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Research Paper

Evaluation of Hydrocarbon Potential in ORSE Field onshore Niger Delta Sedimentary Basin, Nigeria

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ABSTRACT: *Well logs and 3D seismic data were used to evaluate the hydrocarbon potential in ORSE field located onshore Niger Delta sedimentary basin, Nigeria. This study aims at identifying hydrocarbon potential prospects and volumetric analysis in the ORSE field for proper optimization and development. The method adopted involves detailed well correlation with the aid of gamma ray log, resistivity log, density and neutron-porosity log, seismic-to-well tie, calculation of petrophysical properties, structural and stratigraphic interpretation and time-to-depth conversion. Petrophysical modeling was established using Sequential Gaussian Simulation (SGS). Reservoir estimation of the field was done with a stochastic method. The analysis shows that permeability ranges from 1034.98–3113.67 mD and porosity values from 0.11-0.26, suggesting very good to excellent reservoir quality, indicating a probably well sorted coarse-grained sandstone reservoir. Net-to-gross between 0.02-0.86, which implyies more sands than any other rock type in the reservoir. Water saturation ranges from 0.12-0.82 with corresponding hydrocarbon saturation from 0.18 to 0.88, suggesting that the proportion occupied by water in the void spaces is low, hence high hydrocarbon saturation. The average values of these petrophysical parameters were used to rank the three reservoirs, ORSE-01, ORSE-02, and ORSE-03. It was deduced that reservoir ORSE-01 is the most prolific oil reservoir while ORSE-02 is the least within the ORSE field. The Stochastic STOIIP estimation was carried out and the result shows P1 of 83.33 MMSTB, P2 of 50.00 MMSTB and P3 of 30.00MMSTB with an average volume of 50.00 MMSTB, indicating that the reservoir has good hydrocarbon accumulation.*

KEYWORDS: *Reservoir characterization, petrophysical properties, reservoir estimation, volumetric analysis*

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I. INTRODUCTION

The determination of how best a field will produce and the concern with the rock proportion that analyses the quantity, quality, recoverability of hydrocarbon in a reservoir is what petrophysical evaluation is all about [1]. According to [1] a reservoir has to be a formation that has the capacity to store fluid and the ability to release and flow it. The fundamental properties, which determine the potential and performance of a reservoir, include effective porosity, permeability, shale volume, net to gross and hydrocarbon saturation. Their relationships and distribution are used to identify, delineate and analyze reservoirs [1].

Characterization and modeling of the R8-reservoir zone of the Ataga oilfield, Niger Delta was carried out by [2]. Nine reservoirs (R1 to R9) were delineated using six wells and five hydrocarbon-bearing reservoirs were discriminated from Deep resistivity logs. The R8-reservoir (zone of interest) was identified, interpreted and characterized based on pay thickness (10 to 95m), porosity (19-24%) and NTG (63-85%), and water saturation (13–38%). Map and model based volumetric methods were utilized to estimate hydrocarbon volumes in the R8-reservoir. The result of Stock tank oil in place (STOIIP) determined by a with map based volumetic method has an average volume of 97.0MMstb while Stock tank oil in place (STOIIP) calculated with a model based volumetric method has an average volume of 97.8MMstb. The two results show that there was no significant difference in STOIIP using either maps or model-based methods [2].

[3] evaluated reservoirs in 'Jat' Field, Niger Delta, Nigeria to know their quality by using their petrophysical properties through a mathematical relative indexing method. They used results from well log analysis to describe the reservoir properties of the delineated reservoir sands in the study area and relatively rank them. Three reservoirs were delineated (RES 1, RES 2 and RES 3) and correlated in the SW-NE direction across four wells. The reservoir properties considered were lithology, gross thickness, net pay, net to gross (NTG), porosity, permeability and hydrocarbon saturation. The results of the average determined porosity, permeability, NTG and water saturation with respect to each reservoir from RES 1 to RES 3 were 30%, 28%, 29%; 1082md, 2110.75md, 1205.75md; 762%, 82%, 78%; and 48.25%, 54.25%, 51% respectively. The result shows that all the reservoirs can be exploited for hydrocarbon production with RES 1 being the main target for production [3].

The aim of the study is to evaluate hydrocarbon potential in the ORSE field, located in the Swamp depobelt of the onshore Niger Delta Sedimentary Basin, Nigeria (Figure 1) by identifying hydrocarbon potential and carrying out petrophysical evaluation of reservoir rock. The petrophysical parameters to be evaluated include effective porosity, permeability, shale volume, net to gross and hydrocarbon saturation.

