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Direct estimation of Hydrocarbon in place of JAKS Offshore Field, Niger Delta using empirical formulae Technique

*Osaki, L.J.[1], Itiowe, K.[2], Mgbeojedo, T.I.[2], Agoha, C.C.[3], Onwubuariri, C.N.[4], Okoro, E.M.[5]

[1](Department of Physical and Chemical Sciences, Elizade University, Ilara Mokin, Ondo state, Nigeria)
[2](Department of Earth Sciences, Arthur Jarvis University, Akpabuyo, Cross River State)
[2](Geotechnical Department, Arab Center for Engineering Studies, Doha Qatar)
[3](Department of Geology, Federal University of Technology Owerri, Imo State, Nigeria)
[4](Michael Okpara University of Agriculture Umudike, Nigeria)
[5](Department of Geology, University of Nigeria, Nsukka)

Abstract:- The 3D seismic intėrpretation and petrophysical assessment of thė JAKS oil field in the Niger Dėlta was successfully carried out by performing a comprehensive structural analysis, reservoir delineation and volumetric assessment of the field using seismic data, drilling logs and empirical formulas. The work was carried out in two stages; seismic data interpretation and petrophysical data analysis. These phases are combined to evaluate the hydrocarbon reserves of the reservoir using the empirical formula approach. The methodology includes the delineation of lithology from the gamma ray log, the identification of reservoir fluid types from the resistivity and the neutron / density combination log, borehole correlation, horizon and fault mapping from seismic data, determination of petrophysical parameters from empirical equations. The reservoirs' original hydrocarbon stocks were also assessed based on the weighted averages of porosity, water saturation, gross rock volume and net to gross ratio. The research shows a deep structure map with massive, NNW running anticline, with four associated fold-related synthetic and antithetical normal faults (F1, F2, F3, F4); understand that they were folded and faulted by localized overburden stresses resulting from a combination of differential loading on the deep-seated overpressure-ductile beneath compacted marine Akata shale and the gravitational collapse of the Niger Delta continental slope due to the inflow of sediments. The petrophysical analyzes have shown that the mean porosity value of the deposit sand units is in the range of 25, -31%, the mean permeability values of the deposit sand units are in the range of 61-1452 mD, the mean slate volume in the range of 20.5-38.6% lies. The water saturation and hydrocarbon content of the reservoirs ranged from 15 to 41% and 59 to 85%, respectively. The results of the study show that the field has good structural and petrophysical parameters for hydrocarbon potential and enables hydrocarbon production. The average Original Oil in Place (OOIP), which is calculated using the empirical formula method with the petrophysical parameter, is 29 bbls / STB, while the Stock Tank Oil In Place (STOIP), the oil volume after production, is 22 bbls / STB . The primary extraction reserve is 20,381,028.23 barrels, which can be extracted with a primary extraction factor of 10%. The Empirical forecast approach for hydrocarbon in place is a substitute and reliable remedial method pending a qualitative 3D geostatic model technique.

***Keywords**: - Empirical formulae technique, Porosity, Permeability, Hydrogen Saturation, Primary Recovery.*

I. INTRODUCTION

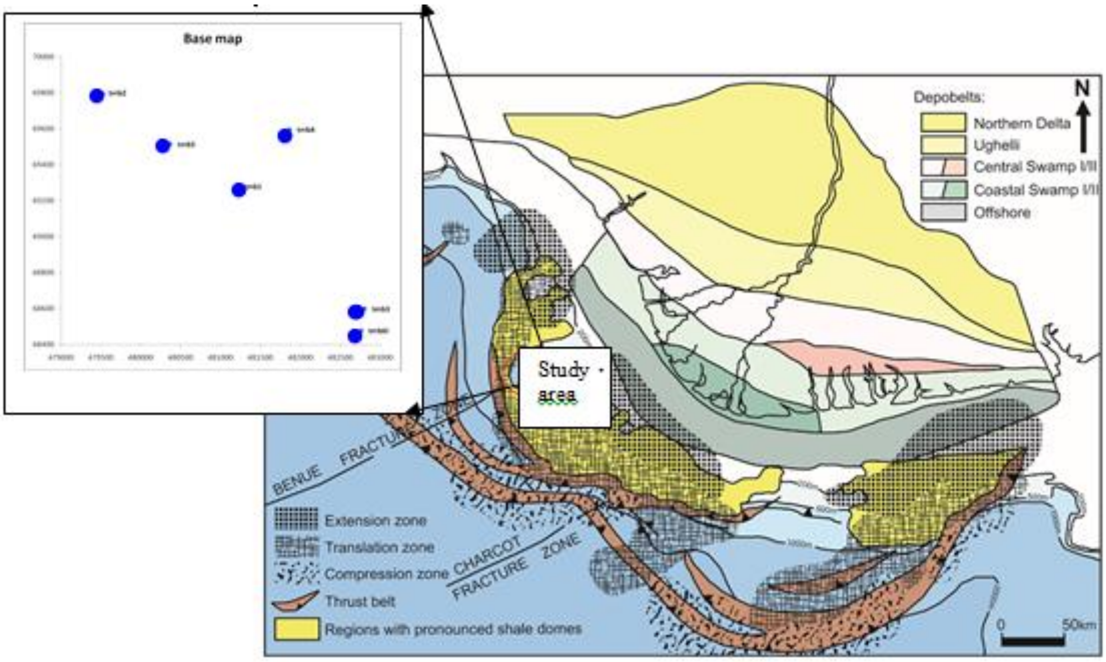
Hydrocarbon exploration becomes more complex and expensive. As most of the prospect zones are drilled especially onshore, hydrocarbon exploration and production require further innovation and creativity. This is because a substantial reserve can only be developed and produced once and mistakes can be tragic and wasteful. In mature oil provinces, where exploration and production strategies merge, a comprehensive understanding of petrophysical properties in reservoir systems can be critical to reservoir management practices (AAPG Bulletin, 2005). A well-understood reservoir will ultimately result in a well-managed field, therefore, effectively identifying the fluid present within the reservoir, predicting petrophysical parameters, accurately modeling and estimating the volume of reserves in the reservoir will help a successful exploitation of hydrocarbons.

