Fine-tuned Permeability Estimation in Un-cored Wells Using Flow Zone Indicator Model

Shirley Onyinye Odunze-Akasiugwu and Collins Akasiugwu

Abstract— It is essential to characterize and model reservoirs units into effective storage containers as well as conduits for fluid flow. For an efficient dynamic reservoir model that can honor the actual history matching of a field, a reliable permeability estimates for the field is required as an input. This input should also respect the facies architecture of the reservoir since log and core measurements often capture a 2 dimensional area of the reservoir. Traditionally, regressions from porosity and permeability plots are often used as most clastic reservoir bear somewhat relation between the two properties. However, this does not capture the flow property within a stratigraphic framework. In this study, flow zones were delineated within various lithofacies unit using core data averages as input. Using resistivity, gamma ray and density logs, a multi-layer perception neural network computation was done to predict an accurate flow zone index (FZI) values in un-cored sections of the reservoir as well, with a view to obtaining permeability estimates that conform to the lithofacies association. A good match between the core permeability and FZI permeability suggests the method has clear benefits and can be a reliable input for flow simulation and history matching.

Keywords— un-cored, flow zones, pore, lithofacies, model, overlay, permeability.

1 Introduction

Clastic reservoirs are heterogenous by virtue of variation of its intrinsic properties like porosity, permeability as well as the net to gross of the reservoir. These variations in property adversely impact on its characterization if all these variations are not properly accounted for.

For a fit-for-purpose reservoir characterization and modeling with regards to its dynamic behavior, intrinsic properties such as pore geometry, pore size distributions and grain mineralogy need to be properly accounted for in permeability estimations. Since this property controls to a large extent the dynamic behavior of reservoir fluid, it is imperative to obtain an accurate estimate. Most permeability estimates from log data do not consider the reservoir at a pore-throat scale, because their measurements are obtained at a macro-scale. To accurately predict the permeability of reservoirs, a more expensive and time consuming cored data are needed; with its characteristic limited reservoir zonal coverage. Log-based estimates of permeability in sandstone reservoirs are either overestimated or underestimated with lots of scatter point in the porosity-permeability cross plots suggesting typical reservoir heterogeneity (Fig. 1). For an enhanced permeability estimates with better zonal coverage within the entire reservoir section, the measured rock properties in the macro scale will have to be calibratibrated to the pore-scale.

This is done while factoring in the effects of pore size distributions and mineralogy of the formation hosting the reservoir. With this, an improved productivity and accurate history match can be obtained for the reservoir.

This study showcases a clear example where core interpreted genetic facies were used in delineating corresponding hydraulic units (flow units) with a view to understanding fluid flow variations within the distinctive pore geometry of different lithofacies units. This improved approach of permeability estimation called Flow Zone Indicator Model was found wanting in earlier permeability models, as most of them relied mostly on the partial relationship of permeability with porosity and irreducible water saturation with little or no input from the geology of the reservoir.

2.2 Previous Models

Earlier studies in permeability prediction from cores relied exclusively on the presumed logarithmic distribution of permeability within a rock fabric, thereby permitting the use of cross-plot of logarithmic permeability versus porosity. These techniques cannot reliably estimate accurate permeability from porosity. The inadequacies of this approach have been noted by several authors [8, 5, and 4]. A more acceptable porosity/permeability relationship based on rock type was proposed which reflect the existence of different hydraulic units in a given rock type [8, 5].
Others estimated permeability in an un-cored reservoir by presuming this non-causal direct relationship with porosity and an inverse relationship with irreducible water saturation. Some of these models are highlighted below.

2.1 Wyllie and Rose Model

This model was obtained by investigating the effect of irreducible water saturation and porosity on absolute permeability, and an empirical correlation was obtained [12]

- *Shirley Odunze-Akasiugwu is currently a Senior Lecturer in Department of Geology, Chukwuemeka Odumegwu Ojukwu University, Anambra State, Nigeria. E-mail: so.odunze-akasiugwu@coou.edu.ng*
- *Collins Akasiugwu is currently working in National Petroleum Services, Dammam, Saudi Arabia. E-mail: colaka2@yahoo.com*

