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Research Article

TRANSMISSIVITY AND PETROPHYSICAL CHARACTERIZATION OF RESERVOIR ROCKS IN FIELD "X", OFFSHORE, NIGER DELTA, NIGERIA

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ABSTRACT

This study is on the evaluation of petrophysical parameters of the reservoir sand bodies and their transmissivity using well logs of six well in pseudo-named 'X' field, offshore, Niger Delta. These parameters have been used to determine the reservoirs potential and quality prevalent in the study area. Three hydrocarbon reservoirs (A, B, and C) were identified across the six (6) wells Bonn 007, Bonn 009, Bonn013, Bonn 015, Bonn 017 and Bonn 019 of total depth 8650ft (2,637m), 8490ft (2,589m) 7980ft (2,433m), 6750ft (2,058m), 8498ft (2591m) and 7819ft (2,384m) respectively. Only reservoir sand body A was found to be continuous across the six wells using gamma ray (GR) log while shale resistivity meter (SRM) was used to cross-check the correlation of GR log. The petrophysical parameters of the reservoir A ranges from 32-22%, 5024-116.2md, 20-14% and 86-80% for porosity (□), permeability, water saturation (S_w) and hydrocarbon saturation (S_h). Its transmissivity ranges from 50,952mdft-648,148mdft. The petrophysical parameters of the reservoir B ranges 30-18%, 1997.8 – 166.5md, 30-14% and 86-70% for porosity (□), permeability, water saturation (S_w) and hydrocarbon saturation (S_h) respectively. Its transmissivity ranges from 14,935-87,806mdft. The petrophysical parameters of the reservoir C ranges from 14-17%, 79.9-22.4md, 20-19% and 81-80% for porosity (□), permeability water saturation (S_w) and hydrocarbon saturation (S_h) respectively. Its transmissivity ranges from 1993.6 –8449mdft. Based on Schlumberger standard, the values indicate that reservoir A has both excellent porosity and permeability with highest transmissivity. Both porosity and permeability in reservoir B are very good while it transmissivity is lower than reservoir A. Reservoir C has fair porosity and moderate permeability, but has least transmissivity. The reservoirs bulk volume water (BVW) values calculated are close to constant resulted that the reservoirs are homogenous and at irreducible water saturation. Therefore, the reservoirs of the study area can be said to be prolific in terms of hydrocarbon production and they will produce water-free hydrocarbon due to the fact that all the reservoirs are homogenous and at irreducible water saturation. The quality of the hydrocarbon reservoirs (A, B, C) in terms

of porosity, permeability and transmissivity decreases down the depth, therefore, it can be concluded that hydrocarbon potential and productivity of the reservoirs sand can be classified in decreasing order of arrangement as A, B and C. Hence, the reservoir A in well Bonn 007, 009, 013, 015, 017 and 019 is the best in terms of hydrocarbon production and has highest transmissivity. Four empirical formulas relating depth, porosity and permeability were generated in the course of the research and formula between porosity and permeability was generated through irreducible water saturation derived from graph.

INTRODUCTION

The Niger Delta is a prograding depositional complex within the Cenozoic formation of Southern Nigeria. It is situated between longitudes 3^0 and 9^0 E and latitudes 4^0 and 6^0 N (Fig. 1). It is a prolific oil province where one petroleum system, the Tertiary Niger Delta (Akata-Agbada) petroleum system has been identified and is one of the largest in the West African sub-region (Fig. 2). Reservoirs in the Niger-Delta exhibit a wide range of complexities in their sedimentological and petrophysical characteristics due to the differences in hydrodynamic conditions prevalent in their depositional settings. The potential and performance of reservoirs depend on both engineering and petrophysical parameters. The engineering parameters are rock compressibility, reservoir storativity, transmissivity, etc, while the fundamental petrophysical parameters are porosity, permeability, and fluid saturation. The relationships among these properties are used to identify and characterize reservoirs.

