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Integrated Approach to Optimal Reservoir Characterization of Z–Oil Field, Niger Delta

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Abstract Reservoir Characterization which entails the understanding of the subsurface reservoir plays an important role in the exploration and exploitation processes of the oil and gas industry in that it gives room for optimum recovery of hydrocarbon at a minimized cost. This research work is aimed at evaluating the formations, estimating the reservoir properties that can be used to characterize the reservoirs and calculating the hydrocarbon reserve of a field located in the Niger Delta region. This was accomplished by identifying and computing reservoir properties and estimating the volume of hydrocarbon using available 3-D seismic and well logs data. A well- to- seismic tie was carried out using the checkshot data in order to relate the horizon tops identified in a well with specific reflections on the 3-D seismic section. The petrophysical analysis carried out on three reservoirs of interest show that porosity values for reservoir G300, H100 and H400 vary respectively across the well from 0.24- 0.32, 0.29- 0.32 and 0.25- 0.31; permeability values vary from 241.27mD-9188.83mD, 457.95mD- 1690.39mD and 618.34mD- 1487.56mD; water saturation values vary from 0.17- 0.34, 0.22- 0.29 and 0.23- 0.27 and the values of volume of shale vary from 0.05- 0.09, 0.05- 0.09 and 0.10- 0.13. Two horizons corresponding to the tops of two reservoirs G300 and H100 and several faults were mapped across the seismic section. Seismic grids were interpolated to generate time structure map which in turn was used to generate depth structure map by developing a velocity model that converted time to its corresponding depth. From the maps, an anticlinal structure was observed at the center of the field. Petrophysical models were generated for two reservoirs using structural framework and geostatistical techniques. The volumetric analysis carried out revealed that the volume of hydrocarbon in place for reservoir G300 was estimated at 62,739,256.3 barrels and that of reservoir H100 was 38,808,7 08.4 barrels. The result confirms that the productive capacity of the field is high and re-assuring.

Keywords Reservoir, characterization, petrophysical models, hydrocarbon, Niger Delta

Introduction

The Niger delta is a hydrocarbon province with a current oil and gas reserve of 37 billion barrels and 192 trillion cubic feet respectively [1]. Characterizing the reservoir is a process which describes various properties in reservoirs using all the available data to provide reliable reservoir geologic models for accurate prediction of the performance of a reservoir [2]. Ezekwe and Filler (2005), described reservoir characterization as a process that involves the integration of various qualities and quantities of data in a consistent way to describe the reservoir properties of interest in inter well locations [3]. The primary objective of reservoir characterization is to create a more representative geologic model of reservoir properties. It is the understanding of the reservoir connectivity in dynamic and static conditions by integrating data from different sources. Hence, in establishing a geologic representation of what a reservoir is most likely to be, it is important to sufficiently capture the uncertainty associated with not knowing its exact image [4].

Reservoir characterization involves the estimation of reservoir properties such as porosity, permeability, saturation, pressure and pores sizes using cores, well logs, production and seismic data. The study is aimed at evaluating the formations in an onshore field, and characterization of the reservoirs of interest with respect to its hydrocarbon potential. This is done by using some models that have been applied in similar fields within the Delta.

Several authors [4-10] have utilized various approaches to estimate the petrophysical purchases from different Fields in the delta, with their results affirming the high productive potentials of the area.

Geologic Setting of the Study Area

The Niger Delta region is situated on the west coast of Africa specifically at the peak of the Gulf of Guinea [11-12] and on the Nigeria's South–South geopolitical zone. It borders the Atlantic Ocean and stretches from about Longitude 3^{o} E to 9^{o} E and Latitude 4^{o} 3′ N to 5^{o} 2′ N [13].

The Niger Delta is recognized as one of the most enormous delta systems in the world with exceedingly productive territories. An improvement in seismic innovation and progresses in assessment demonstrated that the Niger Delta petroleum system includes Lacustrine, Marine and Deltaic otherwise known as Lower Cretaceous, Upper Cretaceous–lower Paleocene and Tertiary respectively [11]. Evaluating the source material geologically showed that the third ranked deltaic petroleum system serves as the fundamental wellspring of oil and gas in this region [11-12].

There is a subdivision of the tertiary area of the Niger Delta into three formations, which signify depositional facies that are recognized taking into account the sand-shale proportions. These are; the Akata Formation, Agbada Formation and the Benin Formation.

Materials and Methods

The materials used for this research were provided by one of the leading Oil Companies in Nigeria. The data sets obtained are Seismic survey data, Well log data of three wells drilled within the area of study, Check shot data and Directional survey data. The software generated base map of the study area is shown in Figure 1.

The method involved in carrying out this research was basically on the understanding of the principles of the software used for data analysis. The software used is the PETREL software developed by Schlumberger and the process involved in the execution includes Lithology delineation using the Gamma ray log, reservoir identification, determination of petrophysical parameters, well to seismic tie, horizons and faults mapping, time to depth conversion and reservoir volume estimation.

