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A New Approach for Enhancing Reservoir Characterization in Sandstone and Carbonate Reservoirs

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Abstract- Inaccurate petrophysical rock typing is a major factor leading to the failure of many Enhanced Oil Recovery (EOR) projects worldwide. Effective reservoir characterization is crucial for guiding field development plans. Understanding the variation in permeability is crucial for characterizing the reservoir and identifying its heterogeneity. Hydraulic Flow Unit (HFU) techniques are typically used to model the petrophysical properties of reservoirs, thus aiding improved oil recovery projects. Various models have been developed to describe reservoirs based on available data, often relying on assumptions about the porous medium, such as cementation factor and connate water saturation. These assumptions can be inaccurate and yield inconsistent rock-type classifications within the same medium, leading to unrealistic results when applied from cored to uncored wells. This study introduced a new approach for better-characterizing sandstone and carbonate reservoirs by leveraging the porosity-permeability relationship exclusively, avoiding the need for traditional petrophysical assumptions. The new approach was derived from a permeability equation developed for several pipes in series, and it utilizes a modified normalized porosity, a modified Flow Zone Indicator (FZI), and a Reservoir Quality Index (RQI). The methodology involved detailed analysis and comparison with existing approaches for identifying the degree of heterogeneity, HFUs and predicting permeability. The permeability variations for carbonate and sandstone reservoir rocks are 0.86 and 0.73, respectively. The new approach demonstrated superior performance, achieving higher correlation coefficients for predicted permeability in both carbonate and sandstone reservoirs. Specifically, the method showed correlation coefficients of 0.95 for carbonate and 0.93 for sandstone reservoirs, compared to 0.85 and 0.82, respectively, for existing methods. Additionally, it identified HFUs with higher accuracy, evidenced by correlation coefficients of 0.92 for carbonate and 0.90 for sandstone reservoirs, as opposed to 0.80 and 0.78 for conventional methods. By eliminating the reliance on inaccurate petrophysical assumptions, this approach enhances the reliability of reservoir characterization, making it a valuable tool for optimizing EOR projects. Further research will explore the applicability of this method across different reservoir types and conditions to fully establish its robustness and versatility.

Keywords- Kozeny-Carman equation, Permeability prediction, Reservoir characterization, Reservoir Quality Index, Rock typing.

1. INTRODUCTION

In previous techniques, many investigators, including (Coates & Dumanoir Schlumberger, n.d.; P., 1949; Timur, n.d.; Wyllie et al., n.d.), and others, developed empirical correlations to predict permeability from effective porosity and connate water saturation. These correlations were utilized to derive petrophysical properties for uncored wells. However, their accuracy in predicting permeability was limited compared to more recent techniques. The recent technique used to characterize reservoirs is Hydraulic Flow Units (HFUs provide a petrophysical description of the reservoir by dividing the formation into different layers, each with its own petrophysical values. The concept of HFUs has various definitions. (Ebanks, 1987) defined HFUs as rocks with similar geological and petrophysical properties, while (Ahr, 1991) defined them as rocks with similar porous medium properties, useful for mapping pore-size distributions beyond cored wells. (Stoudt et al., 1992) defined HFUs using qualitative techniques, including diagenetic overprint and core data.

Print ISSN 2682-3993
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From these concepts, many approaches were investigated to identify hydraulic flow units. (Amaefule et al., 1993a) introduced the concept of RQI and FZI to identify HFUs based on pore geometry with different lithofacies; which is the most common technique used for predicting permeability in uncored wells. Note that it is not the best approach for predicting permeability and identifying rock types with current approaches. Other investigators including (Izadi & Ghalambor, 2012) and (Nooruddin & Hossain, 2011) developed new approaches for enhancing reservoir description; lots of them added more petrophysical properties of porous medium in order to get a better reservoir description and more representative at subsurface conditions; these parameters involving connate water saturation, cementation factor, relative permeability, and fluid properties. However, these parameters are not always available and are sometimes assumed to be constant values for all core data. (Izadi & Ghalambor, 2012) developed a modified RQI model and took into consideration connate water saturation in the porous medium. However, the value of connate water saturation has a direct effect on identifying Hydraulic Flow Units in the same porous medium. In other words, Izadi's model sometimes gives more HFUs in water-wet reservoirs and sometimes gives less HFUs in oil-wet reservoirs. In addition, the accuracy of permeability prediction is affected by the value of connate water saturation as it increases with increasing Swc and vice versa; this could give uncertain results from one well to another and may predict unrealistic petrophysical properties. Moreover, in case of unavailable petrophysical parameters such as cementation factor, relative permeability, or connate water saturation, these parameters will be either assumed constant values for all cores or obtained from empirical correlations. However, these ideas are not recommended and are not always correct. (Nooruddin & Hossain, 2011) developed a MFZI model (modified FZI) and added consideration of the cementation factor which is not usually available in all SCAL experiments as well as in Routine Core Analysis. In this case, it will be assumed a constant value for all cores or can be obtained from Archie's equation (Archie, 1942) although many studies showed that this is not recommended. (Hamada et al., n.d.) stated that Archie parameters (a, m, n) depend on different factors including rock wettability, grain pattern, and presence of clay minerals (George V. Keller, 1982) showed that the cementation factor depends on porosity, degree of compaction, and lithology. (Atkins et al., n.d.) stated that the cementation factor is affected by pore and grain size distributions. In addition, this model, cannot be applicable for extremely heterogeneous reservoirs with small core data because it gives dissimilar values of modified FZI which cannot help to identify hydraulic flow units. (Soleymanzadeh et al., 2018) investigated an approach called the Electrical Quality Index (EQI) which identifies HFUs in order to predict cementation factors in uncored wells. He concluded that EQI is a successful approach for extremely heterogeneous carbonate reservoirs. However, his approach was designed to obtain a cementation factor rather than any other parameters. In addition, EQI requires electrical rock measurements to be used. (Shedid & Almehaideb, 2002) combined three groups involving Capillary Number, Reservoir Quality Index (RQI), and Reynold Number which took into consideration relative permeability data, fluid and rock properties, and concluded that this approach provides HFUs with better correlation coefficients than using conventional FZI; this approach called Characterization Number (CN). However, the approach requires both rock and fluid properties which are not always available for all fields. Therefore; this approach can be applicable only when SCAL data is available. (Mirzaei- Paiaman et al., 2015) developed an FZI* model (Flow Zone Indicator star) to identify HFUs and applied it on the carbonate reservoirs field of Iran. The approach was based on a generalized Kozeny-Carman equation by proper consideration of the mean hydraulic radius concept. It was verified using a large set of capillary pressure data. However, this approach gives few numbers of rock types with low correlation coefficients, and this is not useful for predicting petrophysical properties to obtain satisfied accuracy. (Kharrat et al., 2009) used Artificial Neural Networks and multiple regression to predict permeability in uncored wells based on conventional FZI from well logs and SCAL data. Although this technique is precise, it requires advanced software studies in order to obtain better results. (Kolodzie, 1980) and (Pittman, 1992) made generalized approaches from their field study to identify hydraulic flow units based on pore size type obtained from MICP measurements (mercury injection capillary pressure). However, these approaches are inappropriate for very low permeability rocks as their pore types are mainly classified as mesoport, so they may give a limited number of rock types with low correlation coefficients. In general cases, Amaefule's approach is the most used than other models due to its simplicity which requires only porosity and permeability relationship and gives acceptable results. (Attia & Shuaibu, 2015) established a new study based on storage and flow capacity and rock type, in addition to the reservoir process speed and physical structure. to identify the reservoir barriers and the productive zones by developing a reservoir characterization. This is done by changing the static model to a dynamic model using Flow Zone Indicator (FZI), Winland R35, and Discrete Rock Type (DRT) tools to know the rock types and the reservoir flow units. The purpose of changing the static model to a dynamic model is to count the reservoir flow units using some graphical approaches such as stratigraphic flow profile (SFP), stratigraphic modified Lorenz plot (SMLP), and modified Lorenz plot (MLP).