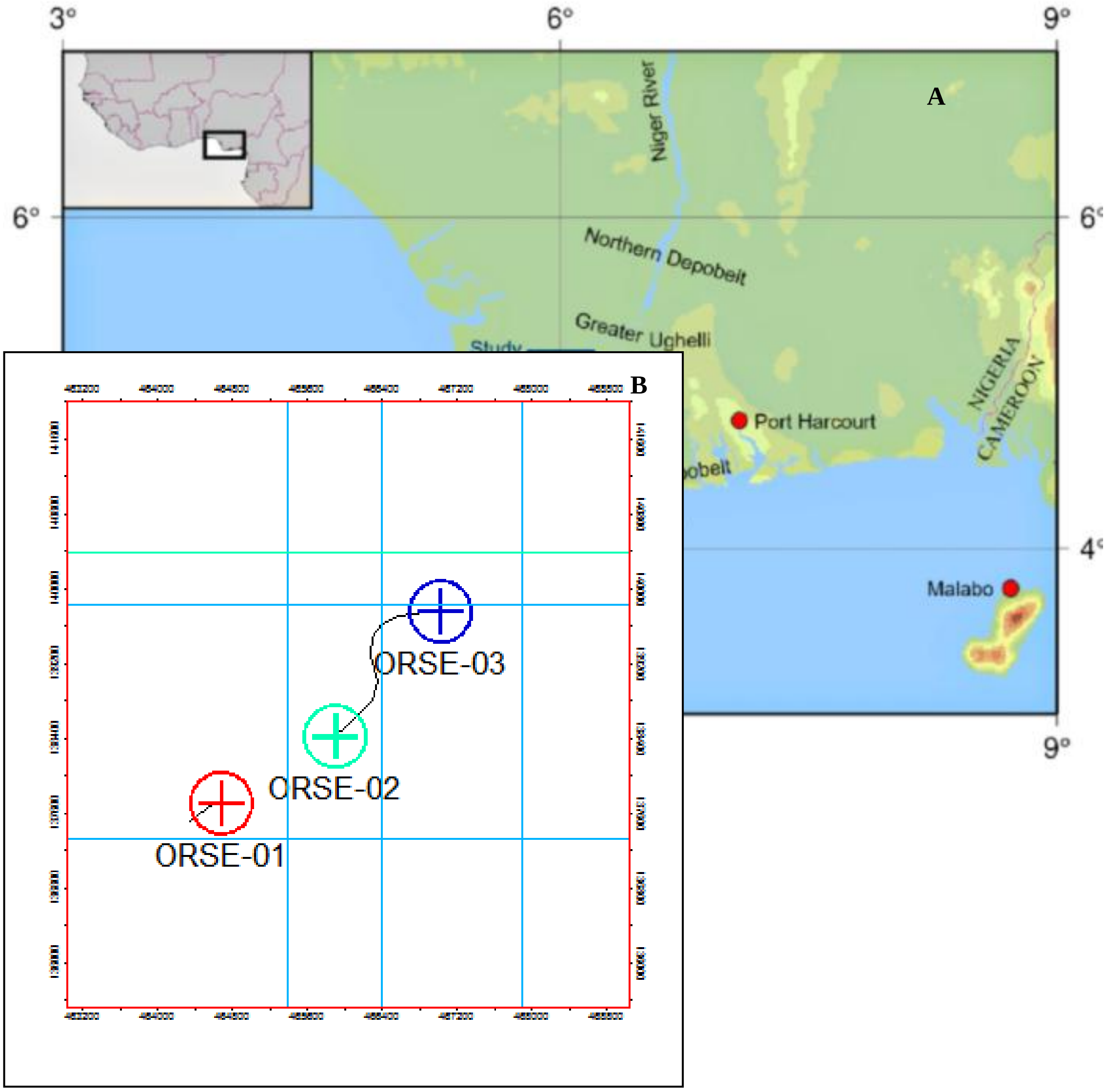

Figure 1: Location of the study area (A) [4] and base map for ORSE field (B)

II. GEOLOGY OF THE STUDY AREA

The Cretaceous history of the Niger Delta and the associated Benue trough was analyzed by [5]. They noticed that the Niger Delta, which is the coastal sedimentary basin of Nigeria, has been the scene of three depositional cycles [5]. Firstly, the marine incursion in the middle Cretaceous terminated by a mild folding phase in Santonian time. Secondly, the growth of a proto-Niger Delta during the Late Cretaceous and ended by a major Paleocene marine transgression and the third cycle from the Eocene to Recent which was the last, began the continuous growth of the main Niger Delta [5]. The Niger Delta is regarded as one of the most prolific oil and gas provinces in the world [6]. The Stratigraphy of the Niger Delta (Figure 2) is subdivided into three distinct formations that are renowned mostly on the premise of their sand-shale ratio [7] from oldest to youngest, that is, from the Akata Formation, Agbada Formation, and Benin Formation [5], with depositional environments ranging from marine, transitional and continental settings respectively [7, 8, 9]. The Benin, Agbada and Akata formations sit on the older Cretaceous Benue trough, meaning they lie over stretched continental and oceanic crusts [10]. Their ages range from Eocene to Recent, yet transgress time boundaries [11, 12].

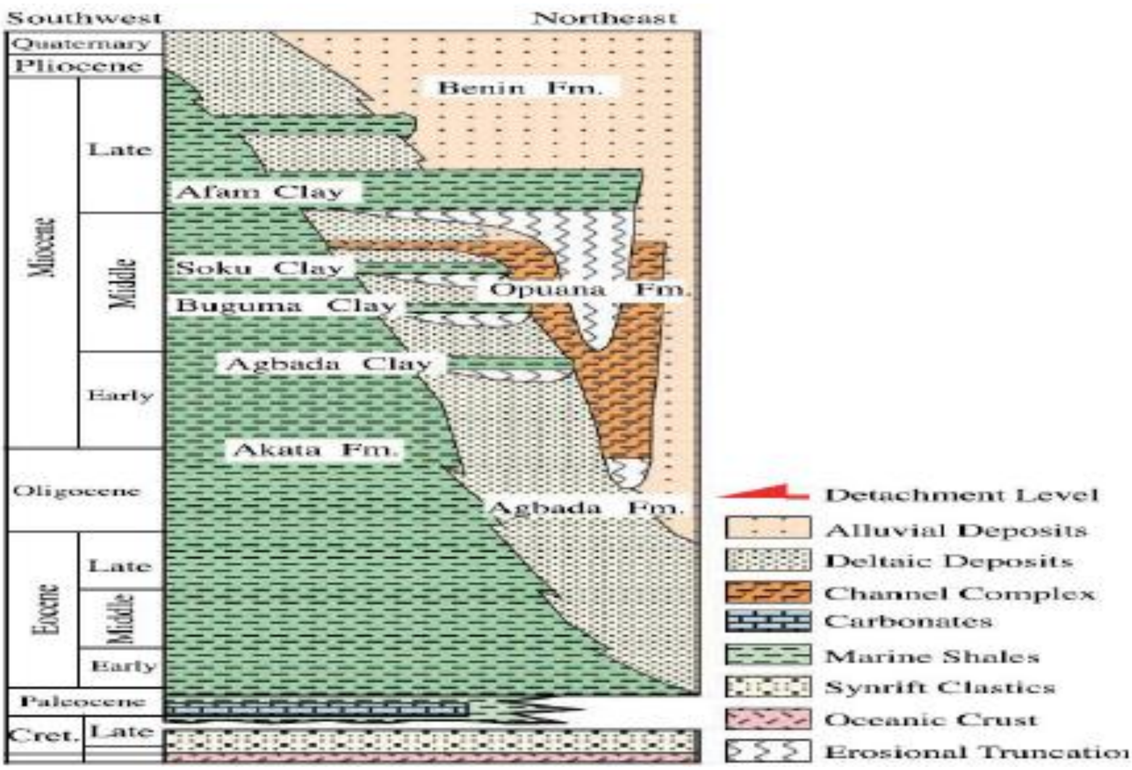

Figure 2: Regional Stratigraphy of the Niger Delta [6.13].

