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Reservoir Characterization to Define Reservoir Quality in Uncored Reservoir: A Case Study, Lower Bahariya Sandstone Reservoir, East Abu Gharadig Basin, North the Western Desert, Egypt

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Abstract

Reservoir characterization includes describing all aspects of the reservoir like porosity and permeability variations which represent the reservoir quality, hydrocarbon saturation, and volumes. One core and five wells were selected to characterize and study the reservoir quality and heterogeneity of Lower Bahariya sandstone reservoir in the northern part of the Western Desert of Egypt. Bahariya formation is subdivided into Upper and Lower Bahariya members where the reservoir is moderate to heterogenous quality. Lower Bahariya formation is dominated by sandstone, siltstone, and shale. The deposition environment is shallow marine. The coefficient of determination (R^2) obtained for the porosity and permeability cross-plot is low of 0.24 which reflects the vital role for rock discrimination. Based on this study, nine hydraulic flow units (HFUs) are identified within Lower Bahariya formation, and a correlation is established between logging data and the rock types allowing us to define the reservoir quality all over the reservoir even in uncored areas. In addition, the paper emphasizes the rock typing application to predict the initial water saturation by using saturation height modeling, and the oil water contact movement.

Keywords: *Reservoir Characterization. Core Analysis. Lower Bahariya Sandstone. Saturation Height Modeling. Porosity. Permeability.*

1. Introduction

Reservoir characterization involves creating geological and petrophysical reservoir models based on fluid flow characteristics and geology. The desired objective of all reservoir characterization models is optimizing production and increasing the recoverable reserve. The distribution of the reservoir properties is validated by matching the production history and after that the model could be used for development and establishing production plans.

Several methods have been presented for appropriate rock typing. The key role of rock typing or discrimination is to appropriately find the relation between the porosity which represents the reservoir storage capacity and the permeability which represents the reservoir flow capacity. Haro [1] performed a comprehensive evaluation of four permeability models: Windland [2], Kozeny [3], Civan [4], and Jennings and Lucia [5]. During the studies of Chopra et al. [6] about developing the reservoir description to improve the designs for EOR projects, it was stated that the permeability to porosity (K/Ø) or (K/PHIE) plots could be used to develop reservoir layering as this ratio is an indicator of the fluid speed at which it flows through the reservoir. Amaefule *et al.* [7] presented the Flow Zone Indicator (FZI) which is a modification of the Kozeny-Carman equation, relates micro-scale factors such as pore shape and size, pore throat radius, and aspect ratio to porosity and permeability.

To calculate the FZI using Eq. 1, two more parameters should be calculated first; the Rock Quality Index (RQI) as described in Eq. 2 and the normalized porosity (Øz) as described in Eq.3.

$$FZI = \frac{RQI}{Ø_z} \quad (1)$$

$$RQI = 0.0314\sqrt{\frac{k}{Ø}} \quad (2)$$

$$Ø_z = \frac{Ø}{1 - Ø} \quad (3)$$

where: K is the reservoir permeability, md; Ø is the reservoir porosity, fraction.

The FZI should be calculated for each plug, then the results will be plotted on a semi-logarithmic scale. The points with same values of FZI should be grouped together and identified as they have the same rock properties or rock type or facies or rock type or facies. In many cases grouping will be difficult, that is why some approaches have been introduced to improve the grouping process like Discrete Rock Typing (DRT) method. In 2007, Shenawi et al. [8] proposed DRT to combine samples with similar petrophysical properties into similar DRT values as described in Eq.4.

$$DRT = 2\,ln(FZI) + 10.6 \quad (4)$$

In 1997, Gunter *et al.* [9] presented another graphic tool for rock typing called Stratigraphic Modified Lorenz Plot (SMLP) which is a plot of percent of flow capacity versus percent storage capacity ordered in stratigraphic sequence. The obtained storage capacity-flow capacity curve is representative for the studied reservoir sequence; on which the Hydraulic Flow Units (HFUs) are presented by some plateaus (line segments) of different slope ranges, separated from each other by inflection points. The closest to the vertical sharp slope represents the super conductive zone, the nearest to the horizontally flattened represents a barrier, whereas the in-between slope range represents conductive zones. The steeper the slope of a plateau, the higher the flow capacity will be. Nabawy [10] presented an improved stratigraphic modified Lorenz (ISML) plot by adding a way of description for each HFU using its slope. Not only Amaefule *et al.* but also several researchers have worked on modifying the Kozeny–Carmen model like in 2011 Nooruddin and Hossain [11] focused on the tortuosity term by including the cementation exponent (m) as a power of the reservoir porosity as shown in Eq. 5 and introduced the Flow Zone Indicator Modified (FZIM). Izadi and Ghalambor [12] presented another modification combining Poiseuille and Darcy equations, which is the Modified Flow Zone Indicator (MFZI). MFZI relates the permeability with irreducible water saturation as well as inherent rock properties as shown in Eq. 6. In addition to Kozeny–Carmen model, Winland [2] developed an empirical equation, depending on pore throat radius when mercury saturation is 35% (R35) as shown in Eq. 7. Kolodzie [13] worked on the Winland equation and developed a slightly different equation of the pore throat radius.

$$FZIM = \frac{0.0314\sqrt{\frac{k}{Ø}}}{\frac{Ø^m}{1-Ø}} \quad (5)$$

$$MFZI = \frac{0.0314\sqrt{\frac{k}{Ø}}\,\sqrt{1-S_{wc}}}{\frac{Ø}{1-Ø}\,(1-S_{wc})^2} \quad (6)$$

$$Log(R_{35}) = -0.996 + 0.588\,Log(k) - 0.864\,Log(Ø) \quad (7)$$

Mohammadian *et al.* [14] analyzed core data from a heterogenous carbonate reservoir in Iran to develop a modification for FZI by using machine learning and used that modification to predict the reservoir permeability and pore throat radius. Ganguli & Dimri [15] summarized most of the key challenges of reservoir characterization and discussed current practices with the adaptation of newly developed technologies. Moradi *et al.* [16] worked on Upper Dalan and Kangan carbonate formation which is considered as world's giant gas reservoirs to evaluate the Hydraulic Flow Units (HFUs) and combine the results with the sedimentary facies. That combination helped in identifying the depositional environment and enhancing the geological model. Karimian *et al.* [17] collected well log data for 10 drilled wells and 490 core data from Permo–Triassic carbonate formations at the Kangan giant gas field in Iran to integrate the petrophysical data with facies by using a Multi Resolution Graph based Clustering (MRGC) method in addition to FZI plot. Wang [18] focused on using the image devices for rock typing through his review about the applications of the image-based microscale rock typing (IMRT) methods as these methods have a significant role to recognize the pattern and texture but the review concluded that these methods couldn't replace the conventional rock typing methods and should be a complementary step for comprehensive rock typing.

Defining the rock types in the reservoir helps in distributing the initial water saturation as each rock type should be deposited under similar conditions and experienced similar diagenetic processes, resulting in a distinct porosity-permeability relationship, capillary pressure profile, and water saturation for a particular height above free water in a reservoir. Leverett [19] introduced a dimensionless function of the water saturation called J-function as shown in Eq. 8. The Leverett - J method relates capillary pressure (Pc, psi) to the changes in permeability and porosity. It also combines the effect for the wettability (Contact angle ϴ) and surface tension (σ, Dyne/cm). J function values are plotted against wetting phase saturation. If porosity and permeability are indeed related, a consistent curve results, therefore for each reservoir rock type there is an equation that describes the relation between the wetting phase saturation and capillary pressure. Capillary pressure measurements are performed on each core plug and are then converted to J values for each sample and plotted against the water saturation.

$$J = \frac{0.2166\,P_c}{\sigma\,COS\,(\Theta)}\sqrt{\frac{k}{\emptyset}} \tag{8}$$

Another method for Cuddy *et al.* [20] was derived from log data from the Southern North Sea, though it has proven to have much wider application. The function provides correlations between the bulk volume of water [21] and the height above contact that are independent of porosity. The function can also be applied to core data of the measured capillary pressures for different water saturations using Eq.9 & 10 where a & b are constants.

$$S_w = \frac{Bulk\ Volume\ of\ Water\ (BVW)}{\emptyset} \tag{9}$$

$$BVW = \emptyset S_w = \frac{a}{{P_c}^b} \tag{10}$$

where: S_w is water saturation, fraction; a & b are constants.