(Shahat et al., 2021) conducted a new study using 1135 core samples along with well-log data from 21 wells in order to perform a petrophysical reservoir characterization and know the reservoir flow units. To figure out the efficiency

Print ISSN 2682-3993

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and viability of the proposed approach, these data were used with the intention of testing and validation. The proposed method proved a high degree of accuracy when compared with the Amaefule method on the Algerian oil field. The RZI method showed correlation coefficients of determination varying from 0.84 to 0.97 when it was applied in order to characterize the reservoir from this field into eight different flow units. (Shahat et al., 2023) proposed a new method for uncored wells using the reservoir rock electrical properties by modifying RZI equation established by (Shahat et al., 2021) by adding the tortuosity factor. The purpose of the new proposed technique is to classify the rock types and know the flow zone indicators along with tortuosity, permeability, and irreducible water saturation. The validity and the reliability of this method were tested using data of 21 logged wells. The proposed method shows a high degree of accuracy as the R^2 values for the estimated tortuosity, flow zone indicators, permeability, and irreducible water saturation were 0.98, 0.98, 0.96, and 0.99 respectively. (Mahmood et al., 2023) proposed a study aimed at improving the reservoir characterization to consider tortuosity, porosity, and saturation of hydrocarbon. Core data from an Egyptian oil field was used seeking to modify characterization number and capillary pressure equations. The results turned out that if those parameters were ignored, decreased accuracy and inaccurate rock types would be the case. The permeability correlations for Egypt carbonate reservoirs were developed which determine uncored well permeability. The study confirmed an increase in accuracy by including such parameters in the characterization methodologies. The research also showed that these parameters played important roles in the characterization number methodology, since this was evidenced by changes in the coefficients of determination R^2 for five different rock types.

The objective of this research is to establish a simple approach that relies on the porosity-permeability relationship that avoids using other uncertain parameters gives a better accuracy prediction of permeability and yields a reasonable number of rock types for a better petrophysical description of the reservoir with a minimum of uncertainties.

2. METHODOLOGY

(Haro, 2004) made a comparison between different permeability models including Lucia, Winland, Civan, and Kozeny-Carman. He concluded that the K-C model is the best model that has a theoretical basis. (Kozeny, 1927) took permeability as a function of specific surface area, tortuosity factor, and effective porosity in the porous medium as a bundle of capillary tubes. Then (C., 1937) made modifications to Kozeny and added consideration of the shape factor. Then (Srisutthiyakorn & Mavko, 2017) added the concept of pore-size distribution and apparent radius and then introduced the revised Kozeny-Carman model and compared with the generalized K-C model and Lattice-Boltzmann model and concluded that the revised K-C model gave better results than the original model and Lattice-Boltzmann model. The permeability of several pipes in series developed by Nattavadee is

$$k = \frac{\pi L}{8 A \sum_i \frac{li}{Ri^4}} \tag{1}$$

Where K is permeability in (μm^2), A is a cross-section area of the core plug (Cm^2). Li is the length of fluid flow through the core i.e. actual length, R_i is a radius of pore tubes in µcm. Because there are a lot of pore radii in the core, and they are different in size, it is believed to take them as the mean hydraulic radius. The model will be

$$k = \frac{\pi L R_m^4}{8 A la} \tag{2}$$

The tortuosity factor can be calculated for Rose and Bruce (1949) [17] equation

$$\tau = (\frac{La}{L})^2 \tag{3}$$

Substitute the equation (3) to the equation (2) yields

$$k = \frac{\pi R_m^4}{8 A \sqrt{\tau}} \tag{4}$$

The specific surface area per unit grain volume is defined as

$$Svg = \frac{1}{R_m}\left(\frac{\varphi}{1-\varphi}\right) \tag{5}$$

Where φ is effective porosity. The mean hydraulic radius can be calculated from

$$R_m = \frac{1}{S_{vg}}\left(\frac{\varphi}{1-\varphi}\right) = \frac{\varphi_z}{S_{gv}} \tag{6}$$

Print ISSN 2682-3993

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Where φ_z is normalized porosity. Substituting for Rm into the equation (4) yields:

$$k = \frac{\pi}{8\,A\,\sqrt{\tau}}\left(\frac{\varphi_z}{S_{vg}}\right)^4 = \frac{\pi}{8\,A\,{S_{vg}}^4\sqrt{\tau}}\,{\varphi_z}^4 \tag{7}$$

Rearranging Equation (7) as follows:

$$k = \frac{\pi\,\varphi}{8\,A\,S_{vg}^4\,\sqrt{\tau}} * \frac{\varphi^3}{(1-\varphi)^4} \tag{8}$$