The oldest is the Akata Formation, which comprises marine shales, with a few sandstone lenses, silt, and turbiditic sands with a 20% to 80% sand shale ratio (Figure 2). The Akata Formation is regarded as the primary source rock in the Niger Delta [14]. Resting on the Paleocene Akata Formation is the Eocene Agbada formation composing the interbeddings of sands and shales, which is paralic sedimentation [15] (Figure 2). According to [8], it is within this Agbada paralic section (Agbada Formation) that oil and gas exploitation occurs in the Niger delta, with most of the traps being structural, developed due to synsedimentary deformation [8]. Agbada formation is composed of a 60% to 40% sand shale ratio. The last formation is the youngest in the Delta, the Oligocene Benin Formation, and rests conformably on the Eocene Agbada formation (Figure 2). It has an average thickness of about 3050m and is composed of predominantly Continental River [16]. The Benin Formation's top is composed mainly of alluvium and was deposited in the alluvial or upper coastal plain environments.

III. MATERIALS AND METHODS

Data utilized for this study are 3-D seismic data in segy format, well logs (gamma ray (GR), resistivity (LLD), caliper (CALI), compressional sonic (DT), and density (RHOB) logs) along with well headers and deviation logs for three wells (ORSE-01, ORSE-02 and ORSE-03) in LAS format and a checkshot in ASCII format. Schlumberger Petrel (2014.1 edition) was used for the interpretation (Figure 3). The first step was well correlation. Horizons were picked based on the prospective zones identified from petrophysical analysis of well logs. It was done using gamma ray (GR), resistivity logs (RT), density logs (RHOB) and Neutron logs (NPHI). Eight horizons were mapped and correlated. Tops and Bases of these horizons were mapped and correlated across the three wells. Well-to-seismic tie and synthetic seismogram (Figure 4) was carried out and attuned to the real data. The tops and bases of the horizons were tied to the seismic section to aid the construction of time surface maps and generate subsequent depth maps using the existing checkshot data (Figure 5).

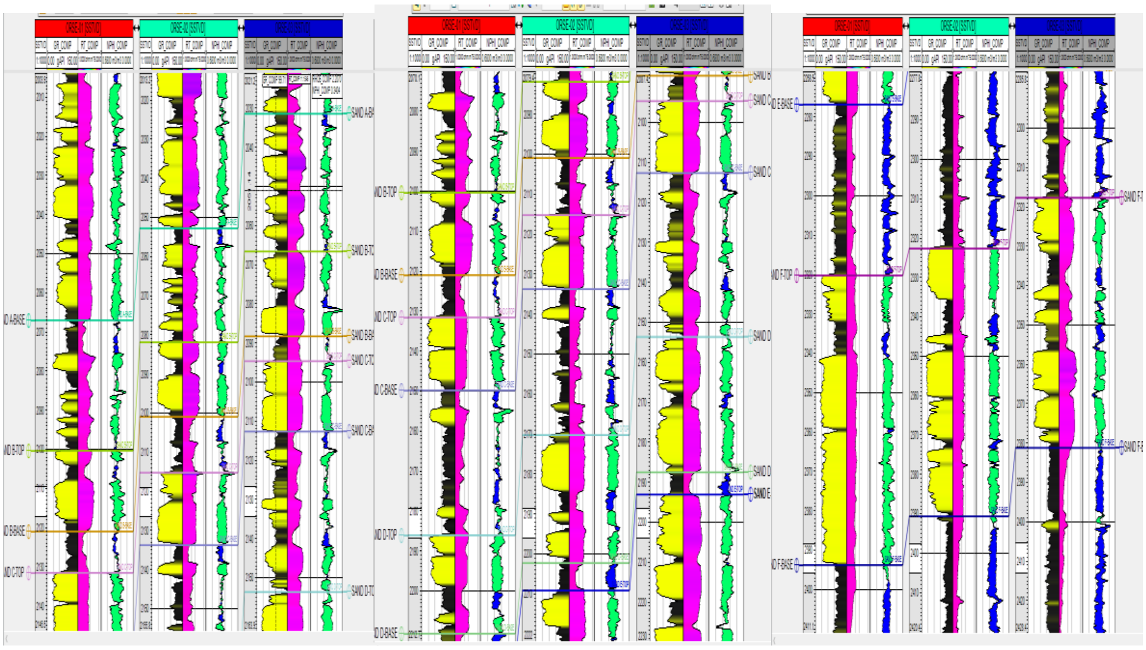

Figure 3: Hydrocarbon bearing Zones identified by Tops and Bases and correlated across the three wells

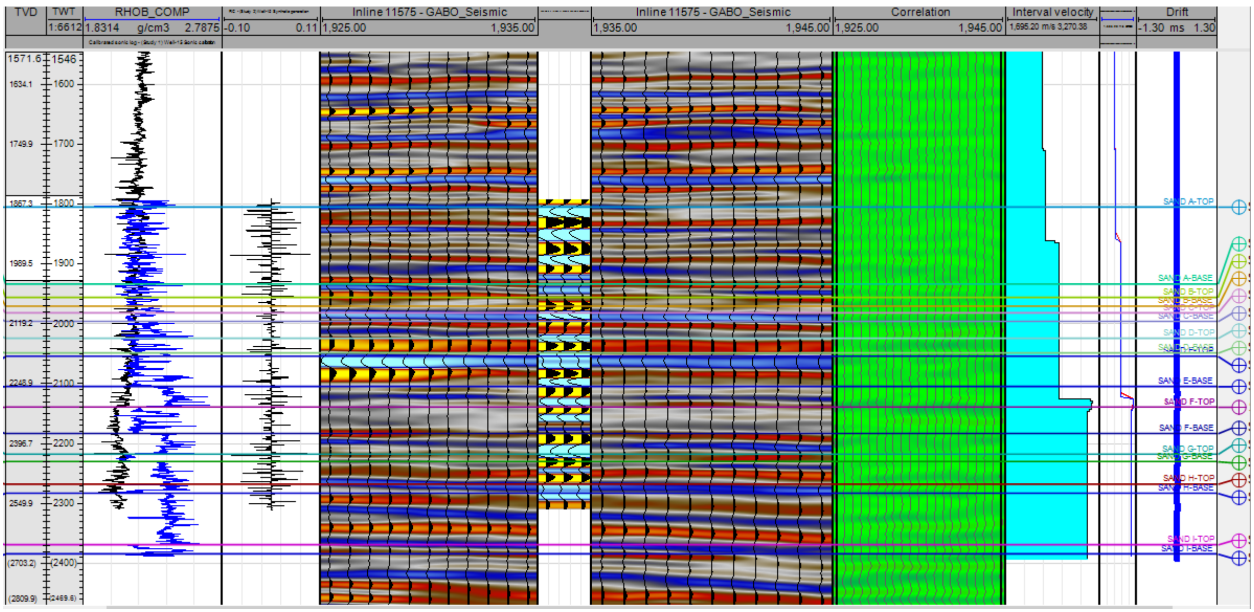

Figure 4: synthetic seismogram was carried out and calibrated to the real data.

