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## RESEARCH ARTICLE

## PETROPHYSICAL STUDY OF 'GLORY FIELD' RESERVOIR IN SOUTHERN PART OF NIGER DELTA, NIGERIA USING WELL LOG DATA

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## ARTICLE DETAILS

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## ABSTRACT

This purpose of this study is to evaluate the petrophysical properties of hydrocarbon bearing reservoirs in 'Glory Field' onshore Niger Delta using well log data from five wells. Petrophysical properties evaluated are shale volume, thickness, porosity, net to gross, formation factor, irreducible water saturation, permeability, water saturation, hydrocarbon saturation and pay thickness. The well logs suite contained the following logs: gamma ray, resistivity, density and neutron logs. A total of three reservoir sands (Sand A, Sand B, and C) were identified and correlated across all five wells using Schlumberger Petrel Software. From the result, on average density, Vp/Vs ratio, AI, shale volume, net to gross ratio, net thickness, effective porosity, permeability, water saturation and hydrocarbon saturation values are 2.15g/cm<sup>3</sup>, 2.28, 5406.67gcm<sup>3</sup>ms<sup>-1</sup>, 26%, 74%, 66.99ft, 25%, 2331.14mD, 48% and 52% respectively for sand A reservoir, while 2.17 g/cm<sup>3</sup>, 2.05, 6117.38 gcm<sup>3</sup>ms<sup>-1</sup>, 14%, 86%, 185.04 ft, 26%, 2359.88mD, 56% and 46% respectively for sand B reservoir, and 2.18g/cm<sup>3</sup>, 2.01, 6275.95gcm<sup>3</sup>ms<sup>-1</sup>, 14%, 86%, 197.52ft, 25%, 2121.27mD, 53% and 47% respectively for sand C reservoir. The results of this research revealed very good effective porosity (>20%), excellent reservoir permeability (>1500mD) and pay zone thicknesses exceeding 70ft which are sufficient for hydrocarbon production and field development.

## KEYWORDS

Petrophysics, Well log, Reservoir, Water saturation, Gamma ray.

## 1. INTRODUCTION

The discovery of hydrocarbon in a field is made possible through several stages of exploration. Gravity and magnetic surveys help in delineating the basin architecture, thickness of sedimentary rocks and also identification of regional sedimentary structures such as faults and folds. The resolution of gravity and magnetic methods makes it difficult to differentiate clearly between the various sedimentary layers that are stacked over a basement structure, hence, the need for a method that can resolve the various stratigraphic rock layers and the structures in the subsurface. Conventionally, the seismic method helps in defining sedimentary rock layers and sedimentary structures including; faults, folds and unconformities (Cannon, 2018). The establishment of the presence of hydrocarbons in any given field is done principally with the aid of the seismic method, which is only confirmed through drilling a well (Alistair, 2011).

After the discovery of hydrocarbons in a reservoir, further studies are conducted to understand the reservoir heterogeneity, delineate the extent of the reservoir in three dimensions and estimate the volume of fluid in the reservoir to know the best development model the reservoir management team will adopt for maximum and efficient reservoir fluid recovery (Toba et al., 2018).

A reservoir is one which by virtue of its porosity and permeability is capable of containing a reasonable quantity of hydrocarbon if entrapment conditions are right, but can also release hydrocarbon at a satisfactory

rate when the reservoir is penetrated by a well (Etu-Efeotor, 1997). Reservoir quality analysis is the application of available data in the description of the reservoir in terms of its cleanliness (shale volume), amount of fluid it can hold (porosity) and produce (permeability), fluid saturation (oil, gas, water), net-to-gross, etc. Reservoir quality assessment at the well scale is often accomplished through Petrophysics (Ma, 2019).

Petrophysics is the study of the physical and chemical properties of rocks and their contained fluids (Canon, 2017). Defining petrophysical properties such as permeability, fluid saturation, areal extent, thickness of reservoir and porosity is very vital to the oil and gas industry. Majority of hydrocarbons produced in the Niger Delta is gotten from the accumulations in the pores of porous and permeable rock bodies. These 'spaces' are a function of the porosity of the rock which is a very important petrophysical parameter. Fluid saturation is how much of oil, water or gas is present in the pore spaces of the rock and is very essential to determine the distribution of fluids in the reservoir (Darling, 2005).

Some studies conducted analysis on shaly sand reservoir rocks in the eastern Niger Delta Basin using geophysical well logs. Their study identified fifteen shaly sand bodies (Fozao et al., 2019). Porosity results for Indonesian and Simandoux models were, respectively 0.14 - 0.23 and 0.22 - 0.28, while the hydrocarbon saturation results were 0.650-0.908 and 0.650-0.911 with permeability values of 1487.442 - 8881.69mD and 1568.532 - 7451.592mD respectively.

A study on petrophysical evaluation and volumetric estimation within

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Central swamp depobelt, Niger Delta, using 3-D seismic and well logs. Two reservoirs, GA and GB were delineated from the logs. The average porosity and permeability estimated for reservoir GA and GB were 20% and 1338mD, 21% and 1392mD respectively. Their results showed that the oil-bearing zones in the reservoirs are porous and highly permeable (Saadua and Nwankwo, 2018).

Reservoir characterization and volumetric estimation of Orok Field Niger Delta Province using well logs, 3-D seismic and check-shot data. Their study revealed four gas-bearing reservoirs with effective porosity ranging between 18 and 20% and hydrocarbon saturation between 77 and 90%. Hydrocarbon volumetric estimation for two of the most viable prospects revealed 151 bbl/ft<sup>3</sup> and 286 bbl/ft<sup>3</sup> of gas respectively. The modelled faults trends approximately northwest to southeast direction and dip in the southwest direction (Okpogo et al., 2018).

Recent study carried out studies on depositional facies and reservoir characterization of Usani Field 1, Niger Delta using 3-D seismic, well logs and cores. About eight reservoirs were mapped at depth intervals of 2886 m to 3533 m with their thicknesses ranging from 12m to 407m. Petrophysical results showed that porosity of the reservoirs ranged from 14% to 28%; permeability, from 245.70mD to 454.7mD; and water saturation values from 21.65% to 54.50%. The model served as a basis for establishing facies model in the field (Aigbadon et al., 2017).

Based their research on modelling petrophysical parameters distribution of an onshore oil field in Niger Delta. They used inverse distance weighting of deterministic techniques of modelling and distributing petrophysical properties. The results of porosity, permeability, water saturation and net to gross and facies models showed uniform distribution within the reservoirs (Emujakporue, 2017).

Seismic interpretation and petrophysical analysis of "Olu Field", Onshore Niger Delta, using 3-D seismic and well log data with a view to identifying potential hydrocarbon reservoirs in the study area. Three hydrocarbon bearing sands were discovered with a good porosity ranging from 14% to 28%. Result shows that the three reservoirs harbour considerable volumes of hydrocarbon enough to make an affirmative business decision (Adikwu et al., 2017).