3D geostatistical model approach is no doubt represents the reservoir as accurately as possible in calculating reserves, which is the uttermost successful system to recover the greatest amount of oil economically, according to several authors Lucia and Fogg (1990), Lake et al. (1991). However, the empirical formulae technique gives preliminary understanding and a constraint validation to the formal. it is a source of remedial support for developmental appraisal. This quantitative research work idėntifies and characterizės the different units in the arėa of study in addition to the hydrocarbon in place of the JAKS field by the synergetic approach of seismic interpretation and empirical formulae techniques from rock petrophysical properties evaluation of the well logs. This flexibility can be used to assess the result of the various three-dimensional geological model layout that contribute to streamlining a field development plan.

II. GEOLOGY OF THE AREA

The Niger Delta forms one of the world's major hydrocarbon basins and is located in the Gulf of Guinea on the west coast of Central Africa, southern Nigeria. It covers the area between 4-9ºE longitude and 4-9ºN latitude (Figure 1). It is formed by a common regression debris sequence that reaches a maximum thickness of about 12 km (Evamy et al., 1978).

The Niger Delta generally has three major lithological stratification units that lie below the Niger Delta. They are Bėnin, Agbada and Akatạ Formation. Each of these formations is deposited in the oceanic, transitional and continental environments, forming thick passive marginal wedges. The Akada Formation is from the Paleocene to the Pliocene, and is a basal layer composed mainly of marine shales, which is the main source rock of the basin. The Agbada Formation is composed of alternating sands and shale, and it's Eocene to Quaternary of age, and the Benin Formation is Oligocene to recent ages, mainly fine to coarse non-oceanic sand. Sandstone lenses (rings) are found near the top of the formation, particularly in contact with the overlying Agbada Formation. The Akata Formation is the main source rock for Hydrocarbons in the Niger Delta (Evamy et al., 1978). Its thickness is uncertain but can reach 7000 m in the central part of the delta (Reyment, 1965). The Agbada Formation which covers the Akata Formation (basal) is a parallel sequence represented by an alternation of sandstone and shale in various proportions (Doust and E. Omatsola, 1990). JAKS offshore field which covers approximately 720 km² is located within the western part of the Niger Delta offshore depobelt as shown in Figure 1. The fault model is NWSE and the traps involved in this area are mostly structural in nature.



Figurė 1: Seismic bạse map of thė study Area Niger delta basin with well locations

III. MATERIAL AND METHODOLOGY

A modern method of seismic interpretation technique, which is carried out on a work station is adopted for this research work. The research interpretation was done at a workstation using the Schlumberger Petrel Software workflow tool, version 2017, an efficient and easy-to-use Windows-based software for reservoir characterization and seismic model visualization. The work was done in two phases namely interpretation of seismic data and evaluation of petro physical data. These phases are put in synergy to evaluate the hydrocarbon reserves of the reservoir using the approach of empirical formulas. The interpretation of seismic data focuses on interpreting the structural model of the area from the available reflection seismic and correlated well log data, and reveals its effect on the interpretation of oil occurrences. The investigative method in a chronological fashion involves working with check data to correlate the section with well logs, interpreting faults and marker horizons at multiple depths to constrain the timing and progression of the fault in three dimensions.

The quality of the logs in the well was first checked to avoid any problems. All the datasets used in this research were imported into the Petrel software platform. Lithological assessment was performed on well logs to identify probable areas containing hydrocarbons, as well as types of lithology within the wells studied, analysis of gamma ray recordings, resistivity, density and porosity revealed marked reservoirs at various depths. A horizon is a plane which separates two different layers of rock but then, a horizon map, a surface linked with a reflection that

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possible be transported along a large area, hence creating a map based on the reflection event. These horizons should guide the interpolation occurring between well logs and seismic sections. The depth of these sand units is then converted to time using the control data (checkshot), where the nearest, brightest and most continuous reflection is mapped to the cross and lines, respectively. In this research, however, two seismic horizons were entered into the seismic data using the well-to-seismic link as shown in Figure 2. The horizons selected were along the troughs of the seismic data and after correlation, it was found that the horizons mark the top of the two reservoir sections (H1 and H 2) in the field, as shown in Figure 3. Sand intervals were assessed and individual reservoirs in these horizons were analyzed. The demarcation of the reservoir was performed by initially identifying the sand units of interest from the four wells in a well correlation panel that is (Top 1 & Base 1) and (Top 2 & Base 2), as shown in Figure 4