Worthington [22] has applied the power method which expresses water saturation as a function of the capillary pressure as described in Eq.11 where a & b are constants. It was specially developed to describe capillary pressure curves. The formula does not apparently contain a rock quality-dependent variable, but it should be generated for each reservoir rock type.

$$Sw = \frac{a}{{P_c}^b} \tag{11}$$

In addition to Leverett model, Abdollahian *et al.* [23] reviewed other models and compared the results to obtain a workflow that could be used to reduce the uncertainties in tight gas sandstones. The results of that review support Brooks–Corey model [24] which is considered as the most conventional saturation height model. Abdollahian et al. compared the results of the saturation and permeability calculation of other models like Skelt & Harrison [25] who developed a model which relates water saturation to the height above the free water level similar to Lambda model which was derived by Wiltgen [26] but with different fitting parameters. Thomeer model [27] includes the pore geometric factor as it could affect the capillary pressure curve.

Tohidi *et al.* [28] worked on cores from carbonate gas reservoir to a saturation height model while considering not only the relationship between capillary pressure and water saturation but also the pore size distribution. The results of the predicted water saturation showed a high level of consistency across the reservoir. Consequently, this study is a trial to throw light on the above-mentioned methods to describe the reservoir accurately and submit the most appropriate workflow for that. Commonly while establishing the field development plan and selecting the location of new wells, the focus is on the 100% oil zone in the reservoir. Ghosh *et al.* [29] reviewed the characterization and production feasibility of the transition zone. The results confirm the potentiality and possibility to produce from the transition zone but with enhanced oil recovery (EOR) methods like polymer and surfactant flooding.

The core and logging data used in this study to describe the reservoir quality are obtained from Lower Bahariya reservoir, a sandstone oil reservoir located in in the eastern portion of East Abu El-Gharadig Basin in the northern part of the Western Desert of Egypt. The Abu Gharadig Basin is the most significant and largest oil-producing basin in the northern Western Desert of Egypt [30]. Several geological and geophysical studies have been performed in the Abu Gharadig sedimentary basin [31-41].

2. Data and methodology

The available data are routine and special core analysis, include permeability, porosity, fluid saturation, capillary pressures. A set of conventional well log data for five wells (A, B, C, D, and E) was available including gamma ray (GR), density (RHOB), neutron (NPHI), and photoelectric (PE) logs. Well (A) was the first drilled well in 2009 in the area then well (B) was drilled and put on production after five months from drilling well (A). The core was taken from the second drilled well in the area well (B). Well (C) was the third well and it was put on production after nine months from well (B). Well (D) and (E) were drilled in 2014 and 2019 respectively.

Analysis of the Lower Bahariya sandstone reservoir quality as illustrated in (Fig. 1) began with describing the degree of permeability anisotropy and heterogeneity then reservoir rock typing. In addition, correlating rock typing results with logging data to predict the rock types in the un-cored wells. Furthermore, saturation height modeling is discussed in this study using the rock types and that correlation to predict the initial water saturation in un-cored wells which allows to monitor the oil water contact movements.

Usually, permeability varies significantly between the vertical and horizontal planes within a formation. This variation in permeability in different planes or directions is known as anisotropic permeability. Anisotropic permeability is especially important when dealing with horizontal or partially penetrated wells since flow occurs in both the vertical and horizontal planes. The permeability in the z-direction (k_z) is typically significantly different, usually less than the horizontal permeabilities (k_x and k_y). The ratio of vertical permeability (k_v) to the horizontal permeability (k_h) is often used to quantify the permeability anisotropy termed as anisotropy index (λ_k). The heterogeneity differs from anisotropy. Anisotropy is simply the property variation with direction like the permeability in x-direction varies from the permeability in z-direction. On the other hand, heterogeneity means that the property has spatial variation. It is important to know the degree of heterogeneity and anisotropy in the reservoir, especially in case of studying the secondary recovery methods. Dykstra and Parsons [42] presented the permeability variation coefficient V as described in Eq.12 where k_{50} & $k_{84.1}$ are the corresponding permeability values at 84.1% and 50% of thickness.

$$V = \frac{K_{50} - K_{84.1}}{K_{50}} \tag{12}$$

Schmalz and Rahme [43-44] introduced the Lorenz coefficient which varies between zero, for a completely homogeneous system, to one for a completely heterogeneous system. A completely uniform system would have all permeabilities equal, and a plot of the normalized $\sum kh$ versus $\sum \varphi h$ would be a straight line. To calculate Lorenz coefficient, the area above and below the straight line should be calculated and the ratio between them is the coefficient.

In this study, four methods for rock typing are applied which are FZI, DRT, FZIM, and MFZI using the core data. The selection for the optimum number of rock types is based on two other methods of analysis which are the least-square regression method [45] and SMLP, then the selection will be validated by comparing the results to Winland R35 and K/PHIE predicted rock types.

Regarding the reservoir characterization in the un-cored areas in the reservoir, it is done using integration between the final HFUs or rock types defined from the core data analysis and the logging data collected from the drilled wells by establishing a correlation using multiple linear regression mathematical method which uses multiple independent variables to predict one dependent variable or one output.

To validate both the correlation and rock types, the calculation for initial water saturation is done based on three different methods using the rock types, which are J-function, power function, and bulk volume of water method.

