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3D Seismic Attributes Analysis and Reserve Estimation of "OTIGWE" Field in the Coastal Swamp Depobelt of Niger Delta Nigeria

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Abstract

3D seismic data, check shot data and suite of well logs from four wells were analyzed with Petrel software for the formation evaluation and reservoir characterization of OTIGWE field. The methods adopted involved delineation of lithology from the gamma ray log, identification of reservoirs from the resistivity log, well correlation, determination of petrophysical parameters, horizon and fault mapping, time to depth conversion, attribute analysis and reserve estimation. Two reservoirs A and B were mapped. From the petrophysical analysis, porosity range of reservoir "A" is 31.48 - 77.47% and reservoir "B" is 18.20 - 33.86% and their permeability values range from 15 - 80md and from 63-540md respectively. The Sw values for the reservoir ranges from 32 - 96% in the study field while the volume of shale ranges from 17 - 82% across the reservoir "A" and 49% in reservoir "B". Four horizons and eight faults were mapped. The Depthe structure maps generated showed an anticlinal structure at the North eastern part of the surfaces dipping towards the western direction. The reserve estimates of all the wells were calculated with OTIG 2having the highest value of 9,279,053.3lmmbls. The resultsofthe petrophysical analysisrevealedthepresenceoflargevolumeofhydrocarboninthereservoirsforcommerci al exploitation.

Keywords: Formation evaluation, reservoir, lithologies, petrophysical, Seismic Attributes.

1.0 Introduction

The prolific demand for hydrocarbon products since the 20th century prompted intensified exploration for oil and gas accumulation in reservoir rocks. This led to an extensive study of the Niger Delta depocenters after a long while of non-productive search in the Cretaceous sediments of the Benue Trough [1]. Petroleum in the Niger Delta is produced from sandstones and unconsolidated sands predominantly in the Agbada Formation. Recognized known reservoir rocks are of Eocene to Pliocene in age, and are often stacked, ranging in thickness from less than 15 meters to 10% having greater than 45 meters thickness [2]. Based on reservoir geometry and quality, the lateral variation in reservoir thickness is strongly controlled by growth faults; with the reservoirs thickening towards the fault within the down-thrown block [3].

In order to avert any loss or wastage of resources there is the need to use a technologically and economically viable and detailed geophysical survey method to properly and adequately characterize formation lithology and delineate reservoirs. This ensures that the porosity, permeability, water saturation and hydrocarbon potentials of the reservoirs are accurately ascertain for maximum exploration and exploitation of oil and gas.

Hence, in this work, 3D seismic reflection data were integrated with well logs so as to characterize the various reservoir units in OTIGWE field using petrophysical analysis and seismic attributes from gamma ray log, resistivity log, well correlation, horizon and fault mapping, time to depth conversion, attribute analysis and reserve estimation.

2.0 Location and Geological Setting of the Study Area

The study area lies offshore Niger Delta in southern Nigeria with an area of about 42.84 km2. The Niger Delta is situated in the Gulf of

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Guinea on the West Coast of Central Africa. It is located in the southern part of Nigeria within latitudes 4^0 00′N to 6^0 00′Nandlongitudes3o 00′E to9o 00′EandboundedintheEastandWestbytheCalabarandBeninflanksrespectively [4].IntheSouthitisboundedbytheGulfofGuineaandintheNorthbytheolder(Cretaceous) tectonicelementsofAnambraBasin,AbakalikiupliftsandtheAfikposyncline(Fig.1).Itisone oftheworld’slargestDeltawiththesubaerialportioncoveringabout75,000km2andextending morethan300kmfromtheapextomouth.Theregressivewedgeofclassticsediments,whichit comprises,hasmaximumthicknessofabout12km.ItbuildsoutintotheAtlanticOceanfrom the Niger–Benueriverwhich is themain sediments supplier [1]. Thestructureandstratigraphy ofNigerDeltaarecontrolledbytheinterplayofsedimentssupply andsubsidence.Importantinfluencesonsedimentaryrateshavebeenecstaticsealevelchanges and climatic variationsin the hinterland. Subsidence hasbeen controlled largelybythe initial basementmorphologyanddifferentialsedimentloading onunstableshale.Hence,itssequenceis extensivelyaffectedbysyn-sedimentaryandpost-sedimentaryfaultsassociatedwithsourcerock structures and lithology types favourablefor the generation, accumulation and retention of hydrocarbonoverconsiderabledistancesalongstrike.ThismakesthisDeltaprolificintermsof hydrocarbonoccurrence[4].

