Petroleum and Coal

Article **Open Access**

Quantitative Petrophysical Evaluation and Reservoir Characterization of Well Logs from "Datom" Oil Field, Niger Delta

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Received March 31, 2018; Accepted June 20, 2018

Abstract

This paper presents a detailed reservoir characterization of three wells in "Datom" Oil Field, Niger Delta using well logs data. The distributions and thicknesses of sand bodies were determined within each of the wells in the field using interactive petrophysical (IP) software. The quantitative and qualitative analysis were done for the three exploration wells with the depth ranges of 8700-9200ft for Datom North well , 8900-9400ft for Datom West well, and 9000-9500ft for Datom East well. Two distinctive porous sand bodies were identified across the field (A and B), Datom North has it reservoirs as 1A (8815-8903ft) and 1B (9100-9157ft), Datom West has its reservoir as 2A (8996-9095ft) and 2B (9263-9321ft) and Datom East as 3A (9101-9219ft) and 3B (9357-9418ft). Petrophysical evaluation was made from a suite of wire-line logs comprising of gamma ray, resistivity, neutron and density logs of the wells. The average porosity values obtained are in the range of 0.18-0.22 with average net pay permeability values ranging from 322.70mD to 733.20mD. The water saturation obtained for each reservoir unit in combination with the resistivity index was used to prove the presence of hydrocarbon in the sand units. The hydrocarbon saturation of the reservoirs are in the range of 0.6-0.7 across the prospect zones with gas effect of the combination logs of neutron and density indicating the hydrocarbon accumulation is predominantly gas. The average net to gross ratio across the reservoirs (0.7-0.9) is defined using an average porosity ($\emptyset$) and volume of clay (V_{clay}) cut offs values of ≥ 0.1 and ≤ 0.5 respectively. With a moveable hydrocarbon index (MHI=S_W/S_{XO}) less than 0.7 across the sand units, it shows favorable hydrocarbon moveability in the reservoirs. The results clearly revealed that the gas bearing sand units have good reservoir potentials favorable for hydrocarbon production.

***Keywords**: Petrophysics; Net-to-Gross; Niger delta; well logs; Porosity; Water and Hydrocarbon Saturation.*

1. Introduction

The search for hydrocarbons starts with a regional knowledge of the prevailing geology in a geologic basin, where the geologist is in charge of the sedimentary sand deposition. After the geophysicist conducts seismic surveys and data processing, risky wildcat exploration wells may be drilled to test the best geological and seismic structural model. If a hydrocarbon discovery is made, data must be collected to evaluate the scale, quality, and quantity of the discovery. The resolution of moving an exploration well to completion is depended on its economic valiabity. To establish this viability a qualitative and quantitative analysis of all available well data is paramount. This analysis carried out at about the midpoint of a critical financial investment in the field development study will eventually determine whether to proceed with well completion and incur the relative cost or otherwise. Unarguably petrophysics plays a sensitive role in the evaluation of well and field potential.

Petrophysics actually converts resistivity, gamma ray and porosity tool measurements into reservoir properties, resistivity and porosity are the single most important measurements made by convectional logging tools and form the foundation on which the entire industry is built. Petrophysics evaluation combines well log, core, mud log, and other disparate data sources for the purpose of analyzing, predicting, and establishing formation lithology and porosity, hydrocarbon saturation, permeability, producibility, and estimating the economic viability of a well. According to Asquith and Krygowski [1], well logs are used to correlate zones suitable for hydrocarbon accumulation, identify productive zones, determine depth and thickness of zones, distinguish between gas, oil and water in a reservoir and to estimate hydrocarbon reserves.

Qualitatively the petrophysical evaluation is centered on translating geophysical responses to geological parameters, for instance, what natural radioactivity means as regard shale content; how sonic velocity can be interpreted as regard shale compaction; what bulk density means in terms of mineral composition etc. The ambit of this independent study is limited to the use of geophysical well log data to achieve not only the lithology and fluid type of the prospect zones but also the average water saturation and the productive capabilities will be predicted. However, as relevant as log parameters are, they should not be applied without the consultation of other necessary data like drill stem test, mud log evaluation, sample shows, nearby production etc, before taking a decision to drill.

In this study therefore, we carried out petrophysical evaluation and volumetric estimation of the "Datom" Field from a suite of wire-line logs comprising of gamma ray, resistivity, neutron and density logs of the wells. The analyses carried out involved the delineation of lithologies, identification of reservoirs and fluid types, wells correlation and determination of petrophysical parameters (porosity, hydrocarbon saturation, volume of shale, formation resistivity, net to gross ratio, water saturation, permeability etc) of the identified reservoirs. The objective of this study therefore was to carry out a detailed hydrocarbon reservoir characterization of the "Datom" Field using well log data.

1.1. Location and geology of the study area

The 'Datom' Oil Field is located within the central swamp depobelt of Niger delta basin, Nigeria (Figure 1). Several earlier scholars have presented detailed information on the regional geology, stratigraphy and structure of the Niger delta basin in several key publications [2-10]. Niger Delta according to Klett *et al.* [11] is situated within the Gulf of Guinea with extension throughout the Niger Delta Province. It is located in the southern part of Nigeria between the longitude 4^0 -9^0 E and latitude 4^0-6^0 N. It is situated on the West African continental margin at the apex of the Gulf of Guinea, which formed the site of a triple junction during continental break-up in the Cretaceous [12].

From the Eocene to the present, the Niger delta has prograded south-westward, forming depobelts that represent the most active portion of the delta at each stage of its development [12]. These depobelts form one of the largest regressive deltas in the world with an area of some 300, 000km^2 , a sediment volume of 500,000 km^3 and a sediment thickness of over 10 km in the basin depocenter [13]. Niger Delta Province contains only one identified petroleum system referred to as the Tertiary Niger Delta (Akata –Agbada) Petroleum System [13-14]. Extended research by Tuttle *et al.* [15] confirmed this one petroleum system with the delta, which was formed at the triple junction related to the opening of the southern Atlantic beginning in the late Jurassic and continuing into the Cretaceous. The delta began its development in the Eocene with the accumulation of sediments that are now about 10 kilometers thick [12-14]. The area is geologically a sedimentary basin, and consists of three basic Formations: Akata, Agbada and the Benin Formations. The Akata is made up of thick shale sequences and it serves as the potential source rock. It is assumed to have been formed as a result of the transportation of terrestrial organic matter and clays to deep waters at the beginning of Paleocene [12]. According to Doust and Omatsola. [12] the thickness of this formation is estimated to about 7,000 meters thick, and it lies under the entire delta with high overpressure. Agbada Formation is the major oil and gas reservoir of the delta, It is the transition zone and consist of intercalation of sand and shale (paralic siliciclastics) with over 3700 meter thick and represent the deltaic portion of the Niger Delta sequence [13,16]. Agbada Formation is overlain by the top Formation, which is Benin. Benin Formation is made of sands of about 2000m thick [2].

