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Research paper

3D seismic interpretation and prospect identification of the dembe field offshore, Niger delta, Nigeria

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Abstract

3D seismic interpretation and prospect evaluation has been carried out in a hydrocarbon bearing field, standard method of seismic interpretation which includes fault interpretation, well-seismic tie, and horizon mapping were carried out with the aid of seismic attributes such as variance edge and root mean square attributes. Well-seismic-tie established a reasonable tie and indicated that the identified reservoirs were of low impedance as the top of this reservoirs coincided with the troughs. TWT vs Depth plot showed a linear trend which aided in creating a velocity model for the time-depth conversion. Fault mapping revealed that the area was divided into 8 blocks by regionally extensive faults associated with several minor faults which are normal and listric in geometry. Petrophysical analysis showed that the reservoirs has an average porosity of 0.24, water saturation of 0.35, and net-to-gross of 0.78 which are favourable reservoir conditions. A lead Dembe-3, and 2 prospects Dembe-1 and Dembe-2 were identified. Volumetric estimation shows that the prospects boasts of a combined petroleum reserve of about 134 MMSTB of recoverable oil and about 167 BCF of recoverable gas. The results from this study show that, away from currently producing zones of the Dembe field, additional lead and prospects exist which could be further explored to optimize hydrocarbon production in the field.

Keywords: *3d Seismic; Lead; Normal Fault; Niger Delta; Prospect.*

1. Introduction

Prior to this project, this field has been surveyed and interpreted which has led to drilling of some exploratory wells. Although it is a producing field, the ultimate goal of this project is to interpret the kind of structures that support hydrocarbon accumulation and establish the spatial extent of the reservoir within the area. Additionally, to also identify and delineate potential prospects in the area. It is against these background that this work focuses on the 3D seismic interpretation and prospect identification of the Dembe Field in Niger Delta in order to explore for hydrocarbon and identify prospect.

3D seismic is a geophysical method used to interpret subsurface geology and it is a valuable tool in allocating potential drilling targets. As a field is developed from its initial discovery, a large volume of well, seismic and production data are established and with the integration of these data set, the accuracy of the subsurface interpretation is improved overtime. Understanding the subsurface geology is of paramount importance to discover hydrocarbon-bearing reservoirs and efficiently extract the hydrocarbon. The study area lies within the Shallow Offshore Depo-belt of the Niger Delta Basin. The Niger Delta Basin ranks as one of the major hydrocarbon provinces of the world with ultimate recovery presently estimated at close to 40 billion barrels. The production of oil and gas is from accumulation in the pore spaces of reservoir rocks. The formation is characterized by alternating sandstone and shale units (Agbada Formation) varying in thickness from 100 ft to 1500 ft, the Niger Delta hydrocarbons are trapped mainly by growth faults, rollover anticlines and collapsed crest structures which are characteristic of extensional deformation.

The findings of this study would be beneficial to the nation, oil companies, researchers and investors in general. Specifically, the results would be beneficial to Nations especially Nigeria that almost has total dependence on the Petroleum sector for revenue generation. Increased energy use from hydrocarbon has been connected to better quality of life and higher GDP, since hydrocarbon is a major economic drive of the society. Consultation of the finished work by students and researchers in education sector, would contribute to their further studies with respect to hydrocarbon exploration using seismic. It will widen their knowledge on the modern approach to hydrocarbon exploration. The findings of the study would as well be an eye opener to the investors who are looking forward to exploring by rejuvenating an already existing oil field or even increasing yield.

1.1. Regional geology

Niger Delta Basin is a large arcuate Delta situated at the West African margin of the Gulf of Guinea and occupies an area extent between Longitude 4º - 9º E and Latitude 4º – 6º N. The basin is Cenozoic in age and covers a sub-aerial extent of about 75,000 km^2, a total area of about 300,000 km^2 (Kulke 1995, Chukwueke 1997) and a sediment fill of about 500,000 km^2 (Hospers 1965). It was formed along a failed arm of a triple junction system (aulacogen) that originally developed during breakup of the South American and African plates in the Late Jurassic (Burke et al. 1972; Whiteman, 1982). Two arms developed into the passive continental margin of West Africa in Southwestern and Southeastern coast of Nigeria and Cameroon while the third failed arm formed the Benue Trough. Subsequent thermo-tectonic events resulting to the uplifting and folding of the Southern Benue Trough, led to the formation of the Basins within the Trough. The Niger Delta happens to be the youngest sedimentary basin within the Benue Trough system. It continued to prograde during Middle Cretaceous time into a depocenter located above the collapsed continental margin at the site of the triple junction. Wright et al. 1985 considered the Cenozoic Niger Delta a southward extension of Anambra Basin. Fig.1 is a sketch of Southern Nigeria showing the location of the study area in the Niger Delta.

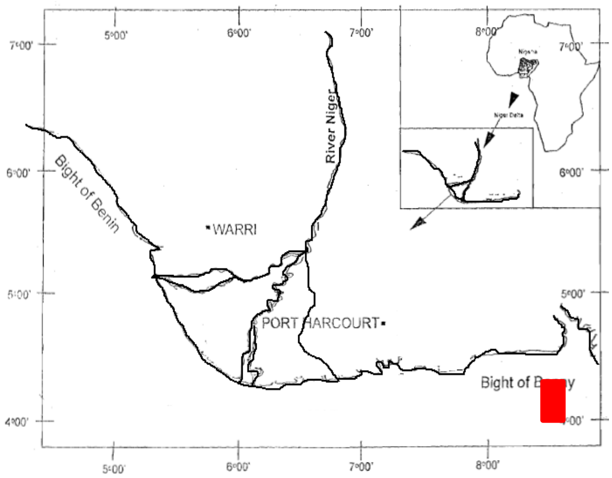

Fig. 1: Sketch of the Map of Southern Nigeria Showing the Study Area Shaded in Red.