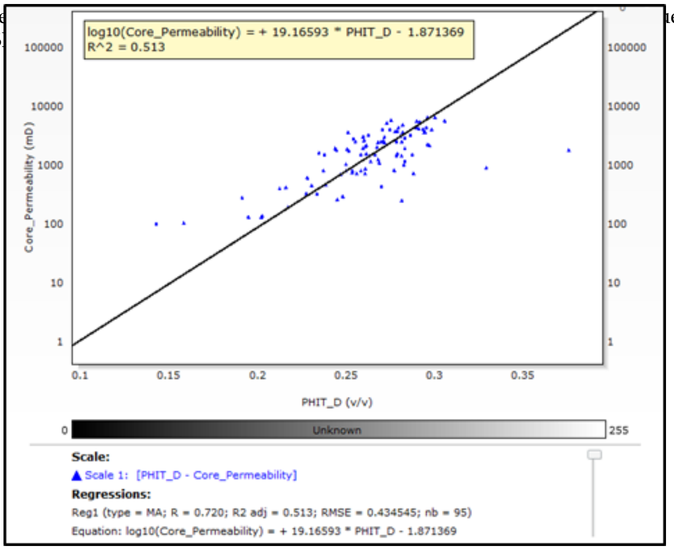

Fig. 1. Core permeability versus porosity cross-plot

$$k = \left(awr^{\emptyset^3} / S_{wi} \right)^2 \qquad [1.0]$$

awr is a constant that varies with hydrocarbon density (For a medium gravity oil=250 and for dry gas 79)
k is in mD
φ and S_{wi} are fractions.

This model was also derived by Timur

$$k = 0.136\, \emptyset^{4.4} / S_{wi}^2 \qquad [2.0]$$

k and S_{wi} are expressed in percentages and are independent of the type of hydrocarbon present on the porous medium [9]

This model does not account for variations of irreducible water saturation in a highly heterogeneous reservoir. It relies mostly on constant irreducible water saturation value obtained from the topmost part of the reservoir where hydrocarbon saturation is maximum. Permeability values from this model are often under-estimated. This model also renders permeability as a sole function of porosity since the irreducible water saturation is a constant within the entire reservoir column [10].

2.2 Kozeny-Carman Model

This model expressed permeability as a function of porosity and a given surface area [6]

$$k = \left(1 / F_S\, \tau S_{V_{gr}}^2 \right) \emptyset^3 / (1 - \emptyset)^2 \qquad [3.0]$$

F_S expresses the pore throat factor, τ is the tortuosity coefficient while $S_{V_{gr}}$ is the specific surface area per unit grain volume. In most porous reservoir, the expression $F_S\ \tau$ may be approximated to 5 [3].

This porosity permeability relationship is largely based on the assumption that the porous rock is represented by bundles of capillary tubes. Even when the expression for tortuosity is introduced to account for the complex network of the pore network, the ability to derive such expression in a log data is very complicated and nearly impossible. This makes the Kozeny-Carman model difficult to apply in highly heterogeneous reservoir such as Niger Delta that is mostly characterized by intra-reservoir shales.

2.3 The Flow Zone Indicator Model

In a bid to modify Kozeny-Carman Model away from its complexities, Reference [1] developed a technique for identifying reservoirs with similar flow attribute. This is based on the microscopic measurements of rock core samples by factoring in the effects of pore throat minerology and texture.

This technique is based on the concept of mean hydraulic radius. The general form of the equation is:

$$k = \left(1 / K_T\, s_{V_{gr}}^2 \right) \left(\emptyset_e^3 / (1 - \emptyset_e)^2 \right) \qquad [4.0]$$

Where k = permeability in μm2
$\emptyset_e$ = effective porosity
$s_{V_{gr}}$ = specific surface area per unit grain volume
K_T = effective zoning factor

Dividing both sides of Eq. [4.0] by porosity and taking the square root of both sides yields:

$$\sqrt{k / \emptyset_e} = 1 / S_{V_{gr}} \sqrt{K_T} \left(\emptyset_e / 1 - \emptyset_e \right) \qquad [5.0]$$

If permeability is expressed in millidarcies and porosity as a fraction, the left-hand side of
Eq. [5.0] becomes:

$$RQI = 0.0314 \sqrt{k / \emptyset_e} \qquad [6.0]$$

From Equation [5.0] the expression

$\left(1 / S_{V_{gr}} \sqrt{K_T} \right)$ is FZI (Flow Zone Index), while

$\left(\emptyset_e / 1 - \emptyset_e \right)$ is $\emptyset_z$ (Pore volume to grain volume ratio)
Then, Eq. [5.0] gets simplified to:

$$k = 1014\, (FZI^2) \emptyset_z \qquad [7.0]$$

Taking the logarithm of both sides of Eq. [7.0] gives rise to

$$logk = \log(\emptyset_z) + \log[1014(FZI^2)] \qquad [8.0]$$

This equation 8.0 forms the bases for subdividing reservoirs

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into distinct flow units, thereby acknowledging the geologic controls of mineralogy and texture of pore network in a reservoir. Extrapolation from the equation has it that depositional environments and diagenetic processes control the FZI valves in a reservoir and thus its permeability. Poor reservoir quality rocks with greater percentage of authigenic clays are characterized by low FZI values while excellent quality reservoir rocks depict higher FZI values [11].

