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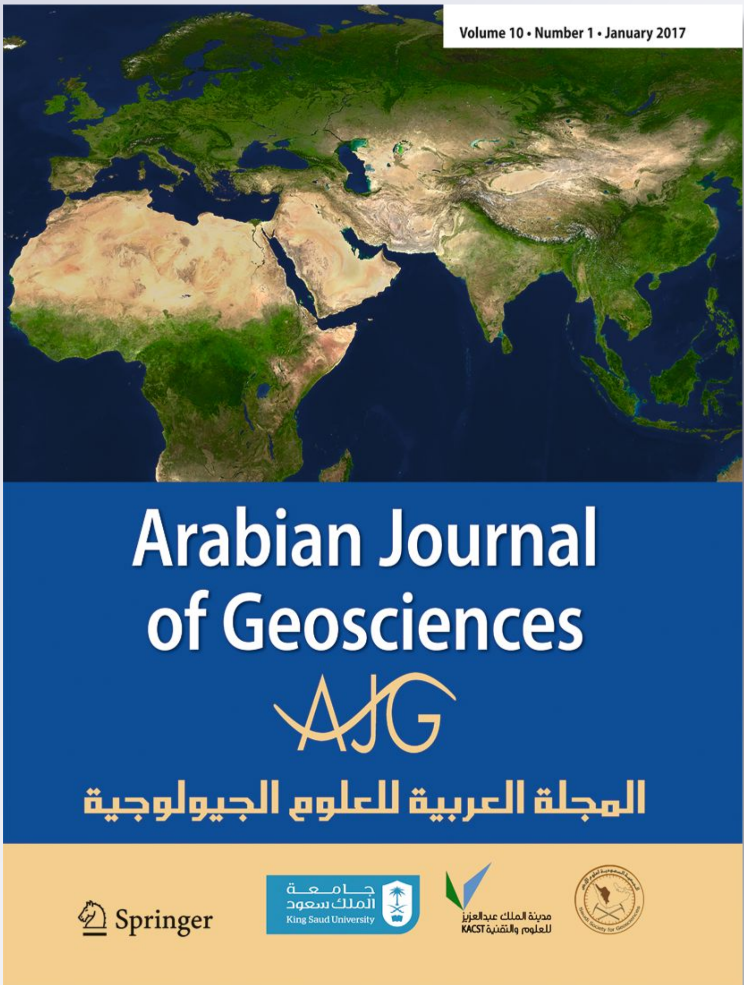

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ORIGINAL PAPER

Continuous permeability predictions in heterogeneous reservoirs using Vshale and microstructure calibrated free-fluid models (a combined study of a Niger Delta field and the tight gas sandstone of the southern North Sea)

S. A. Ojo[1] · V. C. Ozebo[1] · O. I. Olusola[1] · O. B. Olatinsu[1]

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Abstract
The well-established free-fluid model from NMR technique provides continuous permeability values that closely match with core permeabilities better than most theoretical models especially when it is core calibrated for field specific use. However, only few wells have NMR logs in a field while marginal fields may not have any due to economic reasons. This study explored means of achieving one of the overriding objectives of most marginal field operators, which is to reduce the overall cost of production to the attainable minimum. The free-fluid model was modified into two simple and cost-effective models in order to optimize its applicability to predict permeability in the absence of NMR data. The two new models, which were developed for the single and double porosity systems analyzed in this study, consist of calibration parameters that can be empirically determined to account for variation in reservoir quality based on the rock type profile per field. A non-matrix parameter, α, was introduced into the model derived for tight gas sandstone being regarded as a double-porosity formation. This inclusion represents the permeability contribution of natural fractures or any crack-like pores to the different flow units. By using the alternative version to the known free-fluid model, continuous permeability curves that match experimental results were predicted without NMR logs.

Keywords Permeability · Models · Vshale · Microstructure · Niger Delta · Tight gas sandstone

Introduction

A commonly used model in predicting permeability from NMR, especially in hydrocarbon-bearing reservoirs, is the free-fluid model (FFM) by Coates et al. (1991), which is expressed as follows:

$$K = \left[\left(\frac{\varphi}{C}\right)^2 \frac{FFI}{BVI}\right]^2 \quad (1)$$

The constant C known as the Coates constant is a regional or formation-based variable. BVI and FFI stand for bulk volume irreducible water and free-fluid index, respectively. The ratio of FFI to BVI can be determined from bench-top NMR data. Normalized NMR signals and the corresponding T_2 relaxation time values can be processed into frequency distribution curve while a T_2 cut-off is applied to divide pore spaces into ratio FFI/BVI such that their sum is equal to unity. At lower values than the T_2 cut-off, fluids are considered immobile (BVI), either held by capillary forces in small pores or hydrostatically bound in the clay (McPhee et al. 2015), while at higher values than the T_2 cut-off, fluids are considered mobile (FFI), i.e., can flow out of the pore spaces when needed. This model normally has to be calibrated with NMR T_2 relaxation time and core porosity-permeability data for a successful use in a local formation of interest (Coates et al. 1999). However, most marginally operated fields hardly have NMR logs, which often make it impossible to use the FFM in continuous permeability estimation for such fields. Moreover, some fields that have NMR data may not have adequate quantities that will satisfactorily represent all the facies or rock types present in the field, in that way precludes the possibility of calibrating the model over zones with variable rock types or

✉ S. A. Ojo
ojoakinjidesamuel@gmail.com

[1] Department of Physics (Geophysics Unit), University of Lagos, Lagos, Nigeria

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Table 1 Vshale-based rock types, calibration parameters, and calibration vshale values

Rock types	*S*	*Cvsh*
Sand: $0 \leq vsh \leq 0.4$	396,900	0.1
Shale:$0.4 < vsh \leq 1.0$	4750	0.4

facies. The aforesaid limitation will result to oversimplification of the reservoir's permeability if necessary steps are not taken to capture the reservoir's heterogeneity.

The essence of this study is to optimize the applicability of the free-fluid model in the absence of NMR data so that it can become possible to calibrate the model for use over a field or zone of interest without necessarily taking NMR measurements. The calibrated free-fluid model in this study is based on the combination of experimental and theoretical approach. This was achieved by model modification and detailed reservoir rock typing.

Materials and methods

Data obtained for the tight gas sandstone analysis

Core analysis data were gotten for approximately 200 tight gas sandstone samples. These data include (i) scanning electron microscopy (SEM) and quantitative X-ray diffraction (QXRD) data, (ii) overburden corrected core porosity data, and (iii) core permeability data measured at simulated net confining stress. The samples were majorly from the rotlie gend stratigraphic interval and were mainly dominated by quartz, illite, and kaolin with few carbonate minerals such as siderite. Log data (Gamma ray log, neutron porosity log, and density log) from the cored wells were available.

Data obtained for the Niger Delta analysis

Core analysis data were gotten for approximately 500 offshore Niger Delta sandstone samples. These samples were majorly retrieved from the cleanest sand intervals while a scanty amount was retrieved from relatively more shaly and the actual shale intervals. These data include (i) overburden corrected core porosity data and (ii) core permeability data measured at simulated net confining stress. Log data (Gamma ray log, neutron porosity, density log, and deep resistivity log) from the cored well were available.

