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Permeability Modelling of a Sandstone Reservoir in Parts of the Niger Delta

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ABSTRACT

Aimed at determining a more reliable method of estimating permeability from well log data, in the absence of core data, 4 predictive empirical models for estimating permeabilities (RGPZ model, Van Baaren's model, Timur's model and Berg's model) were applied to two different reservoirs in a single well from an oil field in the Niger Delta. With the models employed at different cementation factors (m=1.5, 1.65, 1.80, 1.95, 2.10, 2.25, 2.40, 2.55, 2.70, 2.85, 3.00), using well log data from the reservoirs of interest, as a function of depth, measures of normalized root mean square error (NRMSE), relative to permeabilities measured from core analysis at the same reservoir interval, were used to determine which predictive model was more reliable. Obtained results showed the most reliable predictive model at m=1.65. At this cementation factor, the NRMSE for RGPZ model, Van Baaren's model, Timur's model and Berg's model were 4.95, 30.38, 1.85, and 1.20 respectively in the first reservoir and 4.28, 24.69, 1.56 and 1.09 respectively in the second reservoir. Hence, Van Baaren's model provided a more reliable measure of in-situ permeabilities in the reservoirs of the Niger delta as it had a lower measure of NRMSE in the reservoirs of interest.

Index Terms: Permeability, RGPZ Model, Van Baaren's Model, Timur's Model, Berg's Model, Normalized root mean square error.

1. INTRODUCTION

One of the major existing and emerging challenges in characterizing a reservoir, as encountered by geophysicist and engineers, is to improve reservoir description techniques (Bust et al., 2013). It is well recognized that improvements in reservoir description will reduce the amount of hydrocarbon left behind during exploration (Abass et al., 2018). An accurate description of pore-body/throat (permeability) attributes and fluid distribution are central elements in improved reservoir description (Wu et al., 2018).

Permeability is by definition a measure of the ease with which a fluid can pass through the pore spaces of a formation (Sheriff, 2002) and therefore determines the ability of the rock to transmit fluid (Tiab & Donaldson, 2011). In other words, permeability is a measure of both the amount of connectedness of the fluid containing pore spaces and the size of the connection (Dullien, 2012). Evidently, permeability is a very important petrophysical measure since it is the rock property that relates to the rate at which hydrocarbons can be recovered (Ahn et al., 2015). The Darcy is the standard unit of permeability which by definition is the rock's ability to deliver $1cm^3$ of fluid across an area of $1cm^2$ in a time of 1 second with an imposed pressure differential of 1atm for each centimeter of sample (Adeboye et al., 2012).

It is a well-established fact amongst geophysicist and engineers that the most efficient way of making petrophysical estimations of a geophysical reservoir is from core analysis (McPhee et al., 2015). In other words, a reservoir without core data is often associated with uncertainties as these properties have to be log derived (Aigbedion & Aigbedion, 2011). Additionally, the process of obtaining core measurements are quite expensive (considering the process of obtaining the cores from individual wells to obtaining laboratory core measurements of the reservoir properties) relative to the process of obtaining the same measure of reservoir properties from well logs. Therefore, apart from permeabilities estimated from core measurements, how best can permeability be estimated from downhole wireline logs and other relevant data as they relate to the Niger Delta. This is quite significant since it is quite complicated to directly obtain reliable rock permeabilities from downhole logs (Glover et al., 2006).

2. THE STUDY AREA

The study area is the Niger Delta Basin, also referred to as the Niger Delta Province; an extensional rift basin located in the Niger Delta and the Gulf of Guinea on the passive continental margin near the western coast of Nigeria (Tuttle et al., 1999). This area lies in the south westernmost part of a larger tectonic structure, the Benue trough, bounded on its other side by the Cameroon Volcanic Line and the transform passive continental margin (Fatoke & Bhattacharya, 2010).

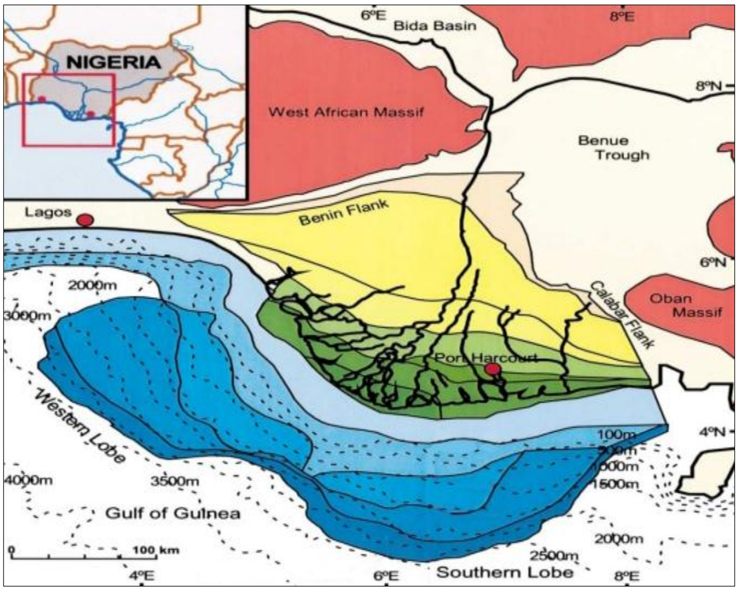

Fig.1: *Location map of the Niger Delta showing the depobelt and geologic features that bounds the delta (Tuttle et al., 1999).*

