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Petrophysical Evaluation of Hydrocarbon Bearing Sands in "MANIN" Marginal Field, Onshore Niger Delta

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Abstract: *Wirelinelog was used in the analysis of the reservoir properties of "Manin" Marginal field, onshore depobelt, Niger Delta. The study essentially focused on determining properties such as lithology, depositional environments and petrophysical properties such as shale volume, porosity (Φ), net pay thickness, net to gross ratio and water saturation. Wireline data of four wells namely well 4, well 7, well 5 and well 11 were evaluated by identifying hydrocarbon bearing sands in each of the four wells and then estimating the petrophysical properties for these reservoirs. The evaluated reservoir sand units mapped were laterally continuous with gamma ray log signatures that are basically cylindrical with a fining upward sequence interpreted as a fluvial dominated channel. The environment of deposition was inferred to be between the foreshores to lower shoreface with reservoirs typically showing a consistent aggradational stacking pattern. A total of four reservoir sand units (A-D) were analyzed for petrophysical parameters such as porosity(Ø), net-pay thickness, volume of shale (V_{sh}), net to gross ratio and water saturation (S_w). Porosity within the field ranged from 25.9-31.9%, volume of shale ranged from 0.204-0.430, while water saturation value ranged from 0.015-0.220. Sand A, B and C had excellent porosity values while sand D had moderate porosity value. The petrophysical properties evaluated reveals possibilities of future drilling prospects in the "Manin" field.*

Key Words*: Niger Delta, Petrophysical properties, Reservoirs, Porosity, Environment of Deposition.*

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I. Introduction

The "Manin" oil field is located onshore with an OML-056 in the Northern Delta depobelt, north-central part of the Niger Delta. It is of extraordinary significance to comprehend the petrophysical properties of reservoir rocks. Exact assessments of certain petrophysical parameters can be produced using wireline logs such as neutron, bulk density and sonic log. Reservoir sands in various depositional situations are described by various sand body shape, size, and heterogeneity; hence this tends to demonstrate that the physical attributes of clastic reservoir rocks mirror the reaction of mind boggling interplay of processes operating in the depositional environments. Likewise, learning of depositional environment of reservoirs through precise interpretation of wire line logs and core data if available allows for a better understanding of reservoir characteristics. A reservoir is said to be commercially productive; if it produces enough oil or gas to pay back its financial investors for the cost of drilling and leaves a benefit.

Numerous studies have attempted to provide better knowledge of reservoir frameworks across the Niger Delta basin in order to reduce the time and cost of exploration especially in challenging environments such as offshore areas. Ulasi *et al.* (2012) integrated core data and petrophysical well log in order to evaluate the reservoir characteristics of Uzek Well in the Offshore Depobelt of the Niger Delta Basin. Eze *et al.* (2013) used petrophysical well logs to evaluate the reservoirs from about three wells in the greater ughelli depobelts in order to ascertain the qualities of the reservoirs and their depositional environment. Ogidi *et al.* (2018) carried out an assessment of the petrophysical characteristics of reservoir sands in 'OTEBE' field using geophysical well logs. In a similar study by Ighodaro *et al.* (2019) petrophysical properties of a well from the onshore Niger Delta oil field were evaluated using well logs in order to determine the hydrocarbon potential. Kafisanwo *et al* (2018) used 3D seismic, well logs and Checkshot data to characterize reservoirs and identify prospects in the Onka field of the offshore Niger Delta.

The purpose of this work was to carry out petrophysical evaluation of hydrocarbon bearing sands in "MANIN" Marginal Field, Onshore Niger Delta in order to determine lithology, delineate depositional environment from gamma ray log motifs and establish the depositional origin and integrate it with the reservoir petrophysical properties. The field is located in the OML-056 in the northern region of the onshore Niger Delta. A total of four wells were drilled in the "Manin" field (figure 1.1).

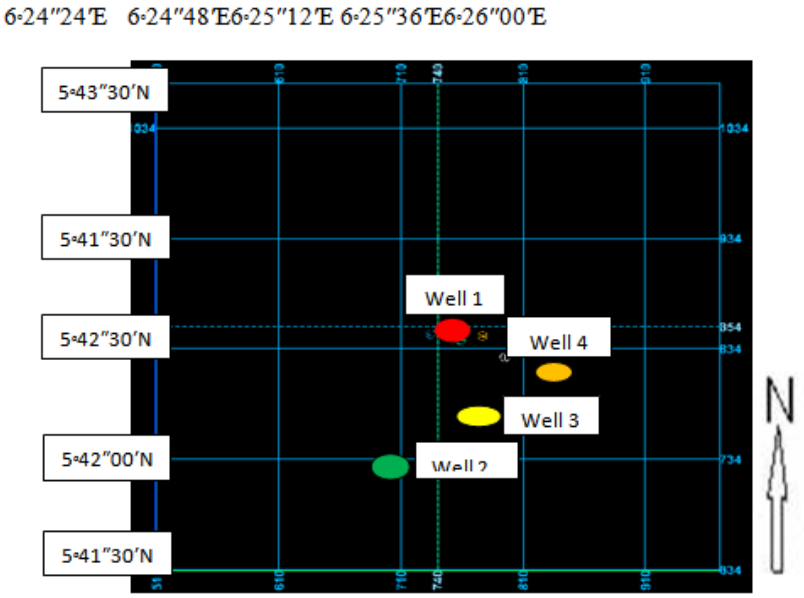

Figure 1.1: Base map of "Manin" field showing the wells onshore Niger Delta.

II. Stratigraphy And Geology Of The Niger Delta

Three major lithostragraphic units have been identified in the Niger Delta basin (Short and Stauble, 1967) (Figure 1.2). Marine shale (Akata Formation): This Formation is characterized by shale as evident on lithology logs such as gamma ray and spontaneous potential log. Akata Formation is plenteous in marine fossils (foraminifera) which constitute over half of the micro-fauna. The environment of deposition of the Akata shales is a shelf setting in the shallow marine depositional medium based on the presence of benthonic foraminifera's assemblage found within them. The Akata Formations age ranges from Eocene to Recent while the Paralic clastic (Agbada Formation) occurs all through the Niger Delta as a bedded sequence of sand and shale. Weber (1971) described this formation as a cyclic sequence of fluvial, marine deposits. Agbada Formation contains predominantly kaolinite (about 75%) with little amounts of mixed-layer illite and montmorillonite. The shales of this formation contain a micro-fauna which is well formed at the bottom of individual shale units. The Agbada Formation is Eocene to Recent in age. The Continental Sands (Benin Formation) contains majorly massive, freshwater–bearing porous sandstones with shales seldom in-between and is often postulated to be of braided stream origin. The sandstones constitute 70 to 100 % of the formation; while where found the shale interbeds predominantly contain some plant remains and dispersed lignite. Most companies prospecting here self-assertively characterize its base as the most profound freshwater-bearing sandstone with very high resistivity. The Benin Formation age varies from Oligocene to Recent.