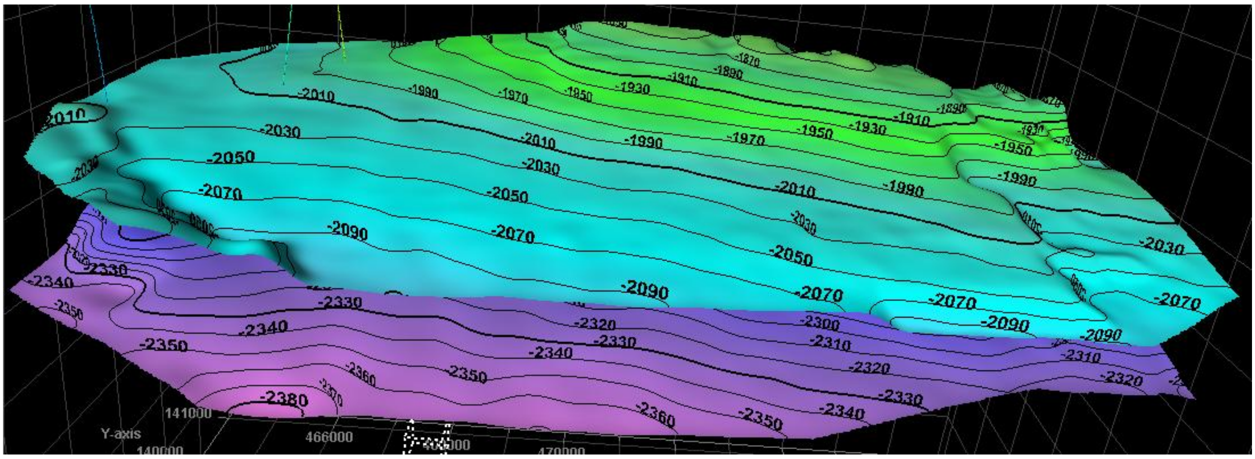

Figure 5: Depth maps were generated using the existing checkshot data.

Reservoir Properties Evaluation: To evaluate the volume of hydrocarbons found within the identified reservoir prospects in the well logs, petrophysical evaluation was conducted using petrophysical parameters and their empirical formulas. The reservoir properties evaluated include volume of shale, porosity (Φ), and water saturation (SW), permeability fluid saturation, net to gross (NTG) and STOIIP. The Gamma ray log was used to discriminate and differentiate the reservoir sands from shales, since shales are more radioactive than sand due to the presence of certain clay minerals within them that are highly radioactive [12]. The resistivity log was used to establish hydrocarbon, while the neutron and density differentiated the fluid types and their respective contacts [17].

Volume of Shale: The volume of shale is the space occupied by shale or the fraction of shale (clay), present in reservoir rock according to [18] was determined from mathematical correlations and gamma ray index (Equations 1and 2) [17, 19, 20, 21].

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad 1$$

I_{GR} = Gamma ray index describes a linear response to shale content
GR_{log} = Log reading at the depth of interest
GR_{min} = Gamma Ray value in a nearby clean sand zone
GR_{max} = Gamma Ray value in a nearby shale

$$V_{SH} = 0.083 * \left(2^{(3.7 * I_{GR})} - 1\right) \quad 2$$

Where V_{SH} is volume of shale

Porosity: The fraction of the bulk volume of a material (rock) that is occupied by pores called porosity, which is expressed in decimal or percentage can represent the total volume of a rock occupied by empty space. Porosity was calculated using Equations 3 and 4 [22, 23]. The void spaces or pores can either be interconnected or isolated. If the pore throats are connected, such type of porosity is referred to as effective porosity. The isolated pores and the interconnected pores combined together give rise to the total porosity.

$$\phi_T = \frac{\rho_{ma} - \rho_{bulk}}{\rho_{ma} - \rho_{fl}} \quad 3$$

ϕ_T is total porosity

ρ_{ma} is matrix density =2.65

ρ_{bulk} is bulk density reading read from density log

ρ_{fl} is fluid density (0.74 for gas, 0.9 for oil and 1.0 for water)

$$\phi_e = (1 - V_{SH}) \times \phi_T \qquad 4$$

ϕ_e is effective porosity

Permeability: Permeability (K) is the ease with which a fluid phase flows through a reservoir. The unit of K is milli-Darcy (mD). According to [24], the permeability equation in Equation 5 is widely used in the Niger Delta.

$$K(mD) = 307 + 26552\left(\phi_e^2\right) - 34540\left(\phi_e \times S_W\right)^2 \qquad 5$$

$K(mD)$ is permeability in milliDarcy

S_W is water saturation

Fluid Saturation Estimation: Fluid saturation in petrophysics comprises of both water and hydrocarbon saturation contents. Saturation is expressed as the fraction, or percent, of the total pore volume occupied by the oil, gas, or water [18].

Water Saturation: According to [25], the fraction of the pore volume that is filled with formation water is water saturation. It is calculated by Archie's formula in Equation 6, [26, 27].

$$S_W = \sqrt[n]{\frac{a}{\phi^m} * \frac{R_w}{R_t}} \qquad 6$$

Where a is a constant, R_w is the formation water resistivity, n is the saturation exponent, m is cementation factor, Φ is porosity and R_t is the true resistivity of the formation. [28] enumerated that the method is substantial for clean, clay-free formations. Generally, $a = 1$, $n = 2$ and $m = 2$; however, for unconsolidated sands (soft formations), $a = 0.62$ and $m = 2.15$ from the Humble formula [28].

Hydrocarbon saturation: Hydrocarbon saturation (S_H) is the proportion of fluid that is (oil and gas) and is derived from the relationship, it is determined by the difference between unity and water saturation (S_w) [29].

$$S_H = 1 - S_w. \qquad 7$$

Net to Gross: Net-to-gross is a measure of the potential of productive part of a reservoir. According to [30], the net to gross calculation is used to differentiate the reservoir productive pay zone from the non-productive shale zone. It is usually expressed either as a fraction or percentage of the producible (net) reservoir within the overall (gross) reservoir packages. It varies from just a few percentages to 100% and it is expressed as:

$$Net - to - gross = \frac{NT}{GT} \times 100 \qquad 8$$

NT is net thickness
GT is gross thickness

The gross thickness is the base depth of the reservoir minus the top depth. The gross thickness minus the shale volume (in meters) gives the net sand thickness (Clean sand).

