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HYDROCARBON RESERVOIR CHARACTERIZATION OF "IGBOBI FIELD", OFFSHORE NIGER DELTA USING PETROPHYSICAL ANALYSIS AND WELL LOG INTERPRETATION

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Abstract

This research was conducted to determine and evaluate the petro-physical properties of Igbobi Field, Niger delta with a view to understand their effects on the hydrocarbon reservoir prospect and oil productivity of the field. The evaluated properties include porosity, hydrocarbon saturation, net/gross thickness, volume of shale, and water saturation that were inferred from geophysical wire-line logs. A suite of wire-line logs comprising gamma ray, resistivity, sonic log, neutron log and density logs for three wells from Igbobi field were analyzed for reservoir characterization of the field.

The analysis carried out were well logging, identification of reservoirs and determination of petrophysical parameters of identified reservoirs.

The area above hydrocarbon water contact was used in volumetric estimation for each segment. The volumetric estimation i.e. stock tank oil originally in place for Sand 1 to 3 are 781, 221 and 170MBL respectively and a total of 1172MBL for the entire Igbobi Field.

From the factual interpretation of Petrophysical and Well logs available, it is therefore recommended that commercial oil exploration in Igbobi field is prospective and should proceed to further stage.

Keywords: *Reservoir; characterisation; petro-physical; well logging; volumetric estimation*.

1. Introduction

Numerous researches have been carried out extensively on Igbobi Oil Field reservoir characterisation using the petrophysical evaluation. Among them are; Laure and Legarre [1] Mode and Anyiam [2], Wilt and Alumbaugh [3] , Noyau *et al*. [4], Sanjay Srinivasan [5], Balch *et al*. [6], Davis *et al.* [7], and Dubrule *et al.* [8], 1998. The economic viability of Igbobi Field, Niger Delta, has been a subject of controversy due to unclear picture of the reservoirs obtained from earlier evaluation of the Field. This has, hitherto, put on hold the development of the identified prospects.

Based on the uncertainties associated with this Field, this research employed the use of an integrated approach in characterizing the reservoir. This approach is intended to clear the scepticism surrounding the Field. To achieve this, we utilized the integrating well data (gamma ray, resistivity and neutron/density) and detailed petrophysical interpretation to estimate the potentiality of the reservoir zones within the Field for possible recommendation during drilling for possible development. This will also help in solving the problem inherent with realistic inter- well petrophysical distribution within reservoirs in the Field. The approach could further be applied to analogue Fields in Niger Delta. This will provide sound vertical and horizontal information of the subsurface images, high resolution and good economic decisions which will enhance, promote, increase recovery and accelerate reservoir evaluation.

The interpretation of electrical logs allows us to determine the shaliness of the subsurface formations, the porosity of the rocks (total and effective) as well as the water saturation. To achieve this objective, it is required to have basic log curves, such as: GR or SP, resistivity (shallow, medium and deep), porosity (neutron porosity, density, acoustic). Three composite logs were used to measure petrophysical parameters such as true resistivity, bulk density, natural radioactivity and hydrogen contents of a clean formation which were translated into the desired petrophysical parameters such as porosity (Φ), water and hydrocarbon saturation (S_w and S_h), movable oil saturation (MOS), Residual hydrocarbon saturation (S_{hr}), mud filtrate saturation (S_{xo}), hydrocarbon movability index (HMI) and bulk volume water (BVW).

The entire hydrocarbon produced comes from the accumulations in the pore spaces of reservoir rocks usually sandstones, limestone or dolomites [9]. Hydrocarbon is produced in the Niger Delta (Fig 1.0) in sandstone and unconsolidated sands of the Agbada formation. This formation is characterized by intercalation of sand and shale units with varying thickness from 100ft (30m) to 15,000ft (4600m) [10]. These sands are main hydrocarbon reservoirs while the shale provides both lateral and vertical seals.

2. Geology of Niger delta and petroleum history

The geology of the Niger delta has been extensively discussed by several authors like [10-12]. The Niger Delta is situated on the Gulf of Guinea on the West Coast of Africa. It is located at the South Eastern end of Nigeria, bordering the Atlantic Ocean and extends from about latitudes 4^0 to 6^0 N and longitudes 3^0 to 9^0E.The basin is bounded to east by the Calabar Flank, which is a subsurface expression of the Oban Massif. To the west, it is bounded by the Benin Basin, to the South, by the Gulf of Guinea and to the North by Older (Cretaceous) tectonic structures such as the Anambra Basin, Abakiliki Anticlinorium and Afikpo Syncline.

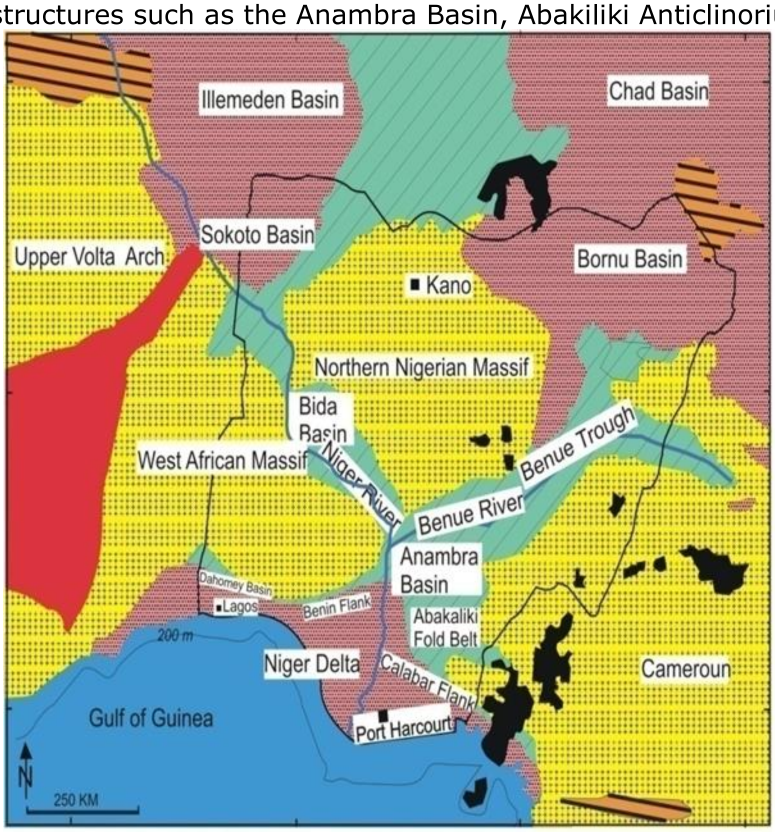

Figure 1. Simplified geological map of Nigeria showing the location of the Niger Delta and someother Nigerian basins. *Modified after Stacher [20]*

The Niger Delta Province contains only one identified petroleum system [13-14]. This system is referred to as the Tertiary Niger Delta (Akata – Agbada) Petroleum System. The maximum extent of the petroleum system coincides with the boundaries of the province (Figure 1). The minimum extent of the system is defined by the areal extent of fields and contains known resources (cumulative production plus proved reserves) of 34.5 billion barrels of oil (BBO) and 93.8 trillion cubic feet of gas (TCFG) (14.9 billion barrels of oil equivalent, BBOE) [15]. Currently, most of this petroleum is in fields that are onshore or on the continental shelf in waters less than 200 meters deep (Figure 2).