The Niger Delta Basin is the major hydrocarbon bearing basin in Nigeria. The basin is very complex and one of the largest sub-aerial basins in Africa. It is situated in the Gulf of Guinea and extends throughout the Niger Delta province (Klett et al. 1997). It is located in the Southern part of Nigeria between longitude 5^0 E and 8^0 E and latitude 3^0 N and 5^0 N (Nwachukwu & Chukwura, 1986). From the Eocene to present, the delta has prograded Southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development (Doust & Omatsola, 1990). It is composed of an overall regressive clastic sequence, which reaches a thickness of about 12 km (Kaplan et al. 1994).

The sedimentary fill of the basin has been subdivided into Akata, Agbada, and Benin Formations (Short & Stauble, 1967; Knox & Omatsola, 1989; Lawrence 2002).

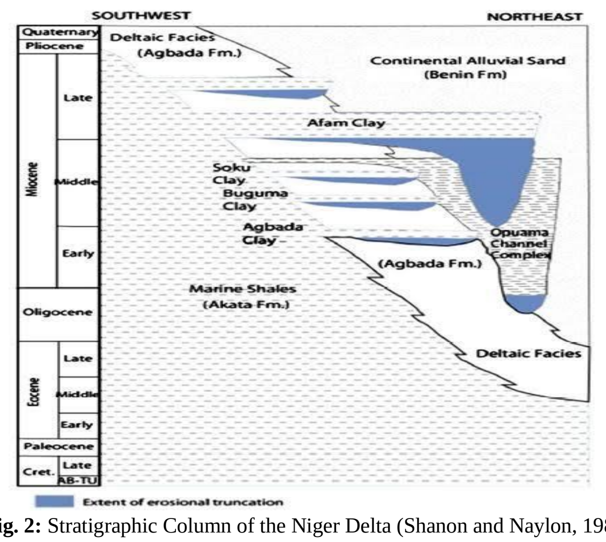

Fig. 2: Stratigraphic Column of the Niger Delta (Shanon and Naylon, 1989).

2. Materials and method

A 3-D Seismic cube, well data with deviations, well logs (including Density, Gamma-Ray, Sonic, Resistivity and Neutron) and check shot surveys from the study area were used in this study. Figure 3 and Table 1 show the available seismic volume and well log data for the study.

The available seismic and well data were quality checked, loaded and interpreted using the Petrel® 2017 software. The well logs were colored and normalized to aid in detailed interpretation. Potential sand reservoirs were identified and correlated across the five (5) available wells (A4X, A5X, A8, A8X, A8Y). Sand-shale discrimination was carried out using the gamma-ray log while hydrocarbon bearing sands were differentiated from water bearing sands using the resistivity log.

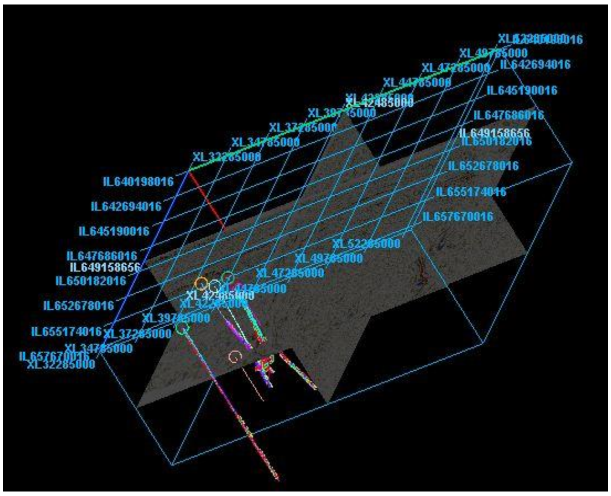

Fig. 3: 3D Seismic Volume of the Study Area.

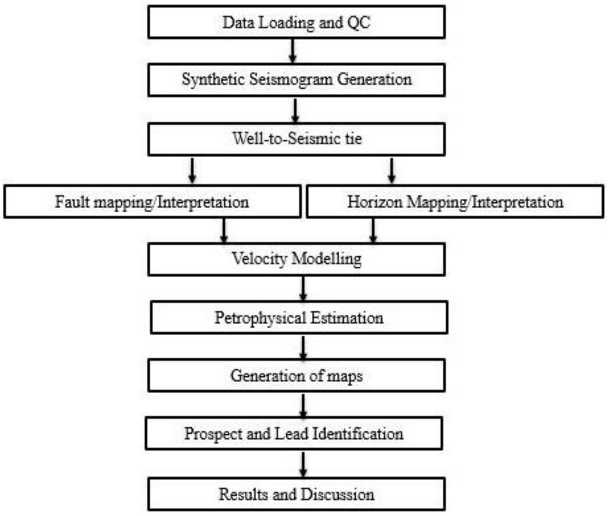

Fig. 4: Interpretation Workflow.