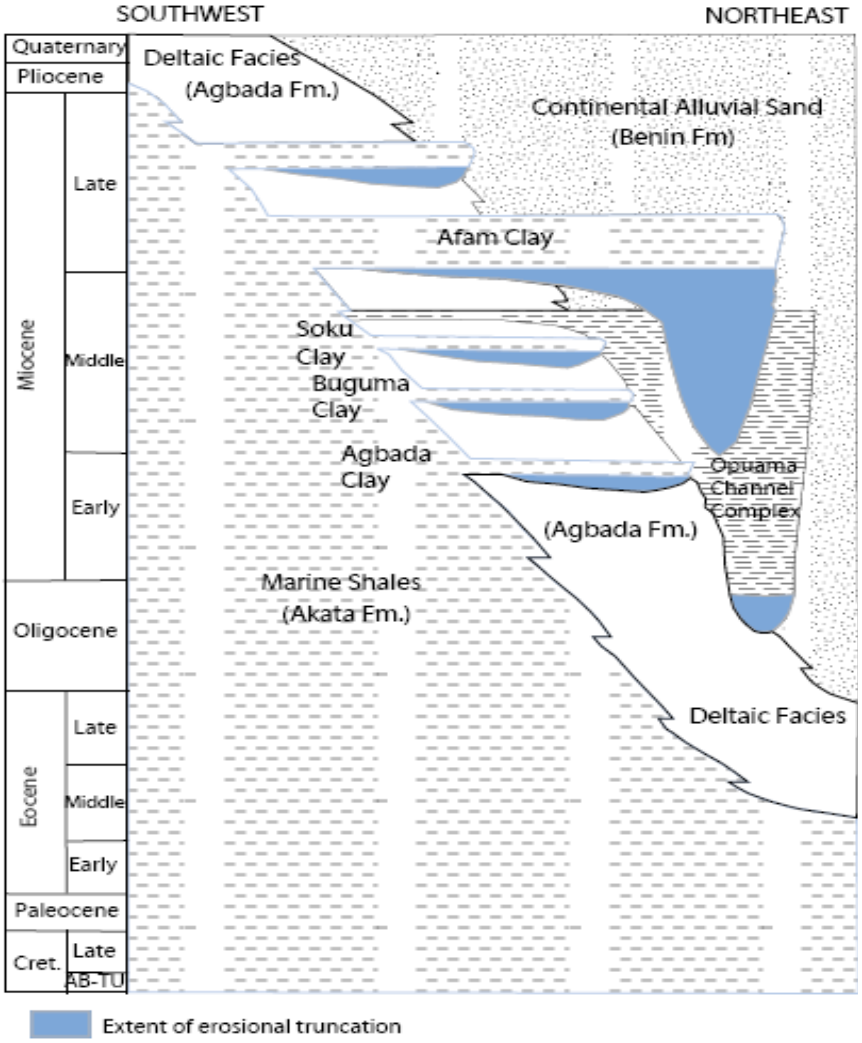

Figure 1.2: Stratigraphic sequence Showing the three Formation of the Niger Delta modified from Doust and Omatsola (1990).

Tectonic evolution of the Niger Delta basin pre-dates post Eocene regressive clastics that are conventionally ascribed to the delta (Frannkl and Cordry, 1967; Weber and Daukoru, 1975). It has also been notably studied in the works of Burke (1972), and Weber and Daukoru (1975) (figure 1.3). Hydrocarbon trapping mechanism in the Niger Delta could be structural, stratigraphic or a combination of both (Figure1.4). The more prevalent structural traps are the rollovers, fault, antithetic or the collapse crest. The traps that are stratigraphic include tidal channel fills which often consist of thin cross-bedded sequences fining upward from a clay pebble/gravel lag at the base. Deposition of all the formations in the Niger Delta occurred in relation to the five offlapping siliciclastic sedimentation (Figure 1.5). These depobelts occurred as a result of sediment supply with subsidence (Doust and Omatsola, 1990). The interaction between these two parameters gave rise to the deposition of other unknown depobelts as a result of other basin subsidence (Doust and Omatsola, 1990).Generally, five noteworthy depobelts are known: Northern Delta depobelts, Coastal swamp depobelts, central swamp depobelts, Greater Ughelli depobelts and Shallow offshore depobelt.

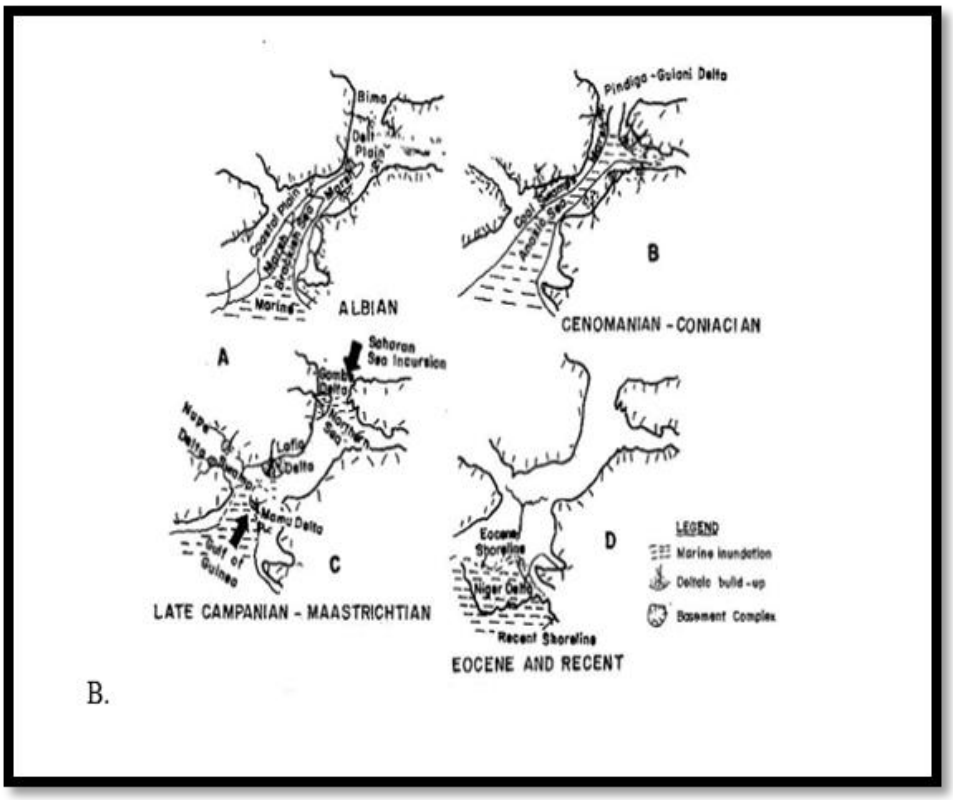

Figure 1.3: Schematic diagrams (A-D) showing crustal evolution and growth of the Niger Delta from failed arm of the rift (R-R-R) triple junction (after Burke, 1972).

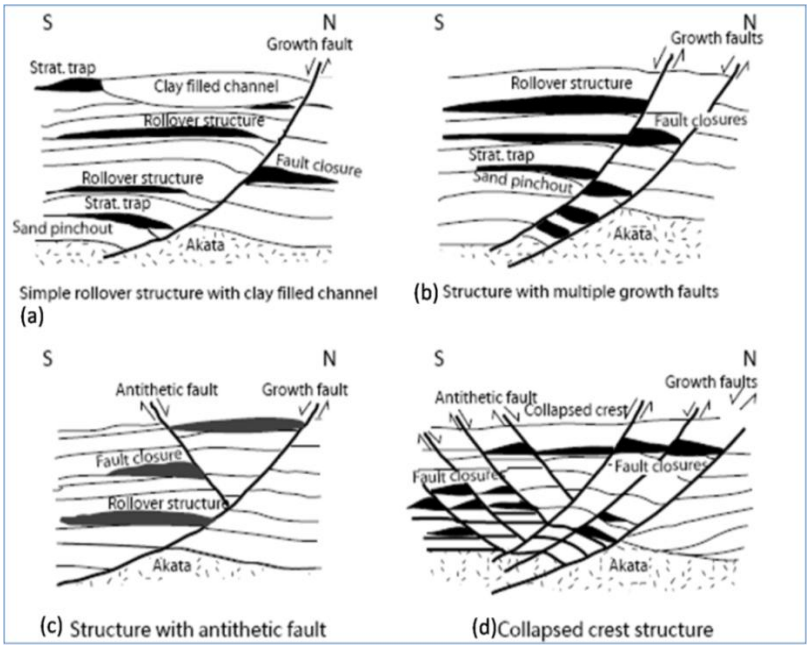

Figure 1.4: Structures related to oil fields in the Niger Delta (Doust and Omatsola, 1990, Stacher, 1995).