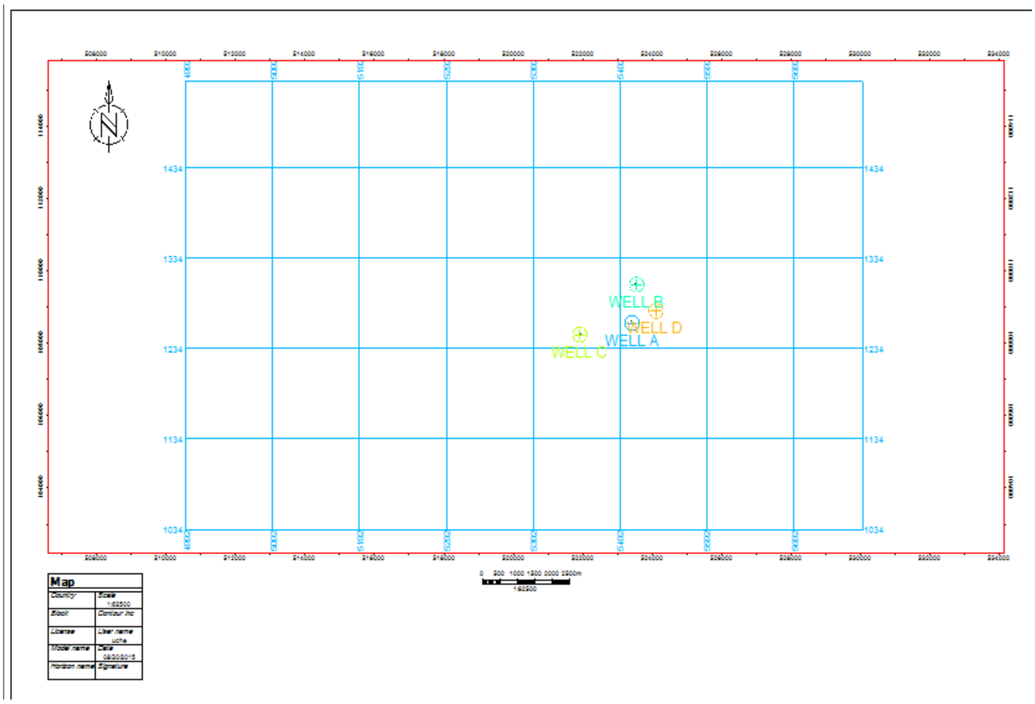

Figure 1: The base map of the study area

Lithology and Reservoir Identification

The delineation of lithology (sand and shale bodies) was done using GR log. The log was set to a scale of 0-150 API with central cut off of 65 API units. Less than 65API was interpreted to be sand while greater than 65API was interpreted to be shale. Further quality checking was carried out on the lithology definition to identify possible areas where there are radioactive sands containing zircon and glauconite. This was done by bringing in deep resistivity log since it can be used to infer permeability. It is expected that in shale regions permeability should be poor so shale regions having high permeability is indicative of a sand package with radioactive substance.

The identification of reservoirs was achieved using the log signatures of both resistivity and GR logs. Intervals with high resistivity are taken to be hydrocarbons while water bearing zones are denoted with low resistivity intervals. The logs were activated and displayed on the well section window, on which correlation was carried out using the GR log. The resistivity log was used to check the fluid contents present within the sediments *i.e.* hydrocarbon or water. The top and base of the reservoir were picked (Fig. 2). Hydrocarbon-water contacts were identified by a resistivity kick towards the right of the log track.

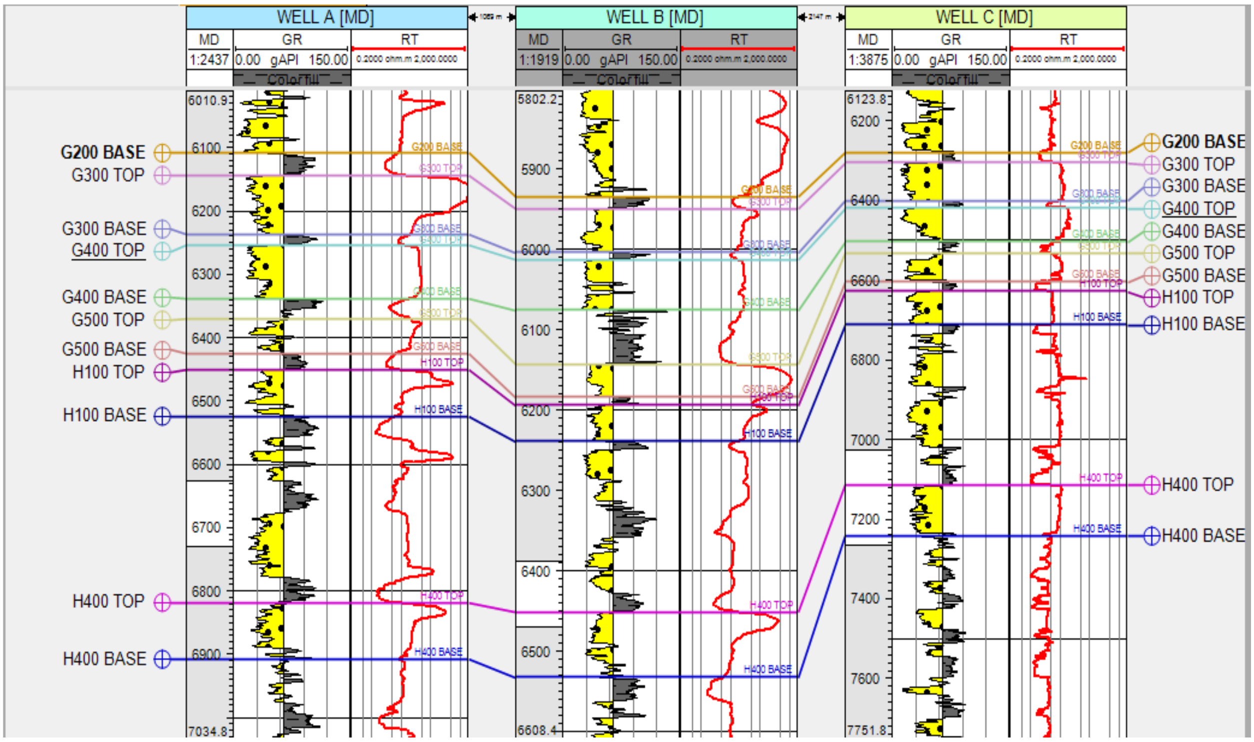

Figure 2: The Top and Base of Reservoir G300 to H400 across Wells A, B and C using well correlation panel

