International Journal of Advances in Engineering and Management (IJAEM)
Volume 4, Issue 8 Aug. 2022, pp: 632-637 www.ijaem.net ISSN: 2395-5252

Formation Evaluation using well log Data: Case Study of "Emmy" Field, Tertiary Niger Delta.

Adebayo, A.E, Ogunleye, O.O, Abolarinwa, D.D
[1,2,3] *Department of Mineral and Petroleum Resources Engineering Technology, Federal Polytechnic Ado Ekiti, Nigeria.*
Corresponding Author: Adebayo, A.E.

Submitted: 05-08-2022 Revised: 11-08-2022 Accepted: 15-08-2022

ABSTRACT: Four wells Emmy-1, Emmy-2, Emmy-4 and Emmy-5 were identified on the Emmy's field offshore Niger Delta. A comprehensive petrophysical analysis on all the wells was carried out using well loggingdata in order to determine their petrophysical properties. Three reservoir sand bodies were delineated for each well. Based on the obtainedresults, the components of the Emmy's Field are characterize by sand shale inter-beds with the sand bed thicken at the upper part and shale thicken at the lower part. Reservoir thickness varies from 29 – 133m. The reservoir rock properties were interpreted as a good qualityreservoir rock which has beenestablished from high total porosity(23–40%), and variable shale volume(10–42 %). A number of highhydrocarbon saturation zones(exceeding 55 %) are detectedthrough intervals having Sw < 60 % which have been considered as economic oilproducers. Emmy's Field in the Niger Delta contains substantial amounts of proven crude oil.
KEYWORDS: Reservoir,Porosity, Petrophysical properties, reservoir quality, well logs.

I. INTRODUCTION

Hydrocarbons are stored below the earth's surface in deposits known as reservoirs. Reservoirs are subsurface rocks that have sufficient porosity (void space) to store commercial volumes of hydrocarbons, sufficient permeability (fluid flow capability) to be able to deliver the hydrocarbons to extraction wells and sufficient hydrocarbon saturation (volumes of hydrocarbons relative to other fluids) to be an economic resource (Fred and Shivaji, 2013).After an oil well has been drilled, the data collected needs to be interpreted in order to identify any hydrocarbons that may have been encountered.

This evaluation means identifying hydrocarbon bearing and non-hydrocarbon bearing sands, delineating reservoir thickness, evaluating the petrophysical parameters of the reservoir, anddetermining the overall quantity and quality of the reservoir.In evaluating a reservoir, the parameters that are considered includes porosity, permeability, water saturation, hydrocarbon saturation, and bulk volume of water.

The Nigerian province of Niger Delta contains commercial quantities of oil and gas. The accumulation of oil and gas in the pore spaces of reservoir rock, typically sandstone, limestone, or dolomite, is the source of oil and gas production. Oil is produced in the sandstone and unconsolidated sand of Agbada formation. This formation is characterized by alternating sandstones and shales. The formation's sand is primarily hydrocarbon reservoir, with shale serving as lateral and vertical seals.Previous work from Selley (1997) and Etu-Efeotor (1997) showed that the gross reservoir properties in the oil bearing reservoir of the Niger delta is a function of the sand/shale ratio and sealing potential of the faults.Avsethet al., 2005 explained that in reservoir characterization and/or evaluation, detailed characteristics of reservoir using seismic and well log data are analyzed and described both in quality and quantity by delineating reservoir parameters such as porosity, permeability, water saturation, pore fluid etc from non- reservoir parameters

This paper aimed at delineating the subsurface lithologies and presence of fluid in the study area, as well as estimating and computing the delineated reservoir's physical properties (porosity, permeability, water saturation, pore fluid, etc.).

International Journal of Advances in Engineering and Management (IJAEM)
Volume 4, Issue 8 Aug. 2022, pp: 632-637 www.ijaem.net ISSN: 2395-5252

II. LOCATION AND STRATIGRAPHIC SETTING OF THE STUDY AREA

The Niger Delta is a prograding depositional complex within the Cenozoic formation of southern Nigeria. It is situated on the Gulf of Guinea on the west coast of central Africa between latitudes 30°N and 60°N and longitude 50°E and 80°E. It covers an area of about 75,000km2. It occurs at the southern extreme of Benue trough, extends from Calabar flanks and it opens to the Atlantic Ocean in the south.

