Original Research Article

Geophysical 3D Seismic Appraisal of Okpella Field within Offshore Niger Delta Basin of Nigeria

Abstract

The Okpella Field is currently experiencing a decline in production which was revealed by analysing the production data. The Okpella Field had an annual production of 430175 MBO (Million Barrel of Oil) in 2008, and it declined significantly to 7839 MBO (Million Barrel of Oil) per annum. Therefore, to sustain the Field hydrocarbon productivity, an appraisal study is carried out to identify viable bypassed hydrocarbon reservoirs that can be exploited. This involves integrating 3D seismic interpretation, petrophysical analysis and production data to characterise and estimate the productivity of the Bypassed hydrocarbon reservoir zones. six hydrocarbon reservoirs were identified by the producing company, which are named major reservoirs Sand A, Sand B, Sand C, Sand D, Sand E, and Sand F. Three additional hydrocarbon reservoirs were identified within this study which are named Bypassed Sand A, Bypassed Sand B, and Bypassed C. The petrophysical analysis estimated the reservoir's petrophysical parameters such as volume of shale, porosity, net to gross, and water saturation for the Bypassed reservoir. The Seismic interpretation delineates the structural style and hydrocarbon traps, generates time maps, attribute maps (R.M.S), and depth maps, and estimates the bulk volumes of the bypassed reservoirs. The STOIIP, GIIP and hydrocarbon productivity were estimated by integrating the results from the petrophysical analysis, seismic interpretation and production data. From this analysis, the most prolific bypassed reservoir is Bypass B. The productivity of all the Bypassed reservoirs was estimated to be to sustain the field for an additional three years.

Keywords: Bypassed Reservoir, Map, STOIIP, GIIP, Attribute, Productivity.

1. Introduction

Economically viable hydrocarbon has been bypassed in mature fields due to poor analysis, reservoir complexities, and management techniques (Bassiount and Velic, 1996)). Over the years, Nigeria has primarily depended on hydrocarbon production to sustain its economy, and in ensuring maximum hydrocarbon productivity, delineating isolated reservoirs and unperforated hydrocarbon-bearing zones is paramount. Reservoir characterisation is a significant process in developing, managing and optimising reservoir production by integrating petrophysical analysis, seismic interpretation and production data (Fred and Shivaji 2013)). The Niger Delta has been producing petroleum for over sixty years now, and its offshore fields are becoming mature. Therefore, considering bypassed hydrocarbons zones in matured fields can sustain productivity and increase recovery (Ekwe and Onuoha, 2017). Conventional techniques have been effective in oil and gas exploitation by identifying drillable locations and the recoverable volume of hydrocarbon (Luis et al., 2018)).

The Okpella Field is a mature offshore field discovered by conventional reservoir mapping techniques, and sustaining its production depends on perforating bypassed hydrocarbon reservoir zones. In identifying and analysing the bypassed reservoir zones, the field was re-evaluated by integrating petrophysical analysis, seismic interpretation and production data. Using 3D Seismic data infusion with composite logs via an integrated interpretation approach would reveal more essential details on the structural styles of the hydrocarbon-bearing closures. Well-log correlation, sequence stratigraphy, 3D seismic interpretation, and seismic attributes concepts were employed to delineate hydrocarbon reservoirs within Okpella Field and identify the yet-to-be produced reservoirs within existing wells. Hydrocarbon volume estimation provides a basis for a good hydrocarbon production plan and information on commercial hydrocarbon accumulations. The production data analysis provided the hydrocarbon productivity of the matured reservoir and was used as a basis for estimating the productivity of the bypassed reservoir zones.

2 Geological Settings

The Niger Delta is situated in the Gulf of Guinea, West Africa, covering an area of 300,000 km^2 onshore and offshore (Fig.1), (Kulke, 1995). South-westerly progradation has taken place from

Eocene to the present, forming a series of depo-belts with sediment thicknesses up to 10 km (Doust and Omatsola, 1990). The lower marine shale package, the Akata Formation, is the primary source rock in the area, with hydrocarbon production from the overlying Agbada Formation sandstone facies (Ekweozor and Daukoru, 1994)). Oil production started in 1958, and production has expanded and continued to date, despite political instability and security issues, to a current level of approximately 2 MMbbl/d.

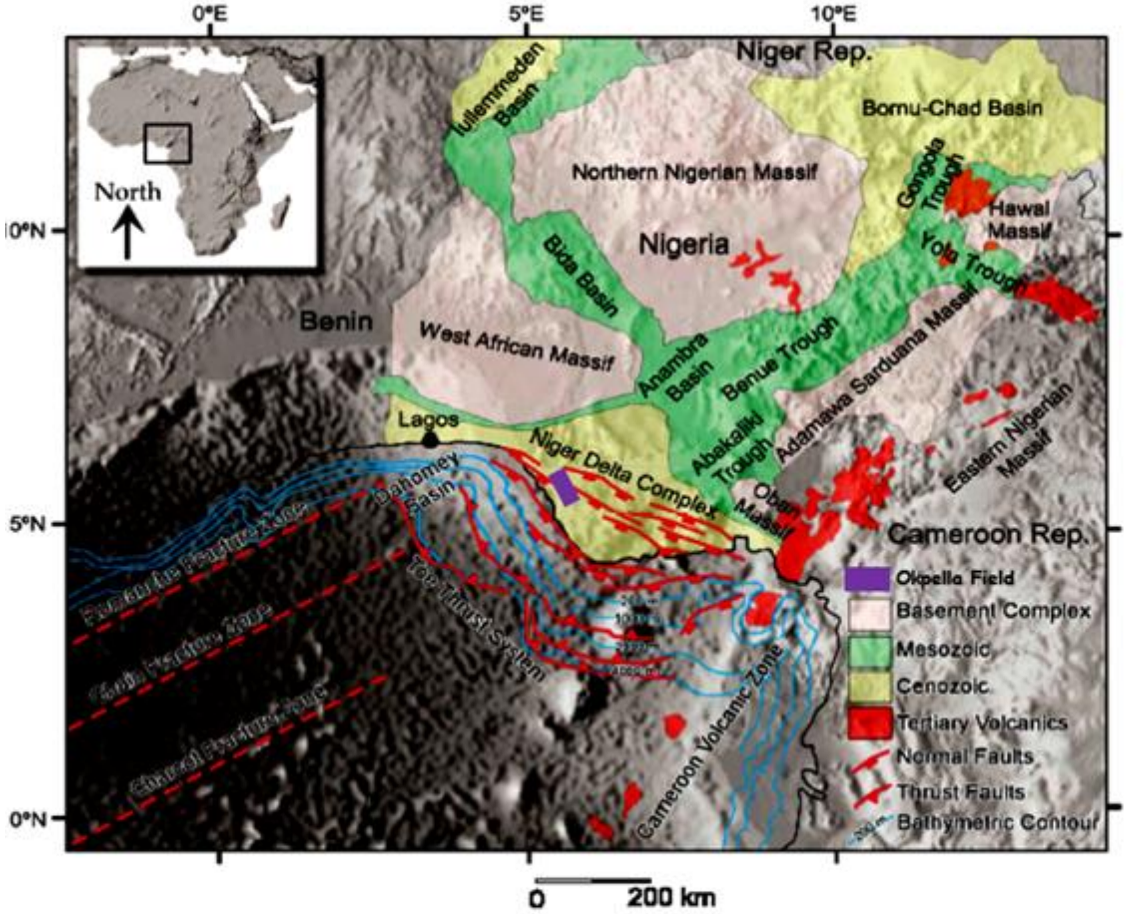

Fig.1. Geological Map of Nigeria shows the Niger Delta basin and location of Okpella Field.

The tectonic framework is controlled by Cretaceous fracture zones (Fig.2) associated with the opening of the Atlantic Ocean, with ridges dividing the continental margin into basins (Weber and Daukoru, 1975). In the Niger Delta area, rifting had stopped by Late Cretaceous and deformation caused by gravitational instability occurred. Shale diapirs resulted from the loading of high-density delta front sands over poorly compacted delta slope clays, and the basinward slope instability occurred due to a lack of support from the clays, which form a detachment surface near the top of the Akata Formation (Kulke, 1995). The depo-belts consist of the three formations, with each successive depo-belt off-lapping the previous. They are the result of variations in sediment supply and rate of subsidence, with sedimentation shifting seaward in response to renewed crustal subsidence. Each depo-belt expresses the deformation results, with structures including shale diapirs, roll-overs, fault crest collapses, and steep, closely spaced flank faults that offset different parts of the Agbada Formation (Fig.3), (Michele et al. 1999)).