3. Analysis of Data

3.1 Lithofacies Architecture and Analysis

Identification and interpretation of genetically related lithofacies was carried out using information from the cored section of the well. This is to understand geologic controls on flow zones and permeability. Although there may be overlaps between the flow units and genetic units, however, facies were interpreted to recognize the effect of reservoir heterogeneity to its permeability which is directly related to FZI.

The core report recognized a total of seven major facies associations (Fig. 2). The depositional environment is interpreted to be characterized by basal coarsening upward profile into fining upward profiles. The described sand from base to top according to figure 2 show a succession from wave/storm shoreline deposit, cut into by tidal inlet which passes upward into tidal delta and overlain by transgressive deposit. Based on the recognized sedimentation, the reservoir sand can be interpreted to represent a transgressive estuarine deposit. From the forgoing, it can be deduced that this nature of deposition results in lithofacies variations within a unit. This change in lithology as well as the sedimentary structures will greatly influence reservoir property and the eventual capacity of fluid flow. For instance, superimposing the facies association with effective porosity from density log shows a marked variation in effective porosity mostly along the shaly heteroliths of the transgressive sands, lower shoreface and obviously within the heterolithic-silty sand section of the estuarine channel sands in figure 2.

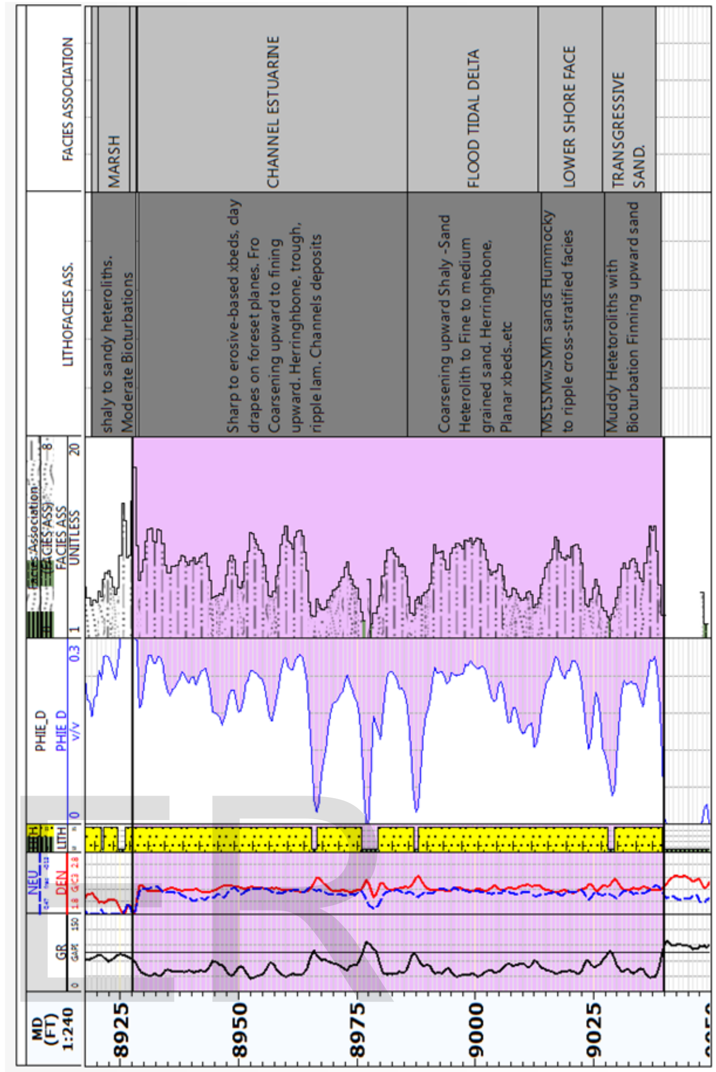

Fig. 2. Facies association distribution within the cored section of the reservoir