Reservoir characterization is the continuing process of integrating and interpreting geological, geophysical, petrophysical, fluid and performance data to form a unified, consistent description of a reservoir and produce a geological model that can be used to predict the distribution of reservoir

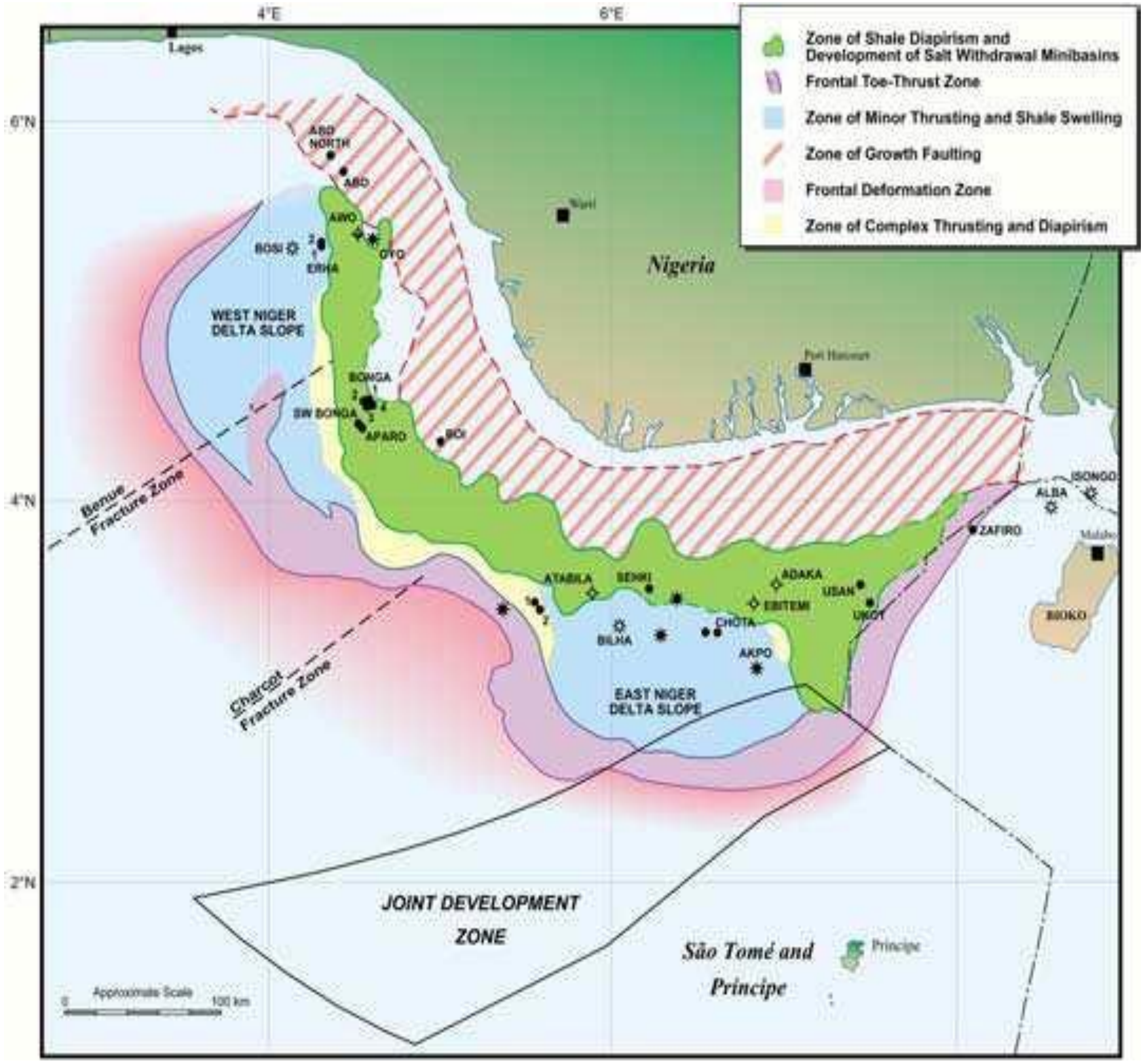

Figure 1: Location map of Niger Delta (Study Area).

properties throughout the field. It can also be defined as the quantification, integration, reduction and analysis of geological, petrophysical, seismic and engineering data (Tinker, 1996).