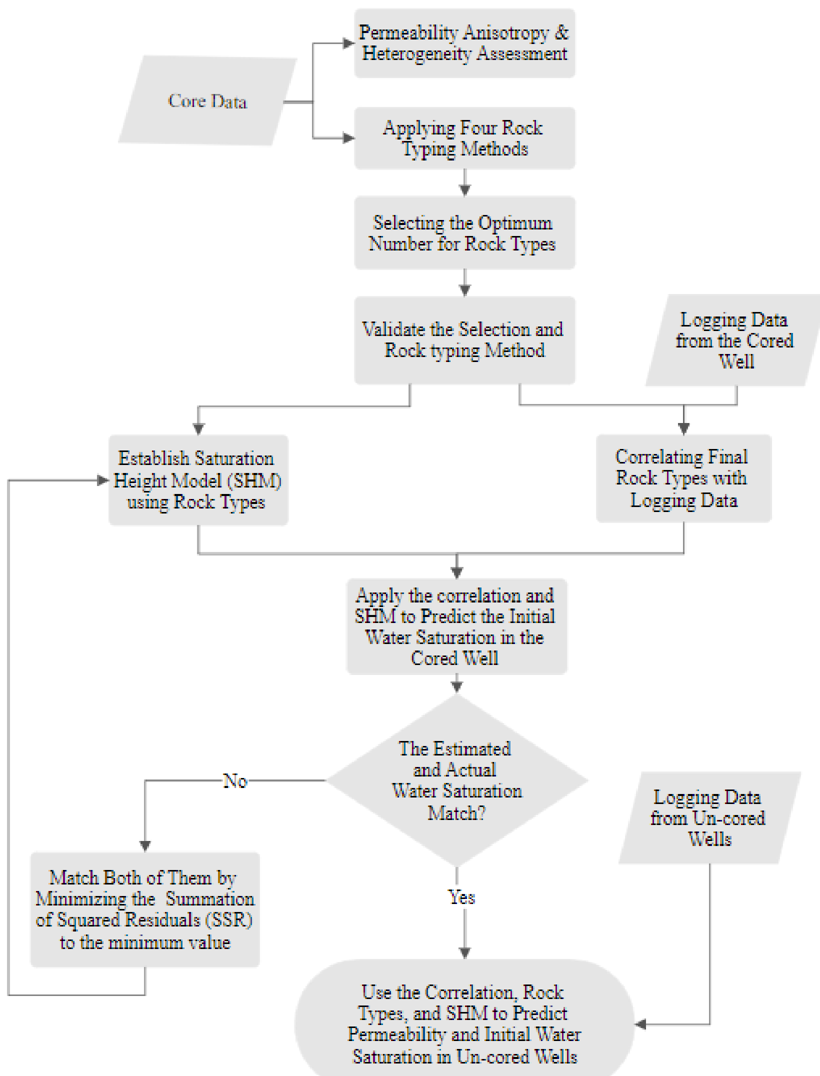

Fig. 1. The workflow of the current study.

3. Results and discussion

3.1. Permeability anisotropy and heterogeneity

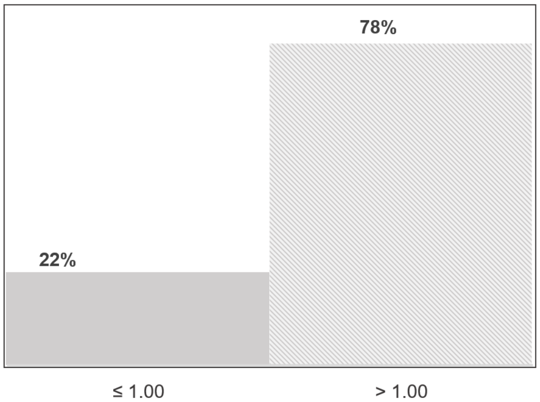

Fig. 2. Histogram analysis for permeability anisotropy index

After calculating the reservoir anisotropy, most samples show permeability anisotropy above one according to the histogram analysis as shown in (Fig. 2) which means that the reservoir is anisotropic. To evaluate the reservoir heterogeneity, permeability variation coefficient is calculated based on Eq.12 and the results as described in (Fig. 3) show permeability variation coefficient of 0.524 which means that the reservoir is heterogenous. Also, Lorenz coefficient calculations show that the reservoir is heterogeneous as the value of it is 0.52 as illustrated in (Fig. 4).

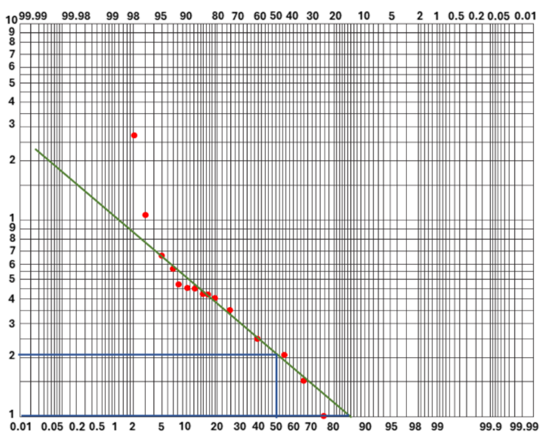

Fig. 3. Log-probability chart to estimate the permeability variation.

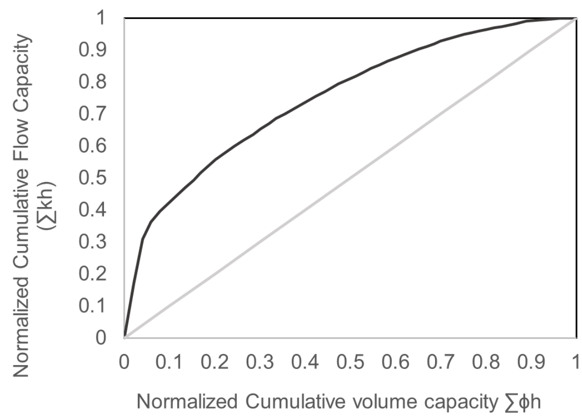

Fig. 4. Normalized cumulative permeability capacity versus the normalized cumulative volume capacity on a cartesian scale.

3.2. Reservoir characterization

The results of FZI calculations Eq.1, 2 &3 after applying show that the reservoir could be divided into nine rock types as shown in (Fig. 5 & 6). The higher the FZI value, the better facies and reservoir quality in terms of the porosity and permeability.

The purpose of the Discrete Rock Typing is to convert the continuous FZI values into discrete values which will facilitate the process of setting an integer value for each grid cell. The results after applying Eq.4 for DRT show a lower number of rock types than the predicted rock types from FZI calculations as shown in (Fig. 7). According to the DRT method, the reservoir could be described by four rock types.

As previously mentioned, the FZIM method incorporates the tortuosity term in a more representative manner by adding the cementation exponent therefore by applying this method using Eq.5 with the cementation factor of the reservoir, which is 1.9, the results show ten rock types as shown in (Fig. 8 & 9).

The other modification of MFZI relates the permeability with the irreducible water saturation as well as inherent rock properties. Therefore, according to Eq.6 this method represents a new modified rock quality index (MRQI). After adding the irreducible water saturation measured in the lab to the analysis and applying Eq.6 the results indicate that the reservoir could be described by eleven rock types. As illustrated in (Fig. 10 & 11).

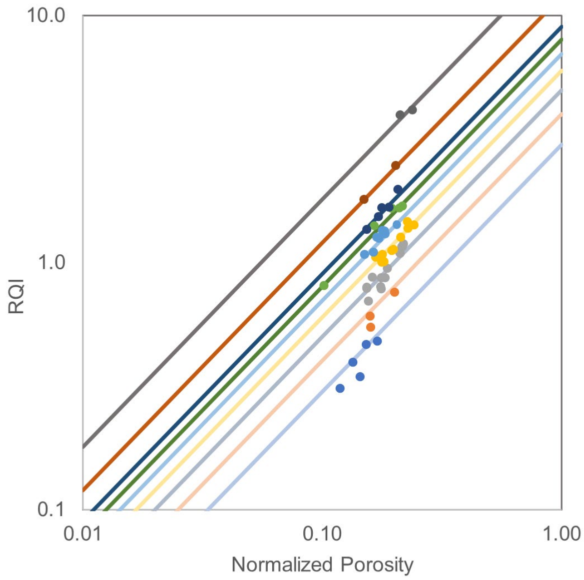

Fig. 5. HFU Determination based on FZI.

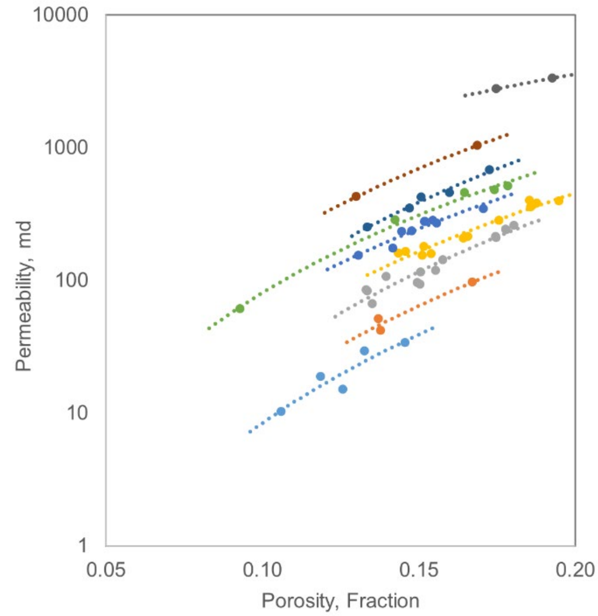

Fig. 6. Permeability vs porosity relationship by using FZI rock typing.

