World Academics Journal of Engineering Sciences
Vol.7, Issue.2, pp.32-44, June (2020)

Research Paper

E-ISSN: 2348-635X

Porosity - Permeability Relationship of Libyan Carbonate Reservoir in Defa Oil Field

Saleh Arwini

Department of Petroleum Engineering, Faculty of Engineering, University of Tripoli, Tripoli, Libya

Author's Mail Id: S.Arwini@uot.edu.ly Tel.: +218926839129

Available online at: www.isroset.org

Received: 10/May/2020, Accepted: 19/May/2020, Online: 30/June/2020

Abstract—Proper understanding of permeability and permeability distribution is critical to effective carbonate reservoir description. The relation between porosity and permeability parameters in carbonated rocks is complicated, indistinct and very difficult to characterize because of their tendency to be tight and heterogeneous due to depositional environment and diagenetic processes. In this paper, the aim was to develop a permeability predictive model for one of Libyan carbonate reservoirs (Defa Oil Field) using the principle of Hydraulic Flow Units (HFUs). This relation will enhance the reservoir description since it considers the entire spread of porosity and permeability data if each Hydraulic Unit (HU) can be recognized across the field.
In this study, the available core data from two key wells of Defa oil field were used to develop permeability model based on Hydraulic Flow Unit Method. Histogram analysis, probability analysis and Log-Log plot of Reservoir Quality Index (RQI) versus normalized porosity ($ø_z$) are presented to identify optimal hydraulic flow units. The results have shown that the HU process based on Flow Zone Indicator (FZI) was successfully applied for studied case from Defa carbonate rocks and they worked perfectly to characterize permeability with good correlation coefficient for each HFU ($R^2 \geq 0.9$). Flow Zone Indicator (FZI) is an effective and suitable parameter in correlating rock properties because it is based on pore throat radius and geometry of porous medium that related to petrophysical rock types.

Keywords— Permeaxbilty, Porosity, Hydraulic Flow units, Reservoir Quality Index, Flow Zone Indicator, Libyan carbonate reservoir.

I. INTRODUCTION

Permeability is one of the essential parameters in reservoir calculation, simulation studies of various enhanced oil recovery schemes, and production estimation. It is determined in different approaches for example core analysis, log data, and well test data. In some intervals/wells core is not on hand to be tested, therefore estimation of permeability should be perform based on other types of data [1].

The most obvious control on permeability is porosity. This is because bigger porosities mean that there are many more and broader pathways for fluid flow. Almost invariably, a plot of permeability (on a logarithmic scale) versus porosity for a formation results in a clear trend with a degree of scatter associated with the other influences controlling the permeability. For the best outcomes these Poroperm cross-plots ought to be developed for clearly described lithologies or reservoir zones. If a cross-plot is built for a whole well with widely varying lithologies, the end result is often a disappointing cloud of data in which the individual trends are not apparent. Figure 1 shows a Poroperm cross-plot for a clean sandstone and a carbonate. It is clear from this figure that the permeability of the sandstone is extremely well controlled by the porosity as seen in Figure 1a, whereas the carbonate has a more diffuse cloud indicating that porosity has an influence, but there are other major factors controlling the permeability. In the case of carbonates, there can exist high porosities that do not give rise to high permeabilities because the connectivity of the vugs that make up the pore spaces are poorly connected [2].

Carbonate reservoirs distinguish themselves from sandstone reservoirs in a number of important respects; **(1)** carbonate minerals are more soluble than silicate minerals , and solution and formation of secondary porosity is even more important than in sandstones, **(2)** carbonate rocks, which otherwise have low porosity and permeability often form fracture reservoirs, **(3)** carbonate minerals have essentially different surface properties from silicate minerals, and generally tend to be more oil wetting than sandstones [3].

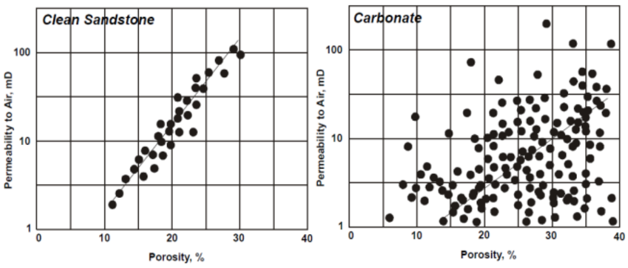

Figure 1. Typical Permeability-porosity relationship for (a) Clean sandstone and (b) Carbonate formations

The complexity of carbonated rock pore spaces always is very problematic (Figure 1 b). Assigning flow-units is one of introduced methods that help to identify permeable reservoir zones and porosity and permeability relationship. The Hydraulic Unit concept has extensively been used in reservoir characterization and management [4, 5]. It relates the geological control properties of a rock for instance cementation between grains, tortuosity, and the structure of the grains to the petrophysical properties for example permeability, porosity, and capillary pressure.

This paper covers the FZI delineation concept from theory to practical application of Hydraulic Flow Units. Porosity - permeability relationship of carbonate reservoir for one Libyan oil Field is derived using Hydraulic Flow Units (HFUs) method.

II. RELATED WORK

Multiple studies have been carried out on this topic and the outcomes show an improved reservoir characterization through classifying reservoir rock into HUs. Hearn *et al*. (1984) introduced the flow unit concept to find the distribution of rock types that most strongly control fluid flow and described a flow unit as a reservoir zone that is continuous both laterally and vertically and has similar permeability, porosity and bedding characteristics [6]. Amaefule *et al*. (1993) developed a novel practical and theoretically based technique which has been introduced to recognize and characterize units with similar pore throat geometrical attributes [4]. The flow unit discriminator parameter presented by Amaefule *et al*. (1993) has theoretical footing from the concept of bundle of capillary tubes considered by Kozeny (1927) and Carmen (1937) [7,8]. Gardner and Albrechtsons (1995) observed a significant improvement in the reservoir description through the refinement of permeability model using HU concept [9]. Svirsky *et al*. (2004) were able to resolve the challenges in Siberian Oil field using the concept of hydraulic flow units (HUs) [10]. Guo *et al*. (2007) showed that hydraulic flow concept proved to be an effective technique for rock-typing in clastic reservoirs in South America [11]. Shenawi *et al*. (2009) developed generalized porosity-permeability transforms depended on hydraulic unit approach with splendid accuracy for carbonate reservoirs in Saudi Arabia [12]. Orodu *et al*. (2009) expressed a satisfactory estimation of permeability from HUs, considering high reservoir heterogeneity, availability of less number of cored wells and poor well log response correlation to permeability [13]. Shahvar *et al*. (2010) noticed an improved prediction of relative permeability by discretizing reservoir rock depended on hydraulic flow units for a carbonate reservoir in Iran [14]. Nooruddin and Hossain (2011) constructed a porosity-permeability model using new parameters with original Kozney-Carman model. They utilized 30,000 data points of an existing Middle East field. The outcomes how an excellent agreement with the data. The results show an excellent agreement with the data [15]. Shujath *et al*. (2013) estimated Hydraulic Unit from predicted permeability and porosity using artificial intelligence techniques. They found that HUs predicted from well logs yielded better accuracy indicating that it is a better to estimate HUs by directly relating them to well logs [16].

Therefore, many efforts had been taken to relate two vital reservoir parameters (porosity and permeability) in hydrocarbon reservoirs but complexity of carbonate reservoirs is still very difficult as seen in Figure 1 b. Geologists and engineers specified the definition of units to shape the description of reservoir zones as storage containers and reservoir conduits for fluid flow.

III. METHODOLOGY

Fundamental Theory of Hydraulic Flow Unit

The Hydraulic Unit concept supposed by Amaefule *et al*., (1993) was selected for subdividing the reservoir into distinct petrophysical types. This combined the Darcy's and Poiseuille's laws for flow in a porous media and tubes and the mean hydraulic unit concept. FZI is applied for flow unit delineation and no distinction shall be made between flow unit and Hydraulic Unit (HU), or hydraulic flow unit. Flow unit and hydraulic unit shall be both employed. Figure 2 illustrates the separation of a formation into hydraulic flow units. Every different reservoir type has a unique FZI value. The FZI is a special parameter that contains the geological attributes of texture and mineralogy in the differentiation of distinct pore geometrical facies (hydraulic units) [4].

