

Original Research Paper

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

ABSTRACT

Evaluation of Eyrām 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.

Eyrām 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 Eyrām 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, Eyrām field, Niger Delta, Archie's equation, Porosity, Permeability

1. INTRODUCTION

Eyrām 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 (Short and Stauble, 1967; Franky and Cordy, 1967; Maron, 1969; Tuttle et al., 1999). 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 hydrocarbon reserves and reservoir bed thickness, and to distinguish between gas, oil and water bearing strata, by observing their electrical resistivity and relative permeability values (Hilchie, 1990; Schlumberger, 1996; Uguru et al., 2002).

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

1.1 Objectives of Petrophysical Evaluation

The objectives of the petrophysical evaluation include:

- Determination of the distribution of petrophysical properties within B-reservoir in Eyrarn Field
- Determination of fluid type and hydrocarbon contact from logs, where possible; and
- Determination of net gas, oil and net reservoir intervals.

1.2 Structural setting of the Field

The field is a faulted anticlinal structure enclosed within structure building faults (Figure 1). The faults are dipping towards the South, with Fault A being the most extensive, extending almost through the entire breadth of the mapped area. The trapping potential of the field is attributed to four way closure sandwiched within the faults and located at the center of the field. Anticlinal or fault assisted closures are regarded as good hydrocarbon prospect in the Niger Delta (Weber and Daukoru, 1975). The bounding Faults A, B and C served as potential conduits for hydrocarbon migration from underlying matured source rocks with the seal provided by overlying shale sequence.

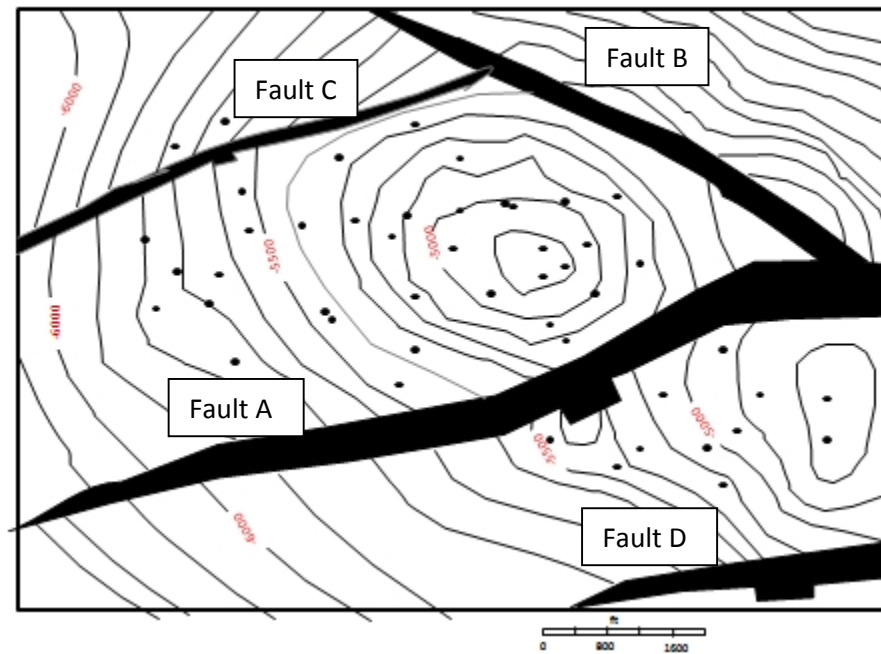


Figure 1: Top Structure Map of Eyram Field

1.3 Geology of the Area

The Niger Delta which covers an area of about 7500 km² is a large acuate delta extending between longitude 3° and 9°E and latitudes 4° and 6° N (Doust and Omatsola, 1990). Its stratigraphy has been described in detail by Short and Stauble (1967) and Kulke (1995), of which they recognized three lithostratigraphic units i.e. the Benin, Agbada and Akata Formations.

The Benin Formation is the uppermost and the youngest rock stratigraphic unit, while the Agbada Formation is a paralic sequence that is characterized by the alternation of sand bodies and shale layers. The Agbada Formation is also associated with synsedimentary growth faulting and as well contains the bulk of the known oil accumulation in the Niger Delta. The Akata Formation is the lowest unit with evidence of some hydrocarbon and is under compacted in much of the delta (Figure 2).

The growth faults in the Niger Delta according to Weber (1987) are considered to be the major migration conduit and leading factor controlling the hydrocarbon distribution pattern in the Niger Delta.

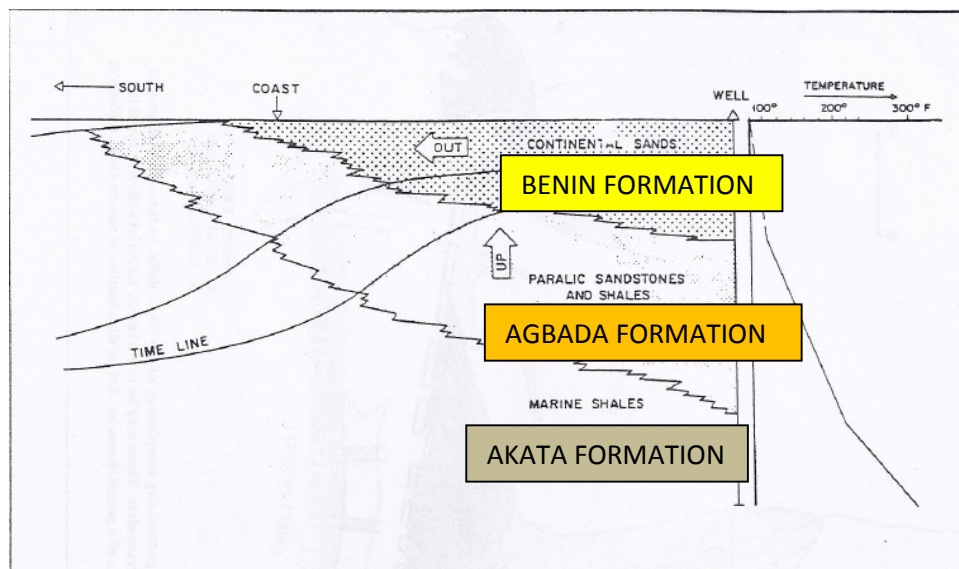


Figure 2: Lithofacies of Niger Delta Basin (Doust and Omatsola 1989)

