Integration of Well Log Analysis and 3-D Seismic in Reserve Estimation of Hydrocarbon Bearing Sands in Q-Field, Niger-Delta Nigeria

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Abstract
Well log analysis and 3D seismic interpretation were effectively integrated to estimate hydrocarbon reserve in Q-field, Niger-Delta, Nigeria. The study objectives were to evaluate petrophysical parameters (net-pay thickness, porosity, water saturation and volume of shale) and estimate area extent of all hydrocarbon bearing sands from subsurface mapping and seismic interpretation.The workflow procedures for analysis involved the delineation of six hydrocarbon bearing sands (A, B, C, D, E and F) and the determination of petrophysical parameters from three well logs, while the 3-D seismic interpretation involved picking of three growth faults (A, B and C) as well as three antithetic faults(D, E and F). The faults were assigned, and four different horizons were picked along the fault planes cutting through sands A, B, D and E respectively. The horizons were interpolated through series of procedures to create isomap layers and were subsequently gridded and converted to generate both time and depth structure maps.The results from well log analysis showed that Q-field had average values of 114.5 feet, 21.0%, 25.2%, and 18.0% for the net-pay thickness, porosity, water saturation and volume of shale respectively while 3-D seismic interpretation showed area estimate of 8,557.44 acres, 1,830.78 acres, 1,680.31 acres, and 2,035.17 acres for sands A, B, D and E respectively.The study concluded that Q-field bears considerable amount of about 284.852 million barrel of oil reserve which could be exploited for commercial uses at profitable rate and about 1.72 billion cubic feet of original gas in-place.

1.0 INTRODUCTION

1.1 Description of Study Area

The Field is located onshore, Addax OML-Q, between 624017 to 625450 on the y-Cartesian axis, northing of the equator and 916909 to 918876 on the x-Cartesian axis, easting of the equator, Figure1.1, in a drowned river valley affected by seasonal flooding which limits the access to the field during the rainy season in the Niger-Delta province.

The producing sequence is between 4500 to 8500 feet as measured from subsea true vertical depth (tvdss) which consists of fourteen stacked hydrocarbon reservoirs characterized by large gas caps with underlying thin oil rims (10ft – 70ft). It is made up of a system of antithetic and synthetic normal faults with compartmentalized reservoirs below 5700ft tvdss into several blocks of variable size.

1.2 Aim and Objectives

The aim of the study is to estimate the volume of hydrocarbon reserve that could be commercially exploited at a profitable rate. The aim shall be achieved through the following objectives:

1. To evaluate the petrophysical parameters for all sands bearing hydrocarbon across the wells; Water saturation (Sw), Porosity (Phi), Net-pay thickness, Gross-sand thickness, Net to Gross ratio and Fluid contacts.
2. To map and estimate area extent of all sands from seismic interpretation.

