

Petrophysics of the B-Reservoir in Eyrarn Field, Onshore Niger Delta

*¹OMOLAIYE G. E and ²SANUADE O. A

¹Orion Energy Services Limited,
Plot 14 Dapo Sholanke Close,
Off Emeka Nweze Street
Lekki Phase one, Victoria Island, Lagos, Nigeria

² Professionals Experts and Energy Company
Limited,
45 Agodogba Avenue, Parkview Estate,
Lagos, Nigeria

ABSTRACT

Evaluation of Eyrarn field reservoir has been undertaken in this work for determination and distribution of petrophysical properties, fluid type and hydrocarbon contact within B-Horizon using log data.

Eyrarn field is located in onshore area of the Niger Delta and it essentially contains oil and gas producing reservoirs. The field consists of the reservoirs of the Agbada Formation, Niger Delta, a succession of alternating deltaic sands and shale layers.

Well log data from 21 wells of the field were studied to characterize the porosity, permeability and water saturation of the B-reservoir. The logs were environmentally corrected and normalized, volume of shale, permeability and porosities were calculated, water saturation were determined by Archie's equation and dual water model, and net pay was calculated.

Within the B-reservoir of the Eyrarn field, the average well has 103.94ft of net sandstone, having average porosity of 26%. Shale volume ranges from 2% to 31% with an average of 21%. The average permeability is 399mD, average water saturation is 48% while average hydrocarbon saturation is 52%.

Porosity and permeability in the field is high on the average due to very good to excellent sand quality.

Keywords: Petrophysical properties, B-reservoir, Eyrarn field, Niger Delta, Archie's equation, Porosity, Permeability

1. INTRODUCTION

Eyrarn is located in onshore area of the Niger Delta, the field consists of the reservoirs of the Agbada Formation, Niger Delta, a succession of alternating deltaic sands and shale layers. Three major lithostratigraphic units have been recognized in the Niger Delta {[1]; [2]; [3]; [4]}. These are the Akata, Agbada and Benin Formations. These Formations were deposited in the continental transitional and marine environments, and together they form a thick, overall progradational passive margin wedge.

The evaluation of reservoir rocks in terms of their porosity, water saturation and permeability determinations, enhances the ability to predict abnormally pressured zones, to estimate

Telephone: +2348055826966

Email Address: gab_omolaiye@yahoo.co.uk

32 hydrocarbon reserves and reservoir bed thickness, and to distinguish between gas, oil and
33 water bearing strata, by observing their electrical resistivity and relative permeability values
34 {[5]; [6]; [7]}.

35 The aim of this paper is to compute various petrophysical parameters, with some
36 techniques, in B-reservoir of Eyram field with information from 21 wells. These techniques
37 include using well log data and combining various mathematical equations which ranges
38 from the linear, non-linear (Vsh Stieber) and the Archie's equations.

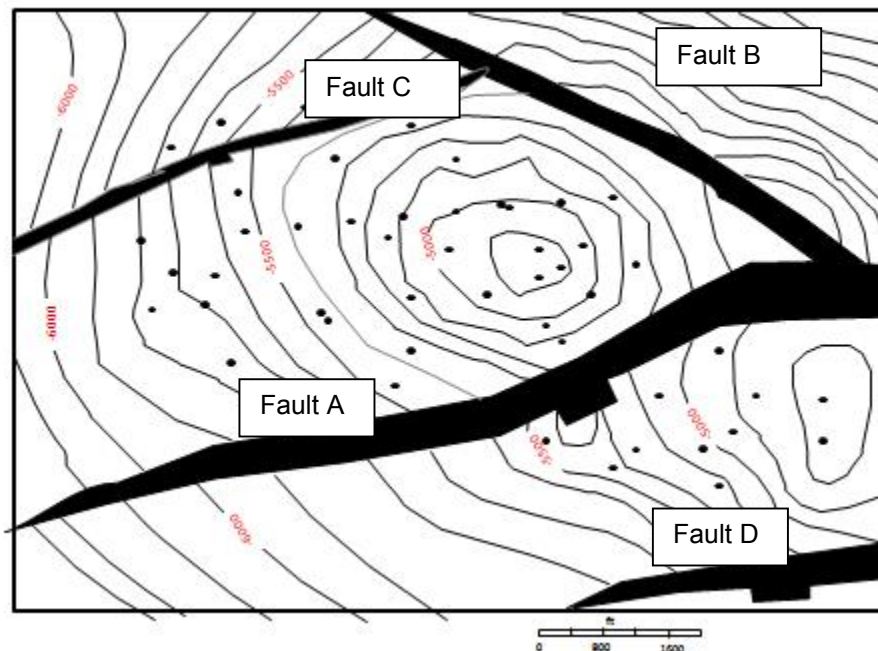
39 1.1 Objectives of Petrophysical Evaluation

40 The objectives of the petrophysical evaluation include:

- 41 • Determination of the distribution of petrophysical properties within B-
42 reservoir in Eyram Field
- 43 • Determination of fluid type and hydrocarbon contact from logs, where
44 possible; and
- 45 • Determination of net gas, oil and net reservoir intervals.

46 1.2 Structural setting of the Field

47 The field is a faulted anticlinal structure enclosed within structure building faults (Figure 1).
48 The faults are dipping towards the South, with Fault A being the most extensive, extending
49 almost through the entire breadth of the mapped area. The trapping potential of the field is
50 attributed to four way closure sandwiched within the faults and located at the center of the
51 field. Anticlinal or fault assisted closures are regarded as good hydrocarbon prospect in the
52 Niger Delta [8].



53
54 **Figure 1: B-Reservoir Top Structure Map**

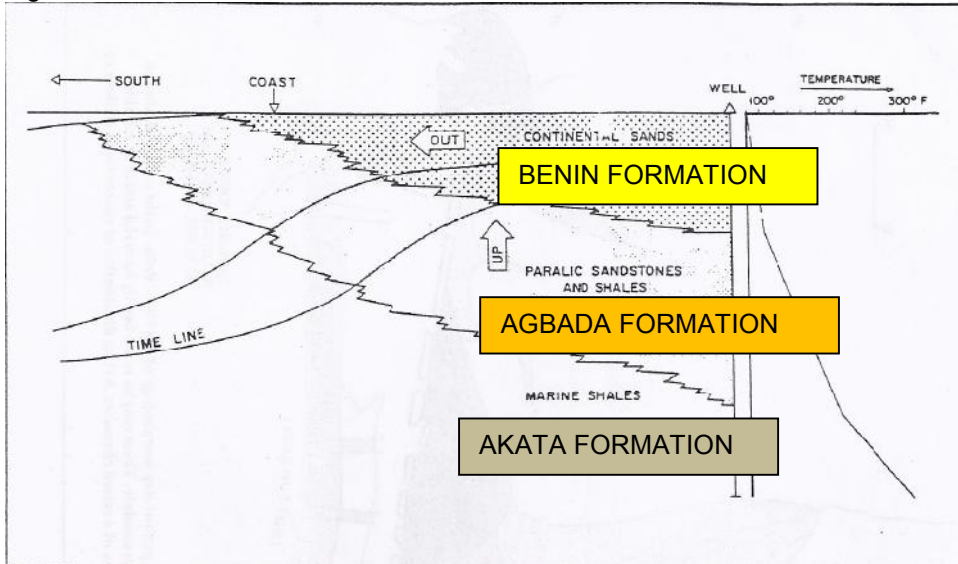
55 1.3 Geology of the Area

56 The Niger Delta which covers an area of about 7500 km² is a large acuate delta extending
57 between longitude 3° and 9°E and latitudes 4° and 6° N [9]. Its stratigraphy has been
58 described in detail by [1] and [10], of which they recognized three lithostratigraphic units i.e.
59 the Benin, Agbada and Akata Formations.
60
61

Telephone: +2348055826966

Email Address: gab_omolaiye@yahoo.co.uk

62 The Benin Formation is the uppermost and the youngest rock stratigraphic unit, while the
 63 Agbada Formation is a paralic sequence that is characterized by the alternation of sand
 64 bodies and shale layers. The Agbada Formation is also associated with syndimentary
 65 growth faulting and as well contains the bulk of the known oil accumulation in the Niger
 66 Delta. The Akata Formation is the lowest unit with evidence of some hydrocarbon and is
 67 under compacted in much of the delta (Figure 2).
 68 The growth faults in the Niger Delta according to [11] are considered to be the major
 69 migration conduit and leading factor controlling the hydrocarbon distribution pattern in the
 70 Niger Delta.



71
 72 **Figure 2: Lithofacies of Niger Delta Basin [12]**
 73

74 **2. METHODS**

75 **2.1 Data Sources**

76 A comprehensive suite of logs acquired in the wells were examined and the relevant curves
 77 were integrated. (Figure 3). A reservoir called B-reservoir was discussed in this study

