RESERVOIR CHARACTERIZATION OF TICK FIELD IN THE NIGER DELTA BASIN USING WELL LOG DATA

By

Anyadiegwu, F. C., Dinneya, O. C., Ijeh, B. I. and Isiguzo, C. V.

Michael Okpara University of Agriculture, Umudike, P.M.B. 7267, Umuahia, Abia State, Nigeria. Email:fzinoz@gmail.com

ABSTRACT

Well log data from the three wells located in TICK field of Niger Delta basin were used in characterization of reservoir. The various lithologic types penetrated by the wells were differentiated on the basis of gamma ray log and caliper logs. The geophysical well logs used were the gross thickness, net thickness, total porosity, effective porosity, water saturation and hydrocarbon saturation. The averages for Total porosity, water saturation and hydrocarbon saturation are 30.18%, 46.23%, and 55.45% respectively. The highest hydrocarbon saturation was seen in Tick 1 and Tick 3 of reservoir 2 with depths between 8400ft -8470ft and hydrocarbon saturation of 80% each.

1.0 INTRODUCTION

Well logging is one of the most fundamental methods for reservoir characterization, in oil and gas industry. It is an essential method for geoscientist to acquire more knowledge about the condition below the surface by using physical properties of rocks. This method is very useful for detecting hydrocarbon bearing zones, determination of the hydrocarbon volume, and many more. Formation evaluation is the study of the properties of the rock and their relationship to the fluids they contain in both static and flowing states using wireline logs (Aigbedion, 2010). The formation of the Niger Delta basin consists of sandstone and shale with environment of formation of the former ranging from fluvial (channel) to fluviomarine (barrier bar), while the later are generally fluviomarine or lagoonal. These formations are mostly unconsolidated and it is often not feasible to take core samples or make drill stem tests. Formation evaluation is consequently based mostly on logs. Petrophysical parameters like the lithology fluid content, porosity, water saturation and hydrocarbon saturation are derived; from the well log data (Ehigiator and Aigbedion, 2010). Petroleum deposits occur as a result of the deposition of plants and animals matter in areas which are slowly subsidizing. These areas which are usually in the sea or along reef margin in the coastal lagoons. Sediments are deposited along with organic matter and the rate of deposition of the sediments must be sufficiently rapid such that at least part of the organic matter is preserved and buried before being destroyed or decayed (Hospers, 2012). As time goes on and the area continue to sink slowly (because of weight of sediments) the organic materials are buried deeper and hence are exposed to higher temperature and pressure. Eventually, chemical changes result in the formation of petroleum; a complex highly variable mixture of hydrocarbon, including liquid and gases. Due to the fact that sedimentary rocks are porous, petroleum collects these cavities, intermingled with water which are buried with the sediments (Efeotor, 2009). When a significant fraction of the pool is interconnected so that it is permeable the oil and gas tends to rise and will eventually reach the surface of the earth and be dissipated unless they encounter a barrier which stops the upward migration resulting in a trap. Logs are useful to geophysicists and geologists as they help in making relevant decisions. Three major litho stratigraphic units have been recognized in the Niger Delta- Nigeria (Aigbedion and Aigbedion, 2011). These are the Akata, Agbada and Benin formations. Details of the geology of

the Niger Delta has been discussed by several authors (eg. Obaje). The Benin formation is made up of loose fresh water bearing sand with occasional lignite and clay which goes up to 2,286m deep with no pressures. The Agbada formation is made up of alternating sand and shale. The sands are mostly encountered at the upper parts while shale are found mostly at the lower parts. The Agbada formation is the thickest at the center of the Delta and goes up to 457.2m. Formation evaluation of the area of study within Niger Delta basin will allow an estimate to be made of porosity, fluid content, type and lithology using well logs. The physical and chemical properties of the rock determined in this way are an invaluable aid to describing sub-surface geology (Aigbedion, 2010).

2.0 Geology and Stratigraphy of Niger Delta

A delta is a large accumulation of sediments deposited at the mouth of a river where it is discharged into the sea with more than one channel called tributaries. It results from a stream reaching a body of water such as the sea and building a deposit of sediments because of the reduction of its velocity of flow.

In an advancing delta such as that of the Tertiary Niger delta, sediments are stratigraphically superimposed. The submarine delta fringe will encroach on sediments and will in turn, be covered by a younger lower deltaic plain.