Model modification

In an attempt to modify the FFM for use without NMR data, every other variable on the right-hand side of the model apart from porosity was considered a control variable. Equation 1 was rearranged so that the control variables can be grouped together, Eq. 2:

$$K = \frac{1}{C^4} * \left(\frac{FFI}{BVI}\right)^2 * \varphi^4 \tag{2}$$

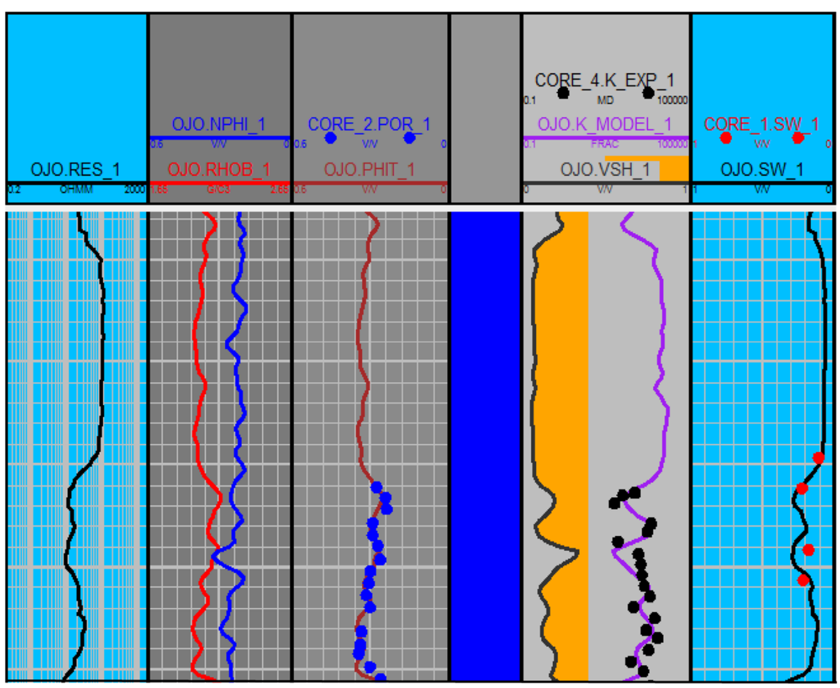

Fig. 1 Zone 1: contains only clean sand

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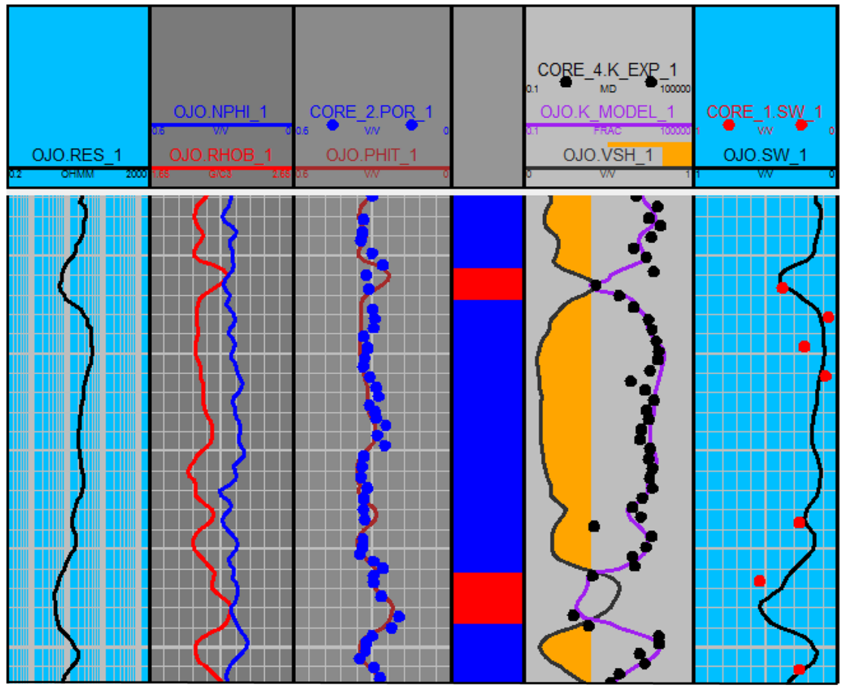

Fig. 2 Zone 2: contains clean sand intercalated with streaks of shale

The control variables were grouped under two terms: (i) formation term (F_T) and (ii) rock capillary term (C_T):

$F_T = \frac{1}{C^4}$ (depends on the processes that created the formation).

$C_T = \left(\frac{FFI}{BVI}\right)^2$ (depends on the capillarity in each rock type).

The control variables were merged into two single calibration parameters S_n and S_t for the Niger Delta and tight gas sandstone, respectively. The calibration parameter as defined in this study is the mathematical product of the formation term and the rock capillary term. For a single formation, the formation term is assumed to be constant while the rock capillary term will vary with rock type. A vshale term, $(C_{vsh}/Vsh)^2$, was introduced into the models to further account for the minor variation in vshale that may exist within an established rock type. The calibration

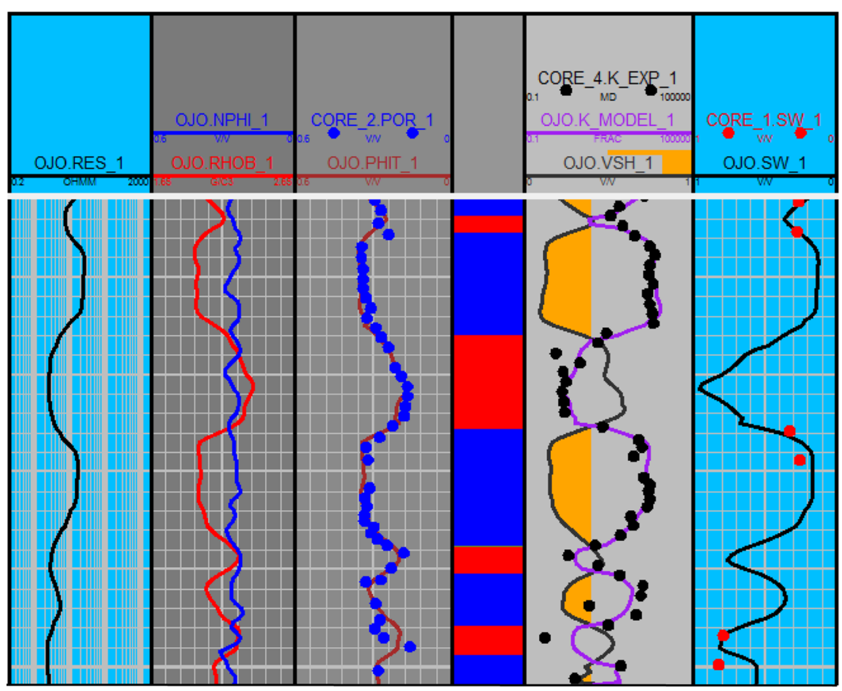

Fig. 3 Zone 3: contains clean sand intercalated with streaks of shale

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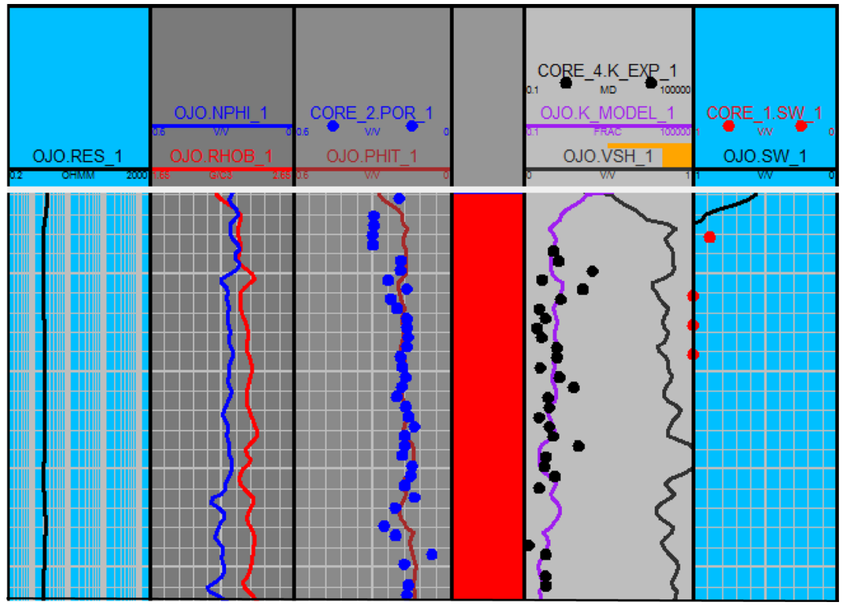