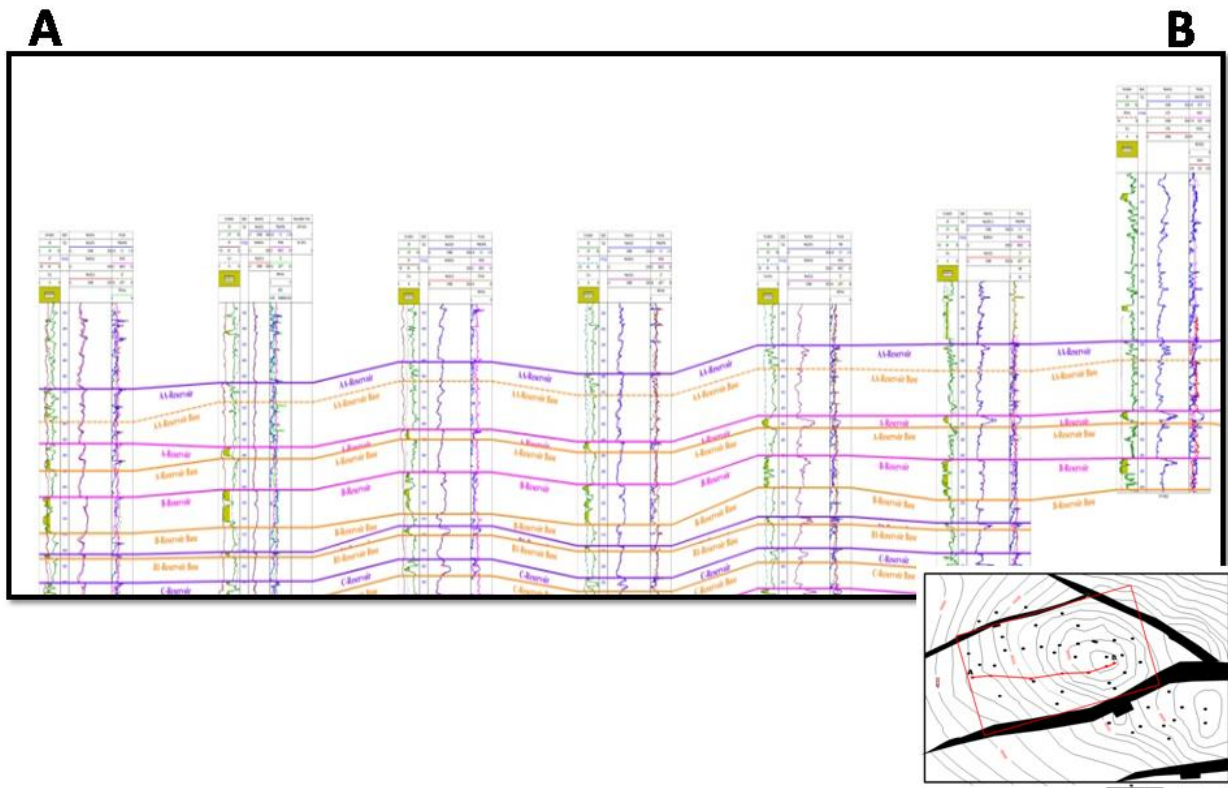


Figure 3: Lithologic Correlation of some wells in Eyram Field

The basic analysis procedure used involves the following steps, each of which is described in the following sections:

- Loaded and validated log data
- QC and depth matched logs
- Environmental corrections and
- Formation evaluation

2.2 Environmental Corrections and Log Normalization

Most petrophysical field studies begin by normalizing the log data to minimize differences caused by random logging errors and other noise in the data set. This noise results from a variety of causes. Logging tools built by different vendors can have different responses to identical formation conditions [13].

The environmental corrections applied to this data included (1) borehole size and mud weight correction to the gamma-ray logs; and (2) matrix corrections to the neutron porosity. Gamma-ray logs were offset to match a consistent clean sandstone line, and a gain correction was applied to match the sandstone-to-shale span of the composite histogram in the same wells used for the porosity normalization (Figure 4). The form of the equation used was:

$$GRC = [(GR - GR_{sd}) \times (GR_{sh_T} - GR_{cl_T}) / (GR_{sh} - GR_{sd})] + GR_{cl_T} \dots \dots \dots [1]$$

where GR is the environmentally corrected log value at each depth, GR_{cl_T} is the target clean sandstone value from the type histogram (45 API units), GR_{sh_T} is the target shale value from the type histogram (110 API units), GR_{sd} is the observed sandstone reading on the subject well histogram, and GR_{sh} is the observed shale on the subject well histogram.

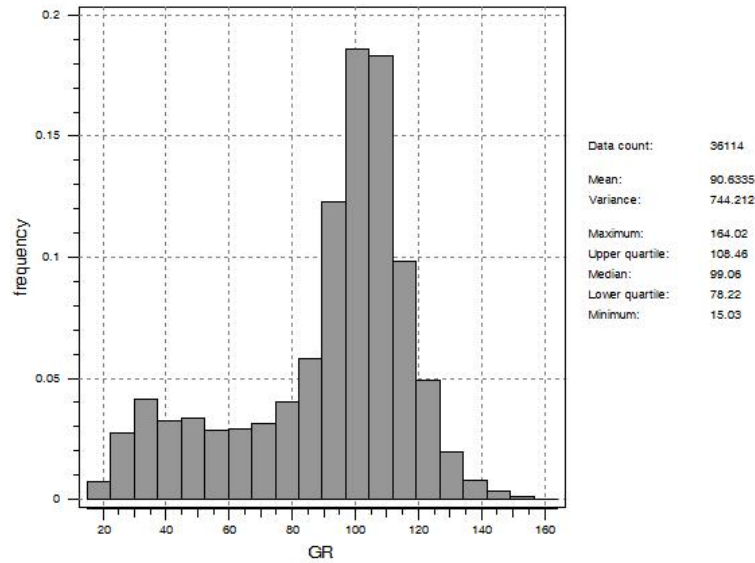


Figure 4: Type histogram for gamma ray (GR) log normalization

Neutron-porosity and bulk-density logs were normalized to match a suite of “type” logs. Composite histograms for each measurement were constructed from the data over the top of reservoirs in these wells (Figures 5 and 6).

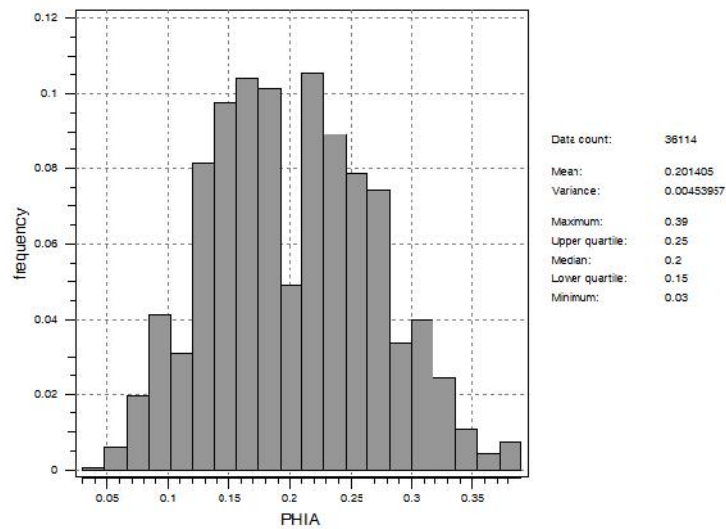


Figure 5: Type histogram for neutron-porosity (PHIA) log normalization

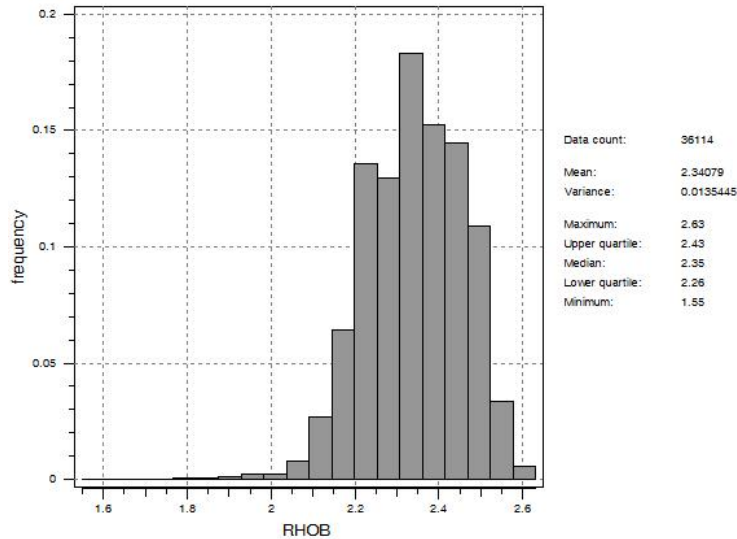


Figure 6: Type histogram for bulk-density (RHOB) log normalization

2.3 Log Evaluation

The petrophysical evaluation of all the twenty one wells was performed and are stated below:

2.3.1 Shale Volume, Total Porosity and Effective Porosity

Shale volume (V_{sh}) was computed from the gamma ray curve. Gamma ray log values were first applied to calculate Gamma Ray Index (I_{GR}), a very essential step. This is because I_{GR} is independent of clay types. The I_{GR} was determined as follows:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \dots \dots \dots [2]$$

Where I_{GR} is the gamma ray index, GR_{log} is the actual gamma value for the formation at a given depth, GR_{min} is the minimum gamma ray or cleanest sand reading and GR_{max} is the maximum gamma ray or shaliest reading. [14] equation was used to calculate shale volume. This equation is given as:

$$V_{sh} = \frac{I_{GR}}{3.2 \times I_{GR}} \dots \dots \dots [3]$$

where V_{sh} is the shale volume and I_{GR} is the gamma ray index.

“Total porosity” is the total pore volume of the rock and includes porosity filled with hydrocarbons, moveable water, capillary-bound water, and clay-bound water [15].

Both the density and neutron logs are considered total porosity tools, because they detect all the porosity in a region surrounding the logging tool, although they have different volumes of investigation and are responding to different physical phenomena that are indirectly related to porosity (electron density in the case of the bulk-density log and hydrogen density in the case of the neutron log). In shaly formations, they read very different values; in particular, the neutron log is strongly affected by hydrogen associated with clay-bound water and reads a much higher apparent porosity than the density log. “Effective porosity” is normally considered that part of the total porosity that is available for hydrocarbon storage and is also

physically interconnected so that fluids can actually move between the pores. In vuggy carbonate rocks, for example, there may be isolated vugs that are part of the total porosity, but which have no pore throats that would allow fluids to move in or out of the vugs. These are not considered part of the effective pore system. In shaly sandstones, a significant portion of the porosity is occupied by clay bound water that is immobile under all conditions and consequently is not part of the effective pore space. We use effective porosity for the fraction of the total porosity that is not associated with clay minerals, thus excluding the volume of clay-bound water but including capillary-bound water on grain surfaces. By this definition, the effective porosity of shale is zero, whereas a clean sandstone has an effective porosity equal to the total porosity. Because it is unlikely that there is much truly isolated porosity in fine-grained clastic rocks, this definition of effective porosity is very close to the hydraulically connected pore volume.