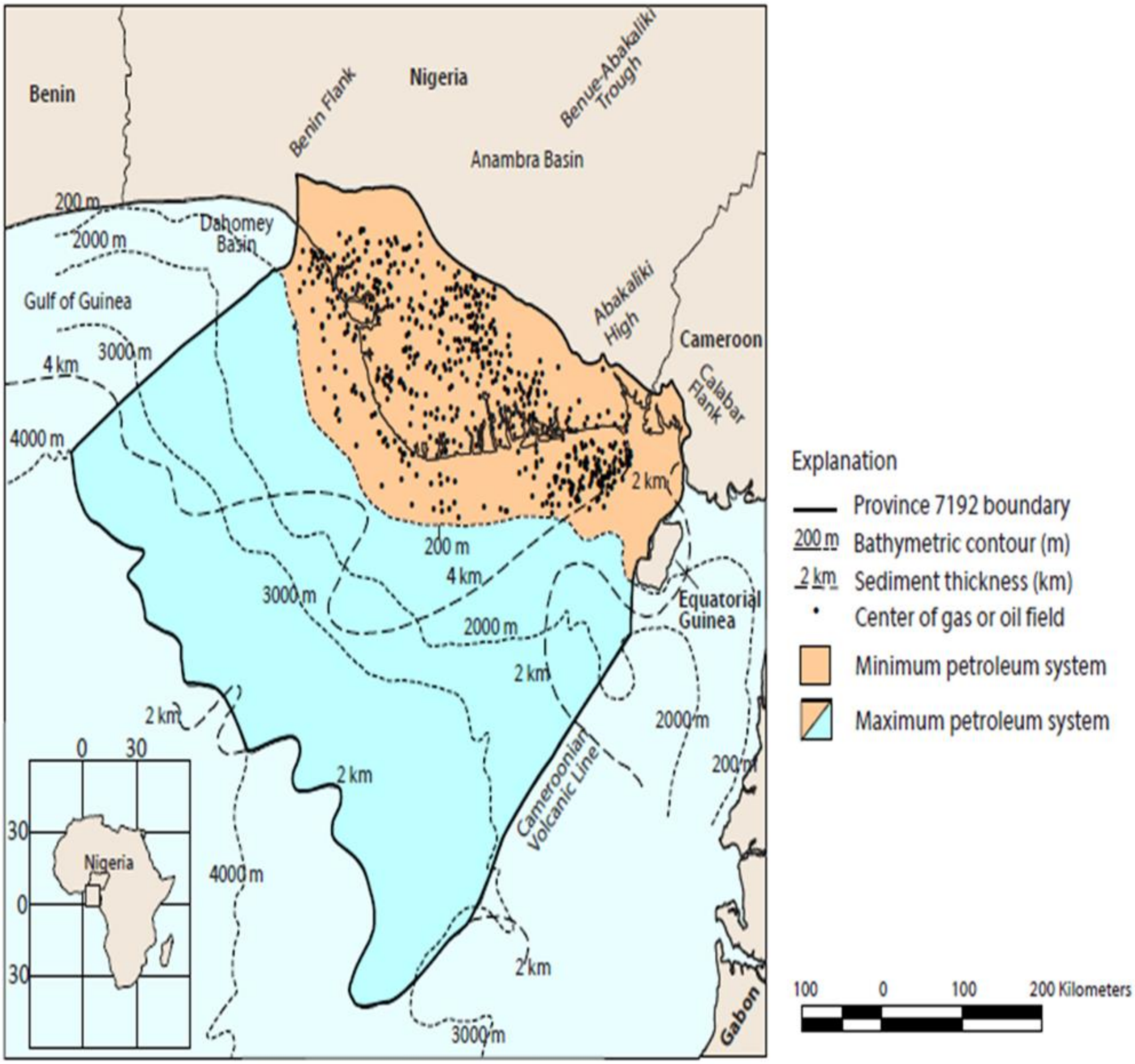

Figure 2. Map of Niger Delta showing Province outline (maximum petroleum system); and key structural features. Minimum petroleum system as defined by oil and gas field center points (*data from* [15]); 200, 2,000, 3,000, and 4,000m bathymetric contours shown by dotted contours; 2 and 4 km sediment isopach shown by dashed lines (*From Tuttle et al.* [21]).

The tectonic framework of the Niger delta is related to the stresses that accompanied the separation of African and South American plates, which led to the opening of the south Atlantic. The Niger Delta is the largest delta in Africa with a sub-aerial exposure of about 75,000km^2 and a clastic fill of about 9,000 to 12,000m (30,000 to 40,000ft) and terminates at different intervals by transgressive sequences. The Proto-delta developed in the Northern part of the basin during the Campanian transgression and ended with the Paleocene transgression.

Formation of the modern delta began during the Eocene. The onshore portion of the Niger Delta Province is delineated by the geology of southern Nigeria and south-western Cameroon. The northern boundary is the Benin flank - an east north-east trending hinge line south of the West African basement massif. The north-eastern boundary is defined by outcrops of the

Cretaceous on the Abakaliki High and further east south-east by the Calabar flank-a hinge line bordering the adjacent Precambrian [16].

The offshore boundary of the province is defined by the Cameroon volcanic line to the east, the eastern boundary of the Dahomey basin (the eastern-most West African transform-fault passive margin) to the west, and the two-kilometre sediment thickness contour or the 4000-meter bathymetric contour in areas where sediment thickness is greater than two kilometres to the south and southwest [16].