**2. STUDY AREA AND GEOLOGY OF NIGER DELTA**

**2.1 Study Area**

The 'Glory Field' is located in Greater Port-Harcourt (Figure 1) in the Niger Delta Basin. The Niger Delta is bounded geographically by Latitudes 5°00'N to 8°00' N and Longitudes 4°00'E to 6°00'E of the Greenwich meridian. The asset owner is Shell Petroleum Development Company (SPDC), and the field is located in OML 17, 12km North of Port-Harcourt.

**2.2 Geology of Niger Delta**

The geology of the Niger Delta sedimentary is divided into three lithostratigraphic units; Akata, Agbada and the Benin Formation as shown in Figure 2.

**2.2.1 Akata Formation**

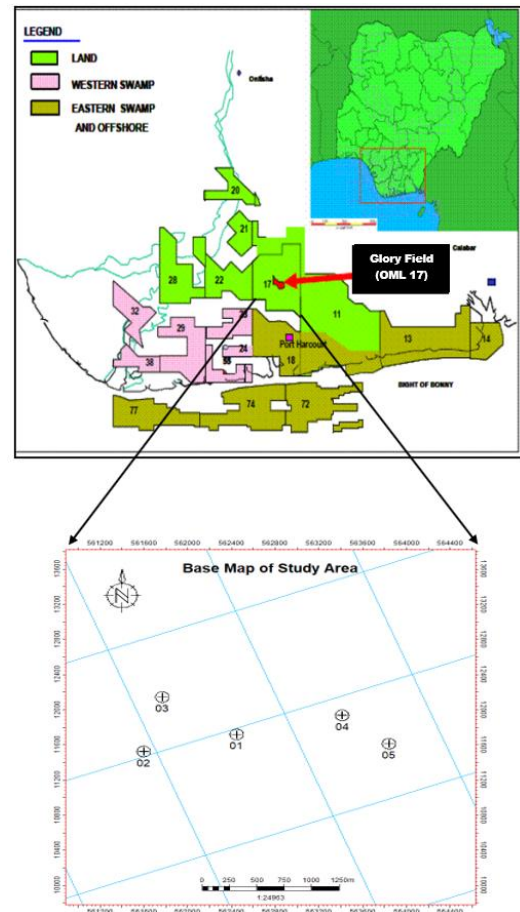
The Akata Formation is the basal unit of the Tertiary delta complex. This lithofacies is composed of shales, clays, and silts at the base of the known delta sequence. They contain a few streaks of sand, possibly of turbiditic origin (Asadu et al., 2015; Doust and Omatsola, 1990), and were deposited in holomarine (delta front to deeper marine) environments. The thickness of this sequence is not known for certain but may reach 7000m in the central part of the delta. Marine shales form the base of the sequence in each depobelt and range from Paleocene to Holocene in age (Asadu et al., 2015).

**2.2.2 Agbada Formation**

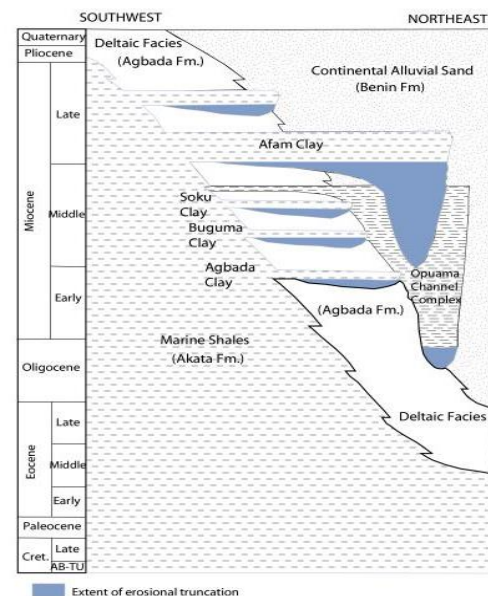
The Agbada Formation overlies the Akata Formation and forms the second of the three strongly diachronous Niger Delta Complex formations. This forms the hydrocarbon-prospective sequence in the Niger Delta. As the principal reservoir of Niger Delta oil, the formation has been studied in some detail. The Agbada Formation is represented by an alternation of sands (fluvial, coastal, fluvio-marine), silts, clays, and marine shales (shale percentage increasing with depth) in various proportion and thicknesses, representing cyclic sequences of offlap units. These paralic clastics are the truly deltaic portion of the sequence and were deposited in a number of delta-front, delta-topset, and fluvio-deltaic environments and range in age from Eocene to Pleistocene (Doust and Omatsola, 1990).

**2.2.3 Benin Formation**

The Benin Formation is the topmost sequence of the Niger Delta clastic wedge, and has been described as the Coastal Plain Sands which outcrop in Benin, Onitsha and Owerri provinces and elsewhere in the delta area. It consists of massive continental (non-marine) sands and gravels considered to have been deposited in the alluvial or upper coastal plain environment. Very little oil has been found in the Benin Formation (mainly minor oil shows). The formation is generally water bearing, thus the main source of portable ground water in the Niger Delta (Asadu et al., 2015).



**Figure 1:** A Map Showing the Location of the Study Area in Niger Delta Source: (Petters and Olsson, 1979)



**Figure 2:** Stratigraphic Column of Niger Delta's Formations Source: (Doust and Omatsola, 1990)

### 3. MATERIALS AND METHODS

#### 3.1 Materials

Gamma ray (GR), Resistivity, Neutron, Density and Sonic logs obtained from five exploratory wells were used for this study. Gamma ray log was used for lithology identification and for estimating shale volume. Resistivity log was used for fluid discrimination and for estimating water and hydrocarbon saturation. Density log was used for total porosity estimation. Total porosity and shale volume were used for estimating effective porosity. Permeability was calculated using water saturation, effective porosity, formation factor and irreducible water saturation. Density and Neutron logs were used in combination for discriminating between types of hydrocarbons.

#### 3.1.2 Data Sets

The data set utilized for this research includes the following:

- Well Headers (contains the locations of the wells in time and space)
- Log Headers (contains the log suite and units of logs provided)

(c) Well Logs (Gamma ray, Resistivity, Neutron, Density)

(d) Well Deviation Surveys (contains information on the well trajectory)

(e) Base Map (shows the location and distribution of the available wells).

#### 3.1.2 Software

The following soft wares were utilized for analysis and visualization;

- Schlumberger Techlog (for determination of petrophysical properties and cross plots)
- Schlumberger Petrel (for reservoir mapping, correlation and data visualization).
- Microsoft Excel (for graphing and statistical averaging).

Table 1 shows the inventory of the available data-set provided and utilized for this study.

Well Name	Well Header	Log Header	Well Deviations	Well Logs			
				Gamma Ray (GR)	Resistivity (Res)	Density (Den)	Neutron (NEU)
01	Yes	Yes	Yes	Yes	Yes	Yes	Yes
02	Yes	Yes	Yes	Yes	Yes	Yes	Yes
03	Yes	Yes	Yes	Yes	Yes	Yes	Yes
04	Yes	Yes	Yes	Yes	Yes	Yes	Yes
05	Yes	Yes	Yes	Yes	Yes	Yes	Yes

### 3.2 METHODS

#### 3.2.1 Data loading and Quality Assessment

The data set were all provided in digital format. The projection coordinates and unit systems for the Field were set in Petrel prior to the loading of any dataset. Each log used in this study was carefully examined in terms of quality and correctness.