In the Niger delta, this sequence is modified by the numerous transgressions which have occurred from time to time, breaking the continuity of the main overall regression, and becoming stratigraphically superimposed (Short and Stauble, 1967). The thick wedge of the Niger delta is considered to consist of three units Benin, Agbada and Akata formations. These formations are strongly diachronous and cut across the time stratigraphic units which are characteristically S-shaped in cross section. The typical sections of these formations are described by (Short and Stauble, 1967) and summarized in a variety of papers (Avbovbo and Omatsola, 1990). These three geologic formations in the Niger Delta are discussed next. The Benin formation overlies the Agbada formation. The age of the formation is Oligocene in the north, and becomes progressively younger southwards. To date, very little hydrocarbon deposits have been found in this highly porous and generally freshwater bearing formation (Short and Stauble, 1967). The Benin formation extends from the west across the wholeof Niger Delta (Doust and Omatsola, 1990) and has been described as coastal plain sands which outcrop in Benin, Onitsha and Owerri provinces. It consists of massive continental sands; gravels with thickness ranging from 0.2 to 100metres.The sand and sandstone are coarse to fine and commonly granular in texture. In general, they appear to be poorly sorted, sub-angular to well round.The sand and sandstone may represent point bar deposits, channel fills and natural levees while the shale may be interpreted as black swamp deposits and oxbow fills.

Agbada formationis a paralic sequence of sandstone and shale intercalations underlying the Benin formation. It consists of the sandy parts, which serve as the main hydrocarbon reservoir of the Delta and shale as the cap rock.

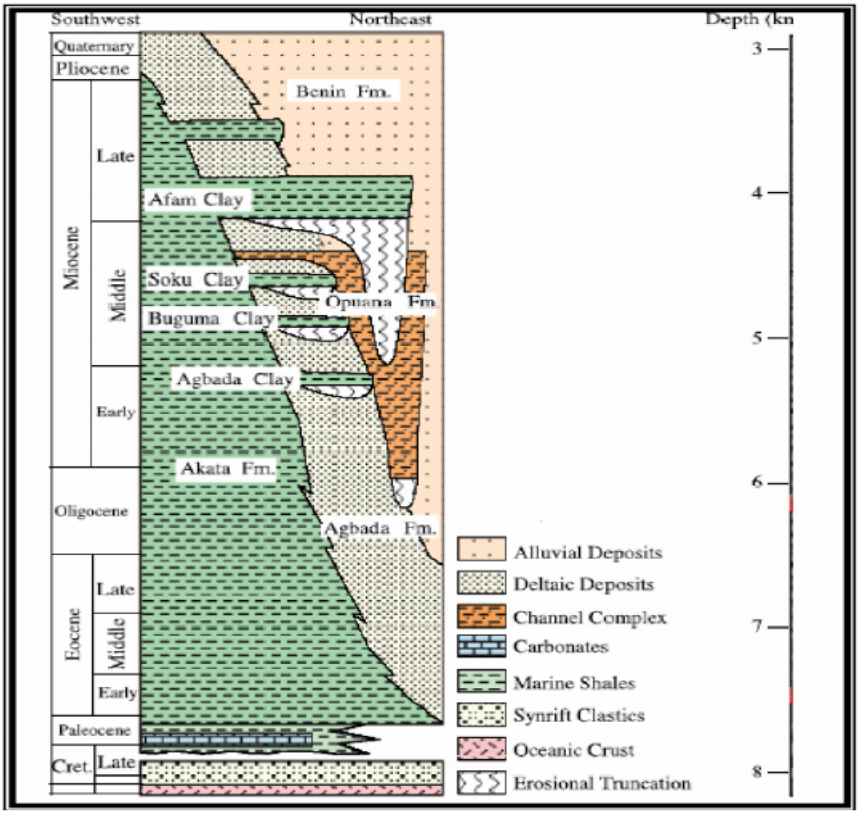


Figure 1: Stratigraphic column showing the three formations of the Niger Delta (Obaje, 2009).

This sequence is associated with syn-sedimentary growth faulting. The Agbada formation is thickest at the center with a maximum thickness of 457.2m (Doust and Omatsola, 1990).The upper part is predominantly sandy unit minor shale intercalation and a lower shalyunit, which is thicker than the upper sandy unit. The formation was deposited beginning from the Eocene and continued into the Recent. The formation consists of siliciclastics over 3700 meters thick, and represents the actual deltaic portion of the sequence. In the lower Agbada formation, shale and sandstone beds were deposited in equal proportions; however, the upper portion is mostly sand with only minor shale inter-beds. The depositional environment is therefore defined as "transitional" between the upper continental Benin formation and the marine underlying Akata formation (Fig 1). It is Miocene in the north and Pliocene/Pleistocene in the south and has a maximum thickness of possibly 4600 meters (Doust and Omatsola, 1990).
The proliferous Agbada formation is divided into four distinct members:

- D-1 member which is predominantly an alternating sequence of regressive sands and marine shale with minor oil and gas reservoir.
- Qua-Iboe consisting of thick pile of shale with thin intercalated sands that are possible oil and gas reservoir in some places
- The Rubble bed consisting of heterogeneous mixture of eroded Biafra sand and shale.
- The Biafra member is predominantly of alternating sequence of sand and shale. It contains principally oil and gas reservoir (Doust and Omatsola, 1990).

