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Evaluation of Reservoir Sands of D-Field Onshore Niger Delta using Well Logs and Seismic Data

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ABSTRACT

This paper is aimed at evaluating the prospecting potential of the reservoir sands of D-field onshore Niger Delta located around 23km west of Uyo, Nigeria. The field covers an area of approximately 6.9km^2, located around latitudes 6^o 13'N and 6^o 14'N and longitudes 7^{o}18'E and 7^{o}20'E. Well logs from eight wells were used – together with the seismic section, to evaluate these potentials from two reservoirs (D-A and D-B) in the field. D-A revealed average porosity and permeability of 0.22 and 7,390md respectively while D-B revealed average porosity and permeability of 0.21 and 3,714md respectively. D-A has 23MBO of oil while D-B has 80MBO. Both reservoirs will yield their oil at irreducible water saturation condition.

Introduction

Information gathered from cores, seismic, well logs and biostratigraphic data help to resolve underlying geology and thus aid in the evaluation of hydrocarbon reservoirs. Reservoirs in the Niger Delta exhibit a wide range of complexities in their sedimentological and petrophysical characteristics due to differences in hydrodynamic conditions prevalent in their depositional settings. Petrophysics therefore plays a fundamental role in the description, characterization and evaluation of reservoirs. Due to the intense petroleum exploration and exploitation activities in the Niger Delta region during the last three decades, a vast amount of data have been accumulated from which it had been possible to establish the historical reconstruction and evolution of the Niger Delta basin (Allen, 1965; Short and Stauble, 1967; Weber, 1971; Avbovbo, 1978). Petroleum in the Niger Delta is produced from sandstones and unconsolidated sands predominantly in the Agbada Formation.

Eleven wells were drilled in the D- field to produce the D-A and D-B reservoir sands; D1, D2, D4, D10 and D11 are oil producers though some produced from either D-A or D-B alone. D3 and D9 are appraisal wells while D6, D7 and D8 are water injection wells.

Well logs (Resistivitry, Density, Neutron and Gamma) were obtained and used to ascertain the petrophysical characteristics of the D-A and D-B reservoir sands from which estimates of the recoverable reserve in place were made for each of the sands. The irreducible water saturation of the reservoirs which verifies whether they can release hydrocarbon water-free were also evaluated.

Geology of Study Area

D-field is a fictitious field name given to a 6.9 km^2 area between latitudes 6^o 13'N and 6^o 14'N and longitudes 7^o 18'E and 7^o 20'E onshore Niger Delta approximately 23km west of Uyo, Nigeria. Figure 1 is the map of Niger Delta showing the position of D- field.

Short and Stauble (1967) outlined the general geology of the Niger Delta. They attempted to explain the origin of the Niger Delta and established that the Tertiary deltaic fill of the Niger Delta is represented by a strongly diachronous (Eocene - Recent) sequence which is divided into three Lithofacies units namely: Akata Formation, Agbada Formation and Benin Formation respectively.

Short and Stauble (1967); Merki (1970); Weber and Daukoru (1975) described how differential loading of under compacted shale at the base of the Tertiary delta by the relatively heavy sandy deposits initiated the formation of growth fault in the basin and if sufficient movement takes place along the growth fault plane, a rollover anticline is formed. Ekweozor and Daukoro (1984) carried out petroleum source bed evaluation of Tertiary Niger Delta. They stablished that the dominant sedimentary kerogen in the Niger Delta were the humic and mixed types. They also stated that habitats of the hydrocarbons are mainly the sandstone reservoirs in the paralic sequence of the Agbada Formation, where the hydrocarbons are characteristically trapped by growth faults at the crest of rollover anticlines. Stacher (1995) showed that the Niger delta basin consist of a series of depocenters while Evamy *et al.* (1978) showed that sedimentation in the depocenter is a function of the rate of subsidence with syndepositional growth fault upsetting the delicate balance. Evamy *et al* (1978) identified two possible migration pathways in the Niger Delta. Migration along the structure building faults which terminate in the Akata Formation and migration from the seaward facies up-dip into the rollover structures. Weber and Daukoru (1975) proposed that the faults serve as pathway for hydrocarbon migration from source rock while Selley (1997) and Etu-Efeotor (1997) showed that the gross reservoir properties in the oil bearing reservoir of the Niger delta is a function of the sand / shale ratio and sealing potential of the faults.

Corredor *et al* (2005) studied the structural style in the deep water fold and thrust belts of the Niger Delta.

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Figure 1. Location of D-field on Niger Delta map.

They defined two main types of imbricate thrust systems in the Niger Delta: "a single basal detachment level" that is typically near the top of the Akata Formation and "an imbricate system with multiple basal detachment levels" which causes massive structural thickening of the Akata Formation and refolding of shallow thrust sheets.