#### 3.2.2 Well Header and Log Header

Well header and log header information were provided in digital ASCII (American Standard Code for Information Interchange) format. The header information were visualized in Microsoft excel before being imported into the Petrel work-station.

The well header information contained the names of the wells, their geographic reference locations (Northing and Easting), well reference datums (Kelly-bushing) and the total drill depth (TD) for each well (Table 2). Meanwhile the log headers contained the available logs for each well, geographic reference locations and the units in which each log was acquired. From the log header information, the logs were provided in the following units; depth (feet), gamma ray (API), resistivity (Ohm.m), density ( $g/cm^3$ ) and neutron log ( $ft^3/ft^3$ ). The total well depth, unit systems and well reference information obtained from the well headers were compared with those obtained from the log headers for validation before loading the data into Petrel Software. After all quality checks have been completed, the well header information was loaded into Petrel as Petrel well heads. The information entered into software were again visualized using the well manager in order to be sure that all the items were loaded correctly.

Well Name	Northing	Easting	Latitude	Longitude	Well Datum Name	Well Datum Value (FT)	TD (TVDSSft)	TD (MDft)
01	562448.16	11722.29	4°06'19.61"N	7°31'34.34"E	Kelly Bushing	78.50	9260.00	9338.50
02	562445.09	11720.77	4°06'19.56"N	7°31'34.24"E	Kelly Bushing	66.00	7032.90	7794.00
03	562445.46	11721.87	4°06'19.60"N	7°31'34.26"E	Kelly Bushing	79.00	7013.80	7878.00
04	562447.74	11721.09	4°06'19.57"N	7°31'34.33"E	Kelly Bushing	79.00	7266.40	8315.00
05	563839.65	11615.86	4°06'16.20"N	7°32'19.47"E	Kelly Bushing	66.00	9382.00	9448.00

#### 3.2.3 Lithology Identification and Correlation

Lithology identification was achieved with the aid of the gamma ray log. Predominant lithologies in the Niger Delta are Sands and Shales. Sand and shale are easily differentiated on the GR log based on radioactivity. Shales are more radioactive than sands based on the presence of radioactive minerals like thorium, uranium and potassium within the minerals (chlorite, illite, montmorillonite and kaolinite) that make up shales. Hence, lithologies that show up on the gamma ray log having high radioactivity are referred to as shales and low radioactivity as sands. The sand baseline and the shale baseline were determined for each of the wells. The sand baseline was selected as the highest mode GR occurrence at the lower spectrum while the shale baseline was selected as the highest mode GR occurrence at the higher spectrum. The sand/shale cut off was selected as the mid-point between the sand baseline and the shale

baseline for each well.

#### 3.2.4 Petrophysical Evaluation

Tiab and Donaldson (2004) defined Petrophysics as the study of rock properties and their interactions with fluids (gases, liquid hydrocarbons, and aqueous solutions). In petroleum studies, petrophysical properties are those properties of the reservoir which enable the reservoir rocks to store and transmit reservoir fluids thus also enabling quantitative determination of the in-situ hydrocarbon as well as the appropriate method of extraction of the fluids. Four main petrophysical parameters are important in defining any reservoir, which include: shale volume ( $V_{SH}$ ), total and effective porosity ( $\phi_T$  and  $\phi_E$ ), Net to Gross (NTG), permeability (K) and water saturation ( $S_w$ ). Various equations applicable to the Niger Delta formations were utilized for their computation in this study.

### 3.2.4.1 Shale Volume ( $V_{sh}$ )

This is the space occupied by shale or the fraction of shale (clay), present in reservoir rock (Cannon, 2017). Shale volume ( $V_{sh}$ ) is very important because it helps to discriminate between reservoir and non-reservoir rock (Schlumberger 1984). The volume of shale is determined from mathematical correlations and gamma ray index. In mathematical equations, the volume of shale is represented as  $V_{sh}$ . The gamma ray index ( $GR_{index}$ ) was first calculated in order to calculate the shale volume based on Schlumberger (1974) empirical equation as follows;

$$GR_{index} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (1)$$

Where  $GR_{log}$  = GR log reading of formation,  
 $GR_{min}$  = GR sand baseline,  
 $GR_{max}$  = GR shale baseline.

The non-linear Larinov (1969) equation for tertiary shaly reservoirs was utilized for calculating the shale volume as follows;

$$V_{sh} = 0.083 \times (2^{(3.7 \times GR_{index})} - 1) \quad (2)$$

### 3.2.4.2 Total Porosity

Porosity is the fraction of the bulk volume of a material (rock) that is occupied by pores (voids). Denoted as  $\phi$ , porosity can also be defined as the ratio of the volume of void spaces in a rock to the total volume of the rock (Cannon, 2017). Porosity is expressed in decimal or percentage and can represent the total volume of a rock occupied by empty space. Porosity can be determined using either density log, sonic or neutron-density log. It is widely accepted today that porosity determined from the density tool is most reliable amongst others (Cannon, 2018). Total porosity ( $\Phi_T$ ) in this study was determined using the density log. The method was based on Dresser Atlas (1979) equation as follows;

$$\Phi_T = \frac{\rho_{ma} - \rho_{log}}{\rho_{ma} - \rho_{fl}} \quad (3)$$

Where  
 $\rho_{ma}$  = density of the rock matrix (Density of sand = 2.65g/cm<sup>3</sup>)  
 $\rho_{log}$  = formation bulk density reading from log;  
 $\rho_{fl}$  = Density of contained fluid.

### 3.2.4.3 Effective Porosity

The effective porosity is the porosity that is responsible for flow to occur within the reservoir. Effective porosity ( $\Phi_E$ ) was calculated using volume of shale ( $V_{sh}$ ) and total porosity ( $\Phi_T$ ) as follows (Dresser, 1979);

$$\Phi_E = (1 - V_{sh}) \times \Phi_T \quad (4)$$

Where,  $\Phi_E$  = Effective porosity;  $\Phi_T$  = Total Porosity;  
 $V_{sh}$  = Volume of shale.

### 3.2.4.4 Net-to-Gross

The net-to-gross ratio reduces the gross reservoir thickness (total reservoir thickness plus contained shaliness) to the anticipated pay thickness (permeable reservoir). Net-to-Gross sand is reservoir thickness less shale thickness (Cannon, 2017). This is a factor used to identify probable producing regions of a formation. To determine the clean sand content, Net to Gross was calculated as follows;

$$Net - to - gross = \frac{NH}{GH} \quad (5)$$

where  $NH$  = Net thickness

$GH$  = Gross thickness.