Hydrocarbon Reserve Calculation: Hydrocarbon reserves were estimated by deterministic and stochastic based approach. Equation 9 shows the basic equation used for the hydrocarbon volume estimation [17].

$$STOIIP = \frac{7758 \times A \times h \times NTG \times (1 - S_w)}{FVF} \qquad 9$$

Where:
A is oilfield closure area (m^2)
h is gross thickness (m)h
FVF is the formation volume factor

IV. RESULTS AND DISCUSSION

The petrophysical properties estimated include shale volume, porosity, net to gross, permeability, water saturation, hydrocarbon saturation and STOIIP. From the analysis of the Gamma ray logs, two lithologies (sand and shale) from top to bottom in the three wells (ORSE-01, ORSE-02 and ORSE-03) were revealed. Five reservoir units (A, B, C, D and E) were identified and correlated across the three wells (Figure 3).

Gross Thickness: The gross thickness of a reservoir is the entire thickness from the top of the reservoir to the base of the reservoir. The thickness of the reservoirs varies from one well to the other across the field. The thickness of reservoir A is 191ft (58.22m) in ORSE-01 well, 155ft (47.24m) in ORSE-02 well and 103ft (31.39m) in ORSE-03 well (Table 1). Reservoir B has a thickness of 323ft (98.45m) in ORSE-01, 19ft (5.79m) in ORSE-02 and 21ft (6.40m) in ORSE-03. Reservoir C has a thickness of 18ft (5.49m) in ORSE-01, 24ft (7.32m) in ORSE-02 and 18ft (5.49m) in well ORSE-03. Reservoir D has a thickness of 25ft (7.62m) in ORSE-01, 32ft (9.75m) in ORSE-02 and 34ft (10.36m) in ORSE-03. Similarly, reservoir E had varying thicknesses across all three wells. The thickness of reservoir E is 60ft (18.29m) in ORSE-01, 71ft (21.64m) in ORSE-02 and 73ft (22.25m) in ORSE-03 (Table 1).

Table 1: Gross Thickness of five reservoir units for three wells in the ORSE-field

Petrophysical property	Wells / Reservoirs	ORSE-01	ORSE-02	ORSE-03
Gross thickness ft (m)	A	191(58.22)	155(47.24)	103(31.39)
	B	323(98.45)	19(5.79)	21(6.40)
	C	18(5.49)	24(7.32)	18(5.49)
	D	25(7.62)	32(9.75)	34(10.36)
	E	60(18.29)	71(21.64)	73(22.25)

Shale Volume (Vsh): Shale volume is the percentage of shale contained within the reservoir. The higher the shale content, the poorer the reservoir quality to yield hydrocarbons. This is because shale acts as barrier to the flow of hydrocarbon. The shale volume of reservoir A is 103.14ft (54%) in ORSE-01 well, 96.5ft (62%) in ORSE-02 well and 28.99ft (28%) in ORSE-03 well (Table 2). Reservoir B has a shale volume of 171.19ft (53%) in ORSE-01, 2.68ft (14%) in ORSE-02 and 3.81ft (18%) in ORSE-03. Reservoir C has a shale volume of 7.38ft (41%) in ORSE-01, 8.54ft (36%) in ORSE-02 and 2.49ft (14%) in ORSE-03. Reservoir D has a shale volume of 4ft (16%) in ORSE-01, 31.424ft (98%) in ORSE-02 and 14.51ft (25%) in ORSE-03. Similarly, reservoir E had varying shale volumes across all three wells. The shale volume of reservoir E is 19.2ft (32%) in ORSE-01, 48.41ft (68%) in ORSE-02 and 22.33ft (31%) in ORSE-03 (Table 2).

Table 2: Shale volume of five reservoir units for three wells in the ORSE-field

Petrophysical property	Wells / Reservoirs	ORSE -01	ORSE -02	ORSE -03
Shale Volume ft (%)	A	103.14(54%)	96.5(62%)	28.99 (28%)
	B	171.19(53%)	2.68(14%)	3.81(18%)
	C	7.38(41%)	8.54(36%)	2.49(14%)
	D	4(16%)	31.424(98%)	14.51(25%)
	E	19.2(32%)	48.41(68%)	22.33(31%)

Net thickness: The reservoir net thickness is the proportion of the reservoir (clean sand) that can be produced. The net reservoir thickness is obtained after the shale volume is removed from the overall gross volume of the reservoir. The net sand thickness of reservoir A is 87.86ft (26.78m) in ORSE-01 well, 58.5ft (17.83m) in ORSE-

02 well and 74.01ft (22.56m) in ORSE-03 well (Table 3). Reservoir B has a net sand thickness of 151.81ft (46.27m) in ORSE-01, 16.32ft (4.97m) in ORSE-02 and 17.19ft (5.24m) in ORSE-03. Reservoir C has a net sand thickness of 10.62ft (3.24m) in ORSE-01, 15.46ft (4.71m) in ORSE-02 and 15.51ft (4.73m) in well ORSE-03. Reservoir D has a net sand thickness of 21ft (6.40m) in ORSE-01, 0.58ft (0.18m) in ORSE-02 and 19.49ft (5.94m) in ORSE-03. Similarly, reservoir E had varying net sand thicknesses across all three wells. The net sand thickness of reservoir E is 40.8ft (12.44m) in ORSE-01, 22.59ft (6.89m) in ORSE-02 and 50.67ft (15.44m) in ORSE-03 (Table 3).

Table 3: Net sand of five reservoir units for three wells in the ORSE-field

Petrophysical property	**Wells / Reservoirs**	**ORSE-01**	**ORSE-02**	**ORSE-03**
Net sand ft (m)	**A**	87.86(26.78)	58.5(17.83)	74.01(22.56)
	B	151.81(46.27)	16.32(4.97)	17.19(5.24)
	C	10.62(3.24)	15.46(4.71)	15.51(4.73)
	D	21(6.40)	0.58(0.18)	19.49(5.94)
	E	40.8(12.44)	22.59(6.89)	50.67(15.44)

Net to Gross: The net to gross is the ratio of the thickness of the clean sand (net sand thickness) divided by the total gross thickness of the reservoir. The net to gross gives an indication of the total amount of the reservoir section that can be produced. The larger the net to gross value (in percentage), the better the quality of the reservoir. The net to gross ratio of reservoir A is 46% in ORSE-01 well, 38% in ORSE-02 well and 72% in the ORSE-03 well (Table 4). Reservoir B has a net sand thickness of 47% in ORSE-01, 86% in ORSE-02 and 82% in ORSE-03. Reservoir C has a net sand thickness of 59% in ORSE-01, 64% in ORSE-02 and 86% in ORSE-03. Reservoir D has a net sand thickness of 84% in ORSE-01, 2% in ORSE-02 and 57% in ORSE-03. Similarly, reservoir E had varying net to gross ratios across all three wells. The net to gross ratio of reservoir E is 68% in ORSE-01, 32% in ORSE-02 and 69% in ORSE-03 (Table 4).

