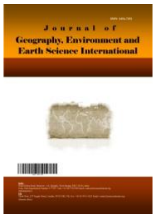

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Hydrocarbon Reservoir Characterization of 'Khume' Field, Offshore Niger Delta, Nigeria

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Authors' contributions

This work was carried out in collaboration among all authors. Authors OME and CA designed the scope of the project and thoroughly supervised the interpretation process. Author KAO performed the interpretation, managed the analyses, prepared and edited the manuscript for submission. All authors read and approved the final manuscript.

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ABSTRACT

The integrative approach of well log correlation and seismic interpretation was adopted in this study to adequately characterize and evaluate the hydrocarbon potentials of Khume field, offshore Niger Delta, Nigeria. 3-D seismic data and well logs data from ten (10) wells were utilized to delineate the geometry of the reservoirs in Khume field, and as well as to estimate the hydrocarbon reserves. Three hydrocarbon-bearing reservoirs of interest (D-04, D-06, and E-09A) were delineated using an array of gamma-ray logs, resistivity log, and neutron/density log suites. Stratigraphic interpretation of the lithologies in Khume field showed considerable uniform gross thickness across all three sand bodies. Results of petrophysical evaluations conducted on the three reservoirs correlated across the field showed that; shale volume ranged from 7-14%, total and effective porosity ranged from 19-26% and 17-23% respectively, NTG from 42 to 100%, water saturation from 40%-100% and permeability from 1265-2102 mD. Seismic interpretation established the presence of both synthetic and antithetic faults. A total of six synthetic and four antithetic faults were interpreted from the study area. Horizons interpretation was done both in the strike and dip directions. Time and depth structure maps revealed reservoir closures to be anticlinal and fault supported in the field.

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Hydrocarbon volumes were calculated using the deterministic (map-based) approach. Stock tank oil initially in place (STOIIP) for the proven oil column estimated for the D-04 reservoir was 11.13 MMSTB, 0.54 MMSTB for D-06, and 2.16 MMSTB for E-09A reservoir. For the possible oil reserves, a STOIIP value of 7.28 MMSTB was estimated for D-06 and 6.30 MMSTB for E-09A reservoir, while a hydrocarbon initially in place (HIIP) of 4.13 MMSTB of oil equivalents was derived for the undefined fluid (oil/gas) in D-06 reservoir. A proven gas reserve of 1.07 MMSCF was derived for the D-06 reservoir. This study demonstrated the effectiveness of 3-D seismic and well logs data in delineating reservoir structural architecture and in estimating hydrocarbon volumes

Keywords: Seismic interpretation; petrophysical evaluation; reservoir characterization; STOIIP; Niger delta.

ABBREVIATIONS

EUR : Estimated Ultimate Recovery
FVF : Formation Volume Factor;
GIIP : Gas Initially In Place;
GOC : Gas Oil Contact;
GRV : Gross Rock Volume;
HCPV : Hydrocarbon Pore Volume;
HIIP : Hydrocarbons Initially In Place;
HKW : Highest Known Water;
K (mD) : Permeability in millidarcies;
MMSCF : Million Standard Cubic Foot;
MMSTBO : Million Stock Tank Barrel of Oil;
NTG (frac) : Net-to-Gross in-fractions;
ODT : Oil Down To;
OWC : Oil Water Contact;
PHIE (frac) : Effective Porosity in fraction;
PHIT (frac.) : Total Porosity in fraction;
R.F : Recovery Factor;
SCF/STB : Standard Cubic Foot per Stock Tank Barrel;
STOOIP : Stock Tank Oil Originally in Place;
S_w (frac.) : Water Saturation in fraction;
TVDss : True Vertical Depth Sub-Sea;
V_{sh} (%) : Volume of Shale in percentage;

1. INTRODUCTION

Exploration of new frontiers and development of aging fields is becoming more challenging as cutting-edge and technological methods need to be used because the easy to explore hydrocarbon reserves have already been found and developed. Consequently, the oil and gas industry is forced to explore hydrocarbon in challenging environments, with the use of more complex technical skills and enhanced oil recovery methods to bring in more resources and reserves to the company portfolio [1]. To achieve this, a vast understanding of the reservoir's geological settings, reservoir heterogeneity conditions, discontinuity, and continuity of the reservoir flow with consideration of fault geometry and quantity of recoverable hydrocarbons would be required. Reservoir characterization and models are currently the most efficient tools in describing reservoirs [2]. With a proper understanding of the reservoir, oil companies can make good development decisions and reduce most of the production challenges that arise as a result of a lack of knowledge of the reservoir [3]. Reservoir characterization usually requires the incorporation of all available subsurface data such as seismic data, well logs, check shot, stratigraphic, biostratigraphic, chronostratigraphic, and cores data. These data are the result of measurements carried out by sophisticated instrumentations and processed using highly developed software [4]. Ergo, providing a geologically relevant subsurface image which will aid interpretation and reduce uncertainty.

Khume field is an aging one with little production based on information obtained from the available wells. Hence, the need for current reservoir characterization and re-evaluation to identify and optimally exploit the untapped enormous available reserves. Khume field is located in one of the OMLs in Nigeria, between X and Y fields in the offshore area of the Niger Delta (Fig. 1). It is about 10 km offshore of southern Nigeria and is situated approximately 45 feet below sea level. The field was discovered in the late nineties with the drilling of Khume-1 well and further defined by two appraisal wells, Khume-2 and Khume-3 two years later. Khume-1 was drilled on a complex northwest – southwest structural trend between the X and Y fields. Though an updip structural closure against the main fault in the trend has been mapped, interpretation is generally hampered by poor seismic imaging in the field. Till date, a total of 10 wells have been drilled in Khume field. Khume field consists of two fault blocks located between X and Y fields. The structure is an east-west trending, faulted anticlinical structure cresting at Khume-1. The field is essentially a faulted anticline separated into 4 blocks by a series of faults antithetic to the major Khume – Y fault. The drive mechanism in most of the reservoirs in Khume field is mainly depletion type, with secondary gas cap expansion. Moderate to strong aquifer influence has equally been observed in some reservoirs. Reservoir pressure declines above 50% of the initial reservoir estimate are quite common. Thus, the quest for more potential hydrocarbon reserves. For this study, integration of seismic data and well logs data from 10 wells were utilized to delineate the subsurface structural geometry, stratigraphy, and hydrocarbon trapping potential of three reservoirs – D04, D06, and E09A – in Khume field, and as well as to estimate the hydrocarbon reserves and predict the future production.