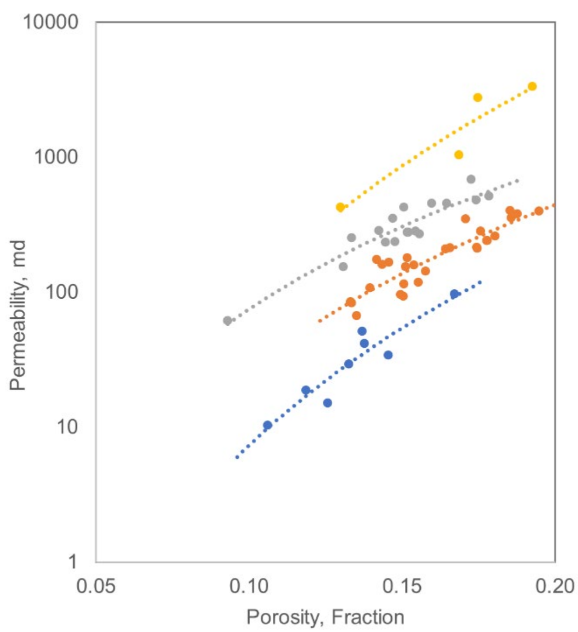

Fig. 7. Permeability vs porosity relationship by using DRT rock typing.

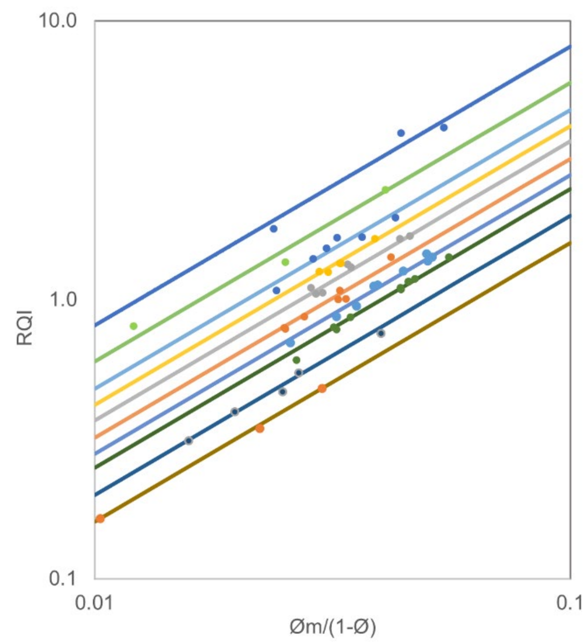

Fig. 8. HFU determination based on FZIM.

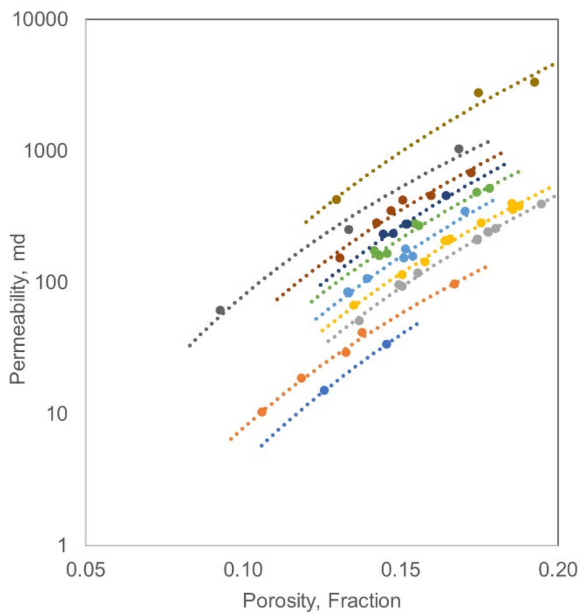

Fig. 9. Permeability vs porosity relationship by using FZIM rock typing.

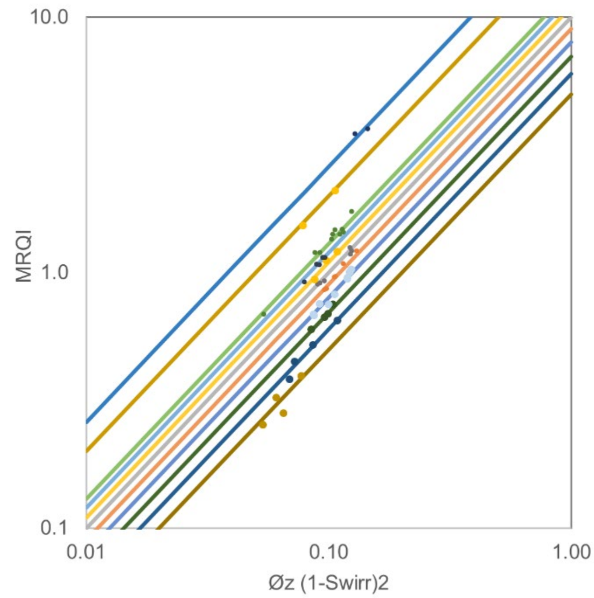

Fig. 10. HFU determination based on MFZI.

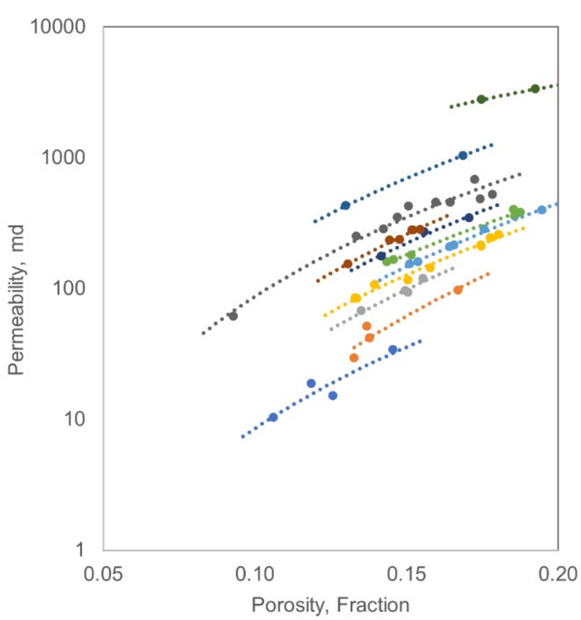

Fig. 11. Permeability vs porosity relationship by using MFZI rock typing.

Table 1 Least-square regression method results.

Method	No. of rock types	Average R^2
No RT	1	0.244
DRT	4	0.938
FZI	9	0.999
FZIM	10	0.970
MFZI	11	0.997

To select one of the previously discussed methods to establish the relationships between the reservoir porosity and permeability per each rock type, two methods are applied. The first one is the least-square regression method. In this method, one single rock type is assumed therefore the permeability–porosity relationship is then established, and the estimated permeability is correlated with the permeability data from routine core analysis (RCA) and the value of coefficient of determination (denoted by R^2) is determined by regression analysis. This process is then repeated for each method then select the method with the highest R^2. As indicated in (Table 1) that summarizes the results of this analysis, the FZI method is selected. (Fig. 12) shows an excellent match between the estimated permeability using FZI method and the core permeability.