Dividing by porosity on both sides of equation (8) gives:

$$\frac{K}{\varphi} = \frac{\pi}{8\,A\,S_{gv}^4\,\sqrt{\tau}} * \frac{\varphi^3}{(1-\varphi)^4} \tag{9}$$

Taking the square root of both sides as equation (9) gives:

$$\sqrt{\frac{K}{\varphi}} = \sqrt{\frac{\pi}{8\,A\,S_{gv}^4\,\sqrt{\tau}} * \frac{\varphi^3}{(1-\varphi)^4}} \tag{10}$$

Rearrange equation (10) as follows:

$$0.0314\sqrt{\frac{K}{\varphi}} = \frac{0.6267}{S_{gv}^2\,\sqrt{A\sqrt{\tau}}}\,\frac{\varphi^{1.5}}{(1-\varphi)^2} \tag{11}$$

Where

$$\text{RQI} = 0.0314\sqrt{\frac{K}{\varphi}} \tag{12}$$

The modified FZI is

$$\text{FZI} = \frac{0.6267}{\mathrm{S_{gv}^2}\,\sqrt{\mathrm{A}\sqrt{\tau}}} \tag{13}$$

The new formula of normalized porosity is

$$\frac{\varphi^{1.5}}{(1-\varphi)^2} \tag{14}$$

Taking the logarithm of equation (11) on both sides' yields:

$$\text{Log}\left(0.0314\sqrt{\frac{K}{\varphi}}\right) = \log\left(\frac{0.6267}{S_{gv}^2\,\sqrt{A\sqrt{\tau}}}\right) + \log\left(\frac{\varphi^{1.5}}{(1-\varphi)^2}\right) \tag{15}$$

$$\text{Log (RQI)} = \log\,(MFZI) + \log\left(\frac{\varphi^{1.5}}{(1-\varphi)^2}\right) \tag{16}$$

Substituting for RQI into equation (16) and solving for permeability gives:

$$\text{Log (k)} = \log\left(\frac{\pi}{8\,A\,S_{vg}^4\,\sqrt{\tau}}\right) + \log\left(\frac{\varphi^4}{(1-\varphi)^4}\right) \tag{17}$$

The equation (17) yields a straight line on log-log plotting RQI vs $\frac{\varphi^{1.5}}{(1-\varphi)^2}$, the intercept of the unit slope line with $\frac{\varphi^{1.5}}{(1-\varphi)^2} = 1$ is the average MFZI.

The equation of permeability is:

$$\mathrm{k} = 1014 * \frac{\pi}{8\,\mathrm{A}\,\mathrm{S_{vg}^4}\,\sqrt{\tau}} * \frac{\varphi^4}{(1-\varphi)^4} = 1014 * \mathrm{FZI}^2 * \frac{\varphi^4}{(1-\varphi)^4} \tag{18}$$

3. METHODOLOGY

The modified approach has been compared with other approaches including conventional FZI by (Amaefule et al., 1993a), modified RQI by (Izadi & Ghalambor, 2012), FZI* by (Mirzaei- Paiaman et al., 2015), Winland R35 (1980) and (Pittman, 1992). Relative permeability data is unavailable, so the Characterization Number (CN) approach was not used. Also, neither the cementation factor; nor electrical rock measurements are not available so, the modified

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FZI by Nooruddin (2011) was not used. The comparison involves the accuracy of the prediction of permeability and identifies the porosity-permeability relationship based on similar values of FZI. The results of rock typing and correlation coefficients are shown in appendix A and B.

I. Carbonate Reservoir

The field X is an extremely heterogeneous reservoir based on (Dykstra & Parsons, 1950), where the permeability variation equals 0.86 (Figure 1). The reservoir lithology is mixed between limestone and dolomite and wettability is mixed-wet (see values of Swi in Table 1). The data results are shown in the appendix, Figures 2 through 7 represent the porosity-permeability relationship based on similar values of FZI and show the technique used; each technique has its table in the appendix showing hydraulic flow units with equations and correlation coefficients. By observing the results of the porosity-permeability relationship in the Appendix, it is clear that using the new approach gives six rock types of very high correlation coefficients and a reasonable number of cores in each hydraulic flow unit (frequency). This will be better for representing field data (Figure 7 and Table 7). In Amaefule's approach (1993), it gives seven rock types with high correlation coefficients (Figure 4 and Table 8). In Winland R35, Pittman R25, and Paiaman (figures 2, 3, and 6), they give three hydraulic flow units with the largest frequency in each rock type, but they give the lowest correlation coefficients which are not suitable for applying to reservoir simulator to get acceptable results (Tables 2, 3, and 6). Izadi's approach (2012), gives seven rock types which are the same in Amaefule's model, but both are different in correlation coefficient and accuracy in the prediction of permeability (Figures 4, 5, 8, and 9)

II. Sandstone Reservoir

This is another field that has a sandstone reservoir, and it is less heterogeneous than the previous case study (see Figure 12), where the permeability variation equals 0.73. The rock wettability is strongly water-wet (see Table 9). The new approach has been compared with other approaches to check its validity in permeability prediction and the number of rock types. In comparison between approaches in the porosity-permeability relationship, it is observed that Winland R35, Pittman R25, and Paiaman (Figures 13, 14, and 19) give three rock types with the same limitations as in the first case study. Izady's approach (2012) (Figure 17), gives seventeen rock types with good correlation coefficients and frequencies. Amaefule's approach (Figure 15) gives thirteen rock types which is less than Izadi's approach (2012) and the new approach. The new approach as shown in Figure 21, gives nineteen rock types which are more than Izadi (2012) and Amaefule (1993). It is believed that identifying more rock types provides a better description of the reservoir and this ensures the reliability of the proposed approach. By adopting the above practices all major constructs of a research paper can be written and together compiled to form complete research ready for Peer review.

Table 16 shows the accuracy of permeability prediction for different approaches. It is found that the new approach is most accurate, then (Amaefule et al., 1993b), then (Izadi & Ghalambor, 2012), and then (Mirzaei- Paiaman et al., 2015). In all cases, the new approach gives higher accuracy of permeability prediction than other approaches although all of them are close to each other because they were predicted from regression analysis. It is believed that these small differences will make significant results when applying reservoir simulation.

