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Formation Evaluation of Wells 1 & 2 in "H" Field, in the Niger Delta Region, Nigeria

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Authors' contributions

This work was carried out in collaboration among all authors. All authors read and approved the final manuscript.

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ABSTRACT

Based on data from two wells in the "H" field (Niger Delta Region), a formation evaluation was performed to locate hydrocarbon-yielding reservoirs and examine reservoir characteristics. Techlog software was used to analyze the geophysical logs, i.e., Gamma Ray log, Resistivity log, Spontaneous Potential log, Neutron log, and Density log. Within the interval logged, the lithology of sandstone and shale could be delineated, which is a characteristic of the Agbada Formation. The petrophysical characteristics of the reservoirs are good especially at the areas of interest (hydrocarbon zones). The reservoirs within the field were shown to be very productive based on their porosity, permeability, shale volume, and hydrocarbon pore volume values. However, the consistency of the findings was examined using geological data and a mud logger. This study has demonstrated that formation evaluation plays a vital role in reservoir characterization.

Keywords: Formation evaluation; techlog software; geophysical logs; hydrocarbon saturation.

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1. INTRODUCTION

The sixth-largest province in the world in terms of land area and known oil and gas reserves is the Niger Delta. Every day, the Basin produces about 2 million barrels of oil. It is evaluated to hold 34.5 billion barrels of oil, 94 trillion cubic feet of natural gas. It is a significant oil producer in the world [1].

The Province, is an extensional rift basin located on the passive continental margin of Nigeria's western coast, near the Niger Delta and the Gulf of Guinea, with speculated or verified access to Cameroon, Equatorial Guinea and São Tomé (Fig. 1). The Niger Delta Basin is one of Africa's biggest subaerial basins. It has a total area of 300,000 km^2, 75,000 km^2 subaerial area, and 500,000 km^3 sediment fill [1]. The sediment layer is between 9 and 12 kilometers deep [2]. It consists of various diverse geologic formations that reveal the regional and continental tectonics of the area as well as how this basin may have formed. An extensional basin, the Niger Delta Basin is surrounded by several other basins formed through related processes [2]. The Benue Trough as seen in (Fig. 2), a larger tectonic structure, contains the Niger Delta Basin in its southernmost region.

A failed rift junction produced the Niger Delta Basin as the South American plate separated from the African plate, and the South Atlantic began to expand. This basin rifting began in the late Jurassic and finished in the mid-Cretaceous. Many faults, including some thrust faults, emerged as the rifting progressed. Sands from the syn-rift and later shales were also deposited in the late Cretaceous. This implies that the coastline shrank during this time. There was a large coastline transgression at the start of the Paleocene [2]. The Paleocene saw the formation of the Akata Formation, which was followed by the Eocene and the Agbada Formation. Due to this loading, the underlying shale Akata Formation was compressed into shale diapirs. The Benin Formation, which is still being formed today, was then deposited in the Oligocene. Because of its tectonic nature, the basin is divided into many zones [2].

The Paleocene is when the Akata Formation was formed. Thick shales, turbidite sands, and a small amount of silt and clay make up its composition. It began in anoxic conditions and at relative sea level low stands. The thickness of this structure could reach 7,000 meters. The Eocene era saw the formation of the Agbada Formation. It is a marine facies that combines characteristics of deep sea and freshwater. This is the basin's primary oil and natural gas bearing facies. The rock in this layer became subaerial and was buried in an organically rich marsh environment, which is where the hydrocarbons in this layer came from. It is thought to be 3,700 meters thick [1]. The Benin Formation is oligocene in age and younger. Sands from the continental floodplain and alluvial deposits make up its composition. It could measure 2,000 meters thick [1].

In the evaluation of clastic reservoirs, the presence of clay particles or shale within the sand is a parameter which must be considered. Carbonate rocks importance as reservoir rocks should not be under estimated. Approximately, 50% of hydrocarbon reservoir are carbonate rocks [3]. Archie sets out the fundamentals of rock-type classification [4]. Petrophysics on the other hand, refers to the careful and purposeful use of rock physics data and theory in the interpretation of reservoir geophysics observation [5]. The Niger Delta oil province is characterised by east-west trending synsedimentary faults and folds [6]. These synsedimentary faults are known as growth faults, and the anticlines that accompany them are known as roll-over anticlines [7].

The significance of estimating the lithology, shale, fluid content, and porosity (a measure of the cleanliness of the reservoirs) in evaluating elastic reservoirs has been well-considered by some workers, such as Aigbedion and Iyayi, 2007; Adeoye and Emikauselu, 2009. Their study used wireline logs from three wells to quantitatively evaluate an oil field within zone G-field onshore in the Niger Delta. In petroleum exploration, formation evaluation is used to determine whether a potential oil or gas is commercially viable. It is the process of recognizing a commercial well when you drill one [8]. The Niger Delta have been discussed by several authors [6,9,10].

An estimate of fluid content, porosity, lithology, and type will be possible through formation evaluation in the study area of the Niger Delta Basin. This method of measuring the physical and chemical properties of the rock is very effective in defining subsurface geology [11]. Reservoir characterization aims to develop a geological model that incorporates the data at hand and can be used to forecast how porosity, permeability, and fluid distribution will be distributed throughout the field operation. Archie stated that a broad relationship exists between porosity and the permeability of a formation [4]. The study's major goals are to evaluate the reservoir rocks in the "H" field using wireline log techniques, to determine the petrophysical parameters using the Archies formation, and to correlate the wells in the study area.