Table 1: Available Well Logs (1=Available and 0=Unavailable)

WELLS	GAMMA	RES	SP	DEN	NEU	SONIC
A4X	1	1	0	1	1	1
A5X	1	1	0	1	1	0
A8	1	1	0	1	1	0
A8X	1	1	0	1	1	0
A8Y	1	1	0	1	1	0

2.1. Petrophysics

The well log suites such as gamma-ray, neutron, density and resistivity logs were used for both qualitative and quantitative analysis. Volume of shale (Vsh), total porosity (PhiT), effective porosity (PhiE), permeability, facie, net-to-gross (NTG) and water saturation (Sw) were all estimated from the log data. Four facies were identified; sand, sandy-shale, shaly-sand and shale. The volume of shale was estimated using the Larinov model for Tertiary rocks;

$$VSH_{\text{Larionov Tertiary Rocks}} = 0.083\ (2^{(3.7\ IGR)} - 1) \quad (1)$$

Where:
V_{sh} = Volume of shale
I_{GR} = Gamma ray index
Total and effective porosity was estimated using the density and sonic log while the water saturation was estimated using the Simandoux's method (1963).

$$Sw = \left(\frac{0.4 \text{ x } Rw}{\emptyset^2}\right) \text{x} \left[\sqrt{\left(\frac{Vshale}{Rsh}\right)^2 + \frac{5 \text{ x } \emptyset^2}{Rt \text{ x } Rw}} - \frac{Vshale}{Rsh}\right] \quad (2)$$

Where:
S_w = Water saturation
R_t = True formation resistivity
R_w = Resistivity of formation water
V_{sh} = Volume of shale

R_{sh} = Shale resistivity value in a formation

2.2. Volumetrics

The volumetric estimation of hydrocarbon reserves involves the integration of various geological parameters obtained from both surface (seismic) and subsurface (well log) geophysical data. The average petrophysical parameters for the already established reservoirs were computed and used in calculating for the hydrocarbon in place. The following formulas were applied in the volumetric estimation.

$$STOIIP = GRV \times NTG \times Ø \times S_o \times 1/B_o \quad (3)$$

$$\text{Recoverable Oil} = STOIIP \times R_f \quad (4)$$

Where:
GRV = gross rock volume
NTG = net to gross
Ø = porosity
S_o = oil saturation
B_o = formation volume factor for oil (=1.2)
R_f = recovery factor (=0.30)

$$GIIP = GRV \times NTG \times Ø \times S_g \times 1/B_g \quad (5)$$

$$\text{Recoverable Gas} = GIIP \times R_f \quad (6)$$

Where:
GRV = gross rock volume
NTG = net to gross
Ø = porosity
S_g = gas saturation
B_g = formation volume factor for gas (=1.0)
R_f = recovery factor (=0.30)

3. Results and discussion

3.1. Seismic-well tie

The analysis of seismic-well tie using sonic and density logs was established by the generation of a synthetic seismogram (Fig.5). A reasonable tie was established and it also showed that the reservoirs were of low impedance. This was evidenced by the coinciding of the blue events (trough) with the top of the reservoirs. A Ricker wavelength (25Hz) was extracted for the well-tie. Three reservoirs Res-A, Res-B and Res-C were identified and correlated across the wells. The well tie aided in creating an appropriate model for depth conversion.

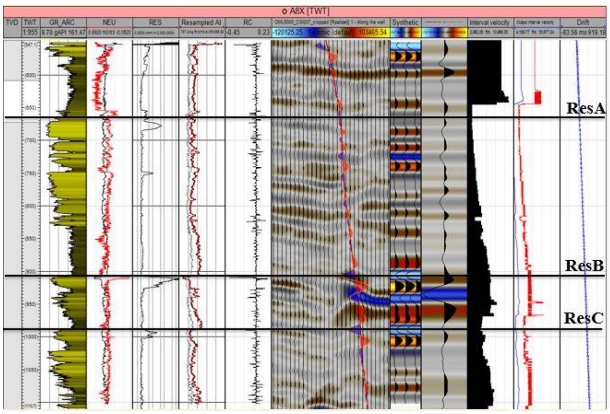

Fig. 5: Seismic-Well Tie with Top of Reservoirs Displayed.

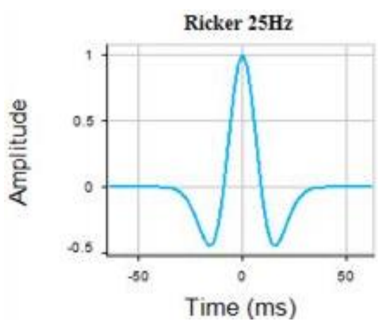

Fig. 6: Extracted Ricker Wavelength (25Hz).

3.2. Fault interpretation

Fault interpretation was aided by the application of a variance edge attribute to a realized seismic volume. This was useful in defining the structural fault framework of the field. The field was divided into 8 major fault blocks (Fig.7) by large laterally extensive faults in association with other minor faults (the wells were located within block 5) which are listric and normal in shape typical of the Niger Delta.