Sedimentary deposits in the basin have been divided into three large-scale lithostratigraphic units: (1) the basal Paleocene to Recent pro-delta facies of the Akata Formation, (2) Eocene to Recent, paralic facies of the Agbada Formation, and, (3) Oligocene-Recent, fluvial facies of the Benin Formation. These formations become progressively younger farther into the basin, recording the long-term progradation of depositional environments of the Niger Delta onto the Atlantic Ocean passive margin [16].

3. Materials and methods

3.1. Available data set

The data set (Figure 3) available for the study area was provided by a multinational oil company operating major fields in the Niger Delta area. Wells Igbobi_1 to Igbobi_4 have composite logs suites including gamma ray, resistivity, sonic, neutron density logs and checkshot data. Wells Igbobi_3 and Igbobi_6 have deviation data.

3.2. Well LOG analysis

3.2.1. Quick look interpretation

The available well logs were interpreted from the well section window on the Petrel 2013, software. The suite of gamma ray, resistivity and neutron-density logs were used to delineate the hydrocarbon bearing sandstone reservoir of interest within the Agbada formation.

In line with the aim of this research, the sandstone reservoir of interest was one which was penetrated by at least most wells or all the available wells in the field since more data point are needed for the reservoirs characterisation.

From the well logs interpretation, the sandstone reservoir body that met this criteria (i.e. penetrated by all available wells) was named the ''Sand'' sandstone with the top and base correlated across the all wells from northwest to southeast across the field. The sandstone reservoir was first delineated in well Igbobi_4 and then the log motif of the marker shales above this sandstone was used to transfer the top to other wells in the field. To ensure appropriate correlation and to ascertain that the same sand bodies were picked, an arbitrary seismic section across four vertical wells was used to constrain the horizon of the top and base of the pay zone since the same picks on the wells would fall on same seismic events.

Figure 5, displays some logs from Well Igbobi_05. The first panel is the calliper which was displayed to check the consistency in diameter of the borehole. This was used to identify wash out zones where some logs data might have been compromised (e.g density log). Narrowing of borehole indicates mud cake which is formed in permeable formations such as Sandstone.

The second panel is the gamma-ray log which was used to distinguish the various lithology or formations. High gamma readings indicate Shale due to its high radioactive mineral contents while regions with low gamma ray indicate Sand formations.

The third panel displays Resistivity of the formation. The resistivity measures the resistivity of the formation and its fluid content where the later is the main factor that influences the resistivity in permeable beds. Shale is represented by low resistivity while resistivity of Sand formations depend on the fluid content either connate water (saltwater) or hydrocarbon. Sand formation with hydrocarbon is represented by high electrical resistivity measurements while low resistivity indicates connate water. Hydrocarbon contact can be identified at this point by combining the gamma-ray (to identify sand formation) and resistivity logs (to identify the extent of the sand bed with hydrocarbon fluid).

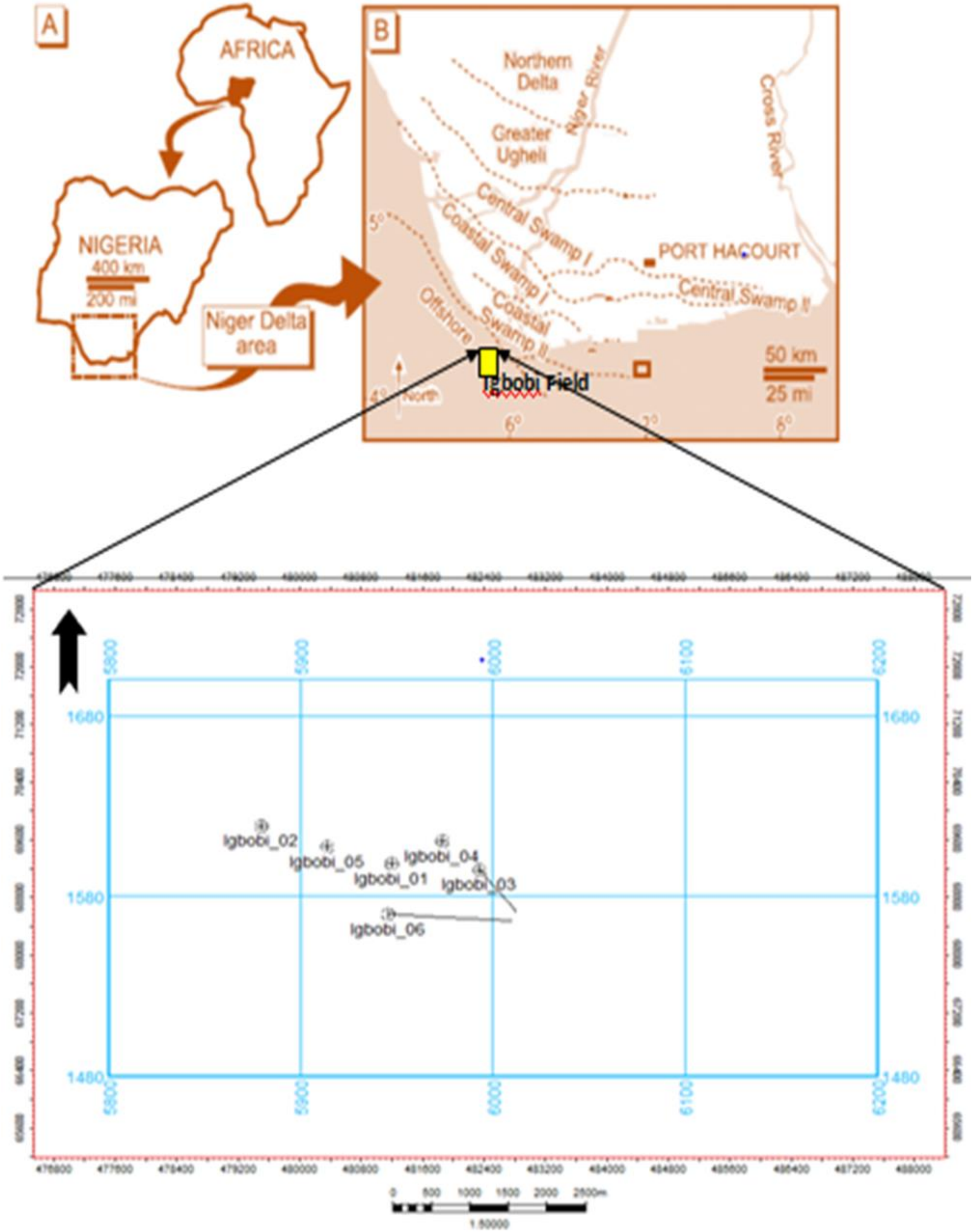

Figure 3. Base map/ seismic grid showing spatial distribution of wells, the inlines and crosslines