Theory and Methods

The data used for this research include four wireline logs (gamma ray, resistivity, neutron and density) cutting across the same reservoir for eight wells in the field. The data set were obtained in ASCII format in softcopy. It was then uploaded in Schlumberger PETREL 2013 to generate continuous logs for the different wells. The reservoir properties were plotted with the use of Golden software SURFER 12 which gave contours by krigging techniques and also generated 3-D surfaces for the reservoir top. It is thus possible to estimate the reserves either by automation using the PETREL software or by the old-conventional technique that involves the planimeter and the isopach contours generated. The petrophysical analysis involves the use of empirical formulae to estimate the petrophysical properties of the D-A and D-B reservoir sands. These reservoir sands which were identified through the use of the electrofacie signatures were further characterized quantitatively to arrive at these petrophysical parameters, which include: volume of shale, formation factor, porosity, water saturation, permeability. etc. Some of these parameters are discussed below:

The volume of shale was calculated by applying the gamma ray index in the appropriate volume of shale equation according to Crain (2005) for tertiary rocks:

$$V_{sh}= 0.083[2^{(3.7 \text{ x } IGR)} – 1.0] \quad (1)$$

Where, Vsh=volume of shale and IG=gamma ray index. The Neutron–Density porosity could be calculated according to Schlumberger (1999) as:

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

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

The determination of the water saturation for the uninvaded zone was achieved using the Archie (1942) equation given as equation (3);

$$S_w^2=R_o/ R_T \quad (3)$$

S_w=water saturation of the uninvaded zone, R_o=resistivity of formation at 100% water saturation, R_T=true formation resistivity. Hydrocarborn saturation (S_{hy}) is obtained directly by subtracting the percentage water saturation from 100 thus;

$$S_{hy}= 1–S_w \quad (4)$$

The Bulk volume of water (BVW) was estimated as the product of water saturation (S_w) and porosity (ϕ_{N-D}) as indicated in equation (5), (Asquith and Krygowski, 2004).

$$BVW=S_w x\ \phi_{N\text{-}D} \quad (5)$$

The hydrocarbon pore volume (HCPV) is the fraction of the reservoir volume occupied by hydrocarbon. This is calculated as the product of neutron-density porosity and hydrocarbon saturation as shown in equation (6) while 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 equation (7) or (8) for oil or gas respectively.

$$HCPV=\phi_{N\text{-}D}\ x(S_{hy}) \quad (6)$$

$$OOIP=(7758*A_{oil}*h_{oil}*s_h(oil)*\ \phi_{N\text{-}D})/b_o \quad (7)$$

$$OGIP=(43560*A_{gas}*h_{gas}*s_h(gas)*\ \phi_{N\text{-}D})/b_g \quad (8)$$

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) b_o and b_g are the formation volume factors for oil and gas respectively. The irreducible water saturation is calculated using the relationship shown in equation (9);

$$S_{wi}=(F/2000)^{1/2} \quad (9)$$

Where S_{wi} = irreducible water saturation, F = formation factor. However, this theoretical estimate of irreducible water is majorly useful in the estimation of relative permeability (k) which is made based on the relationship between permeability, porosity, and irreducible water saturation according to Wyllie and Rose, (1950). The relationship is expressed in equation (10);

$K=[(250x(\phi_{N-D})^3)/S_{wi}]^2$ (10)

The Effective Porosity is the porosity of the interconnected pore spaces. It assumes the absence of shale from the reservoir. It is calculated using the following relationship in equation (11);

$\Phi_{effective}=(1-V_{SHALE})*\phi_{N-D}$ (11)

In this work, I used b_o value of 1.4 bbls/STB in equation (7) in converting OOIP to stuck tank volume; this stuck tank volume is finally converted to recoverable volume by multiplying with a recovery factor (which considers all obstacles the fluid will encounter during extraction) of 0.35 that is based on literature for this locality.

Results and Interpretation

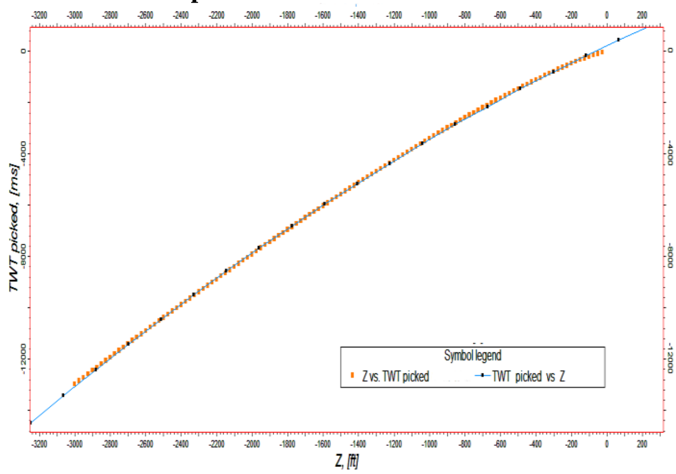

Figure 2. Time to Depth conversion.