Three formations divide the Niger Delta, distinguished by their sand/shale ratio (Fig.4). The Akata shale was deposited in the Palaeocene during a major transgression. By the Eocene, deposition became tide-dominated, sediments accumulated in the Niger Delta Basin, and the shoreline became more convex with progradation. This pattern continues today. The Akata Formation consists of thick marine shale sequences, turbidites, and minor clay and silt underlying the entire delta (Doust and Omatsola, 1990). It was deposited during low stands, with low energy conditions and oxygen deficiency. Thickness is estimated at 7km. The Agbada Formation had been deposited above the Akata Formation from Eocene to Recent and is ~4 km thick.

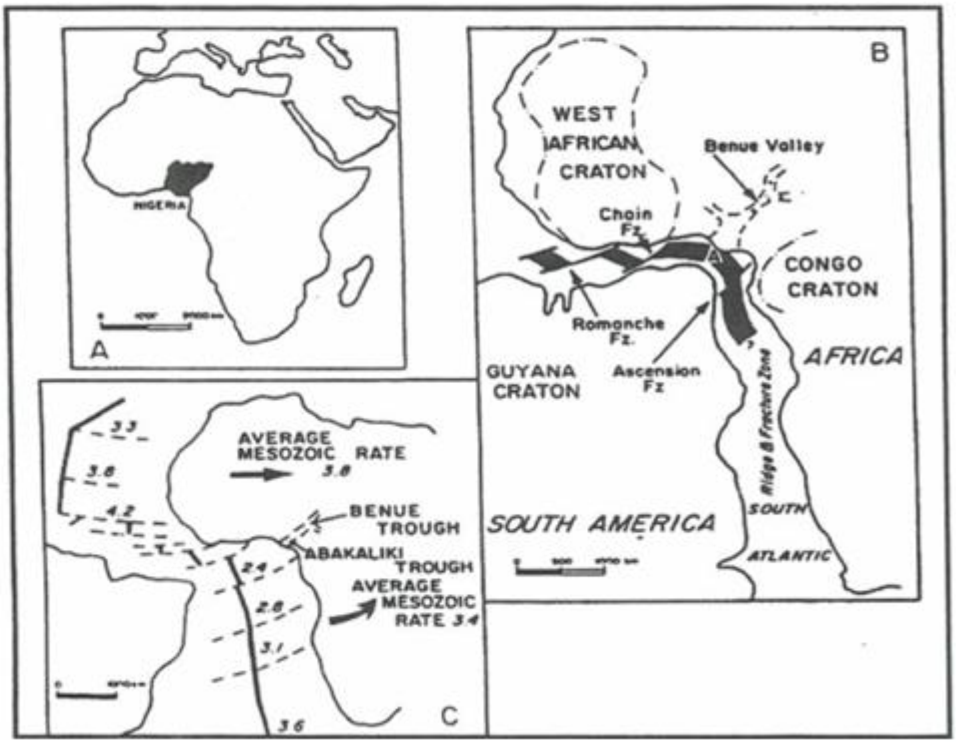

Fig. 1. (a) Location of Nigeria (B) Early cretaceous separation of Africa and South America (C)Mesozoic seafloor spreading for Africa and South America after (Shannon and Naylor, 1989)

The lower Agbada has equal proportions of sand and shale bed, while the upper section is mainly sand with only minor shale inter-beds (Weber, 1986). The Benin Formation overlies the Agbada Formation, the latest Eocene to Recent alluvial and upper coastal sands of up to 2 km thickness (Short and Stauble, 1967)).

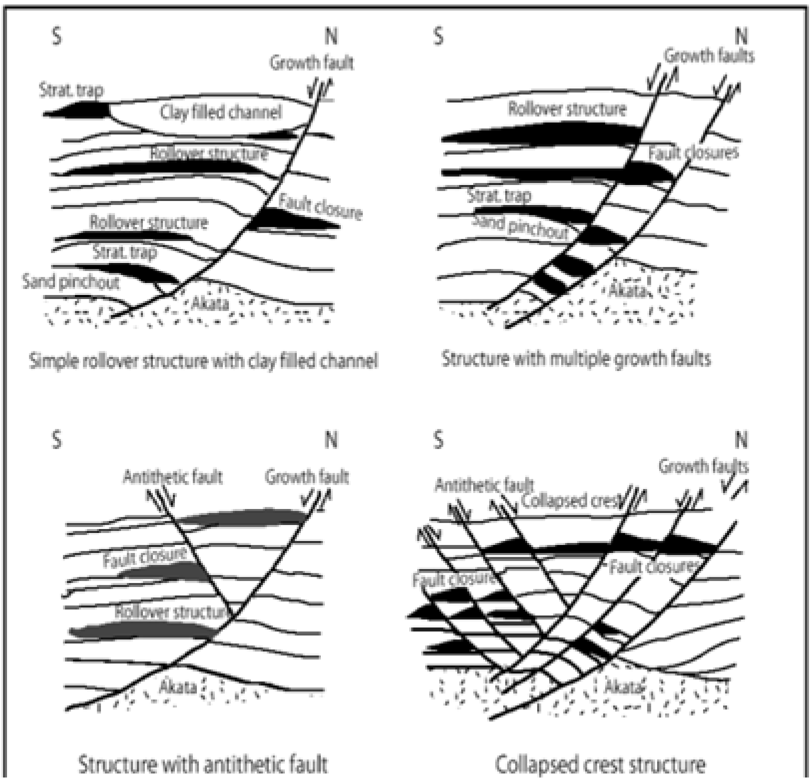

Fig. 2. Schematic Indications of the structural styles and hydrocarbon trapping mechanism in the Niger Delta (Doust and Omatsola, 1990).

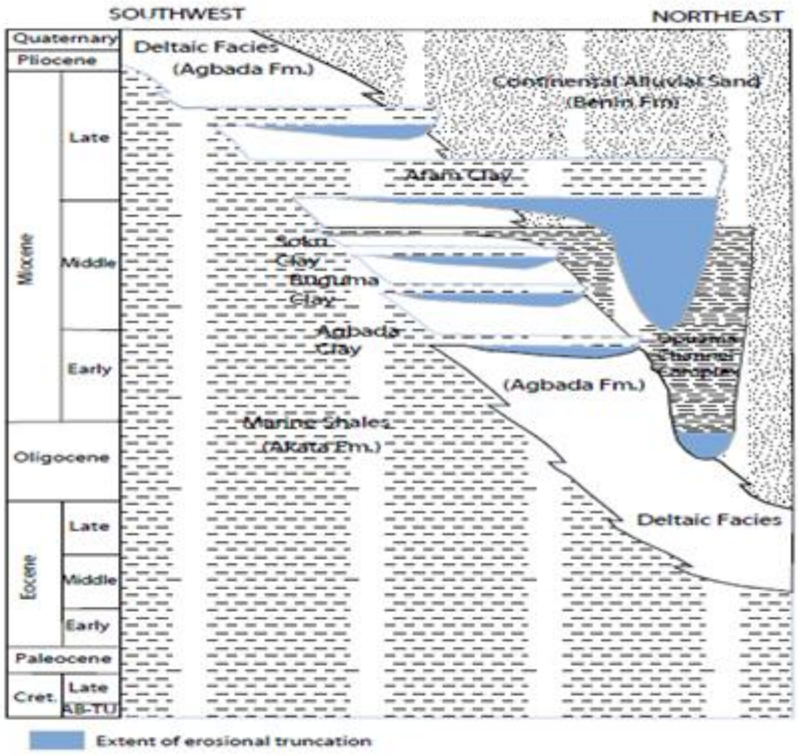

Fig. 3. Stratigraphic column shows the Formations (Benin, Agbada, and Akata) of the Niger Delta (Doust and Omatsola, 1990).

3. Materials and Methods

3.1 Data Availability and Workflow

The data used for this study are 3D seismic data (Fig.5) for seismic interpretation, Composite logs for correlation and petrophysics and production data for reservoir productivity analysis Table 1. This dataset was analysed using Interactive Petrophysics software for petrophysical analysis, Petrel Schlumberger software for seismic interpretation, and Microsoft excel for production data analysis.

Table1. Summary of the provided Dataset used for this study

Data Type	Format	Coverage
Seismic Survey	3D Seismic Volume (SegY)	461 km^2/114,000 Acres
Composite Logs	Calliper, Sonic, Gamma-Ray, Resistivity, Neutron and Density logs	10 Wells
Well Header	ASCII	10 Wells
Check shot	ASCII	10 wells
Deviation	ASCII	10 wells
Reservoir Tops	ASCII	10 Wells
Production Data	ASCII	7 Wells (1997 to 2018)
Additional Data	Biostratigraphy data, Core analysis and petroleum Engineering Report	1 Well (TMG-02)

The workflow approach used in this present study involves three major phases. The first phase involves the regional understanding of the study area, which involves a literature review of the tectonic settings, stratigraphy sequence within the basin, as well as the petroleum system of the basin in order to understand the basin and know the best approach to analysing the basin. Phase two involves quality checking and loading the well and seismic data into the software to interpret the dataset to generate petrophysical properties of the reservoir, maps and attributes. The third phase involves providing the volume of hydrocarbon in potential reservoirs by integrating the production data to give reasonable recommendations for the field's present and future development.