Ranked as the twelfth richest petroleum resources with 2.2% of the world's discovered oil and 1.4% of world's discovered gas by the US Geological Survey's World Energy Assessment (Opafunso, 2007), the Niger delta consists of three broad geologic formations: the Benin Formation (the continental top facies), the Agbada Formation and the Akata Formation. The Akata Formation (comprising mainly of marine shale with sandy and silty beds laid down in turbidites and continental slope channel fills, about 7000 meters in thickness) serves as the source rock, the Agbada

Formation (which is over 3700 meters thick made up of mainly sandstone at the top with shaley intercalations and predominantly shale with sandstone intercalations at the lower part) is the main hydrocarbon bearing unit and the Benin Formation (which is about 2100 meters thick, composed of continental sands and gravels) is the main ground water bearing formation in the Niger Delta Basin (Aigbedion & Aigbedion, 2011; Ajaegwu et al., 2012)

3. METHODOLOGY

The data used for this work was obtained from Total Exploration and Production Company, Nigeria. Data (well log and core) were extracted, from two reservoirs (RESERVOIRS I and II) in a single well in the Niger Delta to aid the determination of how best to describe permeability from well logs in the area. To minimise error, the core and log data were inspected to make sure the driller's depth on the core log corresponds to the measured depth on the well log, since the permeability prediction methods that would be tested later requires comparison of well and core data to see which of the applied prediction methods best matches the data from core analysis. It was discovered that both depths are the same for the reservoirs of interest.

There are many empirical models for permeability prediction. However, based on the ease of data availability, four of these models will be tested, using data extracted from well logs, to identify which one best presents the in-situ permeability of the reservoir unit in the Niger Delta. These models include;

3.1 RGPZ Model:

The RPGZ model predicts the fluid permeability of porous media. Mathematically, this model is expressed as:

$$k_{RGPZ}(mD) = \frac{1013d^2\Phi^{3m}}{4am^2} \qquad \textbf{Eqn. 1}$$

It can be clearly seen that this model relates permeability of a porous formation to the porosity (Φ) of the formation expressed as a fraction, the weighted mean grain size (d) expressed in microns and the cementation exponent (m). The parameter a is a constant which is assumed to be equal to 8/3, assuming the grains are spherical after *Schwartz et al.* (1989).

The factor *'1013'* has been added to the original RGPZ model since the grain sizes will be in microns and there will be a need to convert estimated permeabilities from *square-microns* to *milliDarcies* (since *one square-micron* is equivalent to 10^{-12} *square-meters*, and *one square-meters* is equivalent to 1.013×10^{15} *milliDarcies*)

It is important to note that this model is quite sensitive to the choice of porosity, grain size and the cementation factor (Glover et al., 2006). Hence, the values of porosity will be obtained from well log analysis while a mean grain size $308 microns$ (Acra et al., 2014) will be used. The model will also be tested for different cementation factors (*m=1.50, 1.65, 1.80, 1.95, 2.1, 2.25, 2.40, 2.55, 2.70, 2.85, 3.00*) to ascertain what cementation factor provides a best fit for the model.

3.2 Timur's Model:

Expressing permeability in milliDarcies (mD), Timur relates permeability to porosity and irreducible water saturation of the formation (both expressed as percentages). Mathematically;

$$k = \frac{a\Phi^b}{S_{wi}^2} \qquad \textbf{Eqn. 2}$$

Employing a reduced major axis method to analyse data obtained by laboratory measurements conducted on 155 sandstone samples from three different oil fields from North America, Timur was able to choose from five alternative relationships values of *a* and *b* based on both the highest correlation coefficient and on the lowest standard deviation such that his model can be simplified as (Balan et al., 1995):

$$k_{TM}(mD) = 0.136\frac{\Phi^{4.4}}{S_{wi}^2} \qquad \textbf{Eqn. 3}$$

Since obtaining the irreducible water saturation could be quite challenging, the minimum water saturation for each reservoir unit will be taken as the irreducible water saturation for that unit for this work. Hence, there will be a need to acquire estimates for the water saturation for the reservoir units of interest. This will be done using Archie's relationship which relates water saturation to the porosity (Φ), formation water resistivity (R_w), formation resistivity (R_t), saturation exponent (n), cementation exponent (m) and tortuosity factor (a), mathematically expressed as:

$$S_w = \left[\frac{a \times R_w}{R_t \times \Phi^{\mathrm{m}}}\right]^{\frac{1}{n}}$$ **Eqn. 4**