The total porosity (PHIA) of reservoir intervals was calculated based on the equation below:
.....[4]

Where PHIA (ϕ) = Total Porosity,

PHIA = (RhoM - RHOB) / (RhoM - RhoF)

RhoM = Matrices Density; RHOB = Log Density Interpreted, RhoF = Fluid Density

In this work the value of RhoM was taken as 2.65 g/cm³, while RhoF is 1g/cm³ for water, 0.8g/cm³ for oil and 0.6g/cm³ for gas.

Effective porosity was computed separately for each porosity tool from the matrix-corrected total porosity, V_{sh} , and average values for the total porosity of shale by equations of the form

PHIDE (ϕ_e) = PHIA - (V_{sh} x PHIA_{Sh}) -----[5]

where PHIDE (ϕ_e) is the effective porosity, PHIA is the total porosity from density log,

PHIA_{Sh} is the total density porosity of shale and V_{sh} is the linear shale index from equation 3.

2.3.2 Water Saturation

Water saturations were computed using the dual water model [16] with a constant R_w and Archie's water saturation equation [17]. In this study, the R_w was derived from Pickett Plots (Figure 7) and found to be 0.244 ohm.m.

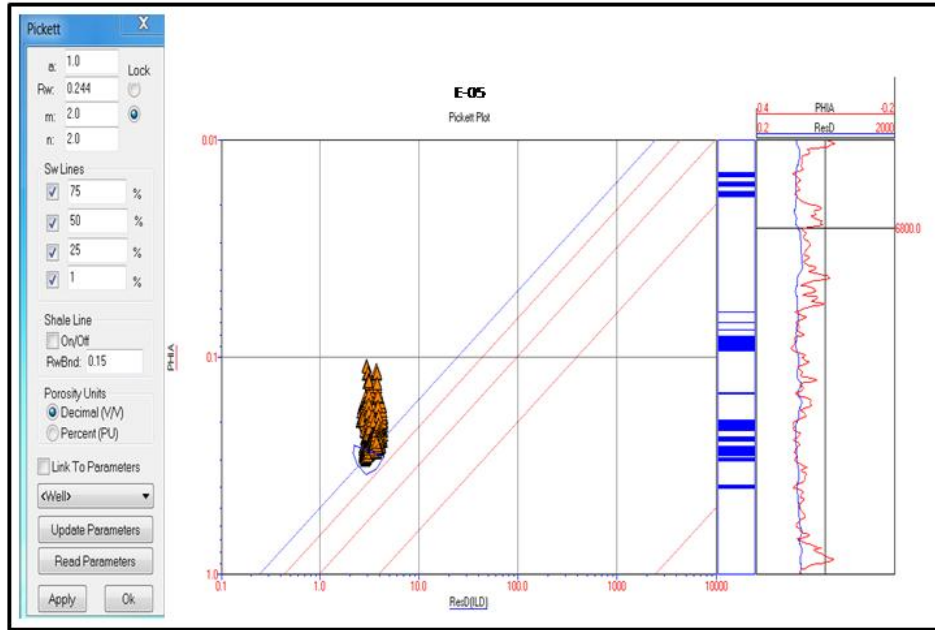


Figure 7: B-Reservoir Pickett Plot of E-5 Well showing R_w Value
The Archie's (1942) Method

The refined form of Archie's (1942) equation is given as;

$$S_w^n = \frac{F \times R_w}{R_t} \text{-----[6]}$$

While the general form of the (Archie, 1942) equation is given thus;

$$S_w = \left(\frac{a \times R_w}{R_t \times \phi^m} \right)^{\frac{1}{n}} \text{-----[7]}$$

where S_w is the connate water saturation, R_w is the formation water resistivity, R_t is the true formation resistivity, m is the cementation factor and n is the saturation exponent, both were assigned the value of 2 respectively in this work, 'a' is tortuosity and taken as 1, while ϕ is the log derived porosity.

The Dual Water Method

The content of clay in sand, such as, deltaic sand of the Niger Delta, makes the use of (Archie, 1942) equation associated with incorrect water saturation values. Therefore, Dual Water Model (DWM), {[18]; [19]} was used for this study. A simplified dual-water-model equation is given as;

$$SwT = Y + \sqrt{\left(\frac{R_w}{R_t \times \phi^2} + Y^2 \right)} \text{-----[8]}$$

Where Y is given by;

$$Y = V_{shl} * \left(\frac{(R_w B_{nd} - R_w)}{(2 * R_w B_{nd})} \right) \text{-----[9]}$$

Where $S_w T$ is the total water saturation, R_t is the true or deep resistivity, B_{nd} is the bond water resistivity, taken as 15 ohms, R_w is the formation water resistivity and V_{sh} is volume of shale.

2.3.3 Permeability

Three empirical methods were used to calculate the field permeability for the purpose of comparison and reliability checks. The methods used were those of [20], [21] and [22, 23]. [21] worked on [24] permeability equation and gave an expression thus;

$$k = 0.136 \frac{\phi^{4.4}}{S_{wi}^2}, \text{-----[10]}$$

[20] further modified his equations to a simpler form, as given thus;

$$k^{1/2} = 250 \frac{\phi^3}{S_{wi}}, \text{-----[11]}$$

where S_{wi} is the irreducible water saturation.

[22] contributed to empirical permeability derivation with the equation;

$$k^{1/2} = \frac{C}{W^4} \frac{\phi^{2w}}{R_w / R_{ti}}, \text{-----[12]}$$

where C is given as; $C = 23 + 465 \rho_h - 188 \rho_h^2$, and -----[13]

$$W^2 = (3.75 - \phi) + \frac{1}{2.0} \left[\log_{10} \left(\frac{R_w}{R_{ti}} \right) + 2.2 \right]^2, \text{-----[14]}$$

For shaly formation, they gave another equation;

$$\left(\frac{R_w}{R_{ti}} \right) = \frac{R_w V_{sh}}{\phi R_{sh}} (\phi S_{wirr})_{cn} + \frac{(\phi S_{wirr})_{cn}^w}{(1 - V_{sh})^{w-1}}, \text{-----[15]}$$

In this work, the [22, 23] equations were reduced to a simplified form, thus;

$$k = (70 * \phi_e^2 * (1 - S_w) / S_w)^2 \text{-----[16]}$$

2.3.4 Lithology Determination

The lithology of the reservoirs was determined applying electrofacies analysis of the gamma ray logs. The Sand/Shale ratio was used as follows:

Table 1: Sand/Shale ratio for the determination of Lithology

Shale Volume (V_{sh})		Lithology
$V_{sh} > 0$ and $V_{sh} < 33\%$	»	Sand
$V_{sh} > 34$ and $V_{sh} < 69\%$	»	Shaly Sand
$V_{sh} > 70$ and $V_{sh} < 100\%$	»	Shale

2.3.5 Determination of Hydrocarbon Types

The hydrocarbon fluid type was defined from the neutron/density log signature as follows:

The neutron-density cross-over criteria (large Neutron-Density cross-over) were used to define gas zones and gas reservoirs. The tracking of the neutron and density curves at intervals with high resistivity was used as general hydrocarbon criteria, attributed to oil in low V_{sh} interval.

2.3.6 Net Pay Determination

226 This conventional notion of net pay leads to the common use of three log- or core-based
227 petrophysical cut-offs to separate pay from non-pay:

228 (1) Shaliness: A volume of shale cutoff, commonly a gamma-ray or spontaneous potential
229 cutoff, is used to separate potentially permeable clean formation from presumably
230 impermeable shaly formation.

231 (2) Porosity: A porosity cut-off is used as a proxy for a permeability or flow cutoff. A porosity-
232 permeability crossplot can be used to define a porosity equivalent to a minimum permeability
233 considered capable of flowing hydrocarbons at commercial rates. Alternatively, a
234 comparison of production test or drillstem test flow rates on a large number of zones can be
235 used to determine the minimum porosity required for a commercial completion.

236 (3) Water saturation: A calculated water saturation cut-off is used to separate wet zones
237 from oil-bearing or gas-bearing pay intervals. In high-porosity and high permeability
238 sandstones, the transition zone from water wet to hydrocarbon saturation is commonly very
239 thin, with a significant difference in water saturation between high water saturation wet zones
240 and low water saturation pay zones. Thus, the actual water saturation cutoff may not be
241 critical, as long as it is between the average wet saturation and the typical hydrocarbon
242 saturation.

243 3. RESULTS AND DISCUSSION

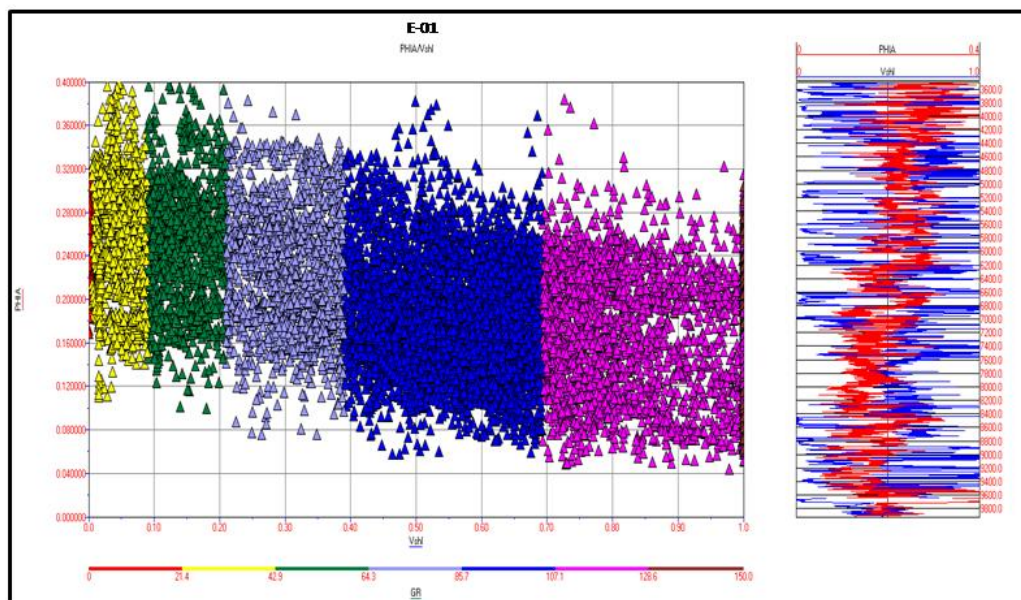
244 3.1 PETROPHYSICS OF THE EYRAM FIELD

245 Because wells in EYRAM field were drilled to different total depths and few wells penetrate
246 the entire reservoirs, it is difficult to sum the petrophysical properties in a manner that allows
247 meaningful well-to-well comparisons without the thickness of section drilled becoming a
248 significant variable.