The results of the petrophysical analysis and 3D seismic data were integrated to estimate hydrocarbon volume in the reservoirs.

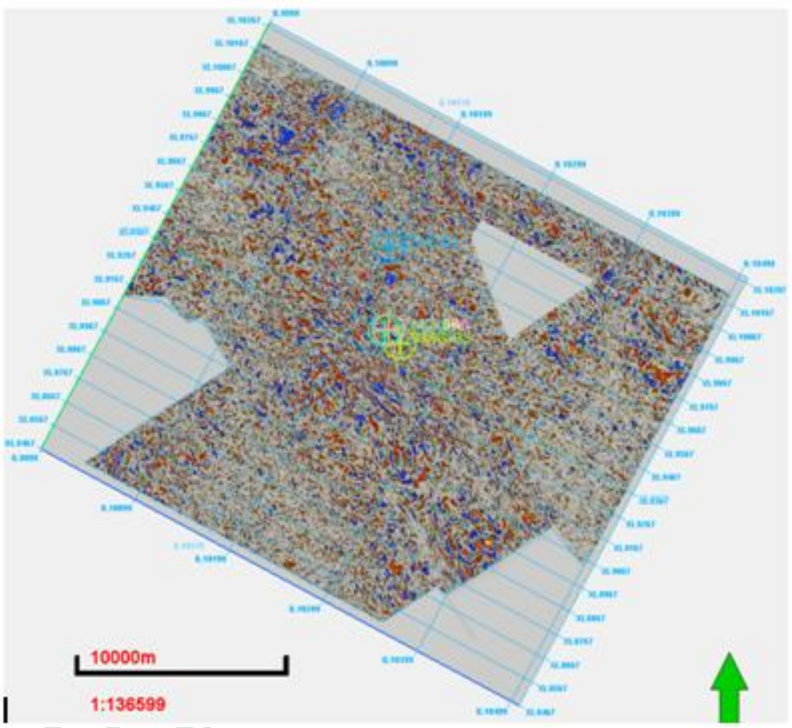

Fig. 4. Basemap of the TMG Field with Seismic coverage and Well locations.

3.2 Petrophysical Analysis

Standard petrophysical interpretation workflow evaluated Okepella Field (Fig. 6). Hydrocarbon bearing reservoirs were identified and correlated across the wells using the gamma-ray and resistivity log. The production data and the provided well tops were used to identify the bypassed hydrocarbon reservoir zones. The Fluid types, shale volumes, porosity, and water saturation were calculated using appropriate equations and parameters (Waziri et al. 2022).

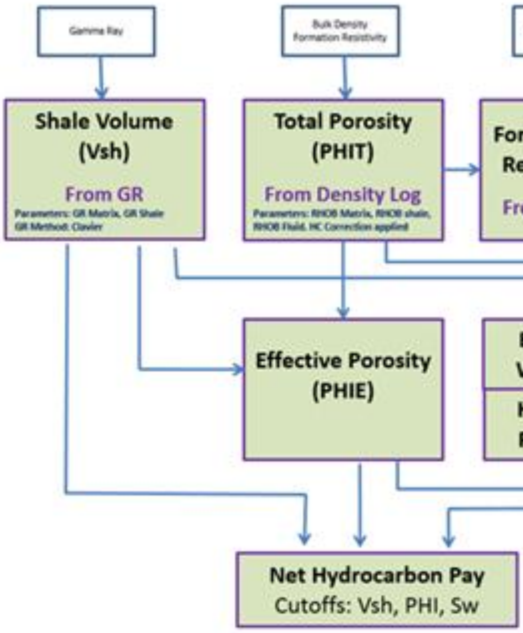

Fig.6. Petrophysical workflow utilised in evaluating Okpella Field

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3.3 Seismic Interpretation

Before interpreting any seismic data, it is essential to establish a relationship between seismic reflections and geological horizons in the well. Synthetic seismograms bridge geological information derived from well-log data in-depth and geophysical data (Seismic in time). This also recalibrates our seismic data from a time domain to a depth domain by establishing time-depth relationships. Acoustic Impedance and Reflection coefficients were calculated, and the reflection coefficients were then convolved with a zero-phased wavelet to obtain the seismic "Wiggle" trace, which was compared with the seismic trace. The faults and seismic horizons tied with reservoir tops were mapped on every fourth inline and fifth crossline section. Seismic attributes extraction was carried out on the 3D seismic data to pronounce regions of horizon discontinuities and bright amplitude reflections. The check short was used to generate a third-order polynomial equation for converting the time map to a depth map (Fig.7). A good Time-Depth trend was established for the fields, and a trend line was fitted, from which a 3rd order polynomial equation was derived from the curve. Fluid contact information from the petrophysical analysis was posted on the depth structure map to ascertain the reservoir area.

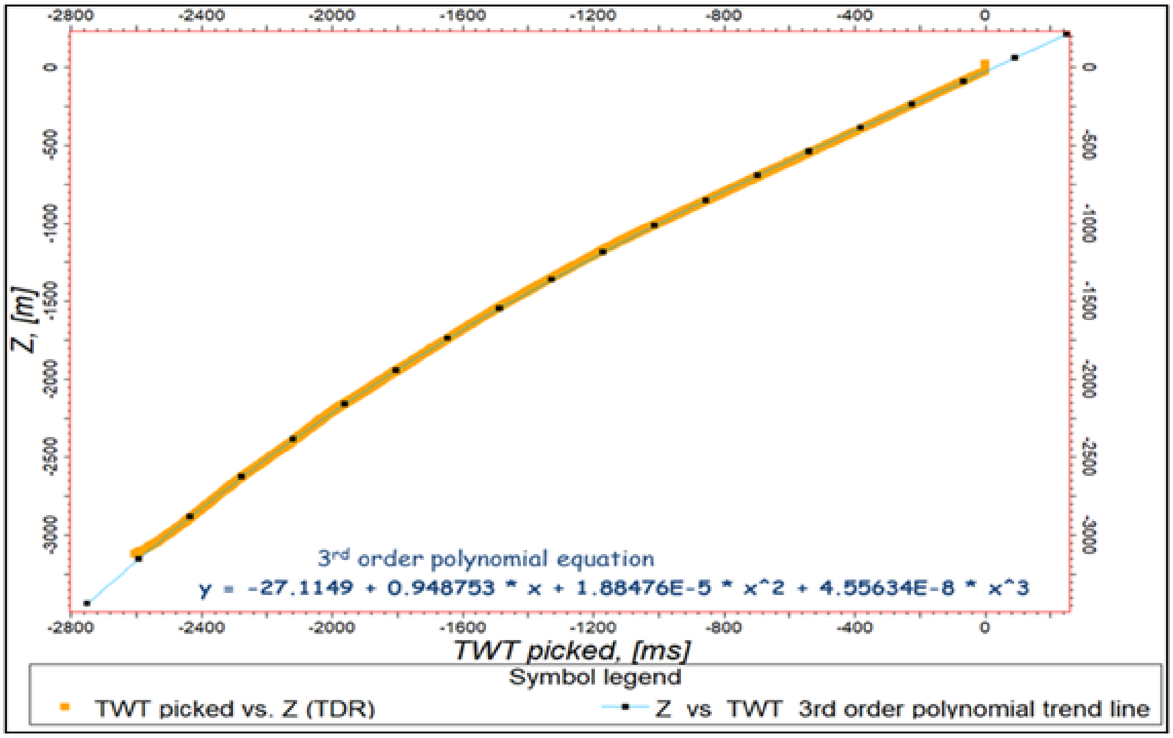


Fig.5.Time-Depth relationship plot of TMG-02 with the 3rd order polynomial function used to generate depth maps.

3.4 Volumetrics

Reservoir Fluid volumes were estimated from the Gross rock volume based on the contacts defined in the wells for the Major and Bypassed reservoir zones. Gross rock volume calculations and Petrophysical parameters were used as input in Equation 1 to estimate oil initially in place volume using all the water saturation scenarios.

$$STOOIP = GRV * NTG * \Phi * (1 - Sw) * (1 / Bo) \qquad (1)$$

$$GIIP = GRV * NTG * \Phi * (1 - Sw) * (Bg) \qquad (2)$$

where: STOIIP = Stock Tank Oil Initially in Place; GIIP =Gas Initially in Place; GRV= Gross Rock Volume; NTG= Net-to-Gross ratio, Φ = Porosity; Sw= Water saturation; Bo= Oil Formation Volume Factor; Bg = Gas Formation Volume Factor.