The Niger Delta is divided into three formations, representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios. The Akata Formation contains mainly shale's deposited on a shallow marine shelf and usually overpressured, with soft and under-compacted plastic shales. Exploration rarely gets to it because of the absence of commercial oil deposits.

The Agbada Formations is made up of alternations of sand and shales. The sand are mostly encounted at the upper parts while shales are found mostly at the lower parts. The Agbada formation is thickest at the center of the Delta and goes up to 1500 ft (457 m) this is the seat of most oil reservoirs and center of overpressures. The Benin formation which is a loose fresh water bearing sand with occasional ignite and clay and going up to 7500 ft (2286 m) deep with no over pressure.

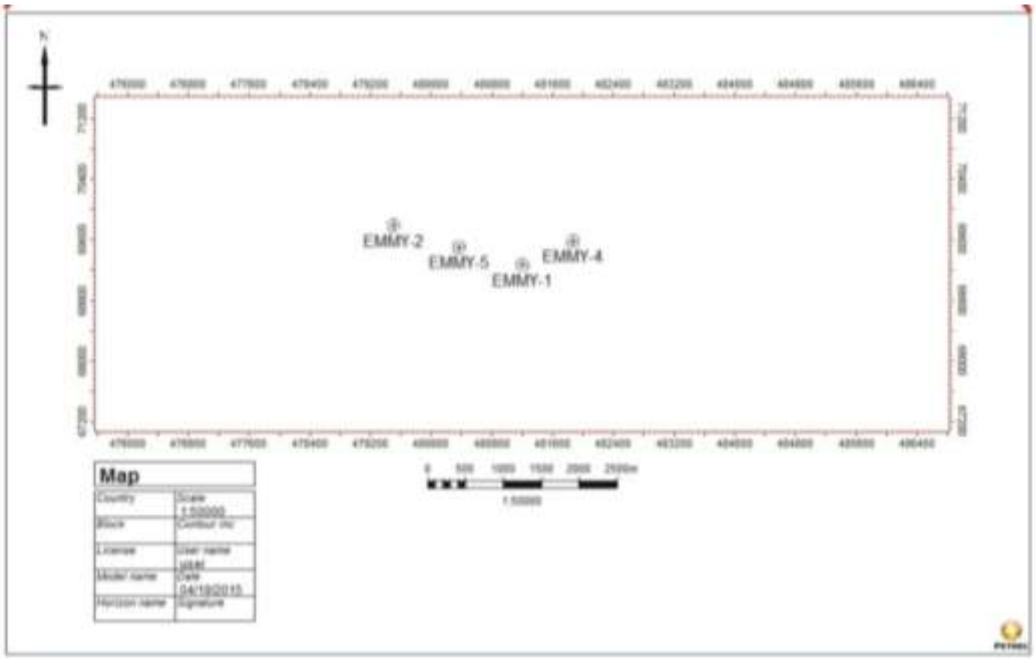

Figure 1 Base map of the Study Area

III. MATERIALS AND METHODOLOGY

3.1. Materials

The materials used involve Composite well logs primarily composed of Spontaneous Potential, Gamma ray, Resistivity, Sonic, Density, and Neutron logs from the four wells.
The method involves interpreting wire-line log data using Petrel Software for the identification of hydrocarbon bearing reservoirs and computing reservoir petrophysical parameters.

3.2. Evaluation Techniques

3.2.1. Identification of Lithology and Hydrocarbon Bearing Reservoirs

Permeable zones (sands) were differentiated from non-permeable zones (shale) using GR, SP and Neutron/Density logs. Based on this, tops and bases of Reservoirs were delineated in all the four wells. Consequently, the zones of interest for the petrophysical interpretation were defined in terms of clean zones with hydrocarbon saturation (low GR and high resistivity).

The formation density and neutron logs were used for the differentiation of the various fluid types. The gas zones are interpreted from crossover of the porosity logs i.e. formation density and neutron logs, oil zones are based on high resistivity values and water zones corresponds to very low resistivities. Hydrocarbon-bearing intervals were discriminated from water-bearing intervals using the resistivity logs. Fluid typing (oil, gas or water) was done using Neutron/Density logs. Reservoirs were interpreted as an oil reservoir because there is little separation between neutron and density curves in the reservoir. Gas usually shows high neutron-density separation, mostly referred to as gas effect.

3.2.2 Quantitative Evaluation from Logs

This involves evaluation of rock properties from well logs. This was done using the Excel programme. The process requires the following steps; determination of the volume of shale, determination of the porosity, determination of the formation waterresistivity (Rw) and determination of the water saturation (Sw).