2. METHODS

2.1 Data Sources

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

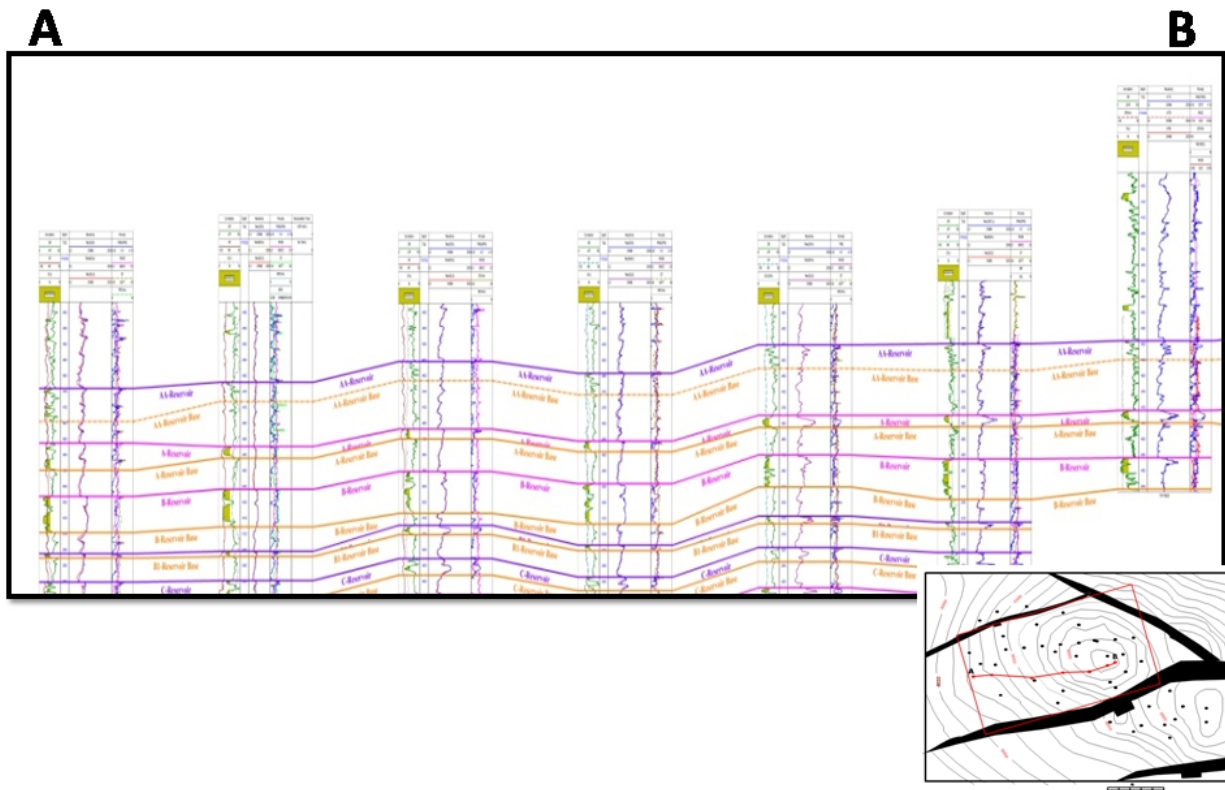


Figure 3: Lithologic Correlation of some wells in Eyrum Field

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 (Cluff and Cluff, 2004).

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 3). 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.

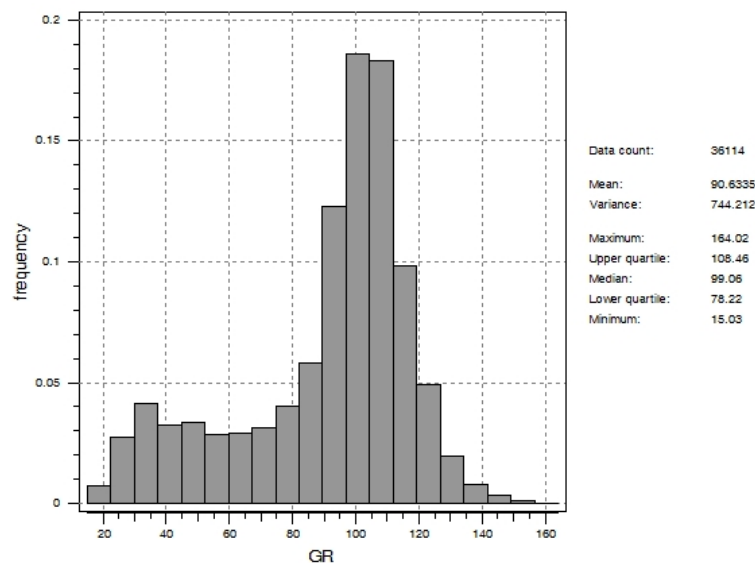


Figure 4: Type histogram for gamma ray (GR) log normalization

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 4 and 5).

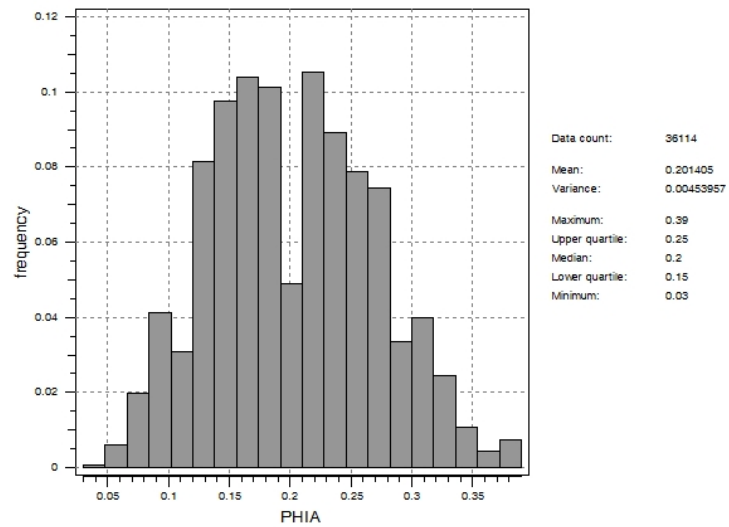


Figure 5: Type histogram for neutron-porosity (PHIA) log normalization

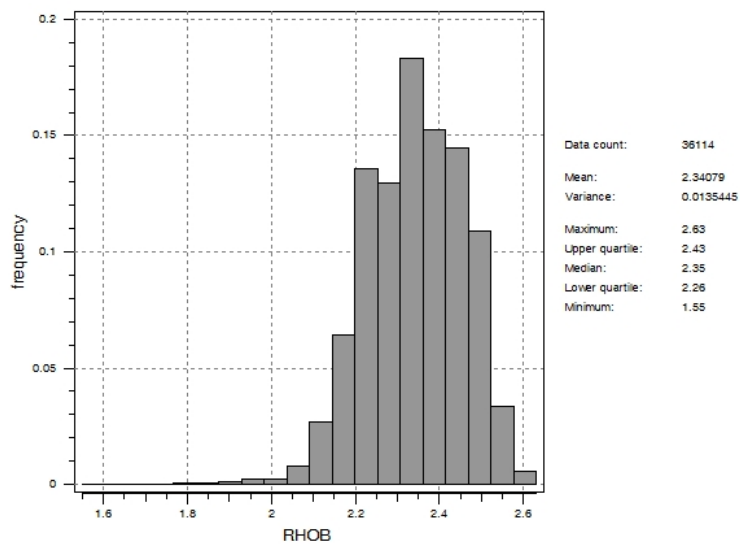


Figure 6: Type histogram for bulk-density (RHOB) log normalization

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. Steiber (1970) 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 (Hook, 2003).

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:

$$PHIA = (RhoM - RHOB) / (RhoM - RhoF) \dots\dots\dots[4]$$

Where PHIA (ϕ) = Total Porosity,

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

$$PHIDE (\phi_e) = PHIA - (V_{sh} \times PHIA_{sh}) \dots\dots\dots[5]$$

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 (Clavier et al., 1977) with a constant R_w and Archie's water saturation equation (Archie, 1942). In this study, the R_w was derived from Pickett Plots (Figure 7) and found to be 0.244 ohm.m.