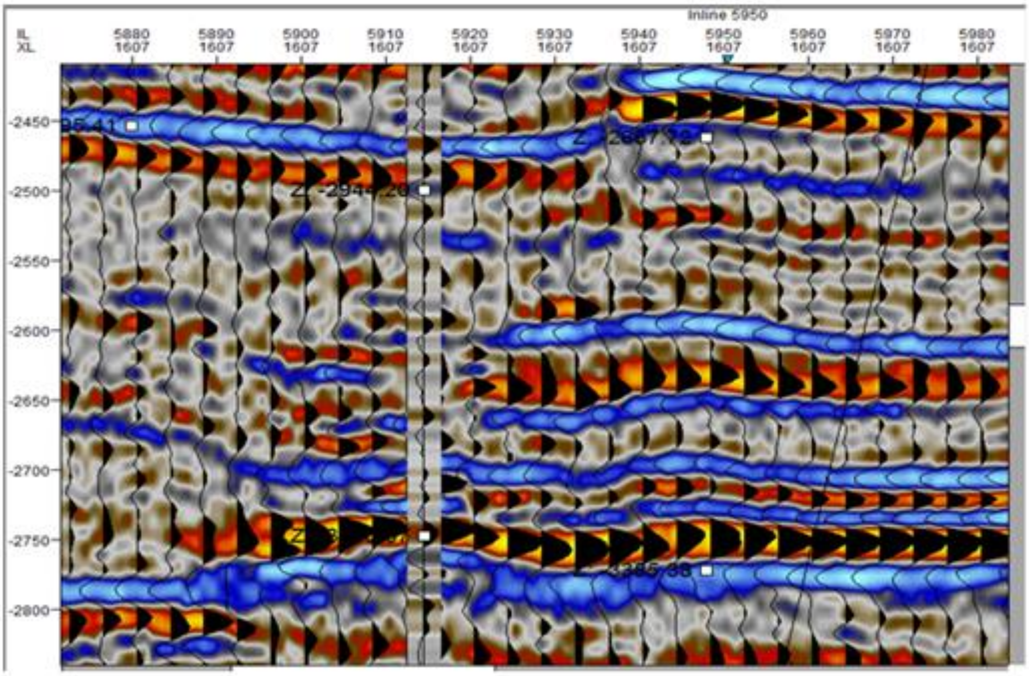

Fig 2: Cross line 1607 of the seismic section penetrated by JAKS-02 well revealing well to seismic tie.

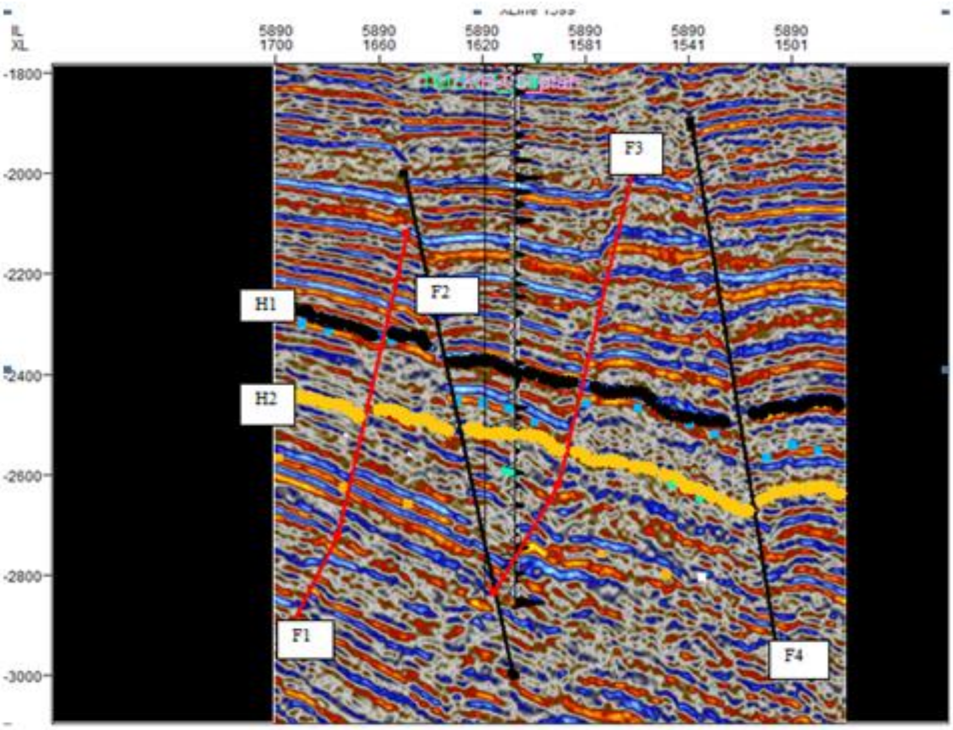

Fig 3: A section of Seismic of inline 5890 exhibiting the fault geometry and picked horizon (H1 and H2)

Petro physical data analysis requires application of simple empirical equations in calculating the rock parameters of a studied reservoir zones depicted from the well logs. The reservoir zones were picked out through the use of Gamma Ray, Resistivity also with combine logs of neutron and density signatures were then further evaluated quantitatively to establish the petrophysical properties of the reservoirs. The empirical formula approach to estimating the quantity of oil available requires the application of some simple formulas which describe the amount of interstitial space occupied with oil in the permeable zones and how same amount of oil converts from time to time in the reservoir when it gets at the surface. The following parameters generated from the research are shale volume, formation factor, irreducible water saturation, porosity, net to gross, water saturation, hydrocarbon saturation, gamma ray index, and hydrocarbon pore volume. This hydrocarbon volume can either be estimated straight from contour map (volume of hydrocarbon column), where the map column covered by hydrocarbon eventually been determined in parts, considering the contour gabs. The product of the various discrete zones and discrete contour will generate volumes of hydrocarbon in place while the total volume of petroleum resources in the field (OOIP) is the summation of all the discrete volumes generated. However, the empirical formulae approach was adopted for hydrocarbon in place estimation (OOIP), this is calculated directly by the use of the mean result for hydrocarbon saturation, net pay thicknesses and mean porosity. The subsequent empirical equation below are relevant in estimating the rock properties (petrophysical parameters).