In Tables 10 through 15, it is observed that the new approach gives more HFUs than (Amaefule et al., 1993b) and (Izadi & Ghalambor, 2012) with less scattering and better correlation coefficients than the rest of the approaches, this emphasizes the reliability of the proposed approach and provides a better reservoir description.

4. CONCLUSION

After comparing different approaches with the proposed approach, it is clear that the proposed approach is very reliable in both carbonate and sandstone reservoirs as it yields rock types with less scattering and better correlation coefficients; this will be useful for reservoir simulation.

The proposed approach is very useful when having routine core analysis or limited data because it is function of porosity and permeability and avoids using any other parameters that could be unavailable or uncertain.

The purposed approach was derived from developed permeability equation for several pipes in series. It was not used any other petrophysical consideration, therefore; it is believed that it provides better and reliable results rather than using incorrect assumptions that lead to unrealistic results. In addition, the approach is robust for HFUs selection and gives a superior distribution of properties through both carbonate and sandstone reservoirs.

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APPENDIX

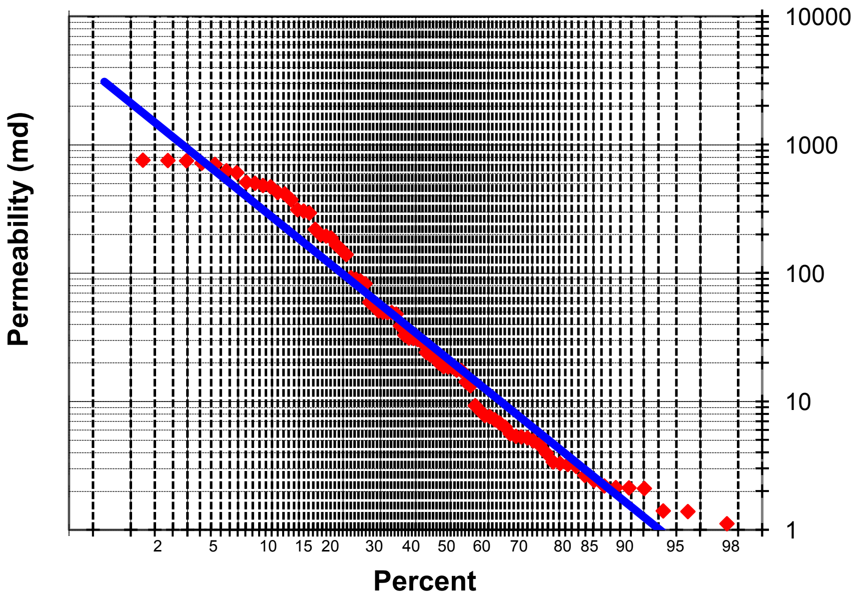

Fig. 1: Dykstra-Parson's coefficient of Permeability Variation in carbonate reservoir

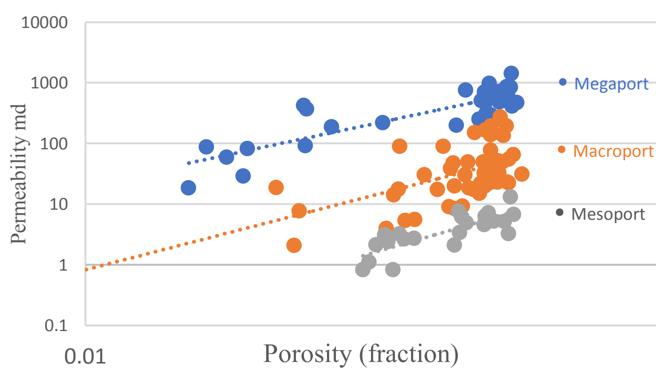

Fig. 2: Permeability porosity relationship using Winland R35 technique in carbonate reservoir.

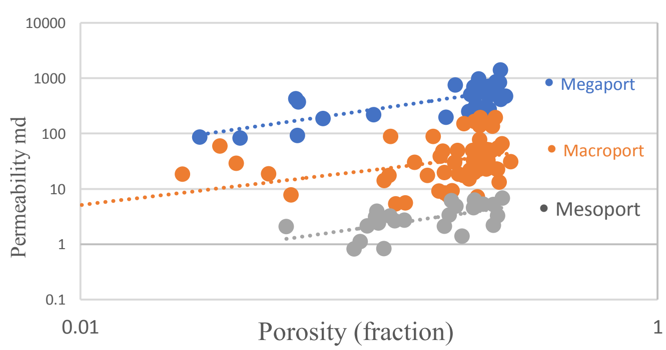

Fig. 3: Permeability porosity relationship using Pittman R25 technique in carbonate reservoir.

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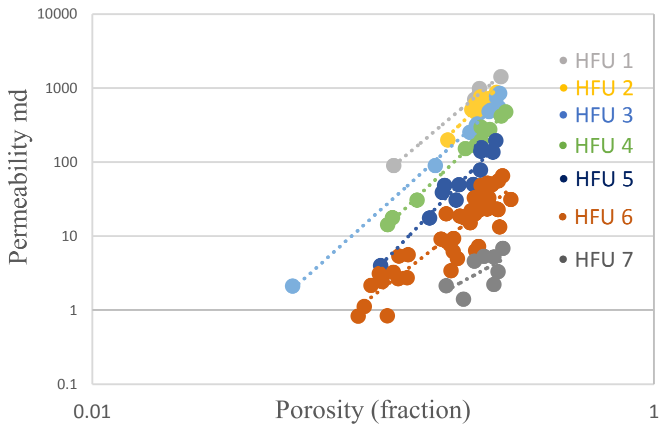

Fig. 4: Porosity-permeability relationship using Amaefule's technique in carbonate reservoir.

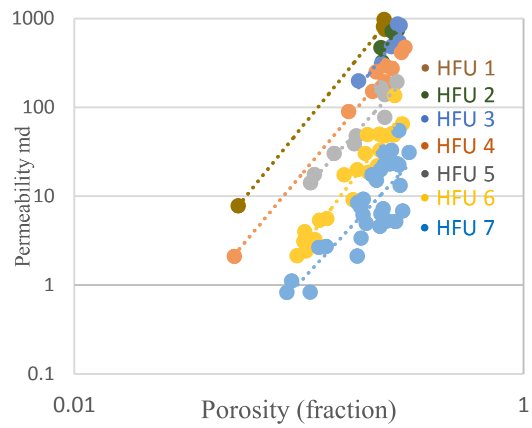

Fig. 5: Porosity-permeability relationship using Izadi's technique (2012) in carbonate reservoir.