### 3.2.5 Identification of Fluid Type

The resistivity log was used to infer the type of fluid in the reservoir. High resistivity log readings in sandy units indicated hydrocarbon bearing zones while low resistivity log readings is indicative of brine water bearing zones (Schlumberger, 1989). Hence, the resistivity log is used to determine the depth of the oil water contact (OWC) in a reservoir. To

differentiate between the type of hydrocarbon contained in the pores of reservoir sands, the Neutron and Density logs were employed. The presence of hydrocarbon in a reservoir sand body is indicated by increased density log reading which allows for a cross-over when the both logs are placed in the same tract. 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 (Asquith and Krygowski, 2004). Hence, the neutron density separation was used to determine the depth gas oil contact (GOC).

### 3.2.5.1 Water Saturation

This is the relative extent to which the pores in rocks are filled with water. Saturation is expressed as the fraction, or percent, of the total pore volume occupied by the oil, gas, or water (Cannon, 2017). Water saturation is denoted as  $S_w$  and is expressed in percent or fraction. To determine the amount of water saturation in the reservoirs, the modified Archie's empirical model was utilized as follows;

$$S_w = \sqrt{\frac{R_o}{R_t}} \quad (6)$$

Where  $S_w$  = water saturation  
 $R_o$  = Resistivity of the oil leg  
 $R_t$  = True resistivity reading

### 3.2.5.2 Hydrocarbon Saturation

The reservoir hydrocarbon saturation was determined by the difference between unity and water saturation (Asquith and Krygowski, 2004). It is given as follows;

$$S_H = 1 - S_w \quad (7)$$

where  $S_H$  = hydrocarbon saturation

$S_w$  = water saturation

### 3.2.5.2 Permeability

In fluid flow, permeability characterizes the ease with which fluids flow through a porous medium. Theoretically, permeability is the intrinsic property of a porous medium, independent of the fluids involved. Permeability is denoted by  $K$  and is expressed in Darcy or millidarcy. Proposed an permeability equation which is widely used in the Niger Delta in calculating the permeability for the reservoirs of interest as follows (Owolabi et al., 1994);

$$K(mD) = 307 + 26552(\phi_e^2) - 34540(\phi_e \times S_{wirr})^2 \quad (8)$$

where  $K(mD)$  = permeability in milliDarcy  
 $\phi_e$  = effective porosity  
 $S_{wirr}$  = irreducible water saturation.

Irreducible water saturation which is the maximum water saturation that a formation with a given permeability and porosity can retain without producing water was calculated based on equation below.

$$S_{wirr} = \left[ \frac{F}{2000} \right]^{1/2} \quad (9)$$

where  $F$  = Formation Factor.

Formation factor was calculated using Humble's formula for unconsolidated formations typical Niger Delta sandstones,

$$F = \frac{0.62}{\phi^{2.15}} \quad (10)$$

where  $\phi$  = Total Porosity

### 3.2.5.3 Delineating Pay Zone Thickness

The pay thickness of the gas column was estimated as the thickness from the top of the reservoir to the gas oil contact (GOC), while the thickness of the oil column was calculated as the thickness from the GOC to the oil water contact (OWC).

## 4. RESULTS AND DISCUSSION

### 4.1 Results

#### 4.1.1 Data Loading

Figure 3 shows the logs after loading and quality assessment. Gamma ray was placed on tract 1, resistivity in tract 2, neutron and density are both placed in tract 3, with the neutron log scale reversed. Various colours were assigned to the logs for easy identification of relevant reservoir properties.

#### 4.1.2 Lithology Identification and Correlation

The results for the lithologies identified and correlated across all wells in Glory Field is presented in Figure 4. Three reservoir sands were identified and correlated across the field. The results show two dominant lithologies in the field which includes; sand and shale. These lithologies are the dominant lithologies found in the Niger Delta area.

#### 4.1.3 Petrophysical Evaluation

The results of petrophysical evaluation conducted on reservoir sands A, B and C are presented in Tables 3, 4 and 5 respectively. Figure 5 shows the distribution of reservoir gross thicknesses across the various wells while Figures 6 and 7 show the shale volume calculated for the reservoir rock units.

#### 4.1.4 Cross Plot Analysis

Figures 8, 9 and 10 shows cross-plots of porosity versus permeability for reservoir sand A, sand B and sand C identified in wells 01, 02, 03, 04 and 05 respectively.

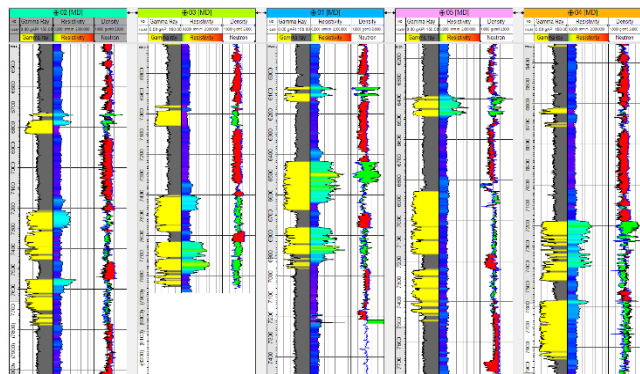


Figure 3: Well Section Window Showing Well Logs Conditioning Prior to Interpretation

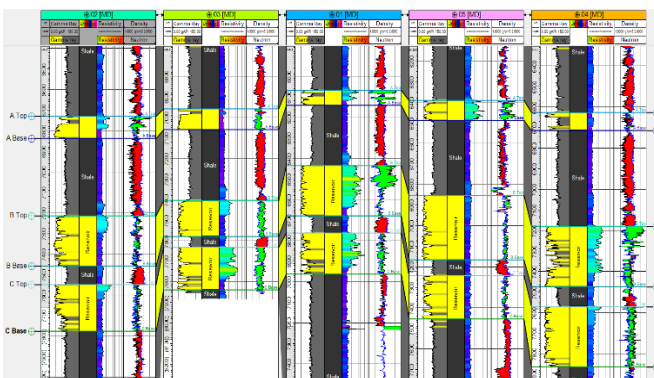


Figure 4: Sand and Shale Lithologies Identified and Correlated across Glory Field

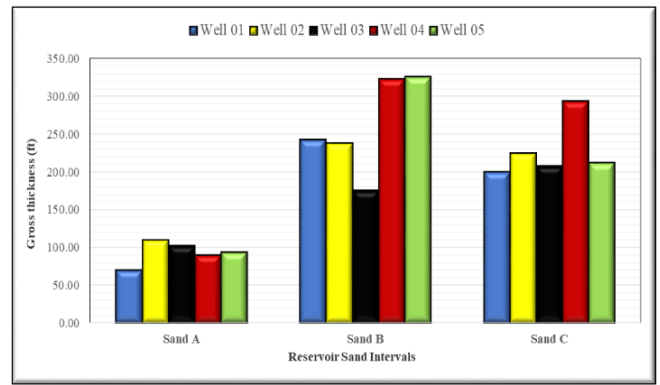


Figure 5: Histogram Plot Showing the Distribution of Reservoir Gross Thicknesses across the various Wells

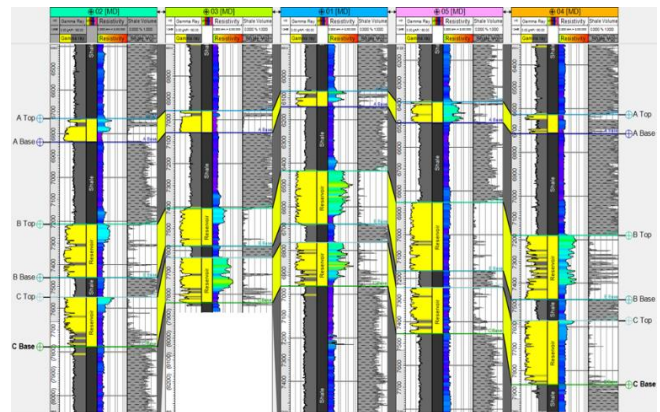


Figure 6: Shale Volume Calculated for Three Reservoir Intervals and Correlated Across all five Wells.