Gamma Ray Index was determined using the gamma ray log as propounded by *Asquith and Gibson, 1982*,

Gamma Ray Index $(I_{Gr}) = (Gr_{log} - Gr_{min})/(Gr_{max} - Gr_{min})$ 1

where:
I_{GR} = Gamma ray index
Gr_{log} = Gamma ray log reading of the formation
Gr_{min} =Gamma ray minimum for porous and permeable medium
Gr_{max} =Gamma ray maximum for impermeable medium

shaliness was estimated using the I_{Gr} in the ideal equation as proposed by *Larionov, 1969*

Shaliness = $0.0830\{2.0^{(3.70 * I_{Gr})} - 1.00\}$
2
Where;
I_{Gr} = Gamma Ray Index.

Porosity was estimated by the application of Wyllie equation for bulk density estimation porosity is exbited below:

Porosity from density = $(\rho_{max} - \rho_b) \div (\rho_{max} - \rho_{fluid})$
3

where:
ρ_{max} = Rock matrix density
ρ_b = Log density
ρ_{fluid} = Fuid in void space density

Formation Factor determined by the use Humble equation,
Formation factor (F) = α/φ^{m}
4

where;
F=*formation factor*
α=*tortuosity factor (0.62)*
φ=*porosity*
m= *cementation factor (2.15)*

Determination of **water saturation** was actualized by using of Archie model, 1942.

$S_w^2 = (F * R_w)/R_T$
5

but; $F = R_o / R_w$
6

where ,
$S_w^2 = R_o / R_T$
7

but,

S_w=Saturated water of the Zone that is Uninvaded
R_o=Formation resistivity (100% Water Saturation)
R_T=Resistivity Formation true resistivty

The hydrocarbon saturation is calculated as shown below
$S_{hy} = 1 - S_w$
8

S_{hy} is the hydrocarbon saturation that could be written as percentage or fraction.

The resistivity index is determined as true resistivity to the resistivity at 100% saturation.

$I = R_t / R_o$ (where; I is the Resistivity Index.)
9

The (BVW), which is Bulk volume of water was calculated by multiplying porosity and saturated water of the uninvaded unit
hence,
Bulk volume water = $S_w * Ø$
10

where; Ø=Porosity.

The (HCPV), which is hydrocarbon pore volume was estimated by multiplying porosity and hydrocarbon saturation

Hydrocarbon Pore Volume = $Ø * (1- S_w)$
11

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Where, $(S_h) = (1- S_w)$

The irreducible water saturation was estimated as shown below;

Irreducible Water Saturation (S_{wirr}) $=(F/2000)^{0.5}$
12

Where: F is the Ḟormation factor.

ṕermeability is considered as the relationship between irreducible water saturation ánd porosity as proposed by Wyllie and Rose, (1950)

Where: permeability $(K)=[(250 * (Ø)^3) \div S_{wi}]^{2.0}$
13

Shaliness (V_{sh} Total, it is determine as indicated below;

Shaliness (V_{sh} Total**)=**Average V_{shale}* Gross thickness
14

The Net Thickness, it is determine as shown below;

Net Thickness =Gross Thickness –Total volume of shale

15

The Net to Gross Ratio is;
N/G = Net Ţhickness / Gross Ţhickness
16

The effective porosity is;

$ɵ_{effective}$ =(1–volume of shale) × ɵ
17

The Storage Volume is;
Storage Volume = ɵ × Net Pay Thickness
18

IV. RESULTS AND DISCUSSION

Seismic interpretation of JAKS field

Interpretations of the faults revealed two listric faults labeled F1 and F3 delineated on seismic data in figure 3, F1 and F3 are the main structural building faults, corresponding to growth faults in the region, while the F2 faults and F4 are antithetical faults. All the faults (F1, F2, F3 and F4) trend about NWSE, but F1 and F3 faults dip in the south the antithetic faults F2 and F4 dip counter-current in the northern direction. The depth and time structure maps mapped from the seismic section from the horizons as revealed in Fig 5, 6,7 &8 are structural maps of H1 and H2, these depth maps are extracted by the conversion of the time maps. As a result of the nearness of the horizons the structural style is similar, the entire structural trapping mechanism consist an anticline (structural highs) at the NW zone and ‘two ways’ roll-over structurally supported by (F2 & F3) faults. This happens to be the major structure accountable for the entrapment of hydrocarbon in the oil field and it trends NNE direction.