Akata formation is composed of deeper marine shale, the deepest stratigraphic unit. It is chiefly represented by plastic, low density, under-compacted and high-pressure shallow marine to deep water-shale; with only local inter-beddings of sands and/or siltstones. It is deposited as the high-energy delta advanced into deep water. In general, the shale is over pressured and this provides the mobile base for subsequent growth faulting associated with the deposition of the overlying paralic sequence. It serves as the hydrocarbon source in the Niger Delta. Majority of wells drilled in the Niger Delta only penetrated into the marine Akata Shale. Little of the Akata formation has been drilled; therefore, not much is known about this formation. It is estimated that the formation is up to 7,000 meters thick (Doust and Omatsola, 1990).

One of the most conspicuous geological features of the Niger Delta is its growth fault pattern. The Niger Delta oil province is characterized by East-West trending syn-sedimentary faults and folds. The energy responsible for their genesis is most likely to be inherent in the sediments themselves rather than in any external orogenic forces. In fact, they are believed to be gravity faults contemporaneous with rapid sedimentation and initiated by the differential loading of the underlying and mobile (laterally and vertically) under-compacted Akata shale. The sedimentation and gravity faulting has resulted in the deposition of thicker sediments on the down-thrown than on the up-thrown block. Besides, because of the large weight of sediments deposited in the delta front and the down dip subsidence accompanying this deposition, the strata have been tilted basin ward. Most of the oil accumulated in the Niger Delta is contained in the rollover anticline structure. The oil in these structures may be trapped in dip closures or against a Synthetic or antithetic fault.

3.0 MATERIALS AND METHOD MATERIALS

Suites of three geophysical well logs recorded at various locations within the Tick field, Niger Delta basin was used in these work.

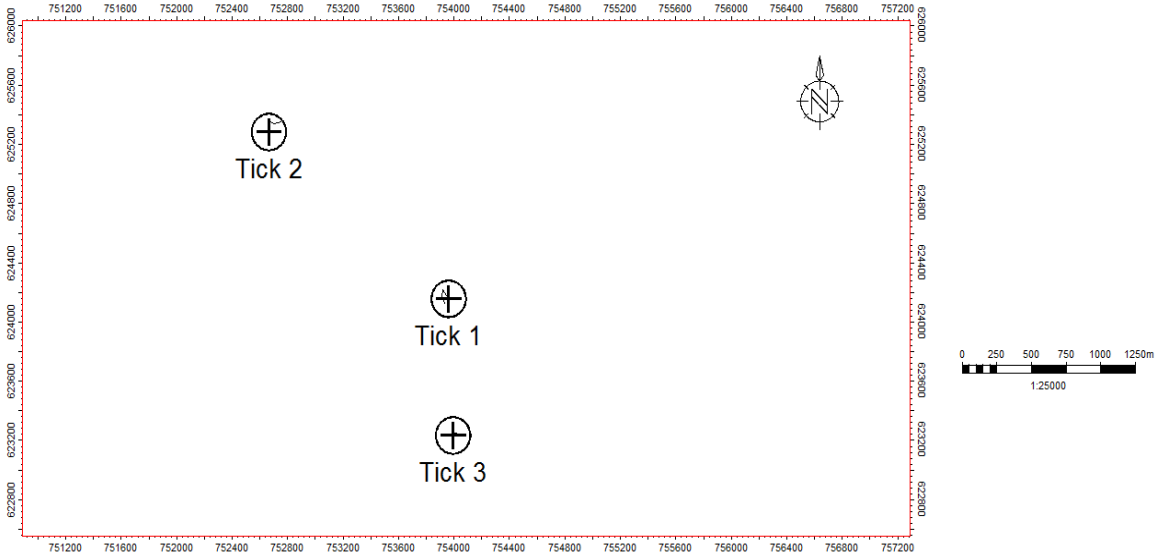


Fig 2: Base Map of Tick Field

The given data was properly studied, and then sorted into format which is PETREL™ compatible. All the data files were stored in a location on the Personal Computer, from where they were accessed.

Before the interpretation process, PETREL™ workflow has defined folders, which are symbolic. According to PETREL™ workflow, the following procedures were followed for the data analysis.

i. Well data import
ii. Delineation of lithology

Porosity, water saturation and volume of shale were then imported for the three wells Tick 1, 2 and 3 respectively.