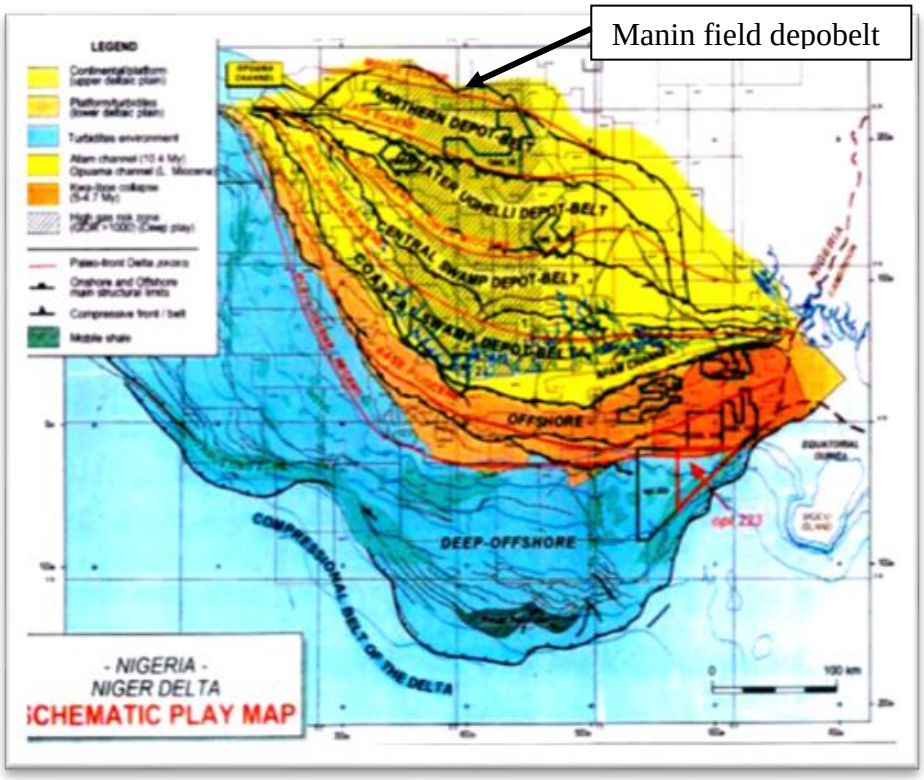

Figure 1.5: "Manin" Field in Niger Delta Showing its Depobelts (Odebode, 2003).

III. Materials And Methods

3.1 Data Sets

The data sets provided includes:

(a) Base map
(b) Well log data for well-4, well-7, well-5 and well-11
(c) Deviation survey for well-4, well-7, well-5 and well-11

3.2 Lithologic Correlation

Lithologic correlation of the four wells in this field was achieved using the interpreted gamma ray log signature of each well. This was done by placing the gamma ray log of each well side by side according to their positions on the base map. Lines of correlations were then drawn to join each of the reservoir sand units across the wells taking note of the presence of geologic structures such as faults.

3.2.1 Establishment of Reservoir Depositional Origin: The integration of Sedimentology and wireline (Gamma ray/Resistivity) log data sets were used to interprete the depositional origin of the field. The sediment types encountered and wireline log responses from the gamma ray logs were put into consideration in establishing the depositional origin.

3.3 Petrophysical Analysis: Petrophysical well log interpretation is a very useful and important tool to a geologist (petroleum) as it is the process of using wireline logs to evaluate the characteristics of a geologic Formation. Formation evaluation was consequently based mostly on wireline logs; they were adequately digitized by reading values from each of their respective tracks. Petrophysical Analysis was done using the software Landmark Geographix.

The properties of primary concern are:

(i) Rock type – lithology
(ii) Fluid type (Gas or oil)
(iii) Reservoir thickness – net pay
(iv) Percentage of pore spaces (occupied by fluids) per unit volume (porosity)
(v) Volume of shale (V_{sh})
(vi) Water Saturation (S_w)

Petrophysical parameters were determined from the following types of wireline logs:

- Gamma Ray Log (GR)
- Resistivity log (LLD)

- Compensated Density log (FDC)
- Compensated Neutron log (CNL)

Petrophysical parameters evaluated include:

(i) Porosity
(ii) Water saturation
(iii) Volume of shale
(iv) Net to gross ratio
(v) Net pay thickness

(i) Porosity Ø

$$\emptyset_{density} = \frac{\rho_{matrix} - \rho_{bulk\ (log)}}{\rho_{matrix} - \rho_{fluid}} \qquad \text{(i)}$$

Where: Ǿ density = porosity estimated from density logs
Pma = density of the matrix
Pb = bulk density of the formation
Pf = density of the fluid

(ii) Water saturation:

The Archie's equation was used to calculate for water saturation

$$S_w = \left(\frac{F \times R_w}{R_t}\right)^{1/n} \text{..... (Archie, 194} \qquad \text{(ii)}$$

Where: S_w = Water saturation
F = Formation factor
R_w = Resistivity of formation water
R_t= True resistivity
N = Saturation exponent (commonly 2.0)

(iii) **Volume of Shale (V_{sh})**

The gamma ray log was used to estimate the volume of shale. This was done by first determining the index of the gamma ray utilizing this equation;

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \qquad \text{(iii)}$$

Where,
I_{GR} = Gamma ray index.
GR_{LOG} = Gamma ray value obtained from log.
GR_{MAX} = Maximum gamma ray reading.
GR_{MIN} = Minimum gamma ray.

(iii) Net-pay thickness: This is the reservoir portion consisting of hydrocarbon fluid only. The net-pay thickness was used to evaluate hydrocarbon thickness value within the reservoirs. Net-pay thickness is estimated by the minus of Gross thickness from the Volume of shale.

(iv) Net/Gross ratio: The tops and bases of the reservoir sands over the wells were utilized to decide the net to gross supply thickness. The gamma beam log which was utilized to decide the repository from non reservoir sands was likewise utilized as a premise to decide the net to gross ratio. It was finished by drawing a shale benchmark and a sand standard on the gamma ray log, the thickness of the shale was subtracted from the gross supply thickness.

IV. Results And Discussion

4.1 Lithologic Correlation: The lithology in the study area was mainly sand and shale with some intermediate nomenclature such as sandy shale, silts and hetroliths in certain parts. Gamma ray logs which measures the natural radioactivity within a Formation was used to reflect the shale contents by the log signature deflection to the right, while in the sands the log signature deflected to the left hence this served as the basis for log correlation as shown in (Figure 1.6).

4.1.2 Geometric Architecture of Reservoir sand Bodies: Based on log view, the reservoirs typically showed a consistent aggradational stacking pattern with thick sand interval. The identified aggrading stacking pattern with thick sand interval may be interpreted as channel deposits (Figure 1.7) with the gamma ray log showing a blocky profile with a weak fining upward sequence pattern and has been interpreted as a fluvial dominated

channel, however channel reservoirs are often disconnected due to minor shale intercalation affecting fluid flow hence, having high chance of vertical connectivity unlike lateral connectivity which will have limitations because of the shale intercalation.

4.1.3 Environment of Deposition from Log Signatures: The integration of gamma ray log patterns which was majorly cylindrical in nature (blocky with sharp top and base) (Figure 1.8), indicated clean sands, the environment of deposition was inferred to be distributary channel-fill (as seen from the scoured or sharp base of the log motif) with alternating energy high and low regimes with minor shoreface deposits.

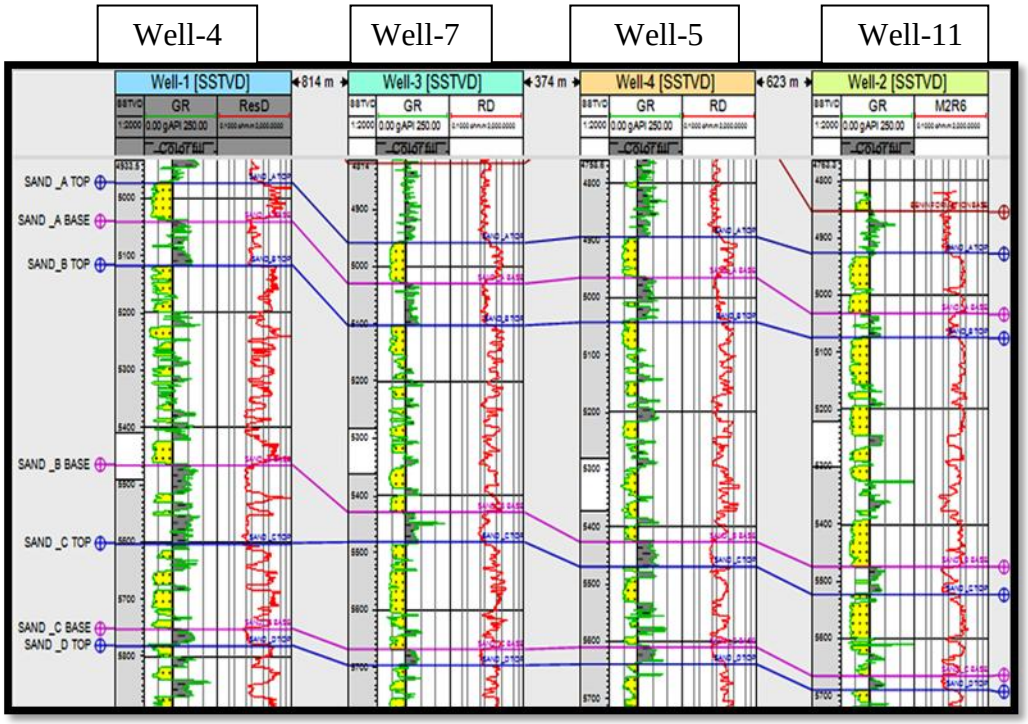

Figure 1.6: Well correlation panel from (Sand-A top-Sand-D top) of the "Manin" Field