1.1 Brief Geology of the Study Area

Sands and shales make up the formation in Nigeria's Niger Delta; the former range from fluvial (channel) to fluviomarine (Barrier Bar), while the latter is typically lagoonal or fluviomarine. These formations are mostly unconsolidated, and taking core samples or doing a drill stem test is often not feasible. The study area is in the southern part of Delta State in the Niger Delta between longitude 50 35E and 50 44N and latitude 60 42W and 50 23s. It is located within the Niger Delta's oil belt.

In the Niger Delta, three significant lithostratigraphic units have been identified.

There are the Akata, Agbada, and Benin formations [10,12].

Fig. 1. The Niger Delta Basin is located in the gulf of Guinea on the west coast of Africa

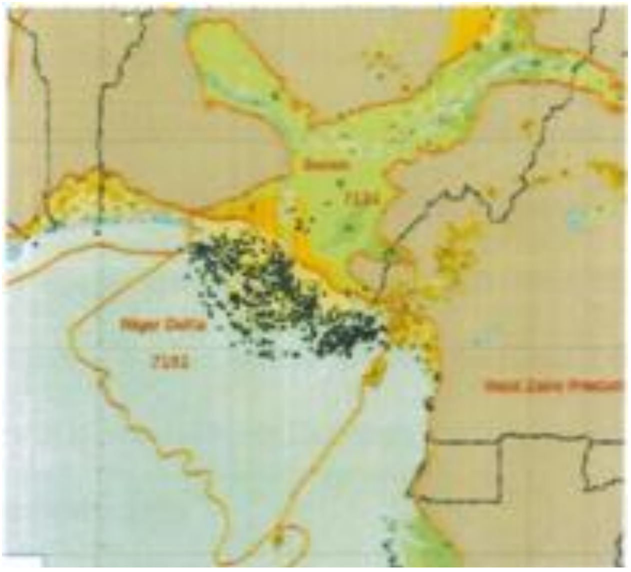


Fig. 2. Geologic map of the Niger Delta and the Benue trough, and the oil fields in the region