The In-Place volumes were evaluated using a probabilistic approach by estimating a Proven Case Scenario (P50), Low Case Scenario P10 and Best-Case Scenario (P90). The lowest known contacts were used as the hydrocarbon contacts for all scenarios (ODT=OWC). The production data was then used to estimate the productivity of the bypassed reservoir based on the productivity of the Major reservoir.

4.0 Results and Discussion

4.1 Petrophysical Analysis.

The Major reservoirs were correlated based on the well tops and biostratigraphic information provided by the operating company, and the reservoir pay zones that the operating company did not identify are the bypassed reservoirs (Fig.8). The petrophysical properties of the Bypassed reservoir zones are estimated for each well in Okpella Field (Fig.9) and Table 2 (Waziri et al., 2022).

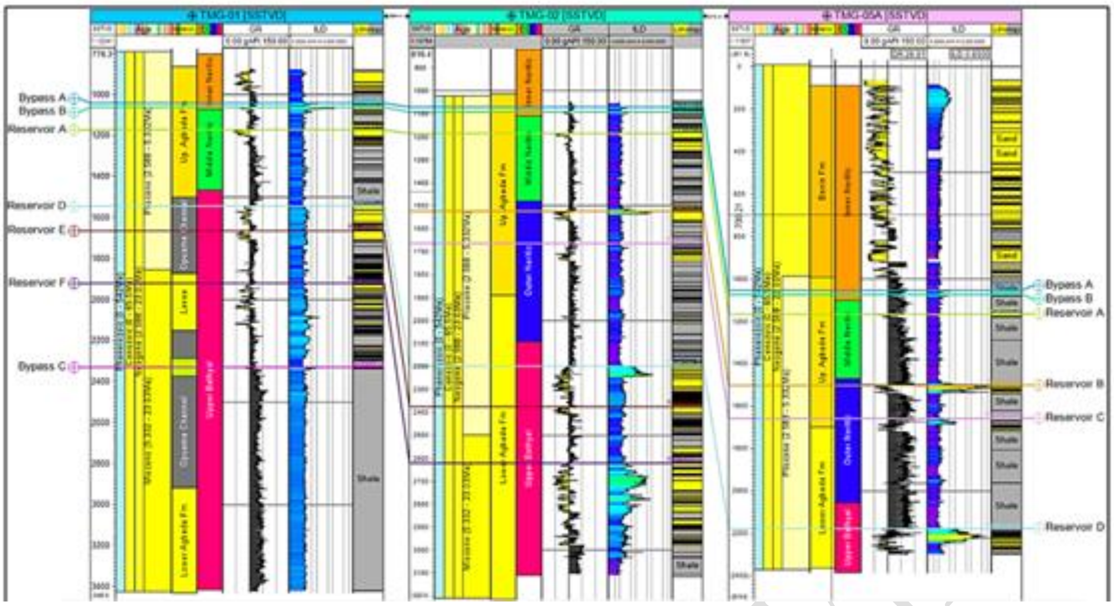


Fig.8. Reservoir correlation of the Bypassed and Major reservoirs.

Table 2. Petrophysical properties estimated for bypassed reservoirs

Zone Name	Top (sstvd)(m)	Base (sstvd)(m)	Gross	N/G	Net pay	Av vcl	Av Phi	Av Sw	Av Sh	Contact	Fluid
Bypass A	1041	1049	7.62	3.05	0.4	0.147	0.287	0.619	0.381	-1049	**GAS**
Bypass B (gas)	1061	1071	8.1	6	0.717	0.13	0.27	0.269	0.731	-1071	**GAS**
Bypass B (oil)	1071	1075	6.3	4.01	0.7	0.13	0.23	0.251	0.722	-1075	OIL
Bypass C	2330	2340	10.67	3.05	0.286	0.085	0.26	0.416	0.584	-2337	**OIL**

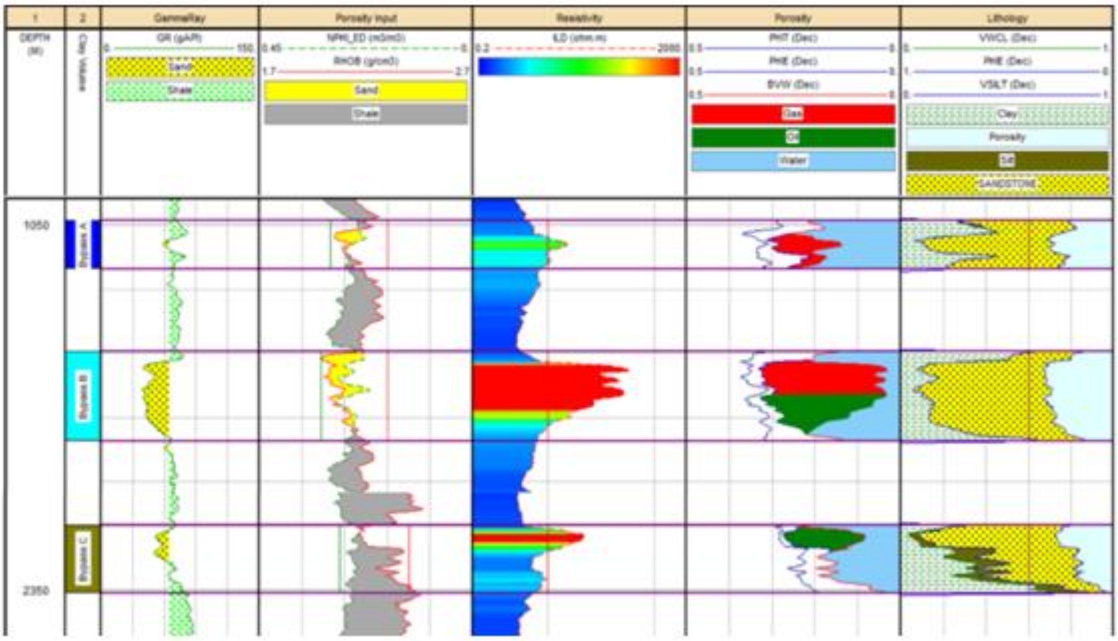


Fig. 9. Petrophysical plot shows the fluid distributions in the Bypassed reservoirs.

4.2 Seismic Interpretation

An extracted variance attribute from the 3D seismic cube at -853 ms was used to delineate the faults within the study area (Fig.10b). The variance time slice shows the various positions and orientations of the major and minor faults within the study area. Four major faults labelled F1, F2, F3 and F4, and over 23 minor faults were interpreted to be synthetic and antithetic to the major faults. The faults trend in the North-West to South-East direction and dip in the western direction (Fig.10b). The major faults divide the TMG field into three main blocks (block 1, block 2 and block 3), but only blocks one and two will be considered because of the presence of wells to have tested the potential of these blocks; block one was penetrated by well TMG-01 and all the wells penetrated block two, and no wells penetrated block 3, (Fig.11b). The faults were interpreted on every fourth inline and fifth crossline within the study area, and the faults are growth faults (Fig.11b) which implies that they originate as a result of shale migrations as sediments were being deposited into the basin. The faults within the study area could also serve as a potential migration pathway and trapping mechanism for hydrocarbon accumulation into the reservoirs (Weber and Daukoru 1975)).

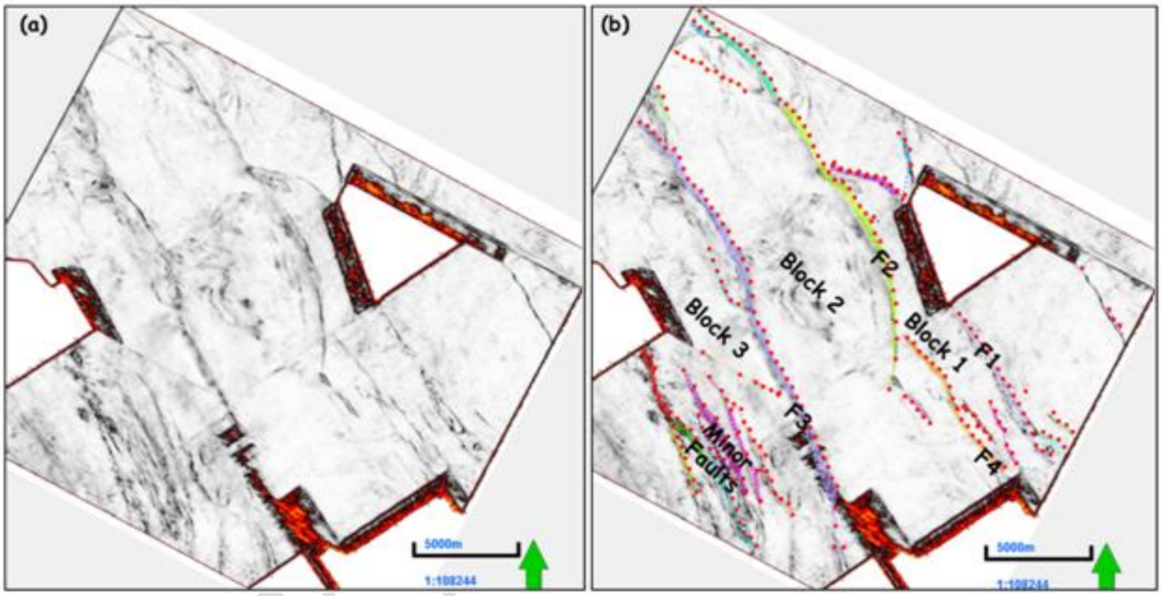


Fig.10. (a)Uninterpreted variance attribute time slice (b) Interpreted variance attribute time slice at -853ms showing faults and blocks within the Okpella Field.