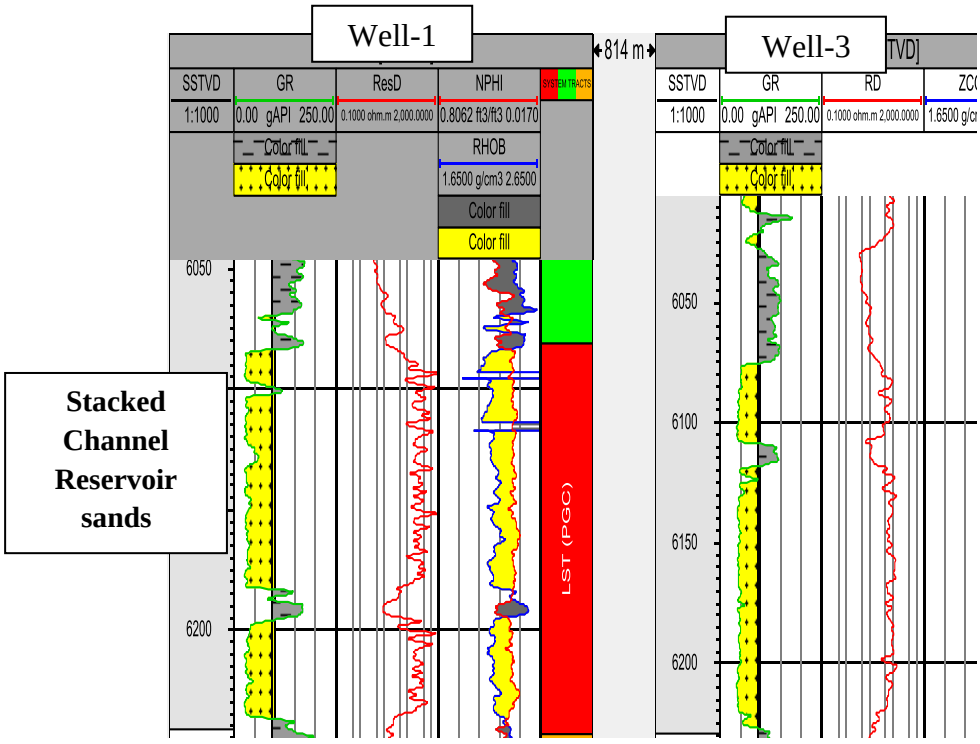

Figure 1.7: Stacked channel reservoir sands in Well-1 and Well-3.

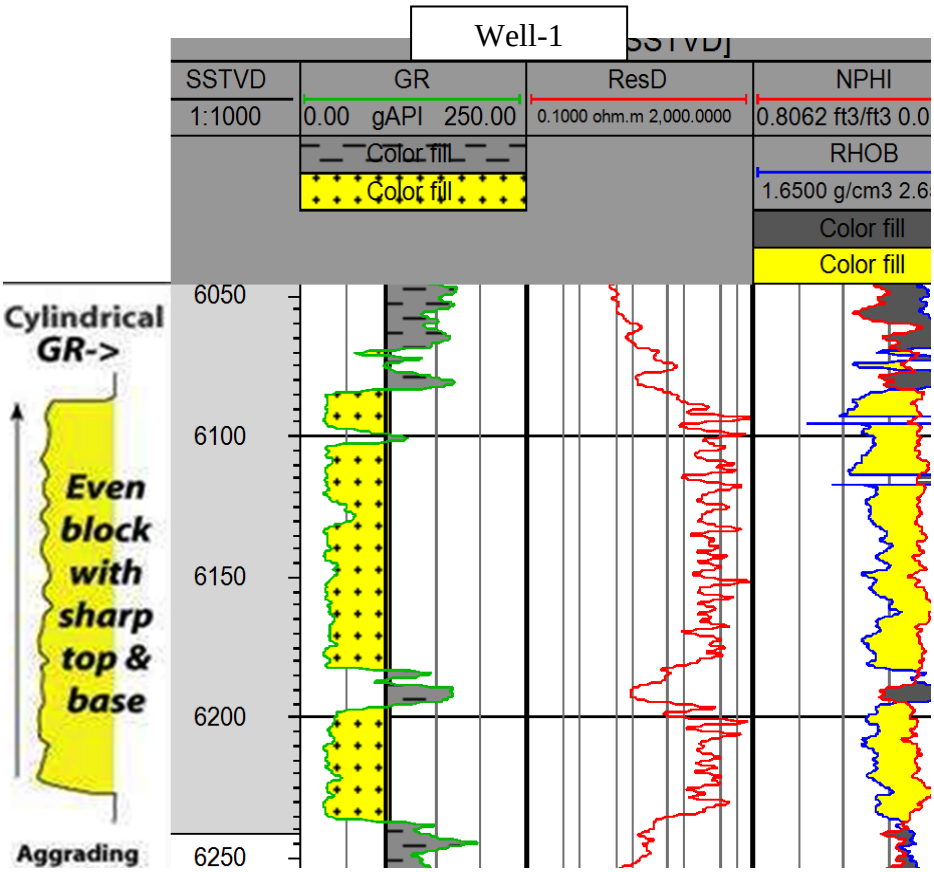

Figure (1.8): Cylindrical shape of Reservoir Sands in the ''Manin" field

4.3 Petrophysical Analysis: A total of four reservoir sands were identified and labeled reservoirs A, B, C and D respectively (Table 1.1 to Table 1.4). Average porosity values within the field were observed to generally decrease with increase in depth, which may be attributed to mainly grain size and sorting effect within the reservoir sands (Pickett, 1960; Beard and Weyl, 1973, Scherer, 1987).

Sand-A: Sand-A was delineated as hydrocarbon bearing in all the wells. In Well-1, the top and base values are 4969.50ft to 5040.00ft (Figure 1.9) with an oil-water contact at 5034.25ft. The reservoir has a gross thickness of 70.500ft and net-pay thickness of 70.476ft with a net to gross ratio of 0.999. The porosity, water saturation and volume of shale values are 30%, 0.228, and 0.024 respectively.

In Well-3, the reservoir top to base depth is 4954.50ft to 5027.75ft (Figure 1.10).The contact type is (ODT) at 5027.75ft, which showed that the sand has oil to the base in this well. The reservoir has a gross thickness of 73.250ft, net-pay thickness of 73.233ft and a net to gross ratio of 0.999. Its porosity, water saturation and volume of shale value are 30.7%, 0.363 and 0.017 respectively.

In Well-4 (Figure 1.11),it was also delineated as hydrocarbon bearing and a top to base depth of 4894.50ft to 4962.00ft. The type of contact was (ODT) at a depth of 4962.00ft. The reservoir's gross thickness was the shallowest of all at a depth of 67.500ft with a net-pay thickness of 67.468ft and net to gross ratio of 0.999. The porosity, water saturation and volume of shale values are 33.1%, 0.346 and 0.346 respectively.

In Well-2, the top to base depth is 4931.75ft to 5037.00ft and oil-water contact (OWC) depth of 5032.75ft (Figure 1.12). The reservoir's gross thickness is 105.250ft, net-pay thickness of 105.235ft and a net to gross ratio of 0.999. Its porosity, water saturation and volume of shale values are 30.1%, 0.392 and 0.015respectively.