249 Reservoir B was evaluated for the formation evaluation in this study.

250 3.2 Net Sandstone Thickness

251 A reservoir cut-off porosity value of 0.1, 0.7 cut-off for V_{sh} (Fig. 8) and 0.7 cutoff for Sw_T
252 were used, including the cross-plots for B-Reservoir encountered in E-1 well (Figures 9 and
253 10).
254
255

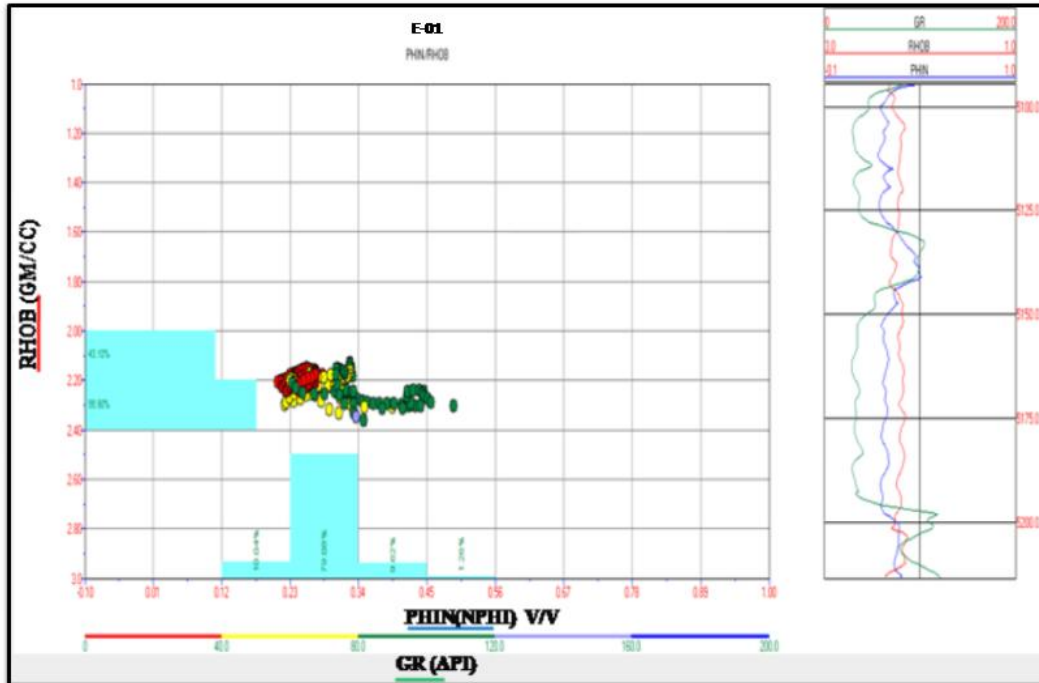


256
257

Figure 8: Cross Plot of E-1 Well Porosity (PHIA) versus Shale Volume (V_{sh})

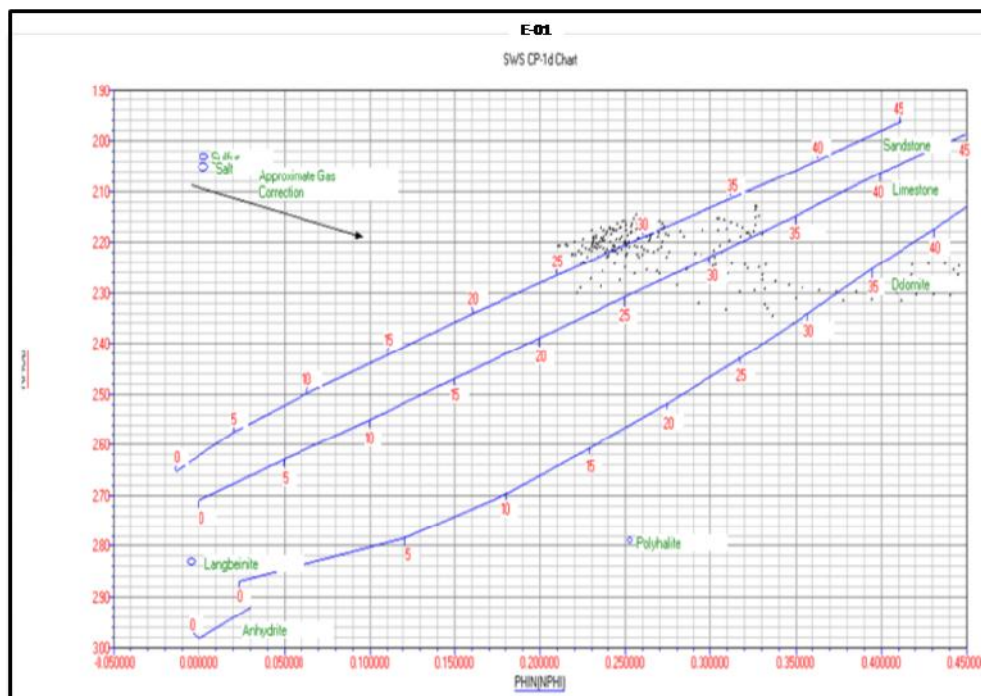
Telephone: +2348055826966

Email Address: gab_omolaiye@yahoo.co.uk



258
259

Figure 9: A Crossplot of RHOB vs PHIN(NPHI) for B-Reservoir in E-1 Well

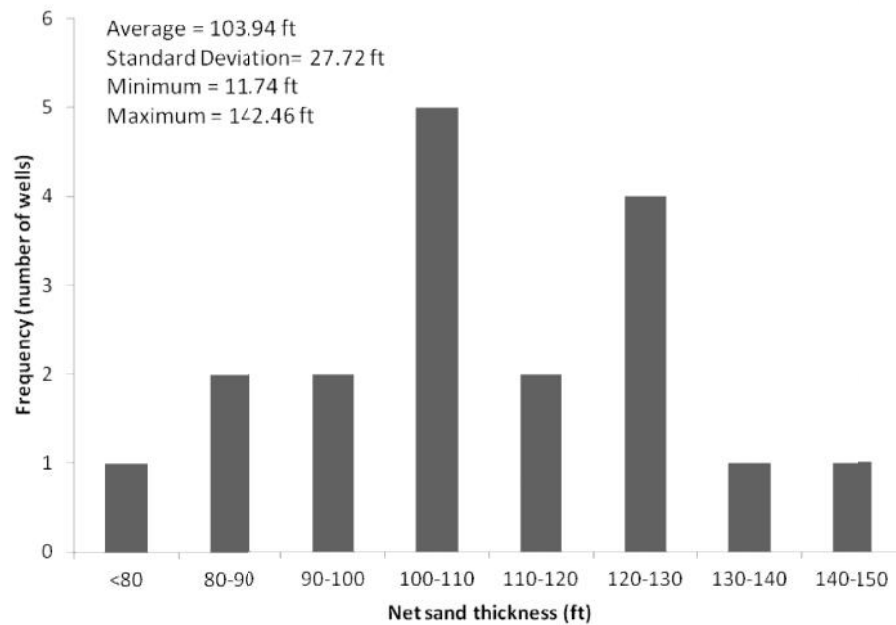


260
261
262
263
264
265

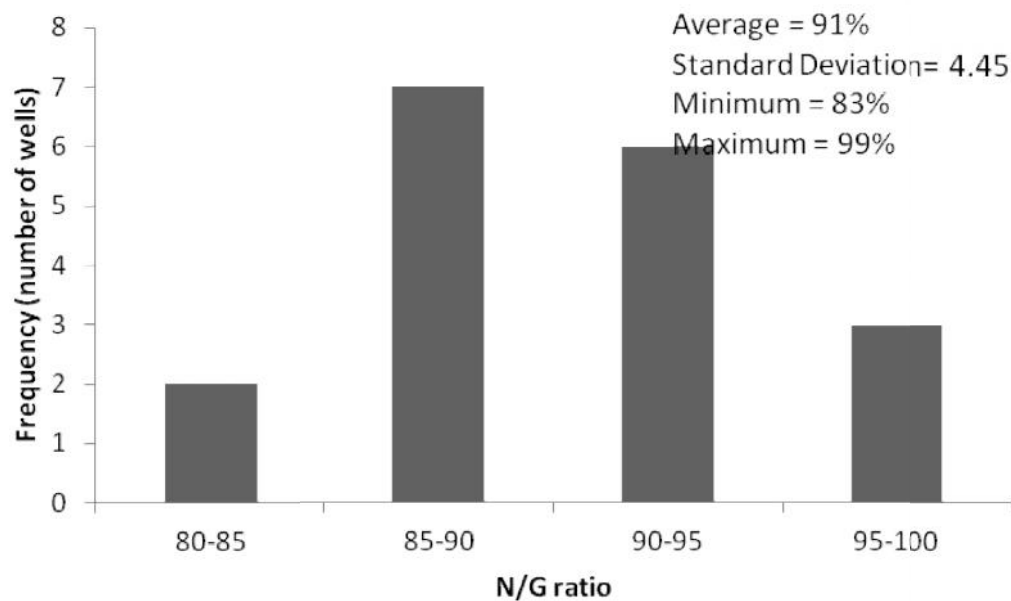
Figure 10: A Crossplot of RHOB vs PHIN(NPHI) for B-Reservoir in E-1 Well, showing the SWS Chart which plots in the Sand Facies.