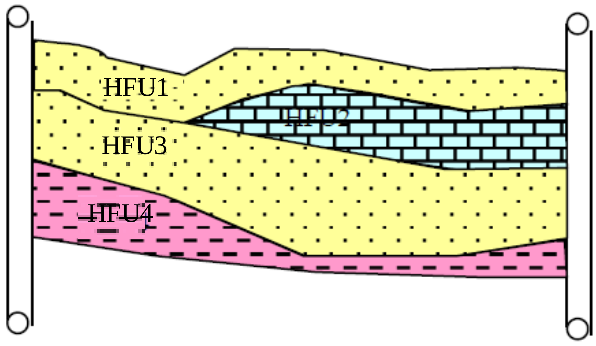

Figure 2. Schematic illustrating the concept of flow units

This technique is based on a modified Kozeny (1927 and Carman (1937) and the concept of mean hydraulic radius:

$$K = \left[\frac{1}{2\tau^2 S_{gv}^2}\right]\left[\frac{\emptyset_e^3}{(1-\emptyset_e)^2}\right]$$

Where:

K = Permeability (mD or μm^2)

τ = Tortuosity (dimensionless)

s_{gv} = Surface area per unit grain volume (μm^{-1})

$\emptyset_e$ = Effective porosity (fraction bulk volume)

S_{gv}: may also be define as the surface area of grains exposed to fluid per unit volume of solid material. Flow zone indicator depends on geological characteristics of the material and various pore geometry of a rock mass; hence, it is a good parameter for determining hydraulic flow units

(HFU). Flow zone indicator is a function of reservoir quality index and void ratio.

Amaefule *et al.* (1993) addressed the variability of Kozeny's constant by dividing the previous equation by the effective porosity, $\emptyset_e$ and taking the logarithm:

$$0.0314\sqrt{\frac{K}{\emptyset_e}} = \left[\frac{\emptyset_e}{(1-\emptyset_e)}\right]\frac{1}{S_{gv}\tau\sqrt{F_s}}$$

Where

F_s = Shape factor (dimensionless)

And constant 0.0314 is the permeability conversion factor from μm^2 to mD. The left-hand side of the equation is referred to as the Reservoir Quality Index (RQI) (µm)

$$RQI = 0.0314\sqrt{\frac{K}{\emptyset_e}}$$

Normalized porosity $\emptyset_z$ (fraction) as:

$$\emptyset_z = \left(\frac{\emptyset_e}{1-\emptyset_e}\right)$$

FZI term designated as the flow zone indicator is given by:

$$FZI = \frac{1}{S_{gv}\tau\sqrt{F_s}} = \frac{RQI}{\emptyset_z}$$

Then the previous equation becomes:

$$RQI = FZI \times \emptyset_z$$

Taking the logarithm of both sides of the equation, then yields:

$$Log\ RQI = Log\ FZI + Log\ \emptyset_z$$

Where

RQI = Reservoir Quality Index (µm)

FZI = Flow Zone Indicator (µm)

$\emptyset_z$ = Normalized porosity, fraction

On a log-log plot of RQI versus φ_z, all samples with similar FZl values will lie on a straight line with unit slope and samples with different FZ1 values will lie on other parallel lines. The value of the FZ1constant can be determined from the intercept of the unit slope straight line at φ_z =1. Samples that lie on the same straight line have similar pore throat attributes and, thereby, constitute hydraulic unit. The permeability of a sample point is then calculated from a pertinent HFU using the mean FZI value and the corresponding sample porosity using the following equation:

$$K = 1014\ FZI^2\left(\frac{\emptyset_e}{(1-\emptyset_e)^2}\right)$$

Field Description

Defa field is situated in the Sirte basin and is located at the western edge of one of the highs, named Zelten arch as seen in Figure 3. Defa field covers a productive area of 25,500 acres; it is a straddling boundary between two concessions, Conc.59W and Conc.71. The field was discovered in October 1959 when the well B1-59W was first drilled. Defa Field development plan began in 1968, by which 49 wells were drilled and put on production. To date, 288 wells drilled in Defa field, of which 275 in the main pool, 6 wells in E. Defa and 7 in the Exploratory S-E Defa. Out of those wells 51 are water injectors, 25 are abandoned and observation wells the remaining 212 wells are capable oil producers [17].

The structure top map of the Defa reef limestone is bounded on the west by a major fault and on the south, east and north by the Lithology changes from porous limestone beds to tight marly limestone's and / or the shale beds of the Hagfa Transitional zone and the Hagfa shale (Figure A-1 in appendix A).

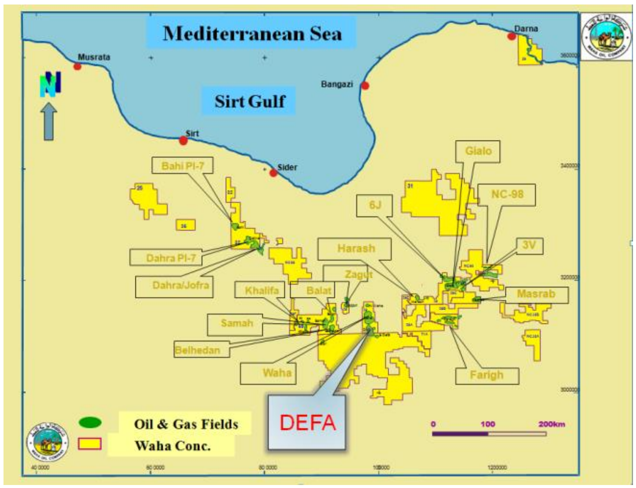

Figure 3. Location of Defa Field

The Lithology composition of the Defa formation is very complex, consisting of a faunal assemblage representing tidal flat lagoonal to reef margin depositional environments. Above, Defa formation lays the carbonate layers and inter-bedded shales of the Beda formation. The Beda formation is subdivided into two units, the Upper Beda and the Lower Beda, which are separated by shale and marly limestone break that can be easily recognized and correlated. Below, Defa formation is the Waha Cretaceous formation, this complex carbonate rocks are water bearing reservoir which had been considered as the supporting aquifer to the Defa oil reservoir. The Waha formation development into oil reservoir is indicated to the east of the main Defa area, and had been called as East Defa Reservoir. A regional West-East cross section has been made to study the lithology, facies changes, and depositional environment at the Defa complex structure [17].

Case Study

Well Q15

The Well drilled in September 1986 and started produced in October 1986 with total depth about 5865 ft. Figure A-2 in appendix A shows a completion diagram of well Q15. It has reservoir pressure 1926 psia, temperature of reservoir 156 deg F, and the test data are flow rate 673.8 STB/day and bottom hole pressure 1187 psig with measured water cut 16% with permeability 35.05 mD, thickness 40ft, oil formation volume factor 1.272 bbl/STB, oil viscosity 0.932 cp, drainage radius 1200ft, wellbore radius 0.354ft. Finally, actual productivity index of well is 0.923 bpd/psi.

Well Q91

The Well drilled in July 1993 and started produced in September 1993 with total depth about 6325ft. Figure A-2 in appendix A shows a completion diagram of well Q91. Well Q91 has reservoir pressure s 1527 psia, temperature of reservoir 156 deg F, and the test data are flow rate 242 STB/day and bottom hole pressure 1322 psig with measured water cut 42%. With permeability 21.23 md, thickness 50ft, oil formation volume factor 1.272 bbl/STB, oil viscosity 0.932 cp, drainage radius 1200ft, wellbore radius 0.291ft. Finally, actual productivity index of well is 1.19 bpd/psi.