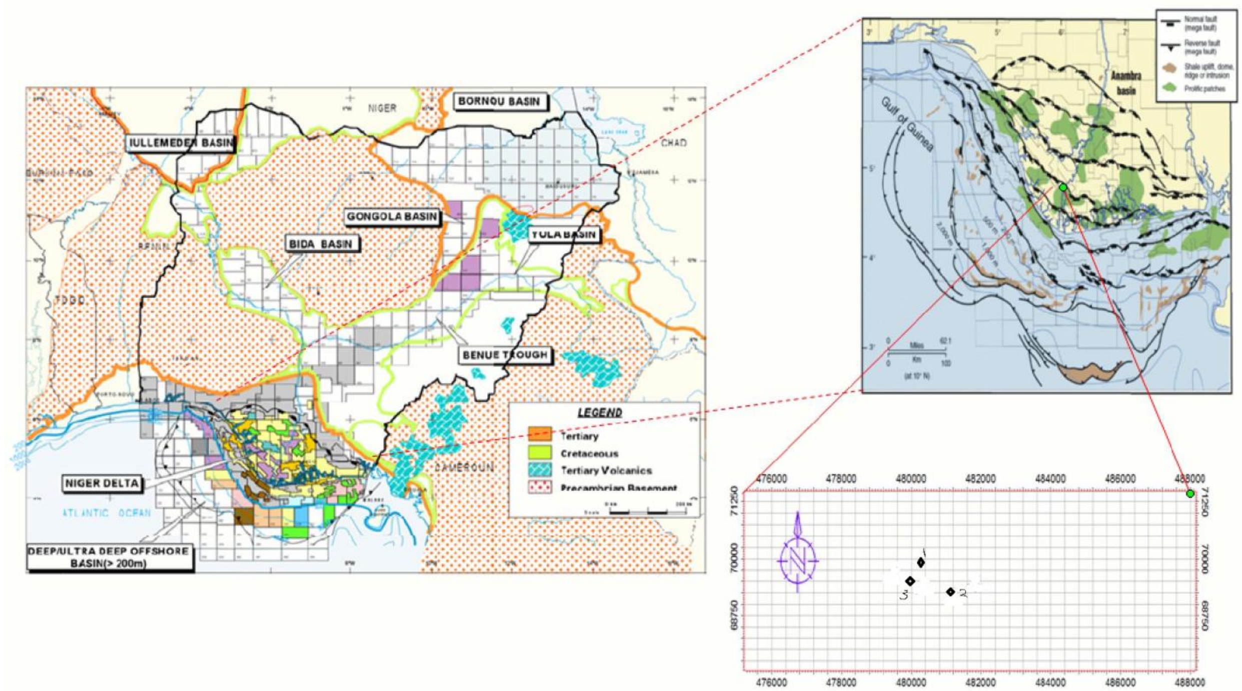

Fig 1. Map of Nigeria Showing the Location of the Niger Delta and the Base map of Datom oil field with well locations (well 1,2,3) representing Datom North, Datom East and Datom West respectively *(Modified from Whiteman [16])*

2. Methodology

Log analysis, or formation evaluation was done with Interactive petrophysics (IP) software. The evaluation requires the synthesis of logging tool response physics, geological knowledge, and auxiliary measurements or information to extract the maximum petrophysical information concerning the subsurface formations. The qualitative and quantitative analyses were carried out on the available petrophysical logs (GR,Resistivity, neutron and Density logs) of the Datom oil field. While qualitative analysis involves the assessment of reservoir properties, fluid type from log pattern, quantitative analysis deals with the numerical estimation of reservoir properties viz; % of gas, oil and water. Empirical formulae were used to estimate the petrophysical properties of the mapped reservoir units delineated on the well logs.

The first task is to identify the zones with a low-volume fraction of shale since such zones (clean zones) are more likely to produce accumulated hydrocarbons. This task has traditionally been accomplished through two measurements: the gamma ray and combine effect of the neutron and density log, In the reservoir units, gamma ray (GR) log which measures natural radioactivity in formations reflects the shale contents while the compensated neutron/density log was use to validate the porosity and the lithology both logs were used for the identification of sand / shale lithology in the Datom field. The resistivity log in combination with the GR logs were used to differentiate between hydrocarbon and non-hydrocarbon bearing zones since hydrocarbon is a nonconductor. The combination of the neutron and density log further validates the sand-shale zones and detection of gas bearing zones. The reservoir units were further characterized quantitatively to arrive at petrophysical parameters, which includes: volume of shale, formation factor, porosity, water saturation, permeability and so on. Some of these parameters are discussed.

Gamma Ray Index

The gamma ray log is generally used to determine the gamma ray index using the formula according to Asquith and Gibson [17] as given in equation 1:

$$I_{GR} = (GR_{LOG} - GR_{MIN})/(GR_{MAX} - GR_{MIN}) . \qquad (1)$$

where: I_{GR} =gamma ray index; GR_{LOG}=gamma ray reading of formation from log ; GR_{MIN}=minimum gamma ray (clean sand); GR_{MAX}= maximum gamma ray (shale).

Volume of shale

The volume of shale was calculated by applying the gamma ray index in the appropriate volume of shale equation according to Larionov [18] for tertiary rocks as given in equation 2:

$V_{sh} = 0.083[2^{(3.7 \times IGR)} - 1.0]$... (2)

where: V_{sh}=volume of shale ,I_{GR}= gamma ray index.