1.1 Study Objectives

- Delineation of hydrocarbon-bearing sands from well-log correlation using the different logs' motifs.
- Evaluate petrophysical properties including volume of shale (V_{sh}), effective porosity (Ø), Permeability (K), water saturation (S_w), hydrocarbon saturation (S_h).
- Generation of a synthetic seismogram to ensure that the seismic reflections in time correspond to its correct lithological depth within the subsurface.
- Seismic interpretation (fault picking and horizon mapping) to better understand the structural framework and trapping mechanisms in the field.
- Estimate the hydrocarbon volumes (Stock Tank Oil Originally in Place) in the identified reservoir prospective areas.

2. DATA SET AND METHODOLOGY

2.1 Data Set

This study utilized geophysical data sets such as:

- Well Headers for all the wells
- Well deviation surveys for all the wells
- Wireline logs (in ASCII) for all the wells
- Formation well tops
- 3-D seismic data (SEG-Y format)
- Checkshot survey for Khume-2

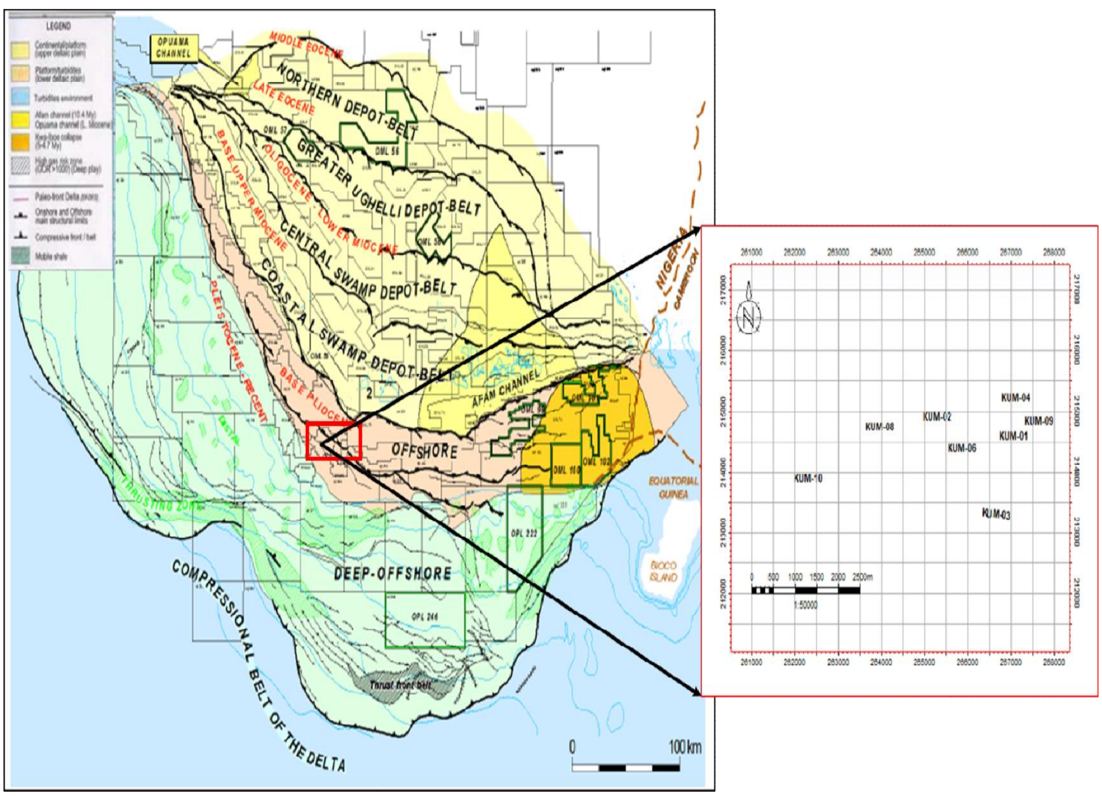


Fig. 1. Location of Khume Field (accentuated in red box) in the offshore area of the Niger Delta Basin (modified after [5])

Well headers were provided for all the ten wells available. The well header contained the well names, the geographic coordinates (Eastings and Northings), the well datum reference values (Kelly Bushing, KB), and the total drilled depth for each of the wells. The well header information was cross-checked with those found on the log headers for any discrepancies. The well header information was finally loaded into Petrel software. Before loading any data into Petrel, the unit system for the wells, well logs, and seismic data were programmed into the software. The depth of drilled wells, well deviations, well logs, and checkshot survey depths were all in feet while seismic data was made available in milliseconds (ms). The well deviation survey file housed the exact well trajectory. Important information contained within the deviation file included the drilled depth (in feet), the azimuth, and the inclination (dip) for the well. This information is all that is needed to calculate the true vertical depth of the well.

The well logs, which were provided in ASCII format, were also loaded into Petrel and attached to their respective templates. The log suites available included gamma-ray log (GR in gAPI unit), caliper log (CALI in meters), resistivity log (RES in Ohm.m), density log (RHOB in g/cm^3), neutron log (NPHI in m^3/m^3) and sonic log (DT in µs/ft). The 3-D seismic data, which was in SEG-Y format, consisting of 410 in-lines and 570 crosslines and covering an aerial extent of 146.06 km^2, was similarly imported into Petrel software using the appropriate template. To cover the study area, the seismic data was interpreted at a step increment of 10 intervals on both in- and cross-lines. The seismic data along with the well points were used to generate a base map for the study as presented in Fig. 2. This study was carried out in two collaborative and interconnected stages – Well log correlation/ Formation Evaluation and Seismic data interpretation (Fig. 3). The workflow employed for this study is shown in Fig. 3.

2.2 Well Log Correlation / Formation Evaluation

Lithology identification was achieved with the aid of the gamma-ray (GR) and resistivity logs. Three (3) reservoir sand units (Sand D-04, Sand D-06, and Sand E-09A) were identified and correlated based on the back-stepping (low reading) of GR log and a high deflection to the right of the resistivity log. These reservoirs were selected based on their hydrocarbon-bearing potentials. The sand bodies' correlations were also supported by the fairly straight behavior of the caliper tool and the wide crossing/overlapping of the neutron-density logs. The larger the crossing between the neutron and density logs, the better the quality of the sand. The line of correlation was chosen to reflect the structural and stratigraphic trend of the subsurface. Petrophysical parameters such as shale volume (V_{sh}), effective porosity ($Ø_E$), permeability (K), water saturation (S_W), etc. were thereafter determined.