IV. RESULTS AND DISCUSSION

Reservoir Heterogeneity

The reservoir heterogeneity is defined as a variation in reservoir properties as a function of space. The main geologic characteristic of all the physical rock properties that have a bearing on reservoir behavior when producing oil and gas is the extreme variability in such properties within the reservoir itself, both laterally and vertically, and within short distances. It is important to recognize that there are no homogeneous reservoirs, only varying degrees of heterogeneity [18]. The degree of reservoir heterogeneity is most importance parameter in reservoir engineering calculations. The Lorenz and Dykstra methods are most common methods to estimate degree of reservoir heterogeneity, because the most of reservoir correlation based on assumption that the reservoir is homogenous so need to identify the heterogeneity. Figure B-1 in Appendix B shows the Dykstra parson probability plot for well Q15. Then applied in the formula:

$$V = \frac{k_{50} - k_{84.1}}{k_{50}} = \frac{19-3}{19} = 0.84$$

Where

k_{50} = Corresponding permeability values at 50% of thickness (mD)

$k_{84.1}$ = Corresponding permeability values at 84.1% of thickness (mD)

The Lorenz coefficient is defined by the following expression as shown in Figure B-2 in Appendix B:

$$L = \frac{\text{Area above the straight line}}{\text{Area below the straight line}} = \frac{\text{Area ABCA}}{\text{Area ADCA}} = \frac{0.39}{0.50} = 0.78$$

Therefore, using Dykstra and the Lorenz methods, the reservoir heterogeneity are 0.84 and 0.78 respectively. It means that the reservoir is extremely heterogeneous as the studied reservoir is a carbonate.

Classical Permeability-Porosity Relationships

Permeability and permeability distribution are usually determined from core data. However, most wells are often not cored. As a result, permeability is estimated in uncored sections/wells from permeability versus porosity relationships that are often developed from statistically insignificant data sets. Conventional method for rock typing is based on simple regression evaluating permeability from log derived porosity. In most cases, a linear relationship between log permeability and porosity is obtained, but in carbonate formation, it does not close to actual case. Therefore, this approach is critical when used to model permeable rocks, as it implies two misleading concepts. First, it considers the relationship between the logarithms of core permeability versus core porosity as linear. Secondly, using log porosities on this plot to predict the permeabilities would imply a scaling agreement between the macroscopic level (core plug) and the megascopic level (log data). Discretizing the reservoir into units such as layers and blocks, and assigning values of all pertinent physical properties to these blocks will give a better agreement with the reservoir heterogeneity.

In this well, Figure (B-3) in Appendix B shows the classic permeability-porosity relationship for studied well using linear model ($k = a + b\emptyset$) and power model ($k = a.e^{b\emptyset}$). As discussed earlier, determining permeability using regression analysis of porosity – permeability gives weak relationships with very low correlation coefficients (R^2 = 0.0125 for linear and R^2 = 0.114 for power model).

Hydraulic Flow Unit (HFU) method

In carbonate reservoirs, the data is more scattered and recognizing the straight lines and the boundaries of flow units through these scattered data and is more difficult. To determine the exact boundary of each hydraulic flow unit, three different ways were applied and compared the results that was obtained.

1-Histogram Analysis

Since FZI distribution is a superposition of multiple log-normal distributions, a histogram of log FZI should show *n* number of normal distributions for n number of HFU's. When the data of flow zone indicator in the form of histogram is plotted, normal distribution will be obtained which represent n hydraulic flow units. Based on histogram analysis, four HFU were distinguished to represent entire reservoir as shown in Figure B-4 in Appendix B. The influence of diagenesis has modified the original depositional parameters to give these multiple hydraulic units. It is often difficult to separate the overlapped individual distribution from histogram plot.

2-Probability Plot

The probability plot is the integral of probability density function (pdf) or histogram. This plot is more useful to determine HFUs because it is smoother than the histogram. As a result, the scatter in the data is reduced and consequently the identification of clusters becomes easier. The number of straight lines in the probability plot is an indication of HFU in the reservoir. Figure B-5 in Appendix B shows a probability plot of the logarithm of FZI for Well Q15. A total of 4 HFU were distinguished for the reservoir in question. However, divide reservoir into more hydraulic unis that could increase accuracy of predicting permeability for uncored wells.

3-Log- log plot of RQI versus ϕ_z

The log- log plot of RQI versus ϕ_z will produce a number of parallel straight lines with a unit slope for each one. Samples that lie on the same straight line have the same pore throat attributes and thereby constitute a hydraulic unit. The mean value of FZI for each HFU can be distinguished from the intercept of the unit slope straight line with ϕ_z =1. In this case, the highest porosity and permeability corresponds to hydraulic unit number one (HU1), and the lowest porosity and permeability corresponds to hydraulic number four (HU4).

Figure B-6 in Appendix B shows the plot of RQI versus ϕ_z in logarithmic scale, four HFUs were identified which means there are four rock types exist in the studied reservoir. HFU1 with FZI mean equals 4, HFU2 with FZI mean equals 1.6, HFU3 with FZI mean equals 0.6 and HFU4 with FZI mean equals 0.3. The high FZI values indicate high permeability values. These intercept values (**FZI mean**) are used to calculated permeability from the following equation.

$$k = 1014\,(FZI_{mean})^2\left(\frac{\phi_e^3}{(1-\phi_e)^2}\right)$$

Permeability in uncored wells

A variety of geostatistical estimation techniques has been developed in an attempt to describe accurately the spatial distribution of rock properties. The traditional approach at predicting HU at uncored wells that have well-logs relies on the Bayesian method. The Bayesian method is applied to predict HU category from well-log based on established HU from cored wells. It involves inferring the probable HU of a well at a particular depth using well-log responses based on the HU probability database of discretized well-log responses [5]. Other methods are Artificial Neural Network (ANN) [19, 20] and the recent classification tree concept [21]. After calculating FZI in uncored well using equations derived from well log data, permeability can be determined for each HFU (mean FZI value).

The mean FZI value was used to predict permeability from core porosity for a given HU. A plot of predicted permeability with hydraulic unitization and measured permeability with 45 deg. line is shown in Figure 4. Good correlation coefficient (R^2 = 0.95) was obtained between permeability calculated based on HFU and permeability of cores.

It is clear that using four HU's in this reservoir decreases the scatter of the data around the HU's lines and gives an improved relationship. The relationship between permeability and porosity for each HU are shown in in Figure 5 and Figure 6. Table 1 summarized correlation coefficients R^2 and best relation between predicted permeability with hydraulic unitization versus core permeability.

A result of calculated permeability versus core permeability with depth is depicted in Figure C-2 (a) in Appendix C. It is observed in this figure a good matching between actual permeability and calculated permeability. Appendix C show the result summary of Well Q91.

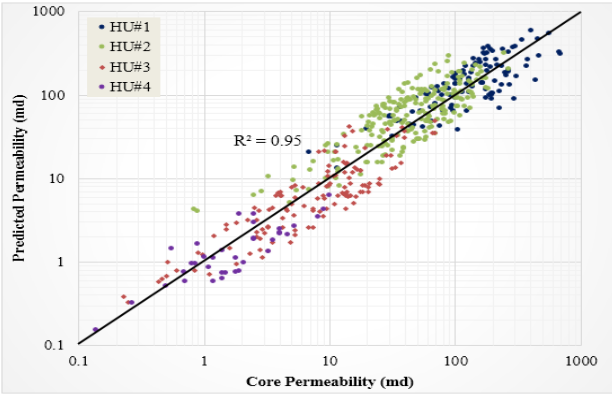

Figure 4. Predicted Permeability with hydraulic unitization versus core permeability (Well Q15)

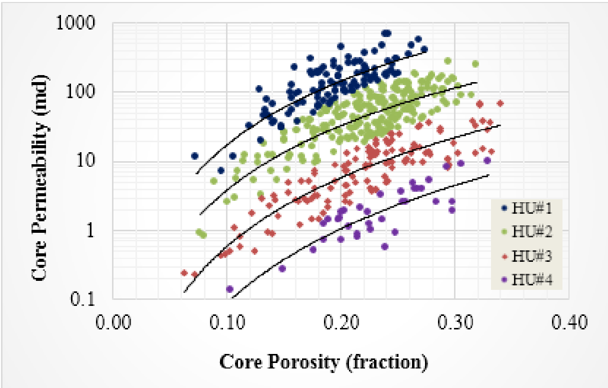

Figure 5. Crossplot of core permeability versus core porosity for different hydraulic units (Well Q15)