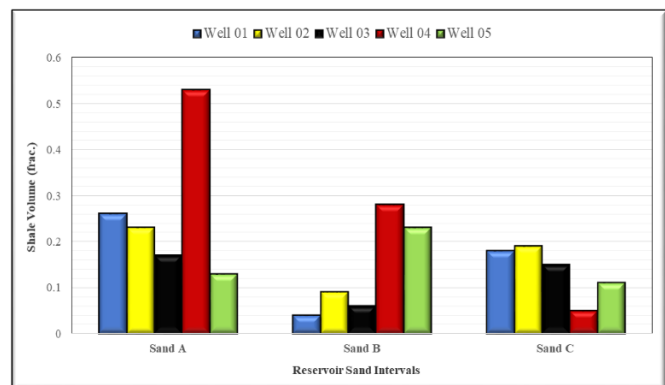


Figure 7: Histogram Plot Showing the Distribution of Reservoir Shale Volume Across the various Wells.

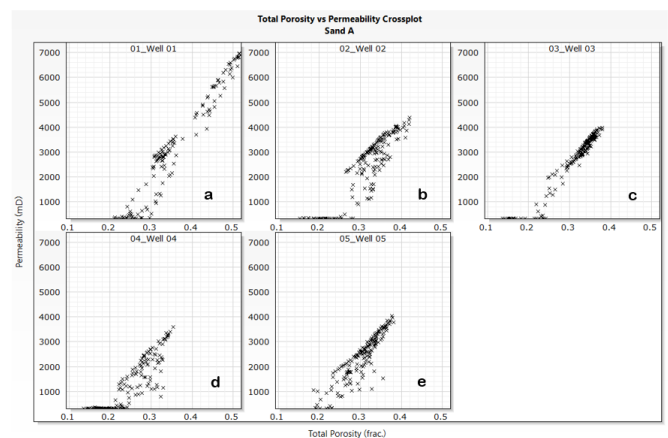


Figure 8: Porosity versus Permeability Cross Plot for Reservoir Sand A across the five Wells (a) Well-01, (b) Well-02, (c) Well-03, (d) Well-04, (e) Well-05

**Table 3: Results of Petrophysical Evaluation for Sand A Reservoir Correlated across all Wells in Glory Field**

Wells	Reservoir Interval (MDft)	Gross thickness (ft)	Shale volume	Shale thickness (ft)	Net thickness (ft)	NTG	Total porosity	Effective Porosity	Formation Factor	Irr. Water Saturation	Water Saturation	Permeability (mD)	Fluid Type	Fluid Contact (ft)	Pay Thickness (ft)
01	6068-6138	70.00	0.26	18.2	51.97	0.74	0.36	0.28	0.00037	0.000414	0.62	3023.35	Gas/Oil/Water	GOC=6110 ft	42.00
														OWC=6120 ft	10.00
02	6729-6838	109.00	0.23	22.31	74.42	0.71	0.32	0.26	0.00044	0.000454	0.48	2347.64	Gas/Oil/Water	GOC=6780 ft	51.00
														OWC=6794ft	14.00
03	6959-7061	102.00	0.17	17.34	85.16	0.83	0.31	0.28	0.00047	0.000461	0.99	2714.35	Water	WUT	
04	6625-6715	90.00	0.53	47.70	42.72	0.47	0.24	0.14	0.00036	0.000615	0.99	1218.98	Water	WUT	
05	6391-6484	93.00	0.13	12.09	80.70	0.87	0.30	0.27	0.00041	0.000459	0.33	2351.36	Gas	GDT=6484 ft	93.00
Min		70.00	0.13	12.09	42.72	0.47	0.24	0.14	0.00036	0.00041	0.33	1218.98			52.00
Max		109.00	0.53	47.70	85.16	0.87	0.36	0.28	0.00047	0.00062	0.99	3023.35			93.00
Avg.		92.80	0.26	23.53	66.99	0.74	0.31	0.25	0.00041	0.00048	0.48	2331.13			70.00

Wells	Reservoir Interval (MDft)	Gross thickness (ft)	Net thickness (ft)	GR (API)	Density (g.cm3)	Vp (m/s)	Vs (m/s)	Vp/Vs	AI (g.cm <sup>3</sup> .ms <sup>-1</sup> )
01	6068-6138	70.00	51.97	54.15	2.07	2515.21	1106.64	2.27	5236.05
02	6729-6838	109.00	74.42	53.56	2.13	2490.31	1084.34	2.30	5324.65
03	6959-7061	102.00	85.16	44.56	2.13	2538.38	1127.37	2.25	5426.05
04	6625-6715	90.00	42.72	70.25	2.25	2633.76	1212.76	2.17	5933.90
05	6391-6484	93.00	80.70	47.50	2.15	2377.72	983.54	2.42	5112.21
Min.		70.00	42.72	44.56	2.07	2377.72	983.54	2.17	5112.21
Max.		109.00	85.16	70.25	2.25	2633.76	1212.76	2.42	5933.90
Avg.		92.80	66.99	54.00	2.15	2511.08	1102.93	2.28	5406.57

GDT – Gas Down To; WUT – Water Up To; OWC – Oil Water Contact; GOC – Gas Oil Contact