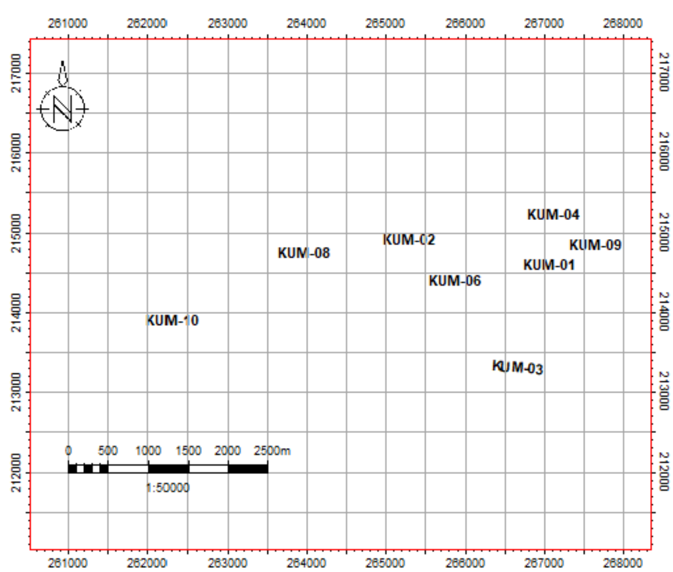


Fig. 2. Base map of Khume field showing the well locations and the survey extent

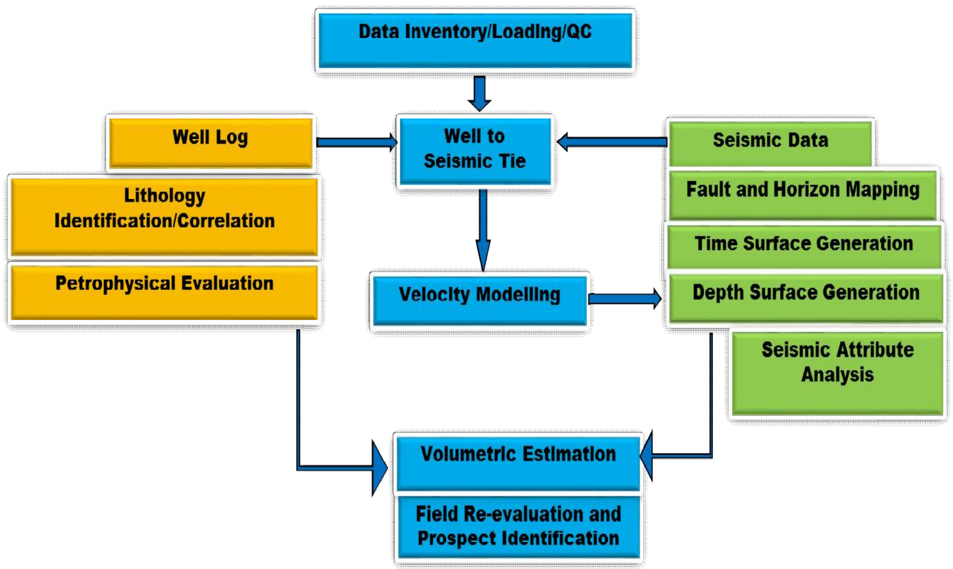


Fig. 3. Workflow employed for the study

2.3 Seismic Interpretation

Upon successful completion of the well logs correlation and loading of the formation well tops to the software interface (Petrel 2017), potential reservoirs identified on well logs were, afterward, tied to the seismic data using available check shot data to generate a synthetic seismogram for the field (Fig.4). The generated synthetic seismogram was then placed side by side with the original seismic data and compared for a match. A good match was achieved after a bulkshift of -10 ms (Fig. 4). Thereafter, the observed faults were picked, first on the time slices using the variance attribute, before subsequently picking them on the inline direction and then quality checked on the crossline direction. Following a successful faults mapping, the corresponding seismic events were then interpreted through on inlines and crosslines using an increment of 10 steps. As expected, seismic reflection events (horizons) terminated across faults and either continued in an updip or downdip manner on the other end depending on the dip angle. Seeded grids generated from the resulting horizons were thus converted to time surfaces using a convergent interpolation algorithm and thereafter contoured and examined using seismic attributes to reveal the structural geometry. Next, the surfaces were smoothened and then depth converted to depth structure maps using the time-depth relationship (TDR) obtained from the synthetic seismogram (Fig. 4).

2.4 Map-Based Volumetrics

Prospect identification was achieved using the depth structure maps and seismic attributes. The map-based hydrocarbon volumes were estimated using the derived statistical average petrophysical parameters, together with the calculated areas from each defined prospect's closures. The map-based original oil in place volume was estimated as follows;

$$STOIIP = \frac{7758 \times \mathrm{A} \times \mathrm{h} \times \emptyset \times \mathrm{NTG} \times (1 - \mathrm{Sw})}{\mathrm{Boi}}$$

Gas initially in place (GIIP) was similarly estimated as;

$$GIIP = \frac{43560 \times \mathrm{A} \times \mathrm{h} \times \emptyset \times \mathrm{NTG} \times (1 - \mathrm{Sw})}{\mathrm{Bgi}}$$

Where;

STOIIP= Stock tank oil initially in place in million stock tank barrel (MMSTB)
A = Area of the reservoir prospect (in squared meters)
h = thickness of the reservoir (in meters)
Ø = Effective porosity (in frac.)
NTG = Net to Gross ratio (in frac.)
S_w = Water saturation (in frac.)
B_{oi} = Formation Volume Factor for oil
GIIP= Gas initially in place at standard conditions in standard cubic feet (scf)
B_{gi} = Formation Volume Factor for gas