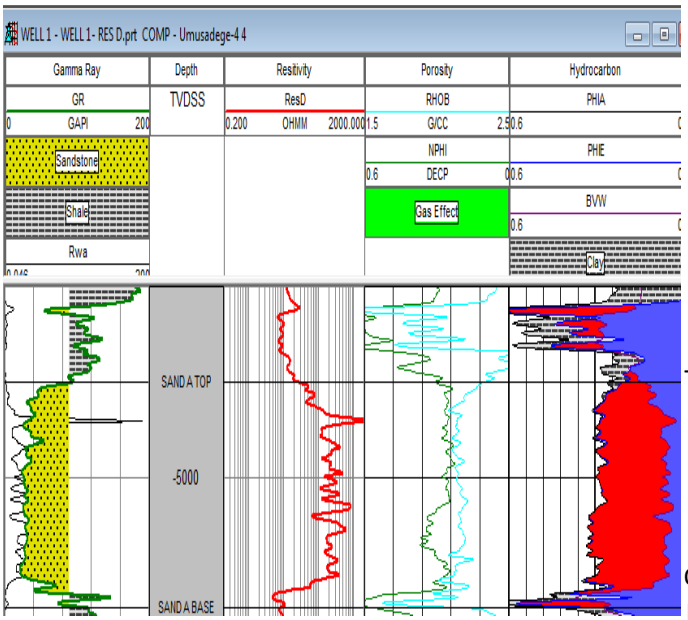

Figure 1.9: Petrophysical Outlook of Sand-A in Well-1

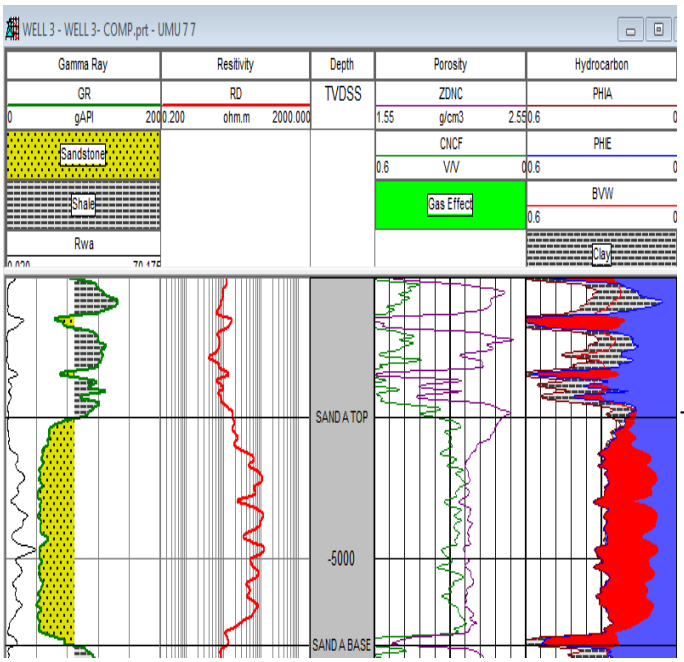

Figure 1.10: Petrophysical outlook of Sand-A in Well-3

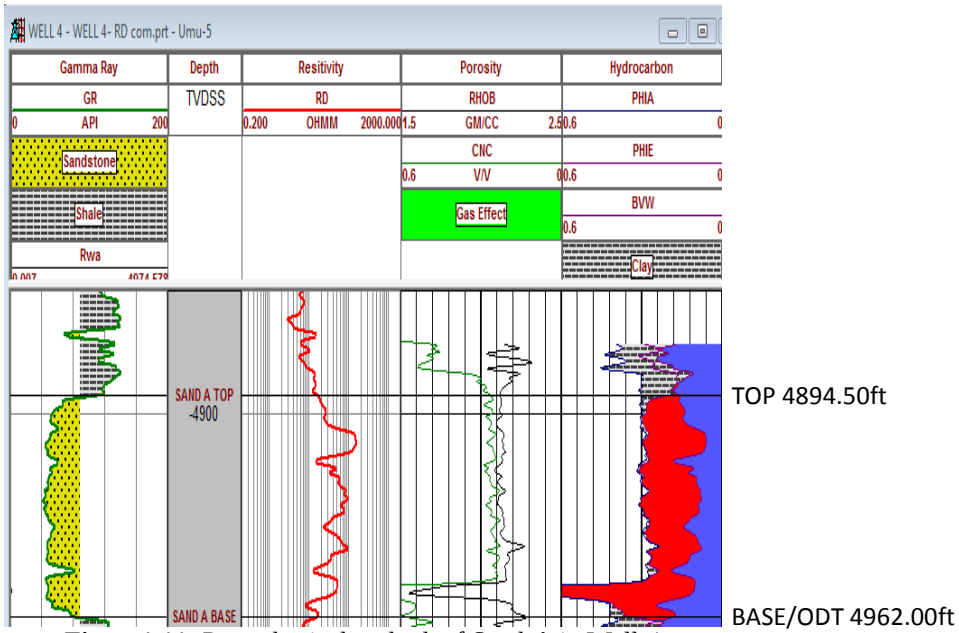

Figure1.11: Petrophysical outlook of Sand-A in Well-4

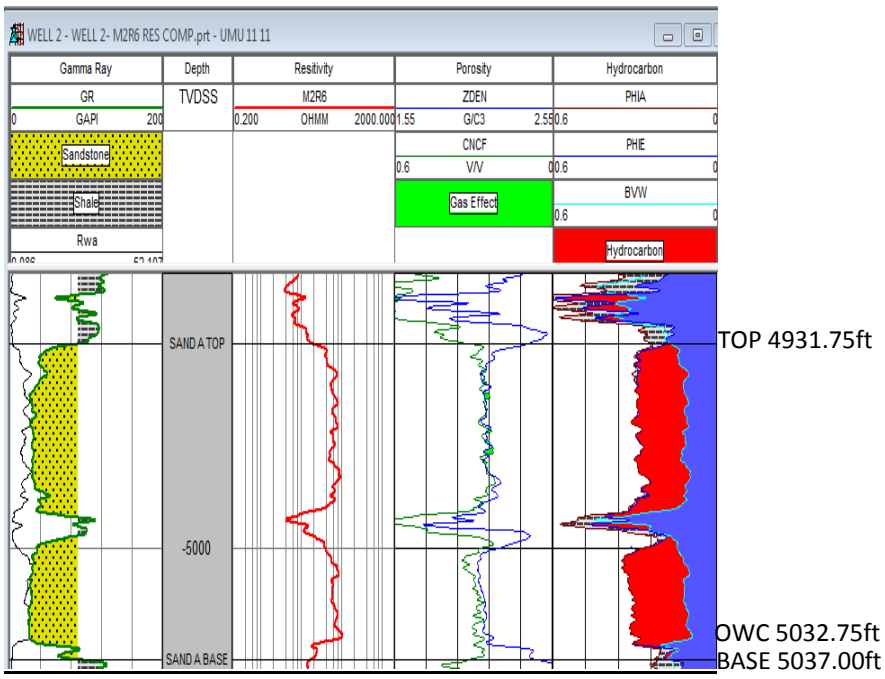

Figure 1.12: Petrophysical Outlook of Sand-A in Well-2

TABLE 1.1: SUMMARY OF PETROPHYSICAL PARAMETERS IN SAND-A

	Well-1	**Well-3**	**Well-4**	**Well-2**
Top (ft)	4969.50	4954.50	4894.50	4931.75
Base (ft)	5040.00	5027.75	4962.00	5037.00
Gross Sand Thickness (ft)	70.500	73.250	67.500	105.250
V_{sh}	0.024	0.017	0.032	0.015
Net-pay (ft)	70.476	73.233	67.468	105.235
Net to gross ratio	0.999	0.999	0.999	0.999
Porosity $\emptyset$ (%)	30	30.7	33.1	30.1
S_w	0.228	0.363	0.346	0.392

Sand-B: Sand-B was delineated as hydrocarbon bearing in all the wells, however, all the wells tested oil till the base (ODT) contacts at 5463.50ft, 5474.50ft, 5430.35ft and 5422.50ft in Well-1, Well-3, Well-4 and Well-2 respectively.