Determination of Petrophysical Parameters

With the use of density log, the bulk density readings within each reservoir are acquired which in turn are substituted into the equations 1 and 2 in order to determine the formation porosity.

$$\Phi tot = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \qquad 1$$

$$\Phi eff = (1- Vsh)* \Phi_{tot} \qquad [14] \qquad 2$$

where: Φtot = total porosity; Φeff = effective porosity, ρ_{ma} is the matrix density = 2.65g/cm^3 (sandstone); ρ_{fl} is the fluid density= 1.0g/cm^3 ; ρ_b = formation bulk density.

The evaluation of porosity quality in the Niger delta reservoir rocks was based on Rider (1986) [15] porosity description.

Reservoirs are saturated with both hydrocarbon and water, although every prolific reservoir should have less water saturation than hydrocarbon. Water saturation (S_w) was estimated using equation 3:

$$S_w = 0.082/\Phi_{tot} \qquad [16] \qquad 3$$

According to Owolabi et al. (1994) [17], permeability was estimated using equation 4:

$$K = 307+(26{,}552*\Phi^2)-34{,}540(\Phi*Swi)^2 \quad (4)$$

where K is the Permeability, Swi is irreducible water saturation and Φ is effective porosity.

Determination of volume of shale (V_{sh})

The volume of shale in a reservoir was calculated using the gamma ray log. In a tertiary unconsolidated sand V_{sh} is given as:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (5)$$

$V_{sh} = 0.083(2^{3.7x\,I_{GR}} - 1.0)$ (Larinov correlation for tertiary unconsolidated sand) 6

where: I_{GR} = Gamma ray index; GR_{log} = Reading of Gamma ray log; GR_{max} = maximum gamma ray (shale) reading; GR_{min} = minimum gamma ray (clean sand) reading.

Determination of Net-to-Gross ratio (NTG)

The "net-to-gross ratio" is defined as the total amount of pay footage divided by the total thickness of the reservoir interval. It can also be referred to as the ratio of the thickness of sand bearing hydrocarbon to the total thickness of sand formation. It shows the volume of shale present in the reservoir. NTG was calculated along the wells using Petrel software as

NTG = If (GR<65, 1, 0)

Where GR is gamma ray log reading. This means that if GR is less than 65 API, NTG is 1 (whole of the reservoir is sand), and otherwise it is zero (does not contribute anything to the subsequent reservoir-engineering oil or gas originally in place even if it contains some quantity of hydrocarbons).

Well to Seismic tie and Horizon Mapping

Well-to-Seismic ties give room for the comparison between well data (measured in units of depth) and seismic data (measured in units of time). This makes it possible to link up the horizon tops identified in a well with specific reflections on the seismic section. It is done with the use of the check shot data which has velocity information that relates both time and depth. Synthetic seismogram is generated by the convolution between acoustic impedance (derived from corrected density logs and sonic logs) and extracted wavelet.

The mapping of two horizons representing the top of two reservoirs was carried out. Time maps were generated after the mapping out of horizons and faults, followed by the generation of a depth map using velocity models which is achieved using the check shots data. The area extent of each reservoir was determined from the depth structural maps and hence the volume of hydrocarbon in place was calculated using the already obtained petrophysical parameters.

Results and Discussion

The study revealed several hydrocarbon sand reservoirs within this field under consideration but of interest are basically three reservoirs namely G300, H100 and H400. The top and base of the three reservoirs of interest are shown in figure 2 using the well correlation panel. Considering the GR, the yellow- coloured interval signifies sand while shale is denoted by the black-coloured interval. The reservoirs consist of intercalation of sand and shale.

Table 1: Average petrophysical properties of Reservoir G300 along well C

MEASURED DEPTH (FT)	VOLUME OF SHALE (FRACTION)	POROSITY (FRACTION)	WATER SATURATION (FRACTION)	NET-TO-GROSS (FRACTION)	PERMEABILITY (MILLI DARCY)
7114	0.193336	0.2439	0.33623	0	62.9009
7114.5	0.178387	0.2548	0.32184	0	91.3136
7115	0.164252	0.2827	0.29009	0	188.6072
7115.5	0.138247	0.2992	0.27411	1	318.4942
7116	0.119885	0.3171	0.2586	1	512.6198
7116.5	0.08951	0.3441	0.23833	1	1025.463
7117	0.083476	0.3526	0.23255	1	1236.114
7117.5	0.076575	0.3469	0.23637	1	1172.629
7118	0.072709	0.3233	0.25361	1	788.2377
7118.5	0.068937	0.3219	0.25471	1	787.0059
AVERAGES:	**0.118531**	**0.30865**	**0.269644**	**0.7**	**618.3385**

Table 1 shows the result of some computed petrophysical parameters for reservoir G300 which cut across well C. Figure 3 shows variation of petrophysical parameters for well C. The results of the petrophysical analysis of the three reservoirs of interest are shown on Table 2.

The porosity values obtained in all the reservoirs across the three wells are rated very good to excellent, likewise, the permeability values are rated good to excellent which revealed a good interconnectivity between the pores and the free flow of fluid within the reservoir. The low values of water saturation indicate a high proportion of hydrocarbon to the quantity of water within the reservoir. Hence the reservoir is a hydrocarbon saturated one.