**Table 4: Results of Petrophysical Evaluation for Sand B Reservoir Correlated across all Wells in Glory Field**

Wells	Reservoir Interval (MDft)	Gross thickness (ft)	Shale volume	Shale volume (ft)	Net thickness (ft)	NTG	Total porosity	Effective Porosity	Formation Factor	Irr. Water Saturation	Water Saturation	Permeability (mD)	Fluid Type	Fluid Contact (MDft)	Pay Thickness (ft)
01	6435-6677	242	0.04	9.68	232.42	0.96	0.34	0.33	0.000343	0.000409	0.31	3217	Gas/Oil/Water	GOC=6539 ft	104.00
														OWC=6642ft	103.00
02	7220-7457	237	0.09	21.33	214.49	0.91	0.32	0.3	0.000464	0.000472	0.72	2346.89	Oil/Water	OWC=7301ft	81.00
03	7405-7580	175	0.06	10.5	165.06	0.94	0.27	0.26	0.000552	0.000519	0.73	2098.08	Oil/Water	OWC=7481ft	76.00
04	7180-7502	322	0.28	90.16	231.54	0.72	0.28	0.22	0.000676	0.000539	0.49	2014.34	Gas/Oil/Water	GOC=7279ft	99.00
														OWC=7408ft	129.00
05	6852-7166	314	0.23	72.22	241.78	0.77	0.25	0.2	0.000546	0.000518	0.99	2123.08	Water	WUT	
Min		175	0.04	9.68	46.16	0.72	0.25	0.2	0.000343	0.000409	0.31	2014.34			76.00
Max		325	0.28	90.16	250.03	0.96	0.34	0.33	0.000676	0.000539	0.99	3217.00			228.00
Avg.		258	0.14	41.284	185.04	0.86	0.29	0.26	0.0005162	0.0004914	0.56	2359.88			148.00

Wells	Reservoir Interval (MDft)	Gross thickness (ft)	Shale volume	Shale volume (ft)	Net thickness (ft)	NTG	Total porosity	Effective Porosity	Formation Factor	Irr. Water Saturation	Water Saturation	Permeability (mD)	Fluid Type	Fluid Contact (MDft)	Pay Thickness (ft)
01	6435-6677	242	0.04	9.68	232.42	0.96	0.34	0.33	0.000343	0.000409	0.31	3217	Gas/Oil/Water	GOC=6539 ft	104.00
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02	7220-7457	237	0.09	21.33	214.49	0.91	0.32	0.3	0.000464	0.000472	0.72	2346.89	Oil/Water	OWC=7301ft	81.00
03	7405-7580	175	0.06	10.5	165.06	0.94	0.27	0.26	0.000552	0.000519	0.73	2098.08	Oil/Water	OWC=7481ft	76.00
04	7180-7502	322	0.28	90.16	231.54	0.72	0.28	0.22	0.000676	0.000539	0.49	2014.34	Gas/Oil/Water	GOC=7279ft	99.00
														OWC=7408ft	129.00
05	6852-7166	314	0.23	72.22	241.78	0.77	0.25	0.2	0.000546	0.000518	0.99	2123.08	Water	WUT	
Min		175	0.04	9.68	46.16	0.72	0.25	0.2	0.000343	0.000409	0.31	2014.34			76.00
Max		325	0.28	90.16	250.03	0.96	0.34	0.33	0.000676	0.000539	0.99	3217.00			228.00
Avg.		258	0.14	41.284	185.04	0.86	0.29	0.26	0.0005162	0.0004914	0.56	2359.88			148.00

x	Reservoir Interval (MDft)	Gross thickness (ft)	Net thickness (ft)	GR (API)	Density (g.cm3)	Vp (m/s)	Vs (m/s)	Vp/Vs	AI (g.cm <sup>3</sup> .ms <sup>-1</sup> )
1	6068-6138	70.00	51.97	37.85	2.09	2748.27	1315.28	2.09	5752.09
2	6729-6838	109.00	74.42	44.32	2.16	2741.67	1309.37	2.09	5922.39
3	6959-7061	102.00	85.16	39.32	2.21	2809.95	1370.49	2.05	6198.48
4	6625-6715	90.00	42.72	53.44	2.19	2815.28	1375.25	2.05	6167.53
5	6391-6484	93.00	80.70	36.59	2.20	2968.86	1512.76	1.96	6546.41
Min.		70.00	42.72	36.59	2.09	2741.67	1309.37	1.96	5752.09
Max.		109.00	85.16	53.44	2.21	2968.86	1512.76	2.09	6546.41
Avg.		92.80	66.99	42.30	2.17	2816.81	1376.63	2.05	6117.38

GDT – Gas Down To; WUT – Water Up To; OWC – Oil Water Contact; GOC – Gas Oil Contact

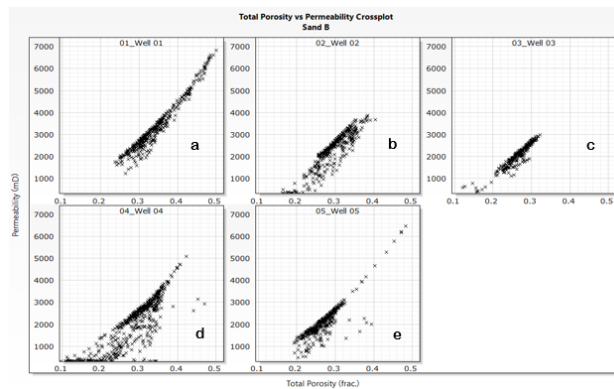


Figure 9: Porosity versus Permeability Cross Plot for Reservoir Sand B across the five Wells. (a) Well-01, (b) Well-02, (c) Well-03, (d) Well-04, (e) Well-05

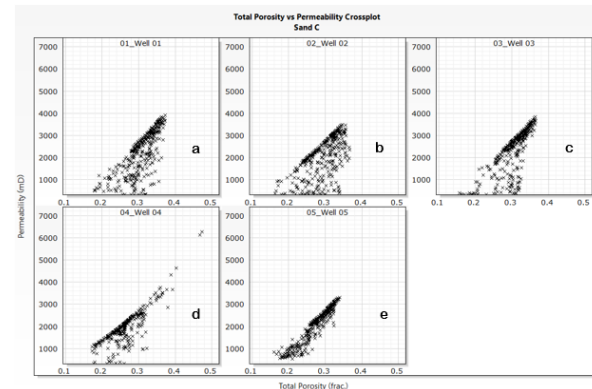


Figure 10: Porosity versus Permeability Cross Plot for Reservoir Sand C across the five Wells. (a) Well-01, (b) Well-02, (c) Well-03, (d) Well-04, (e) Well-05

## 4.2 Discussion

### 4.2.1 Total and Effective Porosity

Total porosity ranges from 24% to 36% in Sand A reservoir (Table 4.1), 25 to 34% in Sand B reservoir (Table 4) and 26 to 31% in Sand C reservoir (Table 5). In reservoir sand A, well 01 showed the highest total porosity, while the least total porosity was found in well 04. In reservoir sand B, well 05 showed the highest total porosity, while the least total porosity was found in well 01. Similarly, in reservoir sand C, well 01 showed the highest total porosity, while the least was found in well 05. Also, effective porosity ranged from 14% to 28%, 20 to 33% and 24 to 26% in Sand A, Sand B and Sand C reservoirs respectively. In reservoir sand A, well 01 and well 3 showed the highest effective porosities, while the least effective porosity was found in well 04. In reservoir sand B, well 05 showed the highest effective porosity, while the least effective porosity was found in well 01. Similarly, in reservoir sand C, well 01 and well 3 showed the highest effective porosity, while the least was found in well 02 and well 04. On average, total and effective porosities are 31% and 25%, 29% and 26%, and 29% and 25% in Sand A, Sand B and Sand C reservoirs. The porosity that is responsible for flow and accumulation in a reservoir is the effective porosity. According to Levorsen (1967), rocks have negligible porosity when < 5%, poor porosity when >5-10%, good porosity when >10-20%, very good when >20-30%, and excellent when >30. Based on this classification scheme, the average total porosity recorded for Sand A is classed as excellent, and very good for reservoir sand B and reservoir sand C respectively. Similarly, the average effective porosity for the reservoirs (sand A, sand B, sand C) are classed as very good based on Levorsen (1967) classification scheme. These results suggest that the reservoirs are porous enough to allow for accumulation of hydrocarbons.