Reserve estimation therefore, is based on the field wide distribution of these reservoir properties. Due to the intense petroleum exploration and exploitation activities in the Niger Delta region during the last two decades, vast amount of data have been accumulated from which it had been possible to establish the historical reconstruction and evolution of the Niger Delta basin (Allen, 1965 & 1980; Short and Stauble, 1967; Weber, 1971; Avbovbo, 1978; Amajor and Agbaire, 1984; Amajor and lekekmo, 1990; Olotu, 1992;

Beka and Oti, 1995; Ekweozor and Okoye, 1980; Lambert-Aikhionbare and Ibe (1984) etc)

This research work is on the application of wireline logs to identify and quantify hydrocarbon reserves and evaluate rock properties in part of the offshore Niger Delta. The petrophysical analyses of the wireline logs provide reservoir characteristics (porosity, permeability and fluids saturation). Quantitative determination of fluid transmissivity (layer thickness times permeability) will be an added advantage to further characterize reservoir rocks. Integrating these two parameters would guide and provide a good knowledge of the potential of porous media and enhance exploration and development of the reservoir rocks.

(a) Location of study area: The field under study is pseudo-named "X" field in accordance with the Shell (SPDC) confidentiality agreement. The field is located in the offshore Niger Delta, but the co-ordinates of the location of this field were concealed due to proprietary reasons.

(b) Objectives of study: This research is aimed at evaluating the reservoir potential of X-field with limitation to the available data primarily to achieve the following objectives:

- ✓ To identify the various sand bodies and correlate them across the field.
- ✓ To identify and quantify hydrocarbons in the reservoirs sand bodies.
- ✓ To determine the petrophysical characteristics of sand bodies.
- ✓ To estimate and compare porosity, permeability and hydrocarbon distribution within the field.
- ✓ To characterize the transmissivity potentials of the reservoirs rocks.
- ✓ To determine the location of reservoirs vertically within the drilled section.
- ✓ To serve as a guide for further exploration within the field or any related nearby oil field.

(c) Literature Review: The Niger Delta basin has been intensively studied, mostly by the oil industry and academia in recent time because of its economic value as a petroliferous province. Most of the workers have investigated and summarized the basic geology, evolution and structural setting, sequence stratigraphy, biostratigraphy, lithology and depositional environment of the basin. Other studies include production characteristics and field development strategies. Some of the workers and their contributions about the Niger Delta are discussed below.

Reyment (1965) and Hosper (1965) described the basement configuration of the Niger Delta on the basic of geophysical data. They suggested that the bulk of the younger Tertiary portion of the delta sequence overlies Cretaceous oceanic crust.

Allen (1965) observed that the modern Niger Delta is a combination of a wave and tide-dominated delta, whose geometry is actuate – estuarine – irregular.

Hydrocarbon habitat and source rock of the Delta have been considered by Weber and Daukoru (1975), Avbovbo and Ogbe (1978) and Evamy et al. (1978). They showed that the hydrocarbon occurrence is restricted largely to the sands of the parallic sequence and is held in traps formed by growth faults and their associated rollover anticlines. The source rocks have posed a lot of controversies among various workers. While Short and Stauble (1967), Frankl and Cordry (1967), were the first to propose Agbada Formation as the origin and source rocks, Ekweozor and Okoye (1980), were opposed to it but rather thought of Akata Formation as the source rock. They established that the dominant sediment kerogen in the Niger Delta were the humic type III.

Beka and Oti (1955) established that the outer portion of the delta complex, deep-sea channel sands low-stand bodies and proximal turbidities create potential reservoirs.

Akaegbobi and Tegbe (2000) established that reservoir heterogeneity and formation evaluation problems can make it difficult to characterize fluid distribution, estimate hydrocarbon in place and determine permeability. They suggested that the approach used in characterize a reservoir involves a combination of analysis of geological framework of the reservoir hydrocarbon trapping components (stratigraphic and structural) formation evaluation and calculation of volumetric hydrocarbon in place.

METHODOLOGY

Geophysical well logging is the recording of the properties or characteristics of the rock formations transversed by measuring apparatus in a borehole, which largely obviates the necessity of the expense of coring.

Casing may be introduced into the borehole section immediately after drilling to prevent the collapse of the wall rocks in the borehole section lined pipe. Generally, any of the normal geophysical techniques can be adapted in borehole logging. The most commonly used is the techniques are electrical resistivity, electromagnetic induction, and self-potential (SP), natural and induce radioactivity, sonic velocity and temperature.