The results of the findings varies favourably well with those of other authors who have done similar studies in the Niger Delta region. Ekine and Iyabe (2009) [5] estimated 11% - 19% average porosity. Results shown by Adeoye and Enikanselu (2009) [18] gave an estimate ranging between 0.22 – 0.31 which can be said to have a close range with that recorded on the field under study. Furthermore, Imaseun *et al*. (2011) [6] recorded a higher porosity value of 44.60%. From the research carried out by Odoh *et al.* (2012) [7], a porosity range of 24% - 29.8% was estimated which is also within the porosity range of the field under consideration.

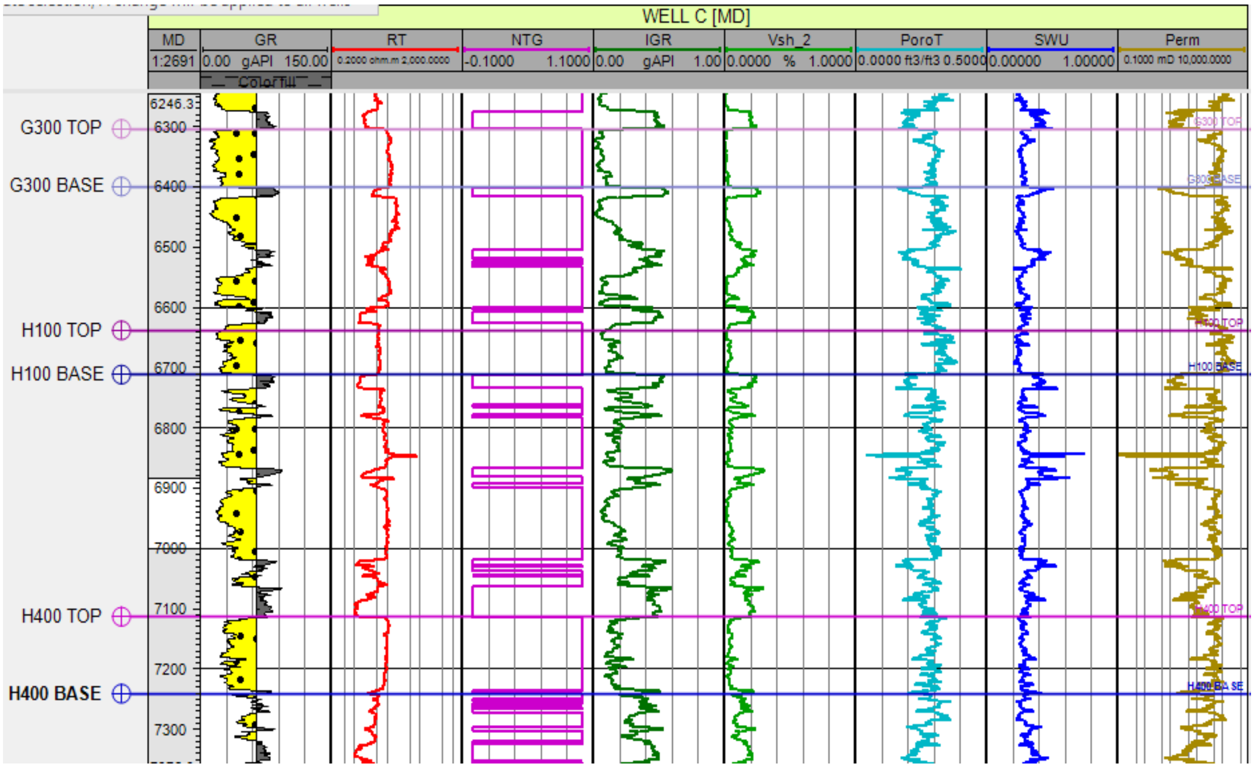

Figure 3: Variations of petrophysical parameters for well C

Table 2a: Summary of the computed petrophysical parameters acquired for Reservoir G300

(Φ)	**Porosity**	**Permeability (K) mD**	**Vshale**	**Water Saturation (S_w)**	**Net-To-Gross**
WELL A	0.26	412.48	0.05	0.33	1
WELL B	0.32	9188.83	0.07	0.17	1
WELL C	0.24	241.27	0.09	0.34	1

Table 2b: Summary of the computed petrophysical parameters acquired for Reservoir H100

(Φ)	**Porosity**	**Permeability (K) mD**	**Vshale**	**Water Saturation (S_w)**	**Net-To-Gross**
WELL A	0.31	859.83	0.07	0.28	1
WELL B	0.32	1690.39	0.09	0.22	1
WELL C	0.29	457.95	0.05	0.29	0.64

Table 2c: Summary of the computed petrophysical parameters acquired for Reservoir H400

(Φ)	**Porosity**	**Permeability (K) mD**	**Vshale**	**Water Saturation (S_w)**	**Net-To-Gross**
WELL A	0.31	623.34	0.13	0.27	0.7
WELL B	0.25	1487.56	0.10	0.23	0.89
WELL C	0.31	618.34	0.12	0.27	0.7

There is a wide difference between the range of permeability values observed within the reservoirs under study and the investigated range of values of 3.2mD – 28.0mD by Ekine and Iyabe (2009) [5] owing to possibly the restricted flow of fluid within the field. Field Y examined by Imaseun *et al.* (2011) [6] recorded a very high permeability value of 106691.5mdD which is greater than the highest value of 9188.83mD recorded. Omoboriowo *et al.* (2012) [19] recorded very low permeability values of 35.03mD – 103.68mD.