3.2 Flow Zone Identification

Applying the techniques of plotting Rock Quality Index (RQI) versus Pore volume to grain volume ratio (ϕ_z), a total of five flow zones were obtained (Fig. 3). This was also validated with the plot of RQI versus Free fluid Index (SHPOR) in figure 4. The identified flow units are found to be in agreement with the interpreted genetic unit from lithofacies analysis. The excellent reservoir sands in the channel deposits recorded the highest FZI values of 14 from the plot, whereas the lowest FZI values around 4 are observed at the uppermost part of the transgressive sand facies and the marsh environment which are characterized by poor reservoir properties. This suggests that the FZI are texturally and mineralogically controlled as depicted in the figures 3 and 4. A A test of normality of the FZI computed through the various plots using a histogram shows a mean value of 10 in figure 5.

The obtained FZI values for the major facies associations are in agreement with the extensive work on FZI values of genetic lithofacies done in Niger delta by reference [10] where transgressive estuarine channel sand was interpreted to have a minimum FZI value of 11.

Having obtained FZI values for the cored section of the well, it is very imperative to extrapolate FZI values for the un-cored section in order to obtain representative values for permeability estimates. So a regression-based relation between cored FZI and more representative log response was sought using the technique postulated by [2]. Gamma ray (GR), resistivity (RT) and density logs (DEN) were used not only because they bear varying levels of connection with reservoir properties characterized in permeable zones, they are also present in all the wells in the study area.

Equation 9.0 summarized the relationship between the various logs and FZI.

$$FZI = A_0 GR^{A1} DEN^{A2} RT^{A3} \qquad [9.0]$$

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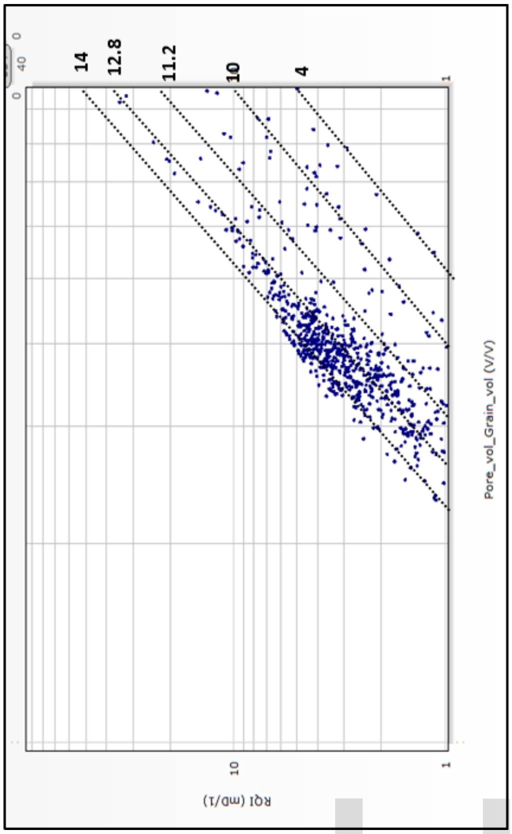

Fig. 3. Rock quality versus pore volume to grain volume plot

Sets of fairly consistent log in terms of quality were correlated with FZI by cross plotting them and generating relationships with cored FZI (Figures 6, 7 and 8). A multi-layer Perception Neural Network (PNN) computation was done using the various logs (GR, DEN and RT) as input to train and realize an accurate estimated FZI value in the un-cored sections of the wellbore. Utilizing the FZI estimates from neural network, a more representative permeability estimates with better well control were computed using the proposed technique by [1]. An excellent relationship between the cored permeability and the permeability from FZI in Figure 9 with strength of regression close to unity suggests that the technique can effectively be used to predict permeability values in other wells lacking core data.
An overlay of the computed FZI permeability with the cored permeability in Figure 10 shows an excellent match when compared to those of Wyllie Rose model evaluated from the same field.

3.3 Error Analysis on FZI derived Permeability

Using the core permeability as a control, an uncertainty analysis on the various evaluated permeability were done. Error analysis on the permeability results are summarized in Table 1. Permeability estimates from the permeability-porosity regression witnessed close to 36% deviation from the core permeability as against the evaluated FZI permeability with 3% deviation. This in effect increases the confident level of the FZI permeability making it suitable for dynamic modeling.