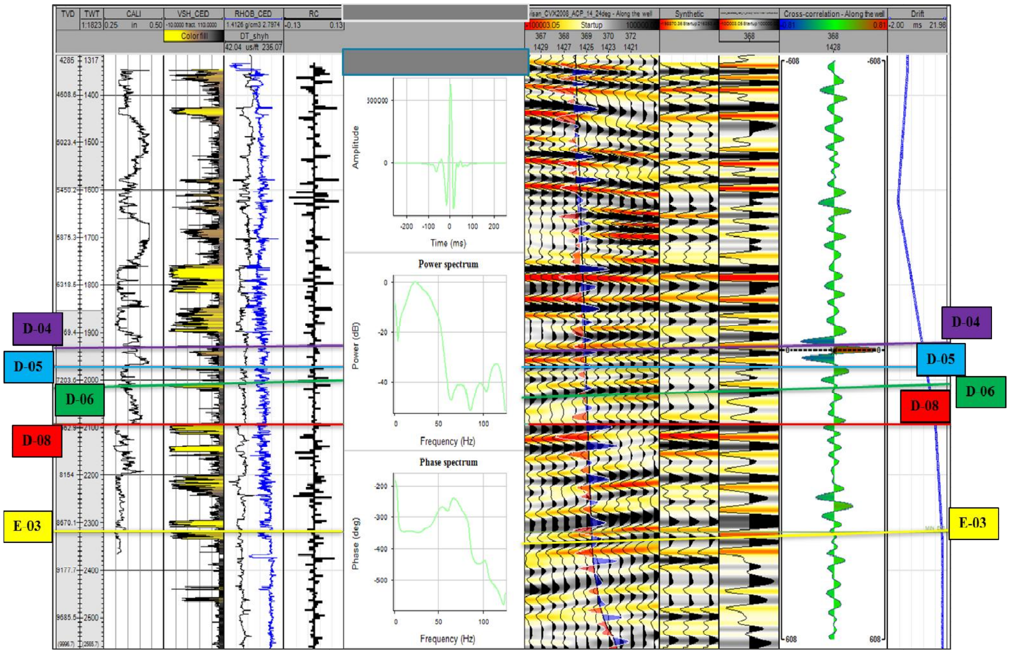


Fig. 4. Synthetic seismogram generated for Khume-02

3. RESULTS AND DISCUSSION

3.1 Well Correlation/ Stratigraphic Interpretation

To establish the lateral extent and continuity of potential sands accommodating hydrocarbons within the field, a careful examination and correlation of the well logs was carried out using an integration of both the GR log and Resistivity log in all the ten wells (Fig. 5). This was achieved by Combining areas of low GR log readings (backstepping of the GR log curve) with areas of high resistivity log readings. Gamma-ray values which deflected to the left of the established cut-off indicated clean sand (reservoir lithology) while deflections to the right of the cut-off indicated shales (Non-reservoir lithology). The sand/shale cutoff was selected as the mid-point between the sand baseline and the shale baseline for each well.

Stratigraphic interpretation of D-04 reservoir across Khume field presented a considerable uniform gross thickness, with the gamut being within 59 ft to 72 ft. Three (3) sand lobes were similarly exhibited by the reservoir across the field (Fig. 5a). D-06 sand package only revealed itself as a sand lobe across the field and had a gross thickness within the range of 27 ft to 35 ft across the field (Fig. 5b); whilst two (2) sand lobes were observed in E-09A reservoir with gross thickness in the range of 27 ft to 35 ft (Fig. 5c). Fig. 5(a-c) depicts the stratigraphic correlation for the three (3) reservoirs of interest– D-04, D-06, and E-09A sand packages respectively.

3.2 Petrophysical Evaluation of Khume Field Reservoirs

Results of petrophysical evaluation conducted on the three reservoirs of interest (D-04, D-06, and E-09A), correlated across the field, showed that; shale volume ranged from 7-14%; total and effective porosities ranged from 19-26% and 17-23% respectively; NTG from 42 to 100%; water saturation from 40%-100% and permeability from 1265-2102 mD. [6] classified porosity as follows; <5% (negligible), 5-10% (poor), >10-20% (good), >20-30% (very good), >30 (excellent). He similarly classified reservoir quality based on permeability 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 Rider's classification, total porosity recorded in this study can be classed as very good, while effective porosity can be ranked as good to very good. Overall, using Rider's classification, the three reservoirs can be categorized as having excellent quality. Detailed information on the petrophysical evaluation results obtained for the individual reservoir across all ten wells is shown in Table 1.

From the values evinced from the table, it is observed that porosity in the Field decreases decreases with depth i.e., D-04 sand has the average highest porosity value of 25.0%, while E-09A sand has the lowest value of 20.0%. NTG similarly follows the same trend of decreasing value with depth (Table 1). D-06 sand has the highest gross thickness value, 143.0 ft., while E-09A sand has the least thickness values of 22.5 ft. The net-to-gross ratio preserved the pattern of gross thickness, and this resulted in D-06 sand still having the highest net thickness and E-09A sand having the least net sand thickness (Table 1). The reservoir intervals within Khume field are considerably good vis-à-vis reservoir properties.

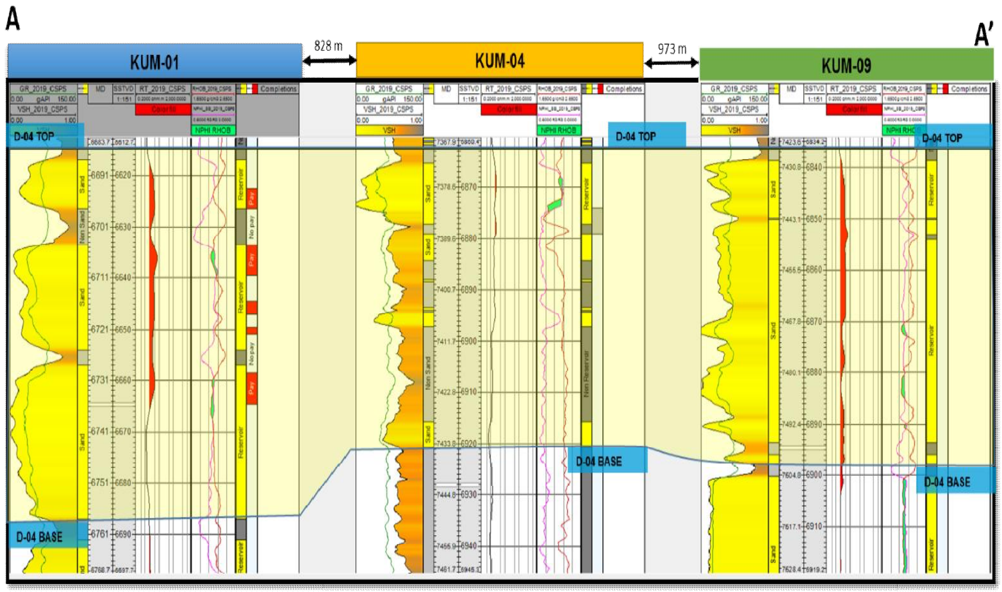


Fig. 5a. D-04 reservoir stratigraphic well correlation panel *(D-04sand flattened on the top marker)*