The instrumentation necessary for borehole logging is housed in a cylindrical metal tube known as *sonde*. Sondes are suspended in the borehole from an armoured multi-core cable. During logging, the sonde is gradually pulled up from the borehole bottom at a certain speed.

Figure 2 displays the steps adopted in the evaluation of the reservoir sand bodies using the geophysical wireline logs. The data are recorded on magnetic tape as analogue or digital signal and can be display on photographic paper. The different logs used for the research work are Gamma ray log, Resistivity logs, Compensated Bulk Density log and Porosity log. The wireline logs were used in the interpretation and calculation of the various functions and parameters of the reservoir sands as described below.

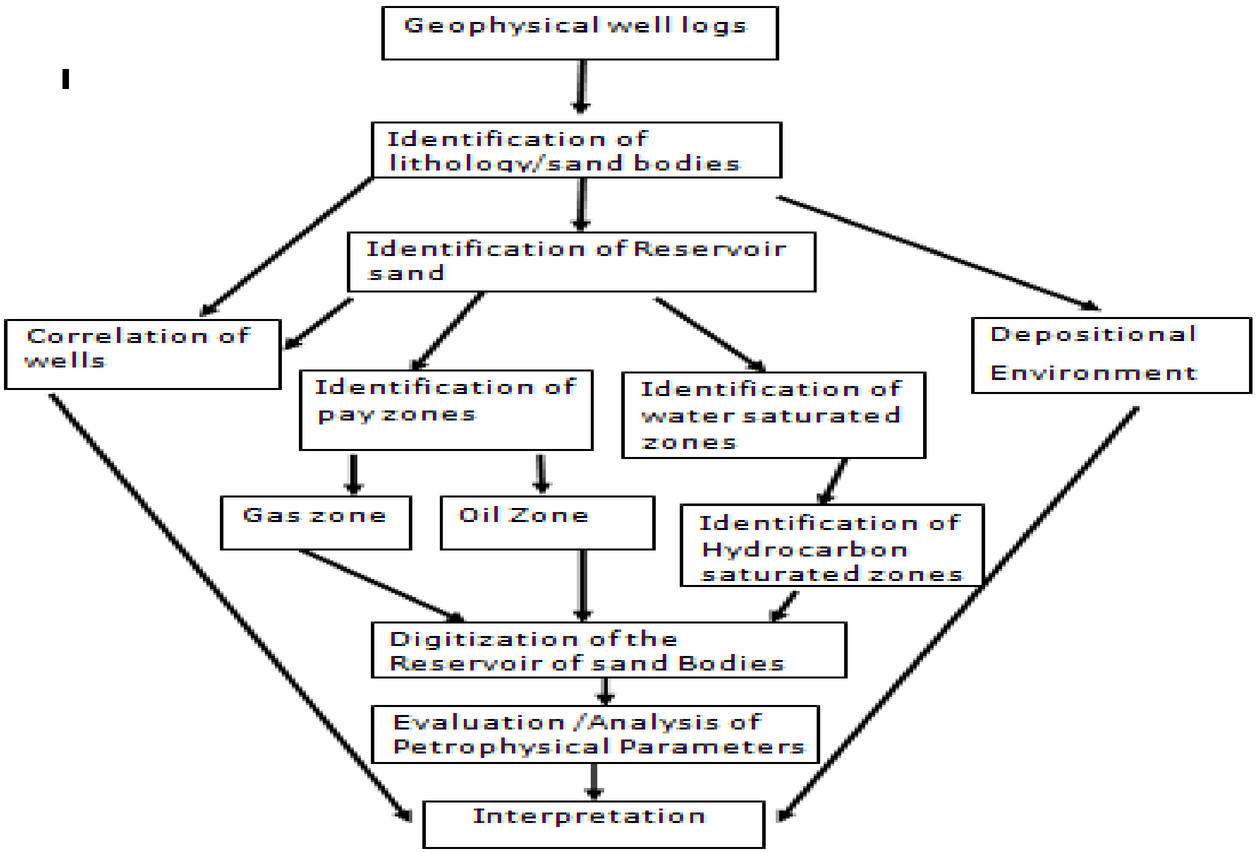

Figure 2: Methodology Flow chart.