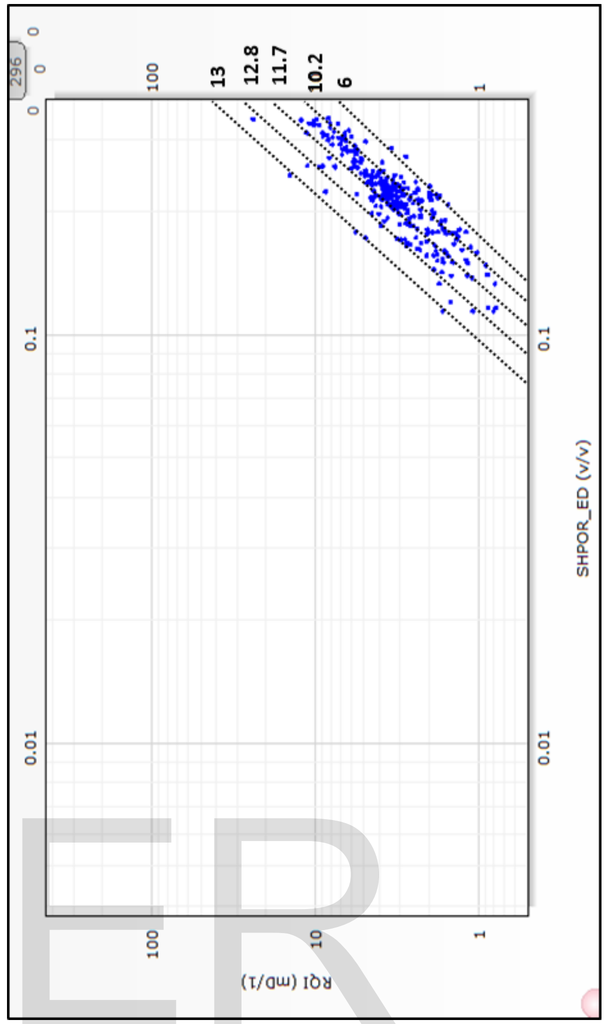

Fig. 4. Rock quality versus free fluid index (SHPOR) plot

4.0 Conclusion

This method enables the evaluation and characterization of reservoir flow property within distinct genetic units that are controlled by similar pore throat geometrical attributes. This cost-effective technique of permeability prediction in un-cored reservoirs is both precise and unambiguous.
Using a case study in Coastal Swamp Depo-belt of Niger Delta, this technique was successfully applied and its results are quite impressive. The obtained hydraulic units from FZI plots can serve as geologic inputs in reservoir layering during dynamic (flow) simulations.

As further FZI related well data are acquired in the reservoirs, refinements to the relationships between FZI and log response can be done in other to predict permeability with more degree of accuracy. This is essential to efficient petrophysical model and field development planning.