The net thickness of sandstone in B-reservoir ranges from 11.74 to 142.46 ft with an average of 103.94 ft (Figure 11). The net/gross ratio ranges from 83% to 99% and averages about 91% (Figure 12). These values are high and are indication of good reservoir sand

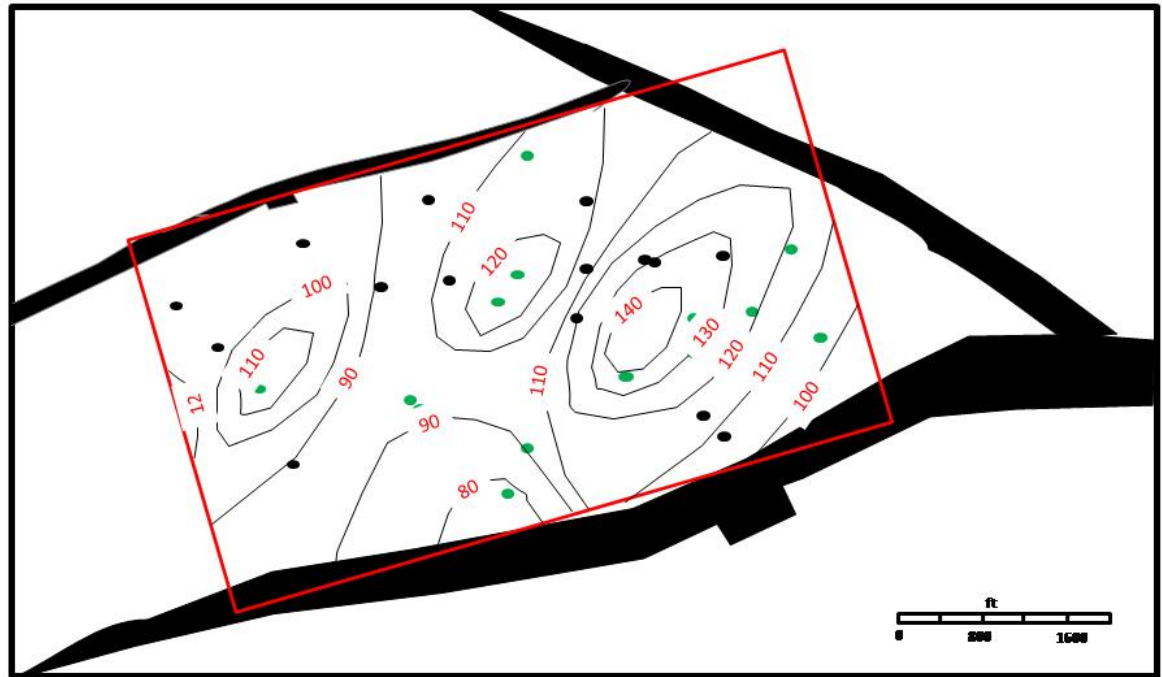
266 development. Figures 13 and 14 show areal distribution of both net sandstone net/gross
 267 respectively.
 268



269
 270 **Figure 11: Distribution of total net sandstone thickness by well in B-reservoir of**
 271 **Eyram field**
 272

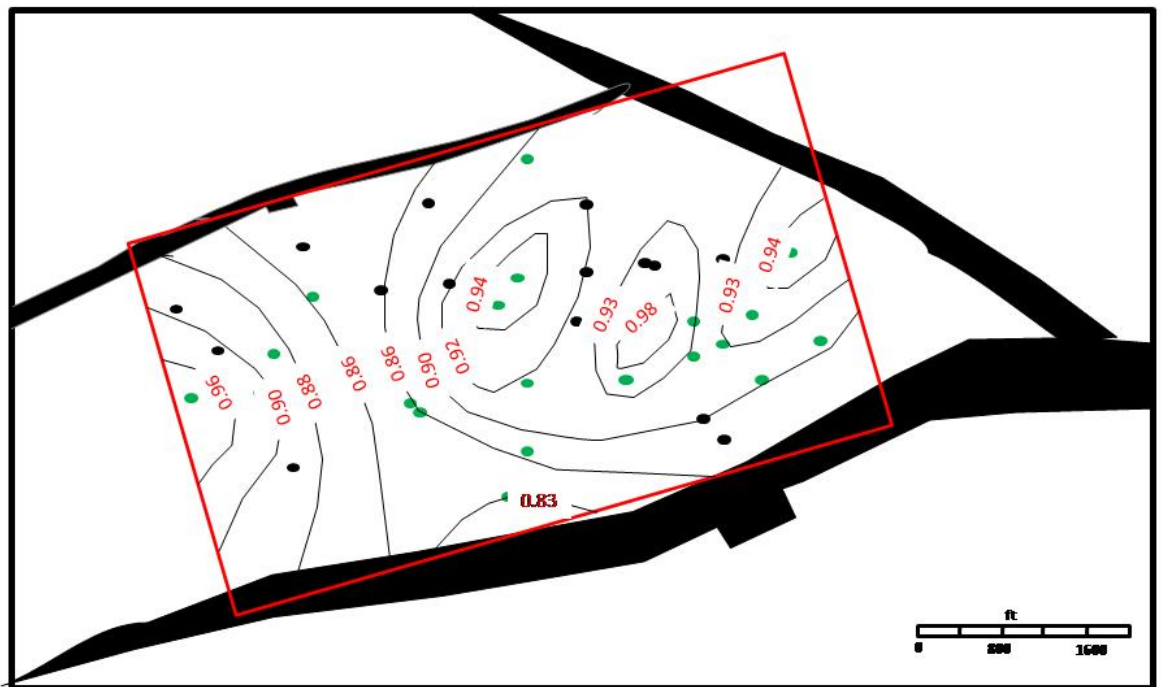


273
 274 **Figure 12: Distribution of the ratio of net sandstone to gross interval, by well, of B-**
 275 **reservoir**



276
277

Figure 13: Net feet of sandstone in the B-reservoir of the Eyrarn field.



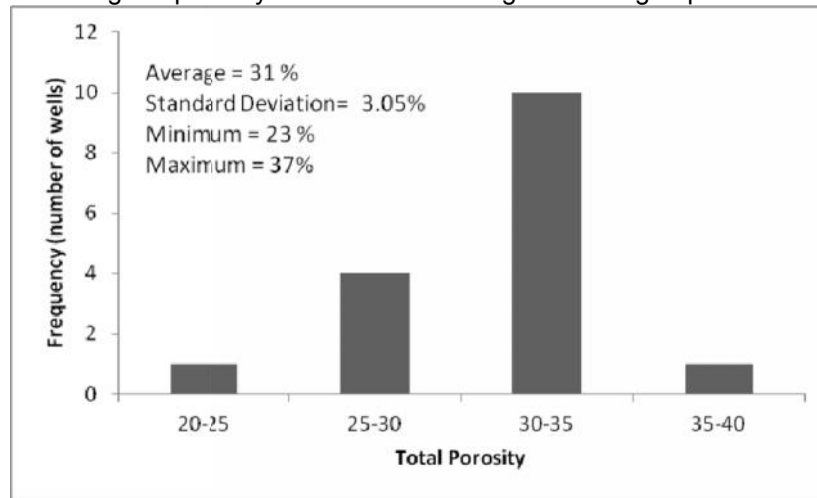
278
279
280
281
282

Figure 14: Ratio of net sand to gross interval in the B-reservoir of the Eyrarn field.

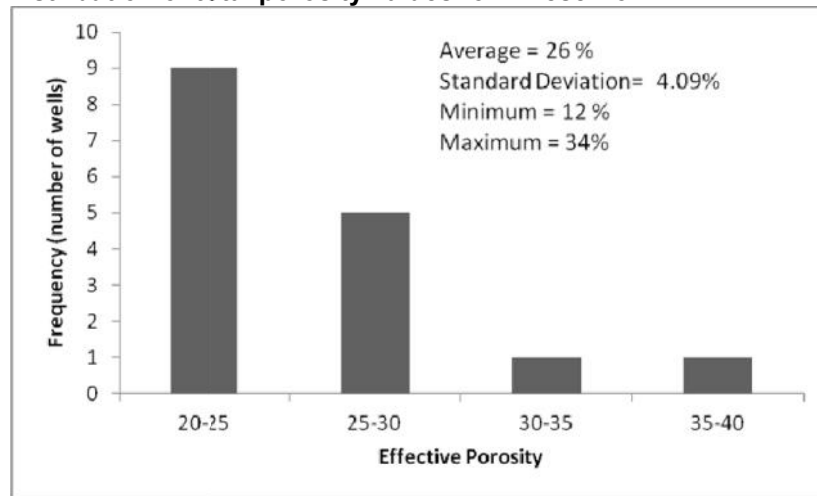
3.2 Porosity

The total porosity ranges from 15% to 40% with an average of 31% while the effective porosity ranges from 12% to 34% with an average of 26% (Figures 15 and 16). Figure 17

283 shows the essentially random variation in average porosity over the study area. Most wells
 284 exhibit a greater range of porosity values than the range of averaged porosities.