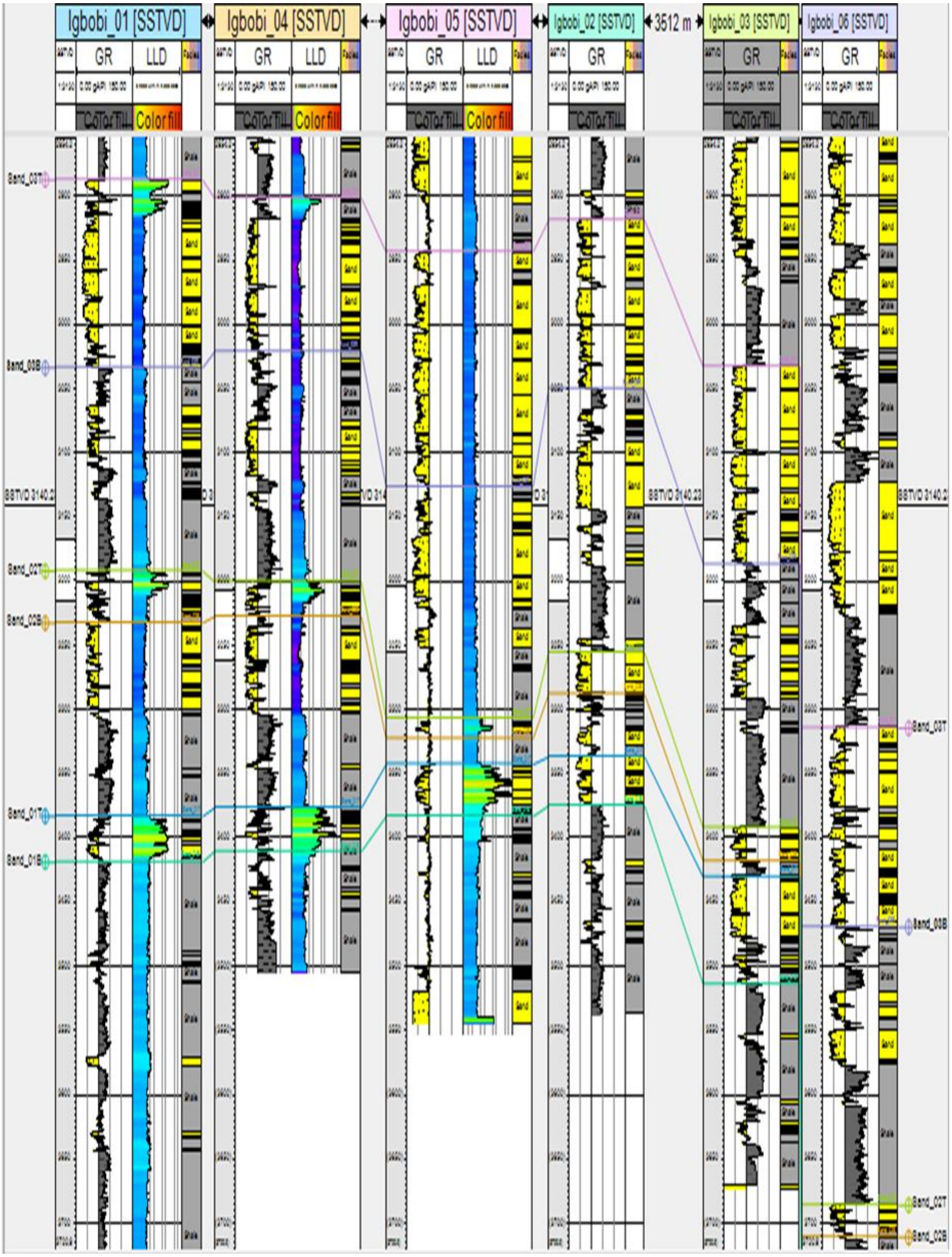

Figure 4. Igbobi Field wells log tracks showing the Agbada formations

The fourth panel is the overlay of neutron and density logs. The neutron log measures the (free) hydrogen count of formation/fluid while density measures the bulk density of the formation. Water is with highest neutron count followed by oil and finally gas with lowest hydrogen count. Likewise water is with the highest density followed by oil and then gas. This overlay is used to distinguish kinds of hydrocarbon in the formation as either gas or oil. Oil shows a track of both logs on each other while gas is indicated by separation with reversal of the logs.