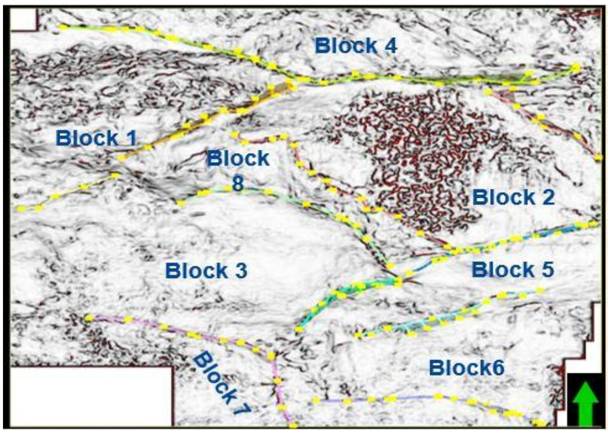

Fig. 7: Regional Faults in the Study Area at -808ms Slice with the Aid of the Variance Edge Attribute.

3.3. Horizon mapping

Three horizons were mapped on the seismic section with the guidance of the result of the seismic-well tie. The locations of the low impedance reservoirs were found on the seismic volume and were mapped continuously through all slices of the seismic section (Fig.8). Horizons (H1, H2, and H3) were picked using equivalents of the top of Res-A, Res-B and Res-C, respectively. The H3 horizon is characterized by low-to-high or variable amplitude reflections with poor-to-low continuity. It has the sharpest contact with shale unit, it probably occurs to the top of the Akata Formation. On the other hand, the H1 horizon is characterized by high amplitude reflections and moderate-to-good continuity. It appears shallow and probably occurs close to the top of the Agbada formation.

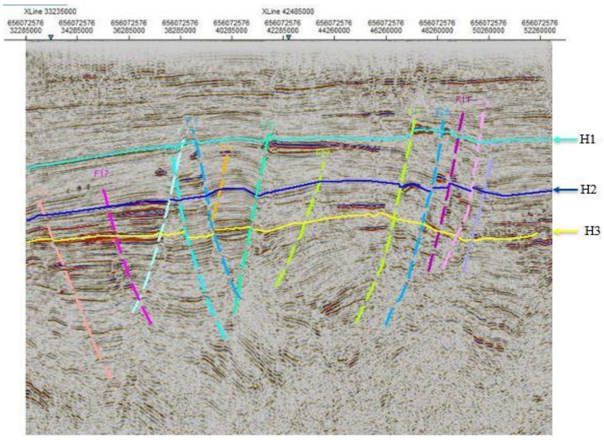

Fig. 8: Seismic Slice Showing the Three (3) Horizons Mapped Across.

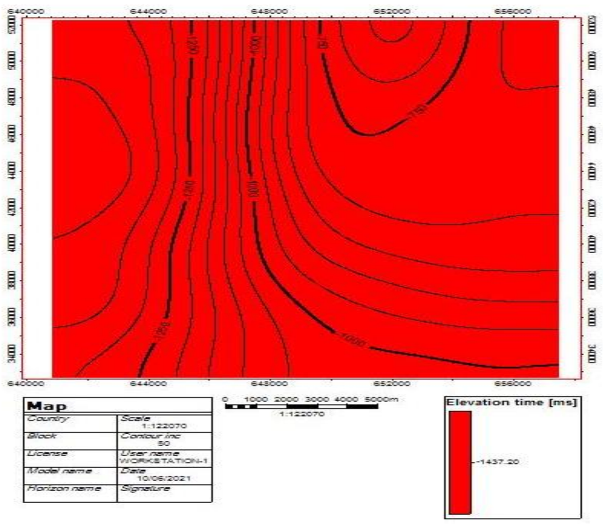

Fig. 9: Top of Reservoir Map for Res-A.

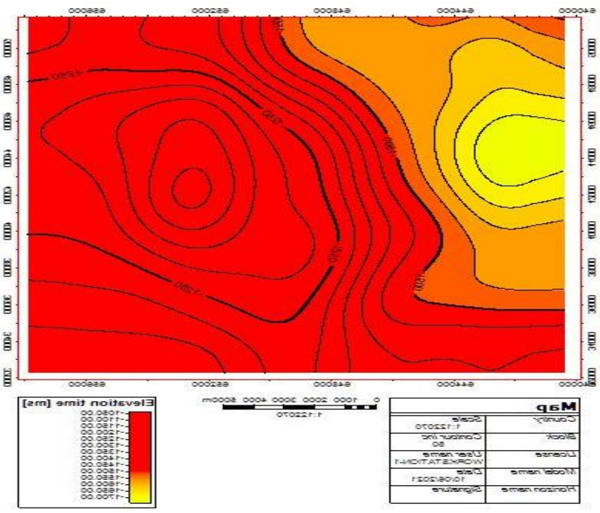

Fig. 10: Top of Reservoir Map for Res-B.

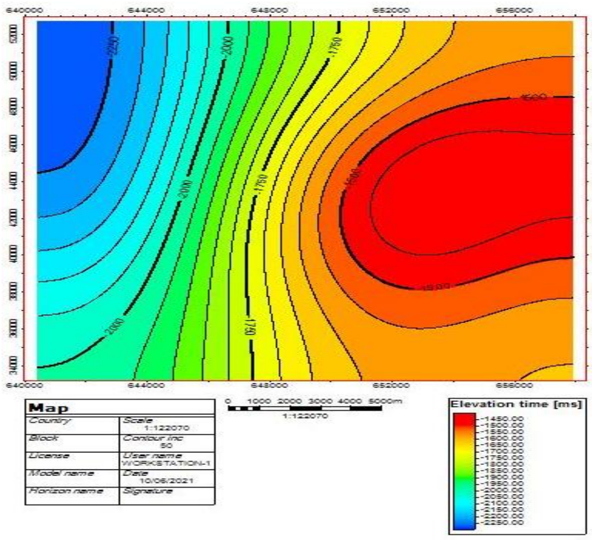

Fig. 11: Top of Reservoir Map For Res-C.