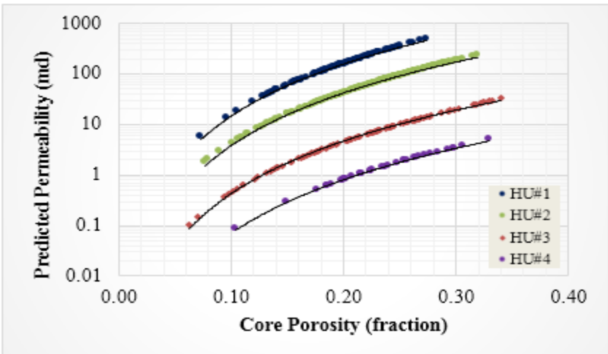

Figure 6. Predicted Permeability with hydraulic unitization versus core permeability (Well Q15)

Table 1. Reservoir rock classification by HFU method (Well Q15)

Layer	Correlation coefficient (R^2)	Relation between k and ø
HFU1	0.9994	$K=38590\,\phi^{3.4209}$
HFU2	0.9991	$K=11208\,\phi^{3.4705}$
HFU3	0.9986	$K=1247.6\,\phi^{3.4662}$
HFU4	0.9988	$K=238.72\,\phi^{3.5354}$

V. CONCLUSION AND FUTURE SCOPE

Based on this study, the following conclusions were obtained:

1. Defa oil field is a very complex carbonate reservoir and the reservoir is extremely heterogeneous
2. The classical Permeability-Porosity Relationship is not capable of predicting the permeability of this carbonate reservoir where porosity alone is not enough to explain the permeability variations. However, there are other major factors controlling the permeability.
3. For studied well, four hydraulic flow units were obtained for well Q15 with high correlation coefficient (R^2 > 97%) and five HUs for well Q91 with R^2 > 92. These HFUs represent the different rock types in the studied formation.
4. The hydraulic unit process has been successfully applied for Defa carbonate rocks. Therefore, Flow Zone. Indicator (FZI) is an effective and suitable parameter in correlating rock properties because it based on pore throat radius and geometry of porous medium that related to petrophysical rock types.

REFERENCES

[1] D. Tiab, “Advances in Petrophysics,” Lecture Notes Manual, Vol. **1**-Flow Units, University of Oklahoma, **USA**, **2000**.

[2] P. Glover, “Petrophysics Permeability,” Petrophysics MSc Course Notes, University of Aberdeen, **UK**, **2014**.

[3] D. Tiab, and E.C. Donaldson, “Petrophysics: Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties,” 2nd edition, *Elsevier*, New York, **USA**, **2004**.

[4] J.O. Amafule, M. Altunbay, D. Tiab, D.G. Kersey, and DR. Keelan, “Enhanced reservoir description: Using core and log data to identify hydraulic (flow) units and predict permeability in uncored intervals/wells,” *Proceedings of the 68th SPE Annual Technical Conference and Exhibition*, *Society of Petroleum Engineers*, Houston, Texas, **USA**, pp.**205-220**, **3-9** Ocober **1993**.

[5] M. Abbaszadeh, H. Fujii and F. Fujimoto, “Permeability prediction by hydraulic flow units- theory and applications,” *SPE Formation Evaluation*, Vol.**11**, pp.**263-271**, **1996**.

[6] C.L. Hearn, W.J. Ebanks, R.S. Tye and V. Ranganathan, “ Geological factors influencing reservoir performance of the hartzog draw field Wyoming,” *Journal of Petroleum Technology*, Vol.**36**, pp.**1335-1344**, **1984**.

[7] J. Kozeny, "Ueber kapillare Leitung des Wassers im Boden," *Sitzungsber Akad. Wiss*., Wien, Vol.**136,** Issue.**2a**, pp.**271-306**, **1927**.

[8] P.C. Carmen, “Fluid F1ow through Granular Beds,” *Trans. AIChE* , Vol.**15**, pp.**150-166**, **1937**.

[9] R. I. Gardner, and E.A. Albrechtsons, “Hydraulic zonation and permeability modelling of the Hibernia formation using an integrated mathematical, petrophysical and geological approach,” *The Petroleum Society of CIM, 46th Annual Technical Meeting of the Petroleum Society of CIM*, Alberta, **Canada**, 14-17 May **1995**.

[10] D. Svirsky, A. Ryazanov, and M. Pankov, “Hydraulic Flow Units resolve reservoir description challenges in a Siberial oil field,” *SPE Asia Pacific Conference on Integrated Modeling for Asset Management*, SPE 87056, Kuala Lumpur, **Malaysia**, 29-30 March **2004**.

[11] G. Guo, M.A. Diaz, F. Paz, J. Smalley, and E.A. Waninger, “Rock typing as an effective tool for permeability and water-saturation modeling: A case study in a classic reservoir in the Oriente basin,” SPE 97033, *SPE Annual Technical Conference and Exhibition*, Dallas, **USA**, **9-12** October **2007**.

[12] S. Shenawi, H. Al-Mohammadi, M. Faqehy, “ Development of generalized porosity-permeability transforms by hydraulic units for carbonate oil reservoirs in Saudi Arabia,” SPE 125380, *SPE/EAGE Reservoir Characterization and Simulation Conference*, Abu Dhabi, **UAE**, pp.**19-21**, October **2009**.

[13] O.D. Orodu, Z. Tang, and Q. Fei, “Hydraulic (Flow) Unit Determination and Permeability Prediction: A Case Study of Block Shen-95,” Liaohe Oilfield, North-East China, *Journal of Applied Science* Vol.**9**, Issue.**10**, pp.**1801-1816**, **2009**.

[14] M.B. Shahvar, R. Kharrat, M.M. Sharif, "Applying Flow Zone Index Approach and Artificial Neural Networks Modeling Technique for Characterizing a Heterogeneous Carbonate Reservoir Using Dynamic Data: Case Study of an Iranian Reservoir". *Presented at the Trinidad and Tobago Energy Resources Conference*, Port of Spain, **Trinidad**, **27-30** June **2010**.

[15] H.A. Nooruddin, and M.E. Hossain, “Modified Kozeny-Carmen Correlation for Enhanced Hydraulic Flow Unit Characterization,” *Journal of Petroleum Science and Engineering*. Vol.**80**, pp.**107-115**, **2014**.

[16] S. A. Shujath, M. E. Hossain, M. R. Hassan, and A. Abdulraheem, “Hydraulic Unit estimation from predicted permeability and porosity using artificial intelligence techniques,” SPE North Africa Technical Conference & Exhibition held in Cairo, **Egypt**, **15 - 17** April **2013**.

[17] Anonymous, “Defa Oil Field Report,” Planning Department, Waha Oil Company, Tripoli, **Libya**, **2013**.

[18] T. Ahmed, “Reservoir Engineering Handbook,” *TX: Gulf Publishing*, Houston, **USA**, **2000**.

[19] K. B. Aminian, S. Thonuls, Ameri and Bilgesu, “New approach for reservoir characterization,” *Society of Petroleum Engineers*, pp.**117-126**, **23-25** October **2002**.

[20] K. S. Aminian, A. Ameri, B. Oyerokun and Thomas, “Prediction of flow units and permeability using artificial neural network,” *Society of Petroleum Engineers*, pp.**297-303**, **19-24** May **2003**.

[21] H. H. Perez, A. Datta-Gupta and S. Mishra, “The Role of Electrofacies, Lithofacies, and Hydraulic Flow Units in Permeability Predictions from Well Logs: A Comparative Analysis Using Classification Trees,” *SPE Reservoir Evaluation & Engineering Journal*, pp.**143–155**, April **2005**.