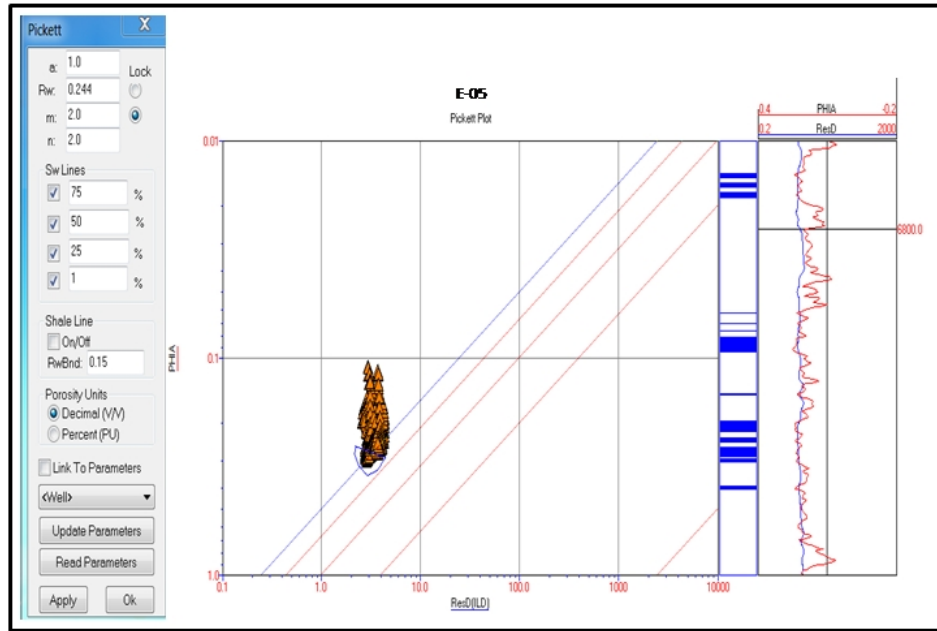


Figure 7: B-Reservoir Pickett Plot of E-5 Well showing R_w Value

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;

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

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

184 **The Dual Water Method**

185 The content of clay in sand, such as, deltaic sand of the Niger Delta, makes the use of (Archie, 1942)
186 equation associated with incorrect water saturation values. Therefore, Dual Water Model (DWM), (Clavier
187 *et al.*, 1984; Asquith and Krygowski, 2004) was used for this study. A simplified dual-water-model
188 equation is given as;

$$189 \quad SwT = Y + \sqrt{\left(\frac{R_w}{(R_t \times \phi^2) + Y^2} \right)} \text{-----}[8]$$

190 Where Y is given by;

$$191 \quad Y = V_{shl} * \left(\frac{(R_w B_{nd} - R_w)}{(2 * R_w B_{nd})} \right) \text{-----}[9]$$

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

194 **2.3.3 Permeability**

195 Three empirical methods were used to calculate the field permeability for the purpose of comparison and
196 reliability checks. The methods used were those of Tixier (1949), Timur (1968) and Coates and Dumanoir,
197 (1973, 1974).

198 Timur (1968) worked on (Kozeny, 1927) permeability equation and gave an expression thus;

$$199 \quad k = 0.136 \frac{\phi^{4.4}}{S_{wi}^2}, \text{-----}[10]$$

200 Tixier (1949) further modified his equations to a simpler form, as given thus;

$$201 \quad k^{1/2} = 250 \frac{\phi^3}{S_{wi}}, \text{-----[11]}$$

202 where S_{wi} is the irreducible water saturation.

203 Coates and Dumanoir (1973) contributed to empirical permeability derivation with the equation;

$$204 \quad k^{1/2} = \frac{C}{W^4} \frac{\phi^{2w}}{R_w / R_{ti}}, \text{-----[12]}$$

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

$$206 \quad W^2 = (3.75 - \phi) + \frac{1}{2.0} \left[\log_{10} \left(\frac{R_w}{R_{ti}} \right) + 2.2 \right]^2, \text{-----[14]}$$

207 For shaly formation, they gave another equation;

$$208 \quad \left(\frac{R_w}{R_{ti}} \right) = \frac{R_w V_{sh}}{\phi R_{sh}} (\phi S_{wirr})_{cn} + \frac{(\phi S_{wirr})_{cn}^w}{(1 - V_{sh})^{w-1}}, \text{-----[15]}$$

209 In this work, the Coates and Dumanoir (1973, 1974) equations were reduced to a simplified form, thus;

$$210 \quad k = (70 * \phi_e^2 * (1 - Sw) / Sw)^2 \text{-----[16]}$$

211

212 2.3.4 Lithology Determination

213 The lithology of the reservoirs was determined applying electrofacies analysis of the gamma ray logs. The

214 Sand/Shale ratio was used as follows:

215

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

217	Shale Volume (V_{sh})		Lithology
218	$V_{sh} > = 0$ and $V_{sh} < 33\%$	»	Sand
219	$V_{sh} > = 34$ and $V_{sh} < 69\%$	»	Shaly Sand
220	$V_{sh} > = 70$ and $V_{sh} < 100\%$	»	Shale

221

222 **2.3.5 Determination of Hydrocarbon Types**

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

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

227

228 **2.3.6 Net Pay Determination**

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

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

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

238 (3) Water saturation: A calculated water saturation cut-off is used to separate wet zones from oil-bearing
 239 or gas-bearing pay intervals. In high-porosity and high permeability sandstones, the transition zone from

water wet to hydrocarbon saturation is commonly very thin, with a significant difference in water saturation between high water saturation wet zones and low water saturation pay zones. Thus, the actual water saturation cutoff may not be critical, as long as it is between the average wet saturation and the typical hydrocarbon saturation.