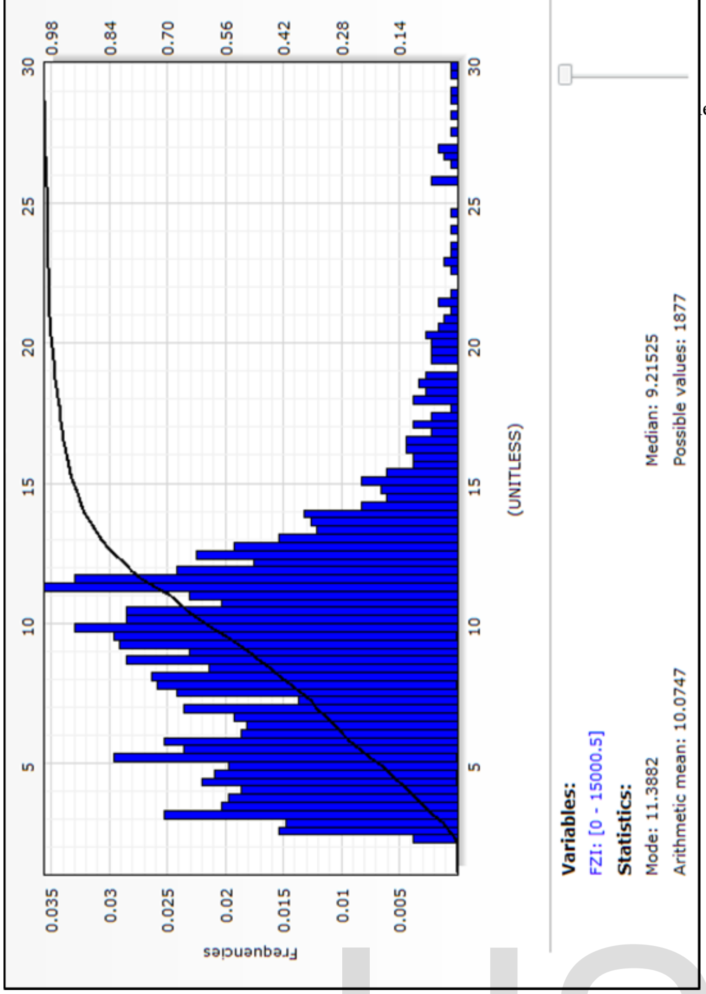

Fig. 5. Histogram distribution of FZI values

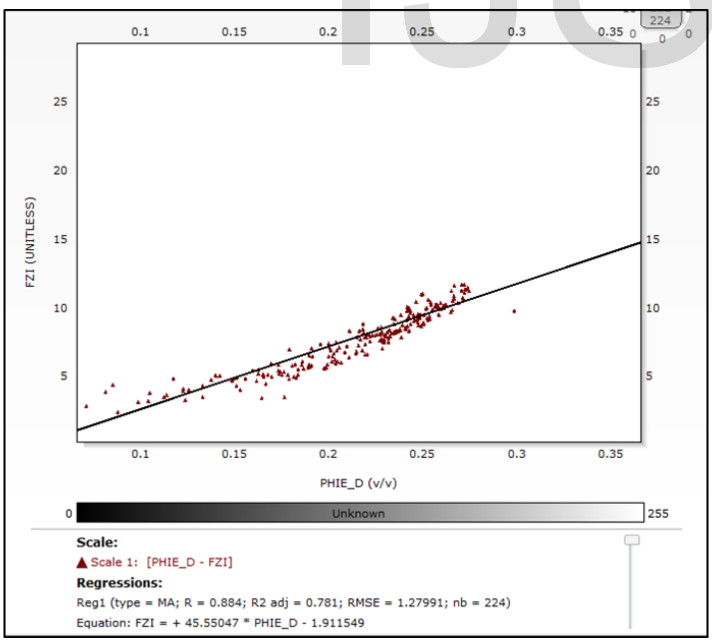

Fig. 6. FZI vs Effective Porosity cross plot

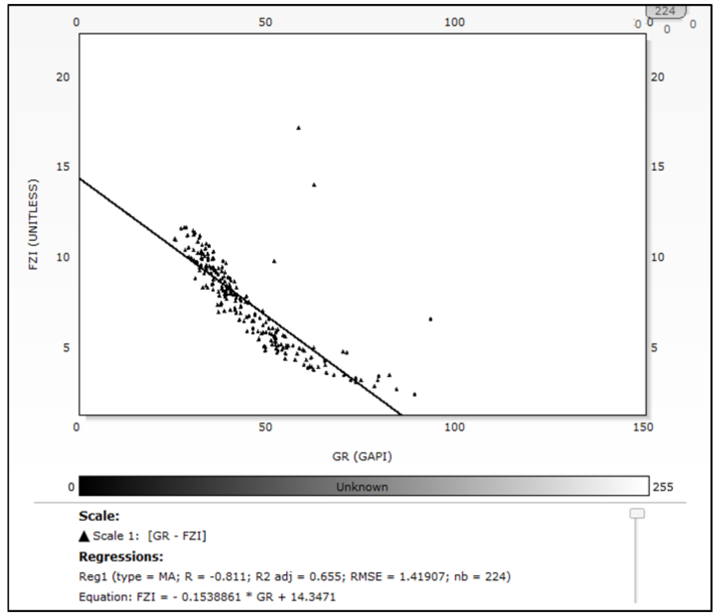