RESULTS AND INTERPRETATION

(A) CORRELATION OF THE RESERVOIR SANDS:

The correlation was carried out based on the positions of the sands and shales on the well logs across the wells .The gamma ray (GR) logs were the main logs used because they exhibit patterns that are easier to recognize and correlate from well to well. The resistivity logs were then used to cross-check the correlation because individual shale beds exhibit distinctive resistivity characteristics across the wells.

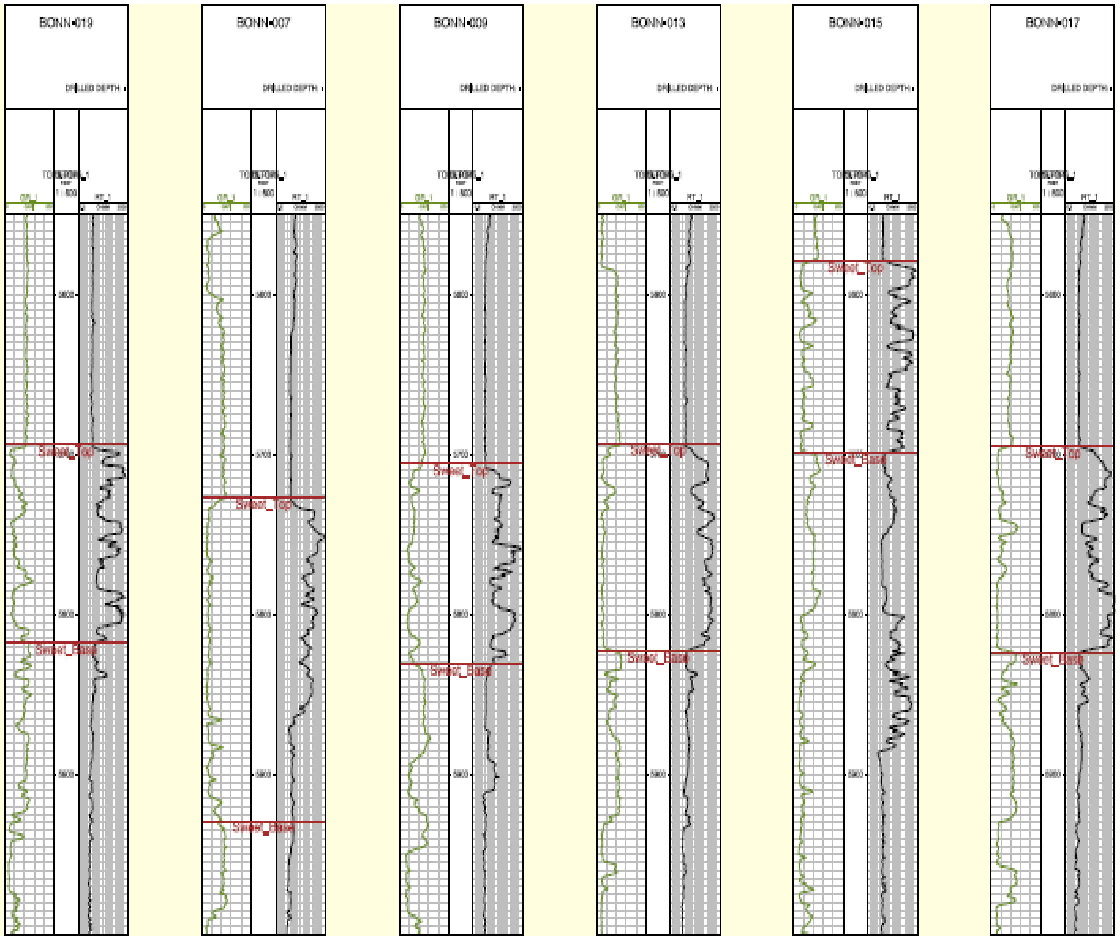

Figure 3: Log correlation profile of reservoir A cutting across the six wells (Bonn 007, Bonn 009, Bonn 013, Bonn 015, Bonn 017 and Bonn 019).

From the reservoir analysis, three reservoirs (A, B, C,) were observed and of which only reservoir A is correctable across the six well. Figure 3 . This implies that reservoir A is genetically equivalent laterally (in the same depositional environment). But, the displacement of this reservoir in depth is probably as a result of synthetic fault.