AUTHOR PROFILE

Saleh Arwini is currently working as Assistant Professor in Petroleum Engineering at University of Tripoli, Libya. He received his Ph.D. degree in Petroleum Engineering from Institute of Petroleum Engineering, Heriot Watt University, Edinburgh, UK and MSc degree in Field and Well Management with Distinction from The Robert Gordon University, UK. He also relieved MSc degree in Information Technology from Heriot Watt University, UK. His main research work focuses on Petrophysics, PVT Modelling, Reservoir Engineering, and Simulation and Production Engineering. He has 20 years of teaching experience.

Appendix A: Structure Top Map and Completion diagram of well 15.

A-1. Defa Structure Top Map.

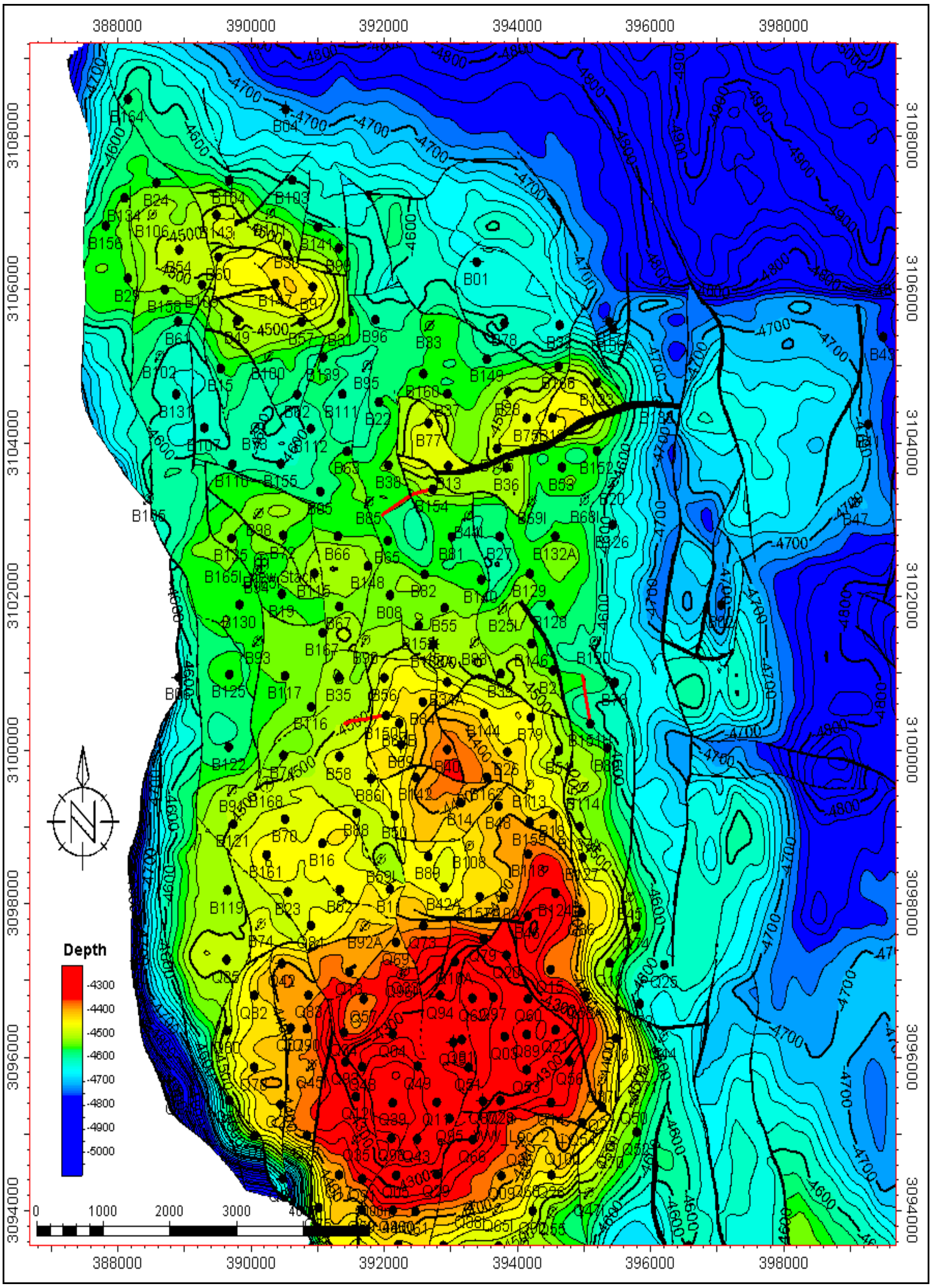

Figure A-1. Defa Structure Top Map

A-2. Completion diagram of well Q15 and well Q91.

Well (Q15) Well (Q91)

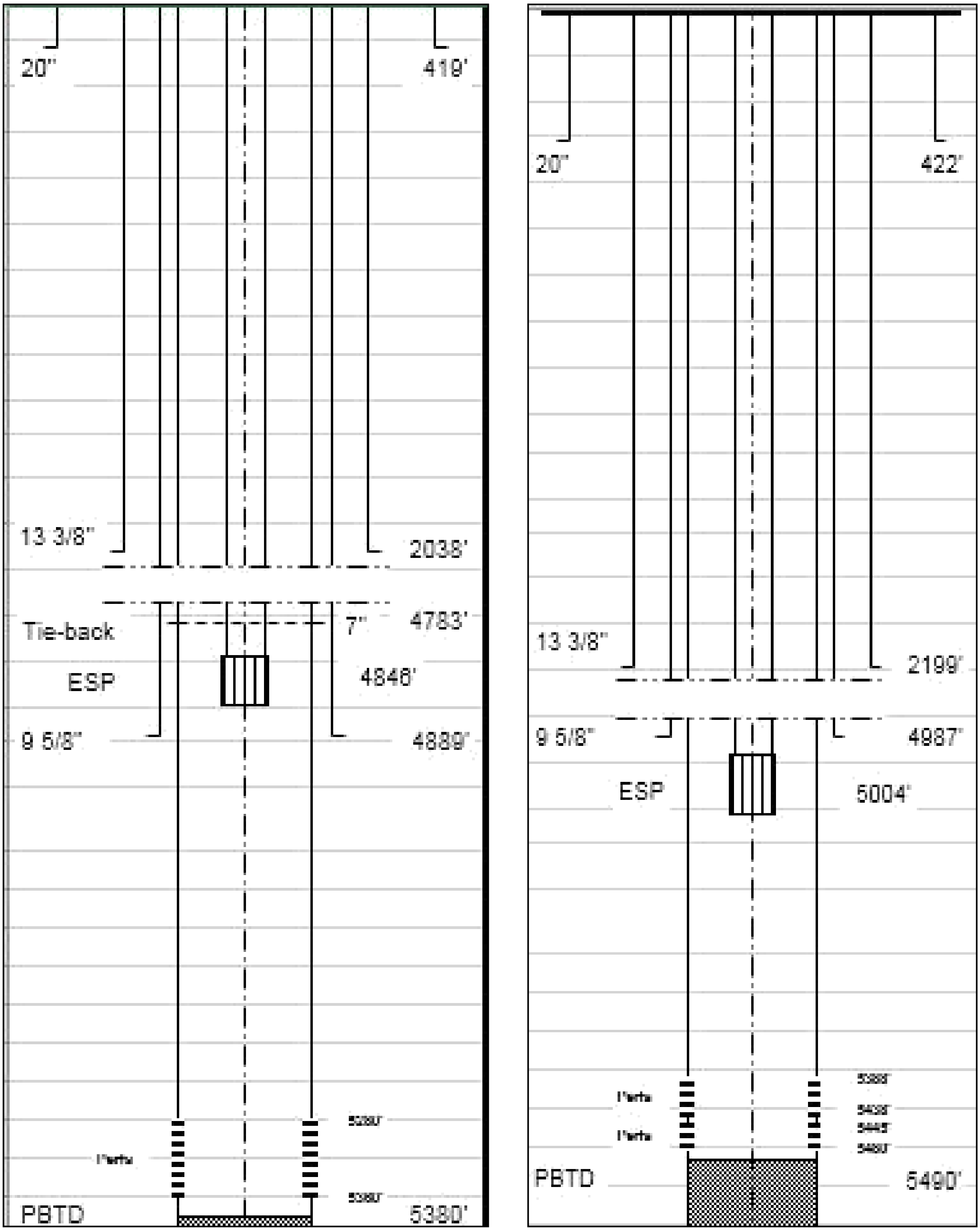

Figure A-1. Well Completion of well (Q15) and (Q91)

Appendix B: Summary of well Q15 results.