The value of m will be used as it was used in the case for the RGPZ model described in the section above. For the tortuosity factor (a), a value of 1.45 (Carothers, 1968) will be used for the reservoirs of interest based on the assumption that the reservoirs in the Niger Delta are average sand units. The formation resistivity will be taken from resistivity logs while the formation water resistivity will be taken as 9.80 $Ohm - m$, adapted from John et al. (2016). For the saturation exponent, *n*, a value of 2 is generally used (Asquith et al., 2004).

3.3 Berg's Model:

Berg (1975) by examining grain packing, grain size, grain sorting and porosity, developed a model which can be expressed in its simplest form as:

$$k_{BM}(mD) = 8.4 \times 10^{-2} \Phi^{5.1} D^2$$ **Eqn. 5**

Where permeability is expressed in milliDarcies and relates to porosity (Φ), expressed as a fraction, and the square of the median grain size (D), which is expressed in microns.

A median grain size of 308 $microns$, according to Acra et al. (2014), to run this model. .

3.4 Van Baaren's Model:

Although Van Baaren's model, bears a striking similarity to Berg's model, *Nelson* (1994) noted that Van Baaren's model is more flexible in comparison to Berg's model as it contains two additional variables, the cementation exponent and the sorting index. Mathematically this model is expressed as:

$$k_{VBM}(mD) = 10 D_d^2 \Phi^{3.64+m} C^{-3.64}$$ **Eqn. 6**

Where D_d is the dominant modal grain size in microns, ϕ is fractional porosity, *m* is the cementation exponent and *C* is the sorting index of the formation (varying from 0.7 for extremely well sorted grains to unity for poorly sorted grains).

Table 1: Sorting Index for different classes of sorting

SORTING	*SORTING INDEX*
Extremely well to very well sorted	0.70
Very well to well sorted	0.77

Well Sorted	0.84
Well to moderately sorted	0.87
Moderately Sorted	0.91
Moderately to poorly sorted	0.95
Poorly sorted	1.00

The value for the cementation factor will be assigned as it as it was done in previously described models with the dominant modal grain size taken as $316\ microns$ according to Akpan et al. (2016). The challenge in applying this model will be in defining the sorting index for the different reservoir units. This will be done with the aid of a chart, *table 1*, provided by Van Baaren (Van Baaren, 1979);

The main reservoir unit, i.e. the Agbada formation, has been described as moderately to being poorly sorted (Omoboriowo et al., 2012). Hence, the associated sorting index for these different formations will be used in applying Van Baaren's model.

Davies et al. (2018) had shown that porosities as modelled from sonic logs are better estimates of porosities in the Niger Delta. Hence the porosity, needed for these models will be modelled according to Willie-time average equation (Wyllie et al., 1958);

$$\phi_S = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_{fl} - \Delta t_{ma}} \qquad \textbf{Eqn. 7}$$

Where $\Delta \boldsymbol{t_{log}}$ *is the sonic travel time (in* $\boldsymbol{\mu s/ft}$*) as defined from the well log,* $\Delta \boldsymbol{t_{ma}}$ *is the sonic travel time in the matrix (*$\mathbf{55}\boldsymbol{\mu s/f}$ *for typical sandstone reservoir),* $\Delta \boldsymbol{t_{fl}}$ *is the sonic travel time in the formation (*$\mathbf{215}\boldsymbol{\mu s/ft}$*, assuming all of the formation is entirely saturated with hydrocarbon).*

3.5 Statistical Measure for model fit:

One frequently employed measure to estimate how closely a predicted model fits actual observed values is to normalise the Root Mean Square Error (RMSE) (also called the root mean square deviation, RMSD), i.e. estimating the normalised root mean square error (NRMSE). Normalising the root mean square error is very useful as it helps one to compare root mean square errors with different units.

According to Janssen and Heuberger (1995), the RMSE of a model prediction algorithm relative to the i^{th} observed, $X_{i,\ observed}$, and the estimated variable, $X_{i,\ model}$, is defined as the square root of the mean squared error:

$$RMSE = \sqrt{\frac{\sum_{i=1}^{N}\left(X_{i,\ model} - X_{i,\ observed}\right)^2}{N}} \qquad \textbf{Eqn. 8}$$

The normalised root mean square error, NRMSE, is mathematically expressed as;

$$NRMSE = \frac{RMSE}{\overline{X_{observed}}} \quad \textbf{Eqn. 9}$$

Where $\overline{X_{observed}}$ is the average of the observed data. The normalised root mean square error goes from zero (for a model that perfectly fits the observed data) to infinity (for a model that is random compared to the observed data). In other words, a better model is characterised by a relatively smaller NRMSE.