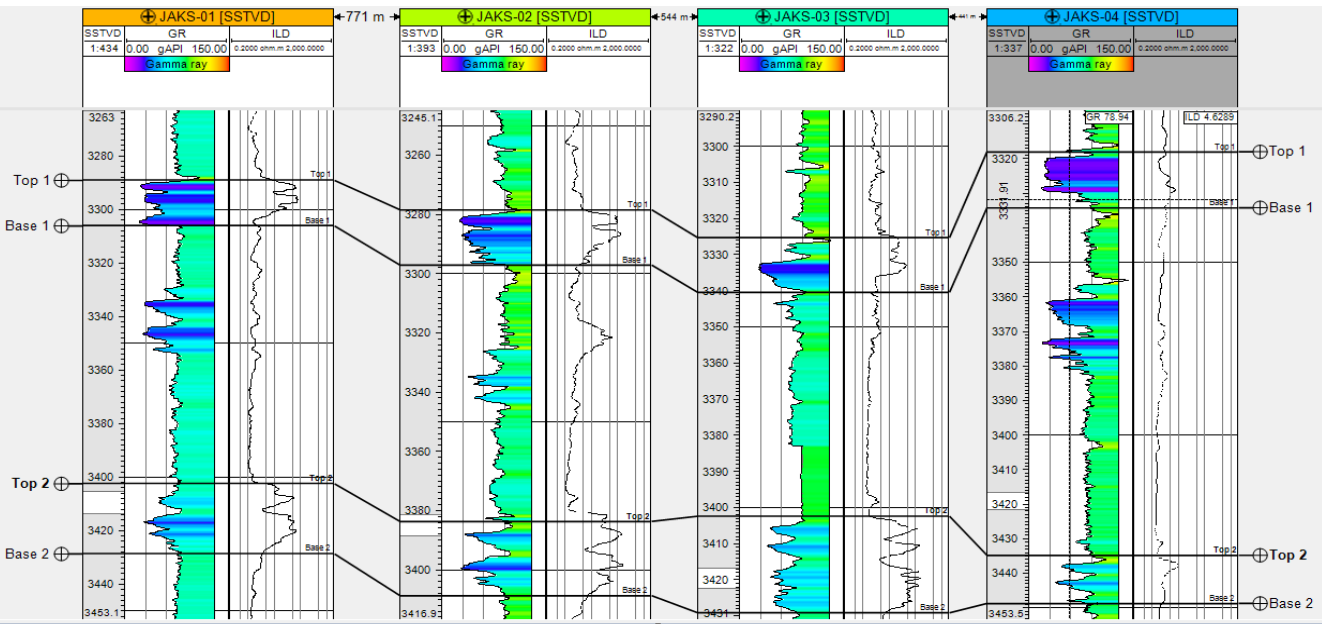

Fig 4: Correlation panel of well logs in JAKS field showing delineated reservoir sand units (Top1&Base 1) and (Top 2&Base 2).