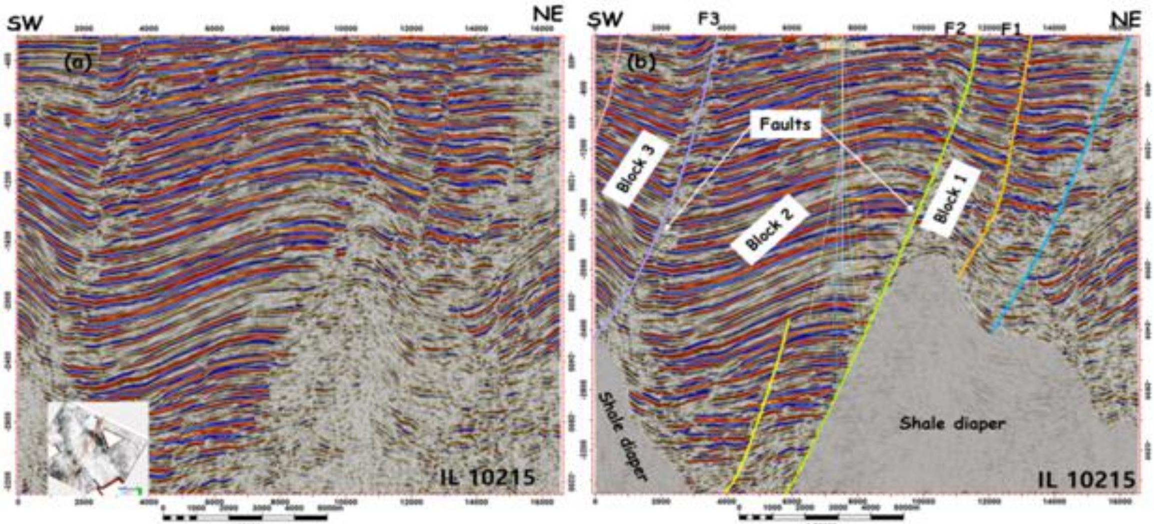


Fig.11. (a)Uninterpreted Seismic Inline (b) Interpreted Seismic Inline showing the growth faults, shale diapirs and associated blocks within Okpella Field.

4.3 Synthetic Seismogram

The generated synthetic seismogram was used to identify the events that coincide with each reservoir's top (Fig.12). Sonic calibration and seismic to well tie were carried out using well TMG-02 because it was the only well that penetrated most of the reservoirs. The synthetic seismogram was generated using the extended white deterministic wavelet method. Adjustments required to fit the well tops to the seismic markers were made within the limit allowed in Niger Delta.

4.4 Horizon Interpretation

From the synthetic seismograph generated (Fig.12), the tops of the Bypassed reservoirs that coincide with the peaks of the seismic horizon were mapped across the seismic volume (Fig.14). Interpreted Horizons are either terminated or interpolated across fault zones (Fig.13). Horizons were interpreted on every fourth inline and eighth cross line across the cropped seismic volume of the Okpella Field.

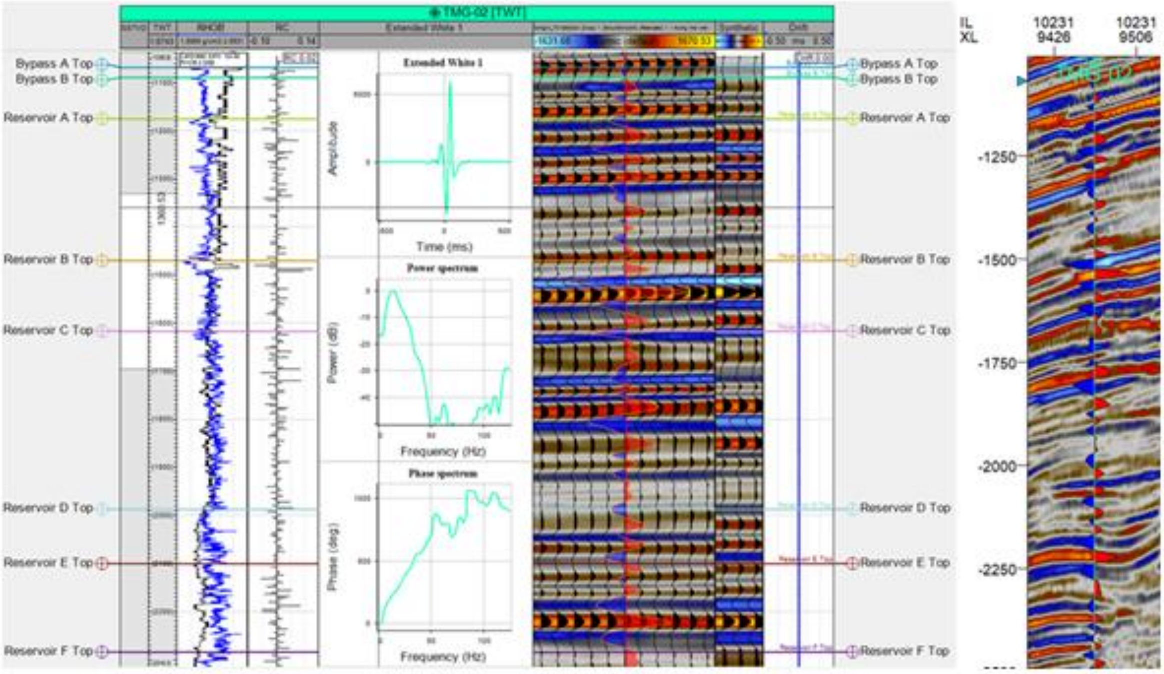


Fig.12. Well to seismic tie of TMG-02 showing events that coincide with the tops of the reservoirs.

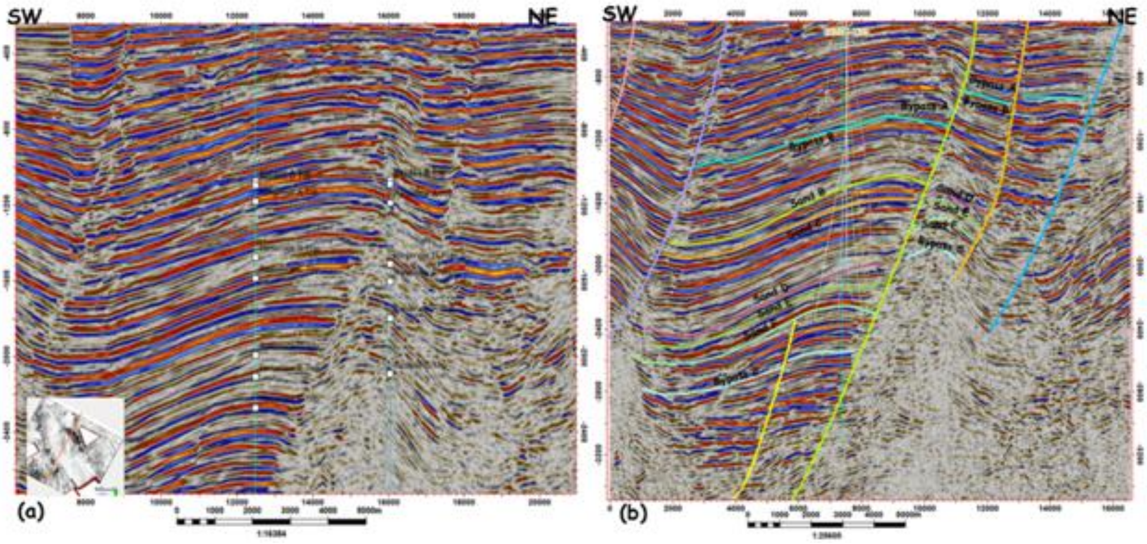


Fig.13. (a) Un-interpreted Inline 10215 showing wells with reservoir tops (b) the mapped

Horizons and interpreted faults.