3.4. Velocity modelling

The depth vs two-way time (TWT) plot showed a steady trend and the velocity function was defined by seismic-to-well tie time-depth relationship (TDR). LinVel was used to create a linear velocity model which reflected velocity trend associated with Niger Delta (Fig.12).

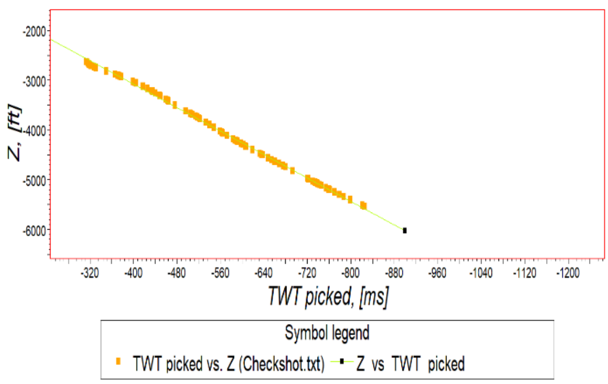

Fig. 12: A Plot of Two-Way Time vs Depth.

3.5. Well log interpretation

Well log correlation was done using four of the wells (A4X, A5X, A8X, A8Y). Sand to sand correlation was completed by identify and picking the thick shale as a marker for flooding surfaces. Three major hydrocarbon bearing sands were identified.

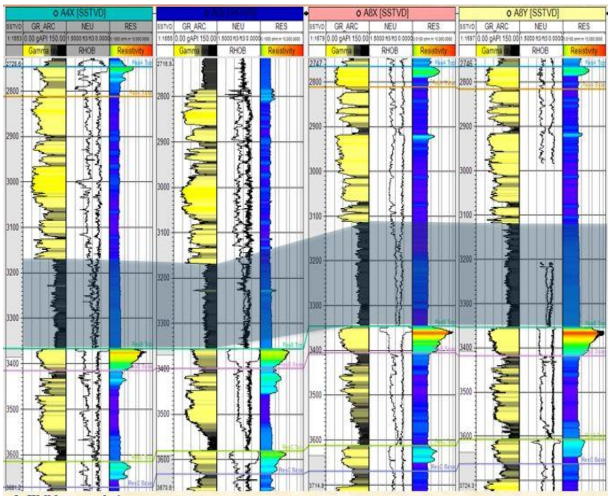

Fig. 13: Well Log Correlation Showing the Identified Reservoirs Across the Wells. Note: Thick Shales Act as Maker for Flooding Surface.

3.6. Evaluation of petrophysical parameters

The identified reservoirs were correlated across the wells. Res-A has an average thickness of 56.79ft, net-to-gross ranging from 0.72-0.77, total porosity ranging from 0.21-0.24, and water saturation ranging from 0.20-0.35. Res-B reservoir has an average thickness of 57.82ft, net-to-gross ranging from 0.65-0.78, total porosity ranging from 0.19-0.24, and water saturation ranging from 0.20-0.24. Res-C reservoir has an average thickness of 53.40ft, net-to-gross ranging from 0.66-0.69, total porosity ranging from 0.17-0.19, and water saturation ranging from 0.20-0.35. Results of etimated petrophysical parameters are displayed in Tables 2a-2e.

Table 2: A) Petrophysical Parameters Dataset for Well A4X

Reservoir	Top(fts)	Base(fts)	OWC	GWC	Gross	Net	PoroE	Sw	Vsh	Fluid
Res-A	-2745.18	-2814.84	-2780.81		69.66	35.63	0.21	0.35	0.20	Oil
Res-B	-3367.72	-3432.18		-3415.50	64.46	46.28	0.23	0.22	0.19	Gas
Res-C	-3615.54	-3671.98	-3655.97		56.44	39.63	0.24	0.21	0.17	Oil

Table 2: B) Petrophysical Parameters Dataset for Well A5X

Reservoir	Top(fts)	Base(fts)	OWC	GOC	Gross	Net	PoroE	Sw	Vsh	Fluid
Res-A										
Res-B	-3355.58	-3396.47		-3391.26	38.89	35.68	0.19	0.24	0.20	Gas
Res-C	-3580.00	-3630.98	-3626.17	-3608.13	50.98	46.17	0.24	0.22	0.17	Gas/Oil

Table 2: C) Petrophysical Parameters Dataset for Well A8

Reservoir	Top(fts)	Base(fts)	OWC	GOC	Gross	Net	PoroE	Sw	Vsh	Fluid
Res-A										
Res-B										
Res-C	-3567.15	-3628.51	-3623.43	-3580.05	61.36	56.28	0.24	0.20	0.19	Gas/Oil

