc)
1	1618.86	6.6	0.061	2.66
2**	1619.16	10.7	7.240	2.66
3*	1619.69	2.1	< 0.001	2.65
4**	1620.42	4.8	2.993	2.64
5	1621.09	4.1	0.017	2.64
6**	1621.39	20.5	1.930	2.63
7	1621.56	3.8	0.048	2.64
8*	1621.86	2.3	< 0.001	2.63
9	1622.21	6.8	0.006	2.64
10**	1623.04	2.9	0.864	2.63
11*	1623.29	1.0	< 0.001	2.69
12	1623.73	8.6	0.004	2.70
13	1624.24	3.0	0.008	2.67
14**	1624.56	2.0	0.009	2.71
15*	1624.60	1.2	< 0.001	2.70
16	1626.80	2.2	0.041	2.65
17	1627.34	2.5	< 0.001	2.64
18*	1627.45	2.2	< 0.001	2.63
19	1627.83	3.7	0.042	2.66
20	1628.39	3.5	0.010	2.65
21	1629.08	3.4	0.002	2.66
22	1629.23	3.8	0.011	2.67
23	1629.79	5.2	1.484***	2.66
24	1630.03	8.4	0.040	2.63
25	1630.35	8.9	0.132	2.66
26*	1631.74	0.7	< 0.001	2.61
27*	1633.10	0.3	< 0.001	2.66
28*	1632.37	2.2	< 0.001	2.66
29**	1619.25	9.2	1.411***	2.70
30	1632.98	6.7	0.019	2.67
31	1633.39	3.6	0.029	2.65
32	1634.14	5.3	0.019	2.83

\*Sample permeability < 0.001 mD ambient porosity reported

\*\*Sample unsuitable for CMS-300 analysis ambient porosity and permeability reported

\*\*\*Possible fracture in sample



**Fig. 2** Relation of permeability with porosity (limestone)

where  $\mu$  is the mean of the distribution,  $\sigma^2$  is the variance, and  $x$  is the independent variable for which the function is evaluated. The cumulative normal distribution function is given by the integral, from  $-\infty$  to  $x$ , of the normal probability density function.

The data calculated based on the NORMSINV (probability) is shown in Table 1.

## Lithology of the study area

The study area comes under the Mumbai offshore basin, India. The basin is located on the western continental shelf of India

**Table 3** Calculated data of normalized porosity ( $\varphi_z$ ) and reservoir quality index (RQI)

Sample number	Permeability (mD)	Porosity (%)	Normalized porosity	RQI
1	0.061	0.066	0.070663812	0.029803
2**	7.24	0.107	0.119820829	0.254999
3*	0.001	0.021	0.02145046	0.006765
4**	2.993	0.048	0.050420168	0.24479
5	0.017	0.041	0.042752868	0.019962
6**	1.93	0.205	0.257861635	0.095118
7	0.048	0.038	0.03950104	0.034841
8*	0.001	0.023	0.023541453	0.006464
9	0.006	0.068	0.072961373	0.009208
10**	0.864	0.029	0.029866117	0.169207
11*	0.001	0.01	0.01010101	0.009803
12	0.004	0.086	0.094091904	0.006686
13	0.008	0.03	0.030927835	0.016008
14**	0.009	0.02	0.020408163	0.020795
15*	0.001	0.012	0.012145749	0.008949
16	0.041	0.022	0.022494888	0.04232
17	0.001	0.025	0.025641026	0.0062
18*	0.001	0.022	0.022494888	0.006609
19	0.042	0.037	0.038421599	0.033028
20	0.01	0.035	0.03626943	0.01657
21	0.002	0.034	0.035196687	0.007519
22	0.011	0.038	0.03950104	0.016679
23	1.484	0.052	0.054852321	0.165606
24	0.04	0.084	0.091703057	0.021392
25	0.132	0.089	0.097694841	0.037753
26*	0.001	0.007	0.007049345	0.011717
27*	0.001	0.003	0.003009027	0.017898
28*	0.001	0.022	0.022494888	0.006609
29**	1.411	0.092	0.101321586	0.121404
30	0.019	0.067	0.071811361	0.016508
31	0.029	0.036	0.037344398	0.027823
32	0.019	0.053	0.055966209	0.018561