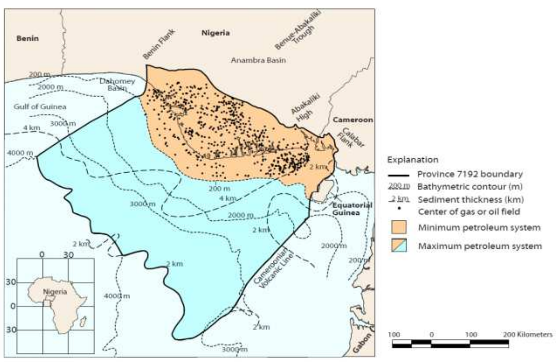

Fig.1: IndexMapoftheNigerDeltaShowingProvinceOutline,BoundingStructuralFeaturesand Minimum Petroleum System After [5]

3.0 Methods of Study

The methods of study include structural interpretation, seismic attributes and petrophysicalanalysis.Theywereadoptedusingdelineationoflithologies,identificationofreservoirunitsand identification of oil and gas zones from the log signatures of gamma ray, resistivitylogs and combination ofneutron/densitylogs. Faultmappingwas also doneon the vertical seismic display acrossthewholeseismicvolume.Seismictowelltiewasdonetomatcheventsonwelllogsto thespecificseismicreflectionswiththeaidofcheckshot.Horizonsweremapped,auto-tracked and convertedto surfacesto obtainthetime structuremaps. Thetime structure maps were convertedtodepthstructuremapsusing thecheckshotdataprovided.Moreover,seismicattribute analysis wascarriedoutusingtwosurfaceattributestimemapwhichareupperloop areaand interval average in order to enhance the hydrocarbon potential of the field and delineate new reservoirs that maybehidden through structural traps.

Thedataobtainedwereappliedintoempiricalformulaetoestimatethepetrophysicalproperties of the mapped reservoir units delineated on the well logs. The reservoir units whichwere identifiedthroughtheuseoftheelectrofaciessignatureswere furthercharacterizedquantitatively to decipher petrophysicalparameters, volume of shale, formation factor, porosity, water saturation and permeability.

Thepetrophysicalanalysisbeganwiththeidentificationofreservoirs (sandbodies)withinthe AgbadaFormation present in the well by observing intervals where the gamma ray reads relatively low values (i.e. deflects tothe left). The fluidcontactwasdeterminedusing the resistivitylogsincehydrocarbonis moreresistivethan water.

Theparametersdeducedfromtheanalysisofgammaray index,porosity,nettogross,volumeof shale,formationfactor,irreduciblewatersaturation, hydrocarbonsaturation,watersaturationand hydrocarbon pore volume were used to effectively quantify the reservoirs in terms of the hydrocarbonpore-volume and Hydrocarbon-in-place.

4.0 Theoretical analysis

4.1 Gamma Ray Index

The gamma ray log was used to determining the gamma ray index using the formula according to [6]:

$\mathbf{I_{GR}} = (GR_{LOG} - GR_{MIN})/(GR_{MAX} - GR_{MIN})$ (1.1)

Where, $\mathbf{I_{GR}}$ = gamma ray index, $\mathbf{GR_{LOG}}$ = gamma ray reading of formation from log

$\mathbf{GR_{MIN}}$ = minimum gamma ray (clean sand) $\mathbf{GR_{MAX}}$ = maximum gamma ray (shale)

Volume of Shale

The volume of shale was calculated by applying the gamma ray index in the appropriate volume of shale equation according to [7] for tertiary rocks:

$\mathbf{V_{sh}} = 0.083[2^{(3.7 \times IGR)} - 1.0]$ (1.2)

Where, $\mathbf{V_{sh}}$ = volume of shale $\mathbf{I_{GR}}$ = gamma ray index.