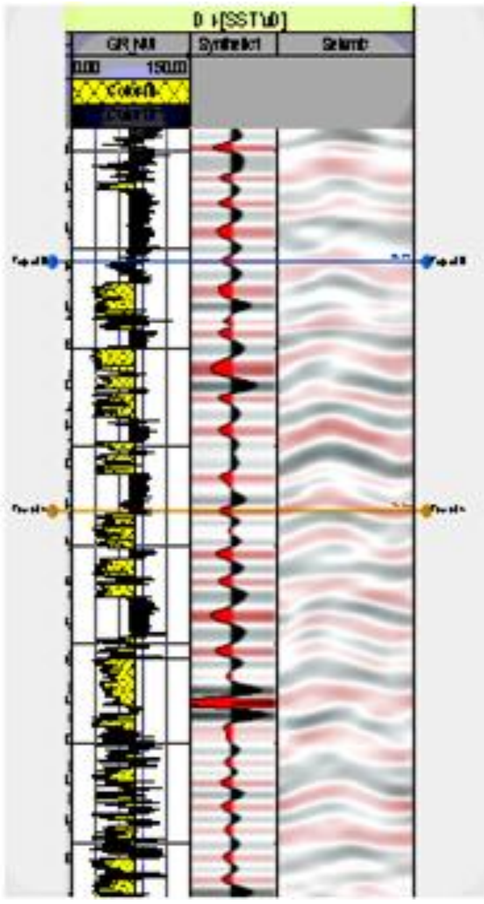

Figure 3. Seismic–to–Well tieing.

The time–to–depth conversion response (used to translate the seismic signals to depth) is displayed in fig.2 while the seismic–to–well tieing process is as displayed in fig.3. The base map of the D-field is as shown in fig.4.

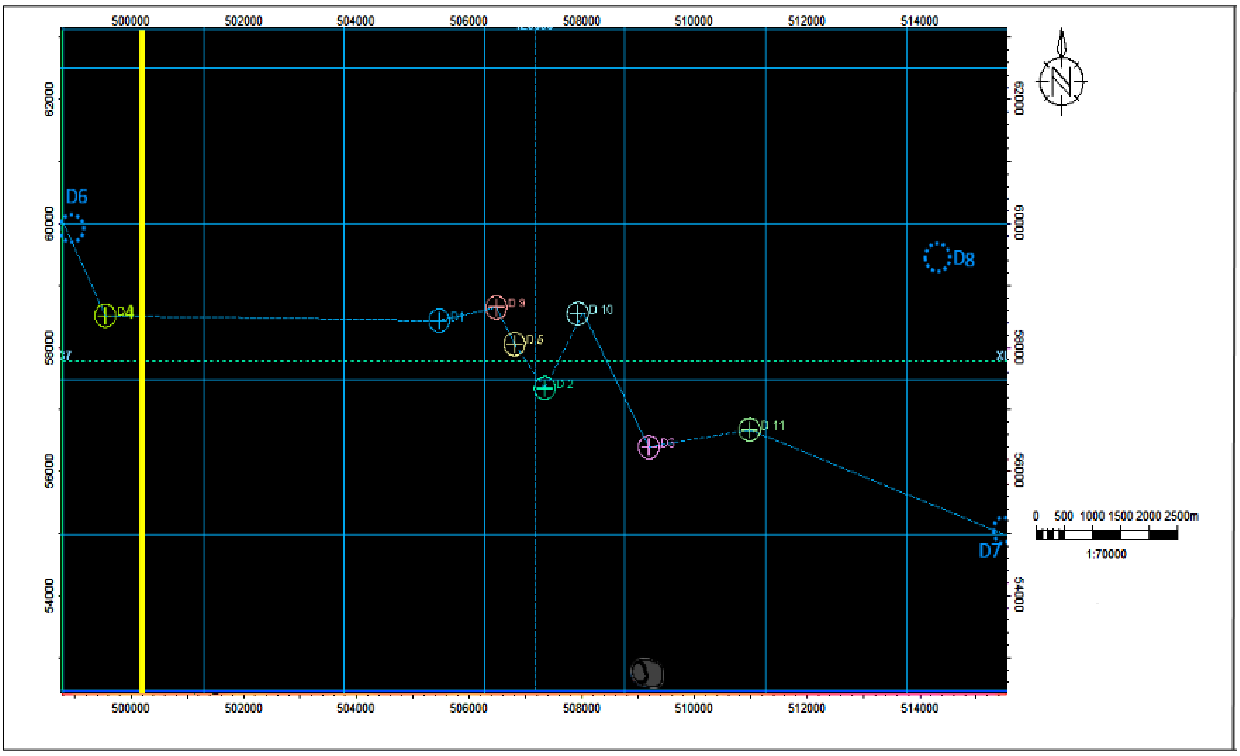

Figure 4. Base map of D-field.

The different petrophysical parameters computed for the D-A reservoir are tabulated in table 1 from which estimate of recoverable reserve was made (using table 2 as summary), k is in md.

Table 1. Petrophysical parameters of D-A reservoir.