3. PETROPHYSICS OF THE EYRAM FIELD

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

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

3.1 Net Sandstone Thickness

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

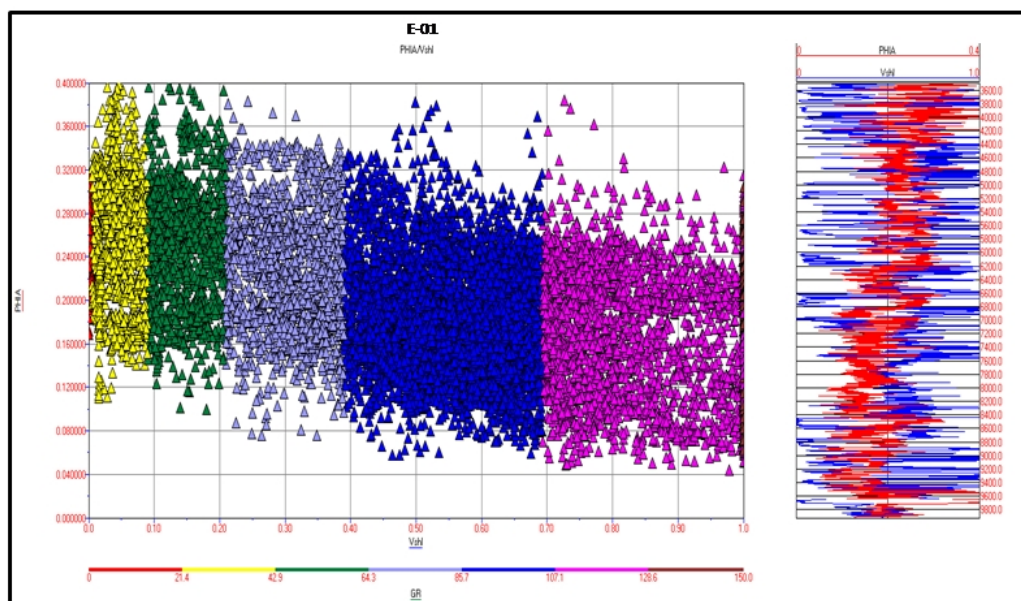
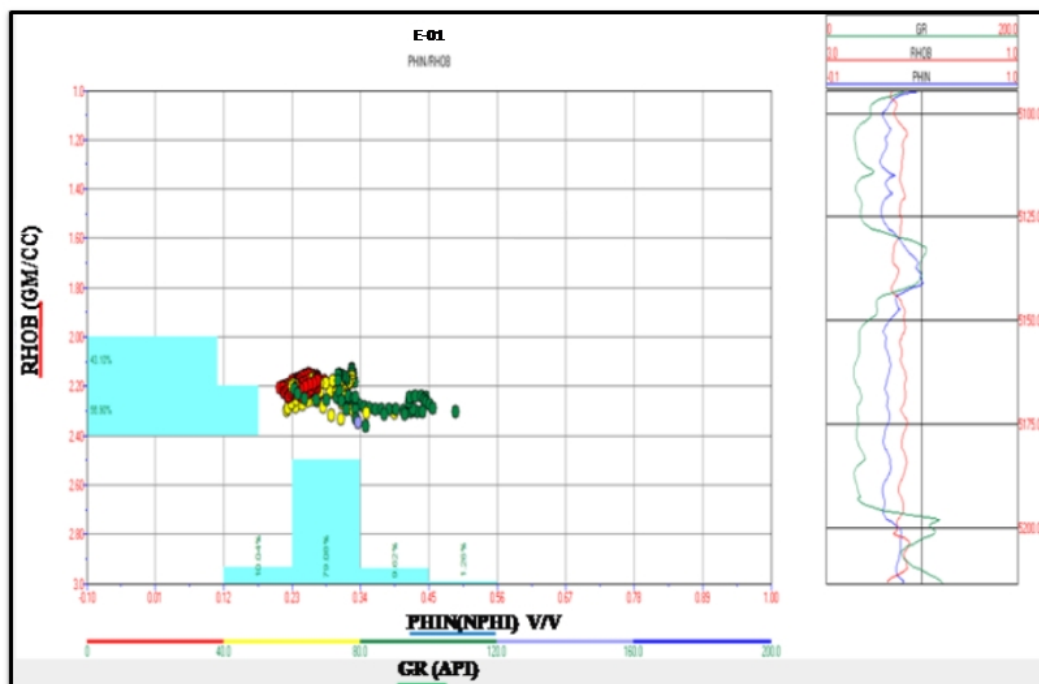
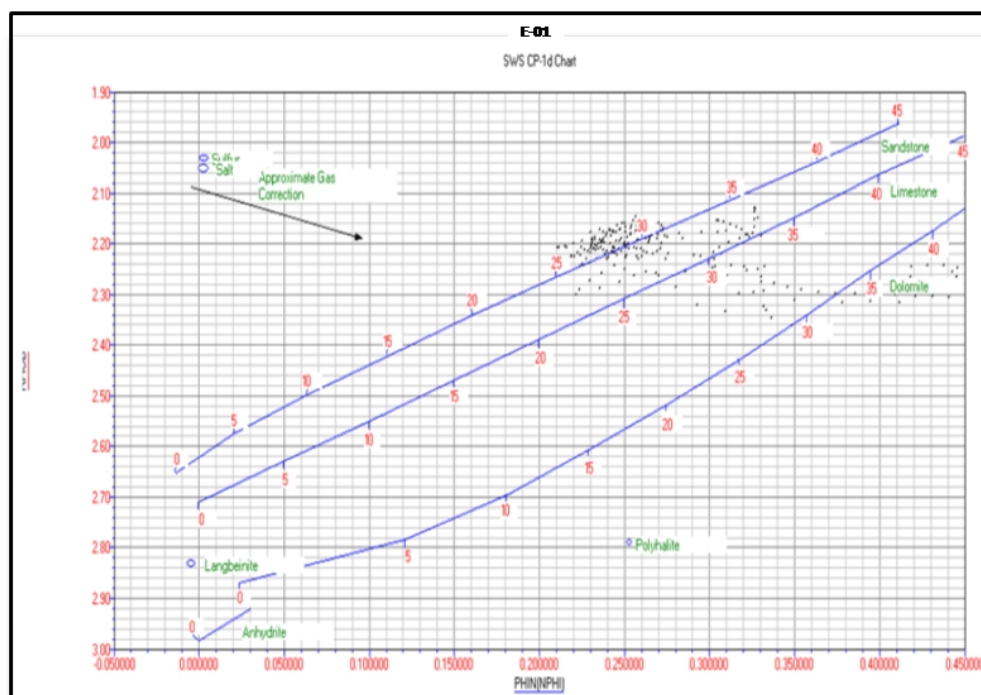


Figure 8: Cross Plot of E-1 Well Porosity (PHIA) versus Shale Volume (V_{sh})



258

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

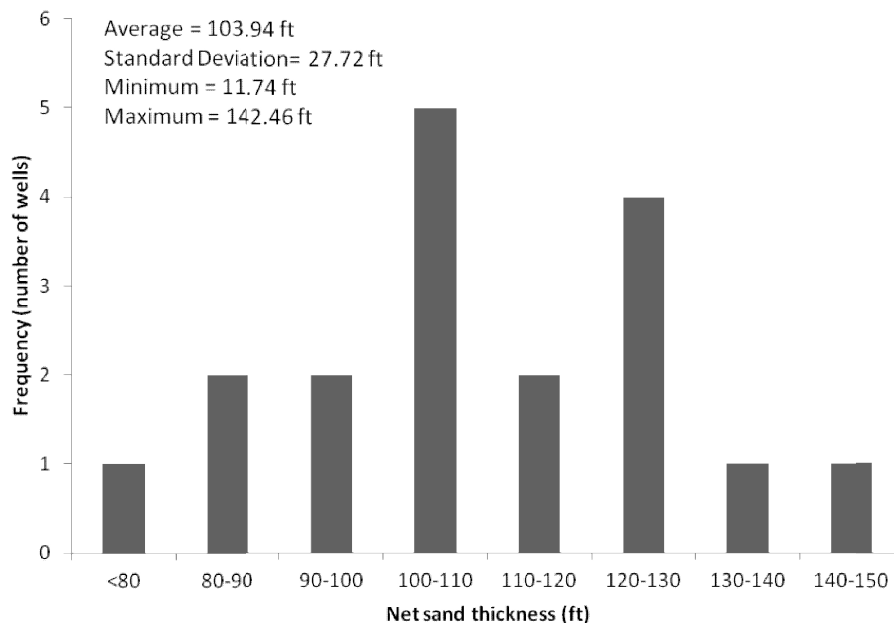


260

261 **Figure 10: A Crossplot of RHOB vs PHIN(NPHI) for B-Reservoir in E-1 Well, showing the**
 262 **SWS Chart which plots in the Sand Facies.**
 263

264 The net thickness of sandstone in B-reservoir ranges from 11.74 to 142.46 ft with an average of 103.94 ft
 265 (Figure 11). The net/gross ratio ranges from 83% to 99% and averages about 91% (Figure 12). These
 266 values are high and are indication of good reservoir sand development. Figures 13 and 14 show areal
 267 distribution of both net sandstone net/gross respectively.