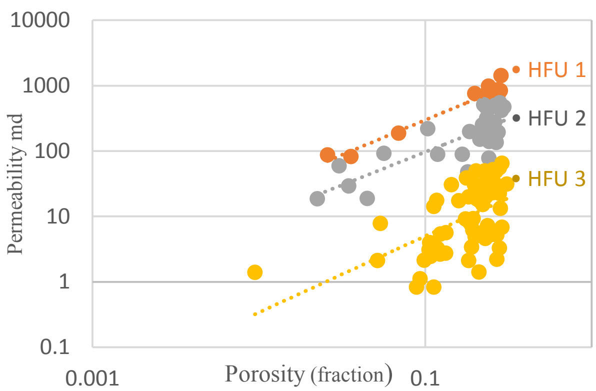

Fig. 6: Permeability porosity relationship using Paiaman's technique in carbonate reservoir

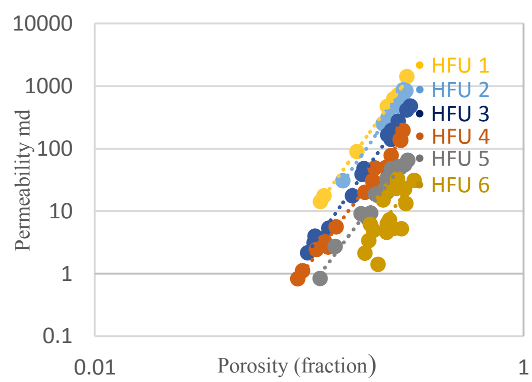

Fig. 7: Permeability porosity relationship using new approach in carbonate reservoir

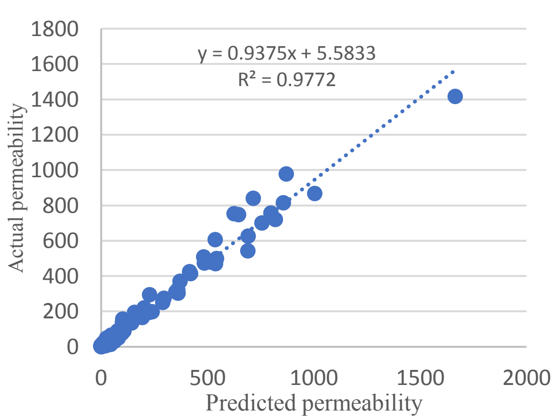

Fig. 8: Actual permeability vs predicted permeability using Amaefule's technique in carbonate reservoir.

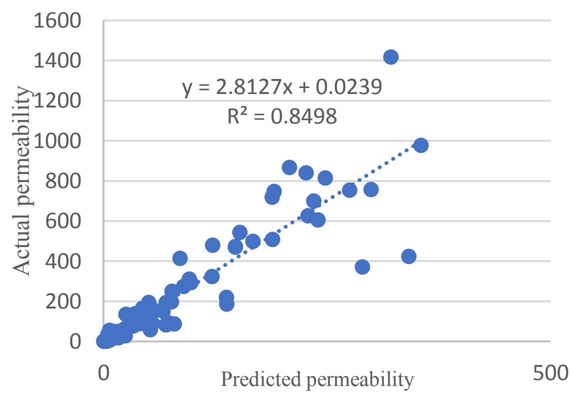

Fig. 9: Actual permeability vs predicted permeability using Izadi 's technique (2012) in carbonate reservoir.

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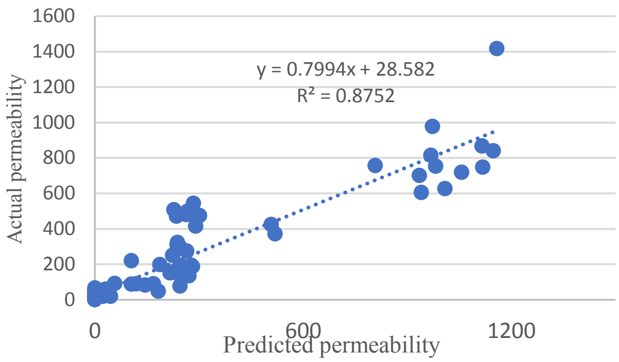

Fig. 10: Actual permeability vs predicted permeability using Paiaman's technique (2015) in carbonate reservoir.

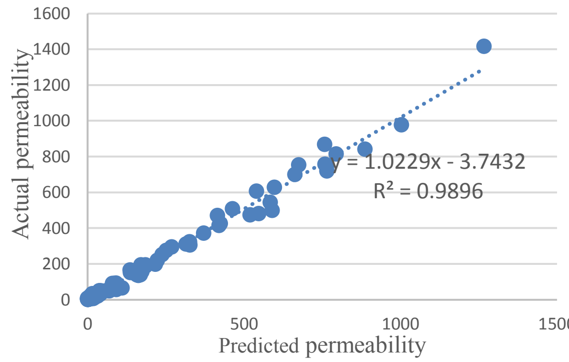

Fig. 11: Actual permeability vs predicted permeability using new approach in carbonate reservoir.

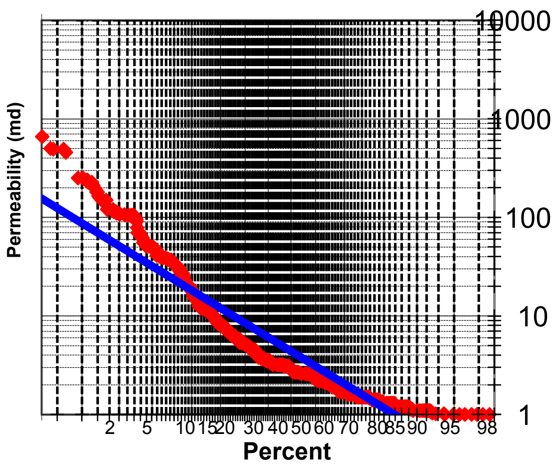

Fig. 12: Dykstra-Parson's coefficient of Permeability Variation in sandstone reservoir