LITHOLOGY

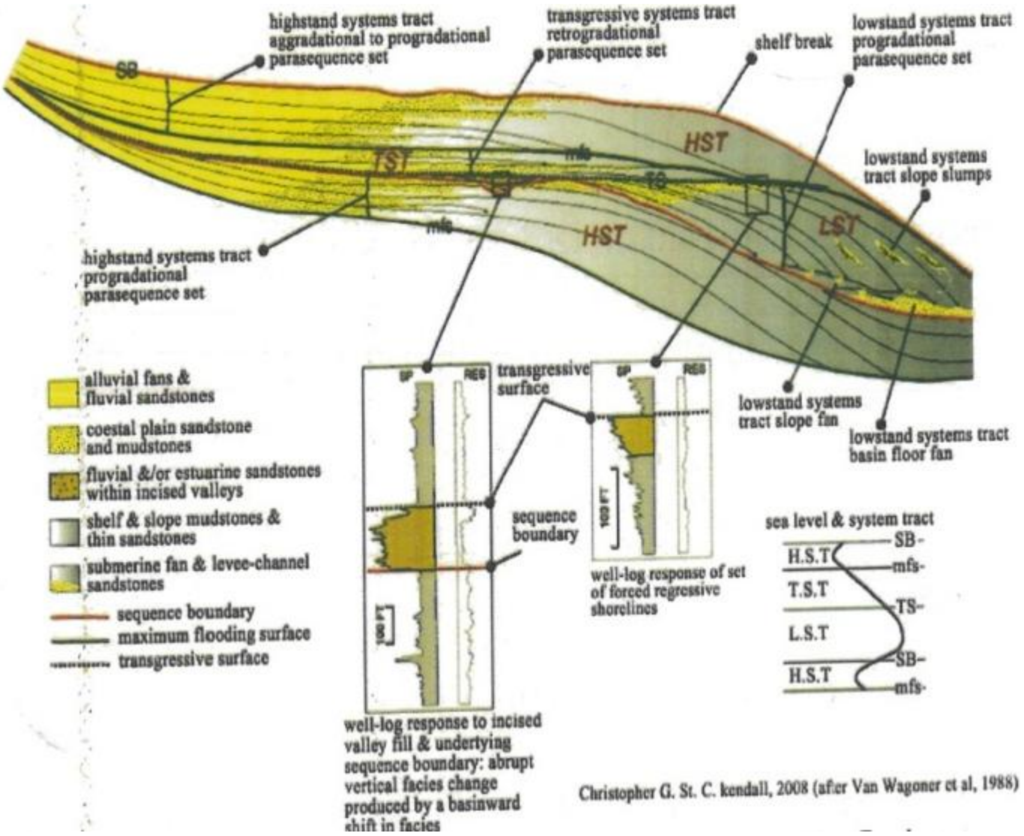


Fig. 3. Sea level highstand and lowstand mapped on a crossection of the basin

TECTONIC STRUCTURE

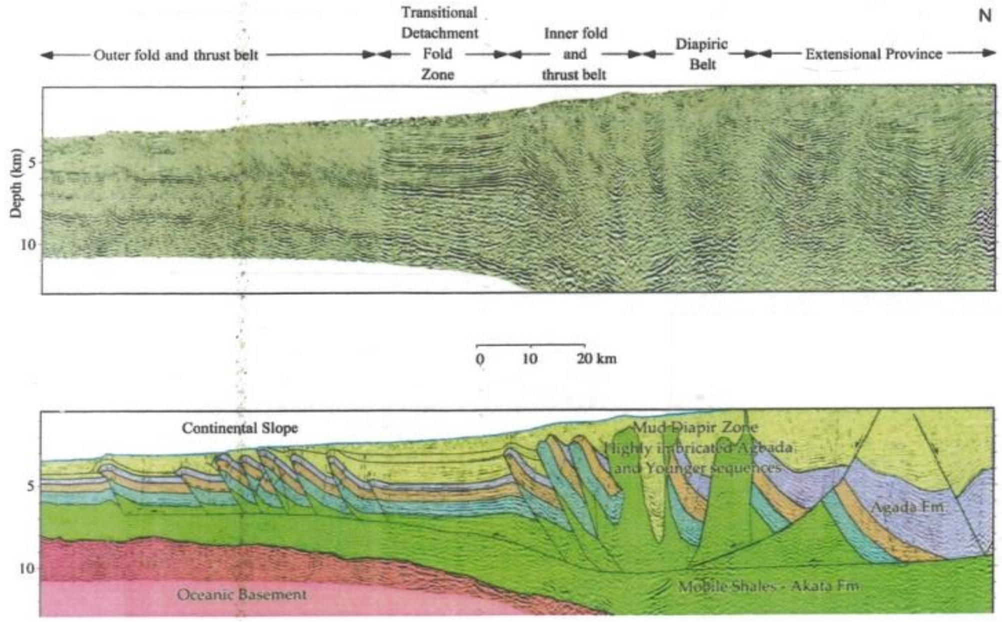


Fig. 4. Tectonic structures drawn over a seismic profile of the Niger Delta Basin

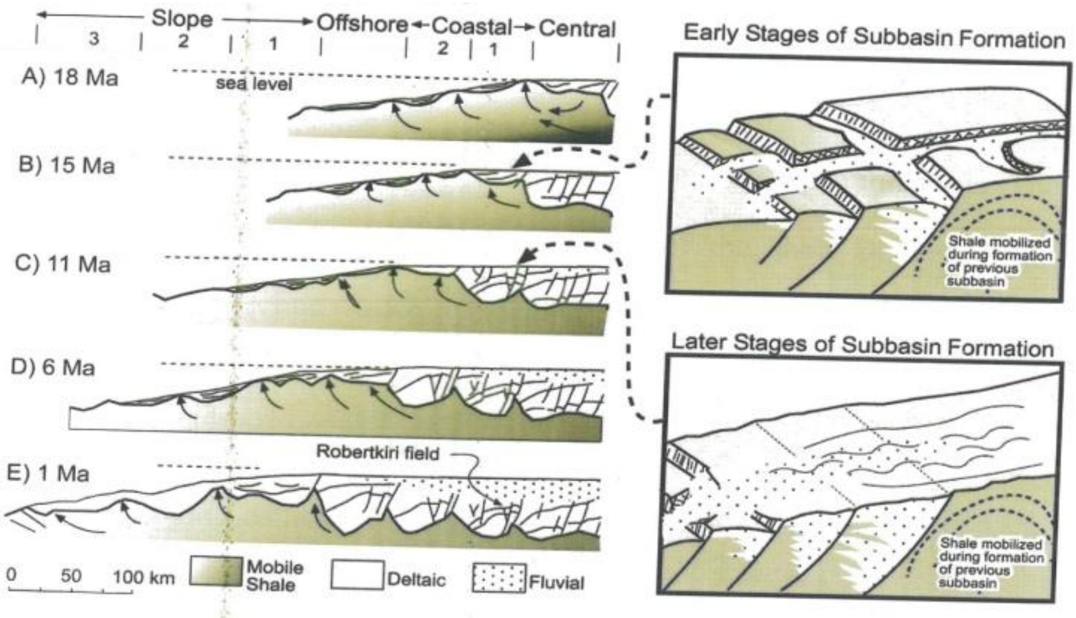
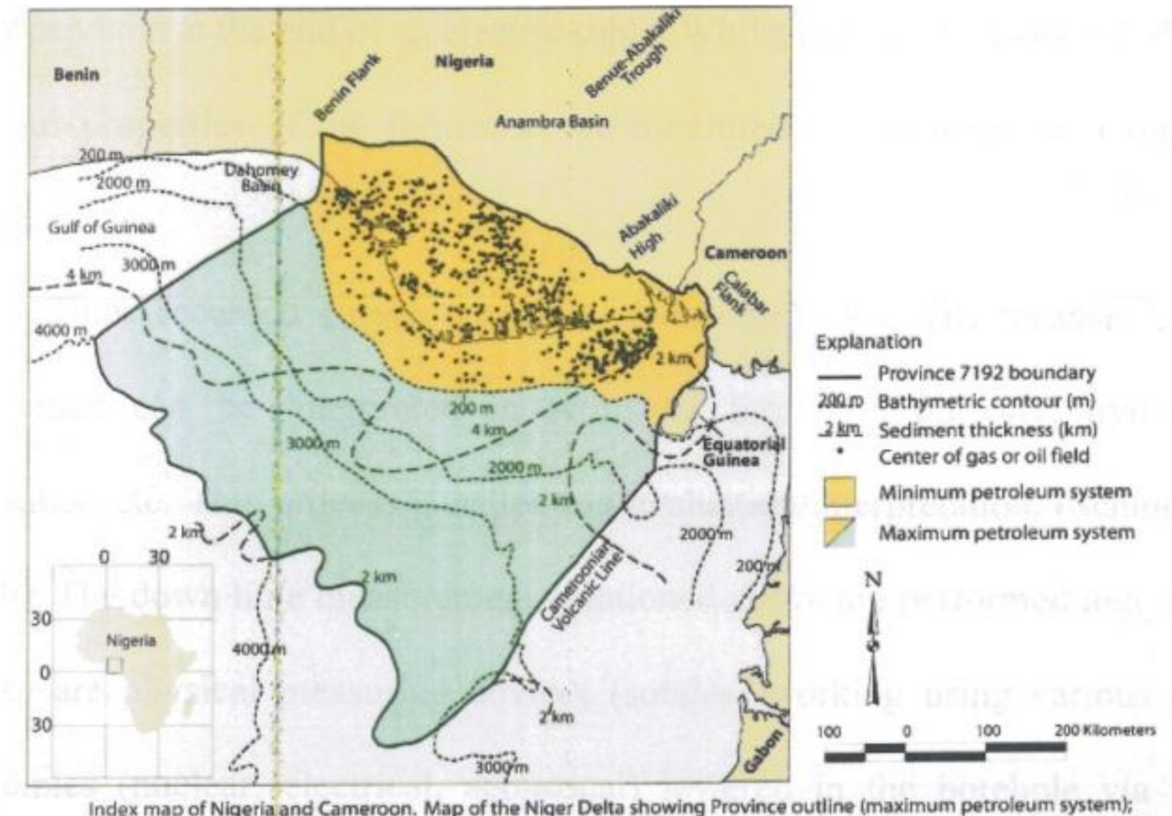