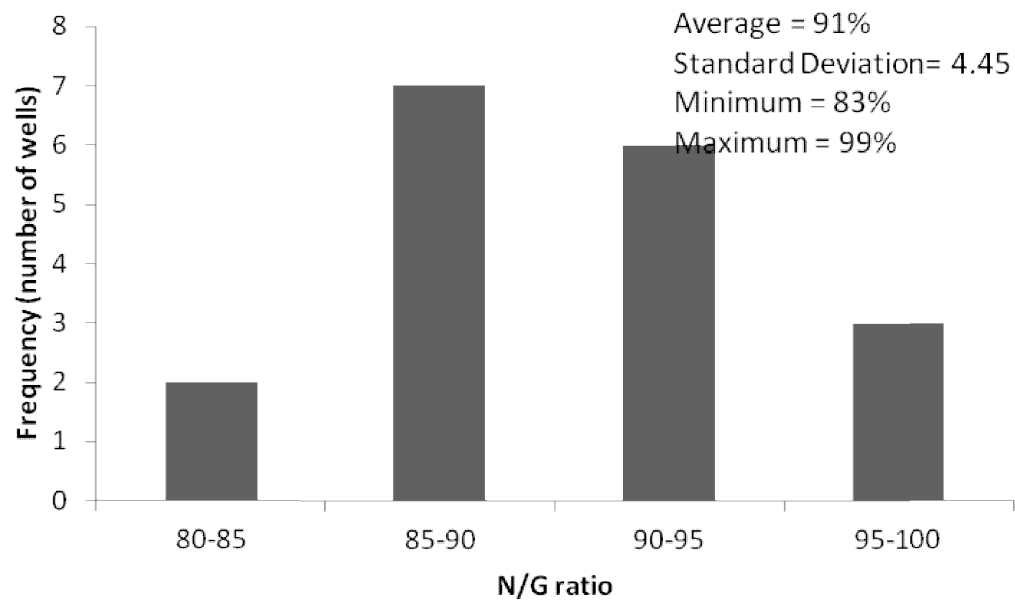
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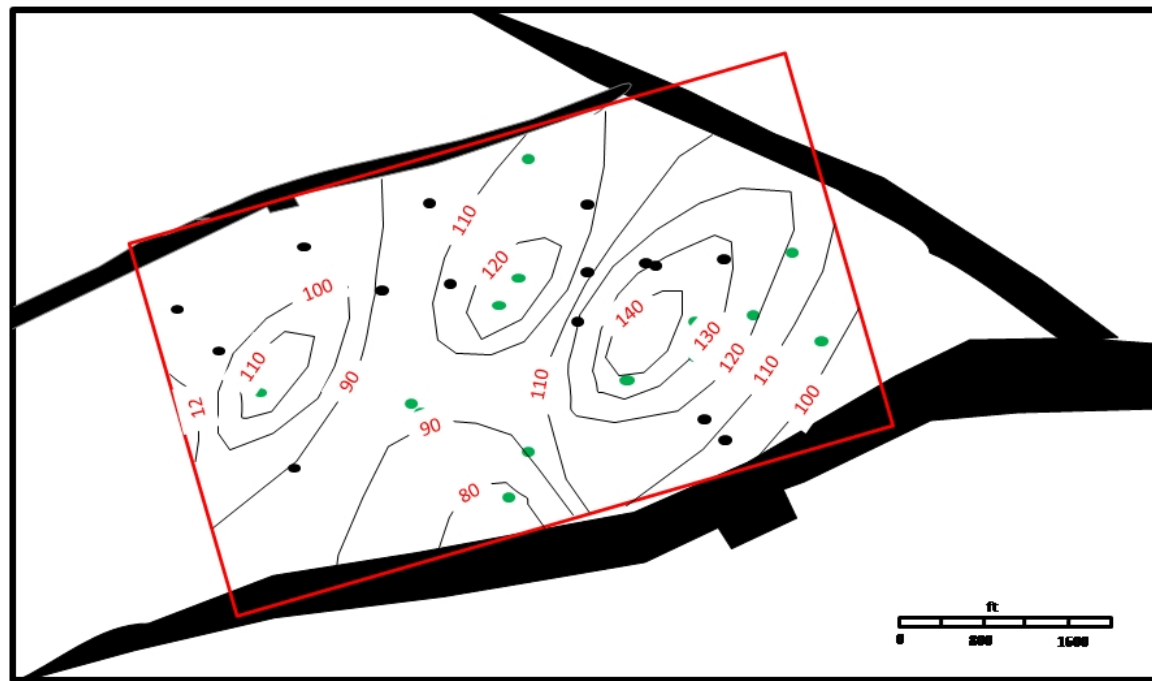
270 **Figure 11: Distribution of total net sandstone thickness by well in B-reservoir of Eyram field**

271



272

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



274

275 **Figure 13: Net feet of sandstone in the B-reservoir of the Eyram field.**

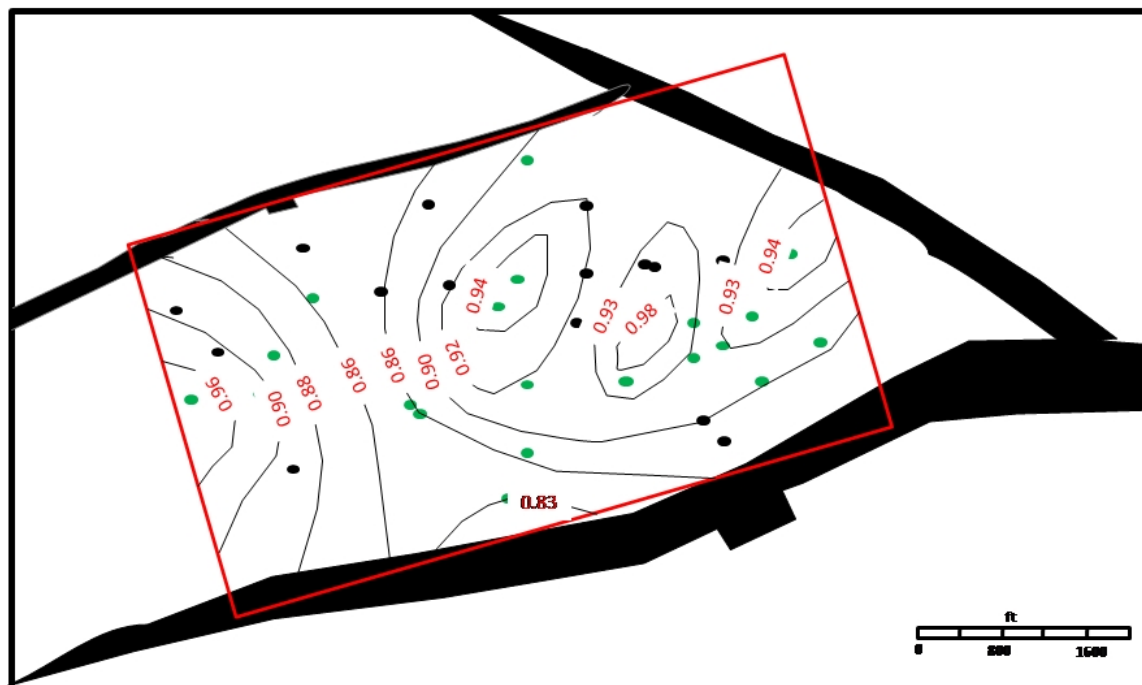
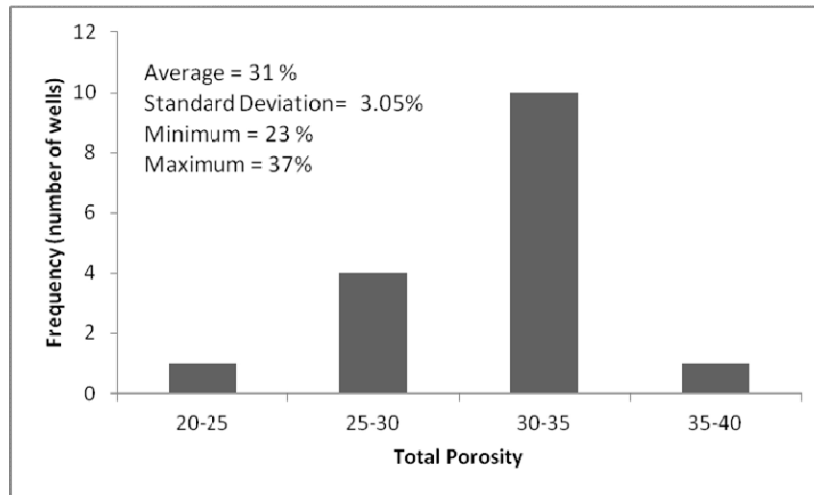


Figure 14: Ratio of net sand to gross interval in the B-reservoir of the Egram field.