285
 286 **Figure 15: Distribution of total porosity values for B-reservoir**



287
 288 **Figure 16: Distribution of effective porosity values for B-reservoir**

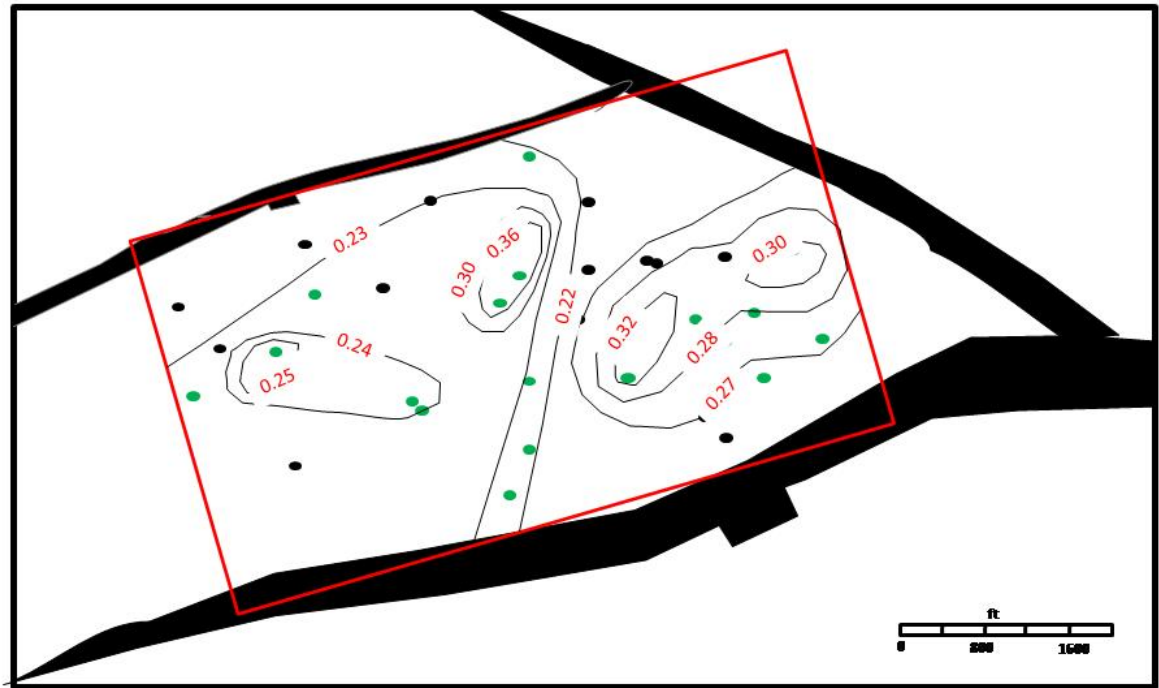


Figure 17: Contour map of average sandstone porosity (PHIE) in the B-reservoir of the Eyrarn Field

According to [25], the following table give better explanation of porosity description of reservoirs.

Table 2: Qualitative Evaluation of Porosity

Percentage Porosity (%)	Qualitative Description
0 - 5	Negligible
5 - 10	Poor
15 - 20	Good
20 – 30	Very Good
> 30	Excellent

From this classification, it could be said that most of the wells have porosity between very good and excellent. This may be due to very good to excellent sand quality.

3.3 Permeability

It was observed that the [20] method of permeability determination yielded the highest permeability values in the studied area and also more reliable. Permeability values range from 155 to 987 mD, 122 to 1364 and 75 to 395 with averages of 359mD, 399mD and 157mD for [21], [20] and [22, 23] respectively. Figure 18 shows the essentially random variation in average permeability of [21] over the study area. Most wells exhibit a greater range of permeability values than the range of averaged permeabilities.

[25] gave better explanation of permeability description of reservoirs (Table 3). The permeability values in all the wells are between good to excellent. This is as a result of very good to excellent sand quality.

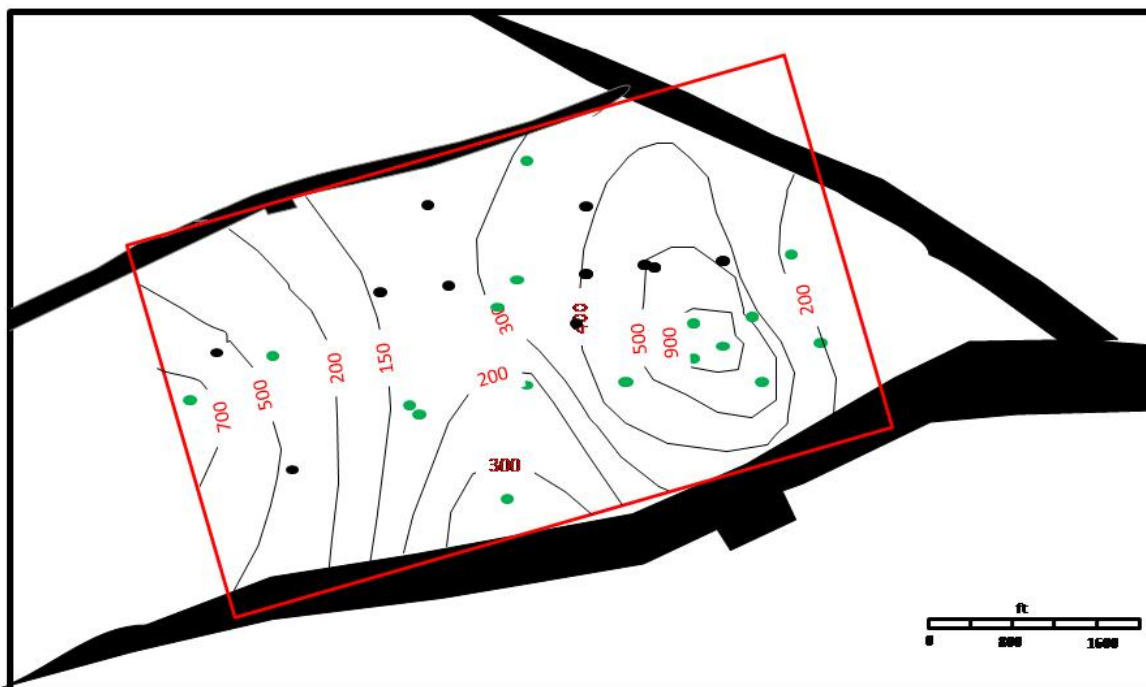


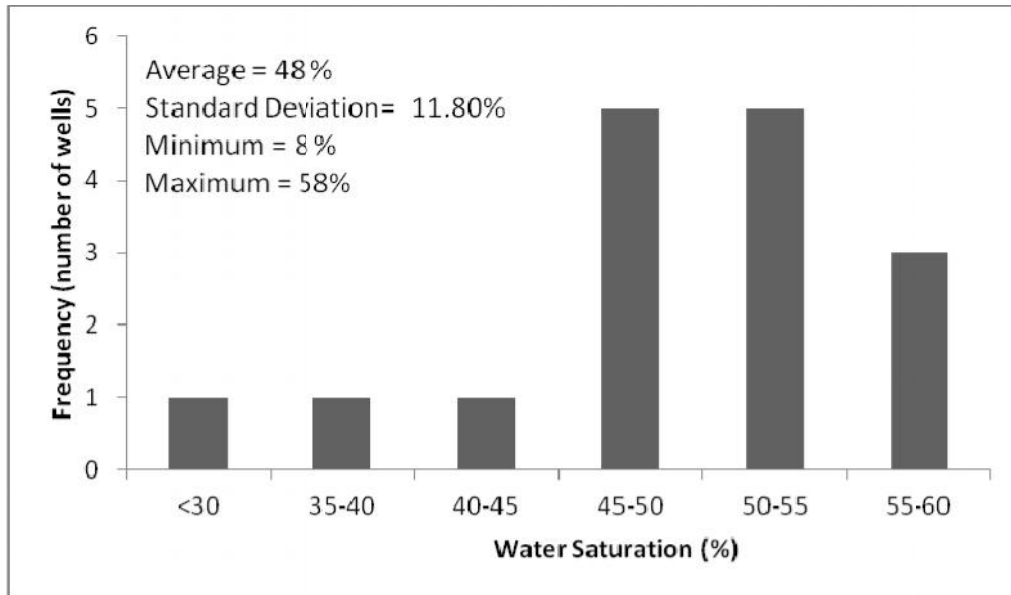
Figure 18: Contour map of average Permeability for sandstones in the B-reservoir of the Eyram Field

Table 3: Qualitative Evaluation of Permeability

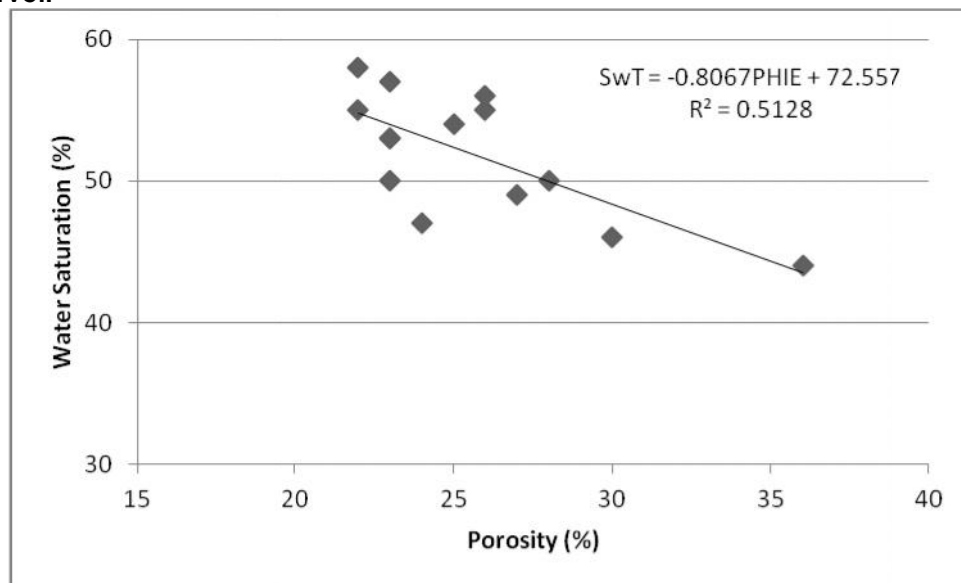
Average K_Value (mD)	Qualitative Description
<15	Poor to fair
15 – 50	Moderate
50 – 250	Good
250 – 1000	Very Good
> 1000	Excellent

3.4 Water Saturation

The water saturation per well by log analysis ranged from 8% to 58%, with an average of 48% (Figure 19). Water saturation correlates with porosity (Figure 20).