WELLS	Top of sand (ft.)	Base of sand (ft.)	GOC (ft.)	OWC (ft.)	Gross reservoir sand (ft.)	Net reservoir sand (ft.)	GR.I	Volume of shale	Total porosity (ϕ)	Effective porosity (ϕ)	S_W	N.T.G	BVW	F	$S_{W(irr)}$	k	Remarks
D 4	9560	9906	8467	8566	346	298	0.34	0.14	0.30	0.24	0.30	0.86	0.0900	8.252	0.0642	11,054	OIL
D 1	8220	8786	8336	8380	566	447	0.40	0.21	0.28	0.15	0.33	0.79	0.0924	9.572	0.0692	6,289	OIL
D 9	8215	8605	WET	WET	390	308	0.48	0.21	0.29	0.23	0.76	0.79	0.0754	8.876	0.0666	8,381	Water
D 5	8270	8608	8346	8363	338	287	0.40	0.15	0.29	0.25	0.28	0.85	0.1102	8.876	0.0666	8,381	OIL
D 2	10592	11332	10836	10914	740	555	0.36	0.25	0.26	0.23	0.32	0.75	0.0832	11.225	0.0749	3,441	OIL
D 10	9280	9970	9365	9686	690	531	0.40	0.23	0.64	0.22	0.30	0.77	0.1920	1.619	0.0285	5,291	OIL
D 3	9608	10350	WET	WET	742	594	0.44	0.20	0.38	0.26	0.79	0.8	0.1102	4.964	0.0498	7,587	Water
D 11	9840	10200	10132	10218	360	296	0.39	0.18	0.32	0.15	0.25	0.82	0.080	7.183	0.0599	8,703	OIL

Table 2. Reserve estimation summary for D-A.

AREA (Acres)	433.40
Sw	0.30
Porosity	0.22
Thickness (ft)	521.5
NTG	0.80
OOIP (barrels/acre feet.)	92,582,076.57
FVF (rb/stb)	1.4
STOIP (barrels/acre feet)	66,130,054.69
Recovery factor	0.35
RESERVE (Barrel of Oil)	23,145,519.14
RESERVE (MBO)	23

It is deducible from table 2 that a recoverable 23MBO of crude oil is possible from this reservoir. The structural depth map is revealed in fig. 5 which also shows the numerous faults that aided in the entrapment of hydrocarbons in the horizons displayed.

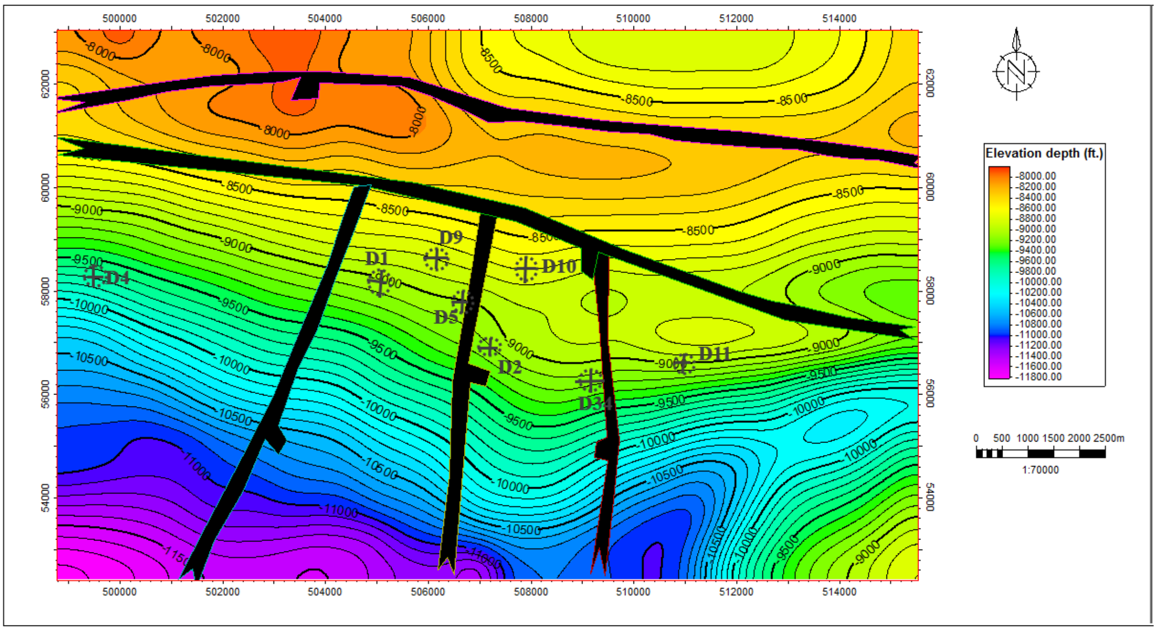

Figure 5. Structural depth map of D-A.

The 2D and 3D contour maps of the oil bearing contacts of D-A sands are shown in figures 6 and 7 respectively; from where we could affirm that wells D1, D2, D4, and D11 are likely major producers for the D-A reservoir.