Gamma Ray Index

The gamma ray log was used to determining the gamma ray index using the formula according to Asquith and Gibson, 1982:

$I_{GR} = (GR_{LOG} - GR_{MIN})/(GR_{MAX} - GR_{MIN})$

Where,

I_{GR} = gamma ray index

GR_{LOG} = gamma ray reading of formation from log

GR_{MIN} = minimum gamma ray (clean sand)

GR_{MAX} = maximum gamma ray (shale)

Shale Volume (Vsh) was calculatedby applying the gamma ray index in the appropriate volume of shale equation according to Larionov (1969) for tertiary rocks:

$V_{sh} = 0.083[2^{(3.7 \times IGR)} - 1.0]$ - Larionov Tertiary rocks method

Where, V_{sh} = volume of shale

I_{GR} = gamma ray index

The computation of porosity was done in stages, the first involved the use of the Wyllie equation to estimate the density derived porosity (ϕ_D), and then the neutron-density porosity (ϕ_{N-D}), was estimated using the neutron (ϕ_N) porosity coupled with the density derived porosity. Equations below were used in the computation.

The Wyllie equation for density derived porosity is given as:

$\phi_D = (\ell_{max} - \ell_b)/(\ell_{max} - \ell_{fluid})$

where:

ℓ_{max} =density of rock matrix = 2.65 g/cc

ℓ_b = bulk density from log

ℓ_{fluid} = density of fluid occupying pore spaces (0.74g/cc for gas, 0.9g/cc for oil and 1.1 g/cc for water).

The Neutron–Density porosity could be calculated according to Shell/Schlumberger (1999) as:

$\phi_{N-D} = (\phi_N + \phi_D)/2$ for oil and water column

$\phi_{N-D} = (2\,\phi_D + \phi_N)/3$ for gas bearing zones.

Resistivity of formation water (Rw) is usually estimated in a clean water-bearing interval using the equation;$R_w = R_o/F$

Water saturation was estimated from Archie's equations (1942).

$S_w^2 = (F \times R_w)/R_T$ - Archie's equation

But, $F = R_o/R_w$

Thus, $S_w^2 = R_o/R_T$

Where,

S_w = water saturation of the uninvaded zone

R_o= resistivity of formation at 100% water saturation

R_T = true formation resistivity.

Permeability Estimation

This was based on the relationship between permeability, porosity, and irreducible water saturation according to Wyllie and Rose, (1950). The relationship is expressed as:

$K = [(250 \times (Ø_{N-D})^3)/S_{wirr}]^2$- oil

$K = [(79 \times (Ø_{N-D})^3)/S_{wirr}]^2$- gas

IV. RESULTS AND DISCUSSION

A total of five sand bodies were delineated. A close look at correlated logs show that there are three reservoir sand bodies for each well and were labeled as reservoir A (SandA), reservoir B (Sand D), and reservoir C (Sand E).

Well 1

Reservoir A

This occurs at the depth range of 2284.3 – 2390.3m. It has a gross thickness of 105.49m and net sand thickness of 96.97m. The net to gross is 91%.

Reservoir B

This occurs at the depth range of 3200.4 – 3306.5m. It has a gross thickness of 106.1m and net sand thickness of 83.9m. The net to gross is 79%.

Reservoir C

This occurs at the depth range of 3385.5 – 3415.2. It has a gross thickness of 29.7m and net sand thickness of 21.8m. The net to gross is 73.