Fig. 4 Zone 4: contains only shale

vshale value (C_{vsh}) is the value of vshale at the interval where the calibration parameter is determined. The inclusion of α into the TGS model is to account for the non-matrix contribution to permeability as TGS is regarded as a double-porosity system:

$$K = S_n\left(\frac{C_{vsh}}{Vsh}\right)^2\varphi^4 \quad \text{(Niger Delta)} \tag{3}$$

$$K = S_t\left(\frac{C_{vsh}}{Vsh}\right)^2\varphi^4 + \alpha \quad \text{(Tight Gas Sandstone)} \tag{4}$$

S_n and S_t were biased to rock types based on the significant rock type profile in each field.

Rock typing and calibration parameter acquisition

The essence of rock-typing in view of using the alternative free-fluid models, Eqs.3 and 4, is to enable the selection of calibration parameters that will honor the

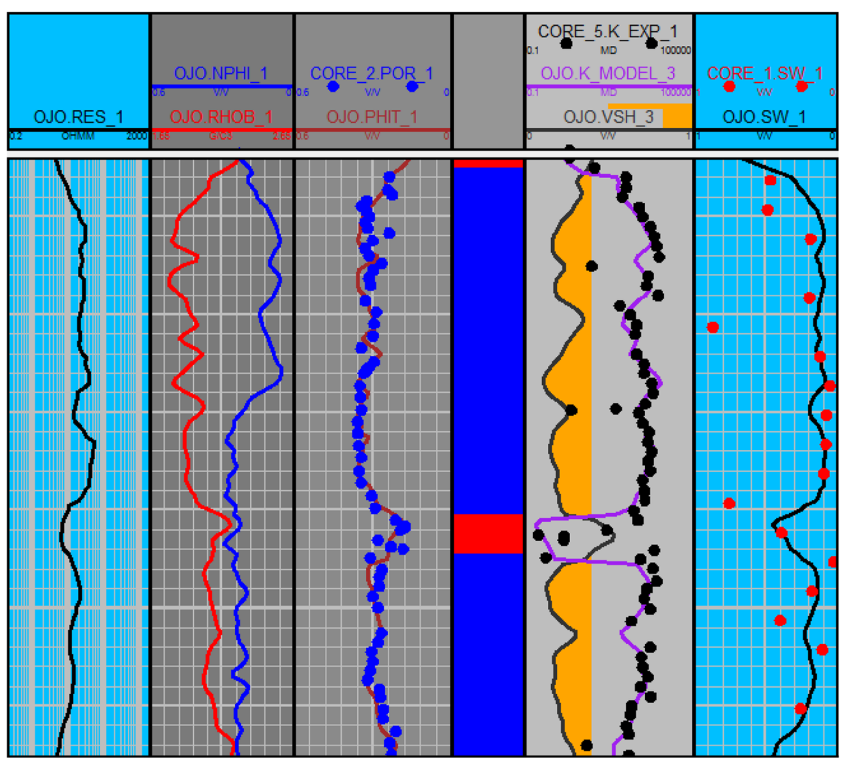

Fig. 5 Zone 5: contains clean sand intercalated with streaks of shale

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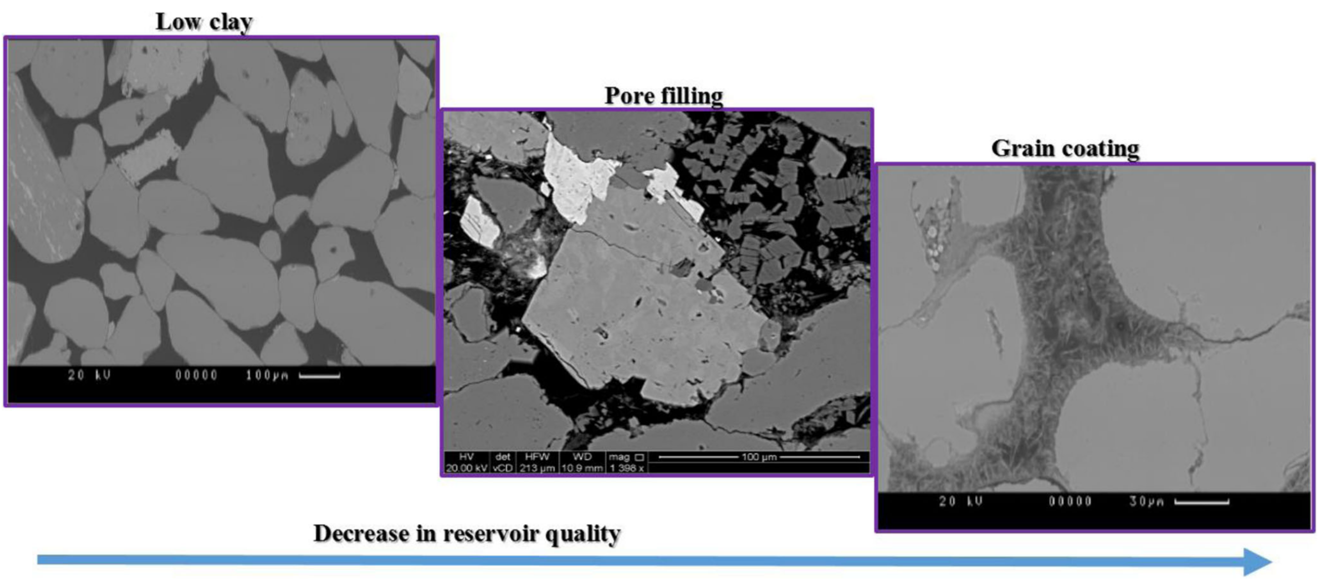

Fig. 6 Three microstructural rock types identified with the aid of SEM analysis

reservoir heterogeneities. Reservoirs were binned into zones of similar lithological or microstructural properties depending on the geological factor that controls the petrophysical property variation.