\*Sample permeability &lt; 0.001 mD Ambient Porosity Reported

\*\*Sample Unsuitable for CMS-300 Analysis Ambient Porosity and Permeability Reported

\*\*\*Possible Fracture in Sample

(Goswami et al. 2007). The lithology is principally of dark gray shales with subordinate sands. Carbonate facies (Devgarh Formation) along the southern edge of Mumbai high are similar to foraminiferal-algal banks. The Mumbai platform has shale interbeds in limestone (Goswami et al. 2007). The limestone of the study area was micrite, biomicrite, and chalky type (Gupta et al. 1981). The thickness of limestone varies from shelf to deeper regimes. Shelf margined has thinner carbonates but is deposited at significant depth. Clastic sedimentation with carbonate bands is found in Diu Formation. The facies within the Daman Formation are of significance as they host a handsome volume of hydrocarbon. In the early Miocene, thick carbonate sedimentation happened in Bombay high and its western part.

The sediments are of fine grain in nature and clayey carbonate in composition (Goswami et al. 2007). The location map is shown in Fig. 1 (Kumar 2009).

## Results and discussions

Reservoir characterization was carried out using core testing data obtained from a well in Oilmax, Mumbai, India. The core testing data is represented in Table 2. The porosity and permeability were determined using the porosimeter and permeameter at the laboratory scale. The data was collected from Oilmax, Mumbai, for the research purpose. The porosity

and permeability varied from 0.3 to 20.5% and 0.002 to 1.484 mD at the burial depth from 1618.86 to 1634.14 m. The grain density ranged from 2.61 to 2.7 g/cc for the sample obtained from 1618.86- to 1634.14-m depth. The abrupt permeability reported in various samples (e.g., samples 2, 4, 6) is due to the possible occurrence of fracture, cemented matrix, and abundance of clay. The porosity range in samples indicates the reservoir's porous nature, while the permeability was found significantly less. Few of the samples showed permeability less than 0.001 mD. The lesser values of permeability indicate a poor flow zone in the carbonate reservoir.

The correlation between porosity and permeability was established, as shown in Fig. 2. The outlier was removed to develop the correlation. The prediction of permeability based on the porosity data was obtained using the trend line shown in Fig. 2. The scattering of data was observed in the correlation between the porosity and permeability, indicating porosity's insufficiency alone to predict the variation in permeability. The trend line equation showed the poor linear and power correlation with  $R^2$  of 0.44. The poor correlation is attributed to the insufficiency of the porosity alone to predict permeability and the requirement of some other input parameters for permeability prediction.

In order to quantify the flow zone, further studies were carried out, and normalized porosity ( $\phi_z$ ), reservoir quality index (RQI), flow zone indicator (FZI), and hydraulic flow unit (HFU) were calculated based on the values given in Table 2. A similar technique was used elsewhere (El Sayed et al. 2021; El Sayed et al. 2020).

## Hydraulic flow unit (HFU) method

The general method of identifying hydraulic flow units (HFUs) is based on the flow zone indicator (FZI), which is calculated based on the values of  $\phi_z$  and RQI. The increase in the product of  $\phi_z$  and RQI results in the quality of the reservoir. The  $\phi_z$  and RQI were calculated as per Eqs. (2) and (3). The results of the computed values are represented in Table 3. The FZI was calculated as per Eq. (1) and represented in Table 4. The optimum number of HFUs was obtained by the correlation between  $\phi_z$  and RQI (Fig. 3). The similar FZI values lie on the straight line of the log-log-scale plot of RQI and  $\phi_z$ . The other FZI values scattered from the straight line. This indicated the similar pore throat as well as flow zones in the samples. Based on Fig. 2, all the data fall in seven rock types and, hence, confirmed the seven HFUs. The FZI varied from 0.071971 to 6.024804 at a depth of 1618.86 to 1634.14 m for HFU1 to HFU7, respectively. Each of the HFUs exhibited uniform rock characteristics with a uniform fluid flow zone. The HFUs also exhibited the porous nature of the carbonate rock. The HFUs with higher FZI values showed an improved quality of fluid flow zone in the rock's porous structure.