Porosity

The computation of porosity was done in stages, the first involved the use of the Wyllie equation to estimate the density derived porosity (ϕ_D), and then the neutron-density porosity (ϕ_{N-D}), was estimated using the neutron (ϕ_N) porosity coupled with the density derived porosity. The Wyllie equation for density derived porosity is given as shown in equation 3 [19]:

$\phi_D = (\ell_{max} - \ell_b)/(\ell_{max} - \ell_{fluid})$ (3)

where: ℓ_{max} =density of rock matrix = 2.65 g/cc ; ℓ_b = bulk density from log; ℓ_{fluid} = density of fluid occupying pore spaces (0.74g/cc for gas, 0.9g/cc for oil and 1.1 g/cc for water).

The Neutron – Density porosity could be calculated according to The Neutron-Density porosity could be calculated using the equation of Hussien *et al*. [20] as:

$\phi_{N-D} = (\phi_N + \phi_D)/2$ *for oil and water column* (4)

$\phi_{N-D} = (2\ \phi_D + \phi_N)/3$ *for gas bearing zones*... (5)

Formation factor

The estimation of the Formation Factor was achieved using the popular Humble Equation [39]:

$F = a/Ø^m$ (6)

where, F = formation factor; a = tortuosity factor = 0.62 ; Ø = porosity; m=cementation factor = 2.15

Formation water resistivity (Ωm)

Using the Archie's equation that related the formation factor (F) to the resistivity of a formation at 100% water saturation (R_o) and the resistivity of formation water (R_w), the resistivity of the formation water was estimated as:

$R_w = R_o/F$ ... (7)

Water saturation

Determination of the water saturation for the uninvaded zone was achieved using the Archie [21] equation given.

$S_w^2 = (F \times R_w)/R_T$ (8)

But, $F = R_o/R_w$ (9)

Thus, $S_w^2 = R_o/ R_T$ (10)

where: S_w = water saturation of the uninvaded zone; R_o= resistivity of formation at 100% water saturation; R_T= true formation resistivity.

Hydrocarbon saturation

This was obtained directly by subtracting the percentage of water saturation from 100.

Thus $S_{hy} = 1 - S_w$ r S_{hy} %= 100 - S_w% (11)

where: S_{hy} is the hydrocarbon saturation (expressed as a fraction or as percentage).

Resistivity Index

This was estimated using the ratio of formation true resistivity (R_t) to resistivity of formation at 100% saturation (Ro) as given in equation 12:

$I = R_t/R_o$ ... (12)

where: I is the resistivity index. When I is equal to unity, it implies that the reservoir is at one hundred percent (100%) water saturation, The higher the value of I, the greater the percentage of hydrocarbon saturation.

Bulk volume water

Bulk volume of water (BVW) was estimated as the product of water saturation (S_w) of the uninvaded zone and porosity ($Ø_{N-D}$). Thus, the bulk volume of water is shown in equation 13:

$BVW = S_w \times Ø_{N-D}$ ... (13)

where: $Ø_{N-D}$ = neutron-density porosity.

Hydrocarbon pore volume

The hydrocarbon pore volume (HCPV) is the fraction of the reservoir volume occupied by hydrocarbon. This was calculated as the product of neutron-density porosity and hydrocarbon saturation as shown in equation 14:

$HCPV = Ø_{N-D} \times (1 - S_w)$ (14a)

$HCPV = Ø_{N-D} \times (S_h)$ (14b)

Irreducible water saturation

The irreducible water saturation was calculated using the following relationship in equation 15. However, this theoretical estimate of irreducible water is majorly useful in the estimation of relative permeability.

$S_{wirr} = (F/2000)^{1/2}$ ... (15)

where: S_{wirr} = irreducible water saturation; F =formation factor.

Permeability

This was based on the relationship between permeability, porosity, and irreducible water saturation according to Wyllie and Rose [19]. The relationship is expressed in equation 16 as:

$K = [(250 \times (Ø_{N-D})^3)/S_{wi}]^2$ ... (16)

Shaliness (V_{sh} Total)

This is the total volume of shale represented as a depth factor within a well. It is calculated by using equation 17:

Average V_{sh} *x Gross thickness* ... (17)

Net thickness

This is the column of the reservoir that is occupied by reservoir formation (e.g. sand) only and exclusive of non-reservoir formations (e.g. shale). It is calculated by using equation 18:

Gross Thickness – V_{sh} *Total* ... (18)

Net to Gross ratio (NTG)

This is the ratio between the net reservoir thickness and the gross reservoir thickness. However in terms of hydrocarbon pay, it could be calculated as the ratio between the net pay thickness and the gross pay thickness. The four main steps in the application of a net-pay cut off to a particular reservoir interval are to establish a standard, calibrate one or more logs to the chosen standard, confirm that the calibration step produces results consistent with the standard, and apply the calibrated model to all wells [22-23]. The primary geological considerations in determining pay and non pay in the reservoir interval are depositional environment and hydrocarbon and structural history. The "net-to-gross ratio" or "net/gross" (N/G) is the total amount of pay footage divided by the total thickness of the reservoir interval (for simplicity, the well is assumed here to be vertical). The depositional environment provides a picture of whether the overall reservoir interval is sand rich (high N/G) or shale rich (low N/G) and the nature of the interbedding of high-quality rock with poor-quality rock. If the reservoir interval is quite interbedded with high-quality rock intimately layered with poor-quality rock on the scale of a few inches to a few feet, the poor-quality rock intervals, if they contain hydrocarbons, will likely contribute to production [24-26]. However, if the layering is on a much larger scale with thick high-quality rock intervals separated from thick low-quality rock intervals, then the poor-quality rock intervals are much less likely to contribute significantly to production [22-26]. The NTG is generally estimated using equation 19:

NTG = Net thickness ÷ Gross Thickness (19)

Effective Porosity

This is the porosity of the interconnected pore spaces. It assumes the absence of shale from the reservoir. It can be calculated using the following relationship as shown in equation 20:

$\Phi_{effective} = (1 - V_{SHALE}) * \phi_{N\text{-}D}$ (20)

Storage Volume

This is the capacity to store hydrocarbon in the reservoir. The storage volume is always higher than the hydrocarbon pore volume within a well because the net pay zone is inclusive of the grain matrix whereas the grain matrix is absent in the hydrocarbon pore volume computation as only the hydrocarbon in the pore spaces is calculated for. The storage volume is generally estimated using the formula given in equation 21.