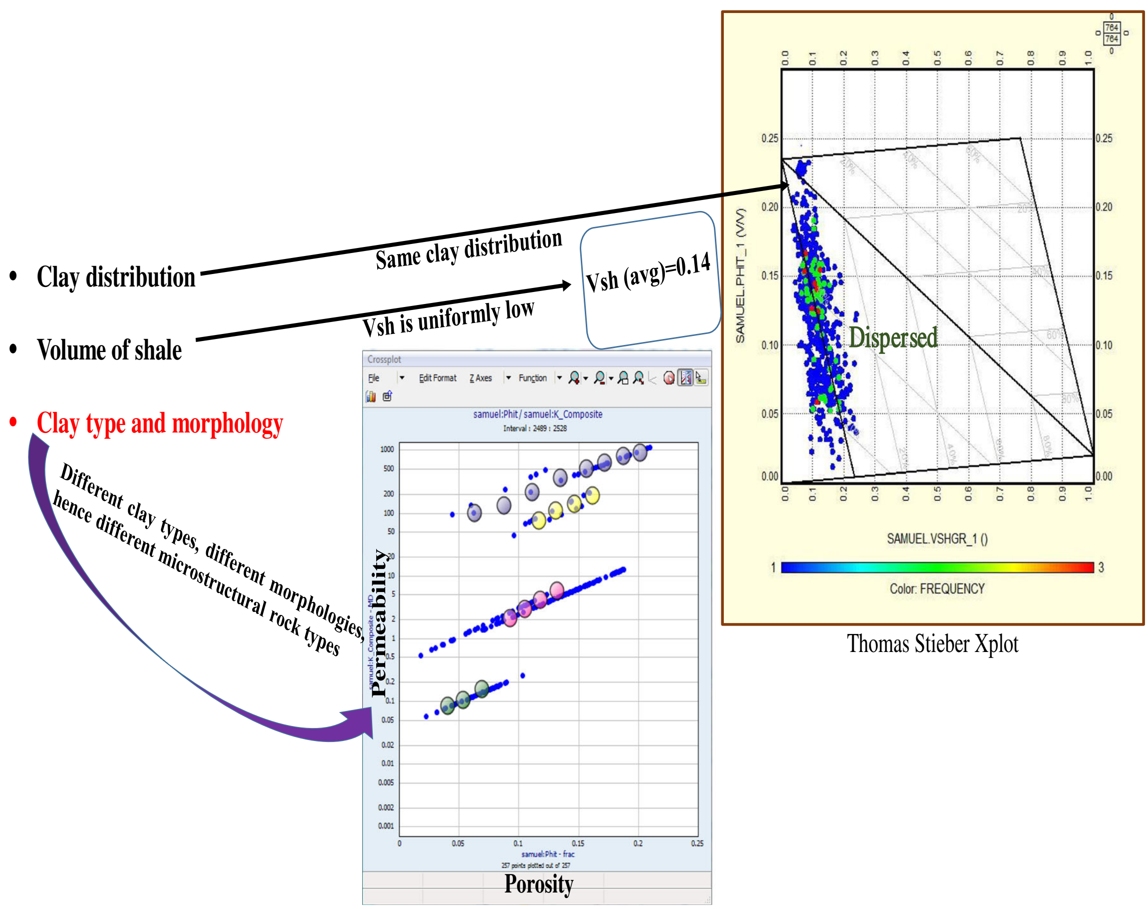

Fig. 7 Significance of microstructural rock typing in permeability predictions (Ojo et al. 2018). The slight separation observed between data points in the uppermost trend is due to minor difference in reservoir quality index between the affected samples despite that they are identified with the same microstructural rock type

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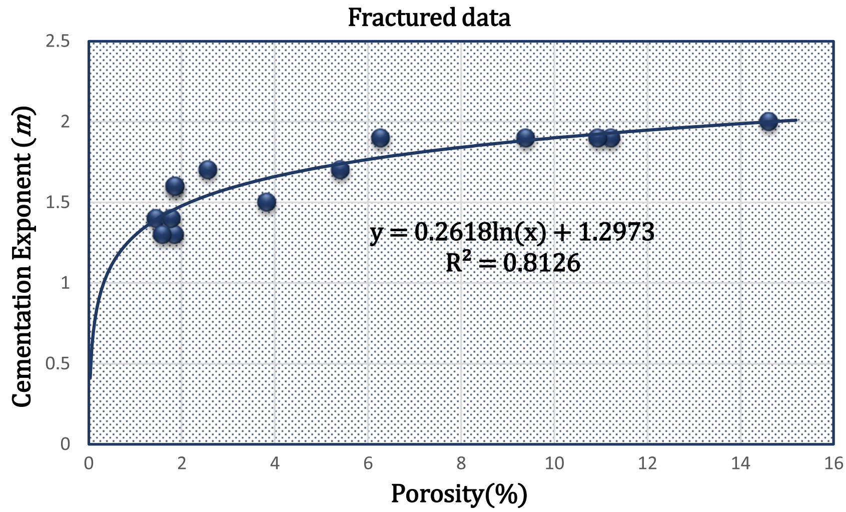

Fig. 8 Cementation-porosity cross plot of fractured samples. A correlation coefficient of 0.81 was achieved by applying the logarithmic regression fitting model to the cementation-porosity plot

Niger Delta field

Lithological rock typing and selection of calibration parameters were done consecutively. The vshale threshold value for rock typing the zones was determined by iteration until a value that divides the zones into two clear sets of the core permeabilities was reached. The calibration parameter was determined within a constant vshale interval in each of the rock types by iterative variation of an empirical constant that will match the predicted continuous permeability with the independently measured core permeabilities. Picking the calibration parameter at a constant vshale interval is to ensure the vshale term does not interfere with the calibration process. Finding the slope of a forced fit regression between K and ϕ^4 would also have achieved the same results as the method of acquiring S_n through iteration for the Niger Delta. However, the forced regression technique was not used due to the fact the Niger Delta data in this study was not evenly acquired across rock types.

Tight gas sandstone

For the tight gas sandstone (TGS), the microstructural rock types were determined using the SEM image and QXRD data. Given the even distribution of data across the microstructural rock types in the TGS, the calibration parameters were determined by conducting a free regression analysis between K and ϕ^4 for each of the rock types within uniform vshale intervals (Figs. 12, 13, 14, and 15). The S and α values were determined by the slope and intercept respectively.S is matrix dependent while α is dependent on fractures or any other form of crack-like pores.

Table 2 Microstructural rock types, calibration parameters, and calibration vshale value

Rock types within sand	S	α	$Cvsh$
Sand: low clay ($\phi \geq 0.14$)	485,619	175.860	0.2
Sand: low clay ($0 \leq \phi < 0.14$)	287,084	16.985	0.2
Sand: pore filling	9051.3	1.61270	0.2
Sand: grain coating	2033.4	0.08360	0.2

Results and discussion

Permeability logs predicted in the Niger Delta field

Since the Coates constant is the same for a single formation, no variation is expected from the formation term. It is thus inferred that the free-to-bound fluid ratio depends on the capillary entry pressure (minimum threshold pressure required by the non-wetting phase to displace the wetting phase), which in turn depends on the pore size (a reflection of shaliness from a simple perspective). The vshale threshold value for rock typing the zones was determined to be 0.4. This cut off is for the purpose of permeability predictions in this study and may not represent the cut off for net pay computation. However, 0.4 vshale cut off is usually set for net pay computations in many hydrocarbon fields of the Niger Delta. Two rock types were therefore established based on the volume of shale threshold value (Table 1):

Sand: $0 \leq vsh \leq 0.4$
Shale: $0.4 < vsh \leq 1.0$

The $Cvsh$ for the shale rock type coincides with the threshold value that divides the reservoirs into two vshale-based rock types. This should always be expected as the calibration parameter is best determined at zones of minimum vshale per rock type. Despite these models were theoretically developed