In Well-1 as (figure 1.13), sand-B has a top to base depth of 5116.00ft to 5463.50ft. Its gross reservoir thickness is 347.500ft, net-pay thickness of 347.414ft and a net to gross ratio of 0.999. Its porosity, water saturation and volume of shale (V_{sh}) were 29.2%, 0.299 and 0.086 respectively.

In Well-3 (figure 1.14), the reservoir has a top to base depth of 5101.50ft to 5430.35ft. It has a gross reservoir thickness of 328.850ft making it the third thickest reservoir in the field with a net-pay thickness of 328.766ft and net to gross ratio of 0.999. Its porosity, water saturation and volume of shale values are 31.4%, 0.392, and 0.084 respectively.

In Well-4, Sand-B has a top to base depth of 5038.00ft to 5422.50ft (figure 1.15). The reservoir has a gross thickness of 384.500ft making it the second thickest reservoir in the field, net-pay thickness of 384.401ft and net to gross ratio of 0.999. Its porosity, water saturation and volume of shale values are 31.9%, 0.319 and 0.099 respectively.

Sand-B has a top to base depth of 5072.00ft to 5474.50ft in Well-2 (figure 1.16). It has a gross sand thickness of 402.500ft making it the thickest reservoir in the field, net-pay thickness of 402.450ft and net to gross ratio of 0.999. It has porosity, water saturation, and volume of shale values of 31.9%, 0.400 and 0.050 respectively.

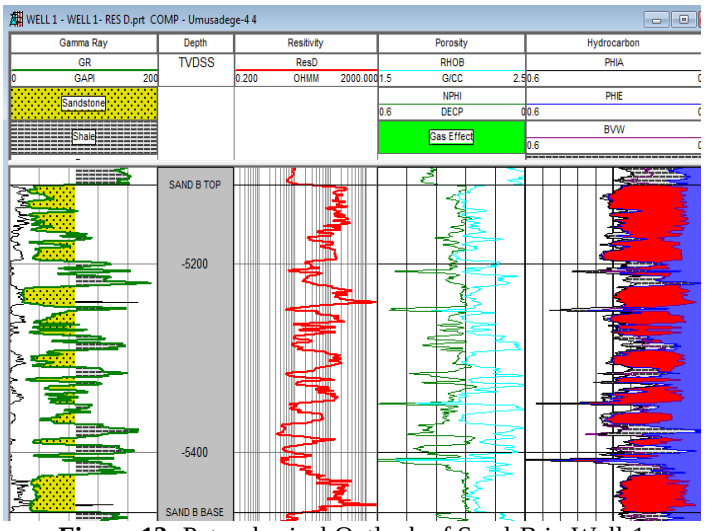

Figure 13: Petrophysical Outlook of Sand-B in Well-1

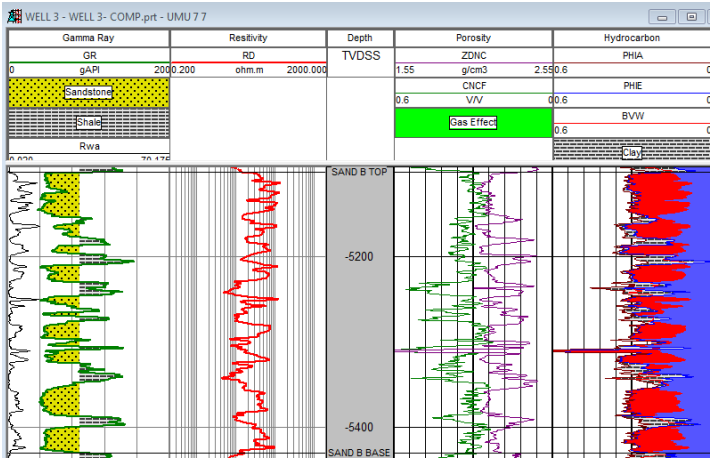

Figure 14: Petrophysical Outlook of Sand-B in Well-3

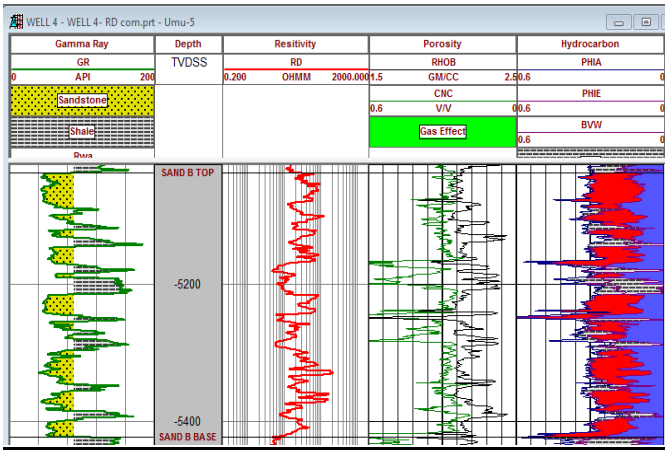

Figure 15: Petrophysical Outlook of Sand-B in Well-4

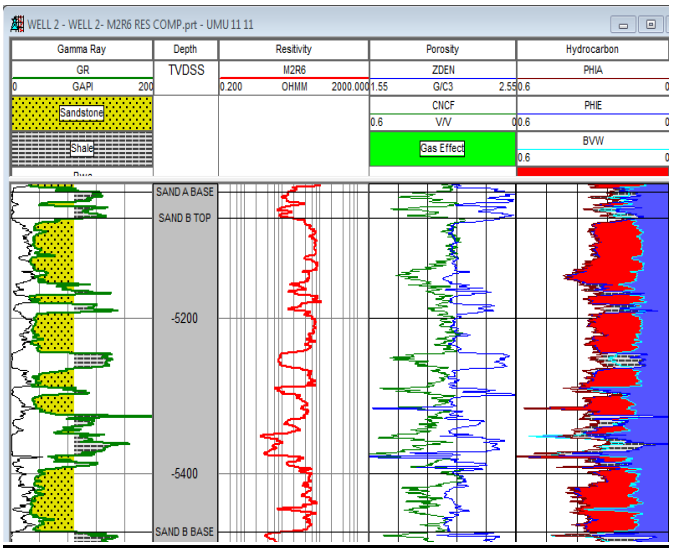

Figure 1.16: Petrophysical Outlook of Sand-B in Well-2

Table 1.2: SUMMARY OF PETROPHYSICAL PARAMETERS IN SAND-B

	Well-1	**Well-3**	**Well-4**	**Well-2**
Top (ft)	5116.00	5101.50	5038.00	5072.00
Base (ft)	5463.50	5430.35	5422.50	5474.50
Gross Sand Thickness (ft)	347.500	328.850	384.500	402.500
V_{sh}	0.086	0.084	0.099	0.050
Net-pay (ft)	347.414	328.766	384.401	402.450
Net to gross ratio	0.999	0.999	0.999	0.999
Porosity Ø (%)	29.2	31.4	31.9	31.9
S_w	0.299	0.392	0.319	0.400

Sand-C: In Sand-C all the wells are hydrocarbon bearing with the reservoirs having moderate to excellent porosity values with the least value in Well-1.

Sand-C in Well-1 has a top to base depth of 5613.75ft to 5750.75ft with an (OWC) at 5748.50ft (figure 1. 17). The reservoir gross sand thickness is 137.000ft, 136.929ft as net-pay thickness and net to gross ratio of 0.999. It has a porosity value of 28.1%, water saturation of 0.305 and shale volume of 0.071.

In Well-3, the top to base depth is 5484.25ft to 5670.00ft with an (OWC) depth of 5666.25ft (figure 1.18). The gross sand thickness is 185.750ft, net-pay 185.699ft and a net to gross ratio of 0.999. The porosity, water saturation and shale volume are 29.9%, 0.389 and 0.051 respectively.

Sand-C in Well-4 has a porosity, water saturation and shale volume values of 31.7%, 0.405 and 0.071 respectively. The top and base depth is 5470.00ft to 5605.50ft with an (OWC) at 5603.50ft (figure 1.19). Its gross sand thickness was 135.500ft, net-pay thickness 135.429ft and a net to gross ratio of 0.999.