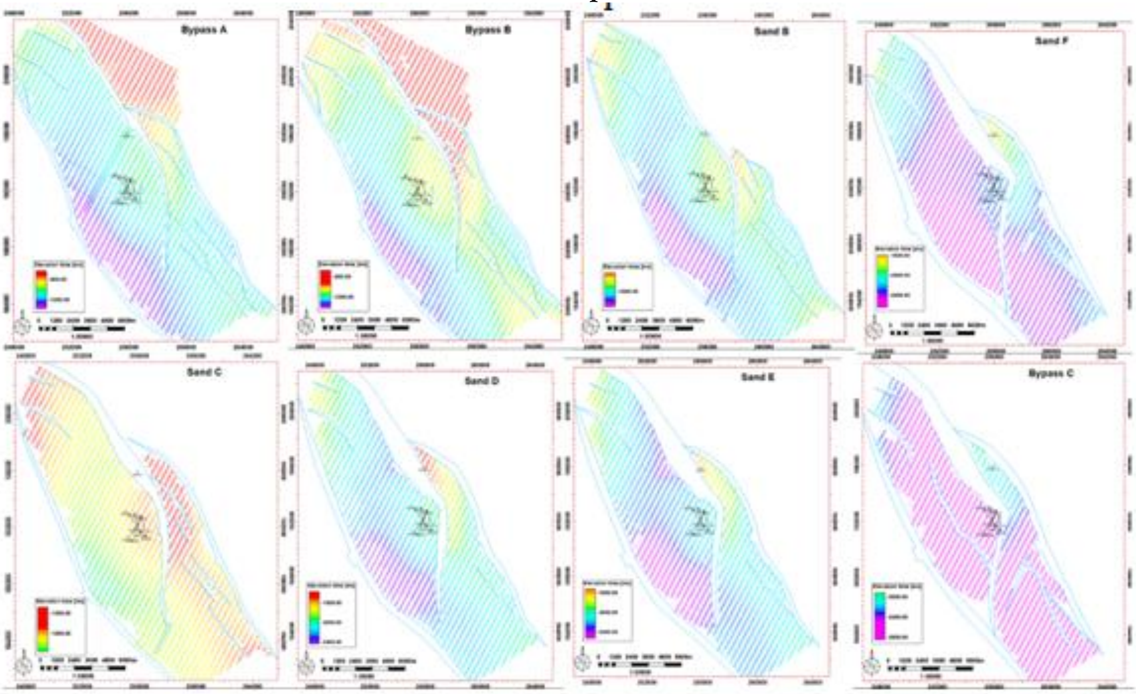


Fig.14. Interpreted horizon grid of the Major and Bypassed reservoirs across the 3D Seismic of the Okpella Field

4.5 Seismic Facie Analysis

A seismic reflection that indicates the presence of hydrocarbons was observed around the Bypass B horizon at the point where well TMG-01 penetrated the Bypass A and B horizon (Fig.15a). The bright flat reflection was suspected to be due to the presence of hydrocarbon water contact within the Bypass B. The Bypass B reservoir also shows a roll-over structure (Fig.15b) associated with all the prolific reservoirs within this study, and this structure usually serves as a suitable trapping mechanism within the Niger Delta Basin. Fif 15c shows the seismic cross line across Well TMG-01 with the variamce time-slice.

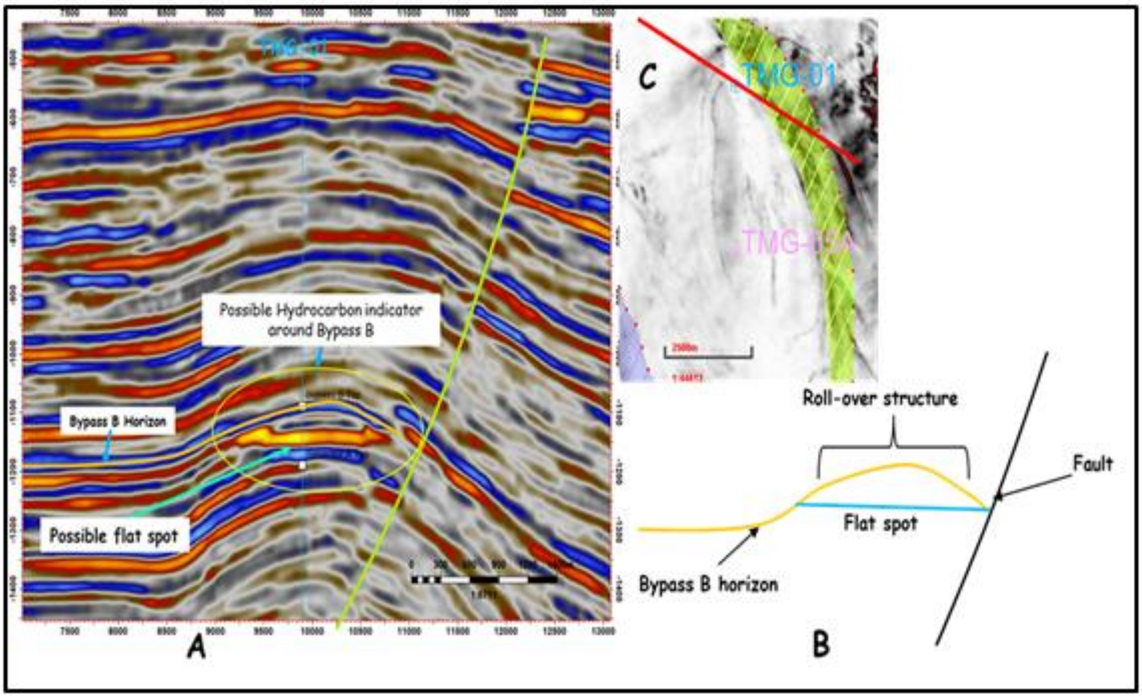


Fig.15. (a) Shows the presence of anomalous bright amplitude around the Bypass B horizon, which could be a pointer of the Direct Hydrocarbon Indicator (D.H.I.) (b) Shows the schematic interpretation of the seismic structural behaviour around the Bypass B horizon and (c) shows the seismic crossline across well TMG-01 along with the variance Time-Slice.

4.6 Time and Depth Structure Maps

The hydrocarbon-bearing horizons interpretation around Okpella Field was completed, fault polygons were drawn, and time structure maps were generated (Fig.16 to 18). The Available check-shot from TMG-02 was used to generate the time-depth relationship curve used in the velocity modelling for depth conversion. The generated depth map was flexed to the well tops. The fluid contacts derived from Petrophysical evaluation were used to create contacts in the depth structure maps to estimate the bulk volume and also to view the fluid distributions across the prolific reservoirs. Bypass C has hydrocarbon in block-1 while the remaining reservoirs have hydrocarbon in block-2 **(**Fig.16 to18).

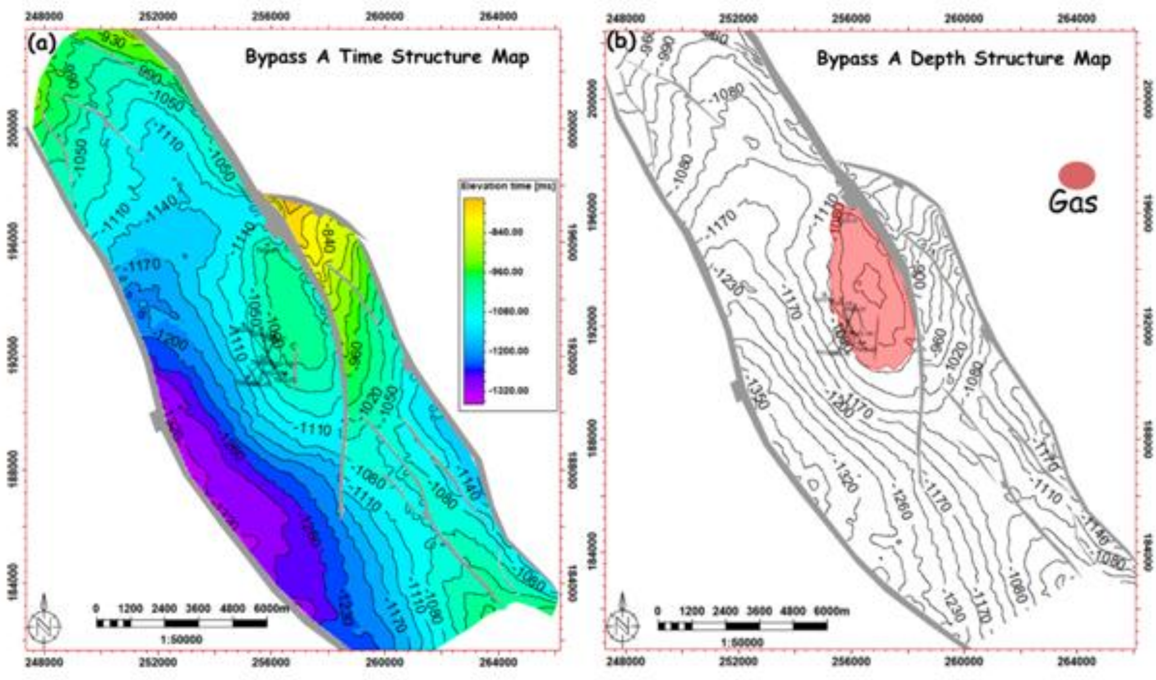


Fig.16. (a) Bypass A Time Structure Map (b) Bypass A Depth Structure map and its fluid distribution.