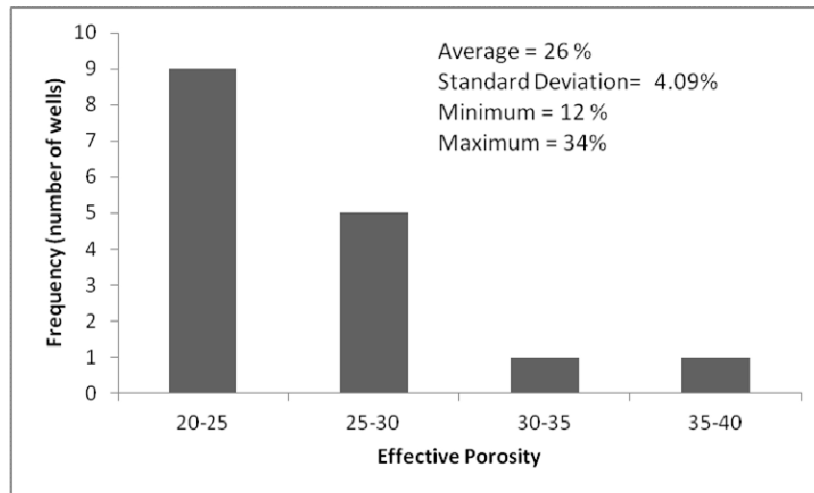
3.2 Porosity

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



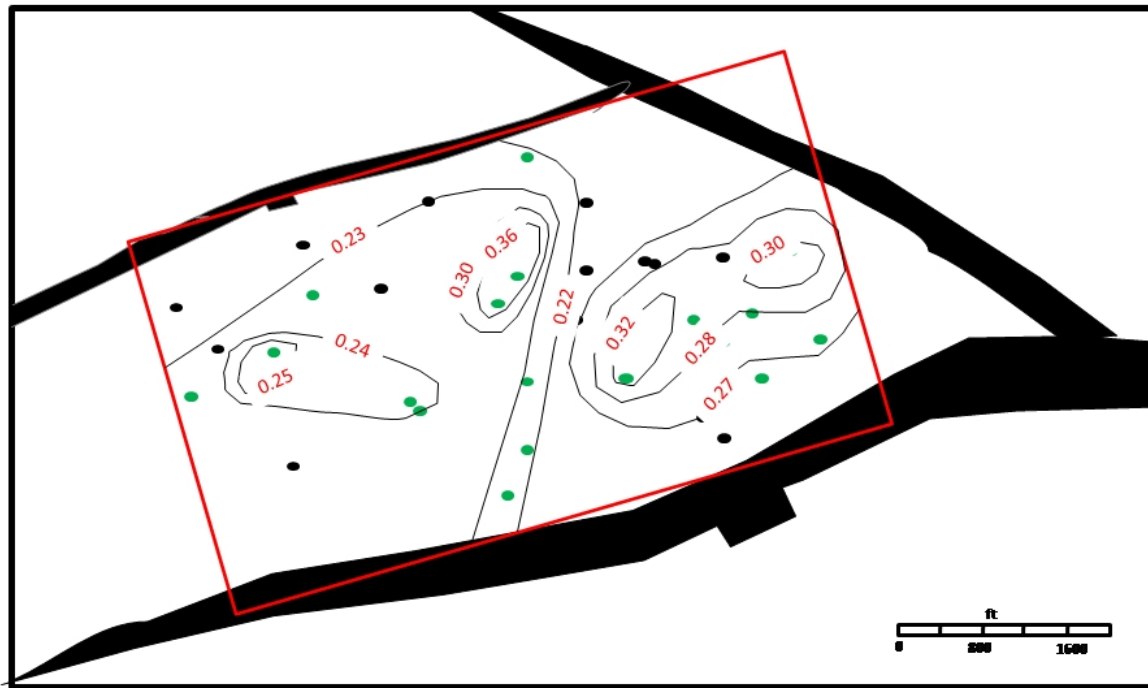
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285 **Figure 15: Distribution of total porosity values for B-reservoir**



286

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



288

289 **Figure 17: Contour map of average sandstone porosity (PHIE) in the B-reservoir of the Eyram**
 290 **Field**

291 According to Rider (1986), the following table give better explanation of porosity description of reservoirs.

292

293 **Table 2: Qualitative Evaluation of Porosity**

294	Percentage Porosity (%)	Qualitative Description
295	0 - 5	Negligible
296	5 - 10	Poor
297	15 - 20	Good
298	20 – 30	Very Good
299	> 30	Excellent

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

302

3.3 Permeability

It was observed that the Tixier's (1949) 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 Timur (1968), Tixier (1949) and Coates and Dumanoir (1973, 1974) respectively. Figure 18 shows the essentially random variation in average permeability of Timur (1968) over the study area. Most wells exhibit a greater range of permeability values than the range of averaged permeabilities.

Rider (1986) 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.

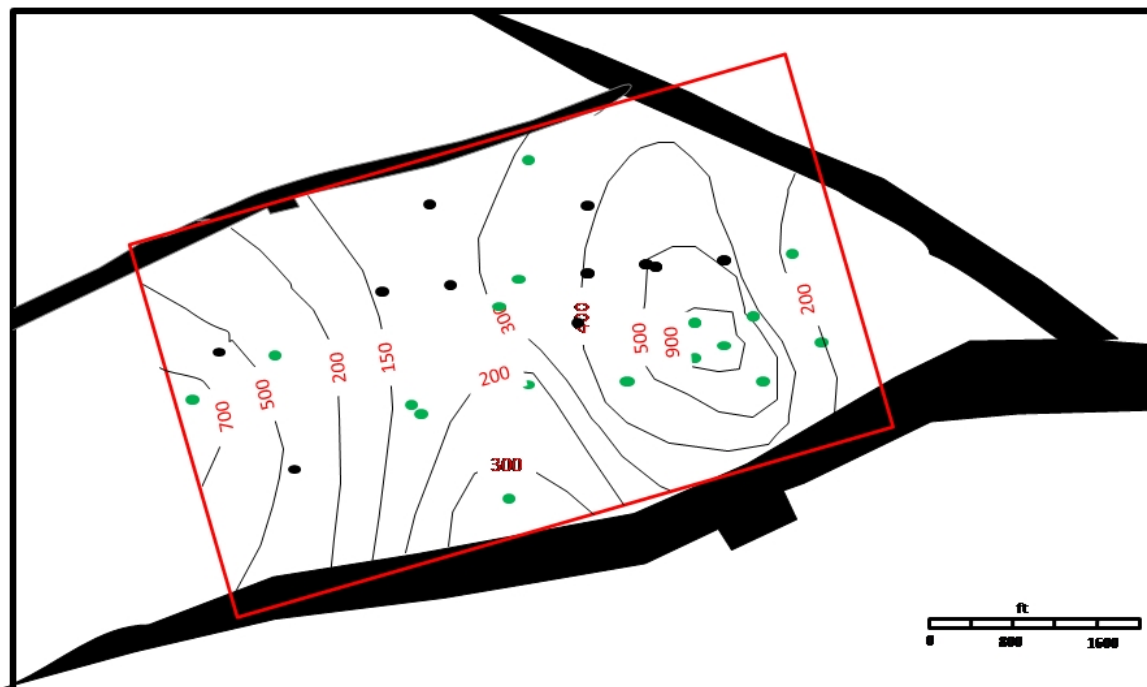


Figure 18: Contour map of average Permeability for sandstones in the B-reservoir of the Eyrarn Field

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).