Storage Volume = $\phi_{N\text{-}D}$ * Net Pay Thickness … (21)

3. Result interpretation

In this study based on the analysis, two hydrocarbon bearing zones (Reser A and B) were identified for further interpretation.The sand units (Reser A and B) were delineated as hydrocarbon bearing sands within the Agbada formation of the field as shown from the correlation of three wells using well logs (Figure 2). The sands were identified to be highly prolific in hydrocarbon yield and were completely analyzed to estimate their petrophysical parameters. Increasing trend of the thickness of the shale units with depth indicate that the sequence is approaching the Akata Formation. The parameters deduced from the analysis include gamma ray index, porosity, net to gross, volume of shale, formation factor, irreducible water saturation, hydrocarbon saturation, water saturation and hydrocarbon pore volume etc. These parameters help to effectively quantify the reservoirs.

Datom North

The reservoirs (1A and 1B) of the Datom North well have its top and base at a depth interval of 8815.50ft - 8903.50ft and 9100ft - 9157.50ft respectively with a gross thickness of 88ft and 57.50ft, net pay interval of 79.25 and 38ft, N/G are 0.9 and 0.6 .The average neutron-density derived porosity for the reservoirs are 20% and 18%, Average water saturations are 0.32 and 0.33 respectively. The net pay permeability of reservoir 1A and 1B is fair to good,733mD and 598mD,average water of the flushed zone (S_{XO}) is 0.82 and 0.79 respectively (table 1.).

Table 1. Summary of the calculated averages of Petrophysical parameters of Datom North

Zone Name	Top reserv.MD (ft)	Base reserv.MD (ft)	Gross interval (ft)	Net pay interval MD (ft)	N/G ratio	Av.Phie (%)	Av Sw (%)	Swirr (%)	Av Vcl (%)
RESER 1A	8815.50	8903.50	88.00	79.25	0.90	20	32	31	22
RESER 1B	9100.00	9157.50	57.50	38.00	0.66	18	34	32	36

Zone Name	Net pay permeability (md)	S_{xo}	BVW	MHI	HCPV	S_h
RESER 1A	733.20	0.82	0.06	0.39	13.56	0.68
RESER 1B	598.60	0.79	0.06	0.43	11.90	0.66

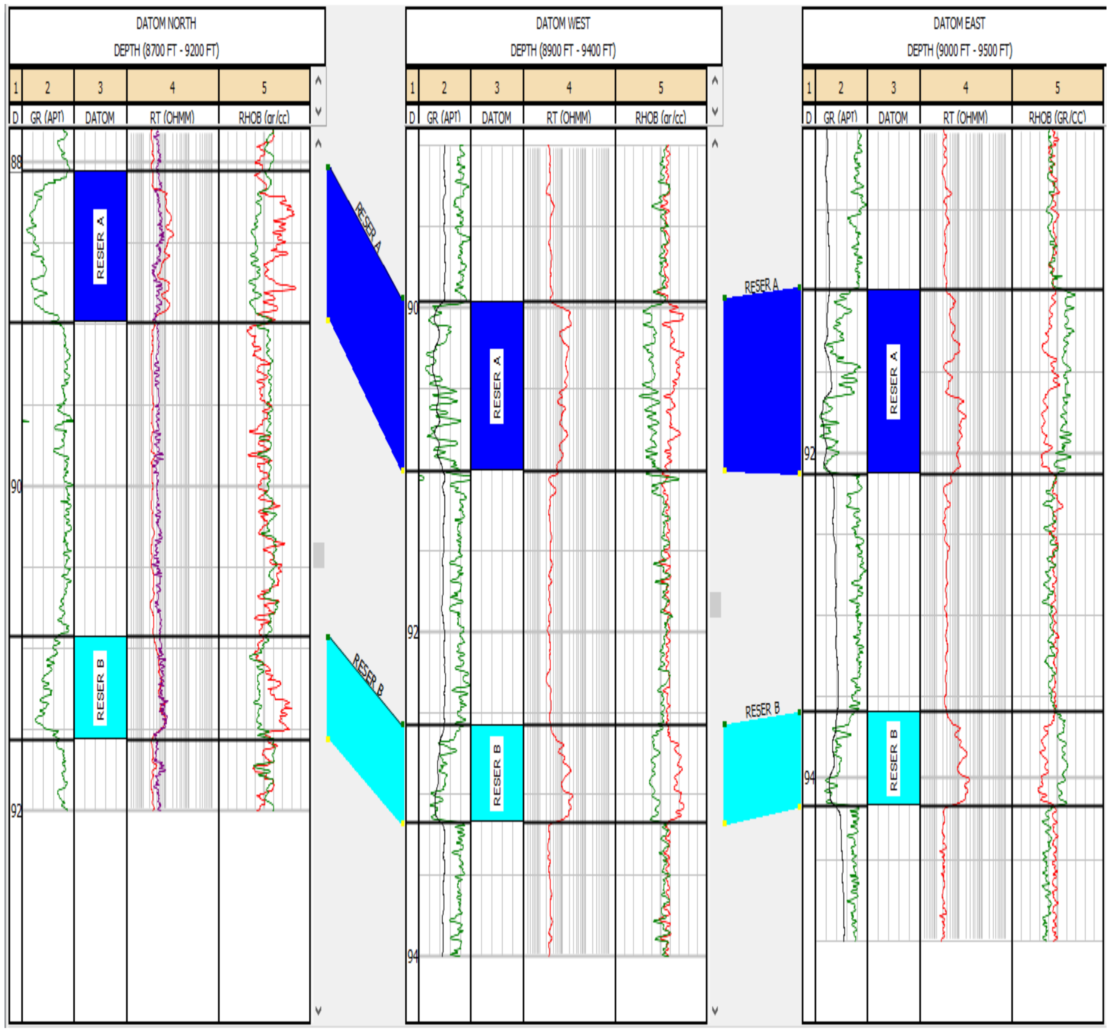

Fig 2. Well-to-well correlation panel of the study area showing hydrocarbon bearing sand units