Hence, the normalised root mean square error (NRMSE) will be estimated to determine the fit of the estimated models to the data from core analysis.

4. RESULTS AND DISCUSSION

4.1 Results

Table 2: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=1.50)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	4022.86	12.63	5252.26	10.35
Timur's Model	5678.69	17.83	7350.55	14.49
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	387.34	1.25	580.21	1.14

Table 3: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=1.65)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	1577.42	4.95	2172.96	4.28
Timur's Model	9675.94	30.38	12527.03	24.69
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	382.91	1.20	554.69	1.09

Table 4: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=1.80)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	590.49	1.85	897.29	1.77
Timur's Model	16296.67	51.17	12527.03	41.59
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	391.33	1.23	554.69	1.10

Table 5: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=1.95)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	383.31	1.20	568.91	1.12
Timur's Model	27256.24	85.58	35296.88	69.56
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	410.88	1.29	573.21	1.13

Table 6: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=2.10)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	459.30	1.44	623.60	1.23
Timur's Model	45394.43	142.53	58790.00	115.86
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	434.14	1.36	596.53	1.18

Table 7: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=2.25)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	523.88	1.64	698.60	1.38
Timur's Model	75411.21	236.78	97668.80	192.48
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	457.25	1.44	621.48	1.22

Table 8: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=2.40)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	558.57	1.75	743.63	1.47
Timur's Model	125084.53	392.75	162007.58	319.28
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	478.45	1.50	645.49	1.27

Table 9: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=2.55)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	575.97	1.81	767.72	1.51
Timur's Model	207285.80	650.86	268477.86	529.11
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	497.13	1.56	667.38	1.32

Table 10: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=2.70)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	584.57	1.84	780.26	1.54
Timur's Model	343315.07	1077.97	444668.29	876.35
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	513.19	1.61	686.74	1.35

Table 11: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=2.85)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	588.82	1.85	786.76	1.55
Timur's Model	568420.36	1784.78	736233.51	1450.96
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	526.81	1.65	703.54	1.39

Table 12: *RMSE and NRMSE for RESERVOIR I and RESERVOIR II (m=3.00)*

	RESERVOIR I		RESERVOIR II	
	RMSE	**NRMSE**	**RMSE**	**NRMSE**
RGPZ Model	590.94	1.86	790.15	1.56
Timur's Model	940931.16	2954.43	1218724.13	2401.85
Berg's Model	590.12	1.85	790.08	1.56
Van Baaren's Model	538.24	1.69	717.94	1.41

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Table 13: *Variables (observed and modelled) for RESERVOIR I for m=1.65*

Depth (Ft)	Core Derived Perm., K_{CORE} (mD)	Sonic Transit Time (μs/ft)	Sonic log-derived Porosity, ϕs (%)	Formation Resistivity (Ωm)	Water Saturation (%)	K_{RGPZ} (mD)	K_{TM} (mD)	K_{BM} (mD)	K_{VBM} (mD)
7874.00	21.46	85.60	23.65	12.13	8.10	2630.03	13909.93	5.10	585.86
7882.00	1625.00	90.71	28.73	53.23	3.29	6895.49	32765.57	13.77	1641.16
7888.00	2166.00	90.10	28.10	14.40	6.45	6180.17	29726.12	12.30	1459.89
7898.00	1115.00	83.35	21.53	21.84	6.52	1654.70	9213.90	3.16	357.05
7906.00	515.50	86.00	24.03	19.23	6.35	2847.97	14929.95	5.54	637.89
7908.00	89.71	88.10	26.08	14.53	6.82	4272.95	21412.81	8.41	984.10
7910.00	2003.00	86.39	24.41	11.43	8.13	3075.54	15985.81	5.99	692.51
7922.00	65.61	84.50	22.61	5.00	13.09	2104.07	11407.55	4.05	461.57
7924.00	550.00	86.10	24.13	3.91	14.03	2904.87	15194.78	5.65	651.52
7926.00	25.91	86.00	24.03	3.50	14.88	2847.97	14929.95	5.54	637.89
7930.00	33.85	79.85	18.39	2.93	20.28	756.90	4597.34	1.41	154.78
7932.00	2.24	79.60	18.17	2.60	21.74	713.40	4361.68	1.33	145.29
7936.00	0.53	80.10	18.61	3.35	18.78	802.68	4843.66	1.50	164.81
7940.00	63.17	80.70	19.14	3.36	18.32	922.37	5480.66	1.73	191.20
7942.00	3.16	80.49	18.95	3.80	17.37	878.84	5250.11	1.65	181.57
7948.00	114.10	77.71	16.54	1.99	26.85	448.41	2886.73	0.82	88.46
7950.00	366.30	77.20	16.11	1.91	28.01	393.44	2569.91	0.72	76.92
7954.00	551.00	80.10	18.61	2.00	24.30	802.68	4843.66	1.50	164.81
7958.00	217.00	79.70	18.26	1.97	24.88	730.53	4454.69	1.36	149.03
7966.00	315.10	85.89	23.93	1.76	21.05	2786.52	14643.23	5.41	623.19
7968.00	401.90	79.56	18.13	2.06	24.46	706.64	4324.94	1.32	143.82
7972.00	210.90	81.00	19.40	1.82	24.61	987.79	5824.83	1.86	205.72