Fig. 5. Evolution of Niger Delta subbasins as mobile shales migrate towards the continental slope

PETROLEUM



Index map of Nigeria and Cameroon. Map of the Niger Delta showing Province outline (maximum petroleum system); bounding structural features; minimum petroleum system as defined by oil and gas field center points (data from Petroconsultants, 1996a); 200, 2000, 3000, and 4000 m bathymetric contours; and 2 and 4 km sediment thickness.

Fig. 6. Map of the Niger Delta showing province outline (max. petroleum system)

2. MATERIALS AND METHODS

The resources used for the Formation Evaluation of the wells are Techlog software, Resistivity log, Gamma Ray log, Spontaneous Potential log, Density log, and Neutron log. Techlog software, a wellbore-centric petrophysical application composed of a platform and a set of add-on-application segments was used to analyse the geophysical logs. Resistivity logs helped in determining the hydrocarbon versus water-bearing zones, Indicate permeable zones and calculate the resistivity porosity. The reservoir fluids were characterized by neutron-porosity and bulk density logs. The percentage of shale and, consequently, the predominant lithology were determined using the gamma-ray index. This was done by identifying the clean sand line using gamma-ray records. The unconsolidated sand in the Niger. Delta was taken into account when correcting the gamma-ray index. The equations used for this study can be seen below:

2.1 Simandoux Equation for Saturation Determination

$$1/R_t = \frac{(Sw)^2}{F\ X\ Rw(1-Vsh)} + \frac{Sw \times Vsh}{Rsh}$$

Shaly Sand

$$1/R_t = \frac{Vsh}{Rsh} + \frac{1-Vsh}{Rsh}$$

$$S_w = \frac{\alpha\ x \mathrm{Rw}}{2\ x\ \emptyset}\ [\ \sqrt{\frac{4\ \mathrm{x}\ \emptyset}{\alpha\ x\ Rw\ x\ Rt}} \mathrm{X}\ \frac{\mathrm{Vsh}}{Rsh} - \frac{\mathrm{Vsh}}{Vsh}\ ]$$

2.2 Archie's Equation

$$(S_w)^n = FR_w/R_t$$

$$(S_w) = \sqrt{FRw/Rt}$$

Where $F=a/\emptyset^m$
$R_w = R_0/F$

$$\text{So, } S_w = (\frac{R_0}{R_t})^{1/n} = (\frac{F\ XRw}{Rt})^{1/n}$$

$$\therefore S_w = (\frac{\alpha\ X\mathrm{Rw}}{Rt\ X\ \emptyset^m})^{1/\mathrm{n}}$$

Where:

S_w = Water of saturation
F = Formation factor
A = Tortuosity factor (often taken to be 1)
M = Cementation factor (varies around 2)
R_w = Resistivity of formation water
R_t=True formation resistivity as measured by deep reading resistivity log
R_0=Resistivity of the water/saturation formation
n=saturation eponent (most commonly 2)
Ø=Porosity
R_{sh}=Resistivity of shale
V_{sh}=Volume of shale