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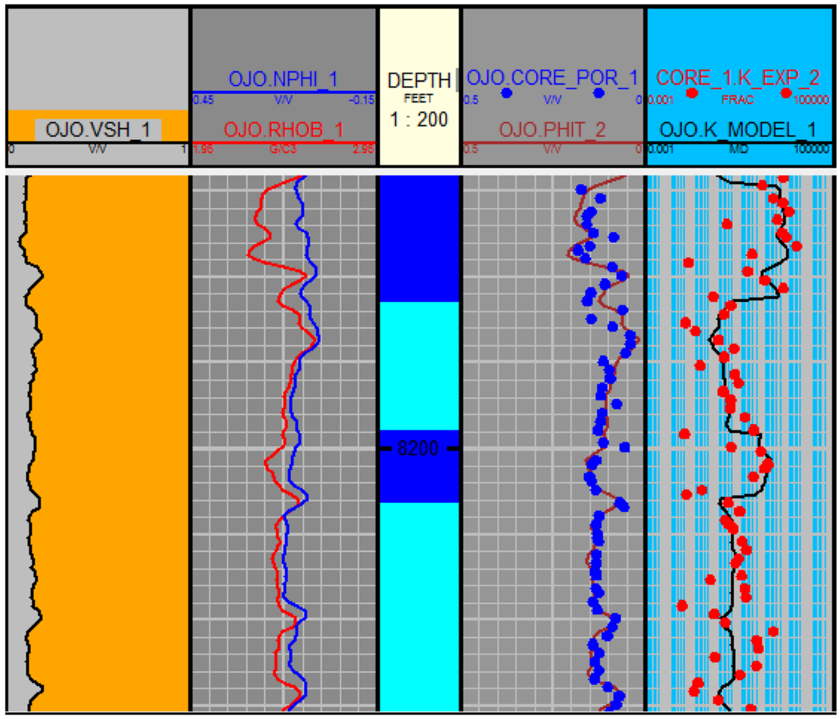

Fig. 9 Zone 1 contains **a** low clay high quality (color coded blue at the start of the zone) followed by **b** pore filling (cyan), **c** low clay reduced quality(blue), and **d** pore filling (cyan)

for wider application, the calibration parameters as the name implies were empirically determined using experimental data. The *Cvsh* and calibration parameters are peculiar to the formation analyzed and can be modified for use in other similar formations. The calibrated models were blind tested on corresponding rock types in other reservoir intervals, and a great magnitude of pictorial correlation was achieved between the predicted permeability and the core-derived permeability (Figs. 1, 2, 3, 4, and 5).

In a simple homogeneous and non-fractured formation where all factors (formation and capillary terms) are kept constant, this model predicts permeability that varies with porosity in a straight relationship for an entire reservoir. However, the reservoirs encountered in this study are far from being

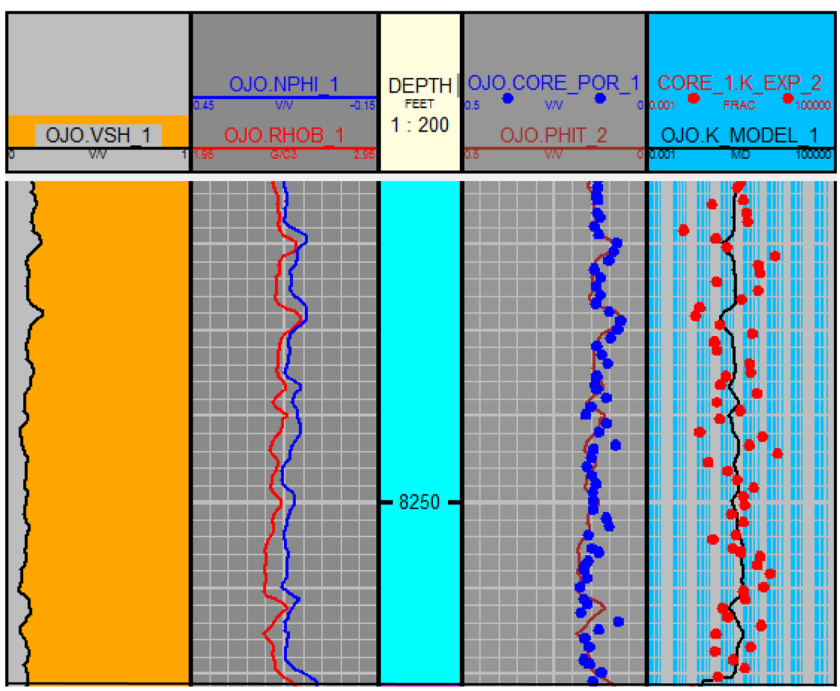

Fig. 10 Zone 2 contains only pore-filling rock type

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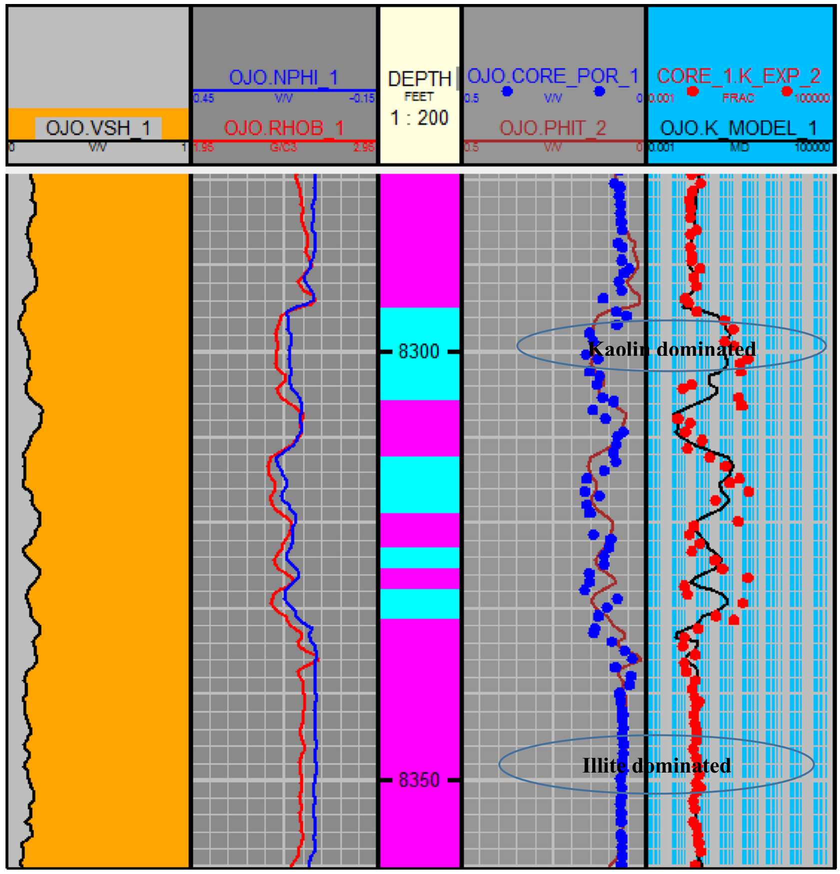

Fig. 11 Zone 3 This unit consists of intercalation of grain coating rock type (magenta) and pore-filling rock type (cyan).The grain coating interval is mainly dominated by illite. Its filamentous nature could be responsible for the drastic reduction in the reservoir quality of the intervals where they are majorly present

homogeneous, so the calibration parameter was considered a control variable that would change between rock types. If uniform vshale exist throughout a reservoir where the calibration parameter is also determined, the vshale term becomes unity for that entire reservoir and will have no effect on the model. However, if the calibrated model is applied afterwards to another reservoir of same rock type but slightly different vshale, the vshale term will account for the difference in vshale in the model.