Porosity

The computation of porosity was done in stages, the first involved the use of the Wyllie equation to estimate the density derived porosity (ϕ_D), and then the neutron-density porosity (ϕ_{N-D}), was estimated using the neutron (ϕ_N) porosity coupled with the density derived porosity.

The Wyllie equation for density derived porosity is given as:

$\phi_D = (\ell_{max} - \ell_b)/(\ell_{max} - \ell_{fluid})$ (1.3)

where: ℓ_{max} =density of rock matrix = 2.65 g/cc, ℓ_b = bulk density from log

ℓ_{fluid} = density of fluid occupying pore spaces (0.74g/cc for gas, 0.9g/cc for oil and 1.1 g/cc for water).

The Neutron – Density porosity could be calculated as:

$\phi_{N-D} = (\phi_N + \phi_D)/2$ for oil and water column (1.4)

$\phi_{N-D} = (2\phi_D + \phi_N)/3$ for gas bearing zones (1.5)

Formation Factor

This was achieved using the Humble equation:

$F = a/Ø^m$ (1.6)

Where, F = formation factor, Ø = porosity m = cementation factor = 2.15

Formation Water Resistivity (Ωm)

Using the Archie's equation that related the formation factor (F) to the resistivity of a formation at 100% water saturation (R_o) and the resistivity of formation water (R_w), the resistivity of the formation water was estimated as:

$R_w = R_o/F$ (1.7)

Water Saturation

Determination of the water saturation for the uninvaded zone was achieved using the Archie (1942) equation given below.

$S_w^2 = (F \times R_w)/R_T$ (1.8)

But, $F = R_o/R_w$ (1.9)

Thus,

$S_w^2 = R_o/R_T$ (1.10)

Where, S_w = water saturation of the uninvaded zone

R_o = resistivity of formation at 100% water saturation , R_T = true formation resistivity

Hydrocarbon Saturation

This was obtained directly by subtracting the percentage water saturation from 100.

Thus: $S_{hy} = 1 - S_w$Or $S_{hy}\% = 100 - S_w\%$ (1.11)

Where, S_{hy} is the hydrocarbon saturation (expressed as a fraction or as percentage).

Resistivity Index

This was estimated using the ratio of formation true resistivity (R_t) to resistivity of formation at 100% saturation (Ro):

$I = R_t/R_o$ (1.12)

Where, *I* is the resistivity index. When *I* is equal to unity, it implies that the reservoir is at one hundred percent (100%) water saturation. The higher the value of *I*, the greater the percentage of hydrocarbon saturation.

Bulk Volume Water

Bulk volume of water (BVW) was estimated as the product of water saturation (S_w) of the uninvaded zone and porosity ($Ø_{N-D}$).

Thus,

$BVW = S_w \times Ø_{N-D}$ (1.13)

Where, $Ø_{N-D}$ = neutron-density porosity.

Hydrocarbon Pore Volume

The hydrocarbon pore volume (HCPV) is the fraction of the reservoir volume occupied by hydrocarbon. This was calculated as the product of neutron-density porosity and hydrocarbon saturation as shown below:

$HCPV = Ø_{N-D} \times (1 - S_w)$ (1.14)

$HCPV = Ø_{N-D} \times (S_h)$

Irreducible Water Saturation

The irreducible water saturation was calculated using the following relationship:

$S_{wiir} = (F/2000)^{1/2}$ (1.15)

Where, S_{wiir} = irreducible water saturation, F = formation factor.

Permeability

This was based on the relationship between permeability, porosity, and irreducible water saturation. The relationship is expressed as:

$Koil = [(250 \times (Ø_{N-D})^3)/S_{wiir}]^2$ (1.16)

V_{sh} Total

This is the total volume of shale represented as a depth factor within a well. It is calculated by:

Average V_{sh} x Gross thickness (1.17)

Net Thickness

This is the column of the reservoir that is occupied by reservoir formation (e.g. sand) only and exclusive of non-reservoir formations (e.g. shale). It is calculated by:

Gross Thickness – V_{sh} Total (1.18)

Net to Gross Ratio

This is the ratio between the net reservoir thickness and the gross reservoir thickness. However in terms of hydrocarbon pay, it could be calculated as the ratio between the net pay thickness and the gross pay thickness.