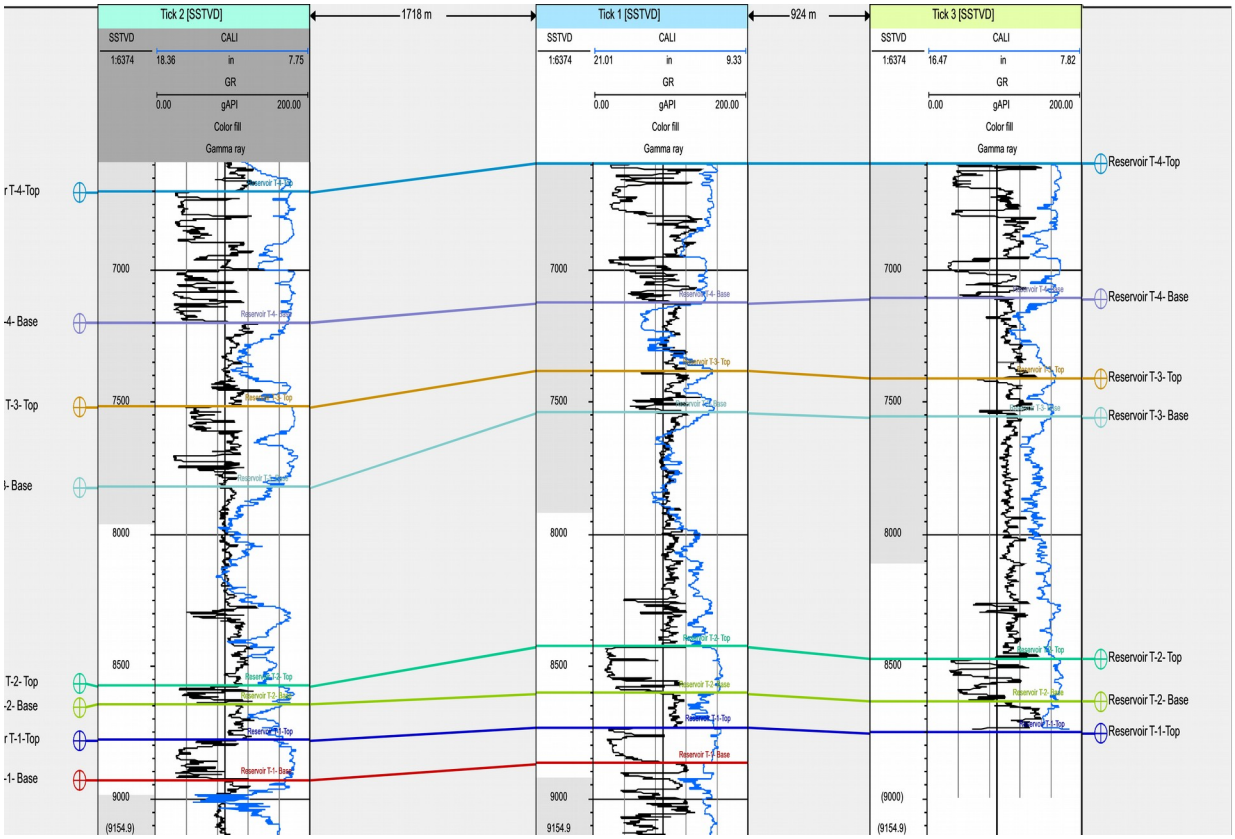


Fig 3: Reservoir correlation using GR and Caliper logs

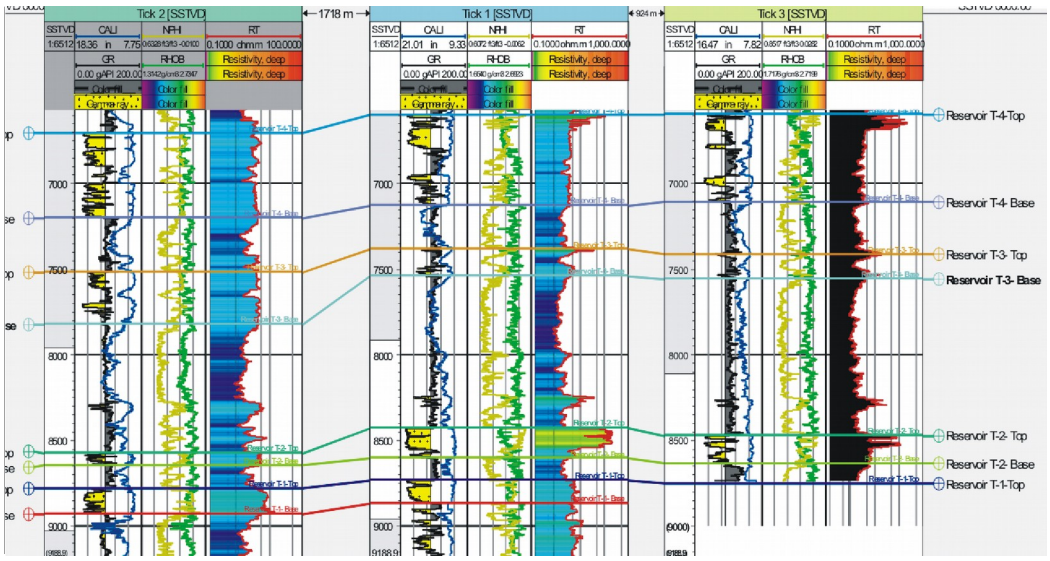


Fig 4: General view of tick field showing the reservoir zones

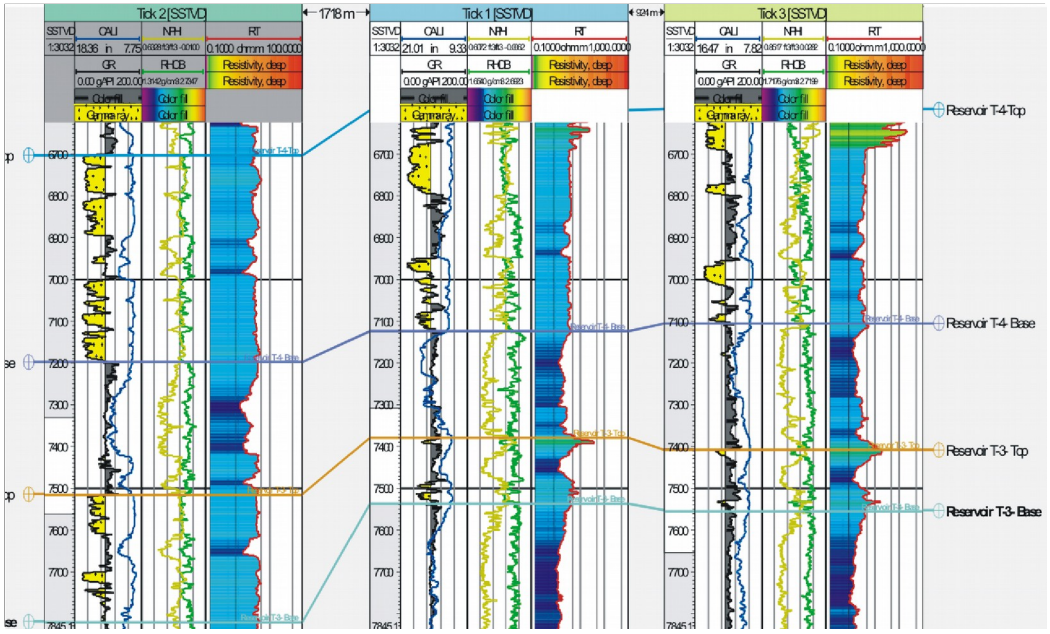


Fig 5: Reservoir correlation of Tick field showing resistivity kicks and balloon features in reservoirs 3 and 4

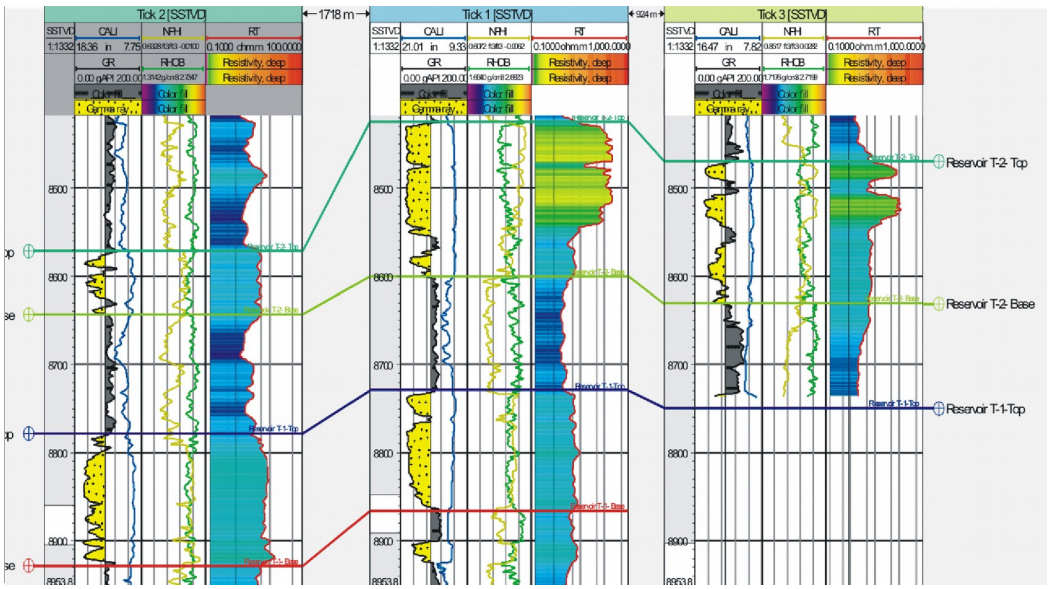


Fig 6: Reservoir 1 and 2 with balloon feature and resistivity kick

METHOD

WELL DATA IMPORT

The sequence of data import begins with the well heads and logs. The well heads file, contain the well name, surface location of the wells (2D-XY coordinate system), Kelly bushing (Kb), the top depth and bottom depth. This will allow the display of well position on the base map. The logs gamma ray, resistivity, and density were delineated from their respective log signatures. Sand bodies were identified by gamma ray deflection to the left due to the low concentration of radioactive minerals in sand while deflection to the right signifies shale which is as a result of high concentration of radioactive minerals in it. Thus, the lithofacies were delineated and the reservoirs formation was found to comprise of sand and shale.