7976.00	791.40	77.75	16.58	2.03	26.54	452.99	2912.90	0.83	89.42
7980.00	56.51	79.20	17.82	1.93	25.64	648.26	4005.81	1.21	131.16
7982.00	487.20	77.10	16.03	2.43	24.94	383.37	2511.34	0.70	74.82
7996.00	19.25	81.00	19.40	3.76	17.12	987.79	5824.83	1.86	205.72
7998.00	1.19	80.65	19.09	4.11	16.60	911.84	5425.01	1.71	188.87
8000.00	4.81	81.25	19.63	2.77	19.76	1045.32	6125.45	1.97	218.55
8002.00	103.10	79.85	18.39	1.76	26.16	756.90	4597.34	1.41	154.78
8004.00	1024.00	77.90	16.70	1.92	27.11	470.51	3012.82	0.87	93.12
8008.00	132.00	77.45	16.32	2.43	24.57	419.62	2721.37	0.77	82.40
8010.00	96.70	78.80	17.47	2.31	23.82	588.29	3674.69	1.09	118.24
8012.00	193.80	78.80	17.47	2.21	24.35	588.29	3674.69	1.09	118.24
8016.00	269.20	83.94	22.08	1.82	22.12	1873.50	10289.31	3.60	407.73
8018.00	169.00	77.35	16.24	2.35	25.09	408.97	2659.91	0.75	80.17
8026.00	248.10	79.25	17.86	2.33	23.29	656.11	4048.91	1.22	132.86
8028.00	59.81	79.00	17.65	3.58	18.98	617.65	3837.25	1.15	124.55
8032.00	33.91	78.90	17.56	3.06	20.61	602.82	3755.23	1.12	121.36
8034.00	0.96	79.00	17.65	4.13	17.67	617.65	3837.25	1.15	124.55
8042.00	88.02	80.85	19.27	2.24	22.31	954.60	5650.53	1.80	198.35
8044.00	19.13	78.50	17.22	2.50	23.18	546.50	3441.73	1.01	109.28
8046.00	84.77	78.35	17.09	2.42	23.70	526.58	3329.98	0.97	105.03
8052.00	69.58	78.70	17.39	2.38	23.56	574.07	3595.61	1.06	115.18
8054.00	103.90	80.70	19.14	2.24	22.44	922.37	5480.66	1.73	191.20
8056.00	113.30	80.70	19.14	2.28	22.24	922.37	5480.66	1.73	191.20
8062.00	24.09	77.25	16.15	2.31	25.41	398.56	2599.62	0.73	77.99

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Table 14: *Variables (observed and modelled) for RESERVOIR II for m=1.65*