NTG = Net thickness ÷ Gross Thickness (1.19)

Effective Porosity

This is the porosity of the interconnected pore spaces. It assumes the absence of shale from the reservoir. It can be calculated using the following relationship:

$\Phi_{effective} = (1 – V_{SHALE}) * \phi_{N-D}$ (1.20)

Storage Volume

This is the capacity to store hydrocarbon in the reservoir. The storage volume is always higher than the hydrocarbon pore volume within a well because the net pay zone is inclusive of the grain matrix whereas, the grain matrix is absent in the hydrocarbon pore volume computation as only the hydrocarbon in the pore spaces is calculated for,

Storage Volume = ϕ_{N-D} * Net Pay Thickness (1.21)

Volume of Oil Resources

This is the volume of oil resources per unit acre in a field. It could be used to estimate oil reserve volume in the field.

Volume of Oil Resources = $(7758*h*HCPV)/B_o$ (1.22)

Where h = net pay oil, B_o = Formation oil volume factor = 1.2 bbls/STB

Volume of Gas Resources

This is the volume of gas resources per unit acre in a field. It could be used to estimate gas reserve volume in the field.

Volume of Gas Resources = $(43560 * h * HCPV)/B_g$ (1.23)

Where h = net pay gas, B_g = Formation gas volume factor = 0.005 cuft/scf

Volume of Oil Originally in Place

Oil originally in place is computed with the following equation:

OOIP = Volume of Oil Resources * Area covered by oil (1.24)

Here, recovery factors have not been applied. This volume could be calculated directly from the volume of oil resources contour map. The area of the map occupied by oil is calculated sectionally with respect to the contour intervals. The individual area is then multiplied by the individual contour value to get the individual volumes. Finally, all the individual volumes are added to get the total volume of oil resources in the field which is equivalent to the volume of oil in place. The unit here is stock tank barrels.

Volume of Gas Originally in Place

This is calculated the same way as that of oil originally in place from the volume of gas resources contour map. The unit here is standard cubic feet.

GOIP = Volume of Gas Resources * Area covered by gas (1.25)

Direct Measurement of Hydrocarbon in Place

The hydrocarbon originally in place could also be computed directly using the average value for the net pay thicknesses, average hydrocarbon saturations and average porosity values and substituted in the following equations:

$$OOIP = (7758*A_{oil}*h_{oil}*s_{h(oil)}*\phi_{N\text{-}D})/b_o \quad (1.26)$$

$$OGIP = (43560*A_{gas}*h_{gas}*s_{h(gas)}*\phi_{N\text{-}D})/b_g \quad (1.27)$$

A_{oil}= Area occupied by oil A_{gas} = Area occupied by gas

h_{oil}= Average height of oil column h_{gas} = Average height of gas column

$s_{h(oil)}$ = Hydrocarbon saturation (oil column) $s_{h(gas)}$ =Hydrocarbon saturation (gas)

5.0 Results and Discussion

The results were obtained from thedifferent studies methods made. Eight reservoirswere mappedoutusinggammaraylog,resistivitylog,Neutron-porosityloganddensitylog.Gamma raylogwhichisalithologylogwasusedforlithologicdifferentiationbetweensandandshale whileresistivitylogwasusedtodelineatehydrocarbonbearingzone.NeutronandDensitylogs were used to delineate oil and gas contact as depleted in well correlated OTIG 2, OTIG11, OTIG9andOTIG7wellsintheNorthwest-Southwestdirection(Fig2).EightfaultslabelledF1, F2,F3,F4,F5,F6,F7andF8werealsomappedoutfromthe faultinterpretationandhorizon mappingon the seismic section (Fig. 3).

The PetrophysicalInterpretation of field was done based on the analysis. Two hydrocarbon bearing zones A and B were identified for the petrophysicalinterpretation using the obtained petrophysical parameters in table1.