Petrophysical Modelling

The petrophysical properties calculated was done at a single point. To represent this across the entire surface, some algorithms were applied. In building a model, the petrophysical properties calculated along the well path were averaged or scaled up and then distributed across the entire reservoir surface using geostatistical techniques. The properties determined here were porosity (Figures 4a, 4d), Net-To-Gross (NTG) (Figures 4c, 4f) and permeability (Figures 4b, 4e).

In figure 4a areas marked violet have the least porosity of about 0.3, those marked deep blue have about 0.32 while regions with blue colour have porosity value ranging between 0.34 and 0.36. Similarly, the permeability model as displayed in figure 4b indicates that areas with red colour have the highest permeability and those with purple colour has the least when compared to others. The porosity model for Reservoir H100 is represented by Figure 6d. All the sections in reservoir H100 tend to have high porosity though areas with yellow have the highest while those with purple have the least value.

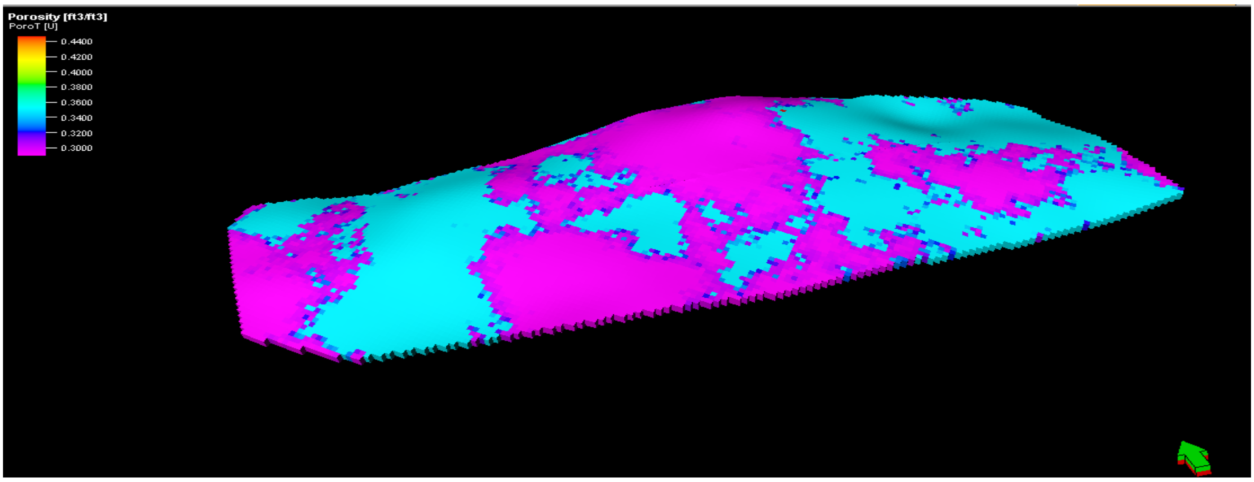

Figure 4a: Porosity model for Reservoir G300

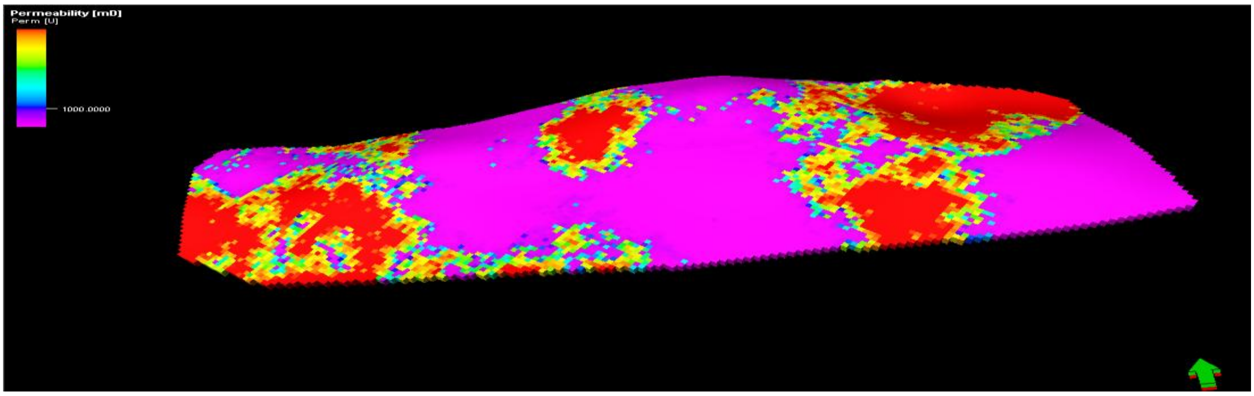

Figure 4b: Permeability model for Reservoir G300

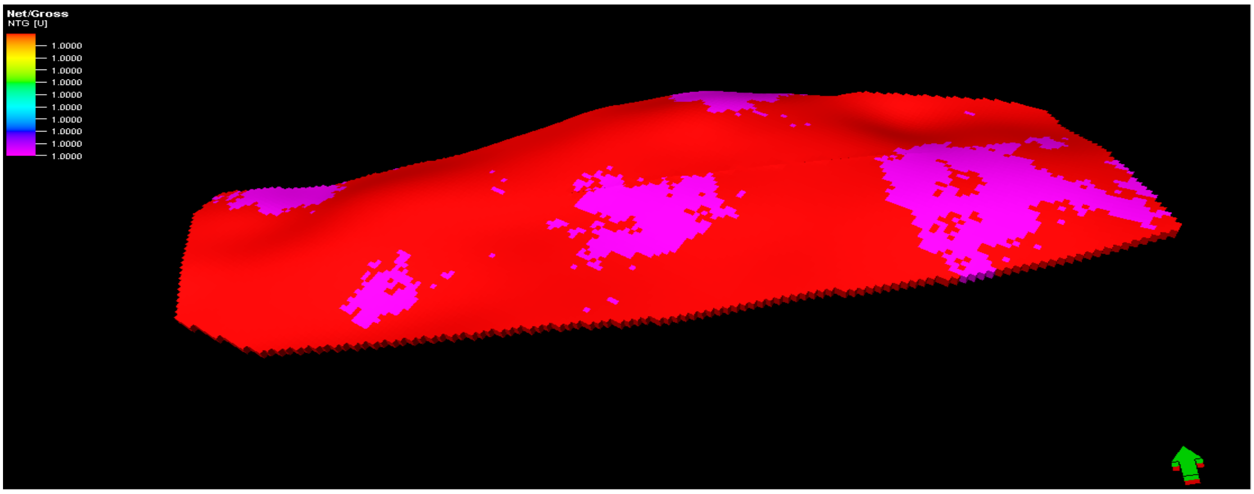

Figure 4c: Net-To-Gross model for Reservoir G300

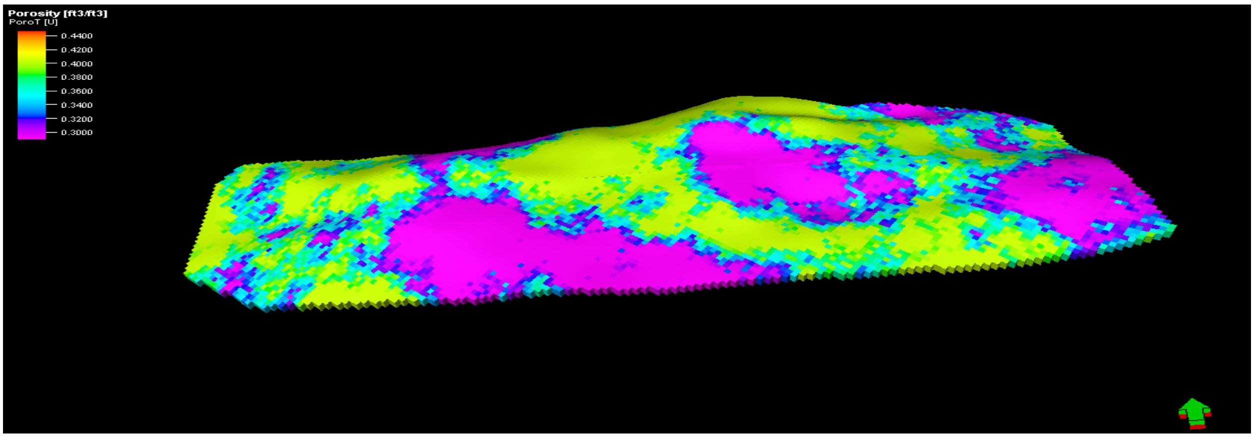

Figure 4d: Porosity model for Reservoir H100

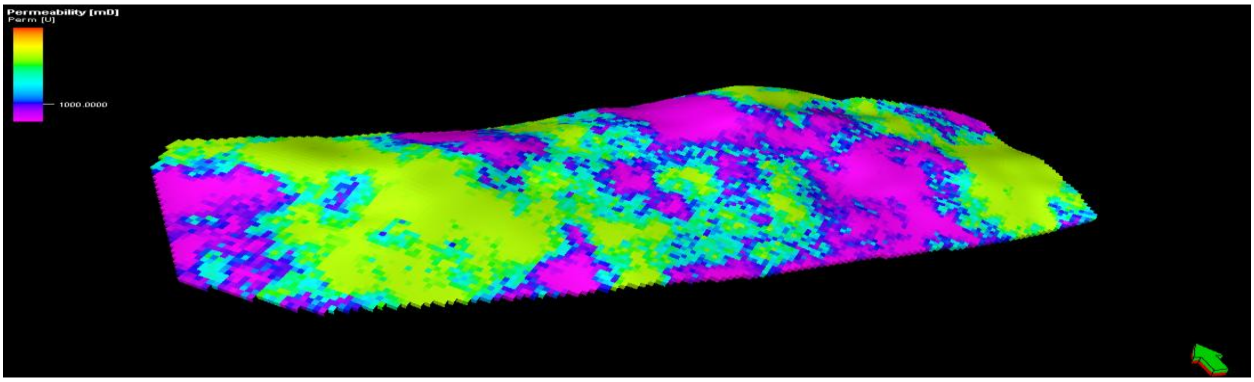

Figure 4e: Permeability model for Reservoir H100

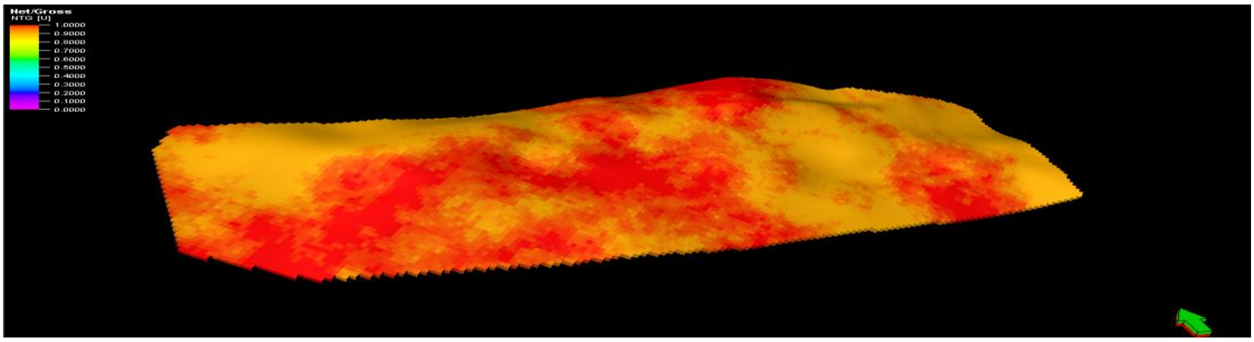

Figure 4f: Net-To-Gross model for Reservoir H100