### 4.2.3 Permeability

The results of reservoir permeability ranges from 606.32mD to 9064.73mD in Sand A reservoir (Table 3), 860.95mD to 5408.52mD in Sand B reservoir (Table 4), and 1911.27mD to 2336.62mD in Sand C reservoir (Table 5). In reservoir sand A and sand B, well 01 showed the highest permeability, while the smallest permeability was found in well 04. In reservoir sand C, well 03 showed the highest permeability, while the smallest permeability was found in well 04. The average permeability values recorded in Sand A, Sand B and Sand C are 2331.13mD, 2359.88mD and 2121.27mD respectively. On average, permeability in all three reservoirs are greater than 1500mD. Both Levorsen (1967) and Rider (1986) classified reservoir quality based on permeability values as; < 10mD (poor to fair), >10-50mD (moderate), >50-250mD (Good), >250-1000mD (very good) and >1000mD (excellent). Based on this classification scheme, reservoir Sand A, B and C are classed as having excellent quality. The permeability values recorded in this study are typical of Niger Delta reservoirs (Akintola et al., 2015). Hence, fluid flow within these reservoir units will occur with ease because of the relatively high permeability values.

### 4.3.3 Shale Volume

As a rock become shalier, it will be more difficult to store and produce hydrocarbons. Shale volume ranges from 13 to 53% in Sand A reservoir (Table 3), 4 to 28% in Sand B reservoir (Table 4), and 5 to 19% in Sand C reservoir respectively (Table 5). In reservoir sand A, well 04 showed the highest shaliness, while the least shaliness was found in well 05 (Figure 7). Similarly, in reservoir sand B, well 04 showed the highest shaliness, while the least shaliness was found in well 01. In sand C, well 02 showed the highest shaliness, while the least shaliness was found in well 04. On average, shale volumes are 26%, 14% and 14% in Sand A, Sand B and Sand C reservoirs respectively. This translates to a shale thickness of 23.53ft, 41.28ft and 29.48ft in Sand A, Sand B and Sand C reservoirs respectively. High shale volume lowers the quality of a reservoir and prevents flow of hydrocarbons to a well. Although Sand B has the highest shale volume thickness, it also had the highest gross thickness. All the reservoir sand bodies have shale volumes less than 30% (on average) of the entire gross thickness. This shows that only a minor amount of the reservoir sands is dirty, hence, about 70% of the reservoir sands are clean and can produce.

### 4.3.4 Lithology of Reservoir Rocks

The lithology for the various reservoir rocks (Sand A, Sand B and Sand C) as revealed from gamma ray log tool ranges from 44.56 to 70.25 API (Table 3), 36.59 to 53.44 API (Table 4) and from 34.31 to 50.57 API (Table 5) for reservoir sand A, Sand B and Sand C respectively. Well 03 showed the highest GR values while Well 04 showed the lowest GR values for Sand A and Sand B. Meanwhile, for Sand C, the lowest GR was recorded in Well 04 and the highest in Well 01. On average, GR values for Sand A, B and C

are 54.00 API, 42.30 API and 44.67 API respectively. Generally, based on gamma ray values, Sand B shows the lowest GR while Sand A showed the highest GR values. The results obtained from the GR logs revealed that Sand B is generally sandy whereas Sand A contains significant shaly constituents based on the higher GR log measurements obtained from this sand interval.

### 4.3.5 Fluid Type

Resistivity log, neutron log and density log were used to identify the fluids in each of the wells as shown in Figure 10. Sand A reservoir contains oil, gas and water in well 01 and 02, only water was encountered in well 03 and 04, and gas in well 05 (Table 3). The gas oil contact (GOC) and oil water contact (OWC) were encountered at 6110ft and 6110ft in well 01, 6780ft and 6794ft in well 02 while Well 03 and 04 were entirely filled with brine (Figure 10). In well 05, a gas down to (GDT) contact was identified which coincides with the base of the reservoir at 6484ft.

For reservoir sand B, oil, gas and water were encountered in well 01, oil and water were found in well 02 and 03, oil, gas and water were encountered in well 04, while water (brine) was the only fluid phase encountered in well 05 (Table 4). In well 01, the GOC and OWC were found at depths of 6539ft and 6642ft respectively. In well 02 and 03, the OWC was found at depths of 7301 ft and 7481ft. In well 04, the GOC and OWC were found at depths of 7279 ft and 7408ft respectively (Figure 10). In well 05, the reservoir was completely saturated with brine from top to the base of the reservoir.

Sand C reservoir contained oil and water in well 01, 02, 03 and 04 respectively (Table 5). Water up to (WUT) contact was encountered in well 05, because the reservoir was saturated with only water from top to bottom. The OWC was encountered at 6926ft, 7582ft, 7785ft and 7589ft in well 01, 02, 03 and 04 (Figure 10). In well 05, water saturated the entire reservoir to the bottom of the reservoir at a depth of 7454ft.

### 4.3.6 Fluid Saturation

Water saturation ranged from 33% to 99% in Sand A reservoir (Table 3), 31 to 73% in Sand B reservoir (Table 4) and 26 to 99% in Sand C reservoir (Table 5). In reservoir sand A, well 03 and well 04 showed the highest water saturation, while the lowest water saturation was found in well 05 (Figure 11). In reservoir sand B, well 03 showed the highest water saturation, while the lowest water saturation was found in well 01. Similarly, in reservoir sand C, well 05 showed the highest water saturation, while the lowest water saturation was found in well 03. On average, the water saturations in the hydrocarbon reservoirs are 48%, 56% and 53% for reservoir Sand A, B and C respectively. This leads to a corresponding hydrocarbon saturation of 52%, 44% and 47% in reservoir Sand A, B and Sand C. Based on these results, reservoir Sand A has the highest hydrocarbon saturation, followed by Sand C and Sand A respectively. These hydrocarbon saturation values are good for reservoir development for production.

### 4.3.7 Gross Thickness

The gross thickness for reservoir sand A ranges from 70 to 109ft (Table 3), 175 to 322ft for reservoir sand B (Table 4), and 199 to 293ft for reservoir sand C (Table 4). The thickness of reservoir sand A is highest in well 02 and smallest in well 01. For reservoir sand B, well 4 had the highest thickness and well 03 had the lowest thickness. In reservoir C, well 04 had the highest thickness while well 01 had the lowest gross thickness. The average gross thickness of the reservoir sands A, B and C are 92.80ft, 258.00ft and 227.00ft respectively. This shows that the reservoir Sand B has the largest gross thickness while Sand A has the smallest gross thickness (Figure 5). Generally, the gross thickness of the reservoir intervals are of sufficient thickness for hydrocarbon accumulation in economic quantities.