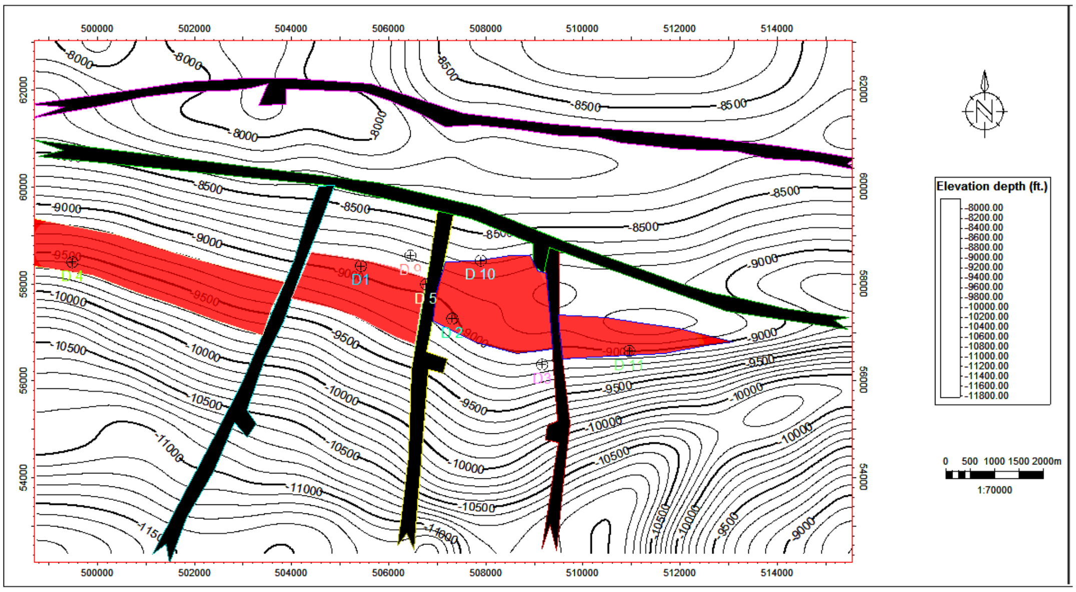

Figure 6. Oil - bearing 2D contour map of D-A.

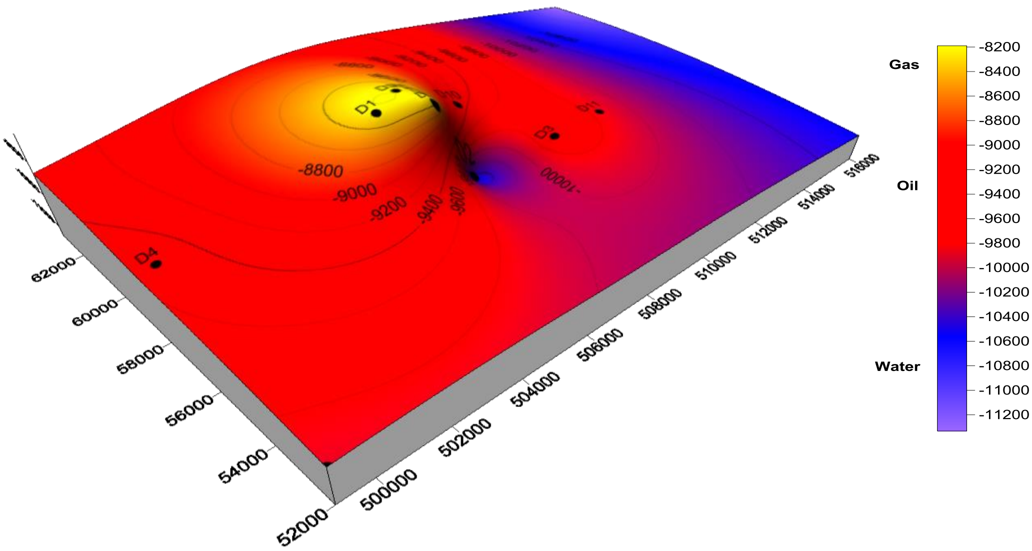

Figure 7. Oil - bearing 3D contour map of D-A.

A look at the porosity contour map for this D-A reservoir (fig. 8) identifies the D4 well as the best producer in terms of fluid flow since it bears the best porosity and permeability values (no wonder it hasn't a neighbouring well nearby). The reservoir will produce at irreducible water condition as affirmed by fig. 9.

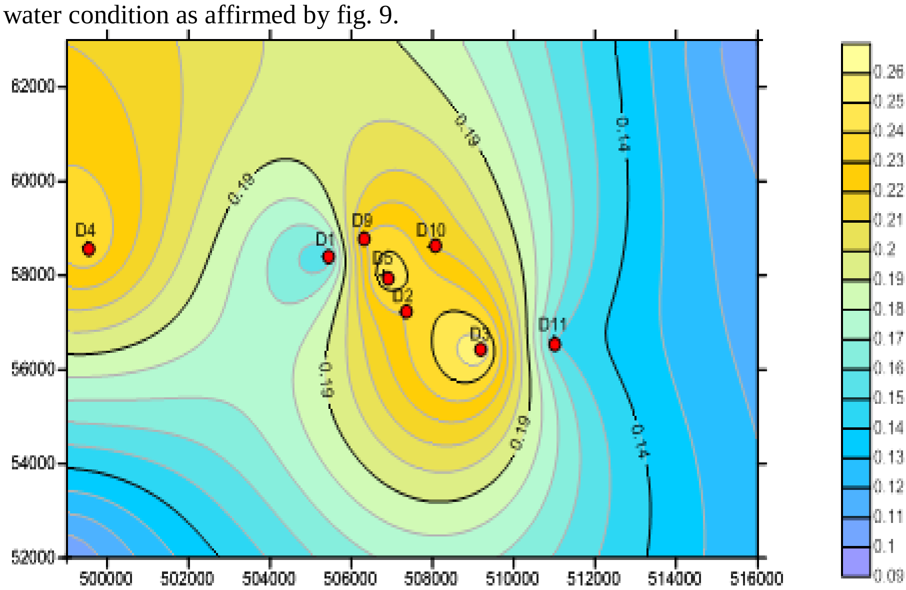

Figure 8. Porosity contour map of D-A.