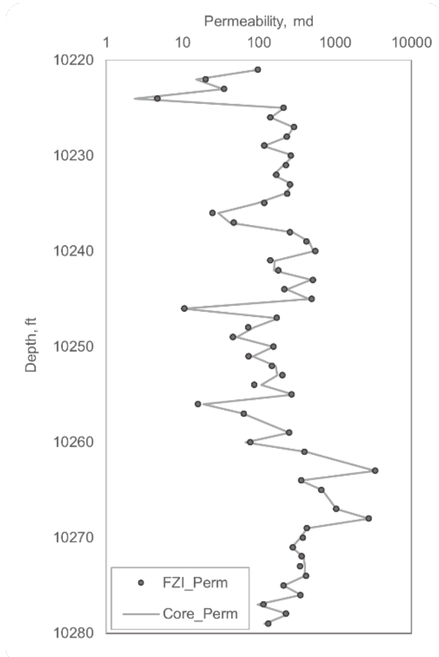

Fig. 12. Predicted permeability using FZI method vs. core permeability.

The Stratigraphic Modified Lorenz Plot (SMLP) is one of the most important techniques that are applied for hydraulic flow unit (HFU) discrimination as previously discussed therefore in this study it is used to as the second method to confirm the optimum count of reservoir HFUs. It is based on core data, porosity, and permeability which are multiplied by their representative bed thicknesses (h), and the obtained results are called storage capacity and flow capacity, respectively. In the common SMLP, cumulative storage capacity for each plug sample is represented on the X-axis versus its corresponding cumulative flow capacity on the Y-axis, both normalized to the unity. The analysis results of applying SMLP as shown in (Fig. 13) show the same count of the rock types as identified by FZI methods.

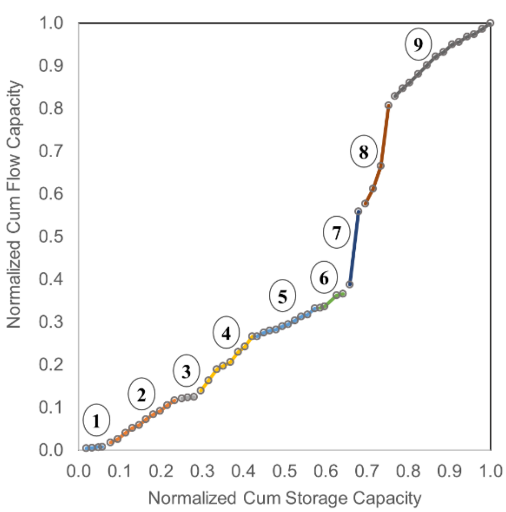

Fig. 13. SMLP method results.

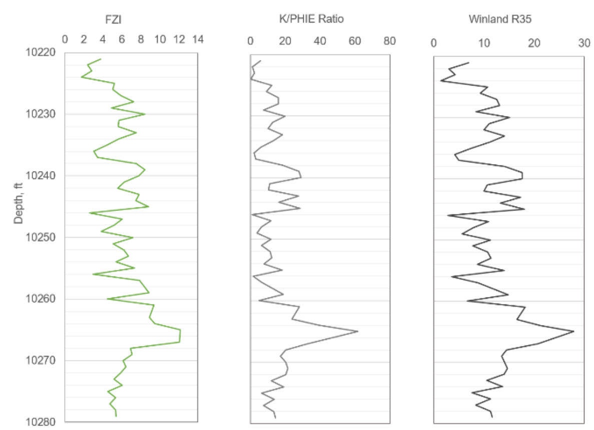

Fig. 14. Winland R35 and K/PHIE methods compared with FZI.

The results for applying Winland R35 method using Eq.7 and K/PHIE methods confirm the results of FZI method by showing same trends as shown on (Fig. 14).

3.3. Integrating reservoir rock types with logging data

The common practice is to take one or two cores from the producing interval and based on the relation between the permeability and porosity, the permeability is predicted in the areas away from the cored wells but in case the reservoir is showing a degree of heterogeneity, the rock typing is very important to consider the effect of heterogeneity while trying to predict the remaining reservoir properties. Applying FZI equations are applied only on the core data although the FZI is the only way to get an accurate permeability distribution for the reservoir therefore we should correlate FZI values calculated by using the permeability and porosity for the cored interval with the logging data. This integration can be done by using the multiple linear regression mathematical method which is a statistical technique that uses two or more independent variables to predict one dependent variable as described in Eq.13.

$$Y = a_0 + a_1X_1 + a_2X_2 + a_3X_3 + \cdots + a_nX_n \qquad (13)$$

where: Y is the dependent variable; X_1, X_2, X_3, …X_n are independent variables; a_0, a_1, a_2, a_3, a_n are constants.

There are two basic terms:

1. Dependent variable: which is here represented by the FZI values because the FZI is the variable which should be estimated in the un-cored wells.
2. Independent variables: which are represented by logging data that gives information about the reservoir rock properties or lithology. The selected logging data here are the Gamma Ray (GR), Neutron (NPHI), Density (RHOB), and Photoelectric (PE).

The equation is generated by using Microsoft Excel. It gives the values of the constants as shown in Eq.14. To confirm the validity of that equation, the FZI values should be calculated again using the regression equation then the results should be compared with the original FZI values as illustrated in (Fig. 15). The match between the original FZI values and the FZI values based on the regression equation is acceptable which means that the equation is valid and could be used in the un-cored wells to estimate the FZI values and if the FZI values are obtained, the permeability could be predicted.

$$\mathrm{FZI} = -22.98 - 0.176\,(\mathrm{GR}) + 7.221\,(\mathrm{NPHI}) + 17.221\,(\mathrm{RHOB}) - 2.145(\mathrm{PE}) \qquad (14)$$

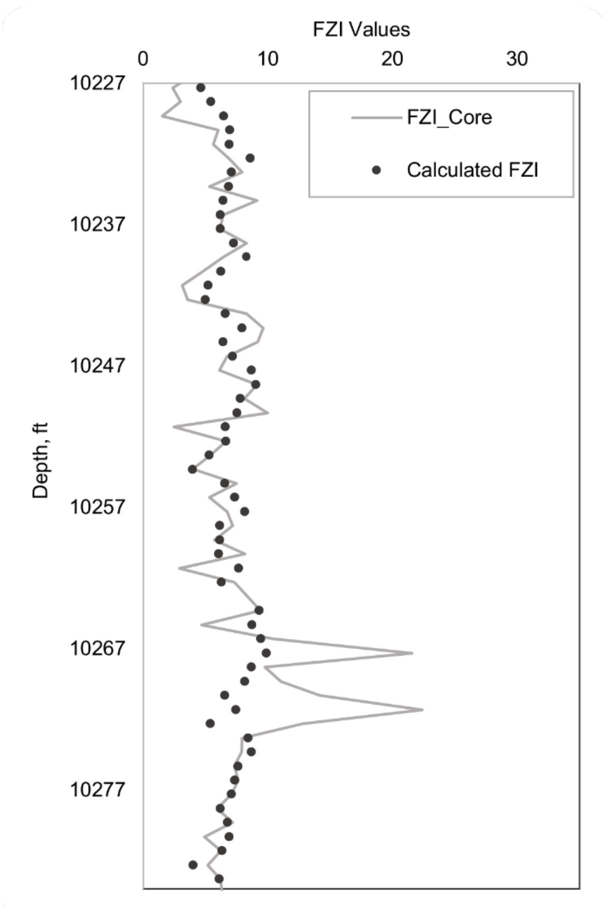

Fig. 15. FZI based on the multiple linear regression equation vs. FZI values of the core.

The equation is utilized to estimate the permeability and RQI for the remaining four wells. The reservoir quality parameters like RQI and FZI are related to the effective pore radius that is responsible for fluid flow. Therefore, by plotting the RQI as function of FZI, the penetrated reservoir quality by each well could be evaluated and then the direction of reservoir quality enhancement could be determined. As indicated in (Fig. 16), well B shows better reservoir quality than well A but both wells (A & B) generally show moderate to good reservoir quality with FZI values range from 4 to 10. Well (C) shows the best reservoir quality as the FZI reaches 14 with RQI above 3 on the other hand well (D) shows the worst reservoir quality. Well (E) has a wide variation of reservoir quality but most of FZI values range from 6 to 11.