### 4.3.8 Net Thickness

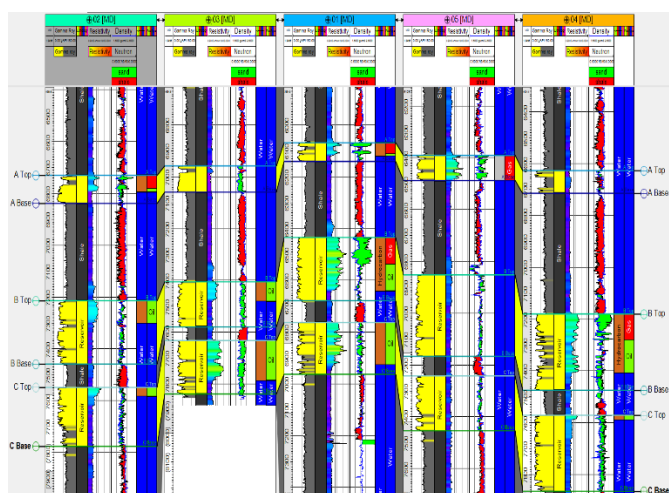
The reservoir net thickness which is the clean sand portion of the reservoir ranges from 42.72ft to 85.16ft in Sand A reservoir (Table 3), 165.06 to 250.03ft in Sand B reservoir (Table 4) and 163.18 to 278.35ft in Sand C reservoir (Table 5). In reservoir sand A, well 03 showed the highest net thickness, while the least net thickness was found in well 04. Similarly, in reservoir sand B, well 05 showed the highest net thickness, while the least net thickness was found in well 03. The average net sand thicknesses are 66.99ft, 185.04 and 197.52ft in Sand A, Sand B and Sand C reservoirs respectively. These results show that sufficient thickness of the reservoirs are available as net sands (clean producible sand, provided they contain hydrocarbons).

### 4.3.9 Net to Gross

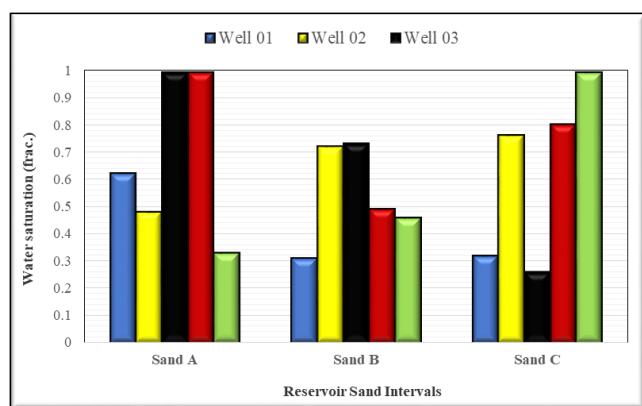
The net to gross ratio ranges from 47 to 87% in Sand A reservoir (Table 3), 72 to 96% in Sand B reservoir (Table 4) and 81 to 95% in Sand C reservoir respectively (Table 5). In reservoir sand A, well 05 showed the highest net to gross, while the least net to gross ratio was found in well 04. In reservoir sand B, well 01 showed the highest net to gross, while the least net to gross ratio was found in well 04. In reservoir sand C, well 04 showed the highest net to gross, while the least net to gross ratio was found in well 02. On average, net to gross ratio are 74%, 86% and 86% in Sand A, Sand B and Sand C reservoirs. These results show that all three sand packages have >70% clean sand volumes, indicating that the reservoirs are clean enough for hydrocarbon production, provided they are hydrocarbon bearing.

### 4.3.10 Pay Thickness

The reservoir pay thickness which is the part of the reservoir occupied by oil and gas ranges from 52 to 93 ft in reservoir sand A (Table 3), 76 to 228ft in sand B (Table 4) and 19 to 163ft in reservoir sand C (Table 5). In reservoir A, the thickness of the gas pay zone is 42ft while the oil pay zone has a thickness of 10ft in well 01. Similarly, in well 02, the thickness of the gas pay zone was 51ft and the oil pay zone had a thickness of 14ft. In well 05, the thickness of the gas pay zone was 93ft. Generally, reservoir A sand contains more gas than oil. In reservoir B, the thickness of the gas and oil pay zones are 104ft and 103ft in well 01, and 99ft and 129ft in well 04 respectively. The thickness of the oil pay zone in well 02 and 03 are 81ft and 76ft respectively. This shows that reservoir B is an oil and gas reservoir. In reservoir C, the thickness of the oil pay zones are 163ft, 31ft, 154ft and 19ft respectively. This shows that reservoir C is an oil-bearing reservoir. On average, the thickness of the hydrocarbon pay zones are 70ft, 148ft and 91.75ft in reservoir sand A, B and C respectively.



**Figure 10:** Fluid types Identified in Three Reservoir Intervals and Correlated across all five Wells



**Figure 11:** Histogram Plot Showing the Distribution of Reservoir Water Saturation across the various Wells

## 5. CONCLUSION

From the results of this research, the following conclusions are reached:

1. Reservoirs in Glory-Field, are predominantly composed of sands,

with thick shales capping each reservoir sand unit.

2. Resistivity log revealed that all three reservoir intervals are hydrocarbon bearing. Neutron/density cross-over effect revealed that some of the wells had developed a gas cap. Resistivity range (0.2Ω.m to 2000Ω.m)
3. On average shale volume, net to gross ratio, net thickness, effective porosity, permeability, water saturation and hydrocarbon saturation values are 26%, 74%, 66.99ft, 25%, 2331.14mD, 48% and 52% for Sand A reservoir; 14%, 86%, 185.04ft, 26%, 2359.88mD, 56% and 46% for Sand B reservoir; and 14%, 86%, 197.52 ft, 25%, 2121.27mD, 53% and 47% for Sand C reservoir.
4. The porosity (24% to 36%) and permeability (606.32mD to 9064.73mD) values show good to excellent for reservoir sands A, B and C respectively.
5. Reservoir sand A is composed of mainly gas with minor oil. Reservoir B is an oil and gas reservoir, while reservoir C is an oil reservoir. Generally, the pay thickness varies from well to well, but on average, the pay thickness is 70ft, 148ft and 92ft in reservoir sand A, reservoir sand B and reservoir sand C respectively.

## 6. RECOMMENDATION

This study recommends that a direct core sample be acquired from one of the wells that are hydrocarbon bearing in the field and the samples evaluated in the laboratory for petrophysical properties. The petrophysical properties determined from routine and special core analysis will help in validating and calibrating the existing empirical models utilized for petrophysical properties determination. This will reduce interpretational uncertainty that may arise in analysis of petrophysical properties from uncored wells and increase reliability on the utilized empirical model.

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