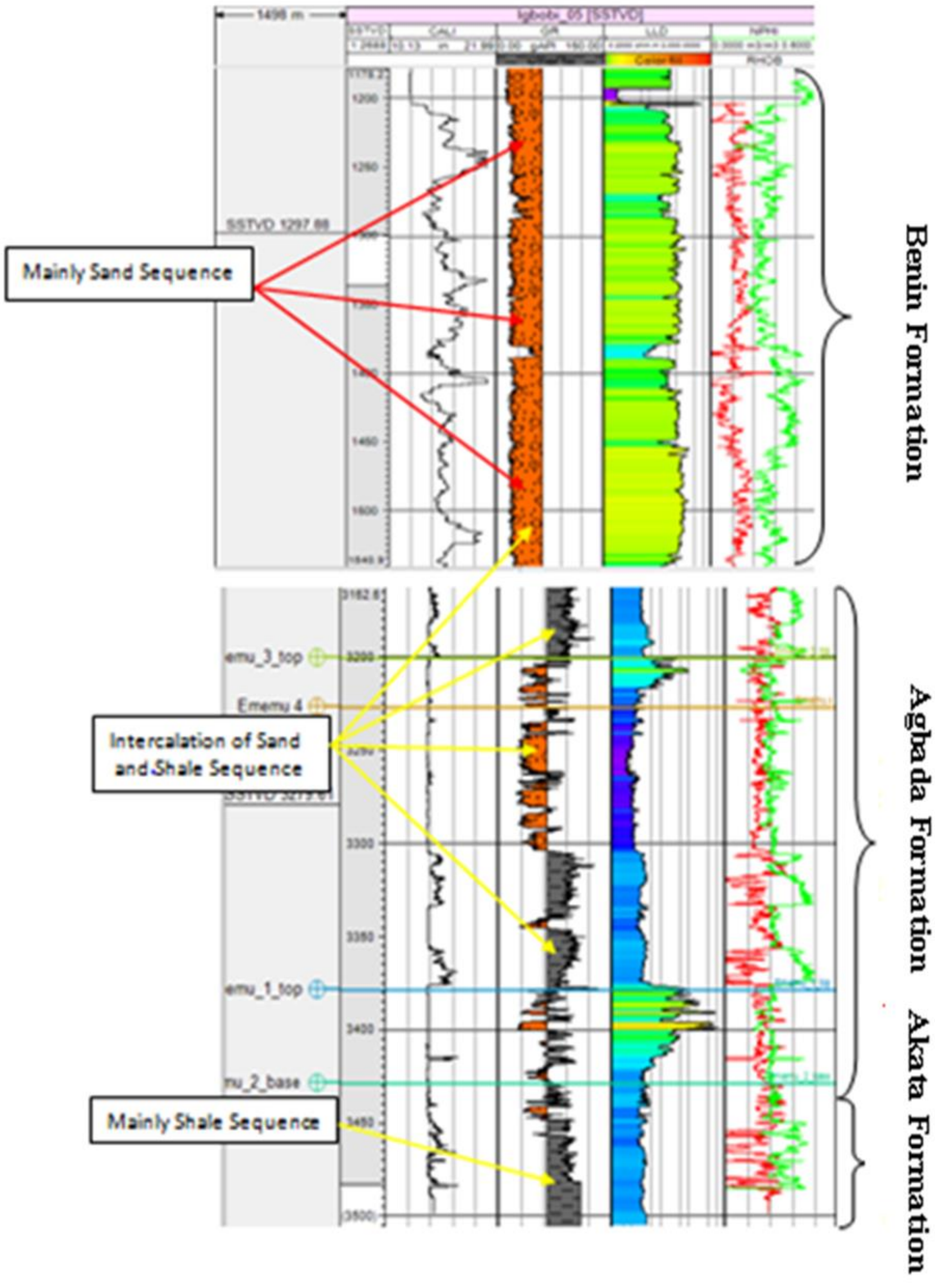

Figure 5. Igbobi Field wells log tracks showing the major formations

From the lithology log (gamma ray log) the top of Agbada Formation (base of Benin Formation) is identified by its intercalation of Shale and Sand sequence. Benin Formation is identified as a major Sandy sequence.

The pay zones were identified from the gamma ray and resistivity logs (Figure 6). Four pay zones were identified in the Agbada Formation named Sand 1 to 4. The neutron-density overlay has been used to identify that the hydrocarbon are mainly oil. The hydrocarbon reservoirs were taken as stacked reservoir because of the thin shale sequence as they were represented as a single event on seismic data. The thickness of the shale streaks was measured and was considered in estimating Net to gross for each reservoir interval. They are rather identified as dirty sands instead of breaking them into different tiny reservoirs. The Oil Water Contact and Lowest Known Oil are identified as displayed in (Figure 6).