B-1. Dykstra parson probability plot.

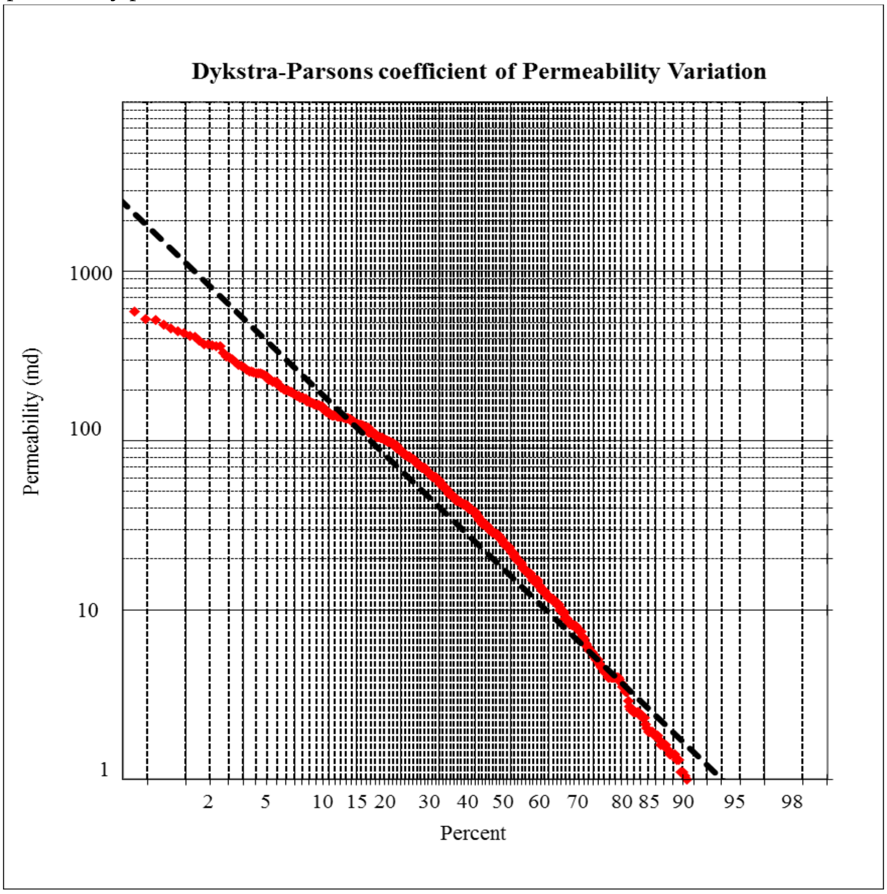

Figure B-1. Dykstra parson probability plot. (Well Q15)

B-2. Lorenz method - Normalized flow capacity.

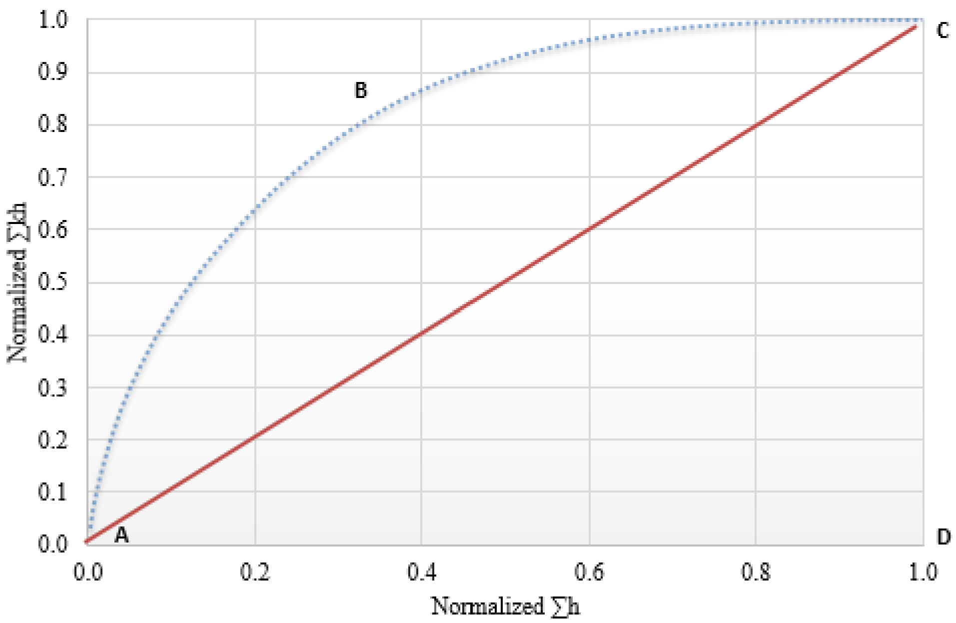

Figure B-2. Normalized flow capacity.

B-3. Regression Analysis.

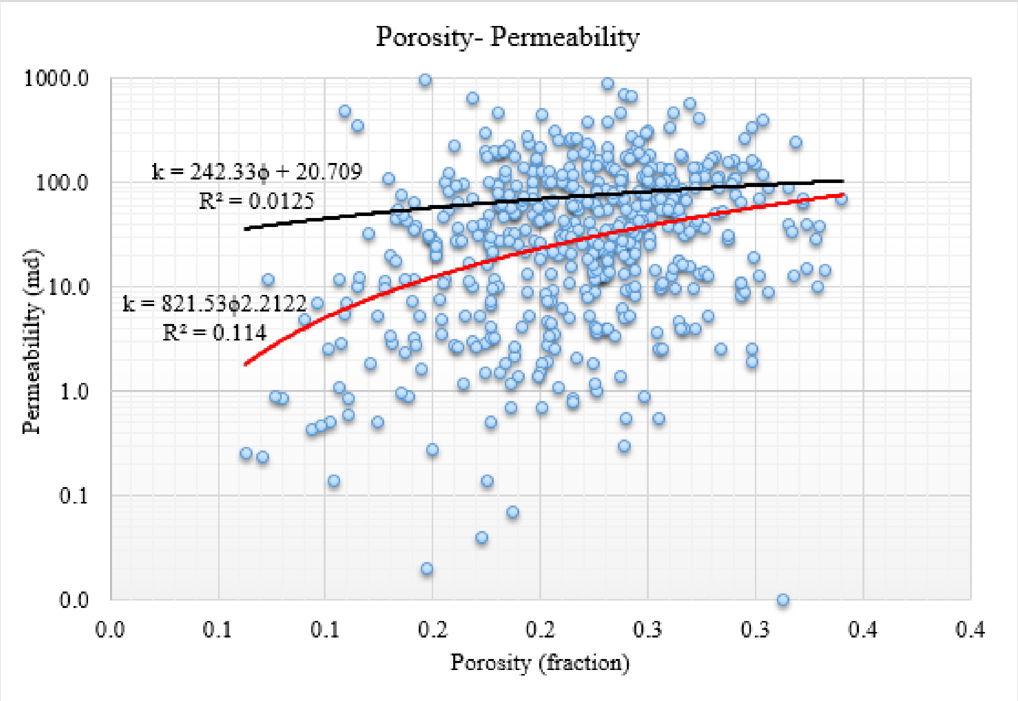

Figure B-3. Regression analysis using Linear and Power model (well Q15).

B-4. Histogram of the logarithm of FZI.