(B) PETROPHYSICAL RESULTS AND INTERPRETATION:

Total of three hydrocarbon reservoirs were identified and evaluated. Reservoir A cuts across the six wells. (Bonn 007, Bonn 009, Bonn 013, Bonn 015, Bonn 017 and Bonn 019).

Reservoir B cuts across the four wells (Bonn 007, Bonn 013 and Bonn 015 Bonn 017). Reservoir C cuts across the three wells (Bonn 009, Bonn 015 and Bonn 019).

The following petrophysical parameters were quantitatively analyzed for the reservoirs: Volume of Shale (V_{sh}), Porosity (ø), formation factor (F), Irreducible water saturation (S_{wirr}), permeability (K), water saturation (S_w), Hydrocarbon saturation (S_h) and Bulk volume water (BVW). The results are summarized in Table 5 and 6.

(i) Characteristics of Reservoirs of well Bonn 007: There are two hydrocarbon reservoirs found in the well BONN 007. See Table 1. These are reservoirs A and B. In reservoir A, it occurs at interval of 5727 – 5931ft (1746-1808m) and has a gross (G) and net (N) thickness of sand, 204ft (62.2m) and 176.5ft (53.8m) respectively, with N/G ratio of 0.87; water saturation (S_w) of 14% and hydrocarbon saturation (S_h) of 86%, porosity (ø) and permeability (K) of 28% and 2092md respectively. Its transmissivity is 426850mdft. Therefore, the reservoir A has very good porosity and excellent permeability.

Reservoirs	Depth Top	Bottom	Thickness (ft)	Gross Thickness of Sands (ft)	Net Thickness of Sands (ft)	N/G Ratio	ϕ (%)	Swirr	SW (%)	SH (%)	BVW	K(md)	T(mdft)
A	5727	5931	204	204	176.5	0.865	28	0.00049	14	86	0.039	2092	426850
B	7673	7761	88	88	70.5	0.801	25	0.00055	14	86	0.035	997.8	87806

TABLE 1: PETROPHYSICAL QUANTITATIVE ANALYSIS of WELL BONN 007

Reservoirs	Depth Top	Bottom	Thickness (ft)	Gross Thickness of Sands(ft)	Net Thickness of Sands(ft)	N/G Ratio	ϕ (%)	Swirr	S_w (%)	S_H%	BVW	K (MD)	T(mdft)
A	5706	5831	125	125	100.5	0.804	22	0.0006	18	82	0.040	432	54000
C	8376	8488	112	112	90	0.804	17	0.0008	19	81	0.032	79.9	8949

TABLE 2: PETROPHYSICAL QUANTITATIVE ANALYSIS of WELL BONN 009

Reservoirs	Depth Top	Depth Bottom	Thickness (ft)	Gross Thickness of Sands(ft)	Net Thickness of Sands(ft)	N/G Ratio	ø (%)	Swirr	SW (%)	SH (%)	BVW	K (MD)	T(mdft)
A	5693	5822	129	129	103.5	0.802	29	0.00045	18	82	0.052	2895	373,455
B	7672	7762	90	90	80	0.889	19	0.00074	30	70	0.057	166.5	14,985

TABLE 3: PETROPHYSICAL QUANTITATIVE ANALYSIS of WELL BONN 013

Reservoirs	Depth Top	Depth Bottom	Thickness (ft)	Gross Thickness of Sands(ft)	Net Thickness of Sands(ft)	N/G Ratio	ø (%)	Swirr	S_w (%)	S_H (%)	BVW	K (MD)	T(mdft)
A	5579	5699	120	120	109.5	0.912	22	0.0006	19	81	0.042	424.6	50952
B	5797	5887	90	90	81.5	0.910	18	0.0007	18	82	0.032	175.5	15795

TABLE 4: PETROPHYSICAL QUANTITATIVE ANALYSIS OF WELL BONN 015

The reservoir B is found at the interval of 7673 – 7761ft (2339-2366m) and has a gross (G) and net (N) thickness of sand, 88ft (26.8m) and 70.5ft (21.5m) respectively, with N/G ratio of 0.80; water saturation (S_w) of 14% and hydrocarbon saturation (S_h) of 86%, porosity (ø) and permeability (K) of 25% and 997.8md respectively. Its transmissivity is 87806mdft. .Therefore, reservoir B has very good porosity and very good permeability.