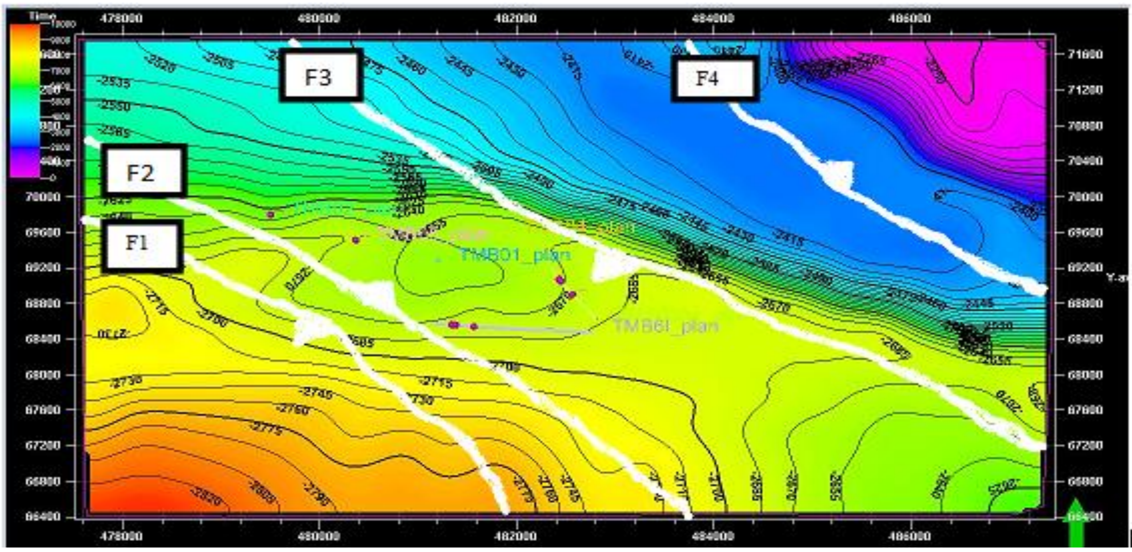

Fig. 5: Structure map in time of horizon (H1) revealing Fault patterns

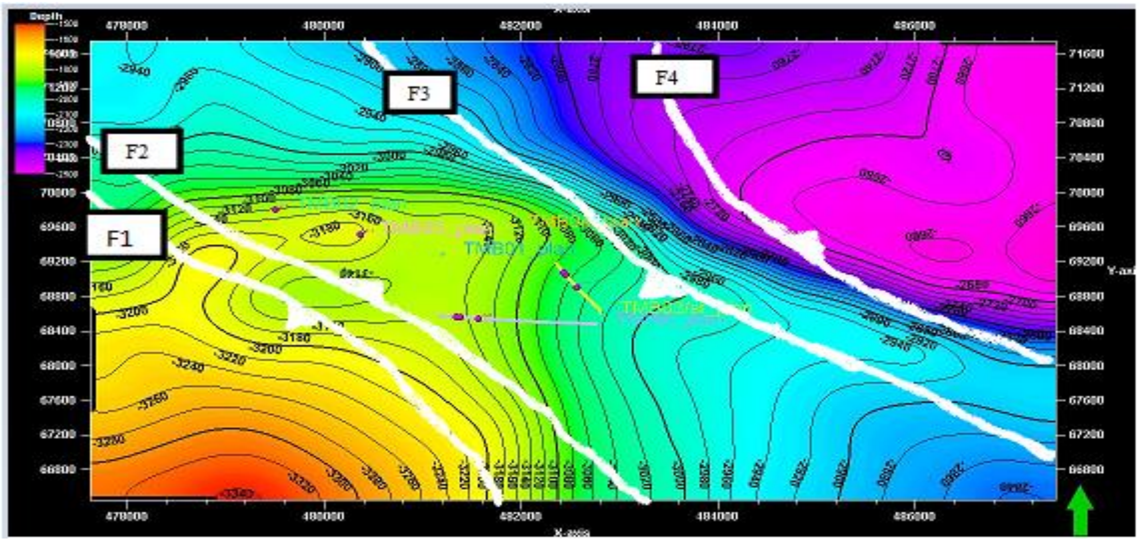

Fig. 6: Structure map in time of horizon (H2) exhibiting Fault patterns

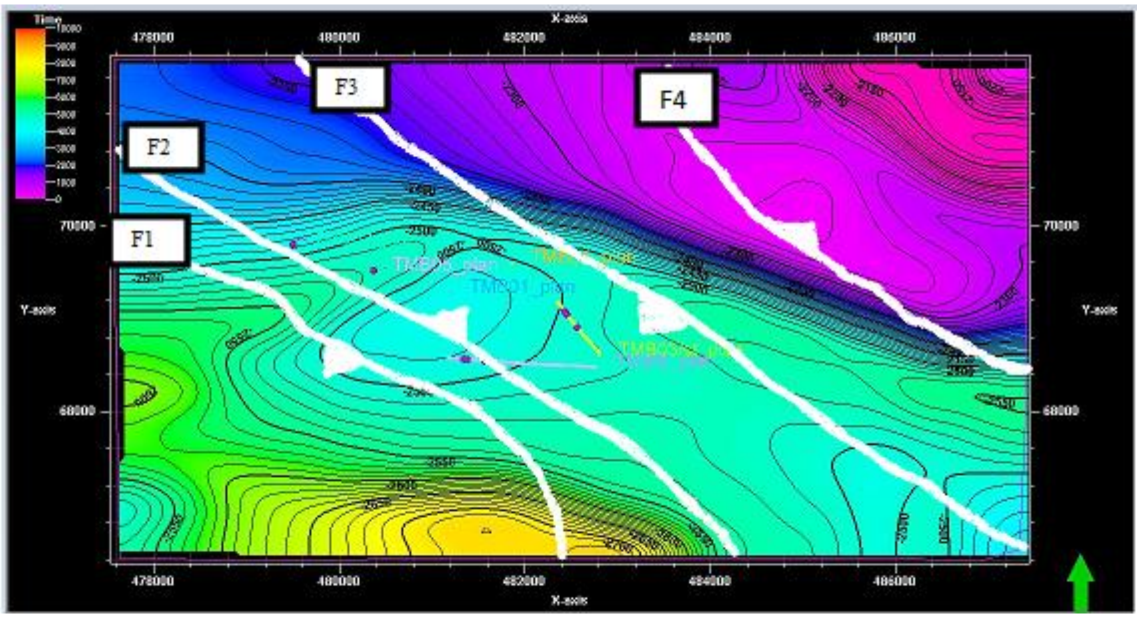

Fig 7:Structure map in depth of horizon (H1) showing major Faults and anticlinal structure of the JAKS field

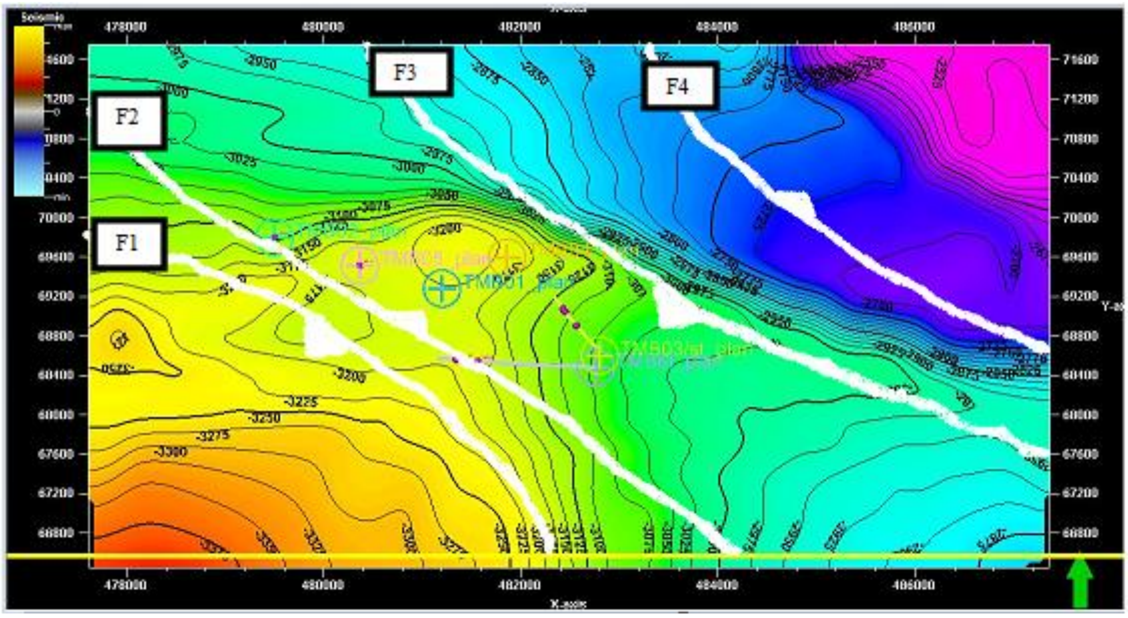

Fig 8:Structure map in depth of horizon (H2) showing major Faults and anticlinal structure of the JAKS field