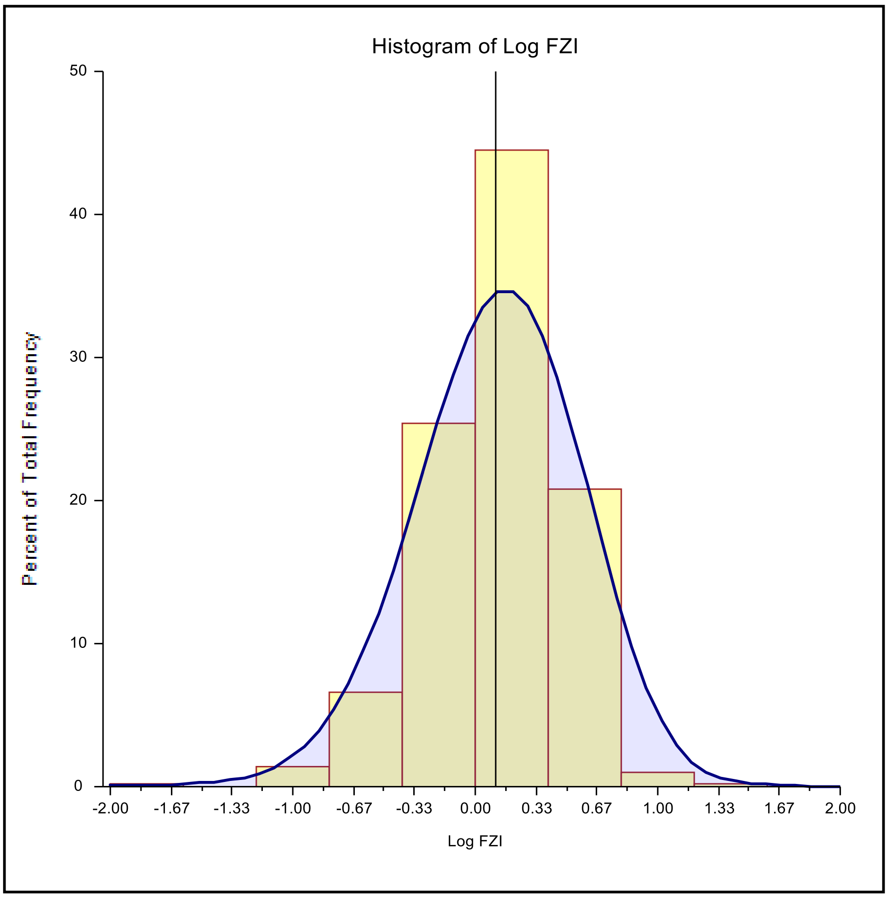

Figure B-4. Histogram of the logarithm of FZI for Well Q15.

B-5. Probability plot of logarithm of FZI for Well Q15.

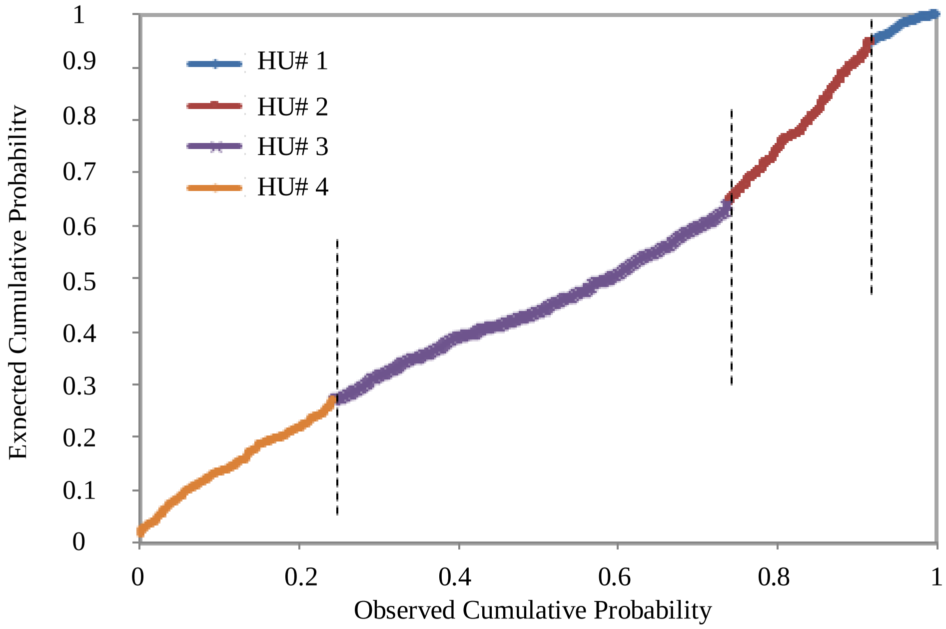

Figure B-5. Probability plot of logarithm of FZI for Well Q15.

B-6. Determination of FZI mean Well Q15.

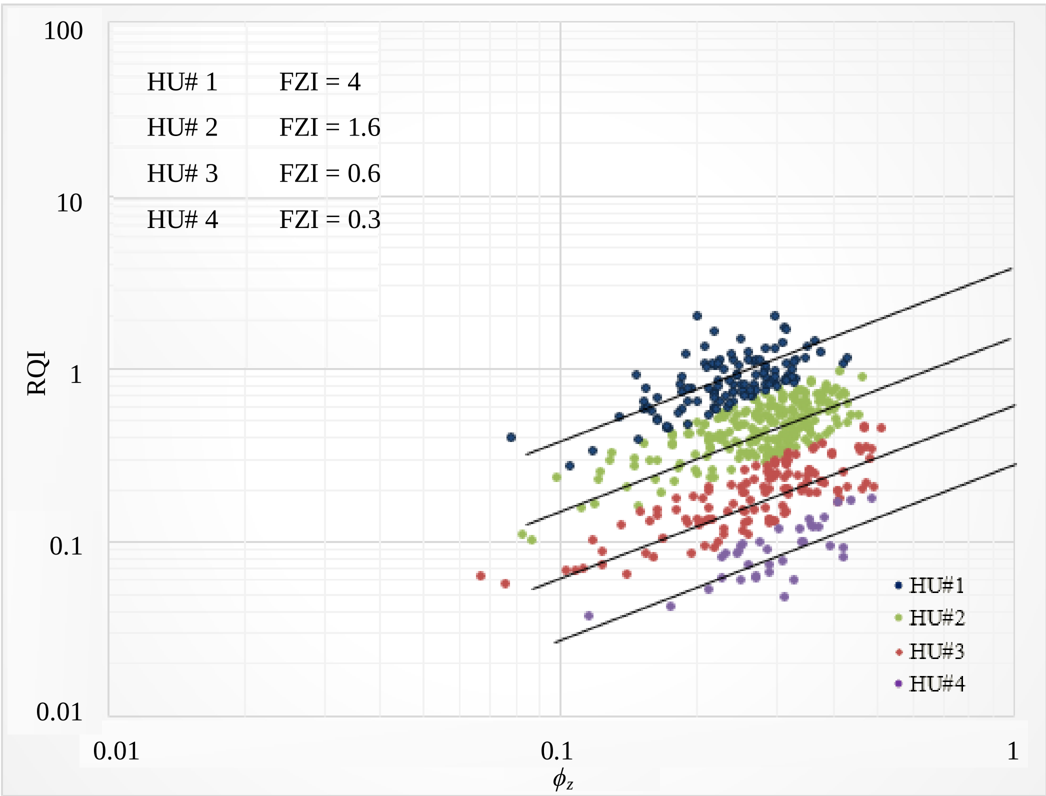

Figure B-6. Determination of FZI mean Well Q15.

Appendix C: Summary of well Q91 results.