Fig. 7. FZI vs Gamma ray cross plot

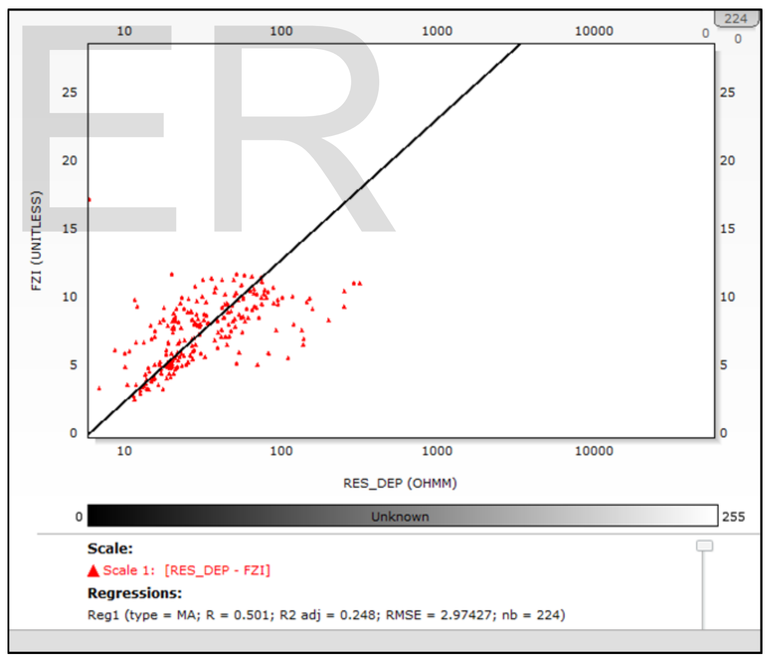

Fig. 8. FZI vs Resistivity cross plot

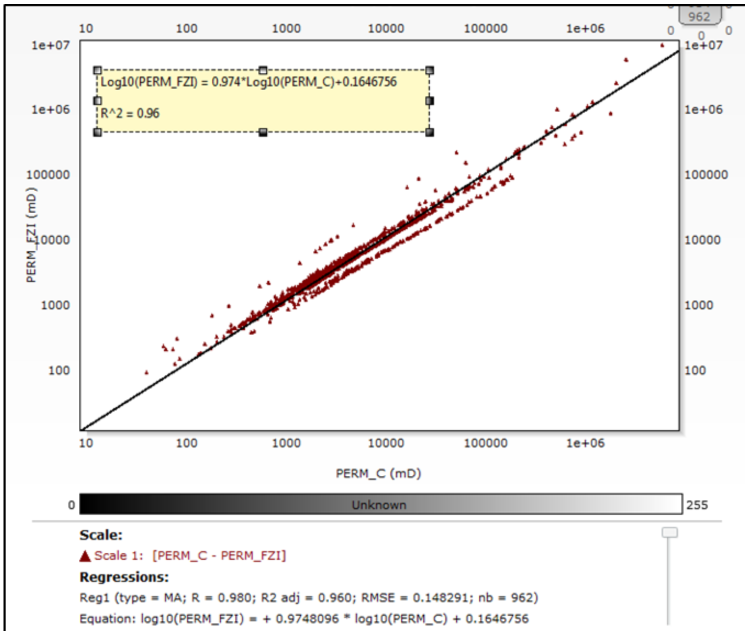

Fig. 9. FZI Permeability vs Core Permeability cross plot.