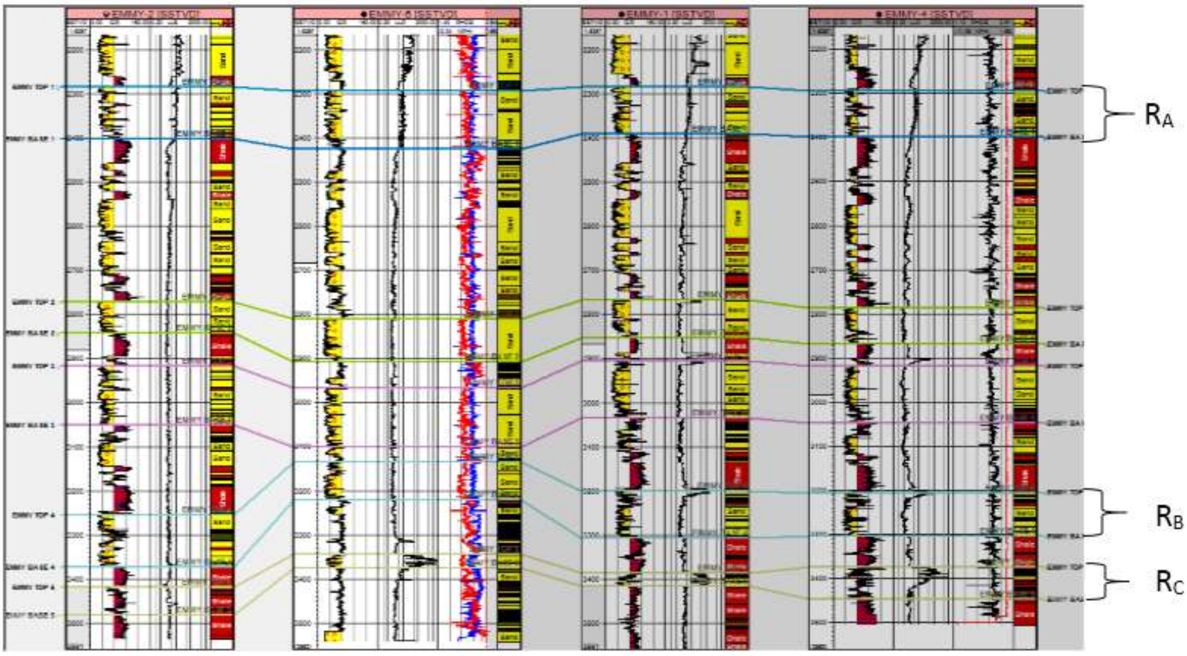

Figure 2 Top and bottom of the reservoirs as differentiated by the gamma ray log

Well 2
Reservoir A

This occurs at the depth range of 2284.3 – 2403.2m. it has a gross thickness of 118.9m and net sand thickness of 92.79m. The net to gross is 78%. The porosity value of the reservoir is 40% and it's constant throughout the reservoir. The permeability value is also constant with value 109115D. This indicates that the reservoir has good to excellent porosity and excellent permeability.

Reservoir B

This occurs at the depth range of 3255.8 – 3378.9m. It has a gross thickness of 123.1m and net sand thickness of 98.6m. The net to gross is 80%. The porosity value of the reservoir is 40% and it's constant throughout the reservoir. The permeability value is also constant with value 6714.1D. This indicates that the reservoir has good to excellent porosity and excellent permeability.

Reservoir C

This occurs at the depth range of 3418.0 – 3482.3. It has a gross thickness of 64.3m and net sand thickness of 17.1m. The net to gross is 26%. The porosity average value is 28.4%, permeability average is 6714.1D, both porosity and permeability values are constant throughout the entire reservoir. It is interpreted that the reservoir has good to excellent porosityand good permeability.

Well 4
Reservoir A

This occurs at the depth range of 2294.2 – 2398.8m. It has a gross thickness of 104.9m and net sand thickness of 87.38m. The net to gross is 83% the porosity values ranges from 16.5% to 48% with an average of 30.4%. Permeability value ranges from 86.2 to 493909.1D with average value of 20857.1D. It is interpreted that the reservoir has very good porosity and has good permeability.

Reservoir B

This occurs at the depth range of 3206.4 – 3303.2m. It has a gross thickness of 96.7m and net sand thickness of 72.9m. The net to gross is 75%. The porosity values of the reservoir ranges from 14.7 to 36.7% with an average value of 23.4%.
The permeability value ranges from 35.04 – 51431.1D with average value of 2512.8D. It is interpreted that the reservoir has very good porosity and has good permeability.

Reservoir C

This occurs at the depth range of 3374.4 – 3447.8m. It has a gross thickness of 73.3m and net sand thickness of 29.9m. The net to gross is 0.40%. The porosity values of the reservoir ranges from 16.3 to 48.2% with an average value of 25.9%.
The permeability value ranges from 77.3 – 453963.2D with average value of 23505D. It is interpreted that the reservoir has very good porosity and has good permeability.

Well 5

Reservoir A

This occurs at the depth range of 2294.9 – 2426.4. It has a gross thickness of 131.5m and net sand thickness of 122.8m. The porosity values of the reservoir ranges from 1.3 – 34.4% with an average value of 27.6%. The permeability average value is 6352.1D. It is interpreted that the reservoir has excellent porosity and has good to very good permeability.