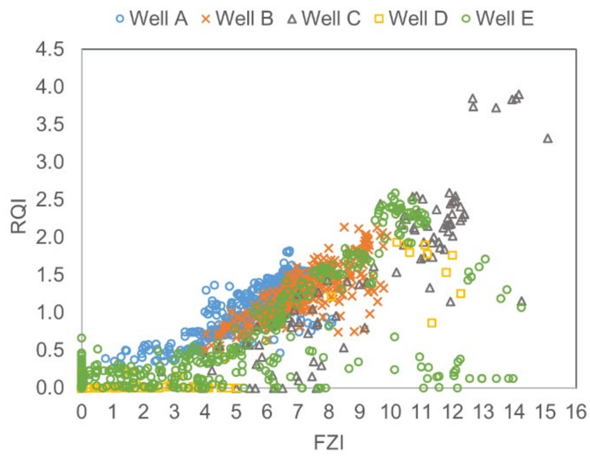

Fig. 16. RQI as a function of FZI for reservoir quality discrimination.

3.4. Saturation height modeling (SHM)

Identifying the initial water saturation is crucial for modeling and analyzing hydrocarbon reservoirs. The original oil in place (OOIP) is determined by the distribution of initial water saturation (S_{wi}) in 3D models, which in turn affects dynamic modeling and reserve calculation. Accordingly, in this study saturation height modeling is done based on the analysis of capillary pressure data after corrections in addition to the rock typing analysis. After correcting the measured capillary pressures and saturations for each plug, the corrected data is used to find a relation between the initial saturation and the height above the oil water contact or capillary pressure to be applied for each rock type in the reservoir therefore the initial saturation for whole the reservoir is distributed.

In this study, three methods of saturation height modeling are applied, which are J-Function, Power function and bulk volume of water method to determine which method gives the best match between the estimated initial water saturation and the petrophysical water saturation defined by logging data. Each method is applied after grouping the samples with same FZI values together as shown in (Fig. 17, 18 & 19) to apply the previously mentioned rock typing analysis in the cored well (B) aiming to achieve an accurate water saturation distribution.

Each rock type expresses a power function equation per each method and to confirm the validity of these resulting equations, the calculated water saturation in the cored well (B) should then be compared with the actual water saturation from the petrophysical evaluation as shown in (Fig. 20). The matching between the calculated water saturation values and the actual water saturation could be enhanced by adjusting the power function constants either a or b and that could be done by using the "Solver" option in Microsoft Excel but first the Summation of Squared Residuals (SSR) value should be calculated by using the following Eq.15. The SSR value is then calculated for all methods for comparison to determine the best fit method

$$\mathrm{SSR} = \sum(\text{Actual Value} - \text{Calculated Value})^2 \quad (15)$$

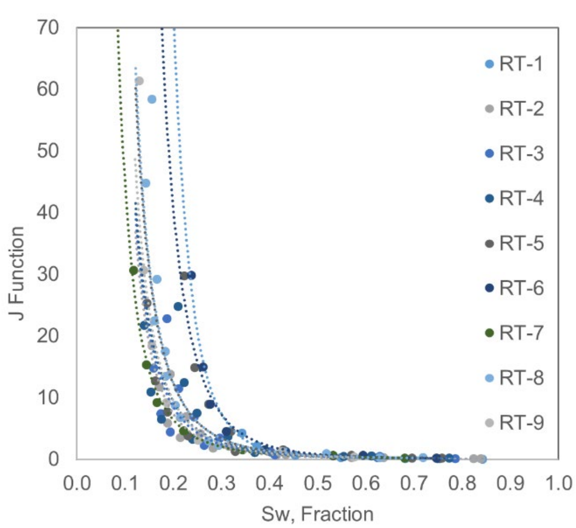

Fig. 17. J-Function vs. water saturation per each RT.

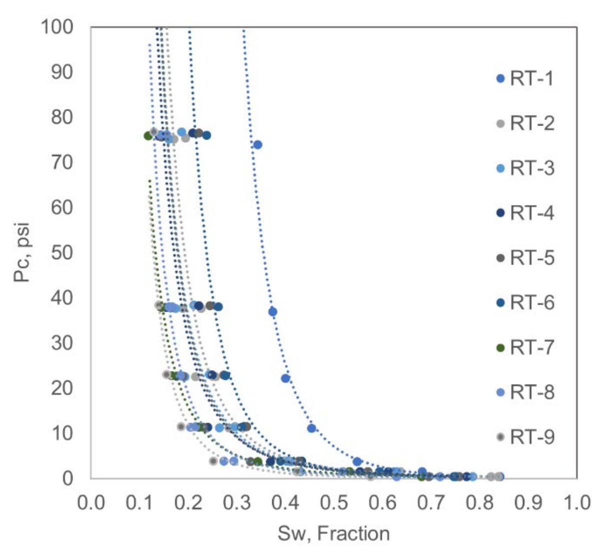

Fig. 18. Capillary pressure vs. water saturation per each RT.

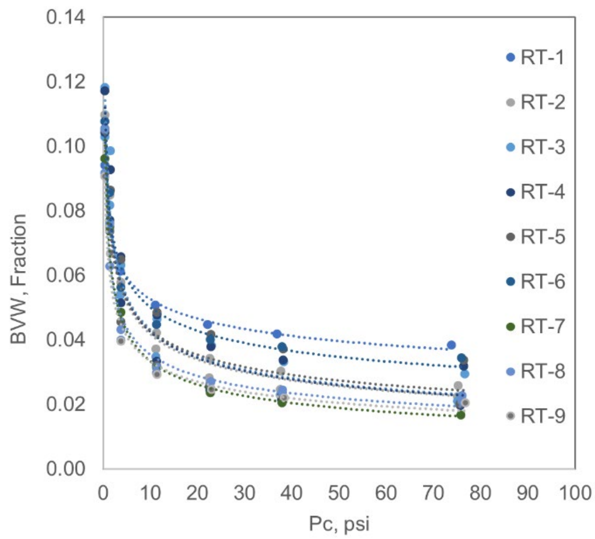

Fig. 19. BVW vs capillary pressure per each RT.

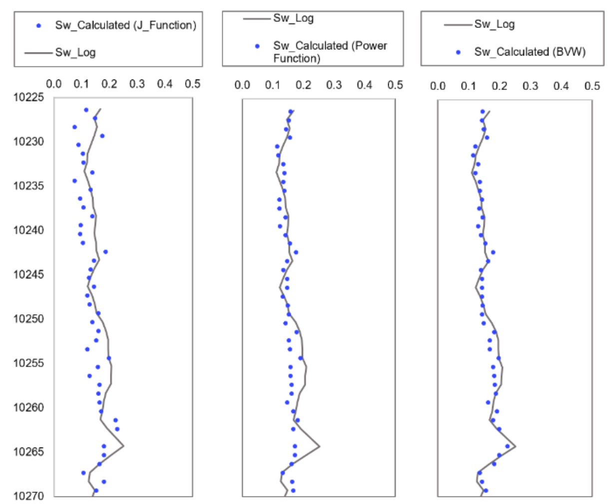

Fig. 20. Estimated initial water saturation using the three methods in comparison to the water saturation defined by petrolphysical data.

The comparison is visually showing that the calculated water saturation based on the BVW method exhibits a very good match to the water saturation defined by logging and petrophysical data. Also, the SSR values as shown in (Table. 2) confirm this conclusion as the SSR value of BVW is minimal of 0.02.