DELINEATION OF LITHOLOGIES

The reservoir formation comprises of Sand and shale

IDENTIFICATION OF RESERVOIRS AND DIFFERENTIATION OF HYDROCARBON AND NON-HYDROCARBON BEARING ZONES

Reservoirs are subsurface formations that contain water and hydrocarbon. They were identified by using the log signatures of both gamma and resistivity logs. Intervals that have high resistivity are considered to be hydrocarbon bearing while low resistivity zones are water bearing intervals.

A combination of the gamma ray and resistivity logs were used to differentiate between the hydrocarbon and non-hydrocarbon bearing units. As the hydrocarbon saturation increases, resistivity also increases; on the other hand as water saturation increases, the resistivity decreases. This is indicated by the deflection on the resistivity log.

WELL CORRELATION

The logs were activated and displayed on the well section window, on which correlation was carried out using the lithology log (Gamma ray log), the resistivity was used to check the fluid contents present within the sediments i.e. hydrocarbon or water. The top and base of the reservoir were picked.

DETERMINATION OF PETROPHYSICAL PARAMETERS

i. Determination of gross and net sand reservoir thickness

Gross reservoir thickness interval is the interval covering shale and sand within a reservoir.

Net thickness of sand is the interval covering only sand within a reservoir. It is called net productive sand. The gross reservoir thickness is determined by knowing interval covering both sand and shale within the reservoir studied using gamma ray log. Net sand thickness is determined by subtracting the interval covering the shale from gross reservoir thickness.

Well log data were used in this analysis to generate rock properties using these formulae

GT (Gross thickness) = Base of sand - Top of sand. (1)

NT (Net thickness) = (Base of sand + Top of sand- shale) if shale is present in the formation, if not **NT** will be the same as **GT**

NTG (Net to gross) = $\frac{NT}{GT}\frac{NT}{GT}$ (2)

ii. Volume of shale (Vsh).

The gamma ray log was used to calculate the volume of shale in a porous reservoir. The first step used to determine the volume of shale from a gamma ray log was the calculation of the gamma ray index using the equation:

$$I_{GR} = \frac{GRlog - GRmin}{GRmax - GRmin} = \frac{GRlog - GRmin}{GRmax - GRmin} \quad (3)$$

Where: IGR = Gamma ray index, GRlog = Gamma ray reading of the formation, GRmin p=Minimum gamma ray (clean sand), GRmax = Maximum gamma ray (shale).

All these values were read off within a particular reservoir. Having obtained the gamma ray index, volume of shale was then calculated using the Dresser Atlas (1979) formula

$$Vsh = 0.083(2 = 0.083(2_{3.7} \times \times_{IGR} - 1.0)(Tertiary - 1.0)(Tertiary$$ consolidated sand) (4)

iii. Porosity (Ø).

Porosity is defined as the percentage of voids to the total volume of rock. The formation density log was used to determine formation porosity. The porosity was determined by substituting the bulk density readings obtained from the density log within each reservoir into the equation 3.22 (Dresser Atlas, 1979).

$$Ø_{den} = \frac{ma - b}{ma - pf} = \frac{ma - b}{ma - pf} \quad (5)$$

Where, $Ø_{den}$: Is the density derived porosity, ρ_{ma} is the matrix density = 2.65gm/cm3 (sandstone), ρ_{fl} is the fluid density= 1.1gm/cm3 (fluid density), ρ_b = formation bulk density

The criteria for classifying porosity given by Baker (1992) is:
Ø < 0.05 = Negligible, 0.05 < Ø <0.1 = Poor, 0.1 Ø< 0.15 = Fair, 0.15 < Ø < 0.25 = Good, 0.25 < Ø <0.30 = Very good Ø > 0.30 = Excellent.

iv. Formation factor (F)

The formation factor was determined from the Archie's (1942) equation below;

$$F = \left(\frac{a}{Øm} = \left(\frac{a}{Øm}\right)\right) \quad (6)$$

Where: Ø= Porosity, a = constant (0.62), m = cementation exponent (2 for sands).