Table 4: Net to Gross of five reservoir units for three wells in the ORSE-field

Petrophysical property	**Wells / Reservoirs**	**ORSE-01**	**ORSE-02**	**ORSE-03**
Net to Gross (%)	**A**	46%	38%	72%
	B	47%	86%	82%
	C	59%	64%	86%
	D	84%	2%	57%
	E	68%	32%	69%

Porosity: The total porosity is the sum total of both the interconnected pores and the isolated pore spaces. The porosity relevant for hydrocarbon production is the effective porosity. The effective porosity is the sum of all the interconnected pore throats. The total and effective porosity of reservoir A are 31% and 11% in ORSE-01 well, 28% and 14% in ORSE-02 well and 23% and 20% in ORSE-03 well (Tables 5 and 6). Reservoir B has a total and effective porosity of 25% and 23% in ORSE-01, 30% and 26% in ORSE-02 and 19% and 17% in ORSE-03. Reservoir C has a total and effective porosity of 22% and 19% in ORSE-01, 21% and 19% in ORSE-02 and 26% and 24% in ORSE-03. Reservoir D has a total and effective porosity of 23% and 21% in ORSE-01, 25% and 23% in ORSE-02 and 26% and 23% in ORSE-03. Similarly, reservoir E had varying total and effective porosities across all three wells. The total and effective porosity of reservoir E is 21% and 19% in ORSE-01, 19% and 12% for ORSE-02 and 16% and 14% in ORSE-03 (Tables 5 and 6).

Table 5: Total Porosity of five reservoir units for three wells in the ORSE-field

Petrophysical property	**Wells / Reservoirs**	**ORSE-01**	**ORSE-02**	**ORSE-03**
Total Porosity (%)	**A**	31%	28%	23%
	B	25%	30%	19%
	C	22%	21%	26%

	D	23%	25%	26%
	E	21%	19%	16%

Table 6: Effective Porosity of five reservoir units for three wells in the ORSE-field

Petrophysical property	Wells / Reservoirs	ORSE-01	ORSE-02	ORSE-03
Effective Porosity (%)	**A**	11%	14%	20%
	B	23%	26%	17%
	C	19%	19%	24%
	D	21%	23%	23%
	E	19%	12%	14%

Permeability: Permeability is the ability of fluids to flow through a reservoir rock. The permeability of reservoir A is 1657.879mD in the ORSE-01 well, 1147.89mD in ORSE-02 well and 1034.98 mD in ORSE-03 well (Table 7). Reservoir B has a permeability of 1587.94mD in ORSE-01, 2362.69mD in ORSE-02 and 1360.89mD in ORSE-03. Reservoir C has a permeability of 2767.47mD in ORSE-01, 2844.75mD in ORSE-02 and 2585.65mD in ORSE-03. Reservoir D has a permeability of 3113.67mD in ORSE-01, 2240.27mD in ORSE-02 and 2692.72mD in ORSE-03. Similarly, reservoir E had varying permeabilities across all three wells. The permeability of reservoir E is 3023.44mD in ORSE-01, 2992.90mD in ORSE-02 and 1386.66mD in ORSE-03 (Table 7).

Table 7: Permeabilityof five reservoir units for three wells in the ORSE-field

Petrophysical property	Wells / Reservoirs	ORSE-01	ORSE-02	ORSE-03
Permeability (mD)	**A**	1657.879	1147.89	1034.98
	B	1587.94	2362.69	1360.89
	C	2767.47	2844.75	2585.65
	D	3113.67	2240.27	2692.72
	E	3023.44	2992.90	1386.66

Fluid type: In a reservoir rock, three types of fluids are commonly found in the pores. The fluids can either be gas, oil, water (fresh or brine) or a combination of two or the entire three fluid phases. The resistivity log was used to determine the presence of oil and water in the reservoirs because oil is much more resistive and water is less resistive. Hence, a sharp increase in the resistivity log measurement indicated the presence of oil water contact in the reservoir (Table 8).

Table 8: Fluid type within reservoirs

Reservoirs / Wells	A	B	C	D	E
ORSE-01	Oil	Oil	Oil	Oil	Oil
ORSE-02	Oil	Oil	Oil	Oil and water	Oil and water
ORSE-03	Oil	Oil	Oil	Oil	Oil

The water saturation of reservoir A is 23% in ORSE-01 well, 15% in ORSE-02 well and 22% in ORSE-03 well (Table 9). Reservoir B has a water saturation of 12% in ORSE-01, 13% in ORSE-02 and 20% in ORSE-03. Reservoir C has a water saturation of 12% in ORSE-01, 41% in ORSE-02 and 14% in ORSE-03. Reservoir D has a water saturation of 17% in ORSE-01, 82% in ORSE-02 and 14% in well ORSE-03. Similarly, reservoir E had varying Water saturations across all three wells. The water saturation of reservoir E is 19% in ORSE-01, 37% in ORSE-02 and 15% in ORSE-03. The hydrocarbon saturation of reservoir A is 77% in ORSE-01 well, 75% in ORSE-02 well and 78% in ORSE-03 well (Table 9). Reservoir B has a hydrocarbon saturation of 88% in ORSE-01, 87% in ORSE-02 and 80% in ORSE-03. Reservoir C has a hydrocarbon saturation of 88% in ORSE-01, 59% in ORSE-02 and 86% in ORSE-03. Reservoir D has a hydrocarbon saturation of 83% in

ORSE-01, 18% in ORSE-02 and 86% in ORSE-03. Similarly, reservoir E had varying hydrocarbon saturations across all three wells. The hydrocarbon saturation of reservoir E is 81% in ORSE-01, 63% in ORSE-02 and 75% in ORSE-03 (Table 9). These results show that all the reservoir intervals are hydrocarbon bearing and can be produced. The result from Table 8 shows that reservoirs B and C in ORSE-01 have the highest value of hydrocarbon saturation and the lowest water saturation respectively. These are indicative of the fact that the reservoir quality increases in the value of porosity and permeability in this reservoir. It also suggests possible good fluid mobility.