2.3 Volume of Hydrocarbon in-Place

$$\text{Vol. of } Hc_{Ip} = k$$

$$\sum_{n=1}^{\infty} Ah(1 - S_w)\ \emptyset$$

Well 1

Oil = 78869198.09 barrels
Gas = 735059345.7 cubic feet

Well 2

Oil = 56105714.12 barrels
Gas = 735089345.7 cubic feet

3. RESULTS AND DISCUSSION

3.1 Qualitative Interpretation of Well Logs

Tables 1 and 2 depict the well's lithology; the top of the reservoirs was defined using a stratigraphical method to distinguish the parameter intervals (reservoir sands) from the logs and was correlated throughout the field. The deeper and shallowest pay sands were correlatable. The Simandoux equation (2.1) was used to assess the impact of shale with regard to water capacity. Water saturation in all the clean sands was evaluated using Archie's equation (2.2). The formula used for the volume of hydrocarbon in place can be seen above (2.3). It was found conclusively that porosity ranged from 24%-to 32%, as seen in Tables 5 & 6 (data evaluation); the thickness of the oil/gas-bearing zone ranged from 4m–to 11m; the hydrocarbon saturation of oil/gas bearing sand ranged from 55%–88%; and the permeability of oil/gas bearing zone ranged from 100md–2900md in WELL 1 and 160–2900md in WELL 2. The depth of oil/gas accumulation was found to range from (2731 – 2755)m to (2853 – 2864)m in WELL 1 and (2755 – 2759)m to (2853 – 2864)m in WELL 2, and the amount of oil/gas contained in WELL 1 is 78869198.09 barrels and 735059345.7 cubic feet, respectively.

From the Formation Evaluation of the WELLS, the following results i.e. lithology, petrophysical and volumetric data are hereby presented in Tables (1-6) and Fig. 7.

3.2 Lithology

The lithological description has been depicted in Table 1.

Table 1. Well 1 lithology

	Lithology	Remark
2652 – 2662	Shale	Shale
2662 – 2665	Sand	Water bearing formation
2665 – 2684	Shale	Shale
2684 – 2696	Sand	Water bearing formation
2696 – 2698	Shale	Shale
2698 – 2703	Sand	Water bearing formation
2703 – 2731	Shale	Shale
2731 – 2735	Sand	Oil bearing formation
2735 – 2755	Shale	Shale
2755 – 2759	Sand	Gas bearing formation
2759 – 2767	Shale	Shale
2767 – 2775	Sand	Gas, oil and water formation
2775 – 2785	Shale	Shale
2785 – 2791	Sand	Water bearing formation
2791 – 2809	Sand	Shale
2809 – 2811	Sand	Gas bearing formation
2811 – 2828	Shale	Shale
2828 – 2838	Sand	Gas and oil bearing formation
2838 – 2853	Shaly sand	Shale
2853 – 2864	Sand	Gas and oil formation
2864 – 2867	Shale	Shale
2867 – 2871	Sand	Water bearing formation
2871 – 2873	Shale	Shale
2873 – 2890	Sandy shale	Water bearing formation
2890 – 2903	Shale	Shale
2903 – 2979	Sand	Water bearing formation