The formation bulk volume water values calculated are nearly constant (Table 4) and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore can produce water – free hydrocarbon. The transmissivity in reservoir A is higher than of B. This means that lateral migration of hydrocarbon from reservoir to a well bore will be easier in A than B.

(ii) Characteristics of reservoirs of Well Bonn 009: Both reservoirs A and C have hydrocarbon. In reservoir A, it is found at the interval of 5706 – 5831ft (1739-1777m) and has a gross (G) and net (N) thickness of sand, 125ft (38.1m) and 100.5ft (30.6m) respectively, with N/G ratio of 0.80; water saturation (S_w) of 18% and hydrocarbon saturation (S_h) of 82%, porosity ((ø) and permeability (K) of 22% and 432md respectively while its transmissivity is 54000mdft (Table 2). Therefore, the reservoir has good porosity and very good permeability.

In reservoir C, the hydrocarbon occurs at interval of 8376 – 8488ft (2553-2587m) and has a gross (G) and net (N) thickness of sand, 112ft (34.1m) and 90ft (27.4m) respectively, with N/G ratio of 0.19; water saturation (S_w) of 19% and hydrocarbon saturation (S_h) of 81%, porosity (ø), permeability (K) and transmissivity are 17%, 79.9md and 8949mdft respectively (Table 4). The reservoir C therefore, has both good porosity and permeability.

The formation bulk volume water values calculated are nearly constant (Table 4) and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore, can produce water – free hydrocarbon. The transmissivity in reservoir A is higher than of C. This means that lateral migration of hydrocarbon from reservoir to a well bore will be faster in A than C.

(iii) Characteristics of Reserviors of Well Bonn 013 There are two hydrocarbon reservoirs found in the well BONN 013. These are reservoirs A and B.

Reservoir A occurs at the interval of 5693 – 5822ft (1735-1775m) and has a gross (G) and net (N) thickness of sand, 129ft (39.3m) and 103.5ft (31.5m) respectively with N/G ratio of 0.8; water saturation (S_w) of 18% and hydrocarbon saturation (S_h) of 82%; porosity (ø) and permeability (K) of 29% and 2895md respectively while its transmissivity is 373455mdft (Table 3). Therefore, the reservoir has very good porosity and excellent permeability.

Reservoir B occurs at the interval of 7672 – 7762ft (2338-2366m) and has a gross (G) and net (N) thickness of sand, 90ft (27.4m) and 80ft (24.4m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 30% and hydrocarbon saturation (S_h) 70%, porosity (ø) and permeability (K) of 19% and 166.5md respectively. Its transmissivity is 14985mdft. Therefore, the reservoir has both good porosity and permeability.

The formation bulk volume water values calculated are nearly constant and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore, can produce water – free hydrocarbon. The transmissivity in reservoir A is far much greater than the reservoir B, this means that the hydrocarbon in reservoir A will flow easier to the well bore than B.

WELL BONN 007

RESERVOIRS	**% SAND**	**% SHALE**
A	86	14
B	63	37
	WELL BONN 009	
RESERVOIRS	**% SAND**	**% SHALE**
A	60	40
C	75	25
	WELL BONN 013	
RESERVOIRS	**% SAND**	**% SHALE**
A	80	20
B	75	25
	WELL BONN 015	
RESERVOIRS	**% SAND**	**% SHALE**
A	50	50
B	80	20
C	85	15
	WELL BONN 017	
RESERVOIRS	**% SAND**	**% SHALE**
A	**75**	**25**
B	**63**	**37**
	WELL BONN 019	
RESERVOIRS	**% SAND**	**% SHALE**
A	60	40
C	75	25

TABLE 5: RESERVOIR SAND/SHALE PERCENTAGE CALCULATIONS FOR SIX WELLS.