Continuous permeabilities predicted by applying the alternative FFM over vshale-based rock types show good agreement with the core permeabilities. In track 4 of Figs. 1, 2, 3, 4 and 5, the color code refers to the clean sand as blue and the shale as red. Black curve in the first track is the deep resistivity, the second track contains the neutron-density curves, and the brown curve in the third track is log porosity calibrated to fit the existing core porosity range. Track 5 contains both volume of shale curve (black curve shaded in orange to the threshold value 0.4) and predicted permeability curve integrated with the core permeabilities (purple curve overlaid with core permeability values). Track 6 contains the water saturation curve overlaid with point data from dean stark analysis. The few experimental data that show departure from the model-predicted permeability are those data unresolved by the logging tool. The possible

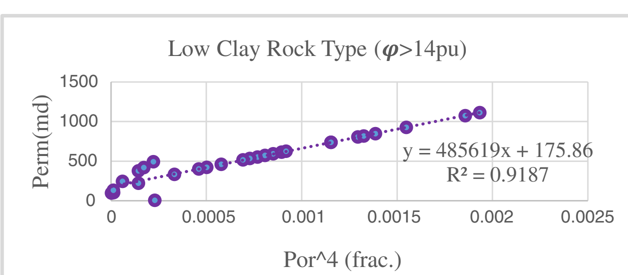

Fig. 12 Permeability-Por^4 cross plot for high quality low clay rock type

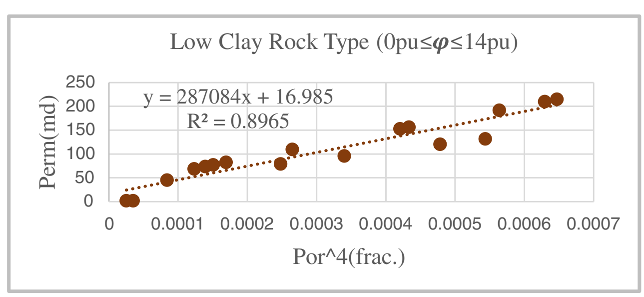

Fig. 13 Permeability-Por^4 cross plot for reduced quality low clay rock type

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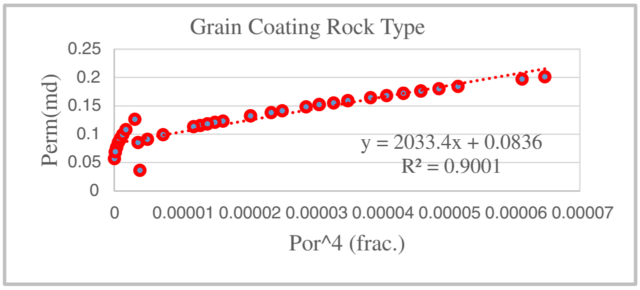

Fig. 14 Permeability-Por^4 cross plot for grain coating rock type

explanation for this deviation is the fact that the major input parameter into the permeability model is a porosity log estimated from an average response of the logging tool which has a different resolution compared to core measurements that represent information on a point-specific scale (Archer and Wall 1986).

Permeability logs predicted in the tight gas sandstones

Unlike the Niger Delta field, the different values estimated as calibration parameters (constants) do not honor lithological variation. A single calibration parameter could not consistently match the predicted permeability with the experimental permeability in an interval with a uniformly low volume of shale (*Vsh* ~ 0.2). This observation implies the existence of more than one rock type in an interval that is presumably meant to be homogeneous, judging by its evenness as regards shale volume. Since all the zones analyzed in the TGS have relatively constant volume of shale, the selection of calibration parameter would not be influenced by vshale and the vshale term in the model will be relatively passive. To corroborate the existence of more than one rock type in the analyzed clean sand interval of the TGS, the poroperm plot that was generated reveals three distinct trends that can be related to the three corresponding microstructural rock types (low clay, pore filling, and grain coating), which were initially established with the aid of SEM analysis (Figs. 6 and 7).

The impact of clay on porosity-permeability correlation of a reservoir depends on the following factors: (i) clay distribution, (ii) volume of shale, (iii) clay mineralogy, and (iv) clay morphology or occurrence (grain coating, pore filling, pore lining etc.). The rock type profile within a reservoir can be drawn from one of the four factors. Dispersed clay which evolve from alteration and precipitation of clay minerals can either coat the rock matrix or partially fill the pore spaces (Tiab and Donaldson 2004). A single rock type could have been assigned to this particular interval in error, if the rock typing was based on Thomas Stieber shale distribution model or if the facie selection criteria were based on volume of shale cut off. This observation validates the essence of understanding the petrological controls on permeability-porosity relationship before selecting a rock-typing technique for poroperm linear regression analysis (Ojo et al. 2018). According to Teh et al. (2012), the value of petrophysical classifier can vary significantly within a single lithofacies. Calibrating the alternative FFM over rock types was directed to take into account the microstructural variation so that more than one alternative FFM model can be generated for a clean sand interval where necessary. Besides the existence of three microstructural rock types within a clean sand interval, the TGS presents two (2) other unique deviations from the Niger Delta scenario especially in the low clay zones:

1. A single calibration parameter could not consistently match the predicted permeability with the experimental

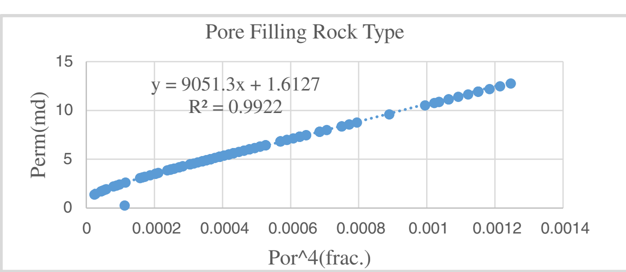

Fig. 15 Permeability-Por^4 cross plot for pore filling rock type

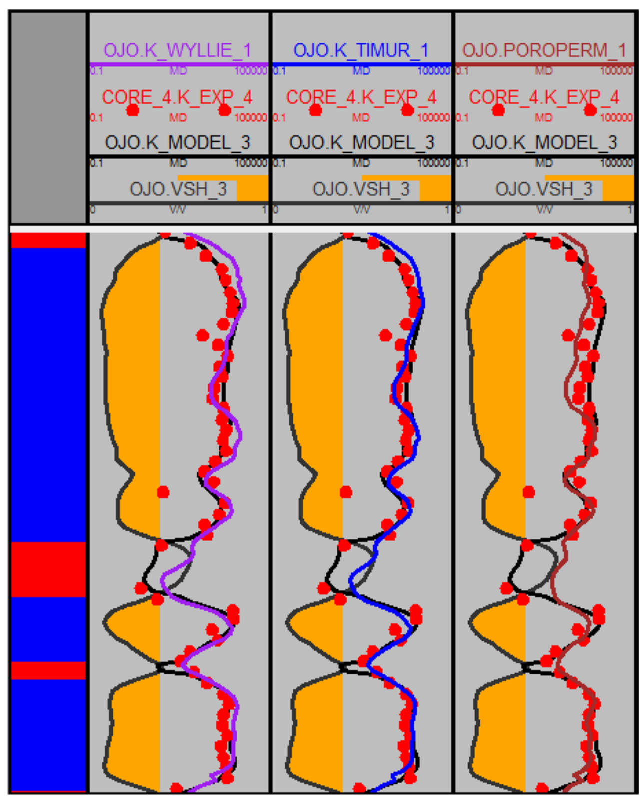

Fig. 16 Comparison between continuous permeability models in a Niger Delta

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permeability in all the reservoir units identified as low clay. This observation implies that there exists an intra-rock-type quality index variation within this micro structure-based facie such that the alternative FFM requires being calibrated over two sub-rock types. This is very similar to the deficiency of the microstructure-based poroperm function in the same low clay interval in Fig. 7. To account for this intra-rock-type variation in the alternative FFM, the low clay rock type was divided into high-quality and reduced-quality low clay so that two functions can be derived for the two categories of low clay rock type. However, the challenge of which function to use in such affected zones, whose permeability is to be predicted, can be worrisome, since it is not expected that experimental permeability data would always be available for subsequent analysis of other wells in the field. The best possible approach is to infer from the calibrated porosity log, what function is to be used between the two established functions. Based on the wells analyzed in this study, the high-quality low clay satisfies the condition $\phi \geq 14pu$ while the reduced-quality low clay satisfies the condition $0 \leq \phi < 14pu$.