In Well-2, the top to base depth is 5520.00ft to 5664.50ft with an (OWC) depth at 5661.25ft (figure 1. 20). The gross thickness was 144.500ft with a porosity value of 31.2%, net-pay thickness of 144.445ft, net to gross ratio of 0.999, water saturation value of 0.406 and shale volume of 0.055.

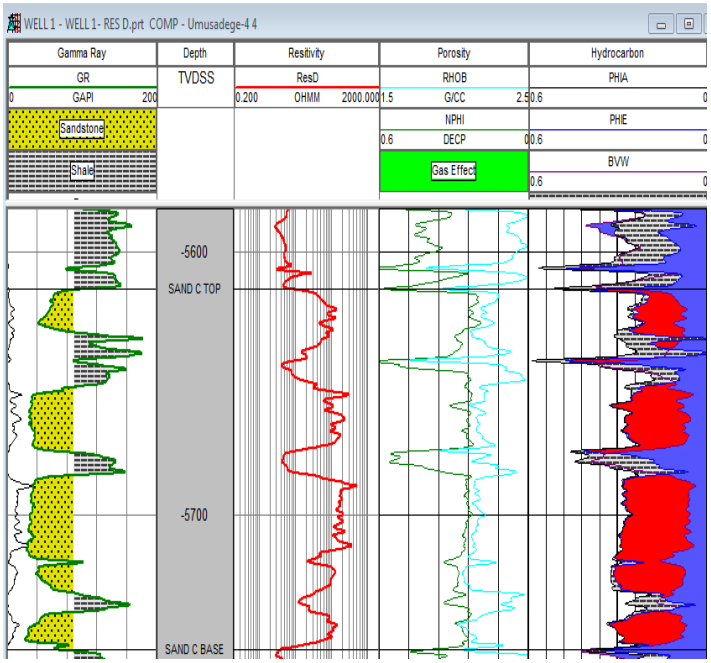

Figure 1.17: Petrophysical Outlook of Sand-C in Well-1

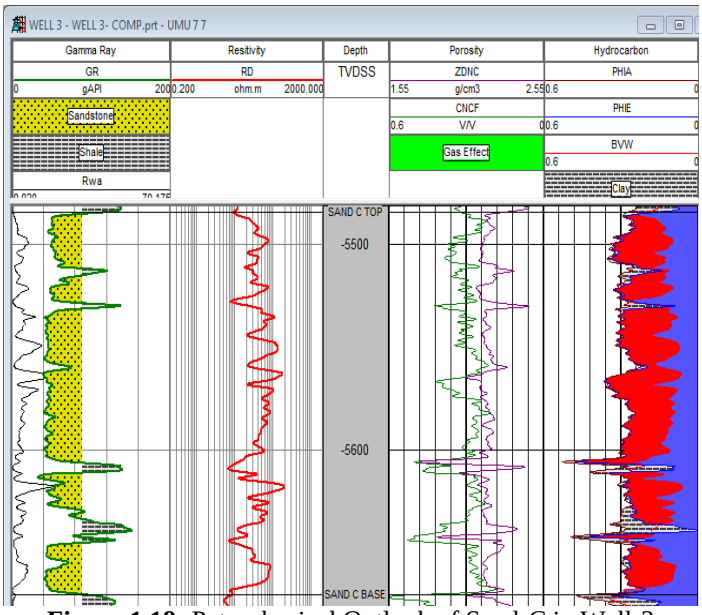

Figure 1.18: Petrophysical Outlook of Sand-C in Well-3

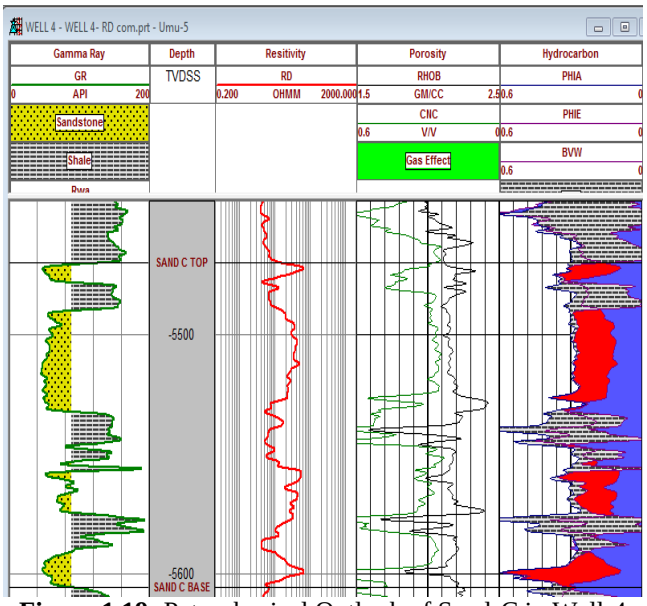

Figure 1.19: Petrophysical Outlook of Sand-C in Well-4

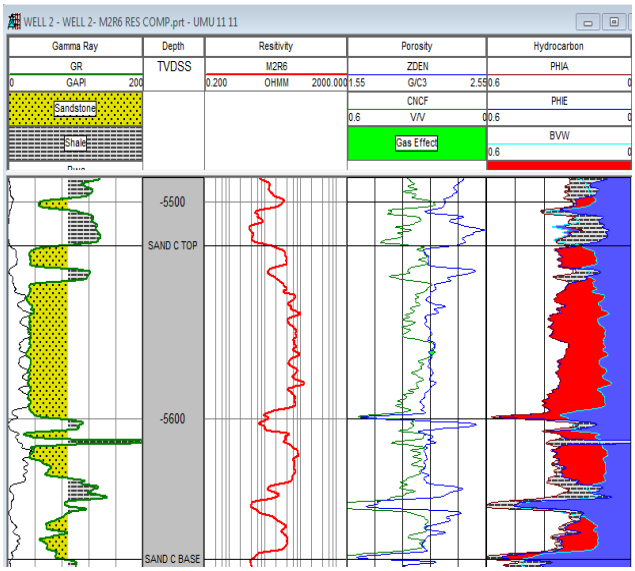

Figure1. 20: Petrophysical Outlook of Sand-C in Well-2

TABLE 1.3: SUMMARY OF PETROPHYSICAL PARAMETERS IN SAND-C

	Well-1	**Well-3**	**Well-4**	**Well-2**
Top (ft)	5613.75	5484.25	5470.00	5520.00
Base (ft)	5750.75	5670.00	5605.50	5664.50
Gross Sand Thickness (ft)	137.000	185.750	135.500	144.500
V_{sh}	0.071	0.051	0.071	0.055
Net-pay (ft)	136.929	185.699	135.429	144.445
Net to gross ratio	0.999	0.999	0.999	0.999
Porosity Ø (%)	28.1	29.9	31.7	31.2
S_w	0.305	0.389	0.405	0.406

Sand-D: Sand-D in Well-1 has a top to base depth of 5778.00ft to 5964.75ft (figure 1.21). It is hydrocarbon bearing with an (ODT) contact depth at 5964.75ft. The gross sand thickness was 186.750ft, 186.666ft net-pay thickness, net to gross ratio of 0.999, porosity of 28.0% and shale volume of 0.084.

In Well-3, Sand-D has a top to base depth of 5695.50ft to 5846.25ft with an (ODT) depth at 5846.25ft (figure 1.22). The gross thickness is 151.250ft, net-pay151.161ft,and net to gross ratio of 0.999.It has a porosity of 29.4%, water saturation of 0.394 and shale volume of 0.089.

Well-4 has a top to base depth is 5634.50ft to 5786.00ft with an (ODT) 5786.00ft (figure 1.23). It has a gross thickness of 151.500ft, net-pay of 151.410ft and net to gross ratio of 0.999. Other petrophysical parameter includes its porosity value of 29.5%, water saturation 0.405 and volume of shale value of 0.090.
In Well-2, the top to base depth is 5689.50ft to 5805.50ft with an (ODT) depth at 5805.50ft (figure 1.24). It has gross sand thickness of 116.000ft, net-pay thickness of 115.934ft, 0.999 net to gross ratio, and porosity value of 31.1%, water saturation of 0.372 and shale volume of 0.066.