Table 2. Well 2 lithology

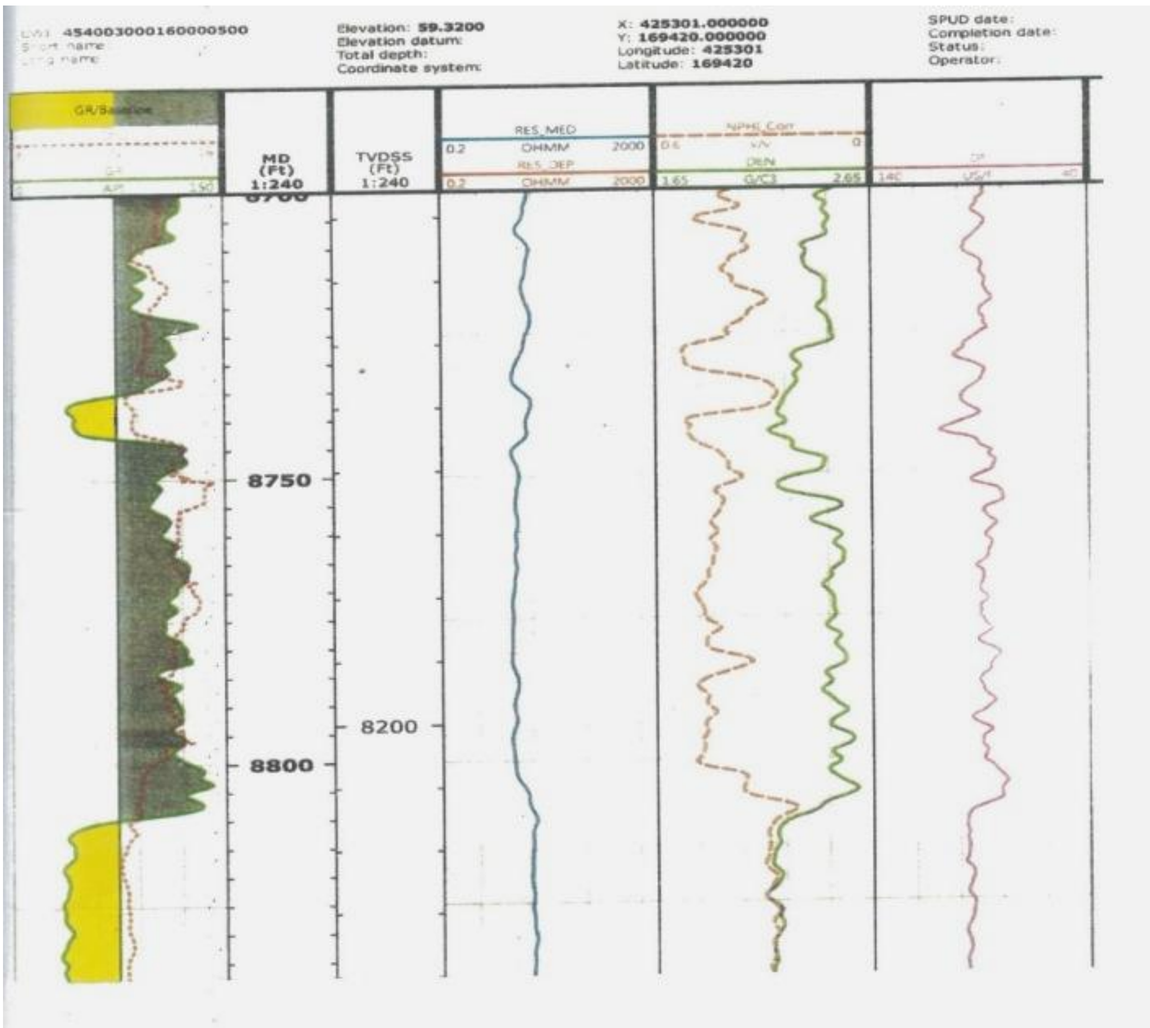
Reservoir interval (m)	Lithology	Remark
2708-2755	Shale	Shale
2755-2759	Sand	Gas bearing formation
2759-2767	Shale	Shale
2767-2775	Sand	Water bearing formation
2775-2785	Shale	Shale
2785-2791	Sand	Water bearing formation though with relatively high resistivity
2791-2809	Shale	Shale
2809-2811	Sand	Gas bearing formation
2811-2828	Shale	Shale
2828-2838	Sand	Gas and oil bearing formation
2838-2853	Shale	Shale
2853-2864	Sand	Gas and oil bearing formation
2864- 2867	Shale	Shale
2867-2890	Sandy shale	Water bearing formation
2890-2918	Shale	Shale
2918-2980	Sandy shale	Water bearing formation