2. During the model calibration over rock types, the forced fit regression approach worked well for the Niger Delta (Eq. 3). It however gave a weaker coefficient of determination ($R^2 \sim 0.6$) compared to the coefficient of determination ($R^2 \sim 0.93$) achieved when a free regression approach was adopted for the TGS (Figs. 12, 13, 14, and 15). This justifies the inclusion of the non-matrix parameter for the TGS permeability model in Eq. 4.

In the forced fit regression, the permeability is zero when the porosity is zero while in the free regression, the permeability returns to the permeability contributed by the non-matrix pores (such as fracture flow paths with extremely low porosity). Therefore, the constant α represents a non-matrix permeability. A non-matrix porosity identified in this study is the fracture porosity. However, other crack-like pores such as thin coarser laminae or slot-like pores that are parallel to beddings may be present (Cluff et al. 2008).

By applying the logarithmic regression fitting model to the cementation-porosity plot, the fracture porosity was retrieved from the model, which is 0.005v/v being the porosity obtained as the cementation exponent approaches unity (Fig. 8). At that

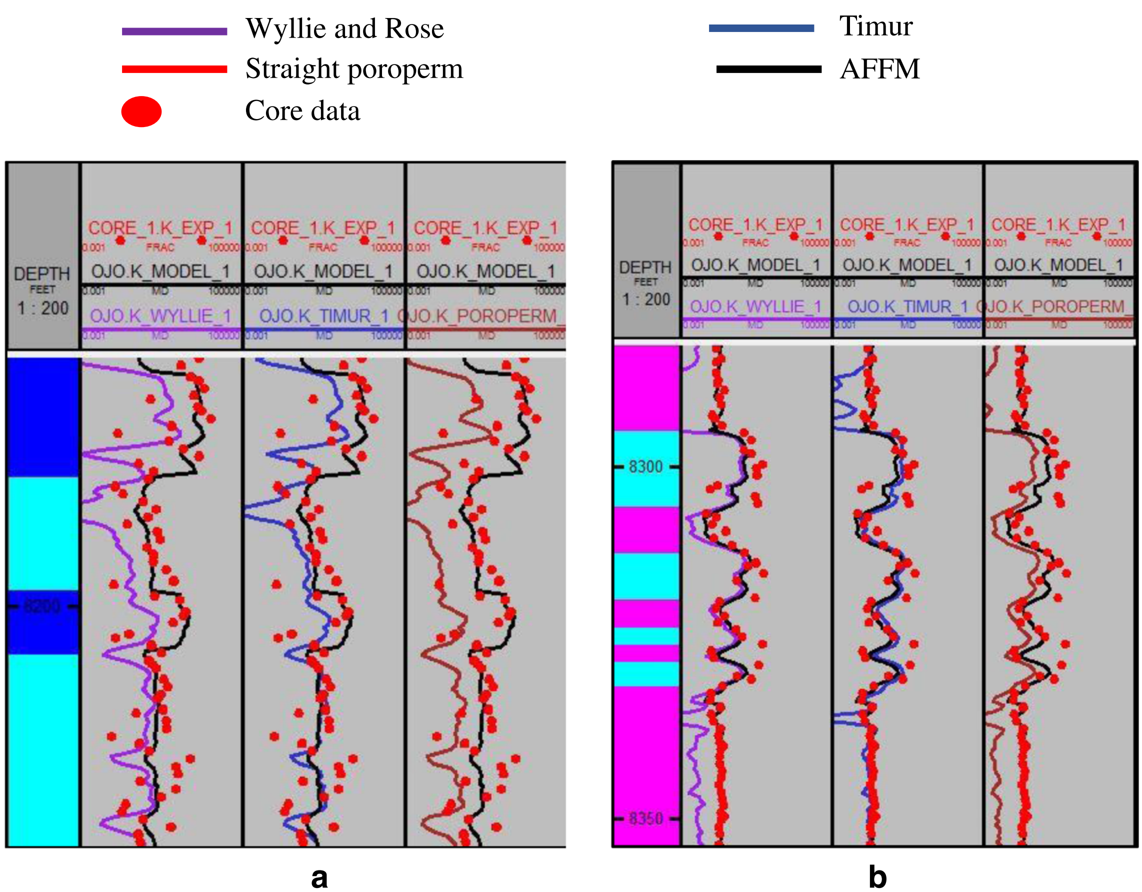

Fig. 17 **a** Comparison between continuous permeability models in TGS (zone 1). **b** Comparison between continuous permeability models in TGS (zone 3)

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hypothetical point when an interval only takes contribution to the total permeability from fractures, $(0.005)^4$ becomes the value for the independent term, ϕ^4 which will give 0.0000000006 (~zero) and the K in Eq. 4 then reduces to α. This reduction further explains why the parameter α represents the permeability contribution from non-matrix pores (Table 2).

The use of vshale-based rock typing technique failed in calibrating the alternative FFM in TGS. Rock typing technique is a major determinant of the predictive accuracy of permeability models. Continuous permeabilities predicted by applying the alternative FFM calibrated over microstructure-based rock types are in Figs. 9, 10, and 11. The first track contains the volume of shale, the second track contains the neutron-density curves, and the brown curve in the fourth track is log porosity calibrated to fit the existing core porosity range. Track 5 contains continuous permeability curve integrated with the core permeabilities (black curve overlaid with core permeability data in color red).

In Figs. 9 and 10, some experimental values alternate side-to-side from the model-predicted permeability curve. This implies the predicted curve fits the experimental permeability range but do not match point-to-point. Similar scenario was observed in a zone of the analyzed Niger Delta field, which was attributed to the inability of the logging tool to resolve every point. Thin bed laminae can cause heterogeneities within a sampled interval for which a logging tool has provided an average response. A cross plot between predicted and core permeability was made for the Niger Delta and TGS and achieved correlation coefficients (CC) of 0.95 and 0.82, respectively (Figs. 18 and 19). The very high CC obtained for the Niger Delta was possible as a result of the sampling intervals that seem to be homogeneous especially in the cleanest sand region as the side-to-side alternation of core data is almost insignificant. The same very high correlation could not be achieved for TGS as most of the sampling intervals by the logging tool seem to be a bit heterogeneous. However, it is important to point out that the main aim for developing these models are to use logs to predict continuous permeability that will closely agree with core permeabilities in trend and in range such that permeability can afterwards be predicted from logs in other wells where there is no core data. The best way to