Table 1: PetrophysicalParametersObtained

H	vsh	VSH (%)	porosity	porosity(m)	F	Swiir	Swiir(%)	K_OIL	Sw	sw%	N/G	N/G %	Shc	Hcs%
							OTIG 2							
26.77	0.49	49.00	18.6980	0.18	23.86	0.4168	41.68	65	0.4168	41.68	0.2214	22.14	0.5832	11.00
49.13	0.82	82.00	14.9008	0.14	40.76	0.3773	37.73	80	0.3773	37.73	0.1194	11.94	0.6227	9.00
							OTIG 11							
18.20	0.49	49.00	20.3033	0.20	28.1	0.1113	11.13	540	0.9606	96.06	0.2220	22.20	0.0394	2.00
53.59	0.17	17.00	13.0874	0.13	15.67	0.1575	15.75	18	0.6879	68.79	0.0534	5.34	0.3121	4.00
							OTIG 9							
26.32	0.49	49.00	18.6664	0.18	24.42	0.1097	10.97	63	0.3228	32.28	0.2225	22.25	0.6772	12.00
31.48	0.29	29.00	13.1422	0.13	51.9	0.1584	15.84	15	0.4557	45.57	0.1006	10.06	0.5443	7.00
							OTIG 7							
33.86	0.49	49.00	19.1461	0.19	25.73	0.1105	11.05	309	0.3539	35.39	0.2240	22.40	0.6461	12.00
77.47	0.17	17.00	13.0874	0.13	50.67	0.1575	15.75	18	0.6879	68.79	0.0534	5.34	0.3121	4.00

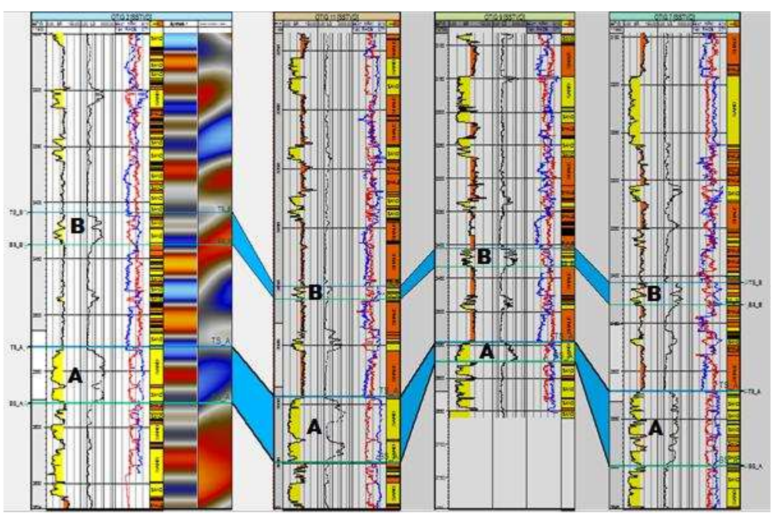

Fig. 2: Wellcorrelation panel showingthe mappedreservoirs.

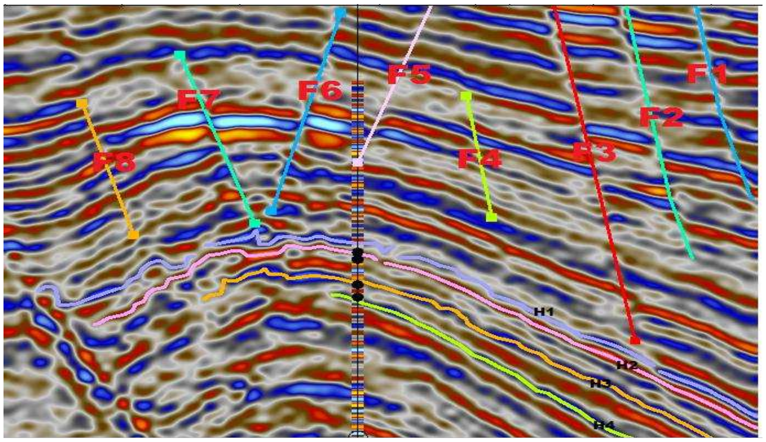

Fig. 3: Seismic to welltieshowing faults andhorizons

6.0 Seismic TimeStructural Maps

Timestructuralmapofhorizonswerecontoured.Thecontourvaluesonthestructuremaprange from2700mto3100mforH$_1$.Theeightfaultsonthemapexistonaprominentclosureatthe NorthEasternpartofthemapanddippingtowardsthewesternpart(Fig.4).Also,HorizonH$_2$ haseightfaultsonthemapandaprominentclosureexistsatthecentralpartofthemap.Thecontour values on the structure map range from 2750 m to 3180 m. (Fig. 5).