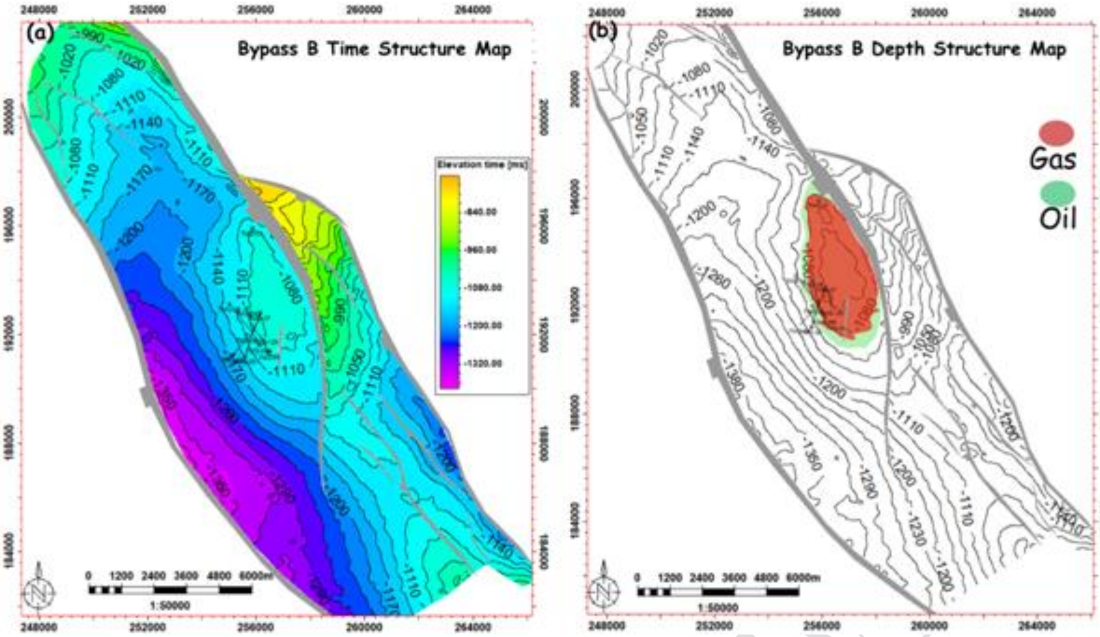


Fig.17. (a) Bypass B Time Structure Map (b) Bypass B Depth Structure map and its fluid distribution.

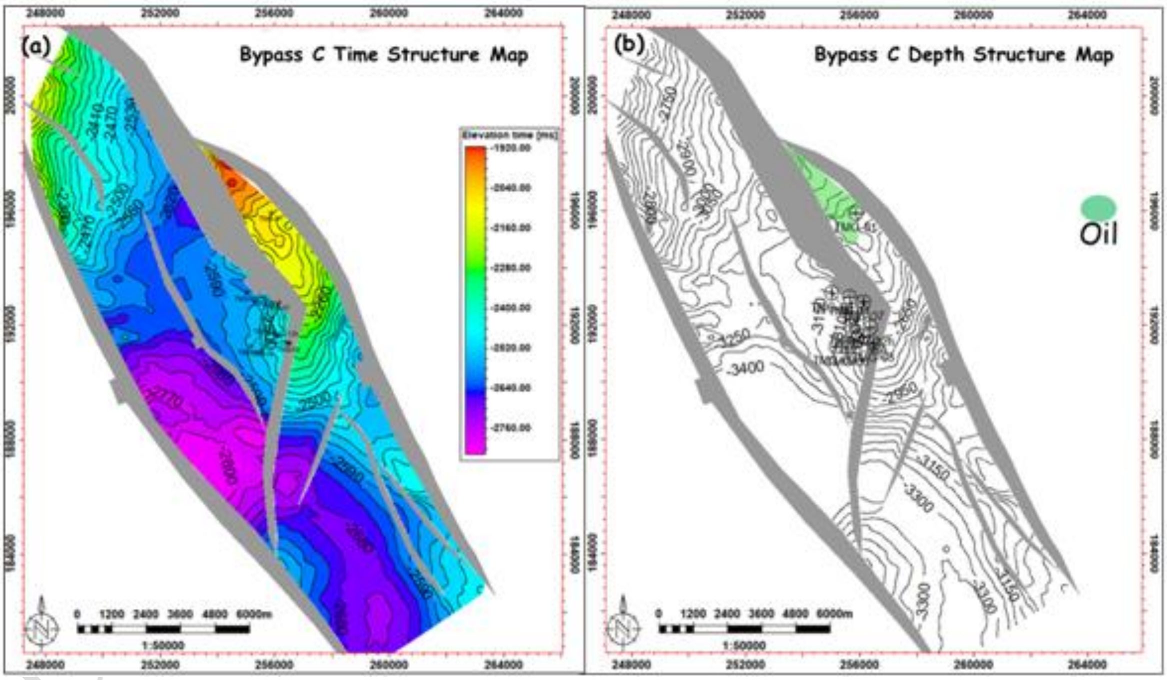


Fig. 18. (a) Bypass C Time Structure Map (b) Bypass C Depth Structure map and its fluid distribution.

4.7 Seismic Surface Attribute Analysis

Seismic surface attribute analysis was carried out on generated time maps to observe regions that are amplitude supported. The amplitude extraction enhances understanding of the facies distribution and possible fluid distribution across the mapped reservoirs. The Seismic attribute used for this analysis is the R.M.S attribute known as Root Mean Square, which is the square root of the sum of the squared amplitude in a data set divided by the sample size of the data within the desired window. The R.M.S amplitude extraction seems appropriate for this analysis since it demarcates regions of different facies. Marine facies such as shales are usually characterised with a relatively low R.M.S amplitude character compared to marginal marine or non-marine facies such as sands. The presence of brighter amplitude reflection on an R.M.S attribute map usually shows the presence of fluid which could be oil, gas or water, and the facies around such bright regions are usually sand facies since they are capable of housing such fluids. The R.M.S attribute analysis is structurally supported because there are bright amplitude reflections around the drilled wells and faults closures. The R.M.S attribute integrated with the Well log analysis helps to show that sand facies control the bright amplitude around the wells, and there is hydrocarbon accumulation around the fault closures or roll-over anticlines (Fig.19a, b,c). The seismic attribute extraction carried out on the Bypassed hydrocarbon reservoirs (Fig.19a,b,c) shows bright amplitude anomalies around the wells and structural closures; this infers that there is a presence of sand facies as deduced from the R.M.S map with hydrocarbon accumulation has deduced from the Well log analysis around the structural closures.

4.8 Volumetric

The expected recoverable hydrocarbon known as the reserve was estimated for the Bypassed reservoirs Table 3. The reserve was also estimated for the already identified reservoirs (major reservoir) Table 4. The total reserve estimated for oil is about 22.4 million barrels, gas is about 258 billion standard cubic feet, and condensate is about 70.29 million barrels of oil, Table 5. The reserve estimate for the Bypass hydrocarbon zones increased the total reserve estimate by about 5.47 million barrels for oil and 42.8 billion standard cubic feet for gas, Table 3. The production data was reviewed to know the possible effect of the volumetrics of the Bypassed hydrocarbon on hydrocarbon production within the Okpella Field. The production data was for oil production in the Major reservoirs. Therefore, analysis of the effect of the bypassed hydrocarbon on oil production was estimated. The cumulative oil, gas and water production from the year 1997 to the year 2018 was provided in the production data. The cumulative production of oil was plotted against the years on a bar chart to view the changes in production over the years (Fig. 20).