Depth (Ft)	Core Derived Perm., K_{CORE} (mD)	Sonic Transit Time (μs/ft)	Sonic log-derived Porosity, ϕs (%)	Formation Resistivity (Ωm)	Water Saturation (%)	K_{RGPZ} (mD)	K_{TM} (mD)	K_{BM} (mD)	K_{VBM} (mD)
8340.00	4.62	85.60	23.65	5.97	11.54	2630.03	13909.93	5.10	585.86
8342.00	213.50	83.09	21.29	7.10	11.54	1565.56	8771.37	2.99	336.53
8348.00	772.20	83.36	21.54	10.12	9.57	1658.21	9231.29	3.17	357.86
8350.00	1306.00	84.55	22.65	12.81	8.16	2125.82	11512.26	4.10	466.67
8360.00	455.00	83.55	21.72	19.92	6.78	1726.23	9567.13	3.31	373.57
8364.00	1887.00	91.90	29.98	24.30	4.70	8505.84	39485.91	17.10	2053.83
8366.00	1873.00	83.95	22.09	13.57	8.10	1877.42	10308.43	3.60	408.64
8370.00	88.49	84.50	22.61	13.40	8.00	2104.07	11407.55	4.05	461.57
8372.00	159.30	87.71	25.70	15.75	6.64	3968.73	20052.16	7.79	909.41
8384.00	95.97	81.40	19.76	7.20	12.19	1081.21	6312.05	2.04	226.58
8386.00	76.55	82.50	20.75	7.04	11.84	1378.61	7833.86	2.62	293.77
8394.00	456.70	85.30	23.36	10.01	9.00	2476.30	13184.79	4.79	549.34
8396.00	112.40	83.05	21.26	6.44	12.13	1552.23	8704.92	2.96	333.47
8398.00	6.12	81.55	19.90	6.22	13.04	1118.17	6503.45	2.11	234.87
8400.00	0.18	82.00	20.30	6.50	12.55	1235.66	7107.47	2.34	261.34
8402.00	859.10	81.45	19.81	9.39	10.65	1093.41	6375.31	2.07	229.32
8404.00	74.33	81.15	19.54	7.64	11.94	1021.97	6003.66	1.93	213.34
8406.00	245.30	80.00	18.52	8.42	11.89	784.09	4743.83	1.47	160.73
8412.00	471.60	84.75	22.84	5.34	12.56	2214.75	11939.39	4.27	487.56
8414.00	6.31	82.90	21.12	4.32	14.89	1503.09	8459.56	2.87	322.20
8422.00	107.00	85.15	23.22	3.67	14.95	2402.42	12834.57	4.65	531.84
8432.00	544.10	81.80	20.12	5.07	14.31	1182.19	6833.39	2.24	249.27

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8436.00	11.89	81.35	19.72	4.58	15.31	1069.13	6249.32	2.02	223.88
8438.00	2.02	83.70	21.86	3.71	15.62	1781.64	9839.59	3.42	386.40
8442.00	119.70	79.70	18.26	4.05	17.35	730.53	4454.69	1.36	149.03
8446.00	6.47	82.29	20.56	3.70	16.45	1316.92	7521.44	2.50	279.74
8454.00	131.80	82.40	20.66	4.51	14.84	1348.93	7683.74	2.56	287.02
8456.00	61.42	80.55	19.00	3.61	17.78	891.09	5315.13	1.67	184.28
8458.00	155.20	82.60	20.85	3.72	16.23	1408.86	7986.46	2.68	300.66
8464.00	185.50	80.25	18.74	2.25	22.78	831.27	4996.72	1.56	171.09
8468.00	0.72	81.55	19.90	3.37	17.72	1118.17	6503.45	2.11	234.87
8470.00	1.91	78.71	17.40	3.57	19.23	575.48	3603.45	1.07	115.49
8472.00	1.45	81.80	20.12	2.11	22.18	1182.19	6833.39	2.24	249.27
8480.00	192.60	81.90	20.21	1.71	24.55	1208.67	6969.28	2.29	255.24
8482.00	14.22	81.30	19.67	2.14	22.44	1057.17	6187.12	1.99	221.20
8488.00	1323.00	79.36	17.96	2.03	24.84	673.67	4145.10	1.25	136.66
8490.00	57.67	82.45	20.71	1.77	23.65	1363.70	7758.49	2.59	290.38
8502.00	10.94	78.85	17.52	3.88	18.34	595.52	3714.78	1.10	119.79
8508.00	233.60	81.00	19.40	2.14	22.70	987.79	5824.83	1.86	205.72
8512.00	1230.00	78.90	17.56	1.95	25.82	602.82	3755.23	1.12	121.36
8522.00	391.90	80.90	19.31	1.84	24.57	965.55	5708.13	1.82	200.78
8524.00	766.50	84.55	22.65	1.44	24.35	2125.82	11512.26	4.10	466.67
8528.00	1382.00	88.70	26.68	1.10	24.34	4781.19	23662.38	9.44	1109.68
8538.00	211.90	83.70	21.86	1.88	21.95	1781.64	9839.59	3.42	386.40
8542.00	2594.00	94.60	32.89	1.00	21.48	13464.94	59396.91	27.44	3355.47
8544.00	8.31	85.90	23.93	1.61	22.01	2792.05	14669.10	5.43	624.51
8550.00	1261.00	86.39	24.41	1.21	24.98	3075.54	15985.81	5.99	692.51
8552.00	1906.00	81.06	19.46	1.93	23.85	1001.34	5895.81	1.89	208.74
8554.00	371.70	81.90	20.21	1.66	24.92	1208.67	6969.28	2.29	255.24