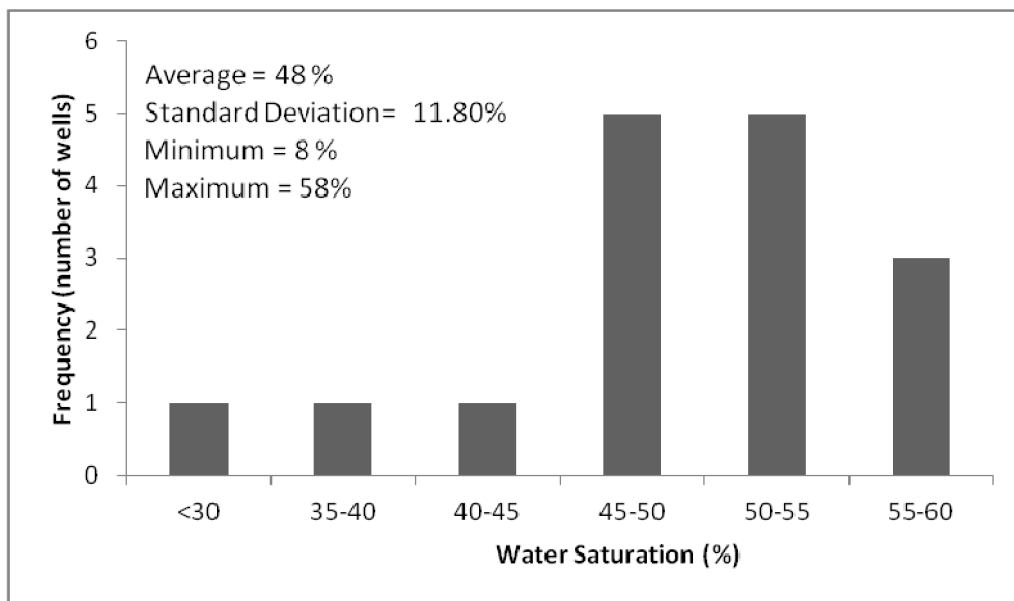


Figure 19: Distribution of average water saturation from log analysis, per well, for B-reservoir

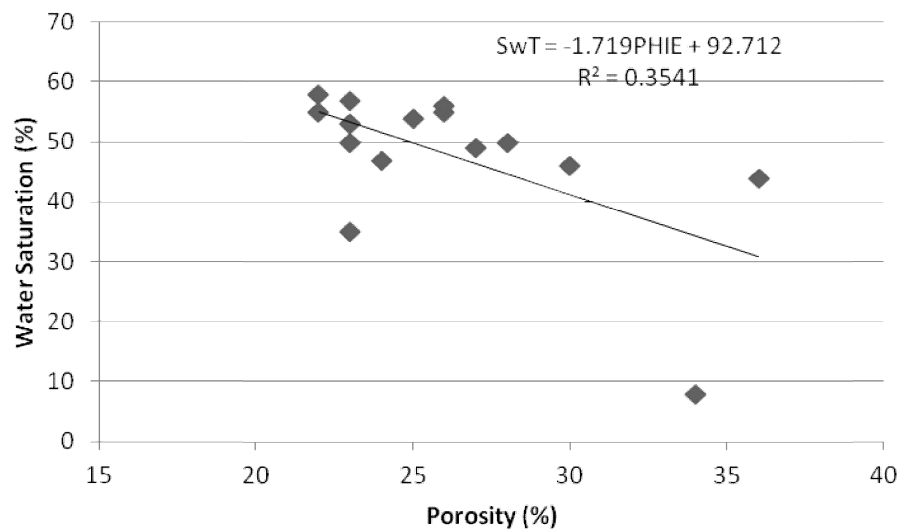


Figure 20: Trend of decreasing average water saturation with increasing average porosity in B-reservoir of the Eyram field.

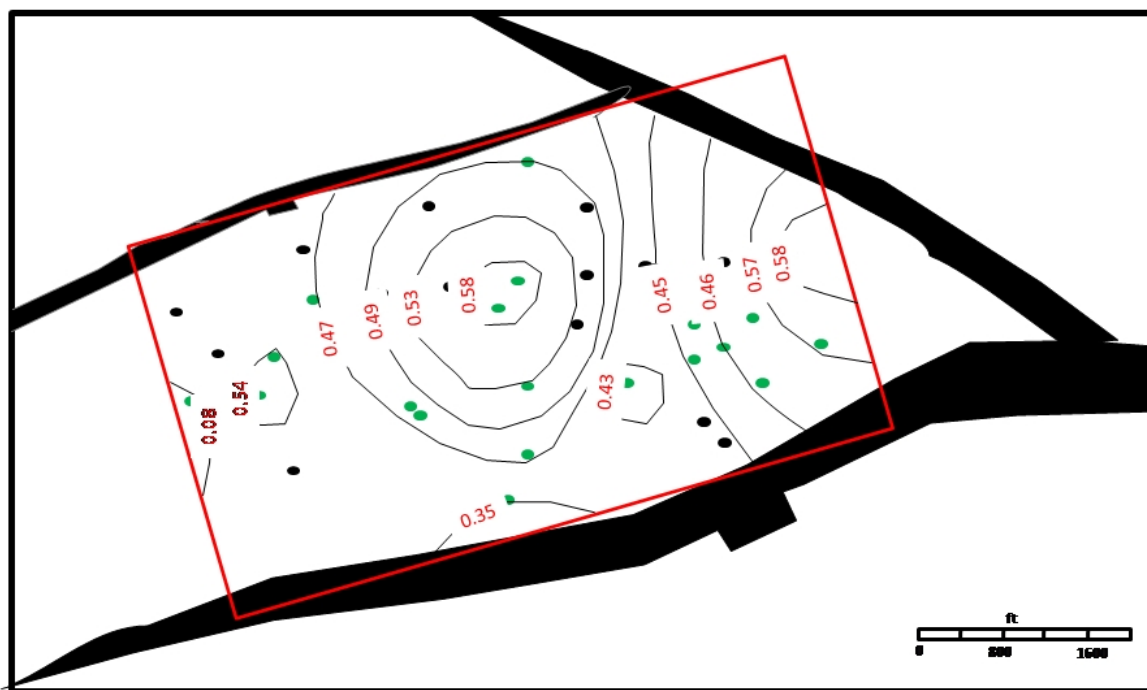


Figure 21: Contour map of average water saturation for sandstones in the B-reservoir of the Eyram Field

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 Eyrarn field are homogenous and nearly irreducible water saturation conditions (Asquith and Krygowski, 2004). 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.

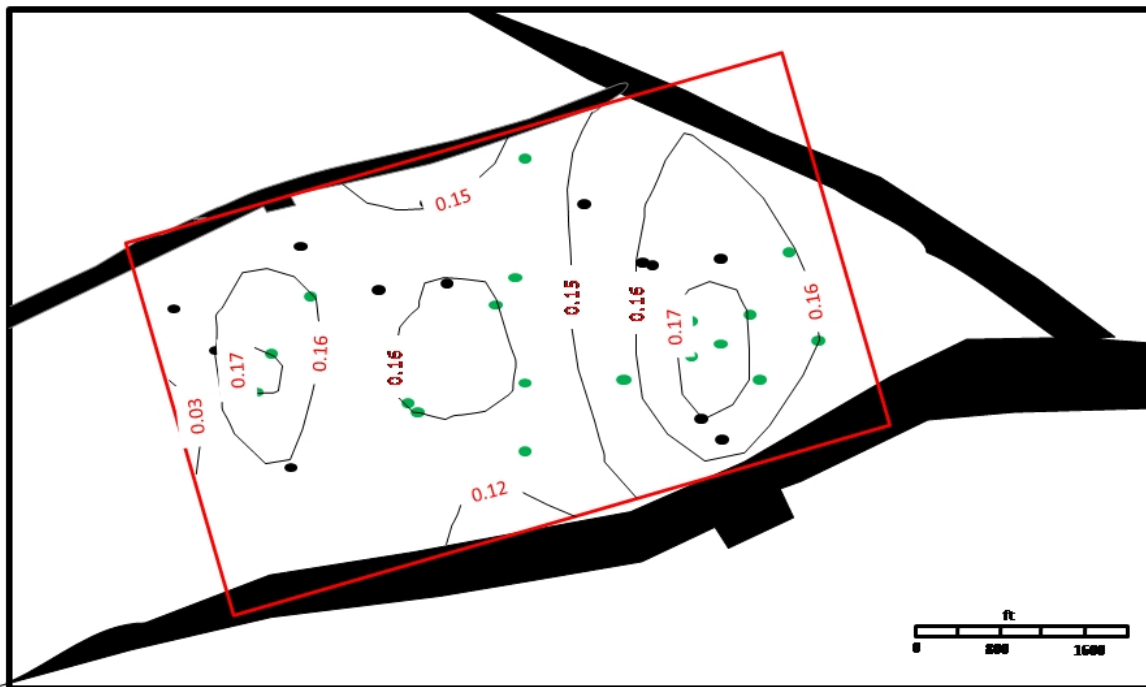


Figure 22: Contour map of Bulk Volume Water for sandstones in the B-reservoir of the Eyrarn Field