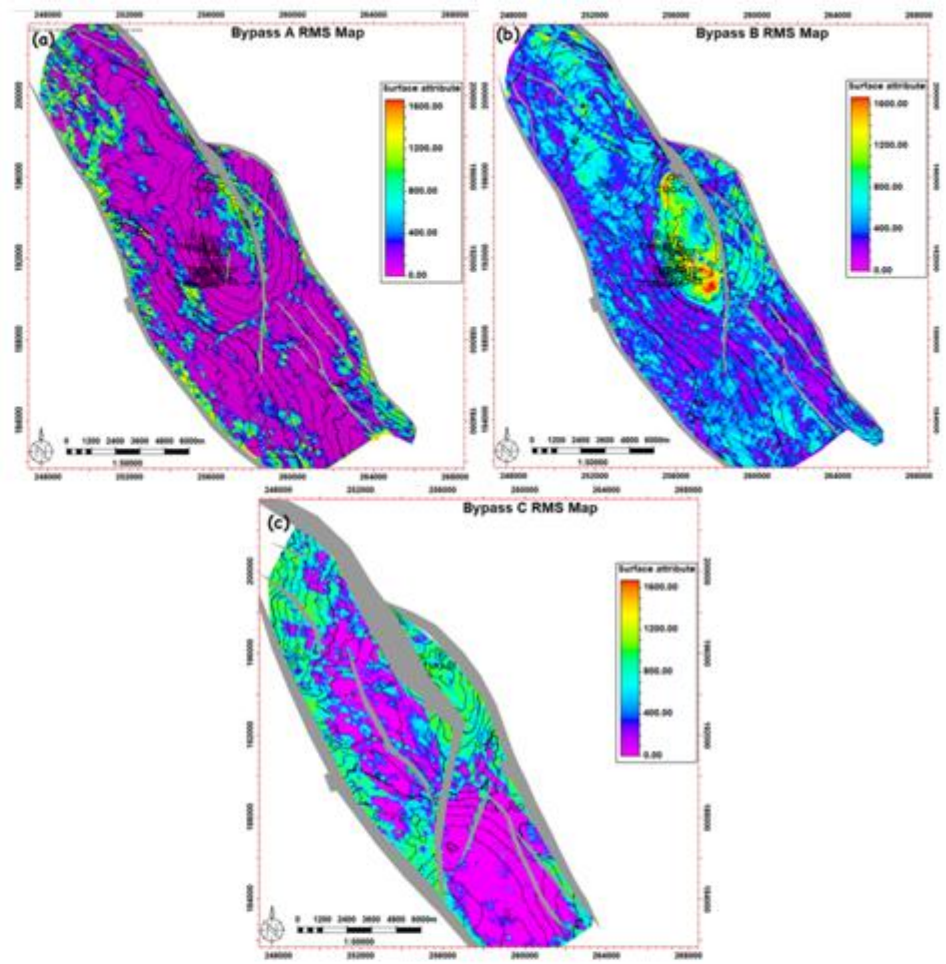


Fig.19. (a) R.M.S. Amplitude Extraction of Bypass A Map (b) R.M.S. Amplitude Extraction of

Bypass B Map (C) R.M.S. Amplitude Extraction of Bypass C

Table 3. Volumetric estimate and reserve for Bypass Reservoirs

Volumes	P10	P50	P90
STOOIP (MMbbl)	14.70	18.2	23.13
GIIP(Bscf)	78.29	142.6	222.57
Oil Reserves (MMbbl)	3.68	5.47	8.10
Gas Reserves (Bscf)	19.57	42.80	77.90

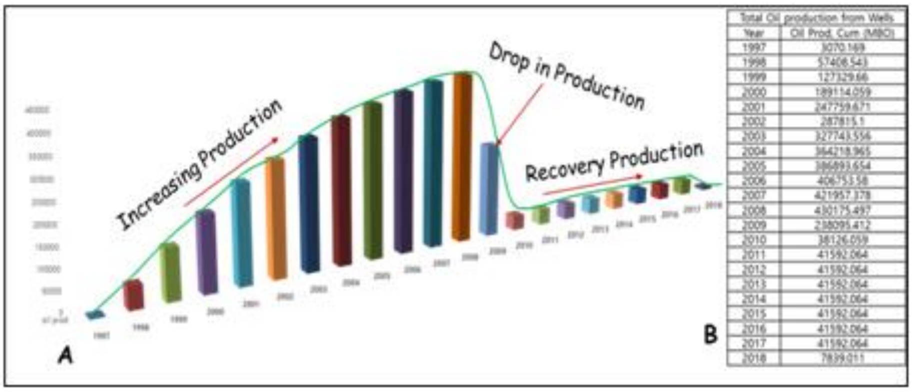
Table 4. Volumetric estimate and Reserves for the major reservoirs.

Volumes	P10	P5o	P90
STOOIP(MMbbl)	44.36	56.57	73.58
GIIP(Bscf)	376.57	718.11	1030.74
Oil Reserves(MMbb)	11.1	16.79	25.75
Gas Reserves(Bscf)	94.14	215.43	360.76
Condensate Reserves(MMbbl)	47.56	70.29	113.31

Table 5. Volumetric estimate and Reserves for all the reservoirs

Volumes	P10	P50	P90
STOOIP (MMbbl)	59.082	74.803	96. 718
GIIP(Bscf)	454.867	860.779	1253319
Gas Condensate STOOIP (MMbbl)	190.255	234.314	323.746
Oil Reserves (MMbbl)	14.770	22.441	33.851
Gas Reserves (Bscf)	113.717	258.234	438.662
Condensate Reserves (MMbbl)	47.564	70.294	113.311

There was an increase in oil production from the year 1997 to the year 2008, and in the year 2009, the field experience decline in oil production due to changes in the reservoir pressure regime. Secondary recovery began in 2010 until 2018 when it was no longer profitable for the company to keep producing the oil (Fig.20). The total volume of oil produced from 1997 to 2009 before secondary recovery is estimated to be 3.48 million barrels, and oil produced during secondary recovery is 0.34 million barrels. The minimum estimated volume of recoverable oil is about 11.1 million barrels for the Bypassed reservoir Table 4. Therefore about 31% of the minimum estimated reserve was produced due to changes in reservoir conditions. Considering the knowledge of production within the Okpella Field, we can also expect to produce about 31% of the minimum expected reserves of the Bypassed hydrocarbon estimated in the volumetric Table 4, which is about 3.68 million barrels and 31% of this estimate will give a producible estimate of 1.1 million barrel of oil from the Bypassed reservoir B and C before secondary recovery. Adding about 1.1 million barrels of oil from the Bypass reservoir to the already produced oil of the Major reservoirs will increase the oil production by 10%, and this should sustain the oil productivity of the field for three more years before secondary recovery considering the previous rate of production employed in the field.



Total Oil production from Wells	
Year	Oil Prod. Cum (MBO)
1997	3070.169
1998	57408.543
1999	127329.66
2000	189114.059
2001	247759.671
2002	287815.1
2003	327743.556
2004	364218.965
2005	386893.654
2006	406753.58
2007	421957.378
2008	430175.497
2009	238095.412
2010	38126.059
2011	41592.064
2012	41592.064
2013	41592.064
2014	41592.064
2015	41592.064
2016	41592.064
2017	41592.064
2018	7839.011

Fig.20. (A) Cumulative oil production plot against years for all the wells (B) shows the sum of the cumulative oil production of all the wells over the years.

5.0 Conclusion

The 3D Seismic interpretation was carried out on Bypassed hydrocarbon zones within the Okpella Field offshore Niger delta basin. Four major faults were mapped across the field from the seismic interpretation, dividing the field into three main blocks. The structural style in the field is growth fault and roll-over anticlinal structures typical of the Niger Delta Basin. The Reservoirs' depth map indicates that the hydrocarbons' major trap is a fault dependent closure. Therefore, the fault has offset the continuity of the reservoirs, thereby juxtaposing the reservoir beds (Sands) with non-reservoir beds (Shales), essentially trapping hydrocarbons. The R.M.S attribute maps show that the Bypassed Reservoirs are amplitude supported, indicating the presence of hydrocarbon accumulation around the structural closures. The Root Mean Square Amplitude attribute was used because it is sensitive to amplitude anomalies which could serve as direct hydrocarbon indicators (D.H.I.s). The volume of oil in the Bypass hydrocarbon zones and major reservoir zones was estimated. The Bypassed reservoir zones increased the volume of oil by 5.47 million barrels and gas volume by 42.8 billion standard cubic feet. The production data revealed the oil production from the Major reservoir in the field. This was used to estimate the producible volume of the Bypassed hydrocarbon zones, which was estimated to have a producible oil of about 1.1 million barrels. This can probably extend the field's production life three years before secondary recovery.

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