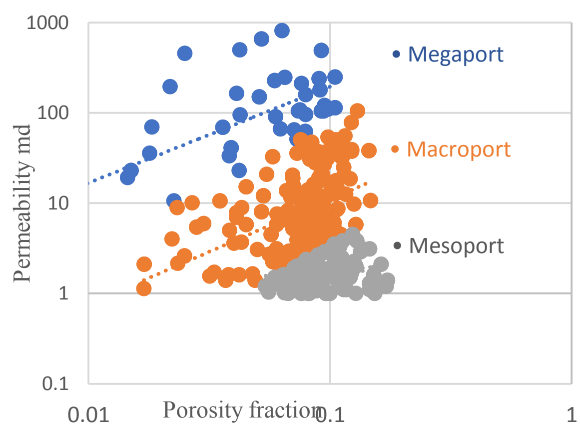

Fig. 13: Permeability porosity relationship using Winland R35 technique in sandstone reservoir

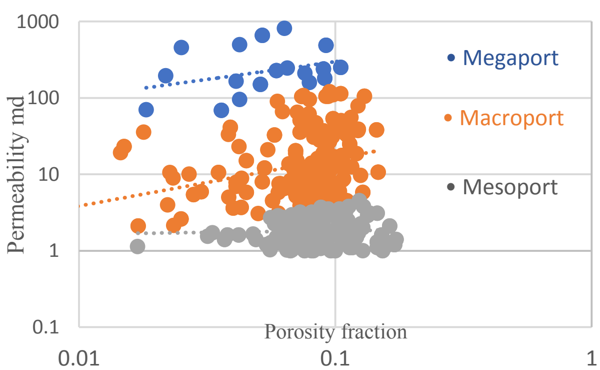

Fig. 14: Permeability porosity relationship using Pittman R25 technique in sandstone reservoir.

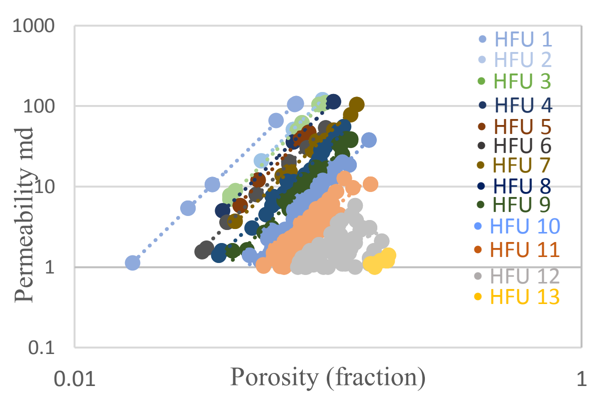

Fig. 15: Porosity-permeability relationship using Amaefule's technique in sandstone reservoirs.

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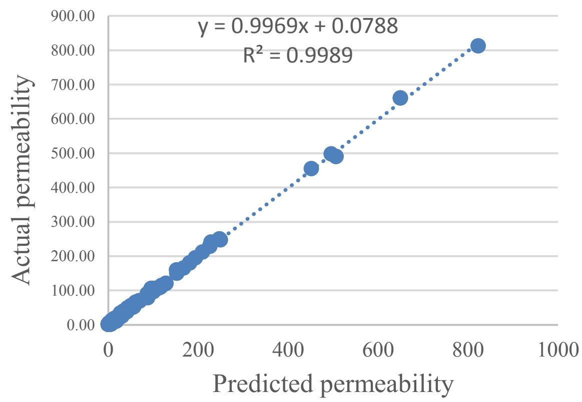

Fig. 16: Actual permeability vs predicted permeability using Amaefule's technique in sandstone reservoir.

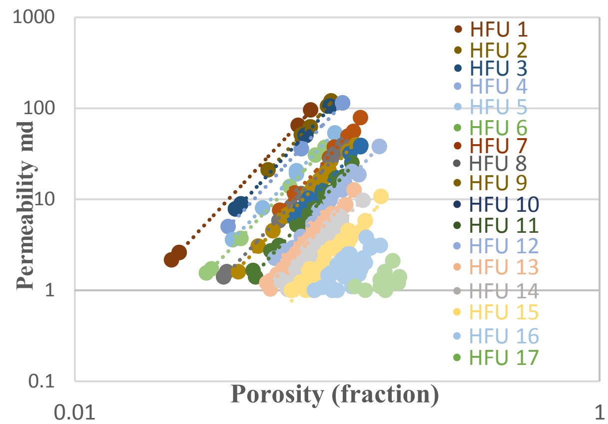

Fig. 17: Porosity-permeability relationship using Izadi's technique (2012) in sandstone reservoir.

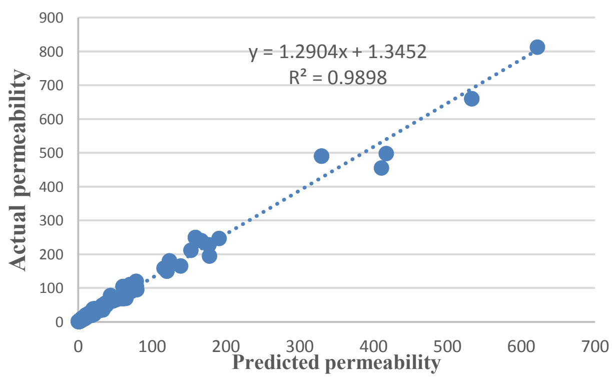

Fig. 18: Actual permeability vs predicted permeability using Izadi's technique (2012) in sandstone reservoir.

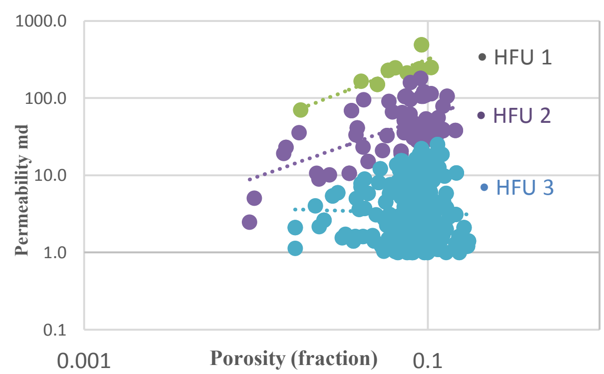

Fig. 19: Permeability porosity relationship using Paiaman's technique in sandstone reservoir.