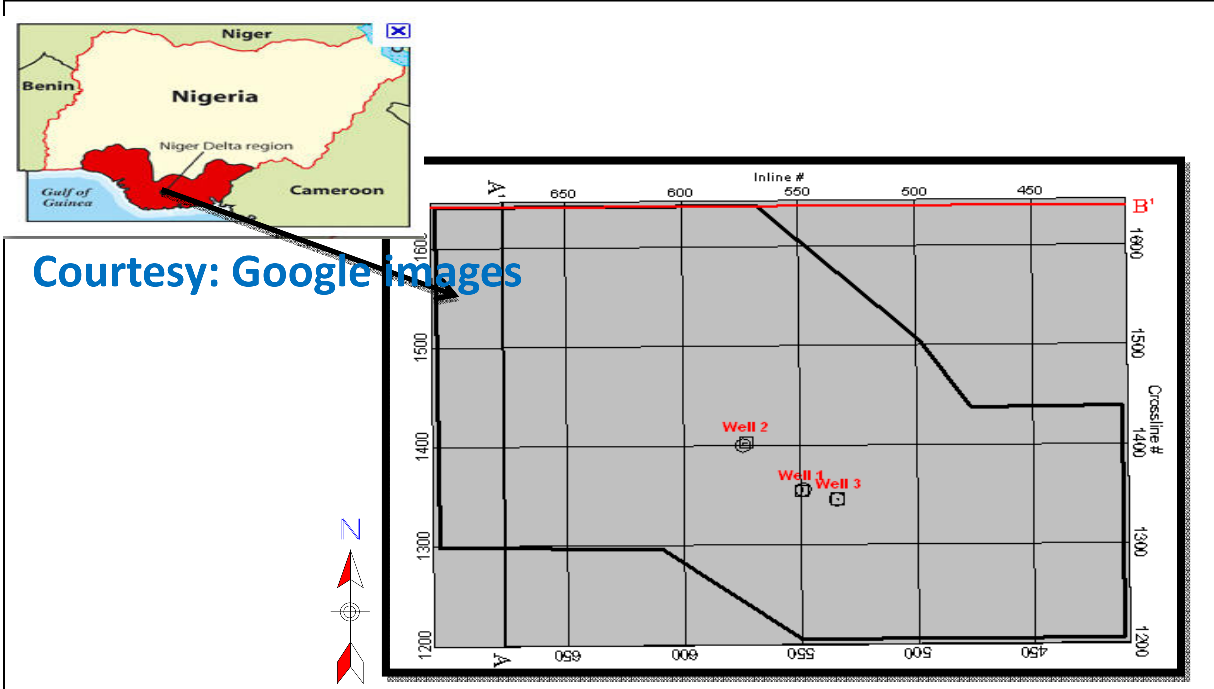

Figure 1.1: Base map of the Study Area Showing Wells Locations on the Q-Field.

2.0 GEOLOGICAL FRAMEWORK

The Niger Delta is one of the most prominent hydrocarbon provinces ranking among the world's first twenty largest producing nations (National Oil Companies, 2009). It is also the most prolific sedimentary basin in West Africa and the largest in Africa (Reijers, 1996;Reijers et al, 1997) from the economic and commercial point of view as it covers a land area in excess of 105,000 km^2 (Avbovbo, 1978) and its petroleum reserves provide the largest portion of the country's foreign exchange earnings.

The Niger delta basin is situated on the continental margin of the Gulf of Guinea between latitude 30 and 60N and longitude 50 and 80E. The geology, stratigraphy and structure of the Niger delta basin have been extensively discussed in several key publications (Short and Stauble, 1967; Merki, 1971; Avbovbo, 1978; Evamy et al, 1978; Burke and Whiteman, 1970.) with the source rock for hydrocarbon in the Niger Delta being a subject of discussion (e.g. Evamy et al, 1978; Ekweozor et al, 1979; Ekweozor and Okoye, 1980; Lambert-Aikhionbare and Ibe, 1984; Ejedawe, 1981; Doust and Omatsola, 1990). Furthermore, there are other possibilities which include variable contributions from the marine interbedded shale in the Agbada Formation and the marine Akata shale, and cretaceous shale (Weber and Daukoru, 1975; Evamy et al, 1978; Ekweozor and Okoye, 1980; Ekweozor and Daukoru, 1984; Doust and Omatsola, 1990; Stacher, 1995; Haack et al, 1997).

There are five offlapping siliciclastic sedimentation cycles postulated and recognized as being responsible for the deposition of the three subsurface Niger Delta formations; Benin, Agbada and Akata. These cycles known as depobelts namely; the Northern, Greater Ughelli, Coastal Swamp, Centrral Swamp and Offshore have widths of upwards of 30-60 kilometres and prograde southwestward 250 km over the oceanic crust into the Gulf of Guinea. Each depobelt recognized in the Niger-Delta depobelt has its own sedimentation, deformation, and petroleum generation history.

3.0 MATERIALS AND METHODS

3.1 Study Materials

The materials used for this study include:

1. **Base map:** The base map supplies information on the location of the study area.
2. **Well log data:** The well log data include the followings:
   a. Wire-line data for wells 1,2 and 3
   b. Deviation survey for Wells 1,2 and 3
   c. Check-shot data for Well 3 only
3. **Seismic data:** 3D seismic data with an area estimate of about 119.68 square kilometer (km^2) were utilized for this work.