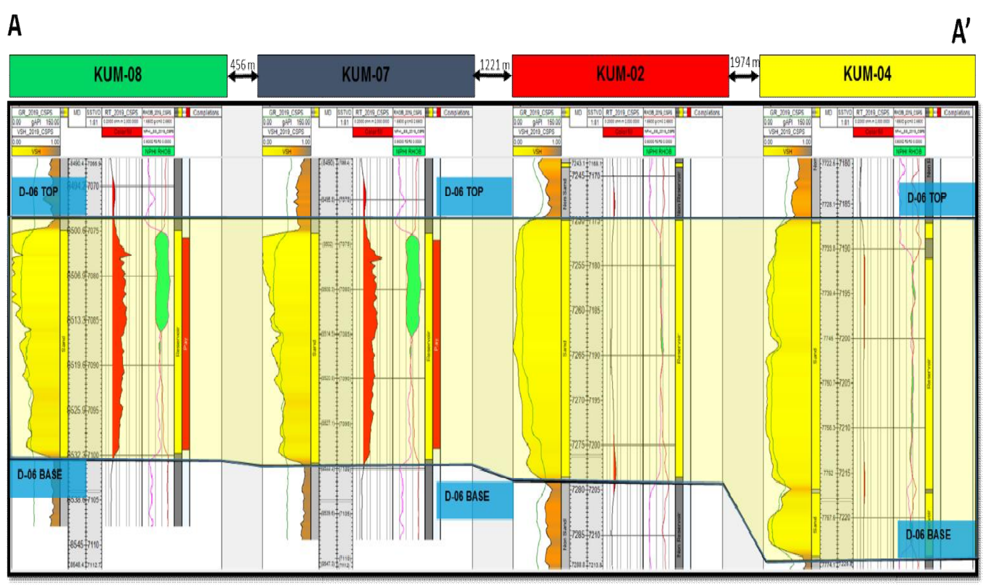


Fig. 5b. D-06 reservoir stratigraphic well correlation panel *(D-06 sand flattened on the top marker)*

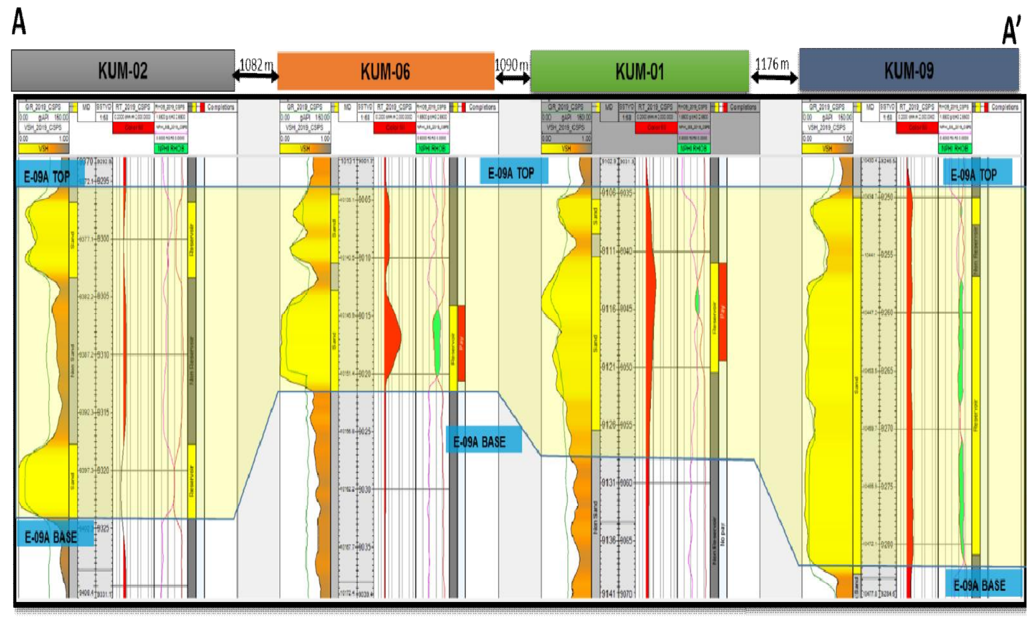


Fig. 5c. E-09A reservoir stratigraphic well correlation panel *(E-09A sand flattened on the top marker)*

Table 1. Average petrophysical estimates across the ten wells

Well Name	Sand	Top (ft.)	Base (ft.)	Gross Thickn (ft.)	Net Thickn (ft.)	V_{sh} (%)	NTG (frac.)	PHIT (frac.)	PHIE (frac.)	S_w (frac.)	K (mD)	Fluid Contacts
Khume-01	D-04	6619	6707	88.00	71.50	8.00	0.81	0.25	0.23	0.83	1966	OWC @ 6671 ft.;
	E-09A	9036	9058	22.50	9.50	11.00	0.42	0.19	0.17	0.58	1266	ODT @ 9058 ft.
Khume-02	D-06	7169	7218	49.00	49.00	7.00	1.00	0.25	0.23	1.00	1966	HKW @ 7174 ft.
	E-09A	9293	9343	50.00	13.00	13.00	0.26	0.22	0.19	1.00	1592	------------
Khume -04	D-06	7186	7328	143.00	108.00	11.00	0.76	0.23	0.21	0.99	1711	HKW @ 7186 ft.;
Khume-07	D-06	6973	7012	39.00	31.00	14.00	0.79	0.26	0.22	0.50	2102	GOC @ 7086 ft. ODT @ 7100 ft.;
Khume-08	D-06	7074	7099	24.70	24.30	9.00	0.98	0.23	0.21	0.40	1711	GOC @ 7086 ft. ODT @ 7100 ft.
Khume-09	E-09A	9249	9283	33.90	26.70	10.00	0.79	0.19	0.17	1.00	1265	HKW @ 9249 ft.

3.3 Seismic Interpretation

Poor resolution (image quality) of the seismic data over the entire reservoir intervals thwarted interpretation of the field, however, major and minor faults were still mapped based on observed linear features in the seismic data. A total of ten faults were mapped across the field (Fig. 6a). These were listric faults that are typical of the Niger Delta growth structures and form the major structural trap types identified in the Niger Delta [7], [8], [9], [10]. Six of the faults were synthetic, while four were antithetic (Fig. 6a). With the guidance of the picked faults, seismic reflection events corresponding to the reservoirs of interest – D-04, D-06, and E-09A – were carefully picked across the entire field using the well tops on both inlines and crosslines on an incremental step of 10 (Fig. 6b). The resulting horizons were, thereafter, converted to time structure maps using a convergent interpolation method. The time structure maps were then converted to depth structure maps using the mathematical relationship obtained by plotting the time-depth relationship gotten from the check shot data. The resulting depth structure maps are as presented in Fig. 7. Identified closures on the time structure maps were preserved on all the depth maps (Fig. 7(a-c)).

From the structural maps, derived from the interpreted faults and horizons, it can be seen that all the sand bodies examined in this study are bound by just one bounding fault, situated northward of the sands and internal faults which divided the sand into four (4) fault blocks i.e. blocks 1 – 4 (Figs. 7a-c). These reservoirs were trapped by fault-assisted dip closures and should normally prevent leakage of any potential hydrocarbon. Anticlinal structures, as evinced in Khume Field, have been proven to contain hydrocarbon in Niger Delta [7], [11] and [12].