Thecontour configurations areindicative of an anticlinal structurethat is favourable in trappingoilandgas.

TimeStructuralMapof HorizonH$_3$ showsthatthecontourvaluesonthestructuremaprange from 2800mto 3200mwith eight faults andaprominent closure at thecentral part of themap. The contour configuration is also indicative of an anticlinal structure that is favourablein trappingoilandgas.

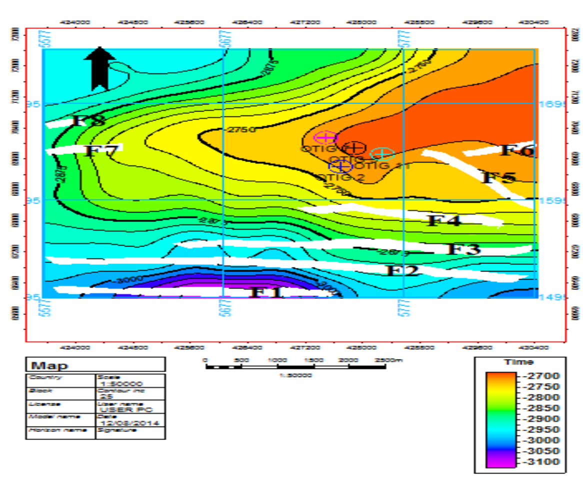

Fig. 4: Time structural map of horizon 1

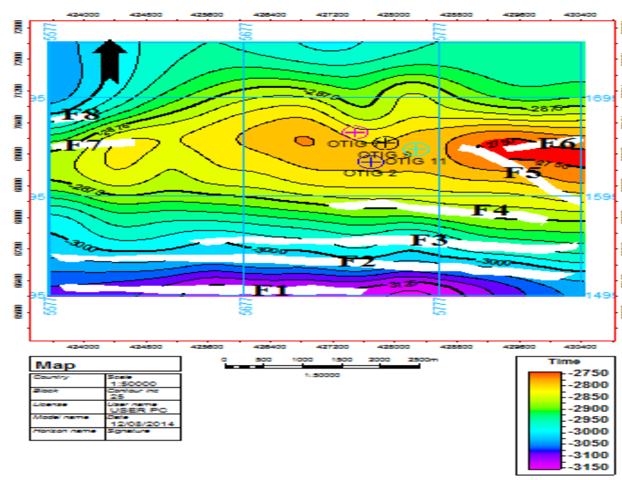

Fig. 5: Time structural map of horizon 2

ThedepthstructuralmapofhorizonH$_1$ hascontourvaluesrangefrom2280mto2550m.Thereisavariationindepthwithinthestudy locationwhichisduetothestructuraldeformation.TherearеeightfaultsandwithprominentclosureattheNortheasternpartofthestudyareadipping towards theWestern direction and identifying four viable hydrocarbonwells (Fig. 6).

ThedepthstructuremapofhorizonH$_2$ hascontourvaluesrangefrom2340mto2580m.Thereis a variation in depth within the study location due to the structural deformation that has occurredinthearea.Eightfaultswithprominentclosureattheeasternandcentralpartofthe studyarea were delineated. The area has ananticlinal closure favourableto existence of hydrocarbonreservoirs (Fig. 7).

The Depth structural map of horizon H$_3$ and H$_4$ show the same trend and harboursufficient hydrocarbon.Fourwells weredelineated in eachcase.