Table 2. Summary for SSR value for each method

SHM method	SSR value
J-Function	0.09
Power Function	0.05
BVW Method	0.02

Moreover, from special core analysis the residual oil saturation (S_{or}) could be defined for each sample therefore a new equation could be established that expresses the residual oil saturation (S_{or}) as the function of the initial water saturation (S_{wi}) as shown in (Fig. 21).

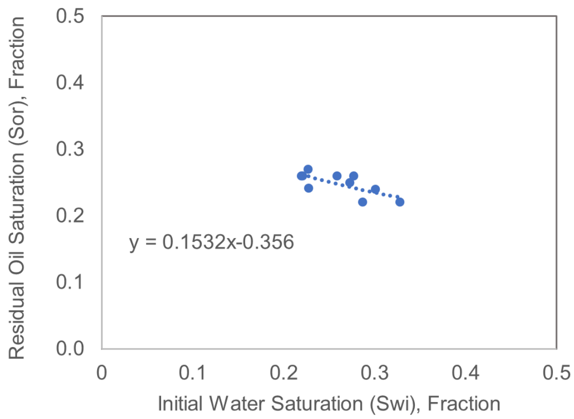

Fig. 21. Residual oil saturation as function of initial water saturation.

Hence, the residual oil saturation (S_{or}) could be added to the analysis to show how much recoverable oil could be recovered and whether the water saturation evaluated by logging data represents the maximum water saturation (equivalent to residual oil saturation) or not. (Fig. 22, 23, 24 & 25) are for the estimated initial water saturation in un-cored wells based on all previous analysis using BVW method in comparison with the petrophysical or logging- defined water saturation in addition to the estimated maximum water saturation which is equivalent to the residual oil saturation based on the fitting power equation that is shown in (Fig. 26)

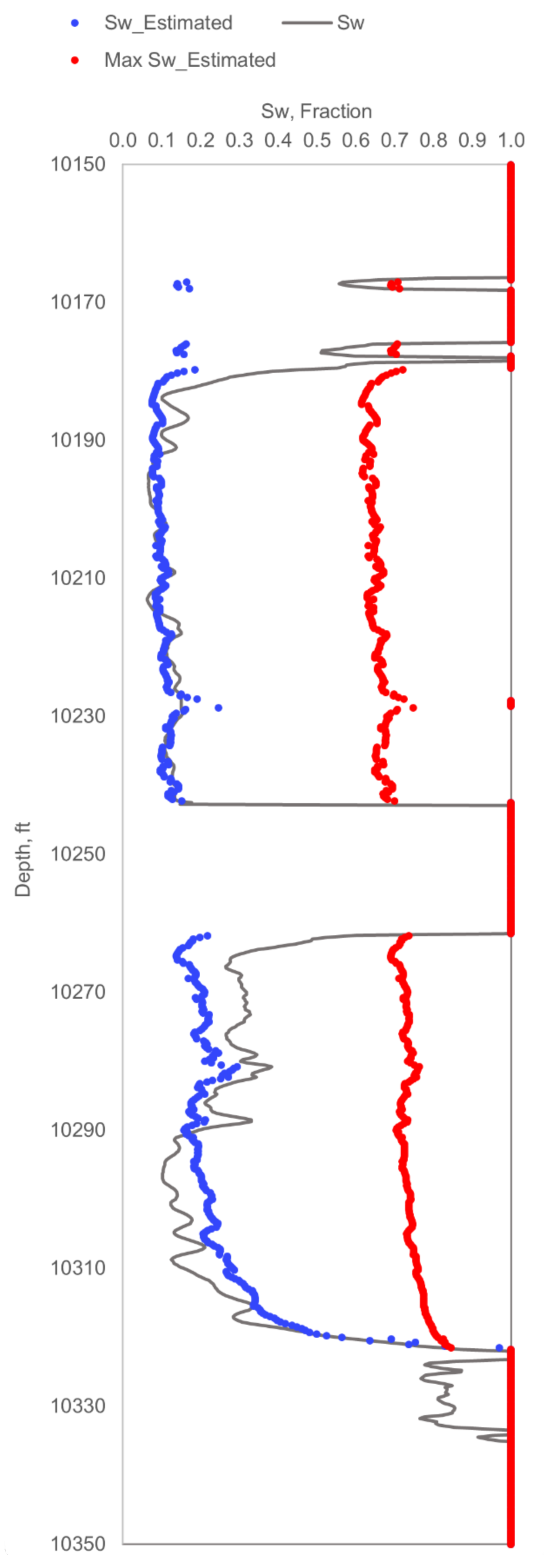

Fig. 22. Well (A) water saturation profile.

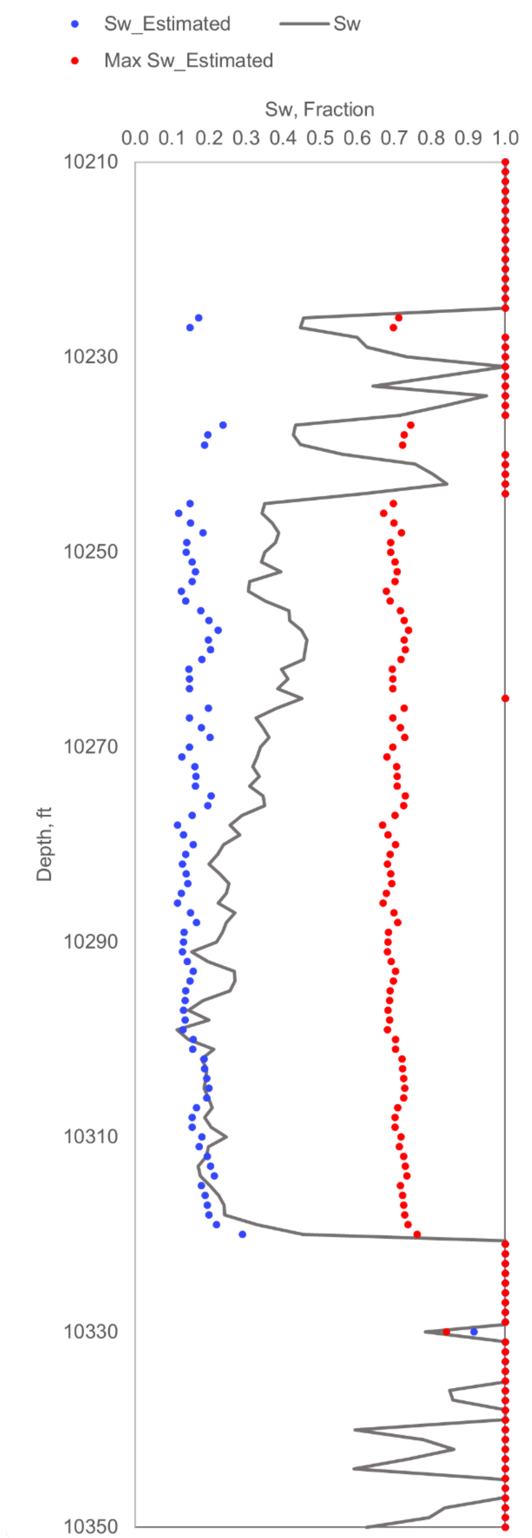

Fig 23 Well (C) water saturation profile.