Table 2: D) Petrophysical Parameters Dataset for Well A8X

Reservoir	Top(fts)	Base(fts)	OWC	GOC	Gross	Net	PoroE	Sw	Vsh	Fluid
Res-A	-2765.05	-2818.75	-2790.68		53.70	25.63	0.23	0.22	0.20	Oil
Res-B	-3345.12	-3404.91	-3403.80	-3360.17	59.79	58.68	0.24	0.20	0.19	Gas/Oil
Res-C	-3618.47	-3669.32	-3651.82		50.85	33.35	0.22	0.32	0.21	Oil

Table 2: E) Petrophysical Parameters for Well A8Y

Reservoir	Top(fts)	Base(fts)	OWC	GOC	Gross	Net	PoroE	Sw	Vsh	Fluid
Res-A	-2764.20	-2815.00	-2785.20		50.8	21.00	0.25	0.26	0.19	Oil
Res-B	-3353.42	-3419.21	-3415.51		65.79	62.09	0.23	0.20	0.19	Oil
Res-C	-3606.70	-3662.21	-3647.41	-3616.57	55.51	40.71	0.22	0.35	0.20	Gas/Oil

3.7. Generated maps

Maps generated include porosity, net-to-gross, reservoir thickness (isopach) and fluid contact maps.

The fluid contact map (Fig.14) indicates that the field is dominantly a gas field with oil and water also present. However, majority of the wells fell within the little oil zone.

From the porosity map (Fig.15), porosity is generally low towards the west, better in the northwest and southeast direction and best towards the southwest as seen in the map, most of the wells penetrated areas of average porosity.

The net-to-gross map (Fig.16) shows that the quality of reservoir materials is good across the area but it is concentrated and best at the center. Most of the wells penetrated areas with good quality reservoir materials.

Additionally, the isopach map (Fig.17) shows the variation in thickness of sand over the entire field. There is slightly low thickness at the Western part, whereas in other parts towards the East, the thickness improves. The wells penetrated areas with average reservoir thickness.

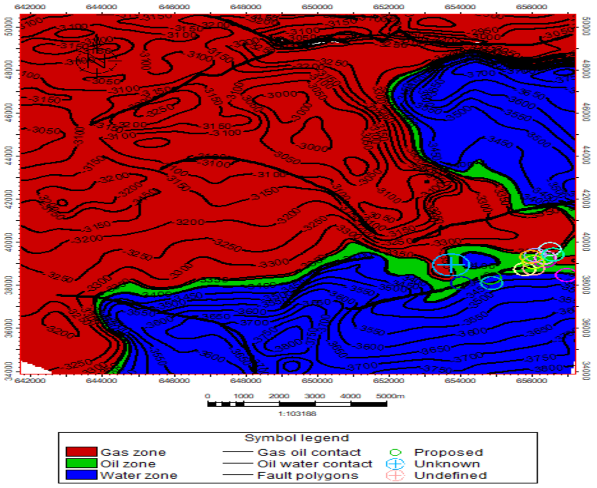

Fig. 14: Fluid Contact Map.

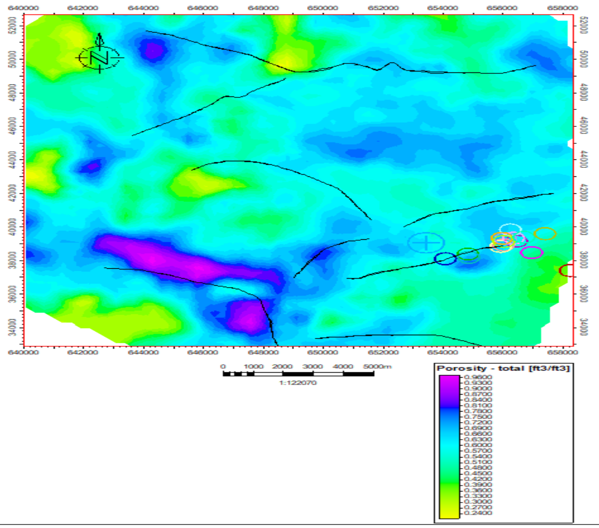

Fig. 15: Porosity Map.

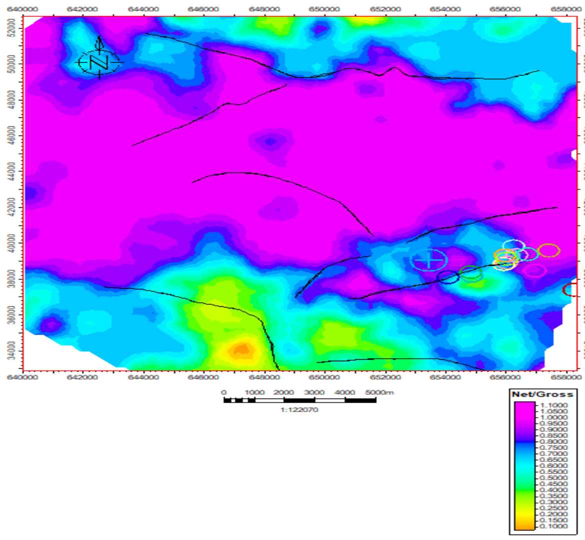

Fig. 16: Net-to-Gross Map.