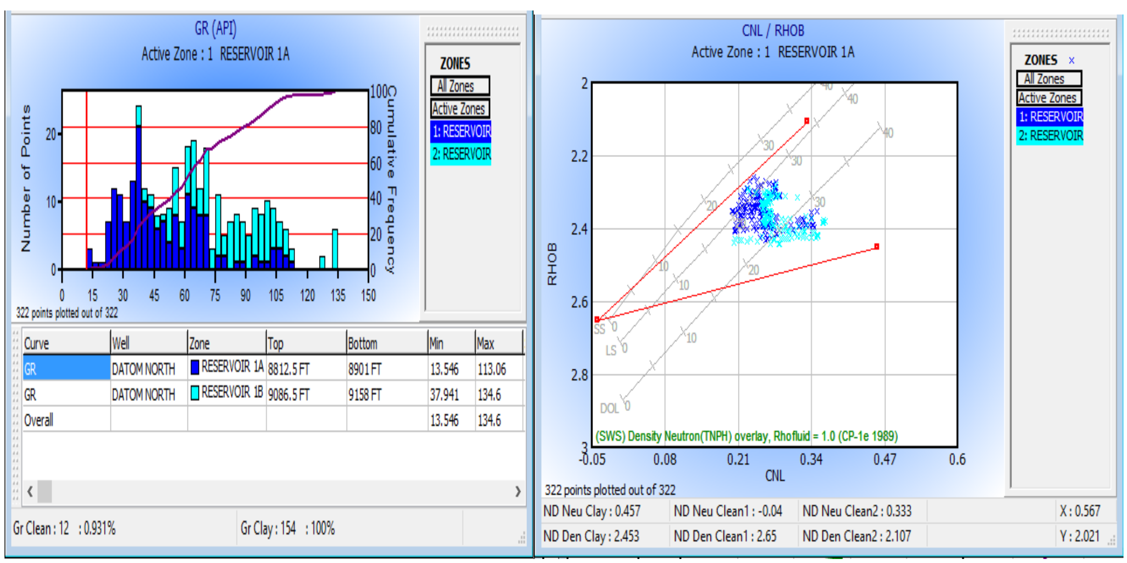

Fig 3. showing GR log histogram and cross plot of neutron-density log of reservoir 1A and 1B of the Datom north well for shale volume estimation

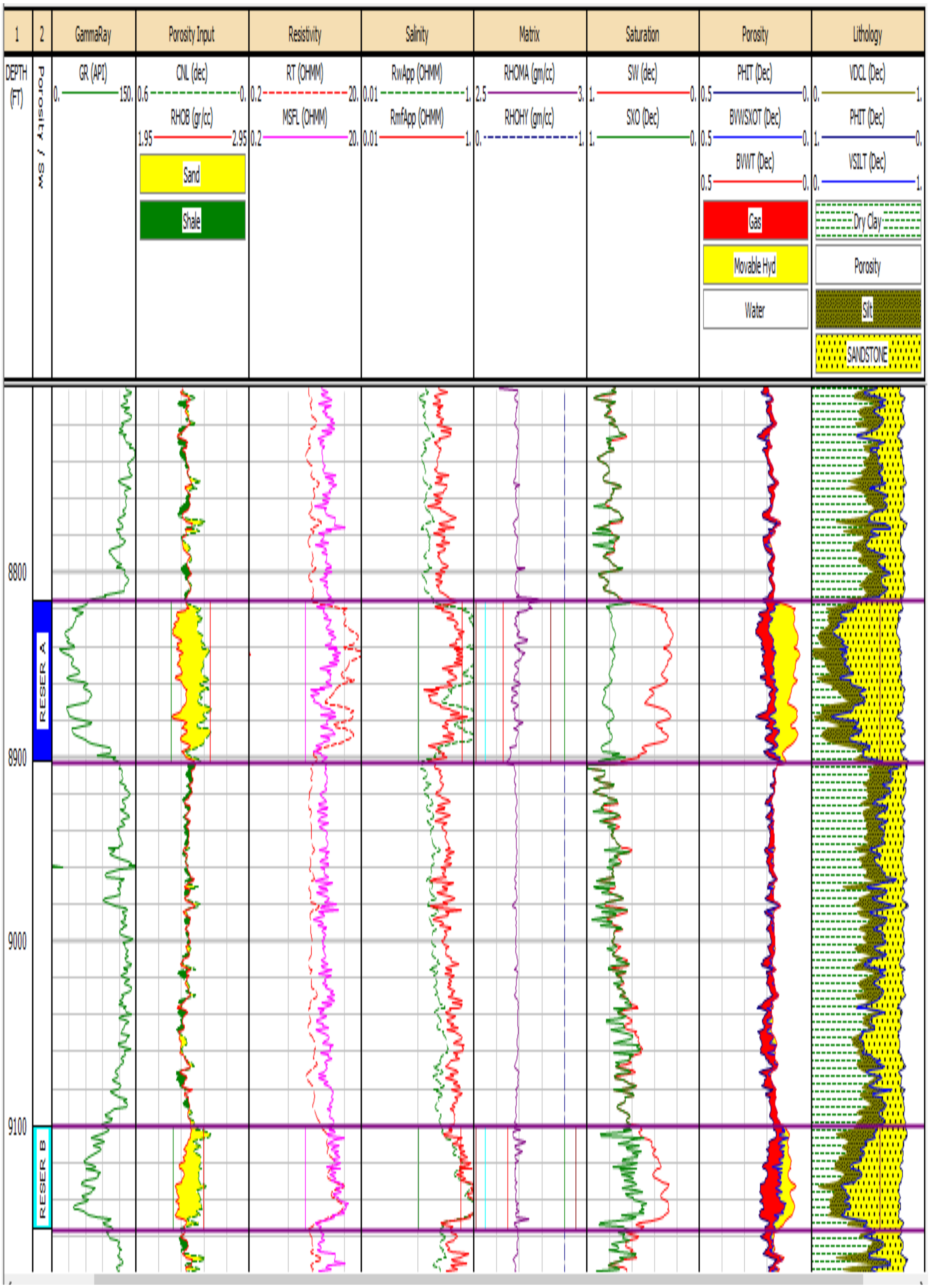

Fig 4. Comparison of petrophysical parameter logs of Datom north to validate lithology, fluid type, hydrocarbon producibilty