Two horizons (horizon 1 and horizon 2) corresponding to the tops of two reservoirs (G300 and H100) and several faults were mapped across the seismic section for this analysis. To ensure a good tie, wells with their tops were superimposed on the seismic sections that intersected each other. Figure 5 displays an interpretation window showing the horizon delineating the top of the reservoir and the different faults acting below the subsurface characterising the geology of the area along inline 5422 .

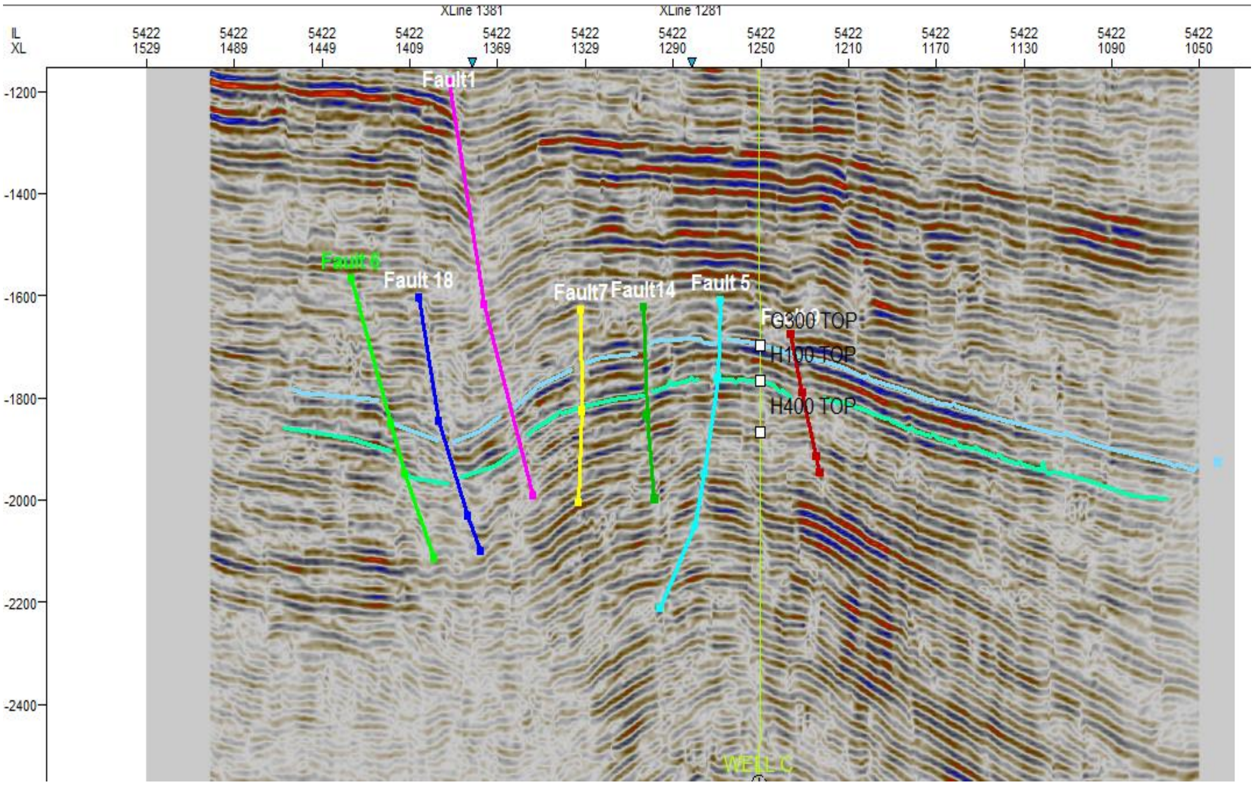

Figure 5: Inline 5422 showing interpreted faults and horizons

Figures 6a and 6b displays the top structural map of Reservoir G300 and H100 respectively. Both maps show anticlinal structures at the center of the surface which serve as traps for hydrocarbon. The locations of the wells are also within the anticlinal region. Two major faults and several others are displayed on these maps.