Table 9: Water and Hydrocarbon saturation of five reservoir units for three wells in the ORSE-field

Petrophysical property	Reservoirs / Wells	A	B	C	D	E
Water saturation (%)	**ORSE-01**	23%	12%	12%	17%	19%
	ORSE-02	15%	13%	41%	82%	37%
	ORSE-03	22%	20%	14%	14%	15%
Hydrocarbon saturation (%)	**ORSE-01**	77%	88%	88%	83%	81%
	ORSE-02	75%	87%	59%	18%	63%
	ORSE-03	78%	80%	86%	86%	75%

On average, the gross thickness of five reservoir units in ORSE-01 is 123.40 ft (37.61 m), 60.20 ft (18.35 m) for in ORSE-02 and 49.80 ft (15.18 m) in ORSE-03 respectively (Table 10 and Figure 6). The average gross thickness of the reservoirs shows that reservoir in ORSE-01 has the highest thickness while reservoir in ORSE-03 has the lowest thickness. These results show that the reservoir sands are of sufficient thickness to accumulate hydrocarbons in economical quantities. On average, the shale volume thickness is 60.98 ft (39%) in five reservoir units in ORSE-01, 37.51ft (56%) in ORSE-02 and 14.43 ft (23%) in ORSE-03 (Table 10 and Figure 6). This suggests that about 39% of the average gross thickness of five reservoir units in ORSE-01 is occupied by shale, 56% of the average gross thickness in ORSE-02 is occupied by shale and 23% of the average gross thickness in ORSE-03 is shaly.

The average net to gross ratio of five reservoir units in ORSE-01, ORSE-02 and ORSE-03 are 61%, 44% and 73% respectively (Table 10). These results show that on average, over 50% of the entire gross thickness of the five reservoir units in ORSE-01, ORSE-02 and ORSE-03 can produce if they contain hydrocarbon.

Table 10: The average values of five reservoir units for three wells in the ORSE-field

Well	Gross thickness ft (m)	Shale volume ft (%)	Net sand ft (m)	Net to Gross (%)	Total Porosity (%)	Effective Porosity (%)	S_W (%)	Permeability (mD)	S_H (%)
ORSE-01	123.40 (37.61m)	60.98 (39%)	62.42 (19.03m)	61%	24%	19%	17%	2430.08	83.40 %
ORSE-02	60.20 (18.35m)	37.51 (56%)	22.69 (6.92m)	44%	25%	19%	38%	2317.7	60.40 %
ORSE-03	49.80 (15.18m)	14.43 (23%)	35.37 (10.78m)	73%	22%	20%	17%	1812.18	81%

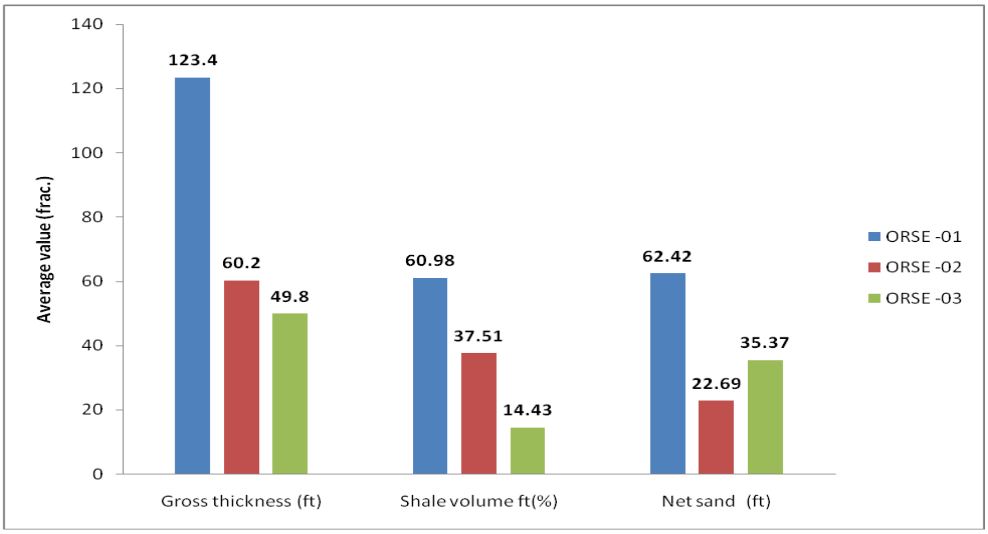

Figure 6: Average gross thickness, shale volume and net sand thickness for the three reservoir intervals

The average total and effective porosity of five reservoir units in ORSE-01 is 24% and 19 %, 25% and 19% in ORSE-02 and 22% and 20% in ORSE-03 respectively (Table 10). According to [31], porosity measurements <5% are negligible, between 5-10% are poor, >10-20% are good, >20-30% are very good and >30 are excellent. Based on this classification scheme, which is globally accepted for porosity classification, the total porosity recorded from reservoirs in ORSE-01, ORSE-02 and ORSE-03 are classed as very good to excellent while effective porosity recorded for reservoirs in ORSE-01, ORSE-02 and ORSE-03 are classed as good to excellent (Figure 7).

The average hydrocarbon saturation values of five reservoir units in ORSE-01, ORSE-02 and ORSE-03 are 83.40%, 60.40% and 81% respectively and water saturation average values are 17%, 38% and 17% for reservoir ORSE-01, ORSE-02 and ORSE-03 respectively (Table 10 and Figure 7). These results show that reservoir in ORSE-01 has the highest hydrocarbon saturation (accumulation) while reservoir in ORSE -02 has the least hydrocarbon saturation (accumulation) (Table 10 and Figure 7)