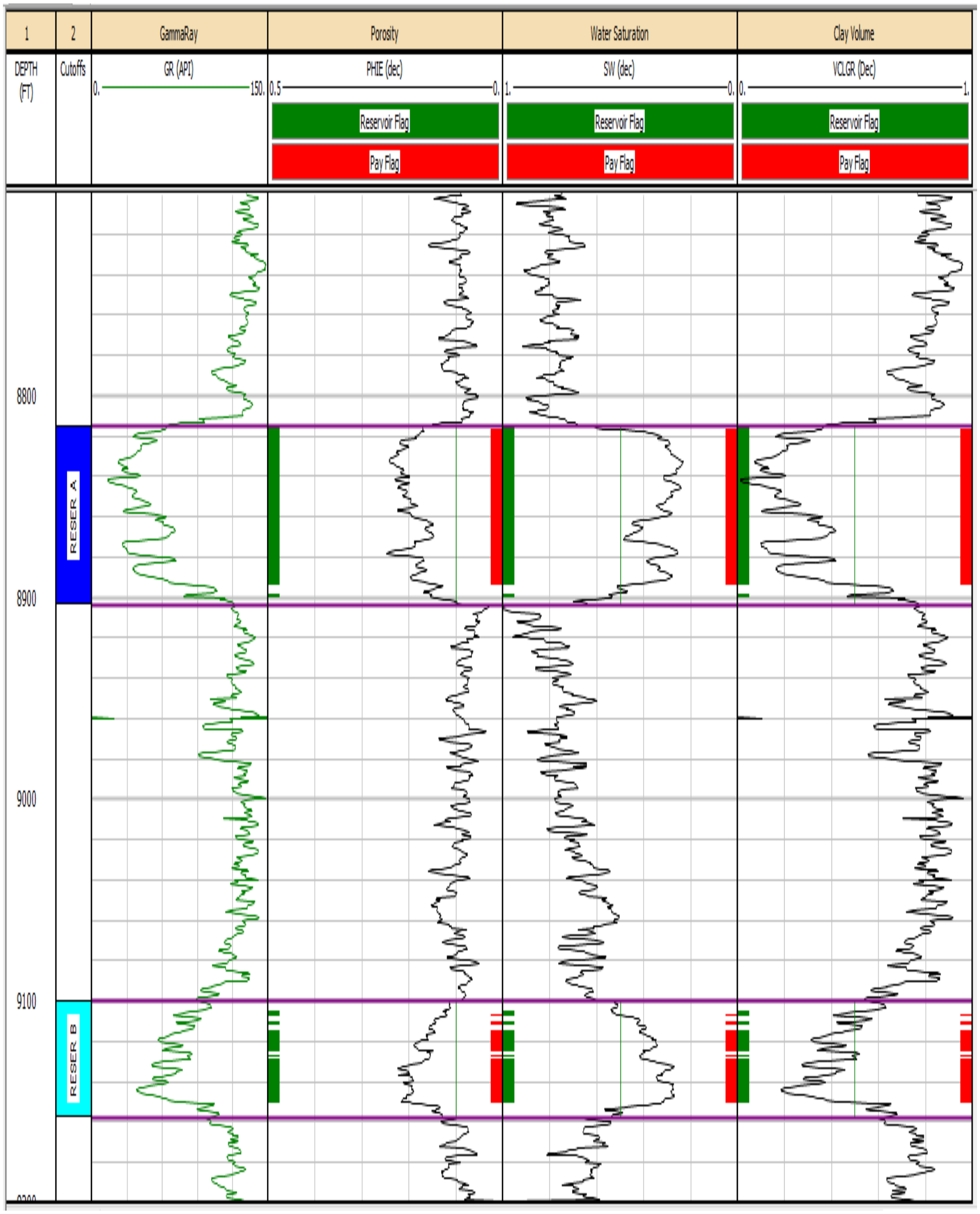

Fig 5. Showing summary of cut off from average porosity, volume of clay, water saturation to estimate net pay zones of Datom north well

Datom West

The average porosity of the reservoirs (2A and 2B) of the Datom West well is approximately 18%, with well top and base at 8996.50ft-9095ft and 9263ft-9321ft respectively. It has a gross thickness of 98ft and 58ft, Net pay thickness of 86.50ft and 48ft with a N/G ratio of 0.878 and 0.828. The water saturation is relatively good at 0.38 and 0.32. The permeability of the net pay zone and the water saturation of the flushed zone for reservoir 2A and 2B are 640mD and 471mD (permeability) and approximately 0.9 for (S_{XO}) (table 2).