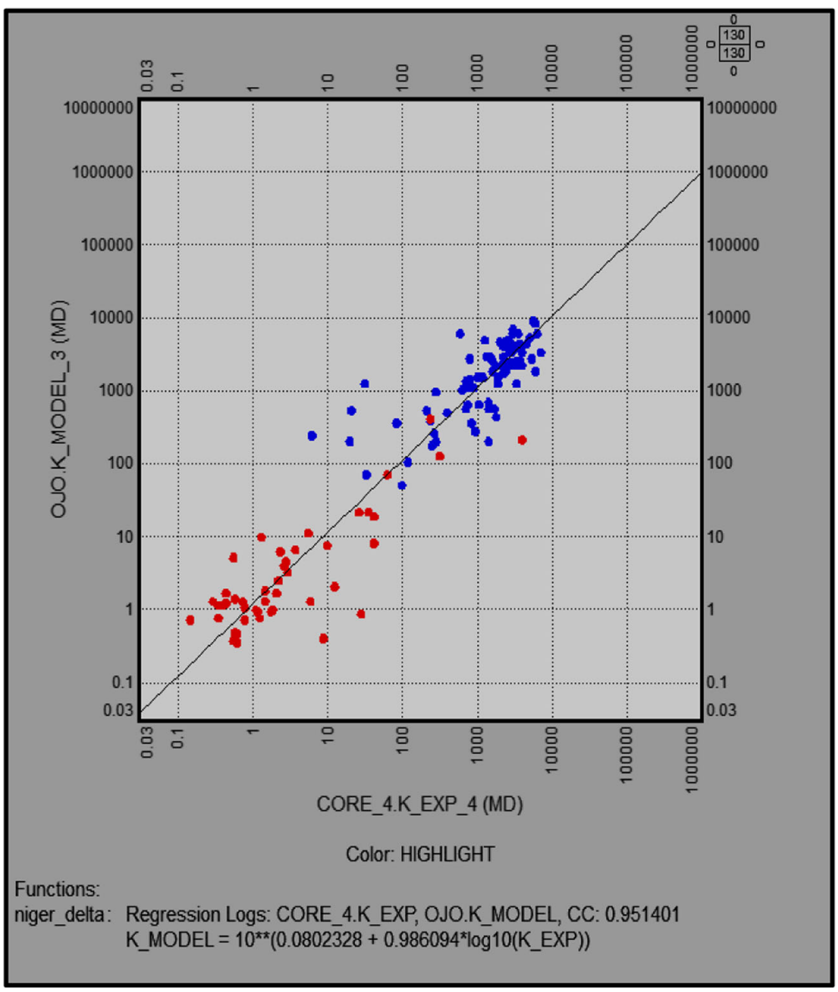

Fig. 18 Core permeability versus predicted permeability in Niger Delta field (CC = 0.95)

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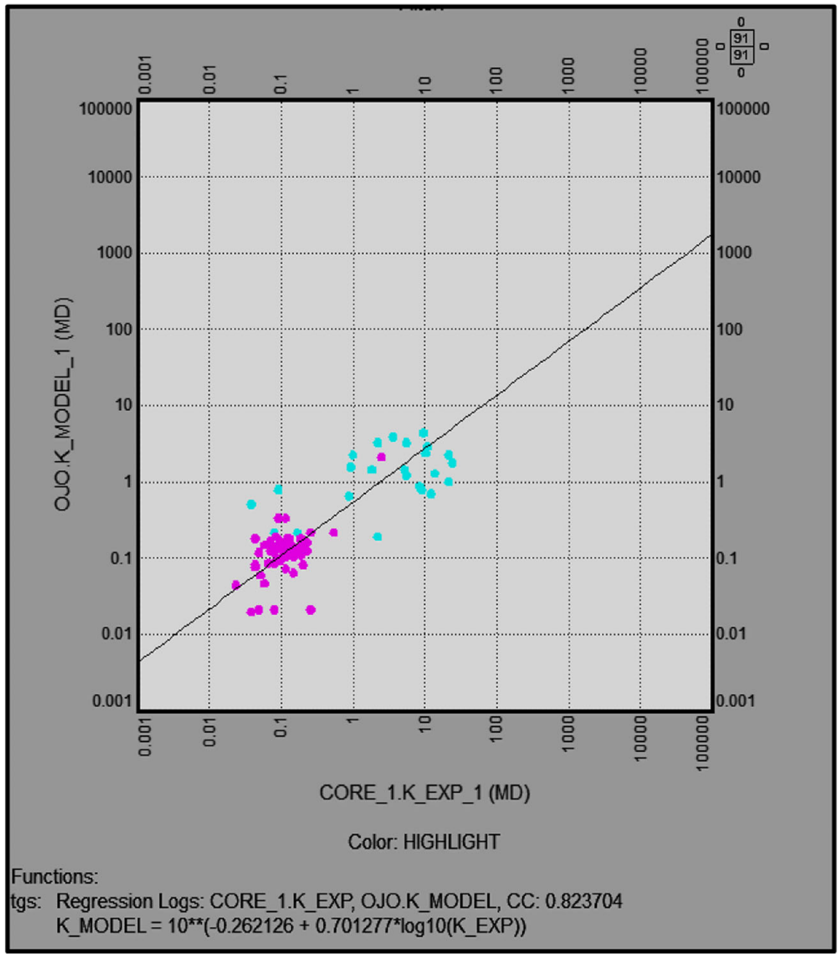

Fig. 19 Core permeability versus predicted permeability in TGS (CC = 0.82)

view this agreement is in the log display alongside the core permeabilities in order to see if the permeability curves from logs fit the existing core permeability range. Cross plotting may not always be a fair test of the accuracy of models in this subject as the coring process and the logging process are not of the same resolution. Depending on the frequency of the logging tool, log information is an average response of a sampled interval while core information is point specific. Where heterogeneous thin layers cannot be resolved by logging tools due to low frequency sampling, result of cross plotting may be too pessimistic and misleading. On the log plot, the weakness of a permeability model can be seen in its departure from the core permeability trend or its inability to fit the core permeability range.

Comparison between the alternative free-fluid model and some theoretical models

An attempt was made to predict depth continuous permeability curves using some theoretical and empirical based models: Wyllie and Rose (1950), Timur (1968), and straight poroperm (Figs. 16 and 17). Uncertainty in the predicted permeability ranges across orders of magnitude. The inconsistency in the predictive accuracy of the theoretical models can be attributed to (i) the difference in geological processes that created various rock formations, (ii) the reservoir rock heterogeneity, and (iii) the absence of empirical fitting parameter(s) in the models. The extrapolative power of straight poroperm is weakened when the rock-type variation is not taken into consideration as experienced in some Niger Delta reservoirs where the straight poroperm underestimates permeability in the clean sand and overestimate permeability in the shaly sand (Fig. 12, 13, 14, 15, 16, 17, 18, and 19).

Conclusion

The alternative free-fluid model calibrated over vshale-based rock types can be effectively used to predict continuous permeability in the Niger Delta formation in the absence of NMR data (a cost-effective approach especially for marginal fields). Since rock typing on the scale of shale volume was sufficient to support the predictive accuracy of the alternative FFM in

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the Niger Delta, it can then be inferred that there is likely not going to be a significant microstructural variation within the clean sand intervals of the Niger Delta formation, at least not at the present age of the formation. It is therefore possible to address the reservoir quality variation straight from how it is depicted by the gamma ray log with the assumption that the influence of non-shaly radioactive accessories is negligible. The alternative free-fluid model developed for the tight gas sandstone (TGS) has proven to be effective in predicting continuous permeability, if the rock typing technique is based on microstructures or mineralogy. The inclusion of the non-matrix parameter in the TGS alternative FFM improves the predictive performance of the model and further confirms the TGS as a double-porosity system. A method of using gamma ray log (a lithology log) as a reservoir quality indicator may be unreliable in TGS as rock-type profile shows variability within clean sands. The alternative models to the well-established free-fluid model can be used without necessarily acquiring NMR logs. However, the extrapolative accuracy of these models is only guaranteed when used in conjunction with an effective rock typing technique.

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