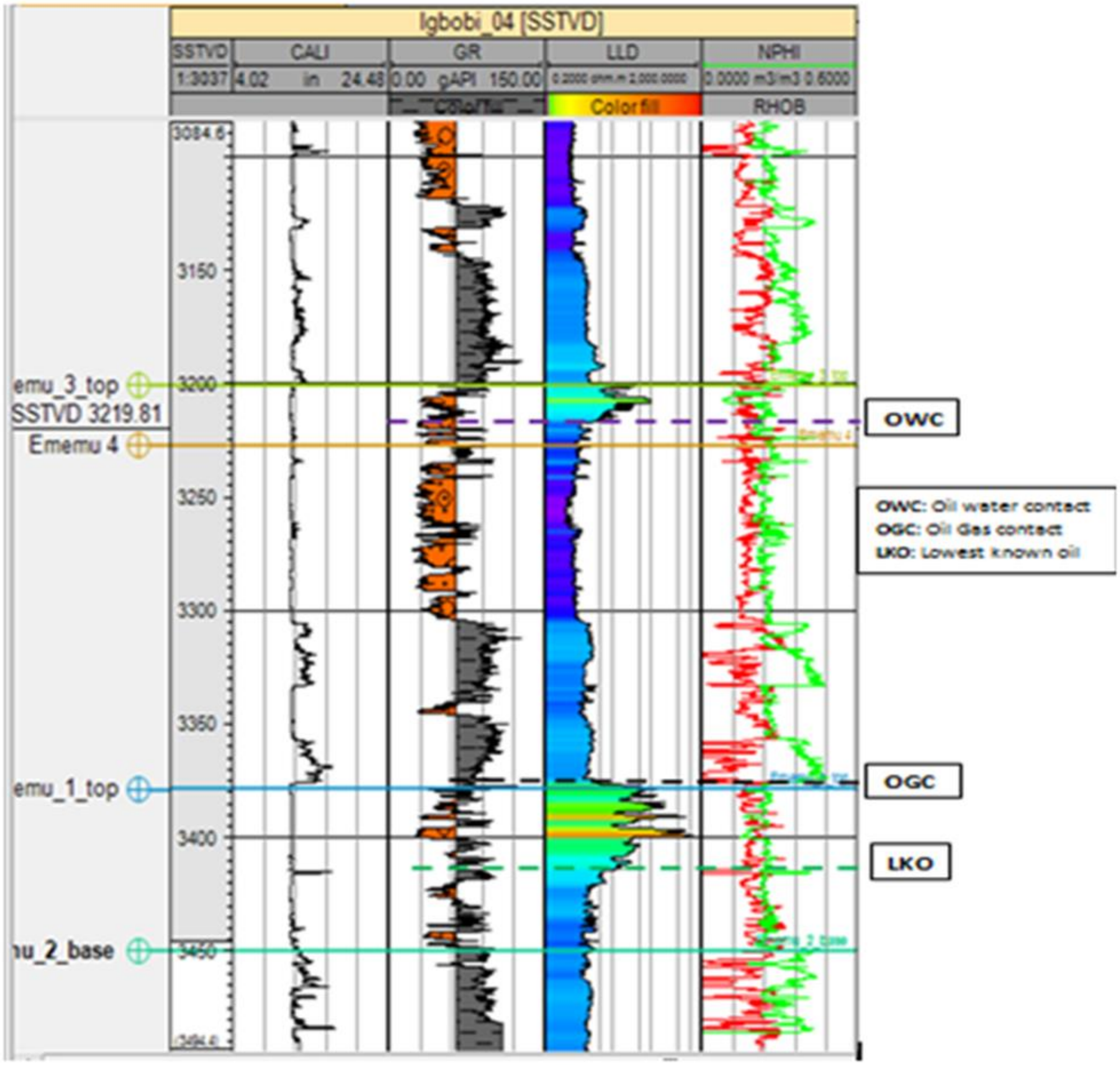

Figure 6. Identified Pay Zones and Fluid Contact on Igbobi_04

3.2.2. Petrophysical analysis

Petrophysical log interpretation is one of the most useful and important tools available to borehole geophysicists or petroleum geologists in arriving at realistic figures for both economic evaluation of the reservoir management which include optimizing recovery for primary and secondary method and its performance [17]. Petrophysical analysis consists of well data loading, data QC and editing, selection of reference well with complete dataset, determination of fluids and reservoir parameters, propagation of the interpretation to the rest of the wells, average reservoir parameter and determination of cut-offs.

Necessary environmental correction that is aimed at removing the effect of variable hole size and acquisition conditions (such as mud weight, salinity) had already been performed.

The PETREL software was used to carry out the petrophysical evaluation. The shale volume was evaluated as the minimum value of the available shale indicator. The shale volume indicators are classified into single indictors (GR, SP, Neutron, Resistivity) and dual indicators (density/neutron, density/sonic, neutron/sonic).

A detailed petrophysical evaluation was conducted for the Igbobi's Field wells (Igbobi_04, Igbobi_05, and Igbobi_01. The interpretation of the logs in general was performed using a deterministic approach and generated output curves for shale volume, net to gross, effective porosity, effective water saturation and permeability.

There were six wells drilled and various basic logs were available for the study. These logs were correlated by picking shale markers to delineate between reservoir rocks and non-reservoir using GR and Resistivity logs.

3.3. Estimation of hydrocarbon reserves

Reserves are the volume of hydrocarbons that can be profitably extracted from a reservoir using existing technology. Resources are reserves plus all other hydrocarbons that may eventually become producible; this includes known oil and gas deposits present that cannot be technologically or economically recovered i.e. Original oil in place (OOIP) Original gas in place (OGIP)

$$HCPV=k*H*A*\Phi*(1-S_w)*NTG \qquad (1)$$

The most important calculation is that of the hydrocarbon reserves in the reservoir and the accuracy of the result depends on the well log and seismic data available and due to the quality of reservoir description, volumetric method was used.

3.4. Calculation of hydrocarbon volume

Considering a reservoir which is filled with hydrocarbon (oil or gas), the volume of hydrocarbon or oil in place (OIP) is given as:

$$OIP = V*\Phi*(1 - S_w) \quad = A*h*\Phi*(1 - S_w) \qquad (2)$$

where: V = the net bulk volume of the reservoir rock; Φ = porosity of the reservoir; S_w = water saturation expressed as a fraction of the pore volume; A = areal extent of the reservoir; h = thickness of the pay zone.

The product of V and φ is called the pore volume (PV) and is the total volume of the reservoir which can be occupied by fluids. Also, the product V φ $(1-S_w)$ is called the hydrocarbon pore volume (HCPV) and it is the total volume which can be filled with hydrocarbons, either oil or gas or both. The bulk volume (V) of the reservoir rock is the product of the thickness of the reservoir rock and the areal extent.

The thickness, porosity, hydrocarbon saturation and Net to Gross were computed from the well log interpretation. while the area (A) was estimated from identified prospect on the seismic structural depth maps of "IGBOBI" field by finding the number of square grids holes occupied by the hydrocarbon bearing region and converting it to equivalent area. The equation utilized for the volumetric estimation of the reserves was STOOIP.

$$STOOIP=K*H*A*\Phi* (1-S_w)*NTG \qquad (3)$$

where k is the unit conversion factor 6.28 for units in meters; H=reservoir thickness; A=area of prospect; Φ= porosity; NTG = Net to Gr.

4. Results and discussion

4.1. Well logs interpretation

From the geology of the region the three formation of the basin are Akata Formation, Agbada Formation and Benin Formation. The Akata Formation is mainly trangressive marine shales and is the source rock but have not been penetrated by most wells. The Agbada

Formation is an intercalation of Sand and shale of which the shale at the base may be matured enough to generate hydrocarbon (Figure 4 and 5). More importantly the intercalation of Sand and Shale in the Agbada formation forms a network of reservoir overlain by a seal which is a key to the accumulation of hydrocarbon. The Benin formation is basically Sand and is of little importance to hydrocarbon in the study area. The base of the Benin Formation has been predicted on the well log based on its gamma ray log characteristics which indicates sequence of Sand. Effective porosity, water saturation and hydrocarbon saturation for Igbobi_1 was not possible because Neutron logs were not available. This also makes it difficult to determine fluid contact of the different fluids present in the reservoir. The porosity value obtained for this field indicates a very good reservoir [18]. From the water saturation values, the hydrocarbon saturation of the reservoir is found to be high.

Figure 8, shows gamma ray, resistivity, neutron-density, facies, porosity, volume of shale, effective porosity, water saturation and hydrocarbon saturation logs indicating different responses in the respectively reservoirs zone. The neutron-density logs overlaid and the scale flipped in opposite increment in Igbobi_4 and Igbobi_5 (Figure 7), a balloon shape signature was attained (i.e. low density and low neutron (low hydrogen content) for sand_1, sand_2 and sand_3 indicating a possible presence of gas accumulation and subsurface geologic structures that are favourable for hydrocarbon accumulation.

4.2. Petrophysical interpretation

The petrophysical analysis (as shown in Table 1) has shown that the reservoirs are of good quality. Three Hydrocarbon bearing sand reservoirs named Sand 1, 2 and 3 were identified with the aids of gamma ray signature and resistivity log response. The following petrophysical characteristics were computed from the reservoirs (Table 1). Water Saturation (Sw), Hydrocarbon Saturation (Sh), Porosity (Φ), Detailed results are presented in. Table 1 shows average petrophysical values of the reservoirs in well Igbobi_1, Igbobi_4 and Igbobi_5. The determination of the effective porosity, water saturation and hydrocarbon saturation for Igbobi_1 was not possible because Neutron logs were not available. This also makes it difficult to determine fluid contact of the different fluids present in the reservoir. The derived petrophysical parameters from available well logs revealed that Igbobi Field has high prolific hydrocarbon accumulation. About two prospects have been identified in the study area. The estimated reserve in Igbobi Field in sand_1 to 3 (as shown in Table 2) are 781MBls, 221MBls and 170MBLs respectively (i.e the STOOIP) and STGOIP for sand_1 to 3 are 243cu.ft, 587cu.ft and 450cu.ft.