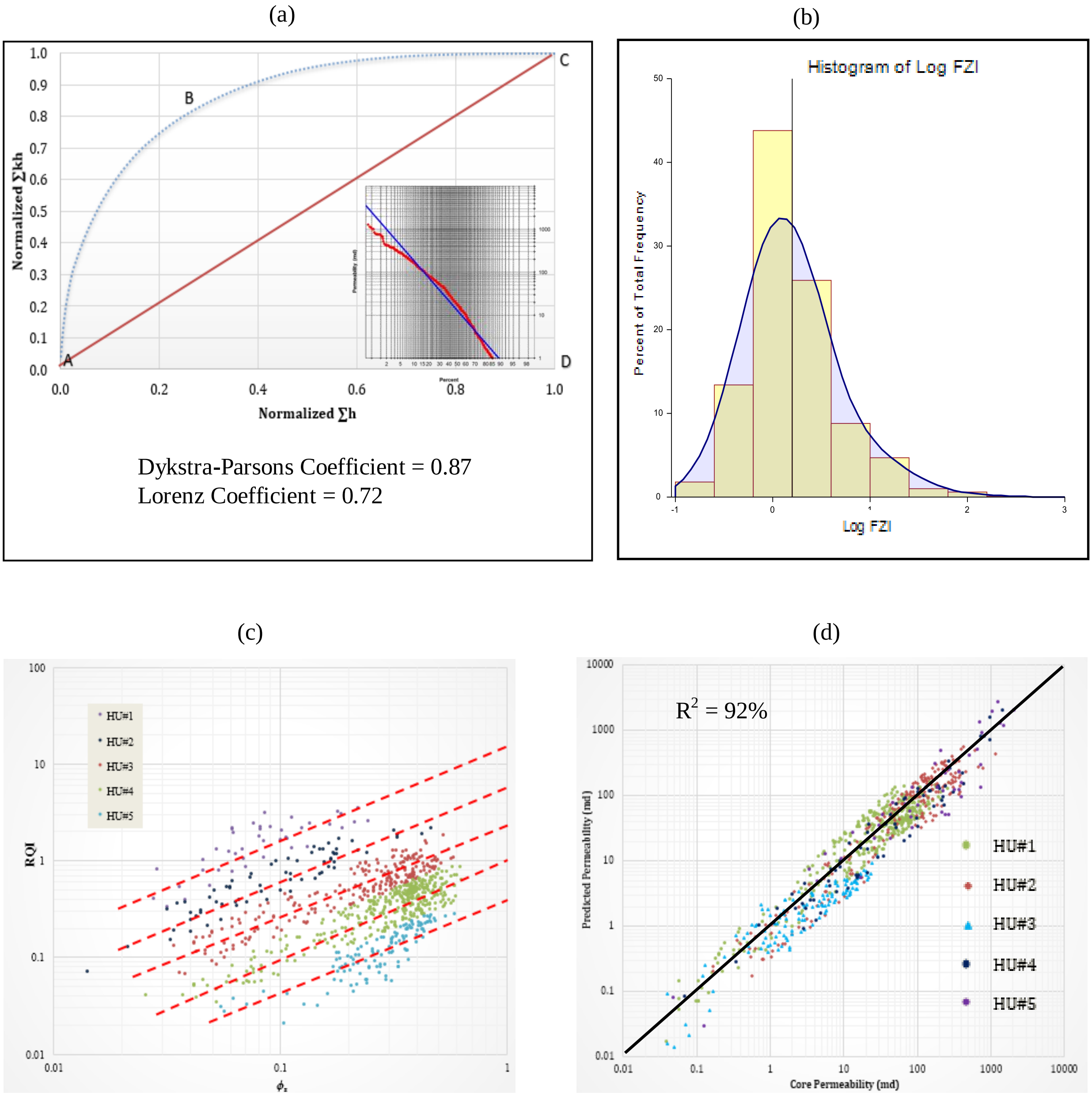

Figure C-1. A summary of well Q91 results. (a) Hetroginety analysis. (b) Hestogram plot (c) Determination of FZI mean (d) Predicted Permeability with hydraulic unitization versus core permeability

Table C-1. Reservoir rock classification by HFU method for well Q91

Layer	Correlation coefficient (R^2)	Relation between k and ø
HFU1	0.9995	$k = 375835\ \o^{3.1209}$
HFU2	0.9991	$k = 60475\ \o^{3.2143}$
HFU3	0.9990	$k = 12832\ \o^{3.3396}$
HFU4	0.9983	$k = 3255.9\ \o^{3.3981}$
HFU5	0.9983	$k = 297.53\ \o^{3.4293}$

C-2. Actual versus calculated permeability with depth for well Q15 and Q91.

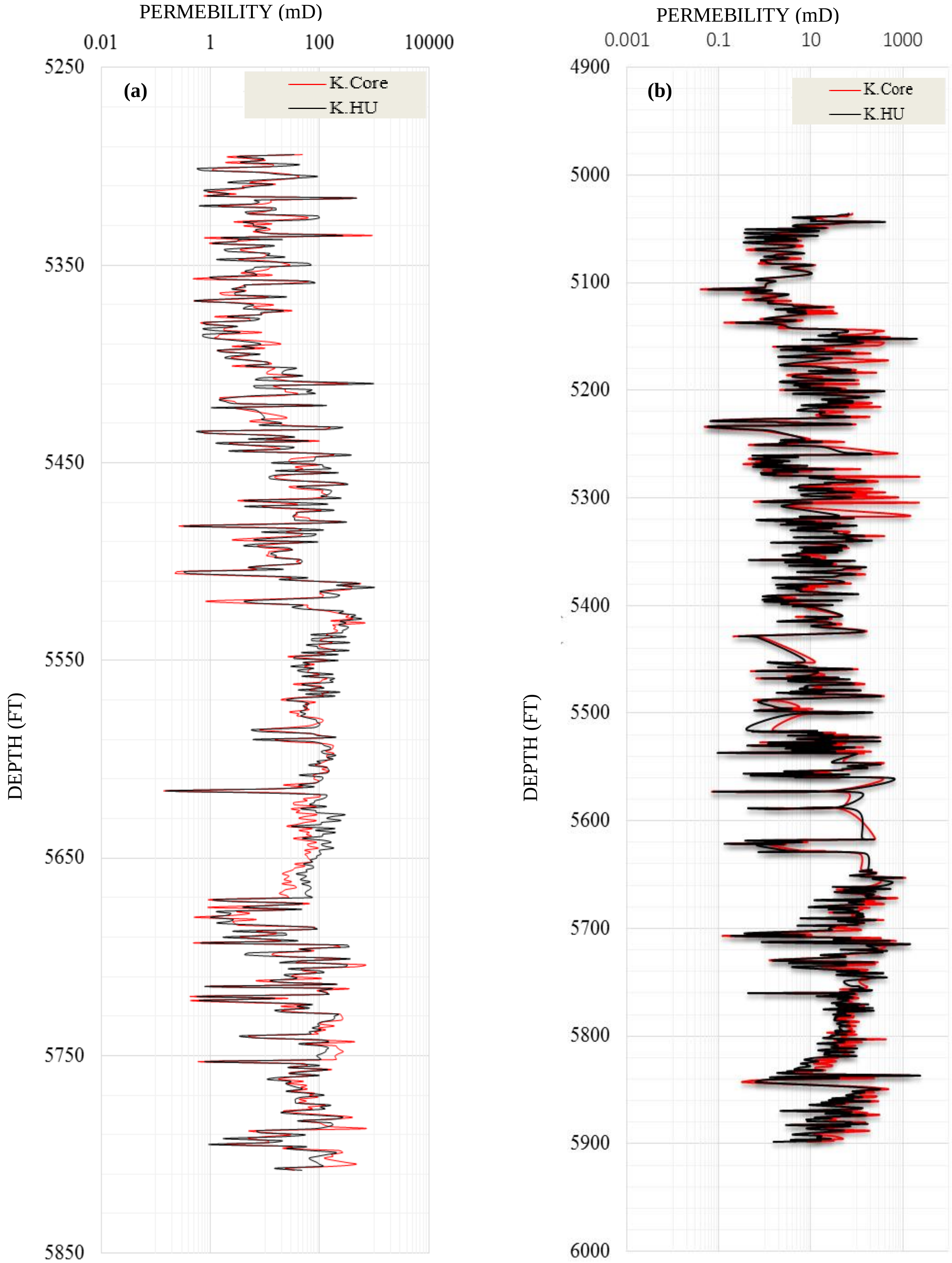

Figure C-2. Actual versus calculated permeability with depth for well (a). Well Q15 and (b). Well Q91.