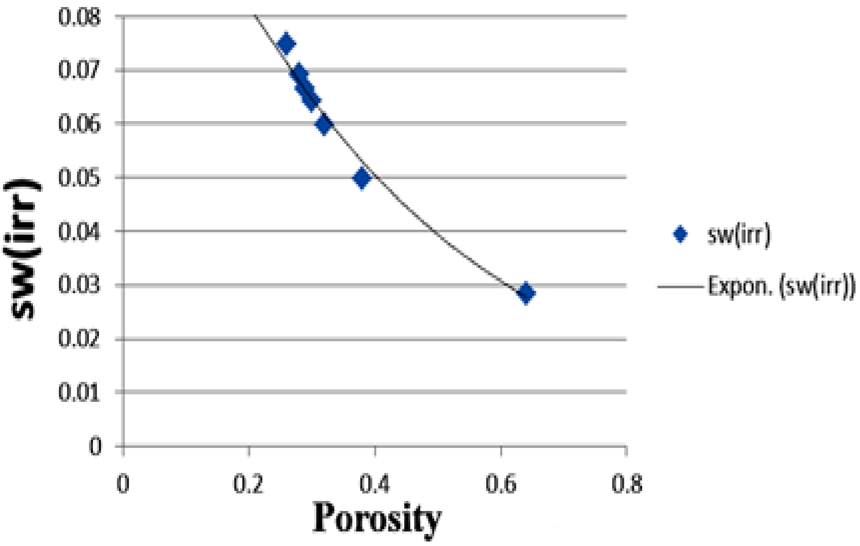

Figure 9. Sw(irr) vs Porosity plot for D-A reservoir.

The different Petrophysical parameters computed for the D-B reservoir are tabulated in table 3 from which estimate of recoverable reserve was made (using table 4 as summary), k is in md.

Table 3. Petrophysical parameters of D-B.

WELLS	Top of sand (ft.)	Base of sand (ft.)	GOC (ft.)	OWC (ft.)	Gross reservoir sand (ft.)	Net reservoir sand (ft.)	GR.I	Volume of shale	Total porosity (ϕ)	Effective porosity (ϕ)	S_W	N.T.G	BVW	F	$S_{W(irr)}$	k	Remarks
D 4	10839	11285	NIL	10775	446	392	0.32	0.13	0.26	0.23	0.70	0.88	0.182	11.225	0.0749	3,442	NIL
D 1	9705	10300	NIL	9775	595	506	0.38	0.15	0.25	0.19	0.29	0.85	0.1975	12.213	0.0782	2,495	OIL:
D 9	9470	9890	NIL	9760	420	357	0.38	0.15	0.27	0.23	0.25	0.85	0.2187	10.351	0.0720	4,671	OIL
D 5	9621	9850	9675	9756	229	201	0.38	0.12	0.25	0.22	0.19	0.88	0.165	12.213	0.0782	2,495	OIL
D 2	12065	13550	NIL	12308	1485	1218	0.25	0.18	0.20	0.18	0.18	0.82	0.144	19.732	0.0993	4.006	OIL
D 10	10604	11875	NIL	11432	1271	1093	0.27	0.14	0.27	0.22	0.20	0.86	0.6177	0.836	0.0205	4,489	OIL
D 3	10836	12000	WET	WET	1164	978	0.46	0.16	0.26	0.23	0.68	0.84	0.1768	11.225	0.0749	3,442	WATER
D 11	10692	12056	WET	WET	1364	1173	0.37	0.14	0.27	0.18	0.69	0.86	0.1863	10.351	0.0720	4,671	WATER

Table 4. Reserve estimation summary for D-B.

AREA (Acres)	364.22
S_h	0.72
Porosity	0.21
Gross Thickness (ft)	871.75
NTG	0.86
OOIP (barrels/acre feet.)	320,299,1336
FVF (rb/stb)	1.40
STOIP (barrels/acre feet)	228,785,095
Recovery Factor	0.35
RESERVE (Barrel of Oil)	80,074,783
RESERVE IN MBO	80

It can be deduced from table 4 that a recoverable 80MBO of crude oil is possible from this reservoir. The structural depth map is revealed in fig. 10 which also shows the numerous faults that aided in the entrapment of hydrocarbons in the horizons displayed.