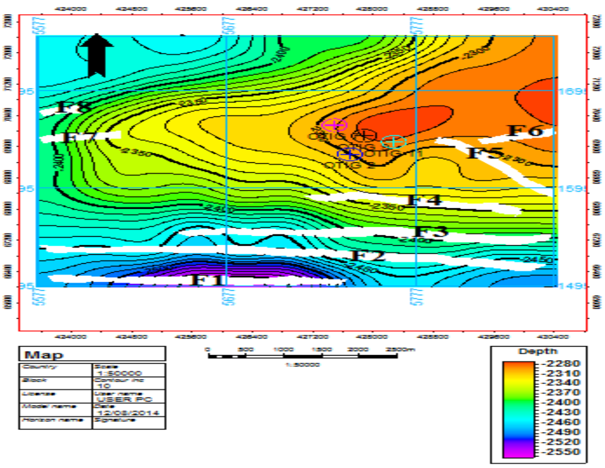

Fig.6: Depth surfacemapof horizon 1

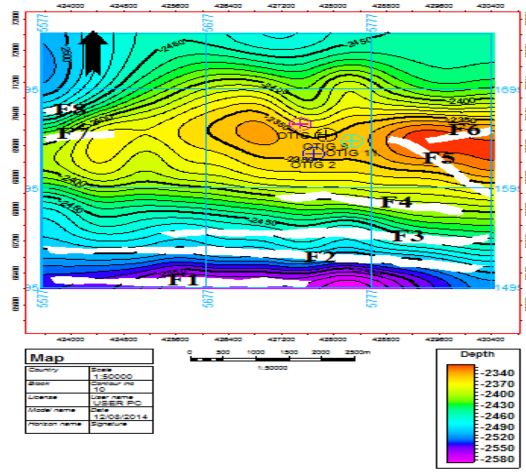

Fig. 7: Depth surfacemap of horizon 2

Twotime surface attributes maps weregenerated.These areinterval average and upper loopmaps. Thesewere carriedout to delineate new reservoirs that maybehiddenfrom structural traps. Theupper loop area and intervalaverage extraction maps forhorizon1 and 2, and the OTIG 2, OTIG7, OTIG9 and OTIG 11 wells in Fig. 8 – 11.

Theupper loop attributes map generated shows abrightspot in and aroundthe fourwells which also coincides to high amplitude anomalygenerated from the interval averageextraction maps forthe horizons,thereby validatingotherinterpretations.

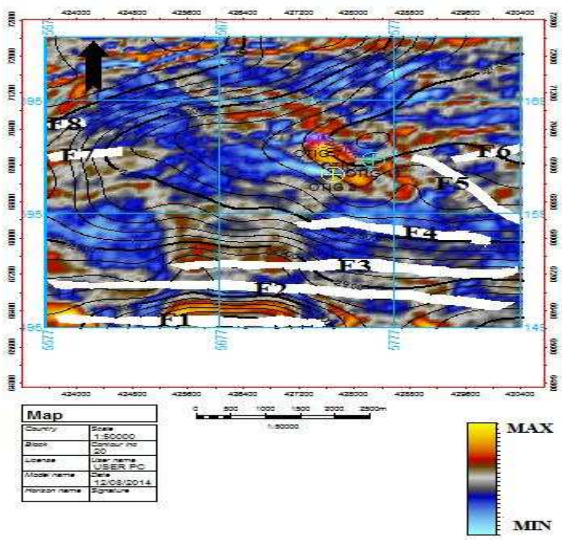

Fig. 8: Interval AverageExtraction from Horizon 1

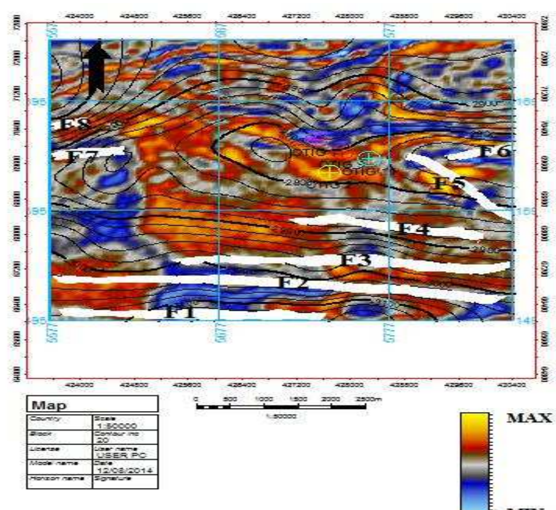

Fig. 9: Interval AverageExtraction from Horizon 2.