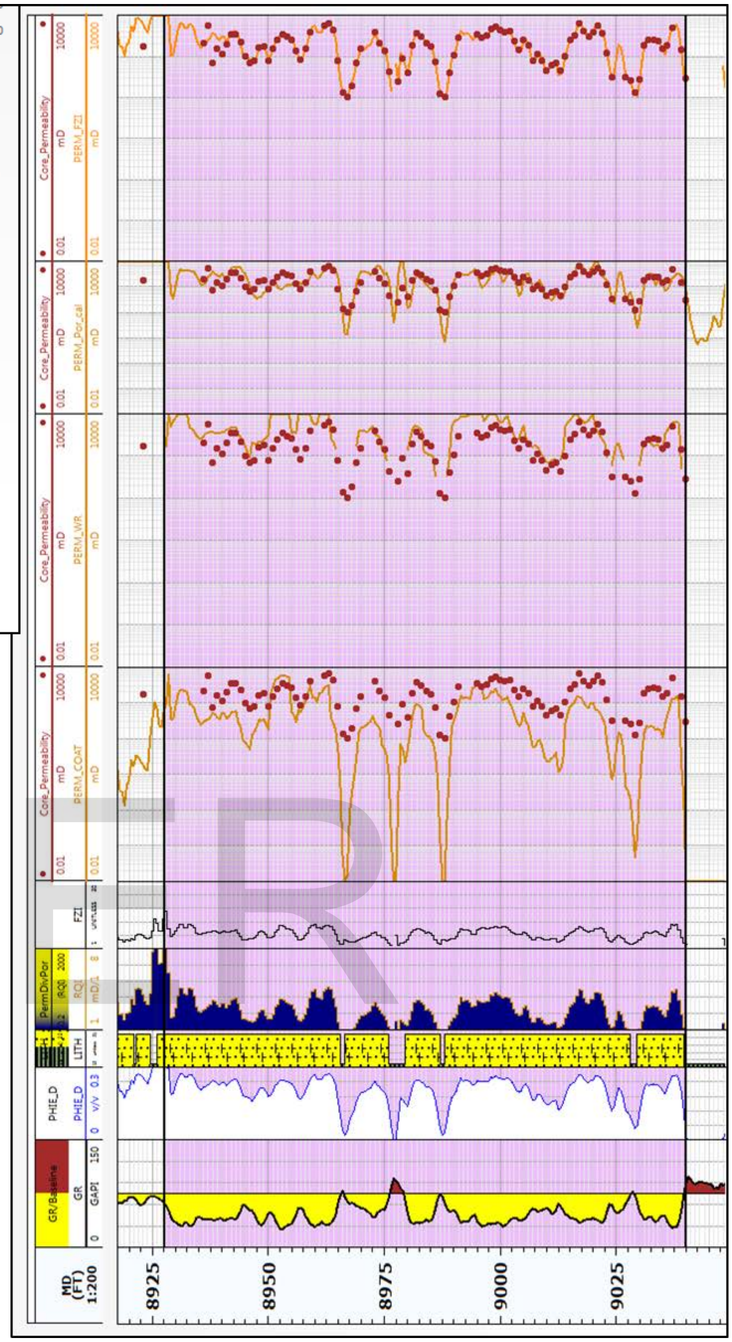

Fig. 10. An overlay of the various computed Permeability profiles

Table 1. Error analysis table for the various permeability estimates

MD	K_CORE	K_WR	PERM_COATES	K_?_CAL	K_FZI	K_WR % ERROR	K_COATES % ERROR	K_?_CAL % ERROR	K_FZI % ERROR
8935	2060	2565.34	239.42	1162.28	2300.00	19.70	88.38	43.58	11.65
8937	5660	3791.97	393.06	2885.66	5413.00	49.26	93.06	49.02	4.36
8943	3550	4846.57	573.94	5631.70	4217.98	26.75	83.83	58.64	18.82
8957	1500	11849.16	1113.00	1131.60	1458.37	87.34	25.80	24.56	2.78
8958	2398	14767.66	1766.19	1690.17	2219.10	83.76	26.35	29.52	7.46
8959	4000	16190.54	2945.17	2329.81	3814.43	75.29	26.37	41.75	4.64
8960	3700	6165.82	1374.59	3872.73	4010.00	39.99	62.85	4.67	8.38
8982	3700	5090.98	887.62	2809.51	3643.26	27.32	76.01	24.07	1.53
8984	2100	1170.91	121.29	1293.52	1974.84	79.35	94.22	38.40	5.96
8985	1720	1051.30	99.22	843.18	1731.15	63.61	94.23	50.98	0.65
8990	1078	6369.35	325.04	1783.04	1095.41	83.08	69.85	65.40	1.62
8991	2900	7427.62	946.46	3387.98	2908.05	60.96	67.36	16.83	0.28
8998	4689	11137.65	2046.07	3211.50	4582.73	57.90	56.36	31.51	2.27
8999	5400	11590.21	2434.39	4926.74	5365.94	53.41	54.92	8.76	0.63
9000	4300	6290.35	1447.78	2885.66	4332.06	31.64	66.33	32.89	0.75
9001	3970	7803.56	1273.20	1932.00	3956.31	49.13	67.93	51.33	0.34
9002	4210	5579.96	958.91	4546.86	4192.96	24.55	77.22	8.00	0.40
9016	3240	9491.74	1024.84	3872.73	3256.10	65.87	68.37	19.53	0.50
9017	6334	8046.83	1431.57	7164.38	6186.19	21.29	77.40	13.11	2.33
9019	3034	7068.02	715.73	3044.23	2992.48	57.07	76.41	0.34	1.37
9020	3920	9287.97	1000.13	6611.97	3968.83	57.79	74.49	68.67	1.25
9021	5600	3707.80	614.18	9114.24	5615.19	51.03	89.03	62.75	0.27
9036	1840	4081.43	462.96	799.26	1841.24	54.92	74.84	56.56	0.07
9037	5200	6019.24	1270.90	2150.17	5104.67	13.610	75.559	58.651	1.833 2
						51.4	69.5	35.8	3.3

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