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)

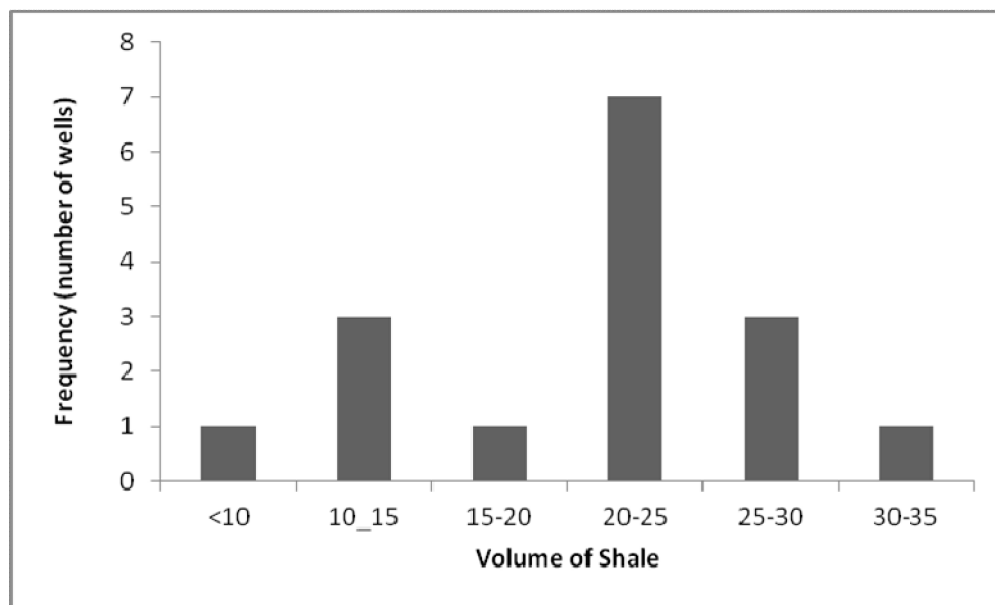


Figure 23: Distribution of shale volume per well for B-reservoir of Eyrarn field

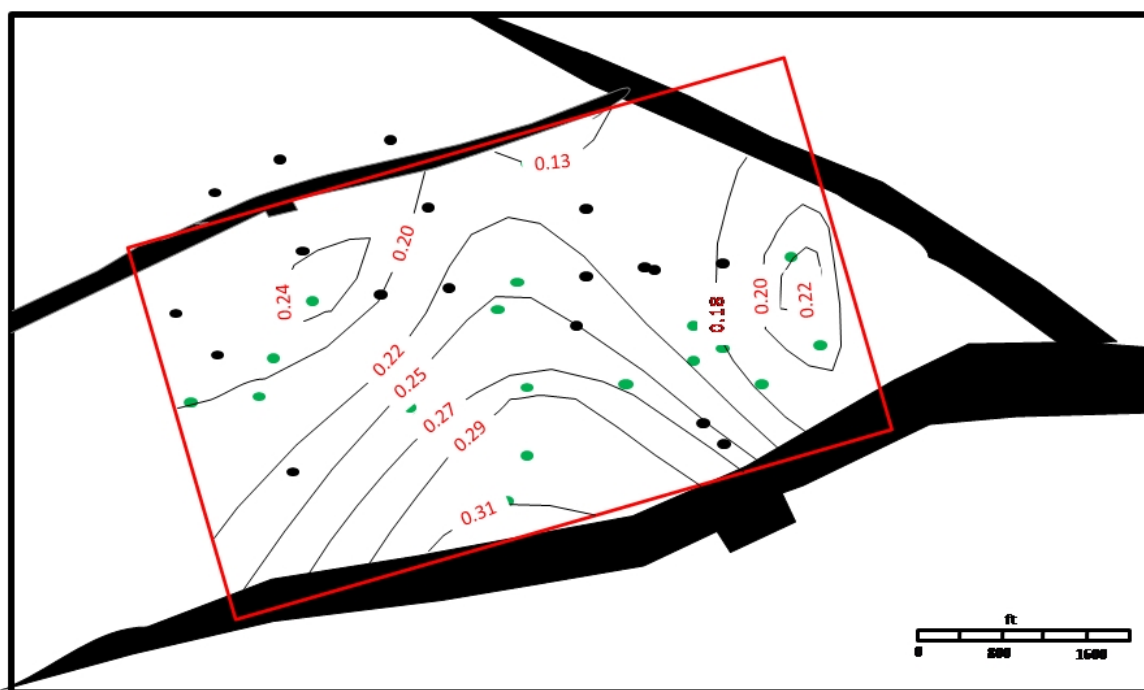


Figure 24: Contour map of Average volume of shale in the B-reservoir of the Eyrarn Field

3.7 Hydrocarbon Types and Contact

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

3.8 Net Pay

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 SwT were used for the determination of net pay. The total net pay of oil column in the reservoir is given as 1278.01ft while gas column is given as 172.91ft. The net/gross pay range from 8% to 88% with an average of 69%

3.9 Hydrocarbon Saturation

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

4. CONCLUSION

This research evaluates the petrophysical properties of Eyrām field. This field is located in onshore area of the Niger Delta. Twenty one Well log data from the field were evaluated to characterize the porosity, permeability and water saturation of the B-reservoir. Sand lobe in the reservoir bifurcated by shale lenses was assessed in terms of thickness, fluid content and types. The logs were environmentally corrected and normalized, volume of shale 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 Eyrām field, the average well has 103.94ft of net sandstone, having average porosity of 26%. The average permeability is 399mD while the average water saturation is 48%.

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

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

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ABBREVIATIONS

- 476 'a' is Tortuosity factor
- 477 BVW is bulk volume water taken as fraction
- 478 F is formation factor
- 479 K is permeability in millidarcy (mD) (Timur, 1968)
- 480 KT is permeability in millidarcy (mD) (Tixier, 1949)
- 481 KCD is permeability in millidarcy (mD) (Coates and Dumanoir, 1973, 1974)
- 482 NET is net reservoir thickness after removing shale thicknesses in or feet
- 483 NTG is net to gross reservoir thick taken as a ratio

- 484 Pay is pay column thickness in meters or feet
- 485 $PHIA$ is the total porosity measured in percentage or fraction
- 486 PHIE is effective porosity measured in percentage or fraction
- 487 ϕ is porosity given in percentage or fraction
- 488 ϕ_e is the effective porosity given in percentage or fraction
- 489 ρ_h is hydrocarbon density (g/cm³)
- 490 ρ_o is formation fluid density (g/cm³)
- 491 ρ_w is formation water density (g/cm³)
- 492 R_o is the formation rock matrix resistivity
- 493 R_{ti} is correction factor for oil density
- 494 R_w is formation water resistivity
- 495 R_t is true resistivity of un-invaded zone
- 496 Sh is hydrocarbon saturation
- 497 SwT is total water saturation measured in percentage or fraction
- 498 V_{sh} is shale volume in the reservoirs, taken as fraction or percentage
- 499 ODT is Oil Down Tool
- 500 GDT is Gas Down Tool
- 501 OWC is Oil Water Contact
- 502 HC is hydrocarbon