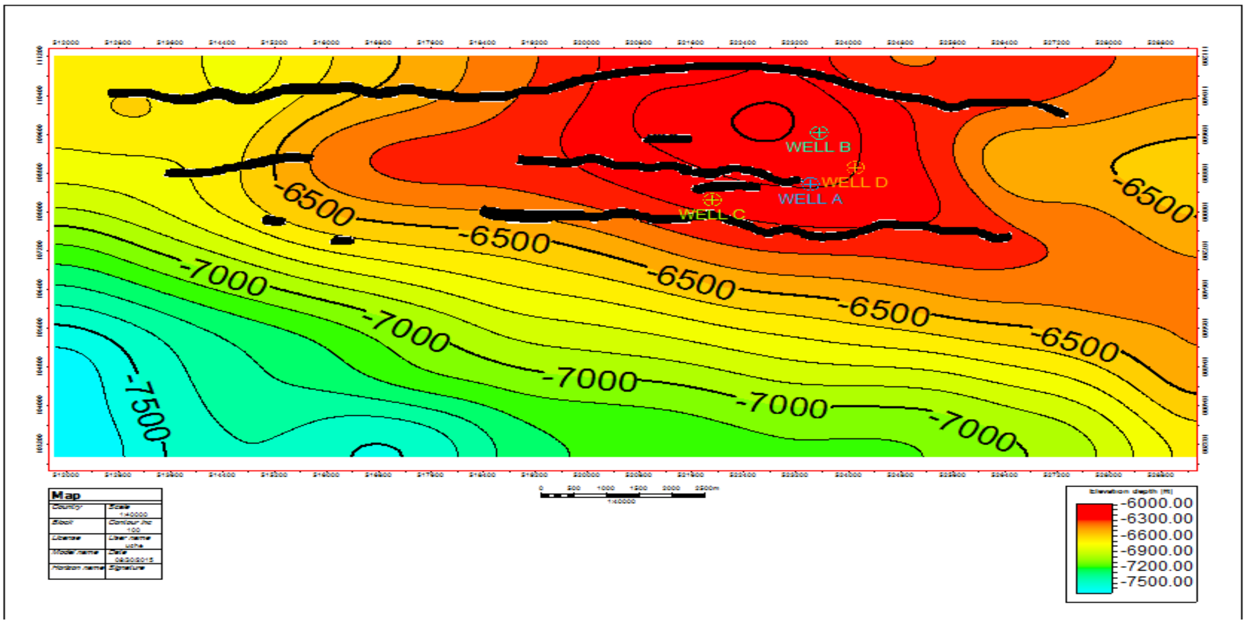

Figure 6a: Reservoir G300 top structural map

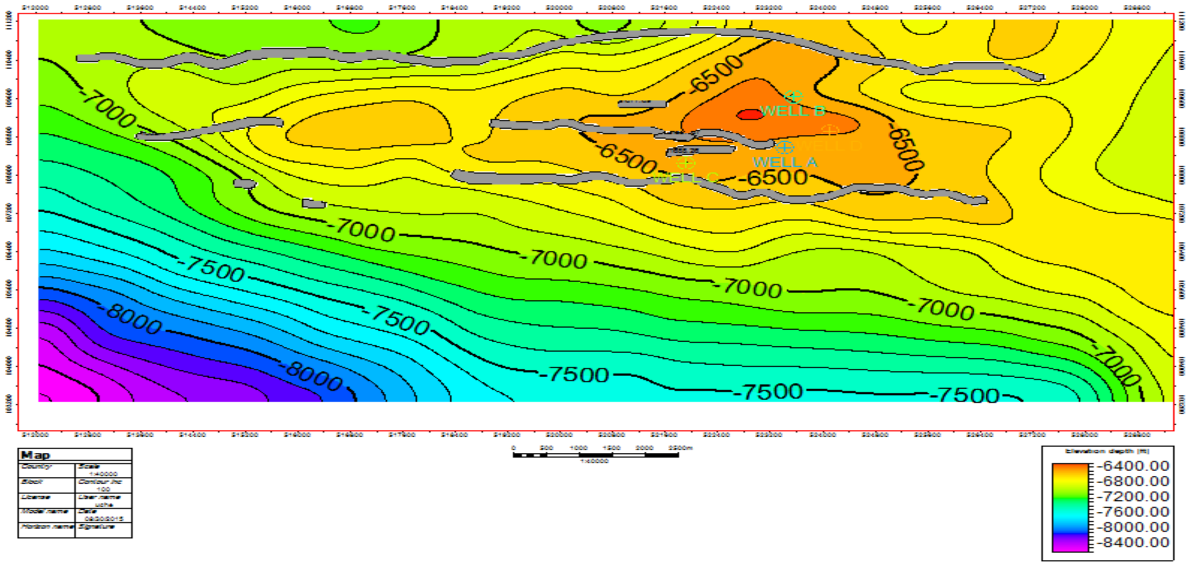

Figure 6b: Reservoir H100 top structural map

Table 3 shows the result of the volumetric analysis within the field of study. The hydrocarbon in place within the field for Reservoir G300 was estimated to be 62,739,256.3 barrels while that of Reservoir H100 was estimated as 38,808,708.4 barrels.This implies that Reservoir G300 is more prolific than Reservoir H100.

Table 3: Results of Hydrocarbon Volume Estimates for delineated Reservoirs G300 and H100

Reservoir	Area (acres)	Thickness (ft)	Bulk Volume	Porosity (Φ)	Pore Volume	Hydrocarbon Saturation (S_w)	HCPV (barrels) (S_h)
G300	650	**64**	41600	0.27	0.28	0.72	62,739,256.3
H100	710	**34**	24140	0.307	0.25	0.75	38,808,708.4

Conclusion

Three reservoirs of utmost interest have been identified in this study. These were identified with the use of the gamma ray log which aided the identification of two lithological units in the area as sand and shale and resistivity log which shows the presence of fluid content. The three reservoirs delineated were identified as hydrocarbon bearing units across wells A, B and C. The values of porosity, permeability, water saturation, net-to- gross and volume of shale were determined during the petrophysical analysis.

The time and depth maps of the reservoir generated show anticlinal structures at the centre of the surface which could serve as traps for hydrocarbon content as delineated by the petroleum system of the Niger-Delta region. The volumes of hydrocarbon of the delineated reservoirs (G300 and H100) were estimated at 62,739,256.3 barrels and 38,808,708.4 barrels respectively.

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