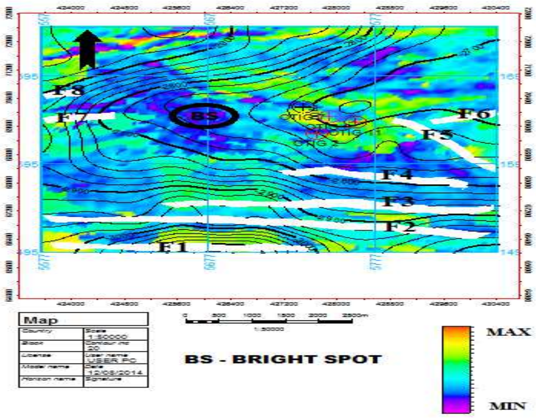

Fig. 10: UpperLoop Extraction Map ofHorizon 1

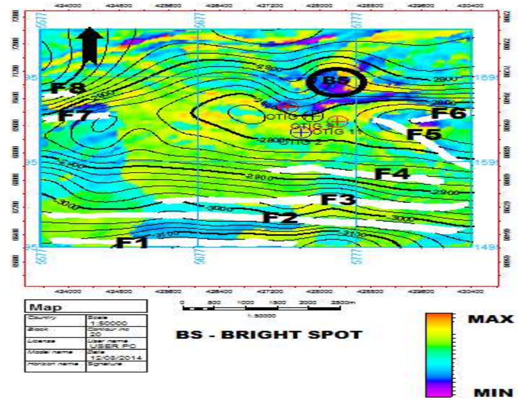

Fig.11: UpperLoop Extraction Map ofHorizon 2

SandAisthedeepestofthe hydrocarbonbearing sand.Itisconsistentacrossthewellswithgross thicknessvaryingfrom31.48mto77.47m.Theresistivitylogshowsthatallthewellsareina hydrocarbonbearingzone.Ithasanettogrossratioof0.05bothinOTIG11andOTIG7and 0.1inOTIG2andOTIG9.Thisreservoirisalsocharacterizedwithaporosity valueof0.13and watersaturationvaluesrangingfrom37.73%to68.79%withthehighestvalueinOTIG11and OTIG7andlowestvalueinOTIG2.Thehydrocarbonporevolumerangesfrom4%to9%with highest in OTIG2.
SandBistheshallowestofthehydrocarbonbearingsand.Itisalsoconsistentacrossthewells withgrossthicknessvaryingfrom18.20mto33.86m.Theresistivitylogshowsthatallthewells are ina hydrocarbon bearing zone. It has a net to gross ratio of 0.22 in all the wells. This reservoiris alsocharacterized with a porosityvalueranging from0.18 to0.20, with highest value inOTIG11watersaturationvaluesrangingfrom32.28%to96.06%withthehighestvaluein OTIG11.Thehydrocarbonporevolumerangesfrom2%to12%withhighestvalueinOTIG7 and OTIG 9.

7.0 Conclusion

Theformationevaluationandreservoircharacterizationof OTIGWEfieldrevealedthatthetwo majorlithologicalunitsintheareatobesandandshale.Ananticlinalstructurewasobservedon thedepthmapintheNortheasternpartofthestudyarea,dippingtowardsthewesternpart.Eight faults labeled F1, F2, F3, F3, F4, F5, F6, F7 and F8 were continuous across the field. The structuraldispositionofthefourhorizonsmappedcoupledwiththegoodreservoirparameters obtainedfromthewell greatlyfavourtheaccumulationofhydrocarbon.Theintervalaverage andupperloopextractionfromthehorizonrevealedhighamplitudeandbrightspotareasonand around the structuralheights. Two reservoirsA andB were mappedout. The petrophysicalanalysis gave porosity values of reservoir "A" ranging from 31.48-77.47% and reservoir "B" ranging from 18.20 - 33.86% across the reservoir. The permeability values of reservoir "A" ranging from 15-80md and reservoir "B" ranging from 63-540md. The Swvalues for the reservoir ranges from 37.73 – 41.68% in OTIG 2, 35.39 – 68.79% in OTIG 7, 32.28 – 45.57% in OTIG 9 and 68.79 – 96.06% in OTIG 11. The volume of shaleranges from 17 - 82% across the reservoir "A" and 49% in reservoir "B". The result of original oil in place for all the wells calculatedshowsthatOTIG2hasthehighestvaluewith9,279,053.3mmbls.Inconclusion,the results of the seismic interpretation and petrophysicalanalysis show that the reservoirs under consideration havegoodprospects.

8.0 References

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