3.4 Deterministic (Map-Based) Volumetrics

3.4.1 D-04 reservoir hydrocarbon volume estimation

Fig. 8 presents the fluid distribution map for D-04 reservoir. It can be clearly seen that D-04 reservoir contains only oil reserves. This was proved by KUM-01 which logged an Original Oil Water Contact (OOWC) at -6671 ft TVD_{ss} (Fig. 9). The oil was calculated to be just 42 ft thick. The result of the map-based volumetric estimation for reservoir D-04 is presented in Table 2. Stock tank oil initially in place (STOIIP) calculated for the D-04 reservoir interval was 11.13MMSTBO (Table 2). With a recovery factor (R.F) of just 10%, only 1.11 MMSTBO estimated ultimate recovery of oil can be derived from this reservoir (Table 2). These reserves can be exploited through a new drill in the form of a side-track well or through a rigless work-over.

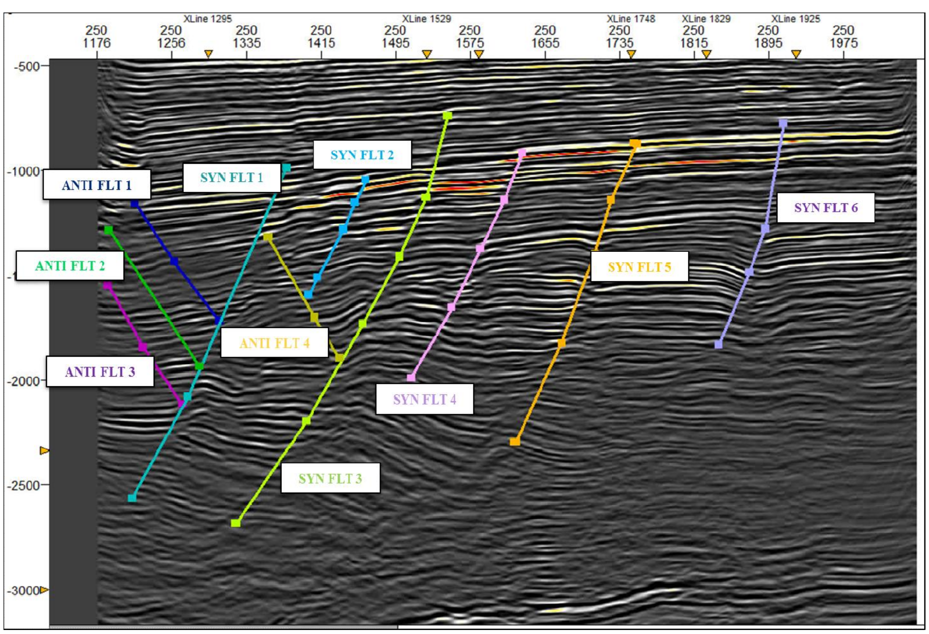


Fig. 6a. Interpretation window displaying the different faults picked in Khume Field

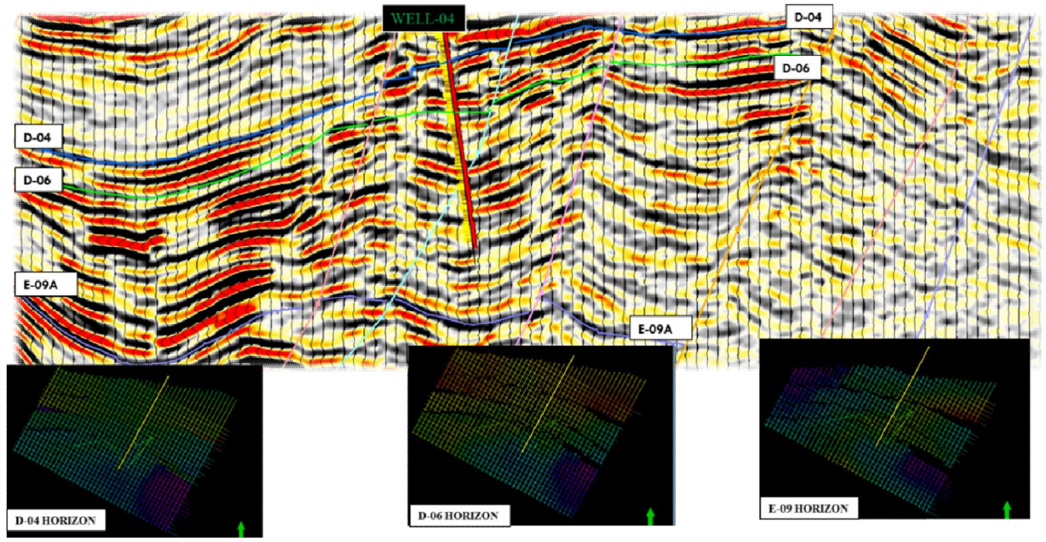
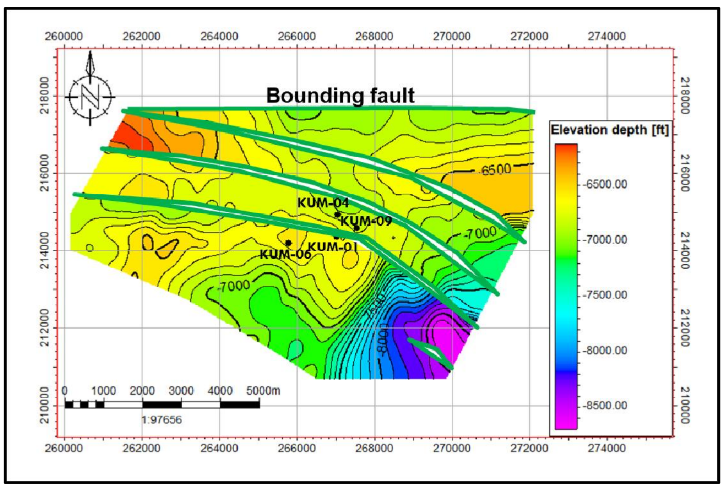
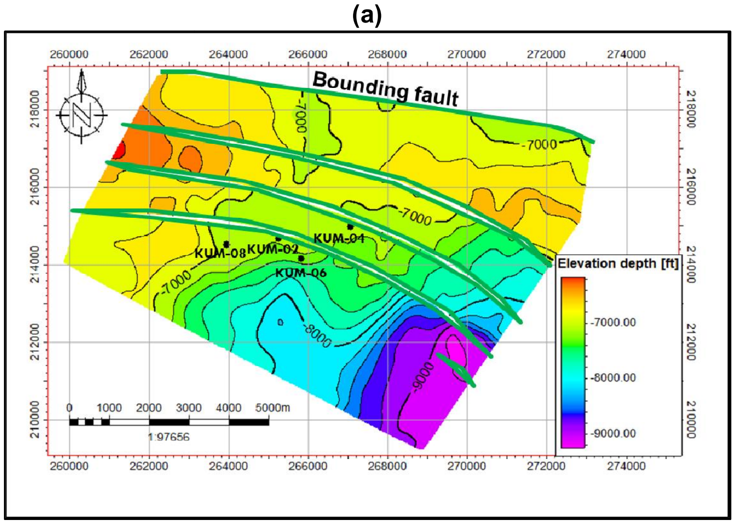