331
332 **Figure 19: Distribution of average water saturation from log analysis, per well, for B-**
333 **reservoir**



334
335 **Figure 20: Trend of decreasing average water saturation with increasing average**
336 **porosity in B-reservoir of the Eyrarn field.**

337
338

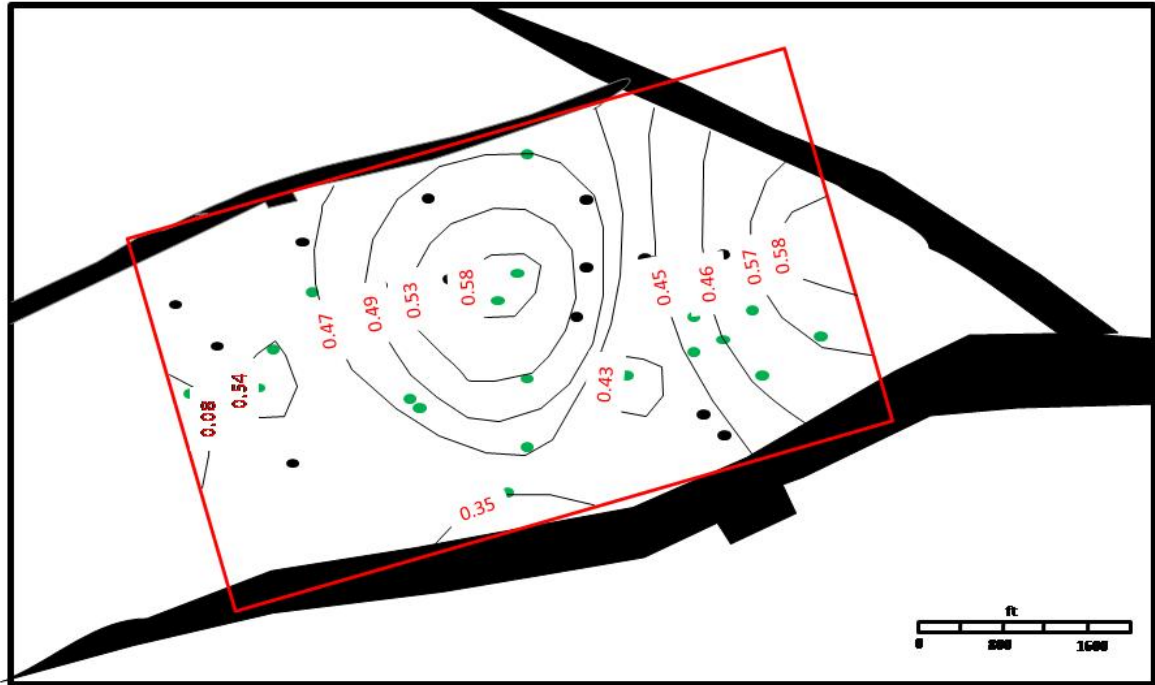


Figure 21: Contour map of average water saturation for sandstones in the B-reservoir of the Eyram Field

3.5 Bulk Volume Water (BVW)

The product of water saturation and porosity (Bulk Volume Water) is nearly constant in all the wells at 12% to 17% (Figure 22) which suggests that the sandstones in Eyram field are homogenous and nearly irreducible water saturation conditions [19]. The only exception is in well EY-7H which has BVW of 3%. This low value may be as a result of faulting or pinch out. Calculated bulk volume water (BVW) correlate with hydrocarbon occurrences; intervals with high BVW is either wet or have hydrocarbon traces.

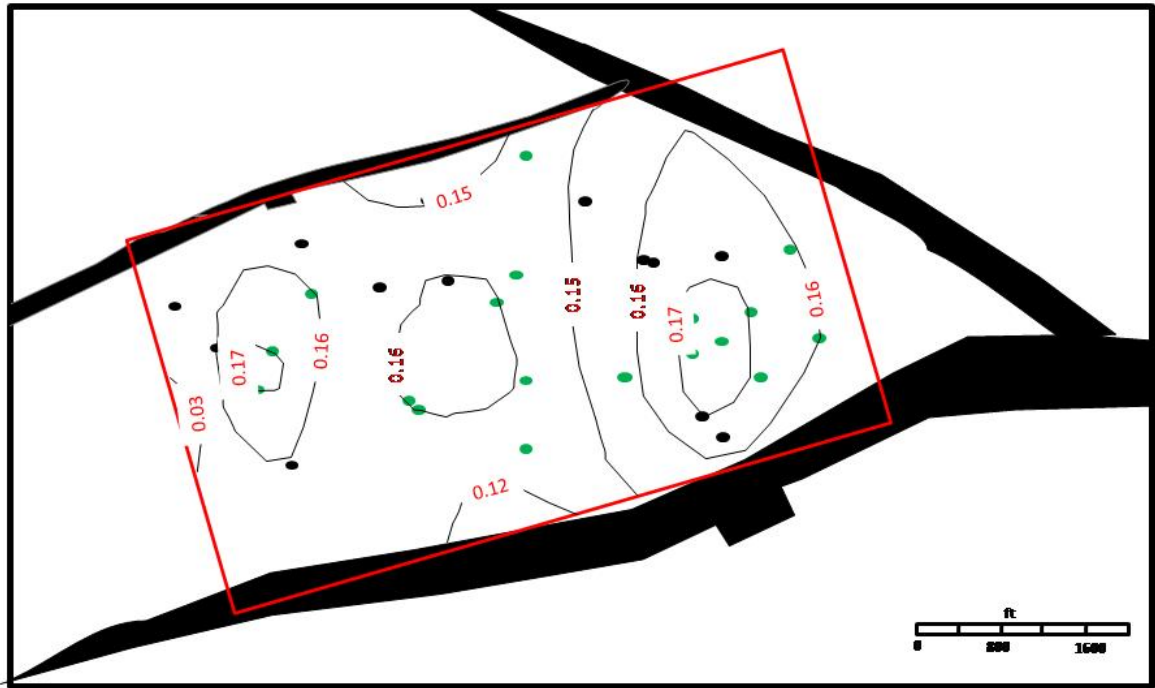
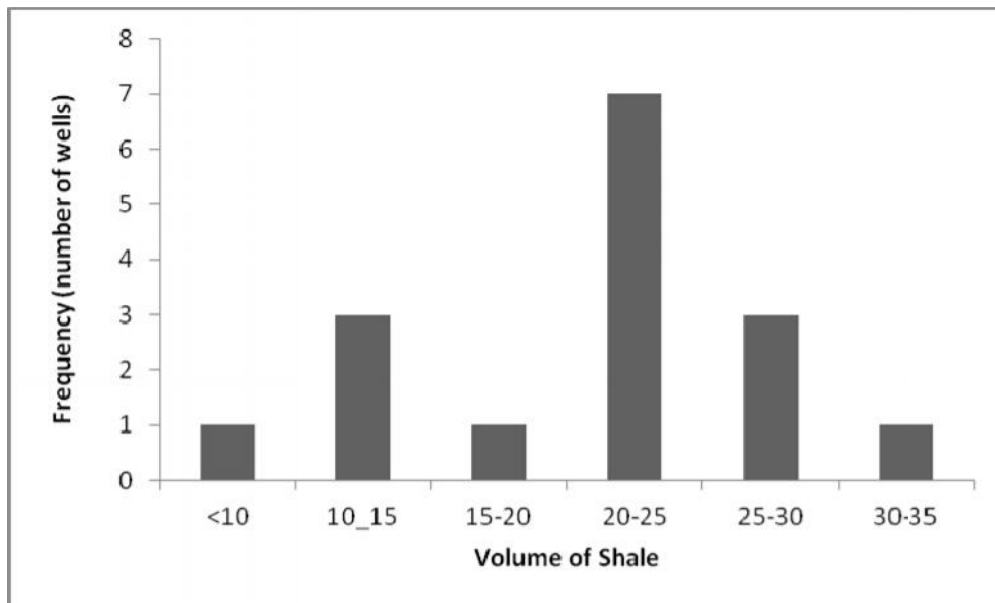


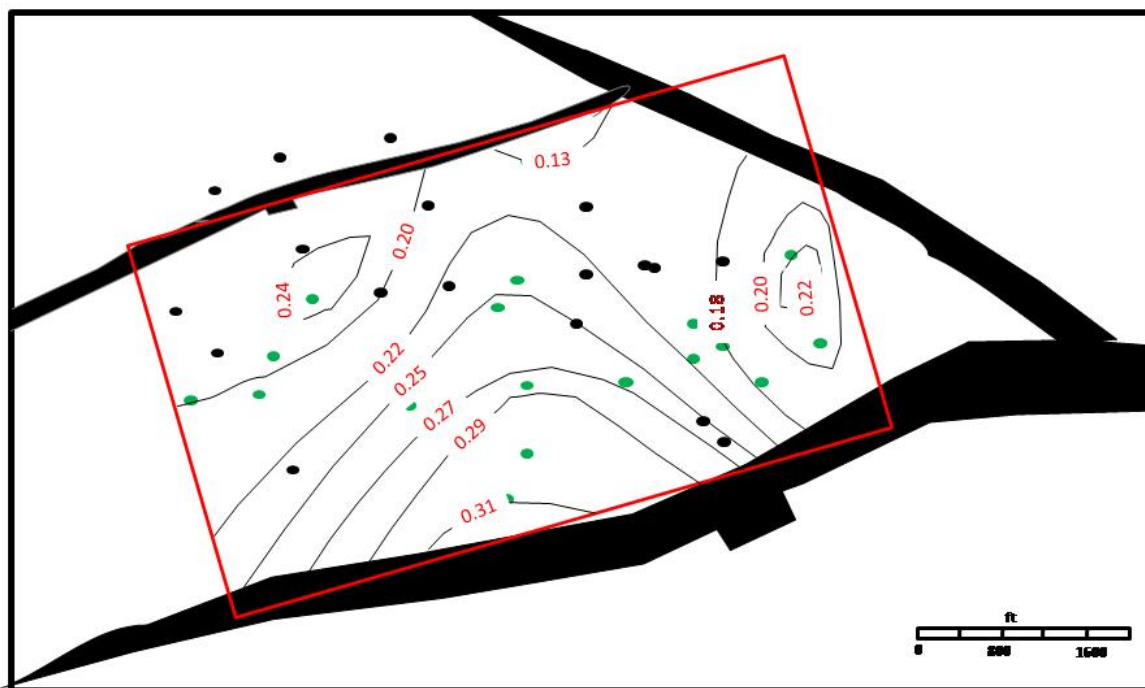
Figure 22: Contour map of Bulk Volume Water for sandstones in the B-reservoir of the Eyrarn Field

3.6 Shale Volume

The volume of shale in Eyrarn field ranges from 2% to 31% with an average of 21% (Figure 23). Most wells have V_{sh} that ranged between 20 and 25% (Figure 24)



359 **Figure 23: Distribution of shale volume per well for B-reservoir of Eyrām field**
 360



361 **Figure 24: Contour map of Average volume of shale in the B-reservoir of the Eyrām**
 362 **Field**
 363

364 **3.7 Hydrocarbon Types and Contact**

365 Sequel to shale layers intercalations and oil and gas association, different hydrocarbon
 366 contact types were observed in the field. The contact types include Oil Down Tool, Gas
 367 Down Tool and Oil Water Contact. Most of the wells are ODT and the field contains mostly
 368 oil.