8564.00	308.40	80.40	18.87	1.91	24.58	860.73	5153.85	1.61	177.58
8570.00	1333.00	85.95	23.98	1.73	21.19	2819.89	14799.03	5.48	631.17
8572.00	195.50	88.10	26.08	1.35	22.39	4272.95	21412.81	8.41	984.10
8576.00	1388.00	81.90	20.21	1.38	27.33	1208.67	6969.28	2.29	255.24
8578.00	1349.00	81.35	19.72	1.77	24.63	1069.13	6249.32	2.02	223.88
8582.00	126.30	87.00	25.00	1.29	23.72	3463.52	17766.33	6.77	786.25
8592.00	782.50	78.15	16.92	1.91	26.90	500.99	3185.73	0.92	99.59
8598.00	1156.00	84.40	22.51	1.52	23.82	2061.17	11200.56	3.97	451.52
8600.00	1098.00	82.35	20.62	1.89	22.97	1334.30	7609.60	2.54	283.69
8602.00	941.30	81.45	19.81	1.62	25.65	1093.41	6375.31	2.07	229.32
8612.00	104.40	79.10	17.73	2.25	23.84	632.79	3920.77	1.18	127.82
8616.00	722.60	80.35	18.83	1.90	24.69	850.81	5101.02	1.59	175.39
8630.00	12.65	80.85	19.27	2.80	19.96	954.60	5650.53	1.80	198.35
8634.00	1.04	81.00	19.40	4.35	15.92	987.79	5824.83	1.86	205.72

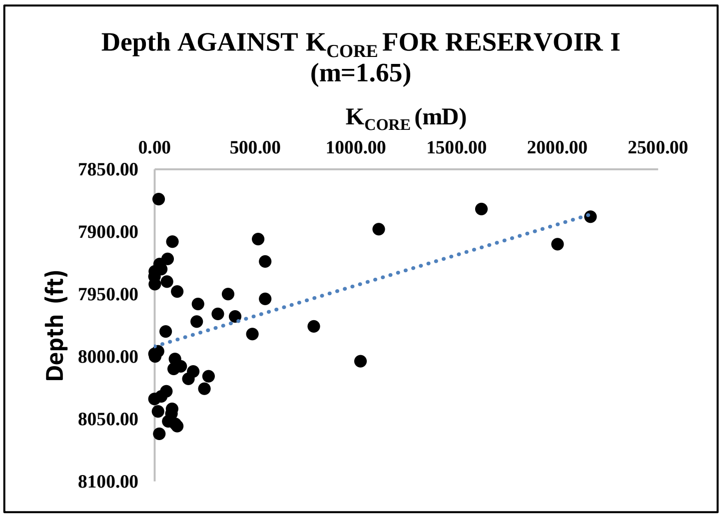

Figure 2: A graph showing the variation of depth core derived permeability for RESERVOIR I

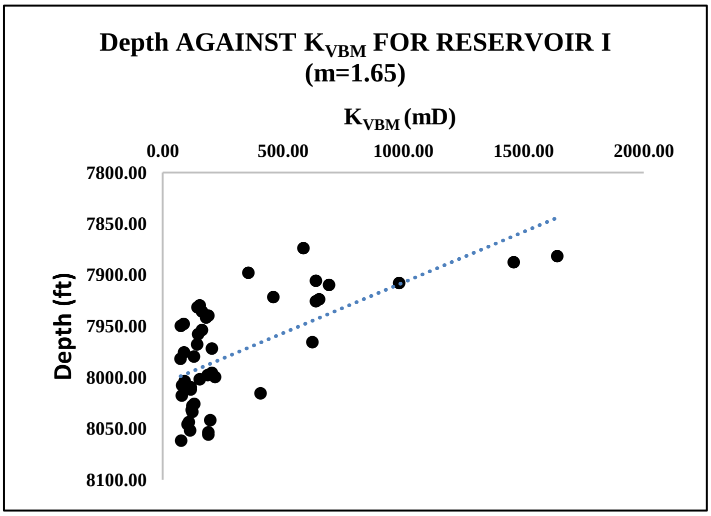

Figure 3: A graph showing the variation of depth with permeability estimated using Van Baaren's model for with RESERVOIR I (For m=1.65)

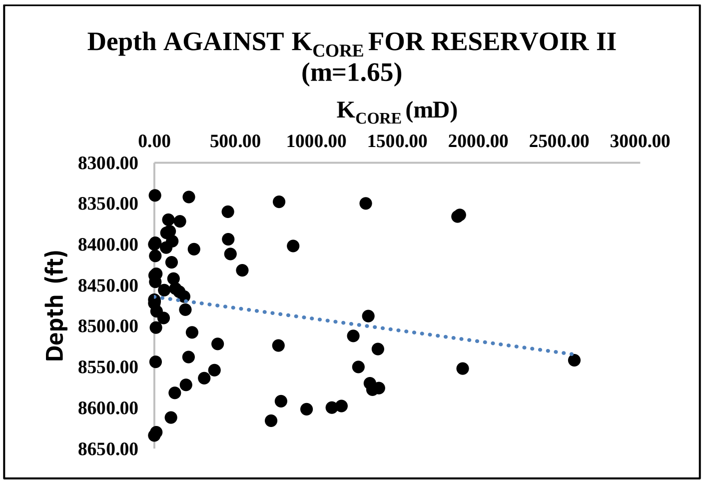

Figure 4: *A graph showing the variation of depth with core derived permeability for RESERVOIR II*