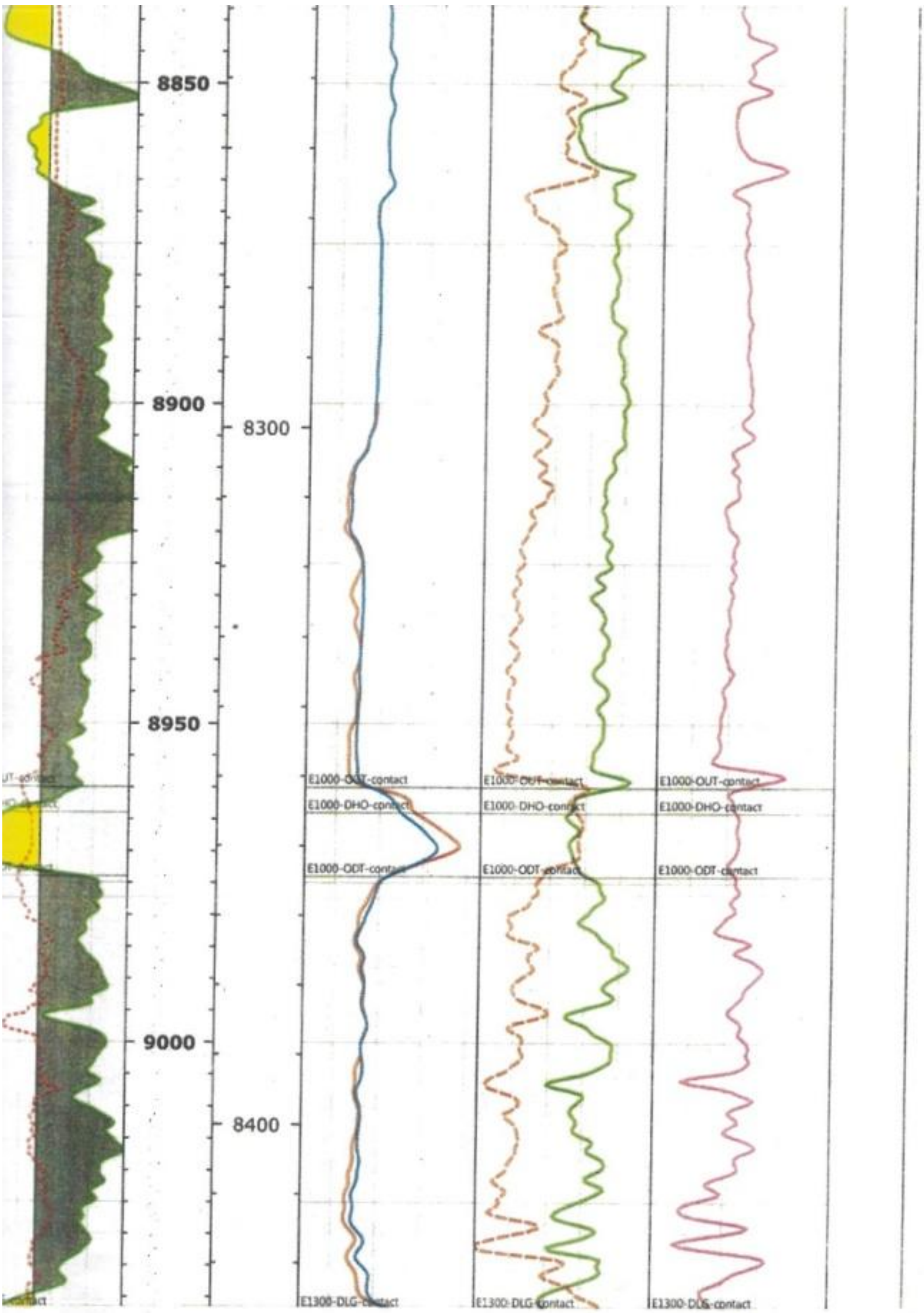
3.3 Petrophysical Analysis

The petrophysical analysis was shows in Table 3.

Table 3. Well 1 petrophysical analysis

Reservoir Interval (m)	GR (API)	Net Thickness (m)	R_t (Ω- m)	P (g/cm^3)	Ø	S_w	S_h	Remark
2662 – 2665	45	3	20	2.23	0.25	1.0	0.0	Water
2684 – 2696	39	12	20	2.21	0.27	1.0	0.0	Water
2698 – 2703	60	5	20	2.17	0.29	1.0	0.0	Water
2731 – 2735	36	4	1280	2.17	0.26	0.13	0.87	Oil
2755 – 2759	42	4	1200	2.05	0.32	0.13	0.87	Gas
2767 – 2775	45	8	1000	2.17	0.26	0.14	0.86	Gas
2785 – 2791	54	6	100	2.23	0.25	0.45	0.55	Gas/oil
2809 – 2811	45	2	1200	2.15	0.27	0.13	0.87	Gas
2828 – 2838	39	10	1400	2.21	0.24	0.13	0.88	Gas/oil
2853 – 2864	42	11	1200	2.21	0.27	0.1	0.0	Water
2867 – 2871	39	4	20	2.21	0.27	0.1	0.0	Water
2873 – 2890	30	17	20	2.25	0.24	1.0	0.0	Water
2903 – 2979	27	76	20	2.21	0.27	1.0	0.0	Water

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E1000-OUT-contact
E1300-DLG-contact