Reservoir B

This occurs at the depth range of 3136.8 – 3221.0m. It has a gross thickness of 84.2m. The net sand thickness is 82.2%. The net to gross is 97%. The porosity values of the reservoir ranges from 13.5 – 44% with an average value of 24.8%, The permeability value ranges from 17.4 – 219141D with average value of 6065.6D. It is interpreted that the reservoir has very good excellent porosity and has good to very good permeability.

Reservoir C

This occurs at the depth ranged of 3343.5 – 3376.2m, it has gross thickness of 32.8m and net sand thickness of 1.54m. The net to gross is 95%. The porosity values ranges between 19.7 to 33% with an average value of 26.3%, permeability has the average value of 4916.1md, it is interpreted that the reservoir has the good porosity and good permeability.

Table 1. Petrophysical parameters obtained for Reservoir A (SAND A)

Well	Top (ft)	Bottom (ft)	Gross (ft)	Porosity	Sh	Vsh	Sxo	Sw	Shr	MOS	HMI
2	2284.34	2403.26	118.92	0.40	0.73	0.17	0.76	0.27	0.23	0.49	0.35
5	2294.96	2426.48	131.52	0.28	0.46	0.28	0.88	0.53	0.12	0.34	0.60
1	2284.83	2390.32	105.49	-	-	0.27	-	-	-	-	-
4	2294.26	2398.85	104.59	0.30	0.44	0.32	0.88	0.56	0.11	0.32	0.63

Table 2. Petrophysical parameters obtained for Reservoir B (SAND D)

Well	Top (ft)	Bottom (ft)	Gross (ft)	Porosity	Sh	Vsh	Sxo	Sw	Shr	MOS	HMI
2	3255.84	3378.96	123.12	0.28	0.15	0.12	0.96	0.84	0.03	0.12	0.87
5	3136.80	3221.00	84.2	0.24	-0.17	0.29	1.03	1.17	-0.03	-0.14	1.13
1	3200.47	3306.57	106.10	-	-	0.36	-	-	-	-	-
4	3206.41	3303.20	97.79	0.23	0.44	0.25	1.04	1.36	-0.04	-0.31	1.26

Table 3. Petrophysical parameters obtained for Reservoir C (SAND E)

Well	Top (ft)	Bottom (ft)	Gross (ft)	Porosity	Sh	Vsh	Sxo	Sw	Shr	MOS	HMI
2	3418.05	3482.32	64.27	0.28	0.18	0.23	0.95	0.81	0.04	0.14	0.84
5	3343.59	3376.45	32.86	0.26	0.51	0.35	0.81	0.48	0.18	0.33	0.53
1	3385.55	3415.28	29.73	-	-	0.38	-	-	-	-	-
4	3374.49	3447.82	73.33	0.26	0.43	0.27	0.86	0.56	0.13	0.29	0.61

V. CONCLUSION

The productive zones of the Emmy's Field have been delineated using well logs. Reservoir thickness varies from 29 – 133m. Calculated petrophysical values such as hydrocarbon saturation and porosity in the three reservoirs were very high ranging from 0.15 to 0.51 and 0.16 to 0.44 respectively.

The reservoir rock properties were interpreted as a good qualityreservoir rock which has beenestablished from high total porosity(23–40%), and variable shale volume(10–38 %). A number of highhydrocarbon saturation zones(exceeding 55 %) are detectedthrough intervals having Sw < 60 % which have been considered as economic oilproducers. The results showed that all the delineated reservoirs within the four wells are producible since the porosity values ranged from good to excellent and moderate hydrocarbon saturation. The calculated values indicate that porosity, permeability values from the hydrocarbon bearing reservoir are good enough for commercial accumulation in the Niger Delta.

REFERENCES

[1]. Avseth, P., Mukerji, T. and Mavko, G. (2005) Quantitative Seismic Interpretation: Applying Rock Physics Tools to Reduce Interpretation Risk. Cambridge University Press,

Cambridge.https://doi.org/10.1017/CBO9780511600074.
[2]. Etu-Efeotor, J. (1997) Fundamentals of Petroleum Geology. Africana-FEP Publishers, Onitsha, 111-123.
[3]. Fred Aminzadeh, Shivaji N. Dasgupta, in Developments in Petroleum Science, 2013
[4]. Selley, R.C. (1997) African Basins (Sedimentary Basins of the World). Volume 3, Elsevier Science B.V., Amsterdam.