369 **3.8 Net Pay**

370 A reservoir cut-off porosity value of 0.1, while 0.7 cut-off for V_{sh} (Fig. 8) and 0.7 cut-off for
 371 SwT were used for the determination of net pay. The total net pay of oil column in the
 372 reservoir is given as 1278.01ft while gas column is given as 172.91ft. The net/gross pay
 373 range from 8% to 88% with an average of 69%

374 **3.9 Hydrocarbon Saturation**

375 This range from 43% to 92% with an average of 52%

376 **4. CONCLUSION**

377 This research evaluates the petrophysical properties of Eyrām field. This field is located in
 378 onshore area of the Niger Delta. Twenty one Well log data from the field were evaluated to
 379 characterize the porosity, permeability and water saturation of the B-reservoir. Sand lobe in
 380 the reservoir bifurcated by shale lenses was assessed in terms of thickness, fluid content
 381 and types. The logs were environmentally corrected and normalized, volume of shale and
 382 porosities were calculated, water saturation were determined by Archie's equation and dual
 383 water model, and net pay was calculated.

384 Within the B-reservoir of the Eyrām field, the average well has 103.94ft of net sandstone,
 385 having average porosity of 26%. The average permeability is 399mD while the average
 386 water saturation is 48%.

Telephone: +2348055826966

Email Address: gab_omolaiye@yahoo.co.uk

387 Evaluation of Eyram field reservoirs; their petrophysical properties and fluid contents
 388 revealed predominant oil reservoirs in the area with minor amount of gas. The oil-bearing
 389 columns thickness cumulatively is 1278.01 ft, while gas columns summed to 172.91 ft.
 390 Porosity and permeability in the field are high on the average due to very good to excellent
 391 sand quality.

392 For effective reservoir management, field development strategies that take these various
 393 petrophysical parameters and contact types into consideration should be implemented.

394 **ACKNOWLEDGEMENTS**

395 We acknowledge Dr. Michael Ilesanmi Oladapo of the Geophysics Department, Federal
 396 University of Technology, Akure for reading through the manuscript and making necessary
 397 corrections.

398 **REFERENCES**

- 399 [1] Short KC, Stauble AJ. Outline of the Geology of Niger Delta. *American Association*
 400 *of Petroleum Geologist Bulletin*. 1967:761-777.
- 401 [2] Franky EJ, Cordy EA. The Niger Delta oil province: recent developments onshore
 402 and offshore. *Geological Society of American Bulletin*. 1967;19:195-199.
- 403 [3] Maron P. Stratigraphical aspect of the Niger Delta. *Journal of Mining and Geology*.
 404 1969;4: 1-3.
- 405 [4] Tuttle LWM, Charpentier RR, Brownfield EM. The Niger Delta petroleum system:
 406 Niger Delta Province, Nigeria, Cameroon and Equatorial Guinea, Africa. U.S.
 407 Geological Survey Open-File Report 99-50-H, Denver, Colorado. 1999:70.
- 408 [5] Hilchie DW. Wireline: A history of the well logging and perforation business in the oil
 409 fields. D. W. Hilchie Inc., Boulder, Colorado, U. S.A. 1990:25 – 86.
- 410 [6] Schlumberger. Log interpretation charts. Schlumberger Well Services, Houston.
 411 1996:2 – 34.
- 412 [7] Uguru, CI, Onyeagoro, OU and Sikiru IO. Permeability modeling for reservoirs in the
 413 Niger Delta based on geological descriptions and core data. SIPM Review Report.
 414 2002:4 –98.
- 415 [8] Weber KJ. Hydrocarbon Distribution Pattern in Nigeria growth fault structures
 416 controlled by structural style and stratigraphy. *J. Petrol. Sci. Engine*. Elsevier
 417 Science Publishers B.V. Amsterdam. 1987:1-12.
- 418 [9] Doust H, Omatsola E. Niger Delta. In Divergent/Passive Margin Basins, J.D.
 419 Edwards and P.A. Santogrossi, editors. AAPG Memoir 48. *American Association of*
 420 *Petroleum Geologists*, Tulsa, USA. 1990:239 – 248.
- 421 [10] Kulke H. Nigeria:In Regional Petroleum Geology of the World. Part II: Africa,
 422 America, Australia and Antarctica, H. Kulke, editor. Gebrüder Borntraeger, Berlin,
 423 Germany. 1995:143-172.
- 424 [11] Weber KJ. Hydrocarbon Distribution Pattern in Nigeria growth fault structures
 425 controlled by structural style and stratigraphy. *J. Petrol. Sci. Engine*.. Elsevier
 426 Science Publishers B.V. Amsterdam, 1987:1-12.
- 427 [12] Doust H, Omatsola E. "The Niger Delta: Hydrocarbon Potential of a Major Tertiary
 428 Delta Province". *Proceedings, KNGMG Symposium "Coastal Lowland Geology and*
 429 *Geo-technology"*. Dordrecht: Kluwe. 1989:203-212.
- 430 [13] Cluff SG, Cluff RM. Jonah Field: Case Study of a Giant Tight-Gas Fluvial Reservoir,
 431 J. W. Robinson and K. W. Shanley, eds.: AAPG Studies in Geology 52 and Rocky
 432 Mountain Association of Geologists; 2004.
- 433 [14] Steiber SJ. "Pulse Neutron capture log evaluation in the Louisiana Gulf Coast"
 434 SPE paper 2961, presented at the SPE Annual Meeting, Houston. 1970;October:4-
 435 7.
- 436 [15] Hook, JR. An introduction to porosity: Petrophysics. 2003;44(3):205– 212.
- 437 [16] Clavier C, Coates G, Dumanoir J. Theoretical and experimental bases for the dual-

- 438 water model for interpretation of shaly sands: *Society of Petroleum Engineers*
 439 *Journal*. 1977;24,(2):153 – 168.
- 440 [17] Archie GE. The electrical resistivity log as an aid in determining some reservoir
 441 characteristics. *Trans. Am. Inst. Mech. Eng.*, 1942;146:54-62.
- 442 [18] Clavier C, Hoyle, WR, Meunier, D. "Quantitative interpretation of thermal neutron
 443 decay time logs: Part 1- Fundamentals and Techniques". *Journal of Petroleum*
 444 *Technology*. 1971;June:743 – 755.
- 445 [19] Asquith G, Krygowski D. Basic Well Log Analysis, 2nd edition. American Association
 446 of Petroleum Geologists: Methods in Exploration Series. 2004; 244:28.
- 447 [20] Tixier MP. Evaluation of permeability from electric log resistivity gradient. *Earth*
 448 *Science Journ*. 1949;2:113.
- 449 [21] Timur A. An investigation of permeability, porosity and residual water saturation
 450 relations for sandstone reservoirs. *The Log Analyst* 1968;9(4):8-17.
- 451 [22] Coates GR, Dumanoir JL. A new approach to improved log-derived 252
 452 permeability. In: Proceeding s of SPWLA 14th Annual Logging Symposium,
 453 Transaction, Paper;1973.
- 454 [23] Coates GR, Dumanoir JL. A new approach to improved log-derived permeability.
 455 *The Log Analyst*, 1974;15 (1):17 – 29.
- 456 [24] Kozeny J. Ober kapillare Leitung des Wassers in Boden: Sitzungsbericht der
 457 Wiener Akademie, Abteilung Na. 1927;136:271. German.
- 458 [25] Rider M. The Geological Interpretation of Well Logs. Blackie, Glasgow. 1986:151 –
 459 165.

460 ABBREVIATIONS

- 461 'a' is Tortuosity factor
- 462 BVW is bulk volume water taken as fraction
- 463 F is formation factor
- 464 K is permeability in millidarcy (mD) (Timur, 1968)
- 465 KT is permeability in millidarcy (mD) (Tixier, 1949)
- 466 KCD is permeability in millidarcy (mD) (Coates and Dumanoir, 1973, 1974)
- 467 NET is net reservoir thickness after removing shale thicknesses in or feet
- 468 NTG is net to gross reservoir thick taken as a ratio
- 469 Pay is pay column thickness in meters or feet
- 470 $PHIA$ is the total porosity measured in percentage or fraction
- 471 $PHIE$ is effective porosity measured in percentage or fraction
- 472 ϕ is porosity given in percentage or fraction
- 473 ϕ_e is the effective porosity given in percentage or fraction
- 474 ρ_h is hydrocarbon density (g/cm³)
- 475 ρ_o is formation fluid density (g/cm³)
- 476 ρ_w is formation water density (g/cm³)
- 477 R_o is the formation rock matrix resistivity
- 478 R_{it} is correction factor for oil density
- 479 R_w is formation water resistivity
- 480 R_t is true resistivity of un-invaded zone
- 481 Sh is hydrocarbon saturation
- 482 SwT is total water saturation measured in percentage or fraction
- 483 V_{sh} is shale volume in the reservoirs, taken as fraction or percentage

- 484 ODT is Oil Down Tool
- 485 GDT is Gas Down Tool
- 486 OWC is Oil Water Contact
- 487 HC is hydrocarbon