v. Estimation of water saturation

Determination of the water saturation for the uninvaded zone was achieved using the (Archie, 1942) equation:

$$Sw^2 = \frac{F \times Rw}{Rt} = \frac{F \times Rw}{Rt} \quad (7)$$

$$\text{But } F = \frac{Ro}{Rw} = \frac{Ro}{Rw} \quad (8)$$

Thus,

$$S_w^2 = \frac{Ro}{Rt} = \frac{Ro}{Rt} \quad (9)$$

Where, Sw= water saturation of the uninvaded zone, Ro= resistivity of formation at 100% water saturation, Rt= true formation resistivity, F = formation factor

vi. Hydrocarbon saturation (Sh)

This is the percentage of pore volume in a formation occupied by hydrocarbons. It was obtained by subtracting the value obtained for water saturation from 100%.

$$\text{i.e} S_h = = (100 - - Sw)\% \quad (10)$$

Where,
Sh = Hydrocarbon saturation, Sw = Water saturation

4.0 RESULTS AND DISCUSSION

Attribute maps extracted on top of key horizons were used for better visualization and interpreting the morphological and reflectivity characteristics of the reservoirs. From the well log data's in chapter three, four tables were generated for each reservoir from figures 3 to 6.

Table 1: Reservoir Evaluation of T-1

Well Name	Top (ft)	Base (ft)	Gross Thickness (ft)	Net Thickness (ft)	Total Porosity (%)	Effective Porosity (%)	Water Saturation (%)	Hydrocarbon Saturation (%)
Tick 2	8800	8931	131	105	33	21	30	70
Tick 1	8730	8865	135	110	29	23	25	75

Tick 3	No data	No data						
Average			133	107.5	31	22	27.5	72.5

Reservoir T-1 was encountered by the three wells but the data for well three was absent and records the hydrocarbon range in the areas between the depths ranges of 8730 – 8931ft. The reservoir T-1 has Gross thickness range of between 131–135ft and average Gross thickness of 133ft, Net thickness range of between 105 – 110ft and Average Net thickness of 107.5ft. The gamma ray and the resistivity logs show Total Porosity range of the reservoir sand between29 – 33% and Average True Porosity of 31%, it shows an Effective Porosity range of between 21 – 23% with Average Effective Porosity of 22%. The water saturation of T-1 range between 25 – 30% and average 27.5%per well. Table 1 shows reservoir T-1 to have a hydrocarbon range of between 70 – 75%. The above data gives reservoir T-1 as a productive reservoir with Tick-2 being the most productive well having hydrocarbon saturation of 75%.

TABLE 2: Reservoir Evaluation of T-2

Well Name	Top (ft)	Base (ft)	Gross Thickness (ft)	Net Thickness (ft)	Total Porosity (%)	Effective Porosity (%)	Water Saturation (%)	Hydrocarbon Saturation (%)
Tick 2	8572	8645	73	53	25	19	100	0
Tick 1	8400	8601	201	160	31	25	20	80
Tick 3	8470	8635	165	115	30	23	20	80
Average			146.5	109.3	28.7	22.3	46.7	60

Reservoir T-2 was encountered by the three wells recording the hydrocarbon range in the areas between the depth ranges of 8470 – 8645ft. The reservoir T-2 has Gross thickness range of between 73–201ft and average Gross thickness of 146.3ft, Net thickness range of between 53 - 160 and Average Net thickness of 109.3ft. The gamma ray and the resistivity logs show Total Porosity range of the reservoir sand between 25 – 31% and Average Total Porosity of 28.7%, it shows us an Effective Porosity range of between 19 – 25% with Average Effective Porosity of 22.3%. The water saturation of T-2 range between 20 – 100 and average 46.7% per well. Table 2 shows Tick-2 well to have no hydrocarbon at all but Tick-1 and Tick-3 have both have 80% hydrocarbon saturation.

The above data gives reservoir T-2 as a nonproductive reservoir with Tick-2 and Tick-3 both having a high hydrocarbon saturation.

Table 3: Reservoir Evaluation of T-3

Well Name	Top (ft)	Base (ft)	Gross Thickness (ft)	Net Thickness (ft)	Total Porosity (%)	Effective Porosity (%)	Water Saturation (%)	Hydrocarbon Saturation (%)
Tick 2	7513	7820	307	215	31	25	100	0
Tick 1	7378	7538	160	75	28	18	33	67
Tick 3	7409	7554	145	45	26	17	35	65
Average			204	111.7	28.3	20	56	44

Reservoir T-3 was encountered by the three wells recording the hydrocarbon range in the areas between the depth ranges of 7378 – 7820ft. The reservoir T-3 has Gross thickness range of

between 145–307ft and average Gross thickness of 204ft, Net thickness range of between 45 – 215ft and Average Net thickness of 111.7ft. The gamma ray and the resistivity logs show Total Porosity range of the reservoir sand between 26 – 31% and Average Total Porosity of 28.3%, it shows us an Effective Porosity range of between 17 – 25% with Average Effective Porosity of 20%. The water saturation of T-3 range between 33 – 100% and average 56% per well. Table 3 shows Tick-2 well to have no hydrocarbon at all but Tick-1 and Tick-3 have hydrocarbon saturation of 67% and 65% respectively.
This data gives reservoir T-3 as a productive reservoir with Tick-1 being the most productive well having a hydrocarbon saturation of 67%.