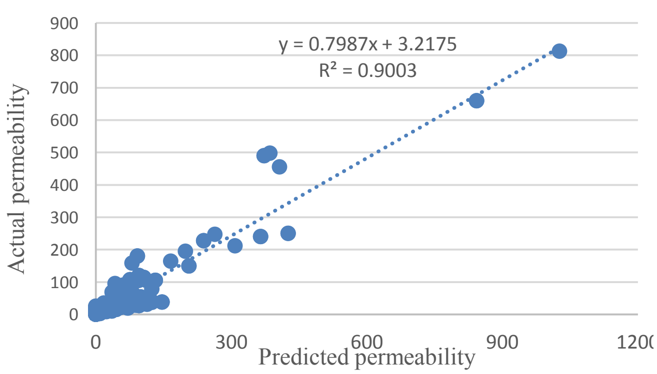

Fig. 20: Actual permeability predicted permeability using Paiaman's technique (2015) in sandstone reservoir.

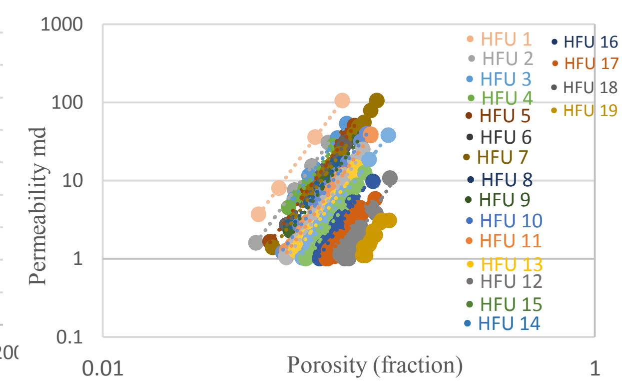

Fig. 21: Permeability porosity relationship using new approach in sandstone reservoir.

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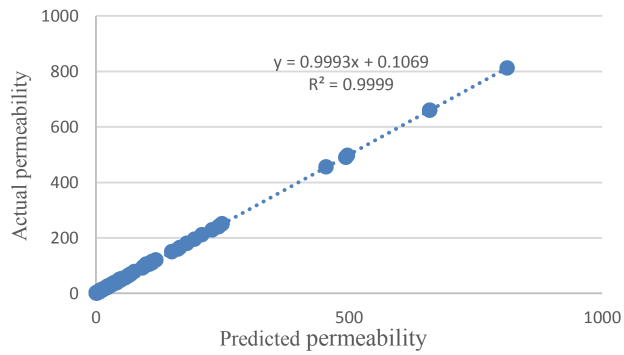

Fig. 22: Actual permeability vs predicted permeability using new approach in sandstone reservoir

Table 1: Field data sample in carbonate reservoir.

Depth ft	*Facies log*	*Porosity %*	*Kh md*	*Kv md*	*Swi (fraction)*	*Grain Density (g/cc)*
6181	Dol. lime	18.2403	19.854	3.75	0.23122	2.85
6182	Dol. lime	12.2890	2.651	2.60	0.16521	2.85
6183	Dol. lime	10.7927	2.426	2.751	0.21173	2.87
6184	Dol. lime	18.2855	8.438	64.148	0.26182	2.84
6185	Dol. lime	18.0024	47.854	0.132	0.24282	2.89
6186	Dol. lime	14.3833	30.346	62.075	0.19795	2.82
6187	Dol. lime	10.5335	18.500	9.181	0.13601	2.87
6188	Dol. lime	13.3351	5.591	5.245	0.15914	2.85
6189	Dol. lime	21.2174	17.411	1.093	0.15933	2.85
6190	Dol. lime	16.7018	89.309	0.037	0.11866	2.87
6191	Dol. lime	11.7393	17.543	0.161	0.17288	2.84
6192	Dol. lime	12.3718	5.347	0.222	0.16880	2.89
6193	Dol. lime	11.8250	3.227	2.651	0.22678	2.82

Table 2: Summary of porosity permeability relationship using Winalnd R35 technique in carbonate reservoir.

Pore type	Equation	Correlation coefficient
Megaport	$k = 2342\emptyset^{1.0281}$	0.7243
Macroport	$k = 257.32\emptyset^{1.246}$	0.4126
Mesoport	$k = 41.975\emptyset^{1.4}$	0.6381

Table 3: Summary of porosity permeability relationship using Pittman R25 technique in carbonate reservoir.

Pore type	Equation	Correlation coefficient
Megaport	$k = 1528.1\emptyset^{0.7593}$	0.5384
Macroport	$k = 90.965\emptyset^{0.6246}$	0.179
Mesoport	$k = 11.515\emptyset^{0.7502}$	0.3301

Print ISSN 2682-3993

Online ISSN 2682-4000

Table 4: Summary of porosity permeability relationship using Amaefule's technique in carbonate reservoir.

Hydraulic Flow Unit	Equation	Correlation coefficient
1	$k = 803580^{3.1881}$	0.9942
2	$k = 1117810^{3.6819}$	0.9109
3	$k = 476540^{3.4159}$	0.9922
4	$k = 370820^{3.6095}$	0.9909
5	$k = 265010^{3.9206}$	0.9259
6	$k = 1414.90^{2.9576}$	0.7926
7	$k = 64.9820^{2.0947}$	0.3672

Table 5: Summary of porosity permeability relationship using Izadi's technique (2012) in carbonate reservoir.

Hydraulic Flow Unit	Equation	Correlation coefficient
1	$k = 730310^{3.1286}$	0.9974
2	$k = 1768580^{4.1876}$	0.7558
3	$k = 443580^{3.3044}$	0.8399
4	$k = 174450^{3.0336}$	0.9807
5	$k = 6129.40^{2.777}$	0.9359
6	$k = 5506.40^{3.3647}$	0.9244
7	$k = 566.250^{2.7352}$	0.6365

Table 6: Summary of porosity permeability relationship using Paiaman's technique (2015) in carbonate reservoir.

Hydraulic Flow Unit	Equation	Correlation coefficient
1	$k = 999.070^{1.0127}$	0.6159
2	$k = 3483.70^{1.0661}$	0.9491
3	$k = 73.6870^{1.1681}$	0.2941

Table 7: Summary of porosity permeability relationship using new approach in carbonate reservoir.