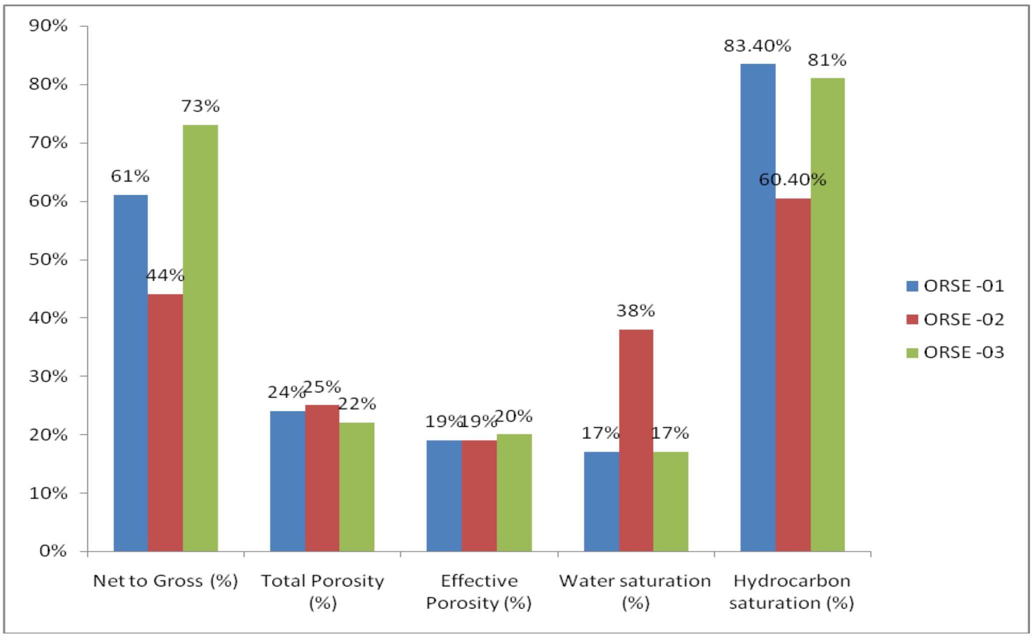

Figure 7: Average NTG, total porosity, effective porosity, water saturation and hydrocarbon saturations calculated for the three reservoir intervals

On average, the permeability values are 2430.08mD, 2317.70mD and 1812.18mD in five reservoir units in ORSE-01, ORSE-02 and ORSE-03 respectively (Table 10). [31] classification of reservoir quality based on permeability values are as follows; < 10mD (poor to fair), >10-50 mD (moderate), >50-250 mD (Good), >250-1000 mD (very good) and >1000 mD (excellent). Based on this classification scheme, reservoir in ORSE-01, ORSE-02 and ORSE-03 can be classed as very good to excellent reservoirs because they have average permeability values ranging between 250-1000mD and >1000mD (Figure 8). These results show that all the reservoirs in the field have very good to excellent permeability values, which are necessary requirements for hydrocarbon flow and production in economic quantities.

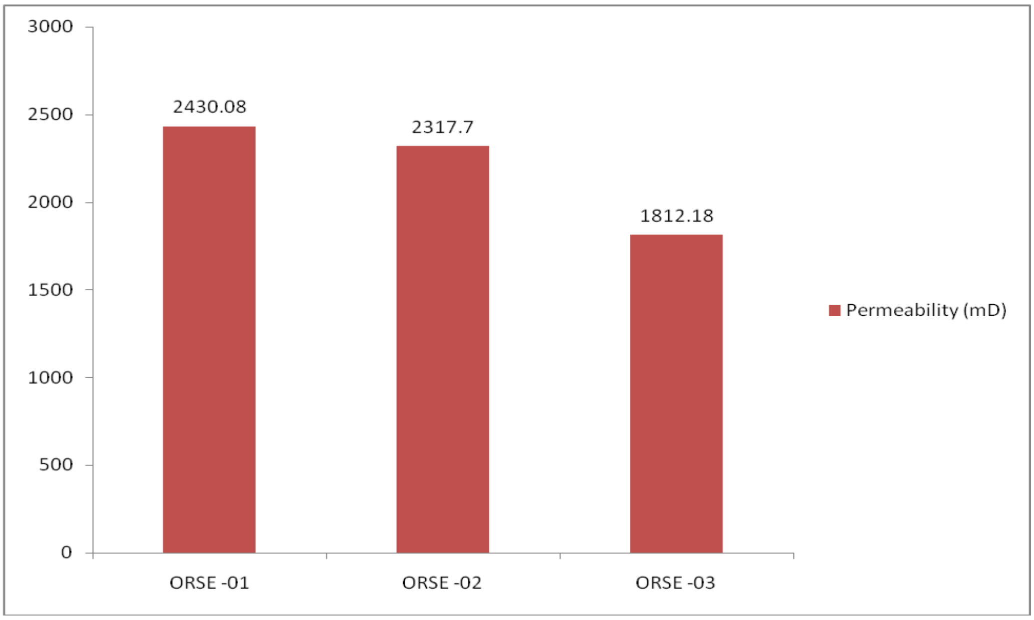

Figure 8: Average permeability for the three reservoir intervals

The Stochastic STOIIP estimation result shows P1 of 83.33 MMSTB, P2 of 50.00 MMSTB and P3 of 30.00MMSTB. The mean of the three probabilities is 50.00MMSTB, which is most likely equivalent to P2 (50.00MMSTB) (Table 11).

Table 11: Volume probabilistic estimation

CASES	**STOIIP (MMSTB)**
P1	83.33
P2	50.00
P3	30.00
MEAN	50.00

V. CONCLUSION

Three wells, namely ORSE-01, ORSE-02, and ORSE-03 were studied with the objective of evaluating the hydrocarbon potential prospects within the study location by carrying out petrophysical analysis. A total of five reservoir units (A-E) were identified and correlated across the three wells using the gamma ray log. Gamma ray logs revealed two lithologies, sand and shale. Layers of shale, which serve as both seals and source rocks, intercalate the reservoirs.

The analysis shows that net–to–gross is between 0.02 - 0.82 indicating more sand than any other rock type in the reservoir. Permeability and porosity range from 1034.98 – 3113.67 mD and 0.11-0.26 respectively, suggesting very good to excellent reservoir quality, which indicates probably well sorted coarse-grained sandstone reservoir. Water saturation ranges from 0.12-0.82 with corresponding hydrocarbon saturation from 0.18 to 0.88. This suggests that the proportion occupied by water in the void spaces is low, hence high hydrocarbon saturation. The result from the Stock Tank Oil Initially in Place (STOIIP) shows that the reservoir has good hydrocarbon accumulation. The average values of these petrophysical parameters were used to rank the three wells ORSE-01, ORSE-02, and ORSE-03. It was deduced that reservoir ORSE-01 is the most prolific oil reservoir while ORSE-02 is the least within the ORSE field because of the excellent values of permeability, porosity and hydrocarbon saturation.

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