A total reserve estimate using deterministic approach STOOIP gives an approximate of 1172 MBLs of oil.

Table 1. Calculated petrophysical values of well Igbobi_1, Igbobi_4, and Igbobi_5

Well	Reservoir	Top of reservoir	Base of reservoir	Φ %	SW (%)	SH (%)	Net thickness	Gross thickness	N/G	Vsh. (%)	Eff.Φ (%)
Igbobi 1	Sand_1	3385.85	3415.55	21	-	-	22.28	29.7	0.75	0.10	-
Igbobi 1	Sand_2	3193.85	3228.43	22	-	-	20.94	34.58	0.61	0.12	-
Igbobi 1	Sand_3	2887.93	3034.22	19	-	-	135.22	146.29	0.92	0.16	-
Igbobi 4	Sand_1	3378.72	3408.58	24	0.26	0.57	14.63	29.86	0.49	0.23	0.58
Igbobi 4	Sand_2	3200.89	3226.94	26	0.18	0.62	18.02	26.05	0.69	0.26	0.53
Igbobi 4	Sand_3	2903.44	3020.09	22	0.52	0.17	97.01	116.69	0.83	0.29	0.57
Igbobi 5	Sand_1	3344.10	3405.78	23	0.28	0.56	55.81	61.68	0.90	0.19	0.65
Igbobi 5	Sand_2	3307.27	3319.09	19	0.30	0.68	9.81	11.82	0.83	0.27	0.72
Igbobi 5	Sand_3	-	-	-	-	-	-	-	-	-	-

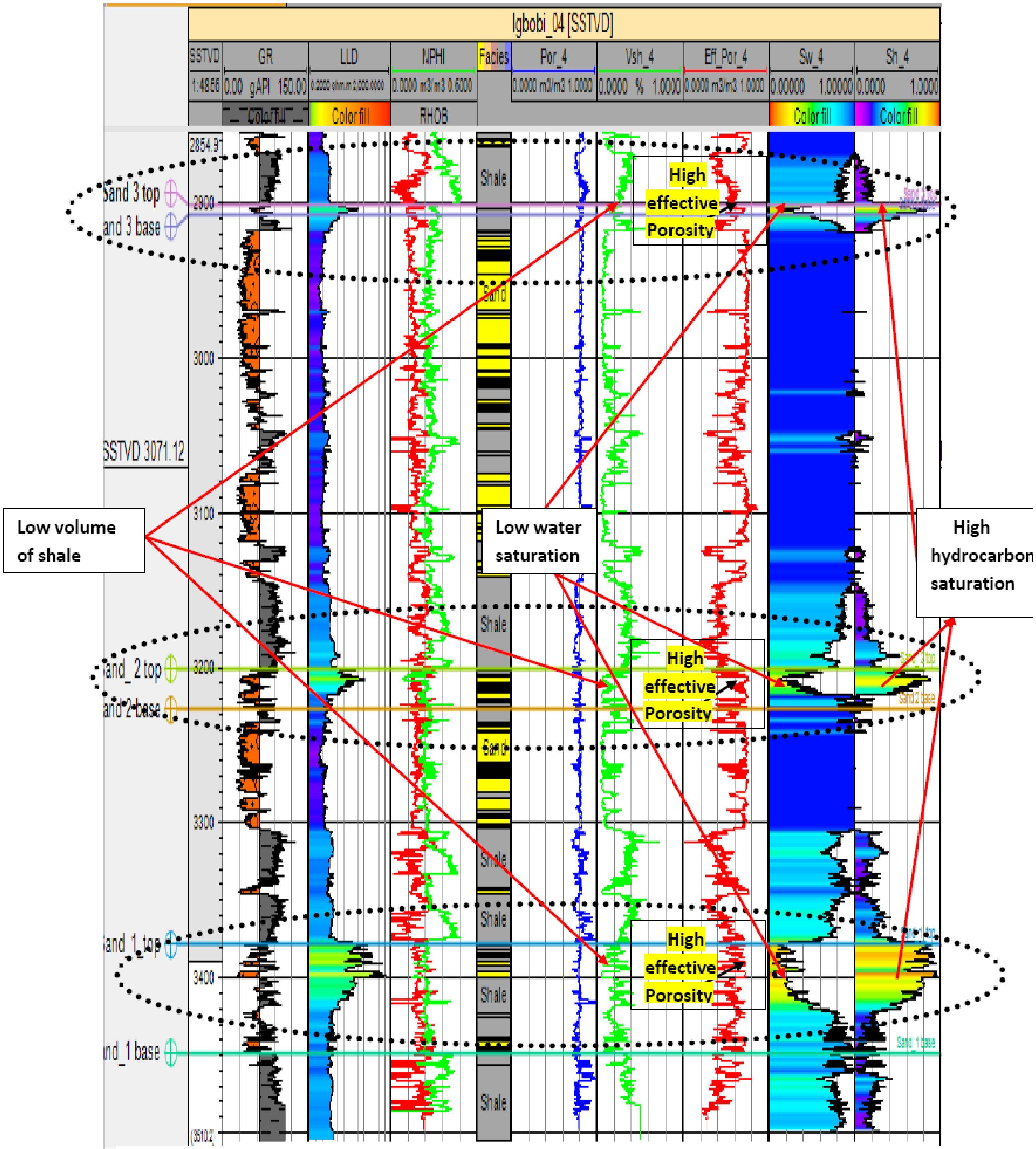

Figure 7. Track 1 to 9 is the GR, LLD, NPHIL & RHOB, facies, Porosity, volume of shale, effective porosity, water saturation and hydrocarbon saturation logs respectively