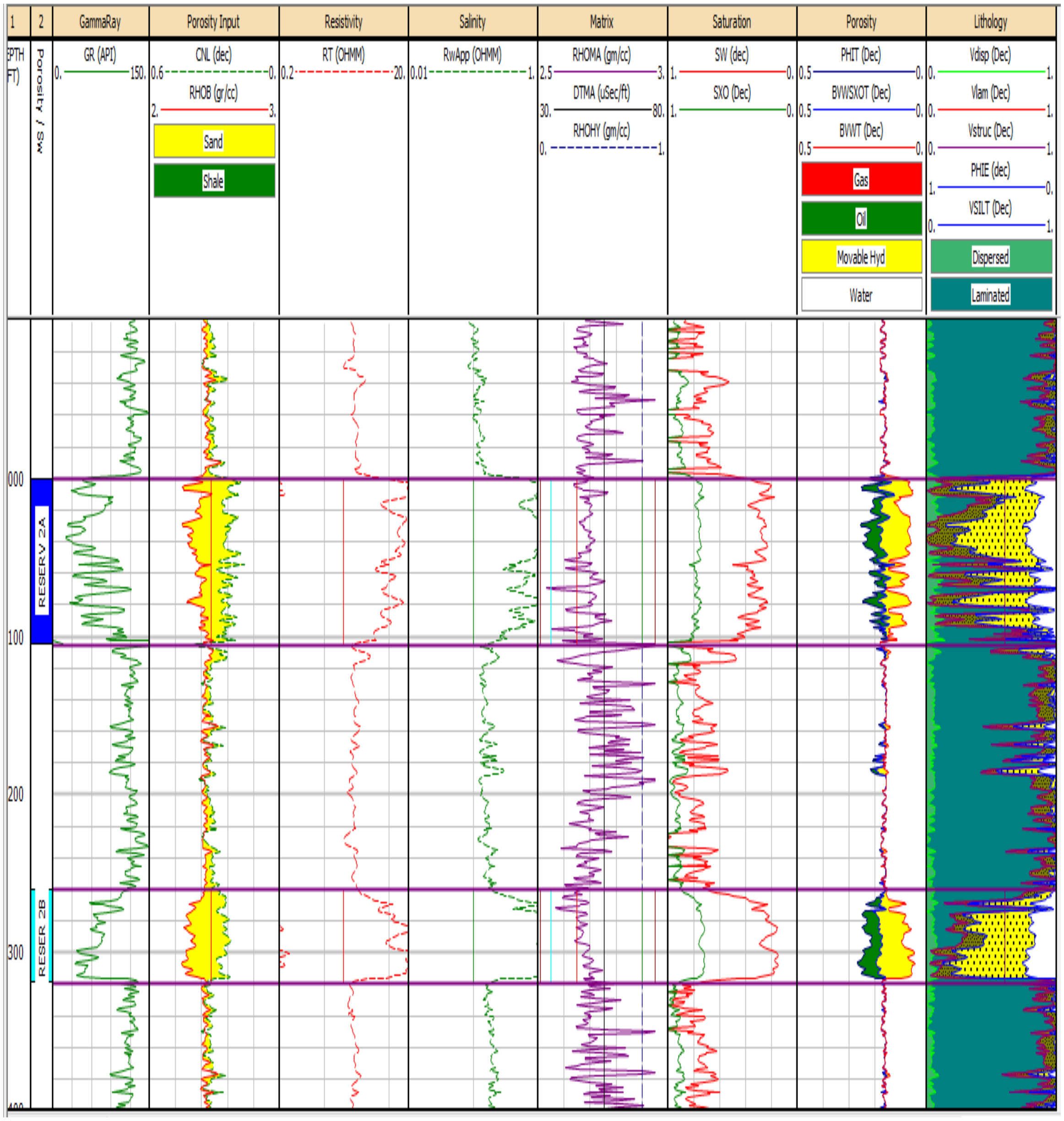

Fig 6. Comparison of petrophysical parameter logs of Datom west to validate lithology, fluid type, hydrocarbon producibilty

Table 2. Summary of the calculated averages of Petrophysical parameters of Datom west

Zone Name	Top reserv.MD (ft)	Base reserv. MD(ft)	Gross interval. MD, (ft)	Net pay interval MD(ft)	N/G ratio	Av.Phie (%)	Av Sw (%)	Sw irr (%)	Av Vcl
RESER 2A	8996.50	9095.00	98.50	86.50	0.88	19	37	35	0.14
RESER 2B	9263.00	9321.00	58.00	48.00	0.83	18	32	31	0.13

Zone Name	Net pay permeability, (md)	S_{xo}	BVW	MHI	HCPV	S_h
RESER 2A	640.5	0.88	0.07	0.26	11.84	0.62
RESER 2B	471.9	0.84	0.06	0.38	12.22	0.68

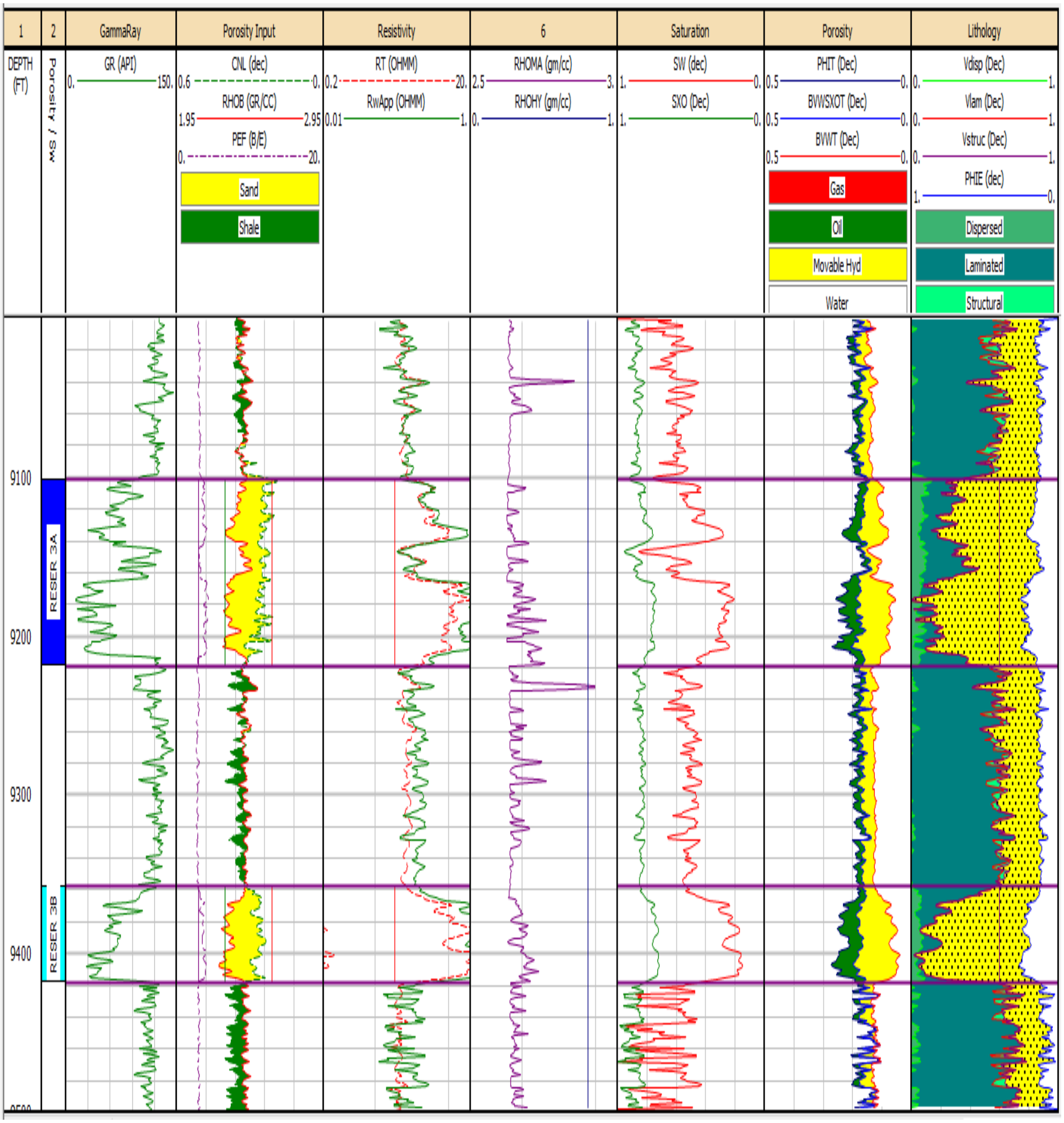

Fig 7. Comparison of petrophysical parameter logs of Datom east to validate lithology, fluid type, hydro-carbon producibilty

Datom East

The reservoirs in this well have average thicknesses from 9101ft-9219ft in reservoir 3A and 9357.50ft-9418ft in reservoir 3B. The average neutron-density derived porosity for the reservoirs are between 19% and 22%, which indicates good average porosity. The water saturation of the reservoirs is 0.34 and 0.22 with a gross interval of 118ft and 61ft respectively. The net pay thickness is 88.50ft and 48ft,N/G ratio of approximately 0.8, Average net pay permeability is 587mD and 322mD with water saturation of flushed zone to be 0.81 and 0.79 respectively (table 3).