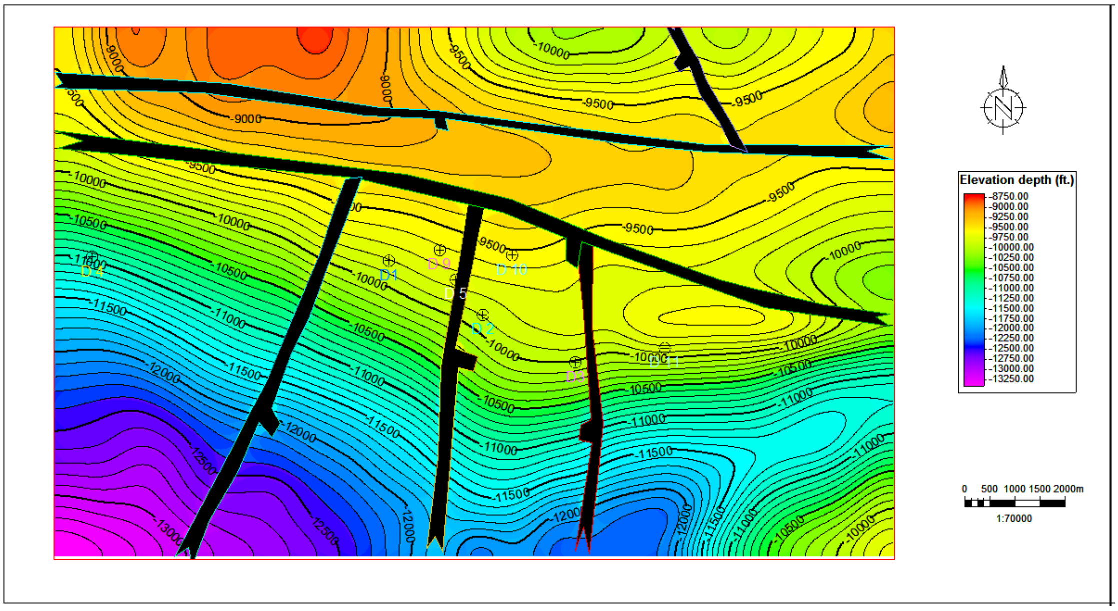

Figure 10. Structural depth map of D-B.

The 2D and 3D contour maps of the oil bearing contacts of D-B sands are shown in figures 11 and 12 respectively; from where we could affirm that wells 1, 2, 5, 9, and 10 are likely major producers for the D-B reservoir.

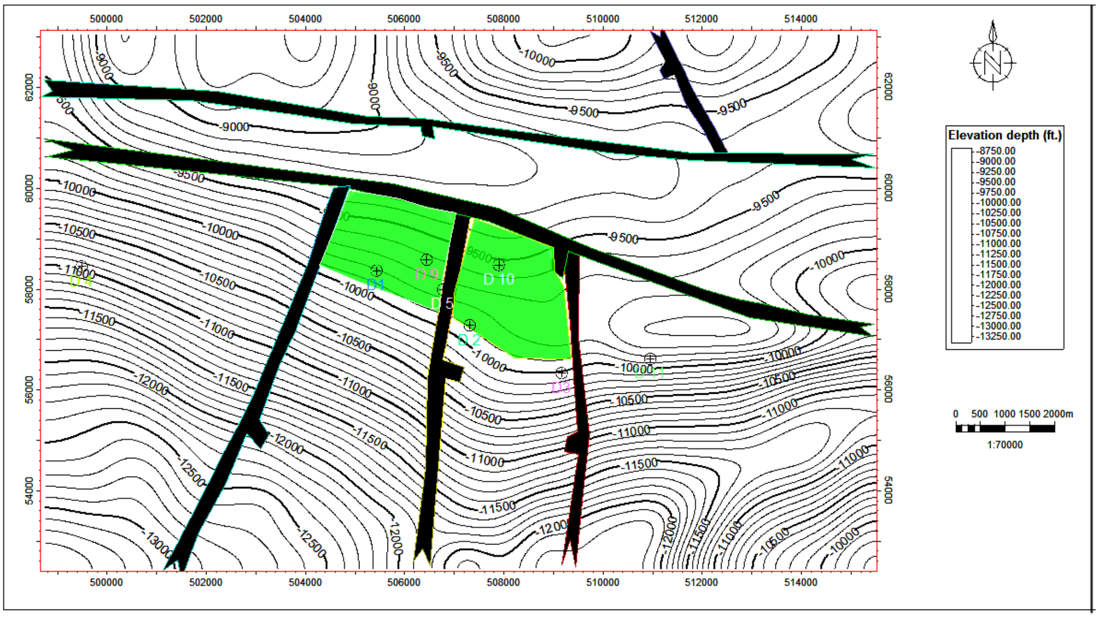

Figure 11. Oil - bearing 2D contour map of D-B.