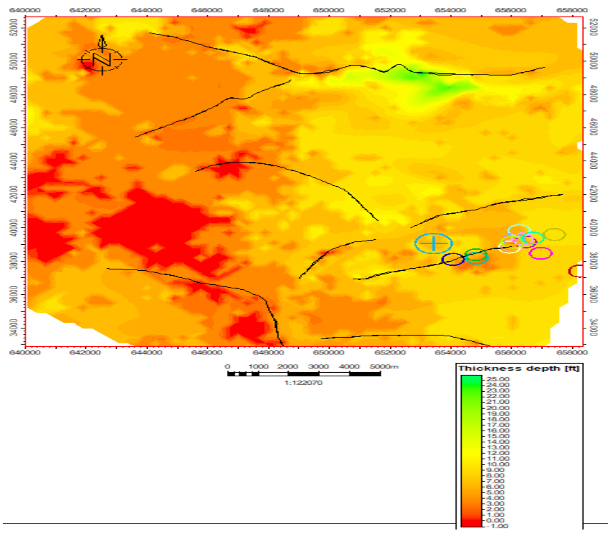

Fig. 17: Sand Thickness Map

3.8. Reserve estimation

The reserves were calculated from the already estimated petrophysical parameters for each of the reservoirs. Table 3 shows the calculated Stock Tank Oil Initially in Place (STOIIP), Gas Initially in Place (GIIP), recoverable oil and recoverable gas. From the results displayed in Table 3, it is apparent that the Res-B reservoir has the highest hydrocarbon reserve, this is followed by Res-C then Res-A which has the lowest reserve. Generally, it could be said that the estimated hydrocarbon in place of the reservoirs is satisfactory.

Table 3: Calculated Reserve Estimation for the Reservoirs

Reservoirs	STOIIP (MMSTB)	Recoverable Oil (MMSTB)	GIIP (MMSCF)	Recoverable Gas (MMSCF)
Res-A	180.96	90.50	100.22	50.22
Res-B	305.52	152.77	231.20	115.50
Res-C	230.06	120.50	150.64	75.32
Total	716.54	403.63	482.06	241.04

3.9. Prospect and lead identification

Root-mean-square (RMS) amplitude attribute was ran on the horizons and areas associated with amplitude burst were interpreted to correspond with possible hydrocarbon accumulation since amplitude burst conform to hydrocarbon presence, reservoir thickness is also suitable in both areas. Prospect and leads were then identified and classified within the identified fault blocks. 2 prospects- Dembe-1 and Dembe-2 were identified in block 1 and block 6 respectively. Dembe-2 prospect is located at the Southern part of the Dembe discovery and is encased by two structural building faults. While Denbe-1 is defined by an extensive structure building regional fault.
The Identified prospects boasts of bright spots which are indicators of hydrocarbon presence. Additionally, the extent of seismic data established the presence of closing contours around the prospect areas. The prospects are also defined by large, medium and small fault-controlled closures against a series of down-to-South growth faults, rollovers and other few synthetic faults. These can serve as potential hydrocarbon traps.
A lead Dembe-3 was identified in block 3. However, the extent of seismic data was not able to establish the presence of structural closures around the lead.

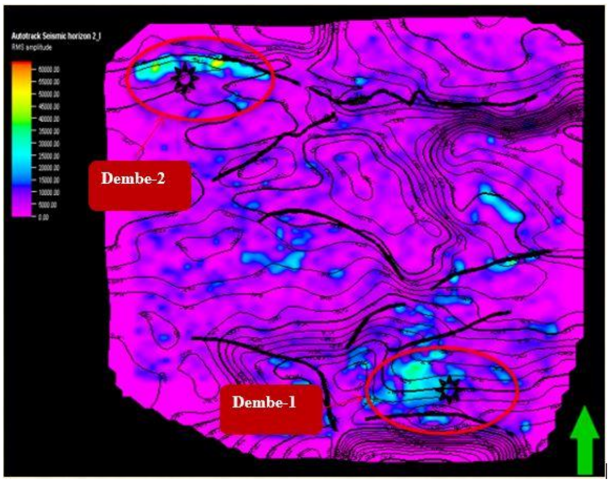

Fig. 18: Identified Prospects Location.

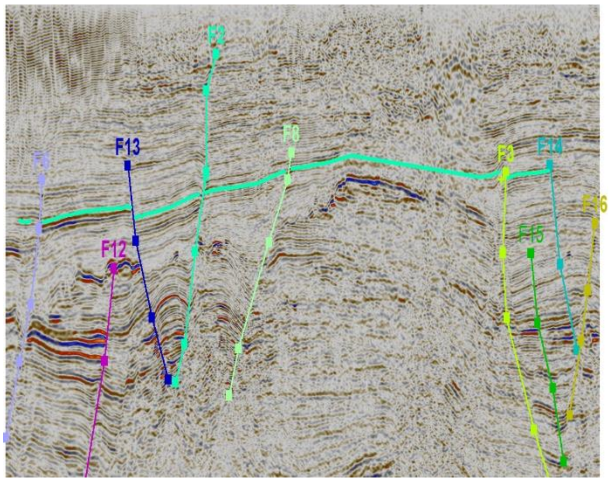

Fig. 19: Faults Around the Prospect Area.