Table 3. Summary of the calculated averages of Petrophysical parameters of Datom East

Zone Name	Top reserv.MD (ft)	Base reserv. MD(ft)	Gross interval. MD, (ft)	Net pay interval MD(ft)	N/G ratio	Av.Phie (%)	Av Sw (%)	Sw irr (%)	Av Vcl
RESER 2A	9101.00	9219.00	118.00	88.50	0.75	19	34	34	36
RESER 2B	9357.50	9418.50	61.00	48.00	0.79	22	21	20	35
Zone Name	Net pay permeability, (md)	S_{xo}	BVW	MHI	HCPV	S_h			
RESER 2A	587.30	0.81	0.07	0.42	12.50	0.66			
RESER 2B	322.70	0.79	0.05	0.27	17.25	0.78			

4. Discussion

A careful examination of the logs recorded through the three wells Datom (North, West and East) oil field shows two distinctive porous and permeable sand bodies (fig 3),where the shallow reservoir is indicated as Reservoirs (1A,2A,3A)and reservoirs (1B,2B and 3B) as the deeper reservoir of the three wells. The average porosity and net pay permeability are hydrocarbon production friendly and also the consistent decrease of these lithological properties with depth is perhaps due to compaction resulting from the weight of the overburden. While the resistivity logs were used to detect the presence of hydrocarbon in the reservoirs, the combination response (gas effect) of the neutron-density log through the sand units (clastic reservoirs) indicates that the hydrocarbons will dominantly be gas inferred from Figures 4, 6 and 7 [26-27].

The bulk water volume (BVW) of the reservoirs was calculated at several depths and are almost constant (0.06-0.07), this indicates homogeneity of the reservoirs and is validated by the close values of the water saturation (S_W) and irreducible water saturation (S_{wirr})as shown in tables 1,2&3.The implication is that hydrocarbon production from the zones at irreducible water saturation should be water free [28].With a moveable hydrocarbon index (MHI=S_W/S_{XO}) less than 0.7 across the sand units shows favorable hydrocarbon moveability in the reservoirs [29], this is in agreement with the increase in average water saturation (S_{XO}) of the flushed zones relative to water saturation (S_W) across the entire reservoir (table 1,2,3). The average net to gross ratio across the reservoirs (0.7-0.9) is defined using an average porosity ($\emptyset$) and volume of clay (V_{clay}) cut offs values of ≥ 0.1 and ≤ 0.5 respectively (fig 5), validates the high level of clean sand in the reservoirs, such sand bodies confirm that the permeability and porosity are prospective [30-32]. An average hydrocarbon saturation (1-S_W) ranging from 0.6-0.7 (table 1,2,3) indicates that hydrocarbon is relatively higher than water in the reservoir, it is important to note that water saturation does not represent the ratio to hydrocarbon that will be produced from the reservoir but a reflection of relative proportion of the fluids contained in the reservoir.

Petrophysical analysis of the study area revealed average porosity values of 18-22% while the permeability values ranged from 322.70 – 733.20 md across the reservoirs. Hydrocarbon saturation and reservoir thickness across the reservoirs ranges from 66 - 78% and 48-98.50 ft respectively. The escalator regression sedimentation model of the Niger Delta makes it clear that younger sediments are found in the distal part of the basin with pronounced thickness greater than that on the proximal part [33]. Compaction was initiated early in the older rocks of proximal facies of the Depobelts of the Niger Delta and graded down basin ward. Similarly, the net-to- gross across the study area varies from 0.60- 0.9. Since it is well known that the lower the volume of shale the higher the N/G and the better the reservoir quality, therefore the higher N/G values across the study area is indicative of very good hydrocarbon reservoirs. Since it is generally believed by some authors that the sealing capacity of faults in a reservoir is a function of the shale percentage / shale content or the shale-sand ratio in a reservoir, it therefore means that the faults of the reservoir with more shale content may be more sealing than the faults of the reservoir with lower shale content [12,34]. There also seem to be a gradual decrease in sand percentage moving away from the structure building bounding faults towards the distal flanks [35]. The stacked thicknesses of the reservoirs ranging between 18.20-33.86m and 31.48-77.47m for reservoirs Sand_A and Sand_B are relatively high.

5. Summary, Conclusion and Recommendation

Gamma ray, neutron, density, resistivity/conductivity logs were employed in the evaluation and examination of three wells, Datom (North, West and East). Two gas rich bearing sand units were delineated across the formation, with porosity ranging from 0.18 to 0.22 indicating a suitable reservoir quality, Favorable net pay permeability values from 322.70mD to 733.20mD derived from logs and hydrocarbon saturation range of 0.62 to 0.78 implied high hydrocarbon production. These results in addition with the hydrocarbon movability index (MHI) values suggest high hydrocarbon potential and a reservoir system whose performance is considered satisfactory for hydrocarbon production.

However, as relevant as log parameters are, they should not be applied without the consultation of other necessary data like drill stem test, mud log evaluation, sample shows, nearby production etc before taking a decision to drill. Secondly, the hydrocarbon reserve was not estimated due to unavailability of the area extent of the reservoir therefore I recommend that 3-D seismic data should be incorporated to allow for detailed and complimentary study of "Datom" Oilfield, which includes necessary parameters to enable an accurate static and dynamic model of the reservoir to be constructed. This will enhance the geometry of the geologic features, reveal the area extent of prospect zones and reduce inherent uncertainty.

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