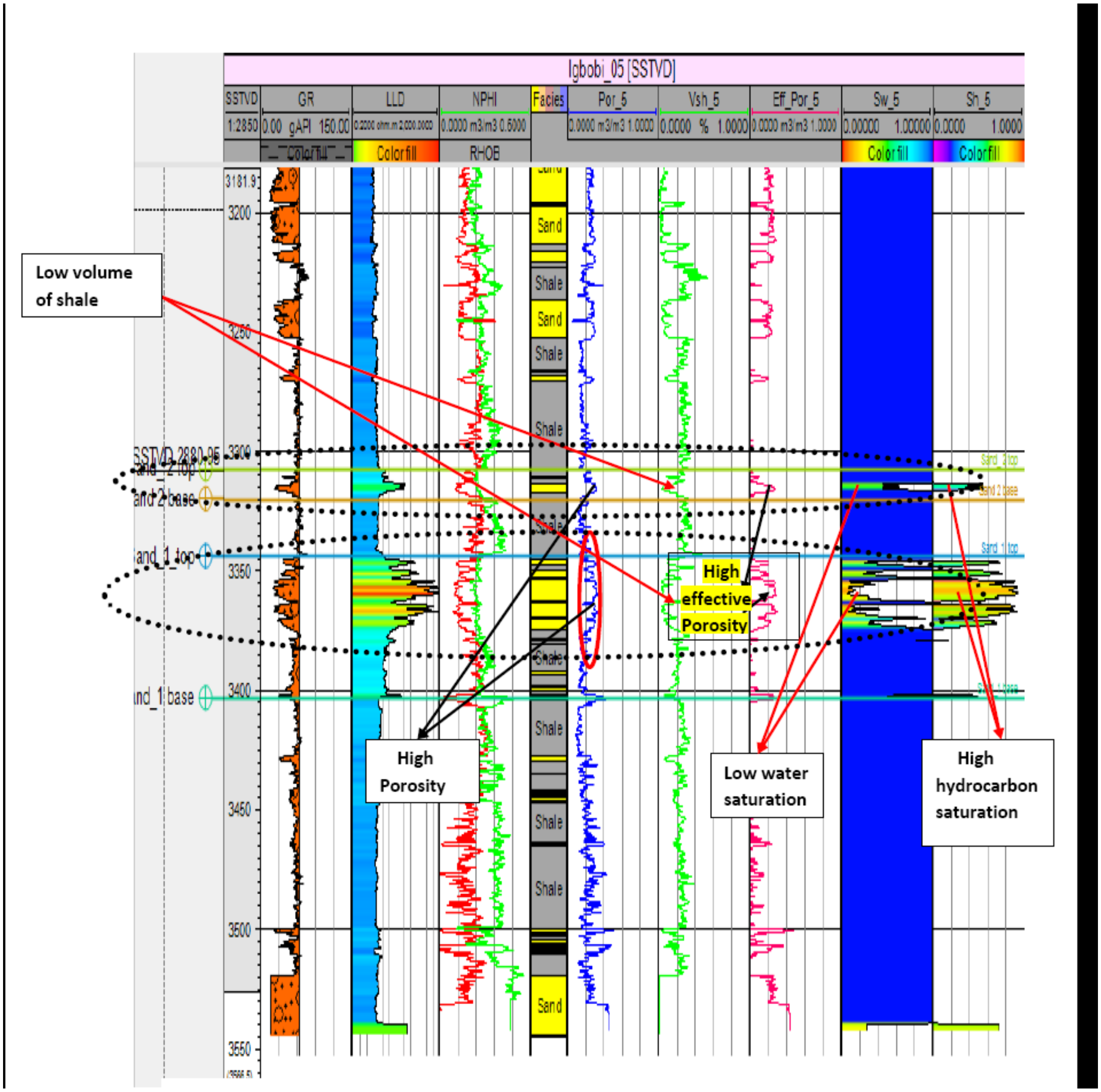

Figure 8. Track 1 to 9 is the GR, LLD, NPHIL & RHOB, facies, Porosity, volume of shale, effective porosity, water saturation and hydrocarbon saturation logs respectively

Table 2. Summary of volumetric estimation

Reservoir	Sand_1	Sand_2	Sand_3
Porosity (Φ)	0.23	0.22	0.21
N/G (Net to Gross)	0.71	0.74	0.88
Sw (water saturation)	0.27	0.24	0.52
Sh (hydrocarbon saturation)	0.57	0.63	0.17
Area(m^2)	5352200	4413700	3365500
Thickness	26.85	7.88	3.25
STOOIP(bbl)	781116880.5	221631880.82	170032978.59
STOOIP(MBL)	781	221	170
STGOIP(*cu. ft)*	243445186397	58665968163	450077350.69
STGOIP(cu. ft)	243	587	450

4.3. Volumetric estimation

Fluid type: Delineation of fluid type contained within the pore spaces of formation is achieved by the observed relationship between the Neutron and Density logs (Figure 6). Presence of hydrocarbon is indicated by increased Density log reading which allows for a crossover. Gas is present if the magnitude of cross-over, that is, the separation between the two curves is pronounced while oil is inferred where the magnitude of cross-over is low [17].

4.3.1. Estimated volume

Table 2, shows the estimated STOOIP (Stock Tank Oil Originally in Place) for each of the Reservoir Sands. The STOOIP ranges from 170MBls to 781MBls. Sand_1 has the highest STOOIP owing to average net pay of 26.85m, water saturation of 27% , good porosity (0.23), and hydrocarbon saturation of 57% , this shows that besides thickness of the hydrocarbon column within a reservoir Sand, the cleanness, water saturation and porosity constitute a major factor in the STOOIP. The porosity and Net to Gross which are highly determined by the environment of deposition, consequently have a great impact on the economic aspect of the reservoir.

5. Conclusion

Based on the uncertainties associated with Igbobi Field, this research employed the use of an integrated approach in characterizing the reservoir. This approach cleared the scepticism concerning oil prospects in the Field. To achieve this, the integrated well data (gamma ray, resistivity and neutron/density) and detailed petrophysical interpretation were used to estimate the potentiality of the reservoir zones within the Field. This made the recommendation during drilling a possible development. This will also help in solving the problem inherent with realistic inter- well petrophysical distribution within reservoirs in the Field. The intercalation of Sand and Shale in the Agbada formation forms a network of reservoir overlain by a seal which is a key to the accumulation of hydrocarbon. The derived petrophysical parameters from available well logs revealed that Igbobi Field has high prolific hydrocarbon accumulation. Based on this, two oil prospects have been identified in the study area.

The estimated STOOIP for each of the Reservoir Sands ranged from 170MBls to 781MBls. This is an indication that these reservoirs are embedded with subsurface geologic structures that are favourable for hydrocarbon accumulation.

From the factual interpretation of petrophysical and well logs available, it is therefore recommended that commercial oil exploration in Igbobi field is prospective and should proceed to further stage.

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