Fig. 6b. A 2-D window showing the different horizons mapped across the field



(a)



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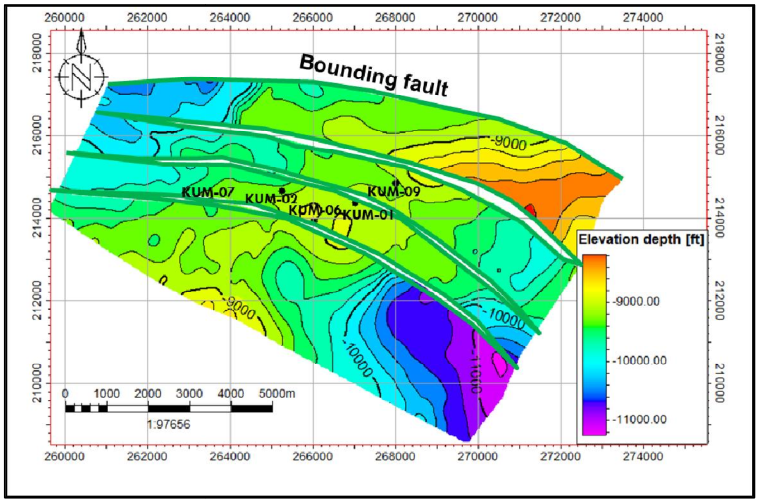

(c)

Fig. 7. Depth structure map of (a). D-04 Sand, (b). D-06 Sand and (c). E-09A Sand

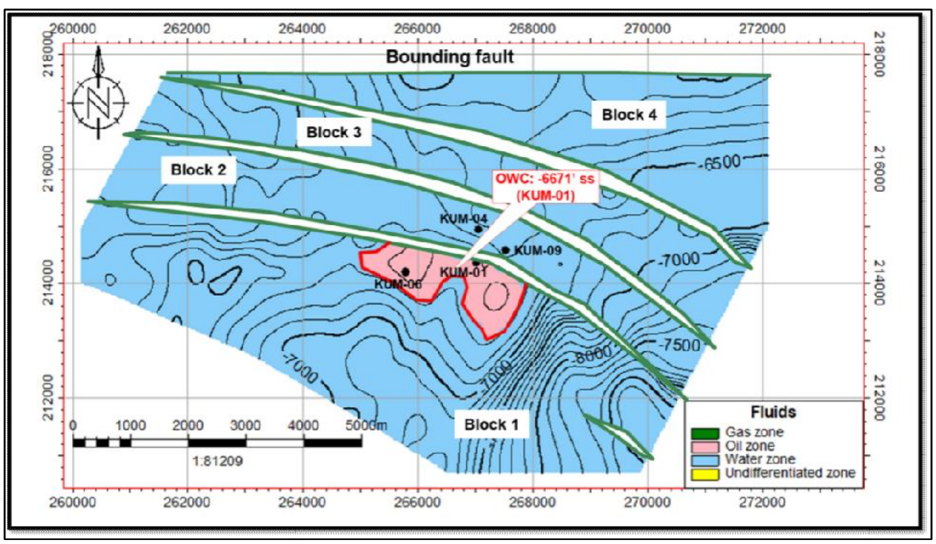

Fig. 8. Original Fluid distribution map of D-04 reservoir

Table 2. Map-based volume estimation for D-04 reservoir

Parameter	Average value
OWC	-6671 ft-TVD_{ss}
Area –Oil (acre)	469.28
GRV –Oil (acre.ft)	20465
HCPV –Oil (acre.ft)	2433
Reservoir NTG	0.70
Reservoir Avg Porosity	0.29
Pay Avg S_w	43%
FVF, oil (B_{oi})	1.696
STOOIP (MMSTBO)	11.13
Recovery Factor (R.F)	10%
Estimated Ultimate Recovery (EUR) (MMSTBO)	1.11

3.4.2 D-06 reservoir hydrocarbon volume estimation

Oil, gas, and undefined fluids were found in D-06 reservoir (Fig. 9). The oil and gas zones were found in block 1, while unknown zones existed in both blocks 1 and 2 of the reservoir (Fig. 9). The unknown zone in block 1 can only be oil based on its occurrence, whilst that in block 2 can either be oil or gas (Fig. 9).

The proven oil column was 14 ft., while the proven gas column was 13 ft. A STOIIP of 0.54 MMSTBO and EUR of 0.054 MMSTBO was calculated for the proven oil column in D-06 reservoir (Table 3); whereas a gas initially in place (GIIP) value of 1.07 MMSCF was estimated for the proven gas columns in D-06 reservoir, and with an R.F of just 10%, only 0.11 MMSCF estimated ultimate recovery of gas can be derived from the reservoir (Table 3). A STOIIP value of 7.28 MMSTBO was obtained for the possible oil column in block 1 of the D-06 reservoir, while a HIIP of 4.13 MMSTB of oil equivalents was derived for the undefined fluid (oil/gas) in D-06 block-2 reservoir. Details of the volumetric estimation for D-06 reservoir are presented in Table 3.