Hydraulic Flow Unit	Equation	Correlation coefficient
1	$k = 5379010^{4.8373}$	0.9985
2	$k = 4046040^{4.9181}$	0.9908
3	$k = 1754150^{4.8773}$	0.9939
4	$k = 602010^{4.6265}$	0.9914
5	$k = 209930^{4.56}$	0.9692
6	$k = 7265.60^{4.6501}$	0.5364

Table 8: Comparison between approaches in actual permeability vs predicted permeability in carbonate reservoir.

Technique	Correlation coefficient
Amaefule (1993)	0.9772
Izadi (2012)	0.8498
Paiaman (2015)	0.8752
New approach	0.9896

Table 9: sample of data in sandstone reservoir.

Depth (m)	Perm. (md)	Porosity (Fraction)	Rhog (g/cc)	Swr (Fraction)
3554.50	35.70	0.07	2.63	0.23
3554.63	35.70	0.07	2.63	0.27
3555.63	1.50	0.09	2.60	0.32
3556.00	62.00	0.08	2.63	0.19
3556.13	62.00	0.08	2.62	0.23
3556.63	9.80	0.09	2.66	0.3
3557.00	6.90	0.10	2.63	0.32
3557.63	12.60	0.12	2.61	0.25
3558.13	0.60	0.07	2.59	0.18
3558.50	54.00	0.08	2.59	0.3
3559.63	50.00	0.10	2.51	0.27

Table 10: Summary of porosity permeability relationship using Winland R35 technique in sandstone reservoir.

Pore type	Equation	Correlation coefficient
Megaport	$k = 2274.50^{1.0653}$	0.3743
Macroport	$k = 159.750^{1.1605}$	0.2228
Mesoport	$k = 2.91410^{0.2466}$	0.0351

Table 11: Summary of porosity permeability relationship using Pittman R25 technique in sandstone reservoir.

Pore type	Equation	Correlation coefficient
Megaport	$k = 861.350^{0.4614}$	0.1059
Macroport	$k = 67.0420^{0.6207}$	0.0891
Mesoport	$k = 2.02560^{0.0444}$	0.0015

Print ISSN 2682-3993

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Table 12: Summary of Porosity-permeability relationship using Amaefule's technique in sandstone reservoir.

Hydraulic Flow Unit	Equation	Correlation coefficient
1	$k = 308822\emptyset^{3.0658}$	0.9997
2	$k = 206888\emptyset^{3.1691}$	0.9997
3	$k = 189197\emptyset^{3.1763}$	0.9977
4	$k = 124101\emptyset^{3.108}$	0.9998
5	$k = 177736\emptyset^{3.3038}$	0.9923
6	$k = 76600\emptyset^{3.115}$	0.9978
7	$k = 46835\emptyset^{3.0146}$	0.9919
8	$k = 43049\emptyset^{3.1504}$	0.9833
9	$k = 29947\emptyset^{3.1865}$	0.9687
10	$k = 21976\emptyset^{3.2876}$	0.9357
11	$k = 2507.5\emptyset^{2.7352}$	0.759
12	$k = 20.742\emptyset^{1.108}$	0.2444
13	$k = 12.455\emptyset^{1.295}$	0.6321

Table 13: Summary of porosity-permeability relationship using Izadi's technique (2012) in sandstone reservoir.

Hydraulic Flow Unit	Equation	Correlation coefficient
1	$k = 244229\emptyset^{3.1032}$	0.9999
2	$k = 194059\emptyset^{3.1519}$	0.9972
3	$k = 155812\emptyset^{3.1048}$	0.9992
4	$k = 124101\emptyset^{3.108}$	0.9998
5	$k = 59841\emptyset^{3.017}$	0.9994
6	$k = 58315\emptyset^{3.0642}$	0.9992
7	$k = 39220\emptyset^{3.1088}$	0.9974
8	$k = 31879\emptyset^{3.1001}$	0.9969
9	$k = 58670\emptyset^{3.1957}$	0.997
10	$k = 30046\emptyset^{3.1718}$	0.9914
11	$k = 24131\emptyset^{3.2003}$	0.9898
12	$k = 19721\emptyset^{3.2298}$	0.9871
13	$k = 10194\emptyset^{3.1388}$	0.9694
14	$k = 6147.9\emptyset^{3.092}$	0.9062
15	$k = 3907.3\emptyset^{3.1589}$	0.9039
16	$k = 143.8\emptyset^{1.9978}$	0.546
17	$k = 4.3693\emptyset^{0.6706}$	0.1305

Table 14: Summary of porosity-permeability relationship using Paiaman's technique (2015) in sandstone reservoir.

Hydraulic Flow Unit	Equation	Correlation coefficient
1	$k = 2312.1\emptyset^{0.8625}$	0.708
2	$k = 348.32\emptyset^{0.7843}$	0.3672
3	$k = 2.7736\emptyset^{-0.064}$	0.0008

Table 15: Summary of Porosity-permeability relationship using new approach in sandstone reservoir.

Hydraulic Flow Unit	Equation	Correlation coefficient
1	$k = 3E+06\emptyset^{4.3002}$	0.9998
2	$k = 2E+06\emptyset^{4.3423}$	0.9999
3	$k = 2E+06\emptyset^{4.4464}$	0.9987
4	$k = 1E+06\emptyset^{4.3363}$	0.9953
5	$k= 873069\emptyset^{4.3423}$	0.9992
6	$k = 826529\emptyset^{4.3801}$	0.9997
7	$k = 851045\emptyset^{4.435}$	0.9987
8	$k = 524246\emptyset^{4.3069}$	0.9957
9	$k = 357039\emptyset^{4.2027}$	0.9994
10	$k = 417993\emptyset^{4.3447}$	0.9968
11	$k = 366450\emptyset^{4.3801}$	0.9991
12	$k = 276001\emptyset^{4.3345}$	0.996
13	$k = 169389\emptyset^{4.231}$	0.991
14	$k = 175164\emptyset^{4.3543}$	0.9892
15	$k = 213209\emptyset^{4.5638}$	0.9774
16	$k = 245250\emptyset^{4.7859}$	0.9589
17	$k = 38061\emptyset^{4.1924}$	0.9367
18	$k = 77071\emptyset^{4.7489}$	0.872
19	$k = 32758\emptyset^{4.7099}$	0.8897

Table 16: Comparison between approaches in actual permeability vs predicted permeability in sandstone reservoir.

Technique	Correlation coefficient
Amaefule (1993)	0.9989
Izadi (2012)	0.9898
Paiaman (2015)	0.9003
New approach	0.9999

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