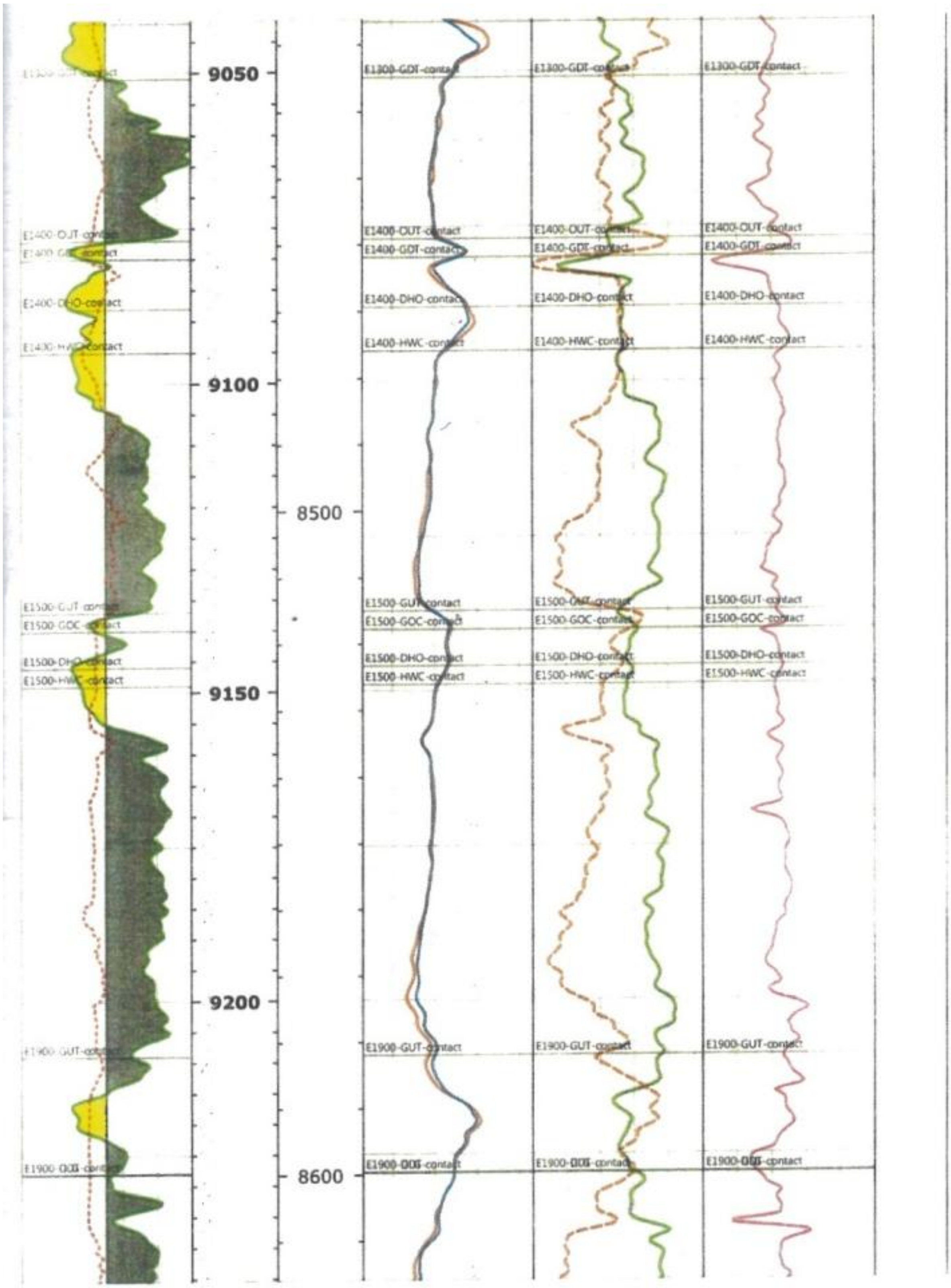

Fig. 7. Cross section of the evaluated petrophysical logs

Table 4. Well 2 petrophysical analysis

Reservoir Interval (ft)	Reservoir Interval (m)	GR (API)	Net Thickness(m)	R_t (Ω-m)	P (g/cm^3)	Ø	S_w	S_h	Remark
9039 – 9053	2755 – 2759	42	4	1200	2.05	0.32	0.13	0.87	Gas
9077 – 9105	2767 – 2775	45	8	1000	2.17	0.29	0.14	0.86	Gas
9136 – 9157	2785 – 2791	48	6	100	2.19	0.28	0.45	0.55	Gas/oil
9215 – 9224	2809 – 2811	45	2	1200	2.17	0.26	0.13	0.87	Gas
9278 - 9310	2828 – 2838	41	10	1400	2.21	0.24	0.12	0.88	Gas/oil
9360 – 9395	2853 – 2864	45	11	1200	2.21	0.24	0.13	0.87	Water
9405 – 9482	2867 – 2890	30	23	20	2.25	0.24	1.0	0.0	Water
9574 – 9776	2918 – 2980	37	62	20	2.23	0.25	1.0	0.0	Water

3.4 Data Evaluation

The data evaluation result has been depicted in Table 5.

Table 5. Well 1 data evaluation

Reservoir Interval (ft)	GR (API)	Net thickness (m)	R_t (Ω - m)	P (g/cm^3)	Ø	S_w	S_h	K (md)	Remark
2731 – 2733	36	4	4	1280	2.17	0.26	0.13	0.87	Oil
2755 – 2759	42	4	1220	2.05	0.32	0.13	0.87	2900	Gas
2767 – 2775	45	8	1000	2.17	0.26	0.14	0.86	1000	Gas
2785 – 2791	54	6	100	2.23	0.25	0.45	0.55	100	Gas/ Oil
2809 – 2811	45	2	1240	2.15	0.27	0.13	0.87	1500	Gas
2828 – 2838	39	10	1400	2.21	0.24	0.12	0.88	1000	Gas/Oil
2853 – 2864	42	11	1200	2.20	0.24	0.13	0.87	900	Gas/Oil

Table 6. Well 2 data evaluation

Reservoir Interval (ft)	GR (API)	Net thickness (m)	R_t (Ω-m)	P (g/cm^3)	Ø	S_w	S_h	K(md)	Remark
2755- 2759	42	4	1200	2.05	0.32	0.13	0.87	2900	Gas
2767– 2791	45	8	1000	2.17	0.26	0.14	0.86	1000	Gas
2785– 2791	48	6	100	2.19	0.28	0.45	0.55	160	Gas/Oil
2809– 2811	45	2	1200	2.17	0.26	0.13	0.87	1200	Gas
2828– 2938	39	10	1400	2.21	0.24	0.12	0.88	1000	Gas/Oil
2853–2864	45	11	1200	2.21	0.24	0.13	0.87	900	Gas/Oil

4. CONCLUSION

In this project, the Simandoux Equation was used to determine the effect of shale on water saturation. Archie's Equation was also used to evaluate the water saturation in all the clean sands. The Techlog software was used to analyze the geophysical logs. The data from the two wells was adequate to enable extensive study, including porosity, hydrocarbon saturation, permeability, and depth. All the sands are fairly homogeneous within pay zone. The lithology is composed of an alternating series of sands and shales, according to the GR and SP logs examination. Hydrocarbon (oil/gas) was found within the middle and bottom of the Agbada formation.

In evaluating oil wells, the proper method should be used, and the parameters for its evaluation should be adequately studied and practiced. The parameters' physical and chemical properties should be carefully examined for a better evaluation of a given oil well.

Based on the qualitative and quantitative interpretation of the two wells in the "H" field, Niger Delta, it is, therefore, recommended that exploration for hydrocarbons can be carried out within the vicinity. However, core drilling can be carried out in order to validate the result of the wireline logging.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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