Petro physical Evaluation of JAKS oilfield

Four composite well logs comprising sonic logs, resistivity, density, neutron and gamma ray were run in JAKS-01, JAKS-02, JAKS-03 and JAKS-04 wells. The logs acquired made it possible to assess the characteristics of the reservoir. Although resistivity logs have been used to detect the presence of hydrocarbons in reservoirs, the combined response (gas effect) of the log neutron density across the sand units (clastic reservoirs) indicates that the hydrocarbon will be predominantly of petroleum inferred by La Vigne et al. (1994) and Doust (1989). The petrophysical evaluation results as represented in Tables 1 and 2, show that the porosity values for the Sand-A reservoir ranges from 29.3 to 31% and for the Sand-B reservoir ranged from 25 to 29%. The permeability values of the Sand-A reservoir range from 61 to1079md and the Sand-B reservoir range from 83 to 1452md.The volume of shale ranges from 20.5 -28.7% across the Sand A and 28.3-38.6% in Sand B reservoir. The net pay permeability and mean porosity of the reservoir are favourable to hydrocarbon production. The tables show porosity decreases with increase in volume of shale (V_{sh}) while increase porosity is a function of increase in permeability. Porosity is also found to change with depth in the two-study reservoir. This shows that as the depth of the reservoir increases, the volume of the pore opening in the reservoir decreases significantly due to the compression and pressure that results from over burden pressure of the overlying strata (Nelson, 1994; Ehrenberg et al., 2006). The water saturation results of the sand-A reservoir ranged from 18 to 41%, sand-B reservoir ranged from 15 to 23% while irreducible water saturation results of the sand-A reservoir ranged from 12 – 32.7%, sand-B reservoir ranged from 10.5 – 34.5%. The reservoir zones have bulk volume water that are not constant in all wells, this depicts variance in irreducible water and water saturation ($s_w>s_{wir}$), it also suggests heterogeneity in the reservoirs. The high variance of the results of the irreducible water saturation and water saturation depicts that reservoir will certainly not generate water-free hydrocarbon. Also, from the gamma ray logs of the wells, the reservoirs show roughly funnel log motif suggesting coarsening upward sequences which is a reflection of high energy environments during sedimentation (Weber and Daukoru,1975). The hydrocarbon saturation values for the sand A reservoir ranges from 59 - 82%, in sand B reservoir it ranges from 77 – 85%. Reservoir sands have very good hydrocarbon saturation which are favourable indicators for commercial hydrocarbon accumulation.

Table 1: Summarized petrophysical data for reservoir sand unit A

WELLS	Gross thickness (m)	Vsh (%)	Porosity (%)	Eff Porosity (%)	Swr (%)	Permeability (mD)	Net/Gross (%)	Oil Water Contact (m)	Water Saturation (%)	Hydrocarbon Saturation (%)
JAK-01	18	20.5	31	25	32.7	99.0	76	3300	25	75
JAK-02	20	22	30	23	13.0	1079.0	79	3290	18	82
JAK-03	12	22.1	30.7	24	20.0	61.0	81	3350	33	67
JAK-04	11	28.7	29.3	21	12.0	106.0	72	3331	41	59

Table 2: Summarized petrophysical data for reservoir sand unit B

WELLS	Gross thickness (m)	Vsh (%)	Porosity (%)	EffectivePorosity (%)	Swr (%)	K (mD)	Net/Gross (%)	Oil /Water Contact (m)	Water Saturation (%)	Hydrocarbon Saturation (%)
JAK-01	24	28.3	29	29	34.5	83.0	84	3420	20	80
JAK-02	26	35.1	27.8	27.8	10.5	1452.0	75	3400	15	85
JAK-03	24	38.6	26.9	26.9	14.0	93.0	77	3430	23	77
JAK-04	8	38.0	25	25	10.7	122.0	61	3450	18	82

Estimation of Hydrocarbon in Place

To estimate hydrocarbon in place from well logs, empirical formulars or equation are used to calculate the petrophysical parameters or properties of the prospect reservoir. Also Gross Rock Volume of the area of interest are calculated by estimating the reserve with the aid of empirical formulae method and the integration of the depth structure maps of the JAKS field from seismic interpretation. The determination of OOIP; oil volume in place includes the use of some formulars which explains the volume of hydrocarbon filled pore space in the permeable zone of the reservoir and how change occurs in the amount of hydrocarbon at the surface from the reservoir. The properties calculated from the analysis which include Irreducible Water Saturation, Hydrocarbon Saturation, Porosity, Water Saturation, Net to Gross, Shaliness, Formation Factor (F), Gamma Ray Index and Oil Pore Volume also, fluid contact was estimated by use the density, resistive log and neutron log for hydrocarbon and water contact. The properties are integral in interpretation processes in most phases of the reservoirs as regard hydrocarbon pore volume and total ámount of hydrocarbon in place. The Hydrocarbon in place is then determine by direct computation using the mean results of the average hydrocarbon, saturations net pay thicknesses and mean porosity values and this is inputted in the formular as shown below:

$$\text{Hydrocarbon volume (OOIP)} = (7758.0\times A_{oil}\times h_{oil}\times s_{h(oil)}\times \phi)/b_o \qquad 22$$