3.10. Risk analysis

The geologic chance of success (GCOS) in both blocks was tied to the Play Chance (%) and Prospect Specific Risk (%), putting into consideration the changes and variation in geology of the area. Probability of Success = P1×P2×P3×P4×P5xP6.
Risk = 1 – GCOS (1 – 0.16) = 0.84 (Favourable)

Table 4: A) Risk Analysis

Play type	Source rock presence (prob)	Source rock quality (prob)	Reservoir presence (prob)	Regional seal presence (prob)	Migration Route and Critical time (prob)	Chance of HC discovery (prob)	Play Success (GCOS)
Struc-tural	1	0.5	1	0.9	0.9	0.40	0.16

Table 4: B) Calculated Reserve Estimation for the Prospects

Prospects	STOIIP (MMSTB)	GIIP (MMSCF)	Recoverable Oil (MMSTB)	Recoverable Gas (BCF)
Dembe-1	113	131	34	39
Dembe-2	300	400	100	128
TOTAL	413	531	134	167

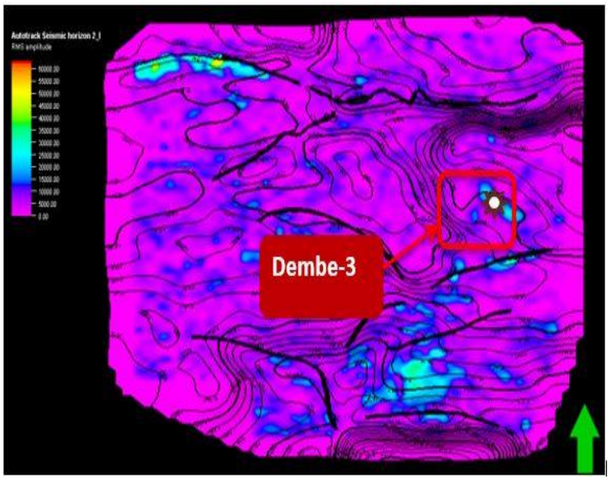

Fig. 20: Identified Lead (Dembe-3) Location in the Area.

4. Discussion

The findings of this project revealed usefulness of 3D seismic attribute in reservoir characterization of the Dembe Field, Offshore, Niger Delta. Three distinct reservoirs (Res-A, Res-B, and Res-C) were mapped across the wells with Res-B being the most prolific of the reservoirs, with a total recoverable oil of about 152.77 MMSTB. Eight (8) of the mapped structures were considered to be major faults because of their relative regional extent while the rest were classified as minor discontinuities. Three (3) horizons corresponding to the top of delineated hydrocarbon bearing sands were mapped. Potential accumulation of hydrocarbon was established in the area with faults and rollover anticlines as the major trapping mechanism. The structural building faults support the identified prospects (Dembe-1 and Dembe-2) which can be explored in the future. The volumetric estimation for the identified prospect showed that the Dembe-1 ranked higher with recoverable oil of about 100 MMSTB and recoverable gas of about 128 BCF against Dembe-2, which has estimated recoverable oil of about 34 MMSTB and recoverable gas of about 39 BCf.
Additionally, the calculated petrophysical values are almost ideal for Niger Delta reservoir sands with average porosity of 0.24, water saturation of 0.35 and average net-to-gross value of 0.78. Generally, it could be said that the Res-B sands are the most prolific reservoir. The generated porosity map, fluid contact map, net to gross map and isopach map also revealed that the reservoirs are of good quality.

Oluwatoyin et al. (2013) carried out a 3D seismic structural interpretation of part of ALOO-field and demonstrated the importance of seismic structural interpretation in understanding the structural styles present and their retentive capability for hydrocarbon. They identified two major faults whose dipping pattern coincide with that of growth fault in the area which enhances the trapping mechanism. They also noted that the two principal structural trapping mechanisms present are growth fault and rollover anticline which are synonymous to Niger Delta.

Opara et al. (2011) carried out a 3D seismic interpretation and structural analysis of Ossu field, onshore Niger Delta. They undertook a multidisciplinary approach which include petrophysics, seismic and volumetric method in the course of their analysis. The result of their study revealed a complex pattern of subsurface structure having predominantly widely spread simple rollover structures bounded by growth faults. However, they stated that the key exploration risk is that growth-faulted anticlinal traps are segmented by normal faults. Their result suggested more development opportunities in the Ossu oil field, OML 124, onshore Niger Delta which is also a good recommendation for the Dembe Field.

5. Conclusion

The 3D interpretation of the Dembe Field resulted in more understanding of structural styles and architecture and also accurate delineation of reservoir sands in the study area from the Niger Delta Basin. Generally, the Dembe Field is a promising field with good structures for hydrocarbon accumulation and as such, it is worthy of investment. There is an important relationship between the style of the field and volume of reserves. These structures and good quality reservoir thickness are suggested to be the controlling factor for economic hydrocarbon accumulation in the study area. The estimated hydrocarbon volumetric of the reservoirs is satisfactory. The reserve is indicative of gas volume although economic viability of oil reserve looks promising. The detailed characterization of the reservoirs in relations to structures and petrophysical properties will bring about the needed production optimization of this field. It will also help in providing effective reservoir management approach. Overall, the distribution of some reservoir properties could also guide the placement of both production and injection wells for optimum recovery.

6. Recommendations

Based on the results, it is recommended that an exploratory well be drilled within the Dembe-1 and Dembe-2 to confirm the prospects. Seismic data should also be reprocessed for clearer and better confirmation of closure around Dembe-3. Further studies may include biostratigraphic study of all the wells. This will provide more reliable data for further interpretation of the field.

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