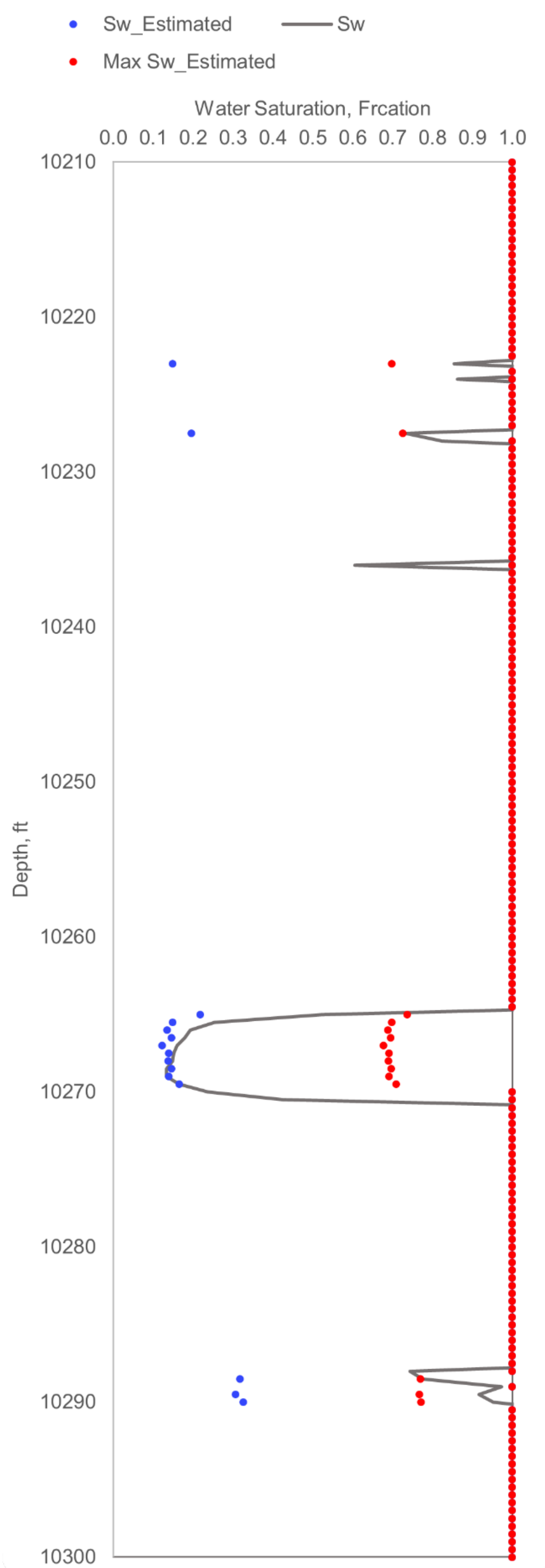

Fig. 24. Well (D) water saturation profile.

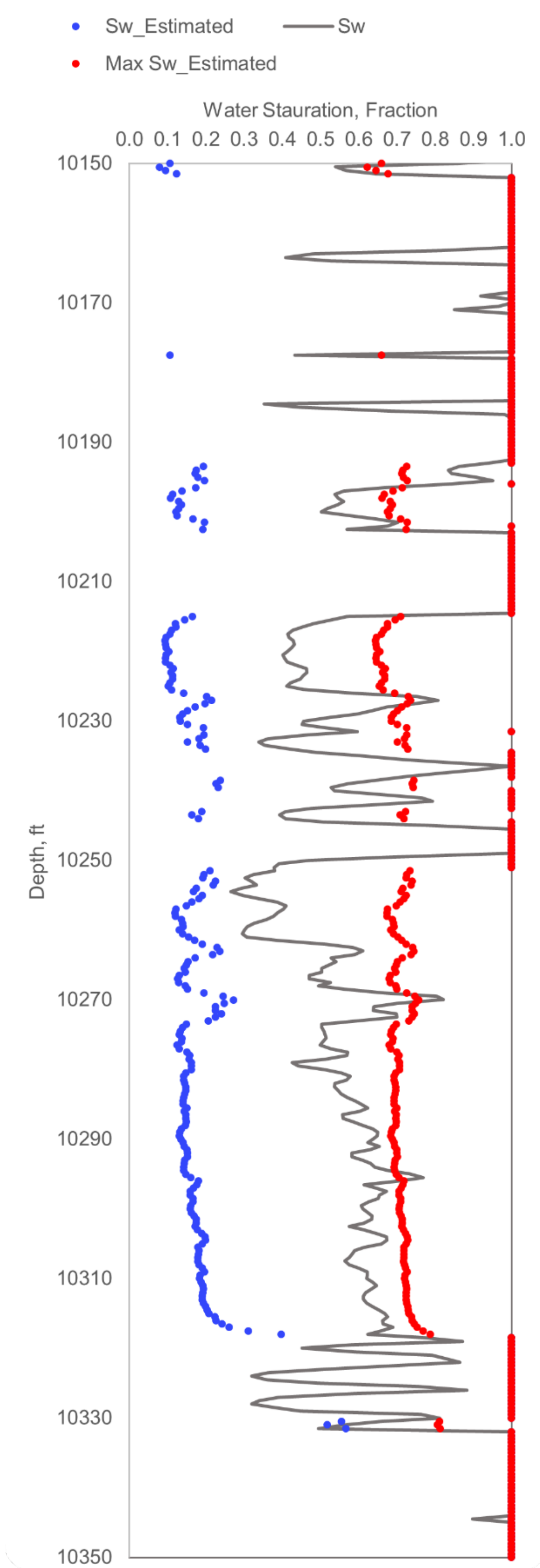

Fig. 25. Well (E) water saturation profile.

For well (A) the estimated initial water saturation shows a very good match to the petrophysical evaluation water saturation and confirms the initial oil water contact. Also, the equivalent residual oil saturation is an average of 0.3 and the initial water saturation is 0.15 therefore the maximum recoverable or movable oil saturation represents 0.55 and if this value is divided by the maximum hydrocarbon saturation of 0.85 which is estimated by (1-Swi), the maximum recovery factor could be calculated and here it is +/-65%. Well (C) shows that the water saturation has increased at the top of the pay interval but didn't reach the maximum water saturation, which means that the pay in this well affected by the production from the previously drilled two wells nine months ago. Well (D) is showing that the reservoir interval was initially water and only 5ft was the net pay. Well (C) which is the latest drilled well in the area shows that due to production from the other wells the oil water contact has been raised by 70 ft. Also, as the average water saturation is 0.45, the maximum oil saturation should be 0.55. The residual oil saturation here is an average of 0.3 which means that the maximum recoverable or movable oil saturation at that time is 0.25 which indicates that the maximum recovery factor from that well at that time is +/-29% and there is water production with oil.

4. Conclusion

The Lower Bahariya sandstone ranges from moderate to extremely heterogeneous reservoir based on the heterogeneity assessment and interpretation of the core porosity and permeability relationship. The FZI method gives reliable and accurate rock types, and it is an adequate method for reservoir quality assessment. SMLP, K/PHIE, and R35 Winland methods should be considered as complementary reservoir quality indicators.

Nine rock types characterize Lower Bahariya reservoir. The first one represents the worst quality which becomes better as FZI increases till reaching the best rock quality that is represented by the ninth rock type. The available recorded logging data in a cored well should be integrated with reservoir rock types and core data analysis. As discussed in this study, the target equation could be established by utilizing the multiple linear regression mathematical method and the determination of the constants in the equation are easily determined by using regression option in Microsoft Excel.

The integration of the logging data and reservoir rock typing is crucial to be utilized in the un-cored wells to predict the rock types all over the reservoir and main reservoir properties. Plotting RQI as function of FZI helps in evaluating the penetrated reservoir quality by each well and the determination of reservoir quality enhancement direction.

The initial water saturation in the Lower Bahariya reservoir is predicted by BVW method. The SSR values reflect the matching accuracy therefore SSR should be estimated to confirm the matching accuracy.By integrating the FZI rock types, the logging data, and SHM using BVW method, the initial water saturation could be predicated in un-cored area.

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