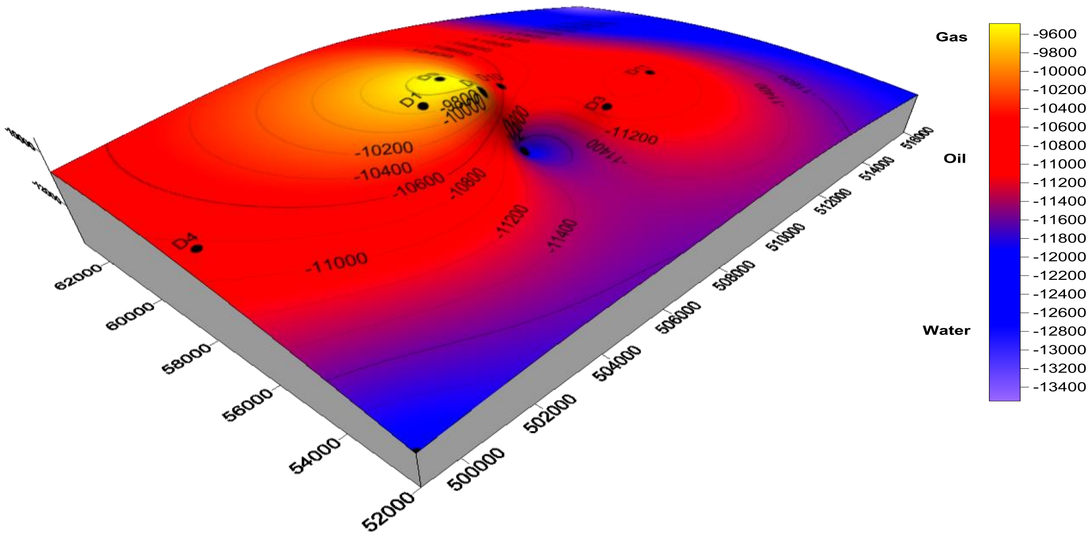

Figure 12. Oil - bearing 3D contour map of D-B reservoir.

A look at the porosity contour map for this D-B reservoir (fig. 13) identifies D9 and D10 wells as the best producers in terms of fluid flow since they bear the best porosity and permeability values. The reservoir will produce at irreducible water condition as affirmed by fig. 14.

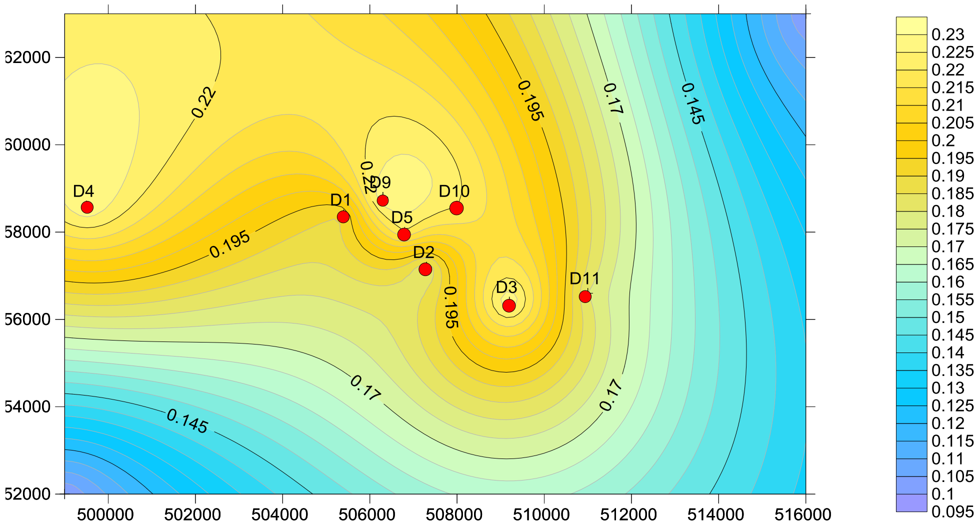

Figure 13. Porosity contour map of D-B.

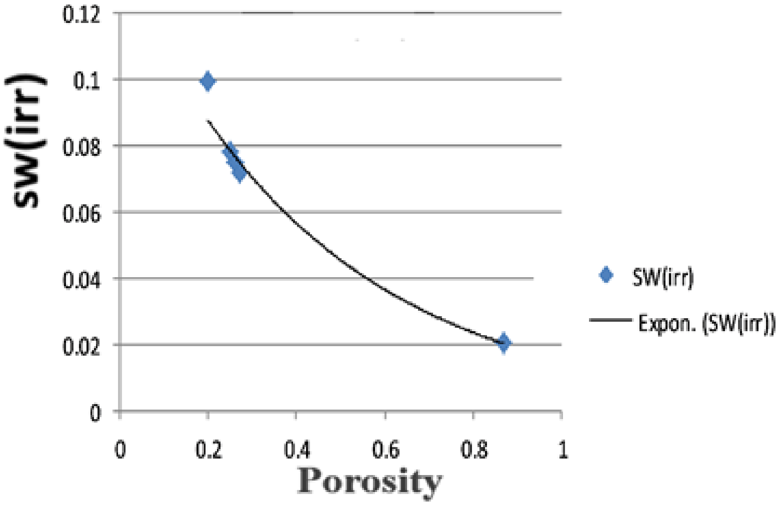

Figure 14. Sw(irr) vs Porosity plot for D-B.

Conclusion

The two reservoirs of the D-field are of good prospect potential though D-B seems more favoured economically (with its 80MBO compared to 23MBO of D-A). D-A has average effective porosity value of 0.22 and average permeability value of 7,390md while D-B has average effective porosity value of 0.21 and average permeability value of 3,714md, it is then obvious from these that porosity and permeability values tend to decrease with depth in the D-field (which is in agreement with already published works).

Reservoir D-A has wells D1, D2, D4 and D11 as good producing wells based on their positioning and petrophysical properties with D4 standing out as best –on noting its location away from boundary fault which in turn guarantees radial fluid flow to the wellbore. D-B on the other hand has D1, D2, D5, D9, and D10 as probable good producers, this means that D1 and D2 Wells can comfortably produce from the two reservoirs with the help of parkers and tubings separating the two reservoirs. Both reservoirs will produce at irreducible water condition since their plots of Sw(irr) and porosity gave constant exponential curves.

Gas was discovered in both D-A and D-B but the quantity is insignificant and as such needn't estimation.

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