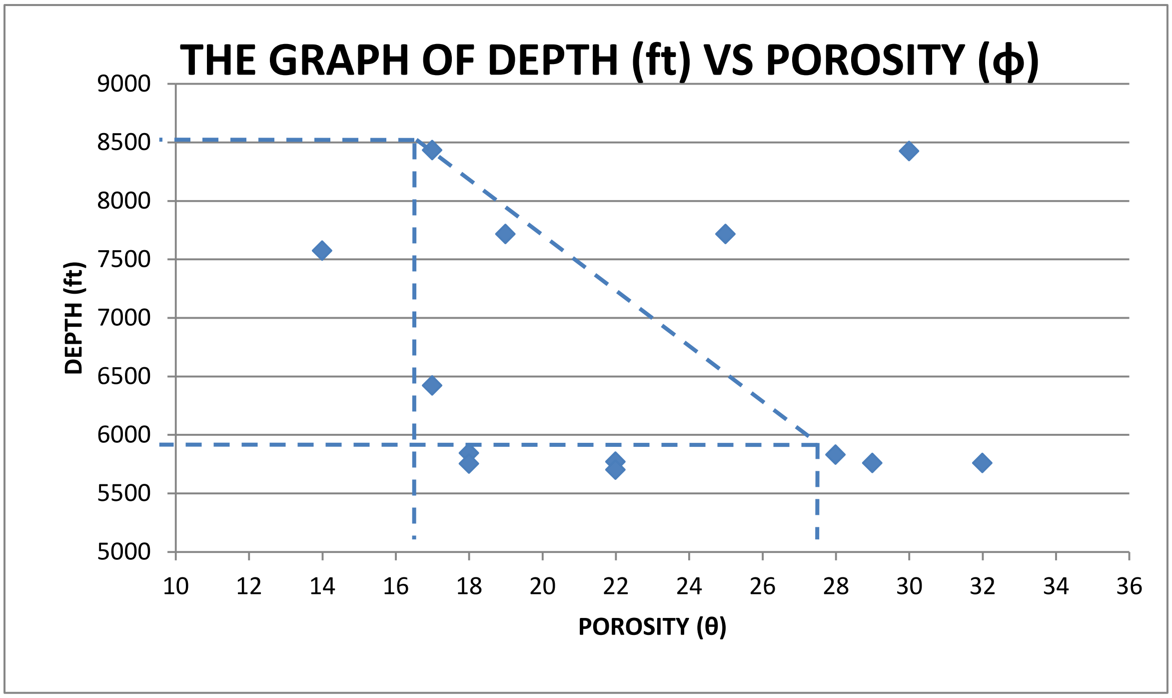

Figure 4: The graphs showing relationship between depth and porosity.

Ø(%)	$Ø^{4.4}$	**B = (0.136x$Ø^{4.4}$)**	**K (md)**
0.32	6.65×10^{-3}	0.000904	5024
0.29	4.31×10^{-3}	0.000586	2895
0.28	3.69×10^{-3}	0.000502	2092
0.25	2.24×10^{-3}	0.000305	997.8
0.22	1.28×10^{-3}	0.000174	424.6
0.19	6.71×10^{-4}	0.0000912	166.5
0.18	5.29×10^{-4}	0.0000719	116.2
0.17	4.11×10^{-4}	0.0000559	79.9
0.14	1.75×10^{-4}	0.0000238	22.4

TABLE 6: SHOWING RELATIONSHIP BETWEEN POROSITY AND PERMEABILITY

CONCLUSION

The reservoir sand bodies of X-field have three hydrocarbon reservoirs (A, B and C) of which only reservoir A cuts across the six wells. In reservoir A, both porosity and permeability are excellent while its transmissivity is the highest. The hydrocarbon saturation ranges 86 – 80%.

In reservoir B, both porosity and permeability are very good. The hydrocarbon saturation ranges 86-70% while its transmissivity is the second among the three reservoirs. Reservoir C has fair porosity and moderate permeability. The hydrocarbon saturation ranges 81-80%. Its transmissivity is the least.

With these petrophysical values, the reservoirs of the study area can be said to be prolific in terms of hydrocarbon production and they will produce water-free hydrocarbon due to the fact that all these reservoirs are homogenous and at irreducible water saturation.

The quality of the reservoirs in terms of porosity, permeability and transmissivity decreases down the depth. Therefore, it can be concluded that the hydrocarbon potential and productivity of the reservoir sands can be classified in decreasing order of arrangement as A, B and C. The reservoir A in well Bonn 007, 009, 013, 015, 017 and 019 is the best in terms of hydrocarbon production and hydrocarbon in such wells can easily migrate to the wellbore as compared to other two reservoirs.

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