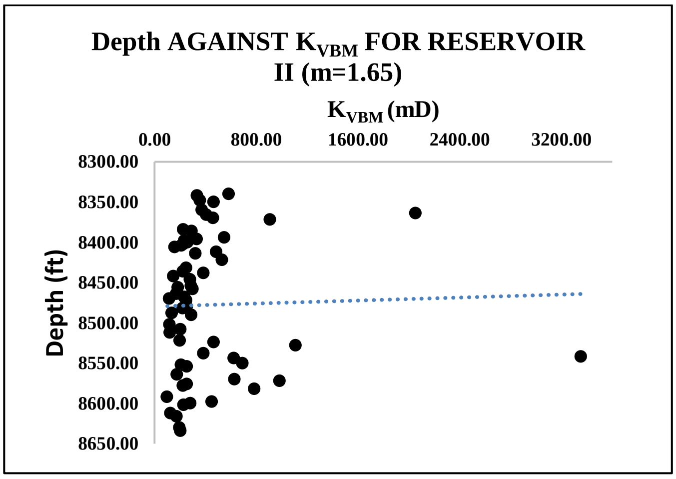

Figure 5: *A graph showing the variation of depth with permeability estimated using Van Baaren's model for RESERVOIR II (For m=1.65)*

4.2 Discussions

Tables 2 to *12* in the result section show the estimated RMSE and NRMSE values for the models in RESERVOIRS I and II. With NRMSE values of 1.20 (for RESERVOIR I) and 1.09 (for RESERVOIR II), as shown in *Table 3*, Van Baaren's model provides better estimates, relative to the applied permeability models, of the in-situ permeabilities for the reservoir under investigation at a cementation factor of 1.65. This value of cementation factor is typical of sandstone reservoirs according to John et al. (2016) and (Mavko et al., 2009).

Tables 13 and *14* show the result for all the modelled variables for RESERVOIRS I and II at a cementation factor of 1.65. It is evident from these tables that at this cementation factor, the in-situ permeability of the reservoirs of interest (as described by estimated permeabilities from core analysis; K_{CORE} on the tables), are over-estimated by the RGPZ model, grossly over-estimated by Timur's model and grossly under-estimated by Berg's model.

Figures 2 and *3* show the permeabilities estimated from core and those estimated from Van Baaren's model, at a cementation factor of 1.65 for RESERVOIR I, plotted against depth. Both figures show a decreasing permeability with increasing depth which might be attributed to increasing effect of diagenesis with increasing depth (Ehrenberg et al., 2006; Giles et al., 1992; Loucks et al., 1986). *Figures 4* and *5* show the same kinds of plot for RESERVOIR II, located deeper in the formation. *Figure 4* shows an increasing permeability with depth which might be attributed to fractioning and solution (Tiab & Donaldson, 2011) or disequilibrium compaction and the onset of overpressure (Nwozor et al., 2013) deep in the reservoir. Though both figures are for the same reservoir, *Figure 3* shows a trend that is indicative of a small rate of decreasing permeability with depth. This misrepresentation by the predictive model might be attributed to the fact that this model could not account for the degree of heterogeneity in the reservoir, according to Balan et al. (1995), deep in the formation. In other words, though Van Baaren's model is presented here as the best permeability predictive model, it is still wrought with errors which could be due to the fact that all empirical models are quite erroneous in predicting the permeabilities of a heterogeneous formation (Balan et al., 1995).

5. CONCLUSIONS

Aimed at deciding how best to empirically estimate permeabilities in the Niger Delta reservoirs, in the absence of core data, reservoir permeabilities estimated from four empirical models (RGPZ model, Van Baaren model, Timur's model, Berg's model), at different cementation factors, were compared to permeabilities estimated from core analysis. The most reliable predictive model was identified by estimated the normalized root mean square error (NRMSE) of different predictive models. The findings from this research includes;

- There is a general decrease of permeability with depth for the shallower reservoir, with a reversed trend of increasing permeability for the reservoir at deeper depths possibly attributed to increased process of diagenesis with depth or disequilibrium compaction and the onset of overpressure.
- The sandstones of the reservoirs in the Niger Delta have a typical cementation factor of 1.65.
- Van Baaren's model provided a better estimate of the in-situ reservoir permeability in the Niger-Delta.

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