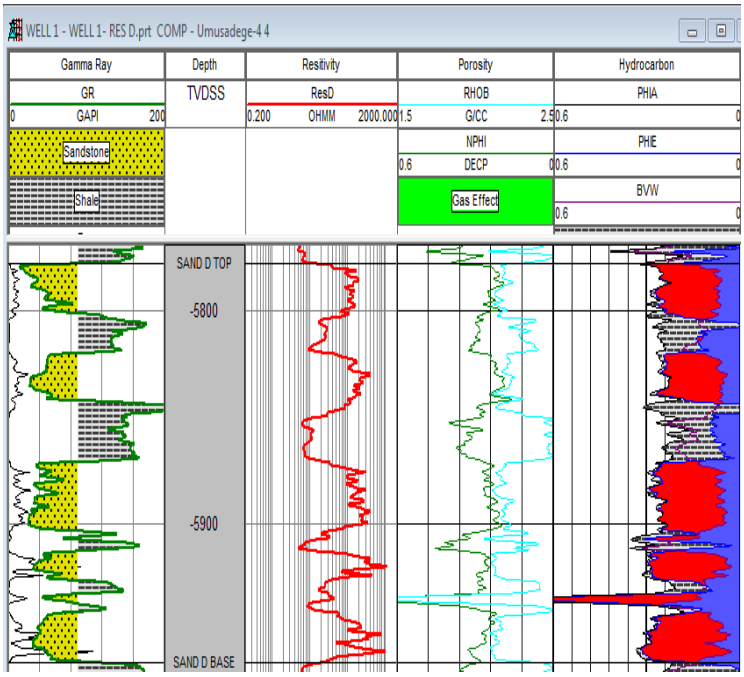

Figure 1.21: Petrophysical Outlook of Sand-D in Well-1

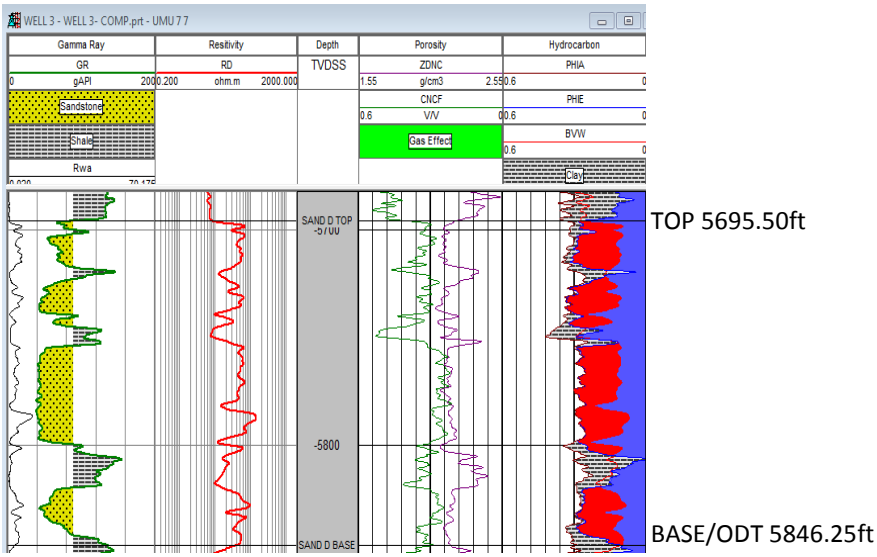

Figure 1.22: Petrophysical Outlook of Sand-D in Well-3

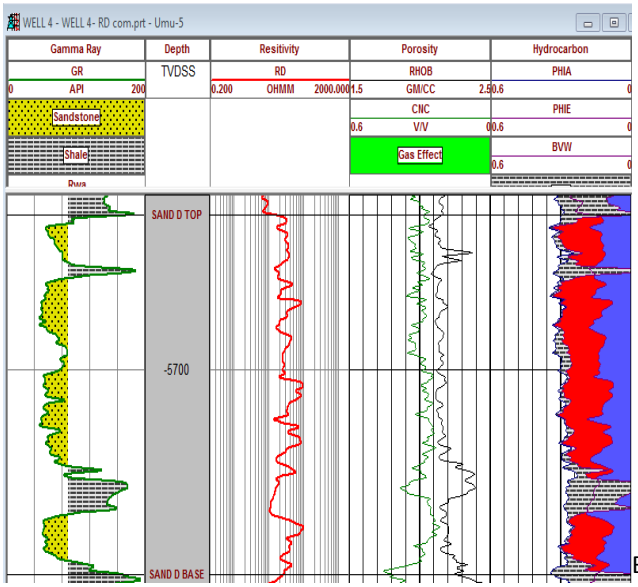

Figure 1.23: Petrophysical Outlook of Sand-D in Well-4

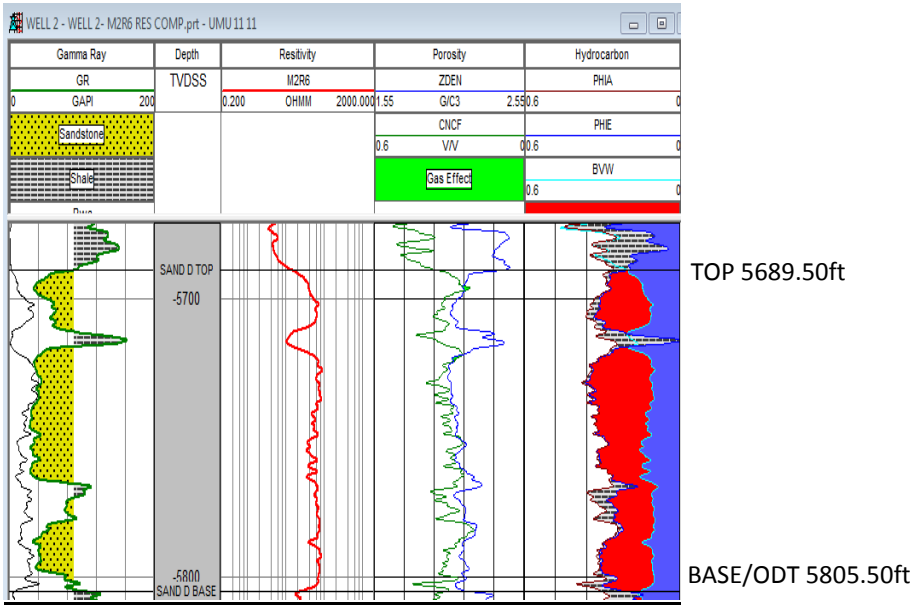

Figure 1.24: Petrophysical Outlook of Sand-D in Well-2

TABLE 1.4: SUMMARY OF PETROPHYSICAL PARAMETERS IN SAND-D

	Well-1	**Well-3**	**Well-4**	**Well-2**
Top (ft)	5778.00	5695.50	5634.50	5689.50
Base (ft)	5964.75	5695.50	5786.00	5805.50
Gross sand thickness (ft)	186.750	151.250	151.500	116.000
V_{sh}	0.084	0.089	0.090	0.066
Net-pay (ft)	186.666	151.161	151.410	115.934
Net to gross ratio	0.999	0.999	0.999	0.999
Porosity Ø (%)	28.0	29.4	29.5	31.1
S_w	0.274	0.394	0.405	0.372

V. Conclusion

Petrophysical properties of the "**Manin"** field were evaluated utilizing wireline logs and the study highlighted the importance of petrophysical parameters in hydrocarbon exploration. The reservoirs typically showed a consistent aggradational stacking pattern with thick sand intervals which is typical of channel deposits, with the gamma ray log having a blocky profile with weak fining upward sequence and can be inferred to be a fluvial dominated channel. However channel reservoirs are often disconnected due to minor shale intercalation affecting fluid flow hence, having high chances of vertical connectivity unlike lateral connectivity

which will have limitations due to the intercalation of shale units. The environment of deposition was inferred to be between the foreshores to lower shoreface environment. The petrophysical evaluation was based on wireline logs and geologic information of the study area. The porosity values ranged from excellent in the shallow parts of the wells to good in the deeper parts, showing a gradual decrease of porosity with increase in depth. All the evaluated reservoir sands had excellent porosity values; hence this reveals excellent plans for future drilling prospects in the "**Manin"** field.

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