Where, A_{oil}=Area occupied by oil ; h_{oil}= Mean height of oil column; $s_{h(oil)}$ =Hydrocárbon saturation (oil zone), B_o is the Formation oil volume factor=1.20 bbls/STB,OOIP unit=stock tank barrels (STB)

The reservoir volumetrics is depicted by volumetric values of 2 reservoir sand-A and B units. The Original Oil in Place (OOIP) is 29,163,451.6 STB while the Stock Tank Oil in Place (STOIP) which is the volume of oil after production is 22,433,424.31 STB. The Primary Recovery Reserve is 20,381,028.23 barrels producible with a Primary Recovery Factor of 10% as summarized in table 4

TABLE 4: Showing volumetric data of reservoir sand unit A and B

RESERVOIRS	Values for Sand unit A	Values for Sand unit B
Area	237.22 Acres	830.30 Acres
Hydrocarbon Pay Volume (HCPV)	15.84 hydrocarbon feet.	36.605 Hydrocarbon feet.
Oil Formation Volume Factor (BO)	1.3	1.3
Hydrocarbon Volume (H)	66ft	172.26 ft
Ordinary Oil in Place (OOIP)	29,163,451.6 STB	235,789,914.177 STB
Stock Tank Oil in Place (STOIP)	22,433,424.31 STB	181,376,857.96 STB
Total STOIP for Sands A & B	203, 810,282.27 STB	
Primary Recovery Factor	10%	
Primary Recovery Reserve	20,381,028.23 barrels	USD 1,019,051,411.35 (@USD50.00/BB)

V. CONCLUSIONS

Reservoir evaluation and reserve estimation of the JAKS oilfield offshōre Nıger Delta was successful analyze using 3-D seismic, empirical formulas composite and well logs. The work was done in two phases; petro physical data analysis and seismic datá interpretation. These phases are synergized to estimate the oil reserves in the JAKS reservoir by using the empirical formulae approach. The fault interpretations from the seismic data revealed two listric faults labeled F1and F3, which are crucial structure building faults corresponding with the grōwth faults of the study area. They appear to be the principal structure accountable for oil entrapment in the oilfield. The faults (F1, F2, F3 ánd

F4) trend about NW-SĒ but then, F1 and F3 faults dip in the south the antithetic faults F2 and F4 dip in the northern direction. It discloses that the zone is extremely faulted, which is a classic model of the tėctonic setting of the Niger Delta (Olowokere and Abe, 2013). Four composite suitės of logs comprising sonic, neutron, resistivity, density and gamma ray logs are used to evaluate the reservoir characteristics of JAKS-01, JAKS-02, JAKS-03 and JAKS-04 wells. The petrophysical evaluation have mean porosity value of the reservoir sand units ranged from 25-31%, the mean permeability values of reservoir sand units range from 61-1452m, the mean volume of shale ranges from 20.5 - 38.6%. The net pay permeability and mean porosity of the reservoir are favourable to hydrocarbon production. Porosity is also found to change with depth in the two-study reservoir. This shows that as the depth of the reservoir increases, the volume of the pore opening in the reservoir decreases significantly due to the compression and pressure that results from over burden pressure of the overlying strata (Nelson, 1994; Ehrenberg et al., 2006). The average water saturation values for the reservoirs ranges from 15 - 41%, while for irreducible water saturation values ranges from 10.5 – 34.5%. The reservoir zones have bulk volume water that are not constant in all wells, this depicts variance in irreducible water and water saturation ($s_w>s_{wir}$), it also suggests heterogeneity in the reservoirs. The high variance in the results of the irreducible water saturation and water saturation also depicts that the reservoir will certainly not generate water-free hydrocarbon, from the gamma ray logs of the wells, the reservoirs show roughly funnel log motif suggesting coarsening upward sequences which is a reflection of high energy environments during sedimentation (Weber and Daukoru,1975). The mean hydrocarbon saturation value for reservoirs ranges from 59 - 85%. The outcome of this research reveals that the study area has satisfactory petrophysical and structural properties a reservoir and to will permit hydrocarbon production. The average Original Oil in Place (OOIP) calculated using the empirical formula method with the petro physical parameter is 29 bbls/STB while the Stock Tank Oil in Place (STOIP) which is the volume of oil after production is 22 bbls/STB. The Primary Recovery Reserve is 20,381,028.23 barrels producible with a Primary Recovery Factor of 10%. Empirical forecast approach for hydrocarbon in place is a substitute and reliable remedial method pending a qualitative 3D geostatic model technique.

RECOMMENDATION ON JAKS RESERVOIRS DRIVE MECHANISM APPROACH

Reservoir type will materially influence the production rate, hence the type of artificial lift installation. It is also obvious that recovėry factor is based on the drive mechanism. The appreciable low gas and water drives in the JAKS reservoirs will contribute to low primary recovery factor. However, recovery production rate can be improved by engineering techniques such as water flooding.

The external enėrgy in the form of fluids should be injected to incrėase reservoir prėssure, to replace or increase the diminished natural resėrvoir drivė with an artificial drivė; 35-45% recovery can be achieved. For enhancėd or tertiary oil rėcovery mėthods, thermal enhanced oil recovery methods (TEOR) may be increasing the mobility of the oil by heating the oil to reduce its viscosity making it easiėr to extract, i.e., steam injėction, fire flooding or microbial treatments can be induced hence, another 5% to 15% could be recovered.

Although recovery methods are dependent on the cost of the extraction mėthod and the currėnt price of crude oil economic feasibility can be factual with an average oil price of about USD50.00 per barrel which will generate about USD1.02billion from a primary productiōn of 20.38million barrels in the JAKS oilfield.

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