The probability plot is easy to predict and understand than that of the histogram; therefore, the probability plot between the FZI and Z values was developed, as shown in Fig. 4. NORMSINV function was used to calculate the probability of inverse normal cumulative distribution (Z value), which has

**Table 4** FZI Values calculated for the probability plot method

Sample no.	Normalized porosity (PHIZ)	RQI	FZI	Sample no.	Normalized porosity (PHIZ)	RQI	FZI
1	0.094	0.006772	0.071971	17	0.043	0.020219	0.472930
2	0.073	0.009327	0.127837	18	0.031	0.016215	0.524281
3	0.035	0.007616	0.216373	19	0.012	0.009064	0.746302
4	0.072	0.016721	0.232850	20	0.037	0.028182	0.754661
5	0.092	0.021668	0.236285	21	0.038	0.033454	0.870719
6	0.026	0.006280	0.244920	22	0.040	0.035291	0.893408
7	0.024	0.006547	0.278120	23	0.010	0.009930	0.983026
8	0.022	0.006695	0.297601	24	0.020	0.021064	1.032124
9	0.022	0.006695	0.297601	25	0.101	0.122970	1.213661
10	0.021	0.006852	0.319436	26	0.007	0.011868	1.683573
11	0.056	0.018800	0.335925	27	0.022	0.042866	1.905577
12	0.258	0.096345	0.373632	28	0.120	0.258290	2.155633
13	0.098	0.038240	0.391426	29	0.055	0.167743	3.058088
14	0.071	0.030187	0.427194	30	0.050	0.247949	4.917655
15	0.040	0.016894	0.427687	31	0.030	0.171391	5.738637
16	0.036	0.016784	0.462759	32	0.003	0.018129	6.024804

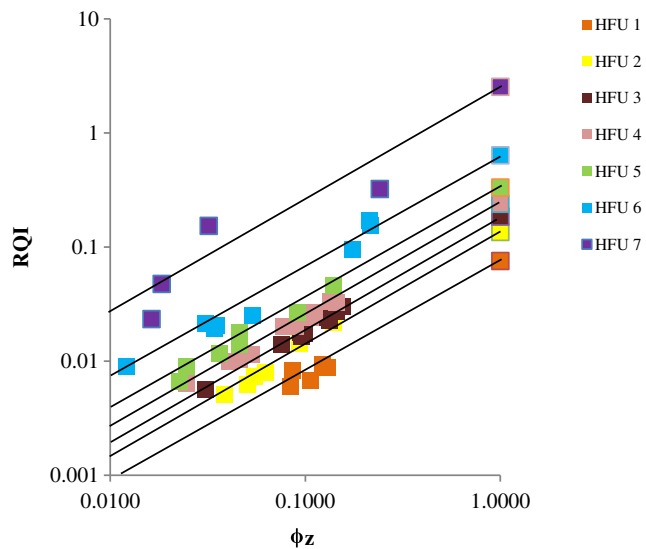


Fig 3 Log-log graph between  $\phi z$  and RQI

a mean and standard deviation. The distribution of data forming a distinct straight line indicated each of the HFUs. Hence, it is possible to obtain the separate HFUs for each set of the data. The distortion of the straight line to some degree was observed due to the superposition effect. In this plot, the regression coefficient for all HFUs varied from 0.65 to 0.97, indicating a poor to approximately good flow zone in the reservoir. The HFU4, HFU5, and HFU7 showed more or less similar flow zone as the slopes are almost equal. The probability plot confirmed the highly porous nature of the reservoir with a good flow zone in most samples.

The correlation between the porosity and permeability classified by FZI for different HFUs is represented in Fig. 5. A classified and satisfactory relationship with  $R^2$  varied from 0.93 to 1 was observed between the porosity and permeability correlations obtained by the FZI curve for each HFUs. A non-

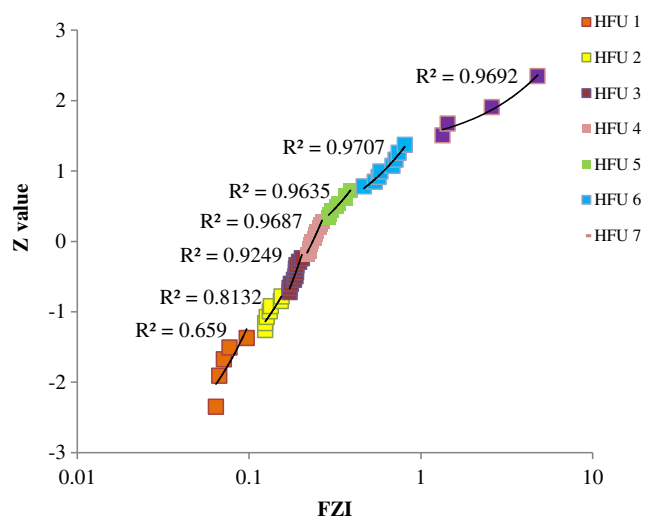


Fig. 4 Log graph between FZI and cumulative probability function (Z value)