Table 4: Reservoir Evaluation T-4

Well Name	Top (ft)	Base (ft)	Gross Thickness (ft)	Net Thickness (ft)	Total Porosity (%)	Effective Porosity (%)	Water Saturation (%)	Hydrocarbon Saturation (%)
Tick 2	6705	7200	495	370	31	20	100	0
Tick 1	6600	7125	525	341	32	23	33	67
Tick 3	6600	7103	503	380	35	25	31	69
Average			507.7	363.7	32.7	22.7	54.7	45.3

Reservoir T-4 was encountered by the three wells recording the hydrocarbon range in the areas between the depth ranges of 6600 – 6705ft. The reservoir T-4 has a gross thickness of 495 – 525ft and average thickness of 507.7ft, Net thickness range of 341 – 380ft and Average Net thickness of 363.7ft. The gamma and resistivity log shows Total porosity of range between 31 – 35% and Average Total Porosity of 32.7%, it shows us an Effective Porosity range of between 20 – 25% with Average Effective Porosity of 22.7%. The water saturation of T-4 range between 31 – 100% and average water saturation 54.7% per well. Table 4.4 shows Tick-2 well to have no hydrocarbon at all but Tick-1 and Tick-3 have hydrocarbon saturation of 67% and 69% respectively.
This data gives reservoir T-4 as a productive reservoir with Tick-3 being the most productive well having a hydrocarbon saturation of 69%.

5.0 CONCLUSION AND RECOMMENDATION

CONCLUSION

The reservoir characteristics of TICK field Niger Delta have been carried out. Four reservoirs were delineated. From the analysis, particularly the resistivity log, of the three wells delineated, reservoirs were identified and were found to be hydrocarbon bearing units across the three wells i.e. Tick1, Tick2 and Tick3.

Average reservoir parameters such as gross thickness (247.75ft), net thickness (173.05ft), total porosity (30.18%), effective porosity (21.75%), water saturation (46.23%) and hydrocarbon saturation (55.45%) were derived from petrophysical analysis.

The four reservoirs were ranked using average results of petrophysical parameters. Reservoir 1 is said to be the most prolific while reservoir 3 is the least prolific within TICK field. From the result, we can say that TICK field has exploitable potential hydrocarbon.

RECOMMENDATION

Based on the petrophysical interpretation of Tick field, Niger Delta, it is therefore, recommended that exploitation for hydrocarbon can be carried out and recovered core samples analyzed and interpreted within the Tick field. However, core drilling can be carried out in other to validate the result of the wireline logs.

REFERENCES.

Archie, G. E. (1942). The Electrical Resistivity Log as an Aid in determining Some Reservoir Characteristics. Transactions of AIME. Vol 146, pp 54-62.

Aigbedion I. (2010). Characterisation of reservoir Using Petrotrophysical parameters and core data, (A case study of Abura field Niger Delta of Nigeria), Geophysics Journal, Russia. 19-29:71-75.

Aigbedion I, and Aigbedion H. O. (2011). Hydrocarbon volumentric analysis using seismic and borehole data over umoru field, Niger Delta-Nigeria. International Journal of Geosciences, United State of America. 2:179-183.

Avbovbo, A.A. (1978). Tertiary lithostratigraphy of Niger Delta. *American Association of Petroleum Geologists Bulletin,* **62:** 295-300.

Doust, H. and Omatsola, E. (1989). Niger Delta. *AAPG Memoir*, **48**: 201–238

Doust, H. and Omatsola, E. (1990). Niger Delta, *in*, Edwards, J.D. and Santogrossi, P.A. eds.,

Divergent/passive Margin Basins, *AAPG Memoir***48**: Tulsa, American Association of Petroleum Geologists, p.239-248.

Dresser Atlas, (1979). Log interpretation chartsDresser Industries Inc, Houston, Texas, p. 107. Efeotor EJO. Fundamentals of petroleum geology. Paragraphics, Portharcourt. 1997; 12-22.

Ehigiator, M. O., and Aigbedion, I. (2010). Characterisation of reservoir Using Petrotrophysical parameters and core data, (A case study of Abura field Niger Delta of Nigeria), Geophysics Journal, Russia. 19-29:71-75.

Hospers J. Gravity field and structure of The Niger Delta Nigeria. Geological Society of America Bulletin. 1971; 76.

Short KC, and Stauble J (1967) Outline geology of the Niger delta. AAPG Bull 5:761–779.