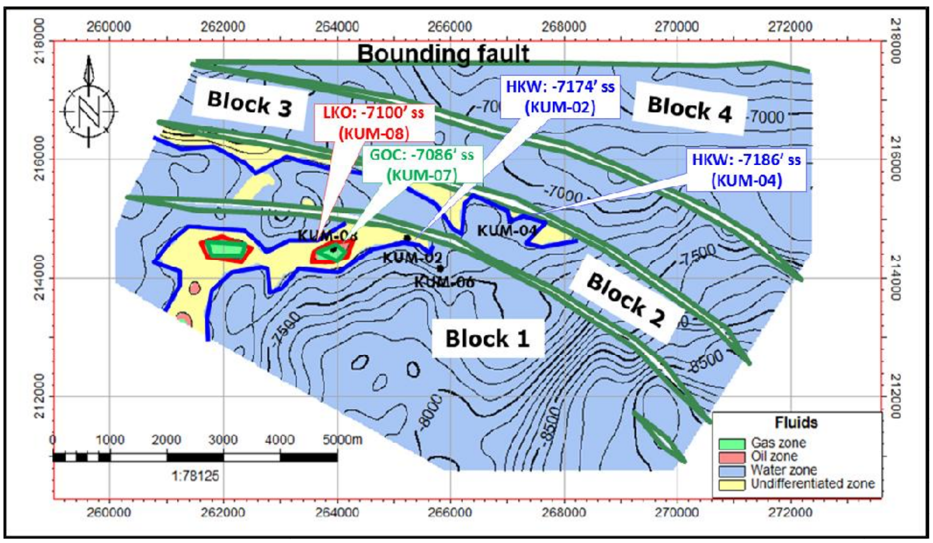

Fig. 9. Original Fluid distribution map of D-06 reservoir

Table 3. Map based volume estimation for D-06 reservoir

Petrophysical Parameters	Proven Oil Column	Proven Gas Column	Possible Oil Column	Block 2 Undefined Fluid
Reservoir Interval (ft-TVD$_{ss}$)	7086 – 7100	7073 – 7086	7100 – 7174	7100 – 7186
Hydrocarbon Type	Oil	Gas	Oil	Oil/Gas
GOC or HKO (ft-TVD$_{ss}$)	-7086	-7086	-----------------	-----------------
OWC or LKO (ft-TVD$_{ss}$)	-7100	-----------------	-7100	-7100
HKW (ft-TVDSS)	-----------------	-----------------	-7174	-7186
Area (acre.ft)	99.4	-----------------	678.3	422.33
GRV (acre.ft)	1645	1645	10818	6312
HCPV/Pore Volume (acre.ft)	123	426	1591	902
Reservoir NTG	0.88	0.88	0.88	0.88
Reservoir Average Porosity	0.24	0.24	0.24	0.24
Pay Average S_w	0.43	0.43	0.43	0.43
FVF, oil (B_{oi})/gas (B_{gi})	1.696	0.9072	1.696	1.696
STOOIP/GIIP	0.54 MMSTB	1.07 MMSCF	7.28 MMSTB	4.13 MMSTB
Recovery Factor (R.F)	10%	10%	10%	10%
Estimated Ultimate Recovery (EUR)	0.054 MMSTB	0.11 MMSCF	0.73 MMSTB	0.41 MMSTB

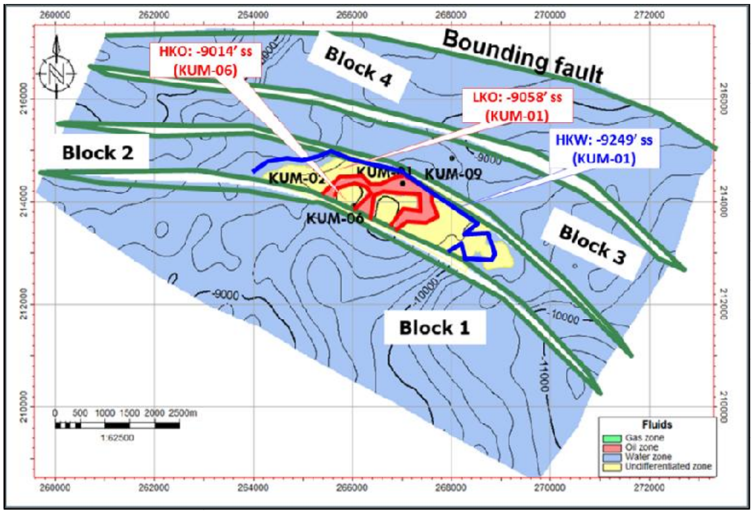

Fig. 10. Original Fluid distribution map of E-09A reservoir

Table 4. Map based volume estimation for D-06 reservoir

Petrophysical Parameters	**Proven Oil Column**	**First Possible Oil Column**	**Second Possible Oil Column**
Reservoir Interval (ft-TVD_{ss})	9014 – 9058	9003 – 9014	9058 – 9249
Hydrocarbon Type	Oil	Oil	Oil
GOC or HKO (ft-TVD_{ss})	-9014	-9014	-9058
OWC or LKO (ft-TVD_{ss})	-9058	-----------------	-9249
HKW (ft-TVD_{ss})	-----------------	-----------------	-----------------
Area (acre.ft)	352.11	149.67	814
GRV (acre.ft)	6560	2064	17073
HCPV/Pore Volume (acre.ft)	413	140	1063
Reservoir NTG	0.58	0.58	0.58
Reservoir Average Porosity	0.19	0.19	0.19
Pay Average S_w	0.34	0.34	0.34
FVF, oil (B_{oi})/gas (B_{gi})	1.482	1.482	1.482
STOOIP	2.16 MMSTB	0.73 MMSTB	5.57 MMSTB
Recovery Factor (R.F)	30%	30%	30%
Estimated Ultimate Recovery (EUR)	0.65 MMSTB	0.22 MMSTB	1.67 MMSTB

3.4.3 E-09A reservoir hydrocarbon volume estimation

Fig. 10 shows the fluid distribution map for the E-09A reservoir. One proven oil column and two (2) possible oil zones were delineated for the E-09A reservoir (Fig. 10). The proven oil column had an estimated thickness of 44 ft while differences in size existed for both possible oil zones. A STOIIP value of 2.16 MMSTBO was calculated for the proven oil zone and, with a recovery factor of 30%, a EUR of 0.65 MMSTBO was estimated for the reservoir (Table 4). These proven reserves, when exploited, will improve the overall production capacity of Khume Field. The first possible oil column had an estimated STOIIP of 0.73MMSTBO and EUR of 0.22 MMSTBO, whilst the bigger possible oil column had a STOIIP of 5.57 MMSTBO and EUR of 1.67 MMSTBO (Table 4).

4. CONCLUSION

Three reservoirs at different intervals in the well logs were mapped in the field. Average petrophysical parameters from the well-logs showed a good-excellent reservoir quality. Seismic interpretation of Khume Field revealed that the reservoir intervals are anticlinal and structurally controlled by synthetic and antithetic faults. The closures identified on all three reservoirs are fault-supported anticlines.

Deterministic (map-based) volumetrics showed the existence of prospective volume of hydrocarbons in all three reservoirs. Depending on petroleum economics, these prospects can be harvested via drilling of a side-track well or via a rig/rigless work-over such as the addition of a new perforation, zone switch, etc. Ergo, improving production from Khume Field.

DISCLAIMER

The products used for this research are commonly and predominantly used products in our area of research and country. There is absolutely no conflict of interest between the authors and producers of the products because we do not intend to use these products as an avenue for any litigation but for the advancement of knowledge. Also, the research was not funded by the producing company rather it was funded by personal efforts of the authors.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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