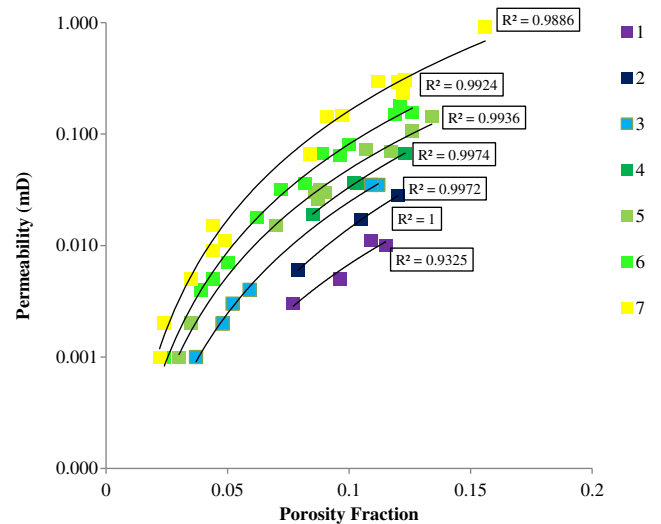


Fig. 5 Semi-log graph between porosity and permeability

linear and predictable relationship was obtained in Fig. 5. The non-linearity in the correlation between porosity and permeability is due to the reservoir’s highly porous nature. This is also important to know that a high porous reservoir is may not necessarily be highly permeable. The correlation coefficient was used to predict the significant deviation in the characteristic properties in the reservoir. Figure 4 showed that HFU 3 with an  $R^2$  value of 0.93 indicated more deviation than the other. The overall observation indicated the highly porous nature of the carbonate reservoir in the study area. The HFU1 showed poor flow compared to the other HFUs, while HFU2 showed good flow because of the highest  $R^2$  value, i.e., 1. Other HFUs like HFU3 HFU7 indicated near to good flow zone in the carbonate reservoir of the study area.

### Conclusions

The following conclusions were drawn for the carbonate reservoir at Oilmax, Mumbai, India, based on the data collected and the statistical analysis.

- The variation in porosity and permeability was observed from 0.3 to 20.5% and 0.002 to 1.484 mD at the burial depth from 1618.86 to 1634.14 m, respectively.
- The grain density varied from 2.61 to 2.7 g/cc for the sample obtained from 1618.86- to 1634.14-m depth.
- The porosity range varied from 0.3 to 20.5% indicates the reservoir’s porous nature, while the permeability was found significantly less. Few of the samples showed permeability less than 0.001 mD. The lesser values of permeability indicate a poor flow zone in the carbonate reservoir.
- The poor correlation between porosity and permeability showed the insufficiency of the porosity alone to predict

permeability and the requirement of some other input parameters for permeability prediction.

- The  $\varphi_z$  and RQI varied from 0.070663812 to 0.257861635 and 0.029803 to 0.254999 at a depth of 1618.86 to 1634.14 m. The values were used for the prediction of the FZI using a log-log plot.
- Each of the HFUs exhibited uniform rock characteristics with a uniform fluid flow zone. The HFUs also revealed the porous nature of the carbonate rock. The HFUs with higher FZI values showed an improved quality of fluid flow zone in the rock's porous structure.
- The HFU4, HFU5, and HFU7 indicated more or less similar flow zone as the slopes were almost equal. The probability plot confirmed the highly porous nature of the reservoir with a good flow zone.
- The HFU1 showed poor flow compared to the other HFUs, while HFU2 showed good flow because of the highest  $R^2$  value, i.e., 1.

**Acknowledgement** We express our gratitude towards Oilmax, Mumbai, for providing us the desired inputs. We appreciate the extended support of Mr. Sumani Das & Dr. Vidyadhar Kamatah throughout. Without their support, this would have not possible. Thank you team Oilmax once again.

## Declarations

**Conflict of interest** The authors declare that they have no competing interests.

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