All data obtained from Addax Petroleum Development (Nigeria) Limited through the directive of the director of Department of Petroleum Resources (DPR), Kofo Abayomi,Lagos.

The data were analyzed and interpreted using Landmark Geographix software.

3.2 Methodological Workflow

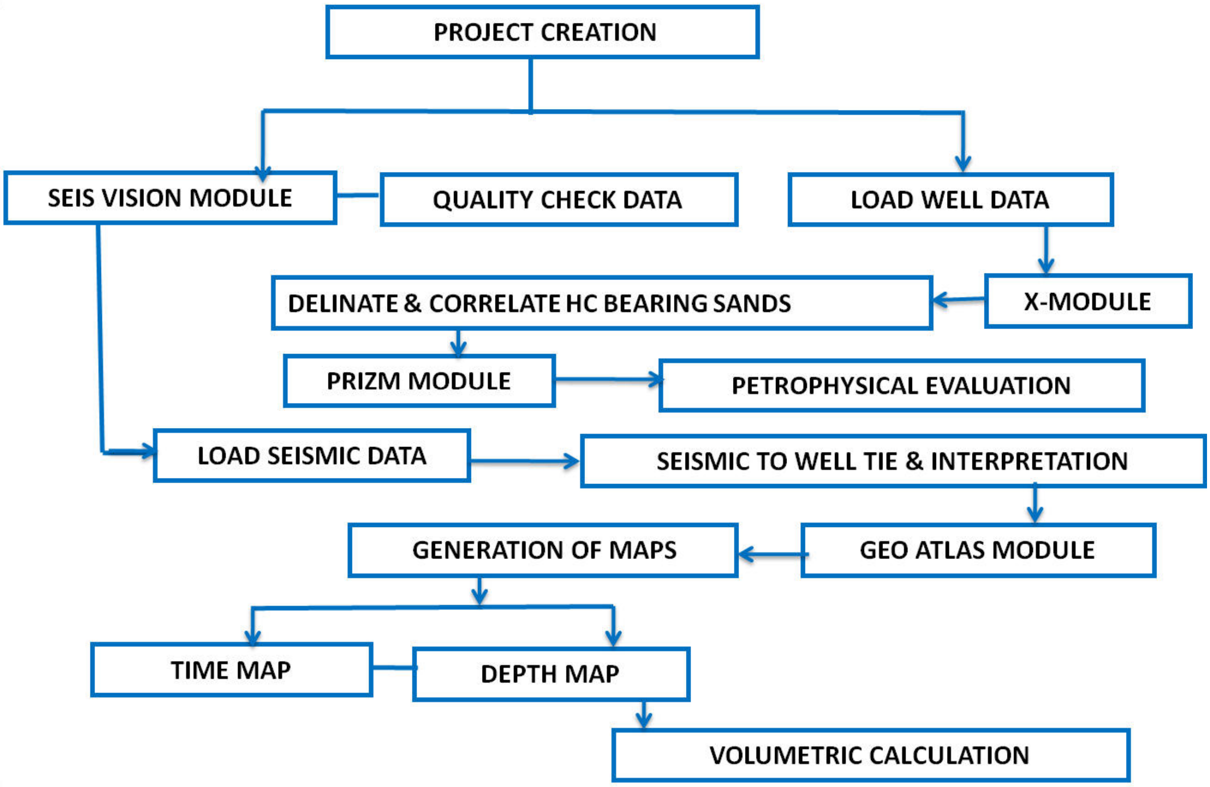

Figure 3.1: Petrophysics and 3D Seismic Methodological Flow Chart

4.0 RESULT PRESENTATION AND DISCUSSION

Six sands (A,B,C,D,E and F) were delineated as hydrocarbon bearing sands within the Agbada formation of the Q-field as shown in figure 4.1, while sands A, B, D and E were only identified to be highly prolific in hydrocarbon yield at commercial quantity as observed from their petrophysical analysis.

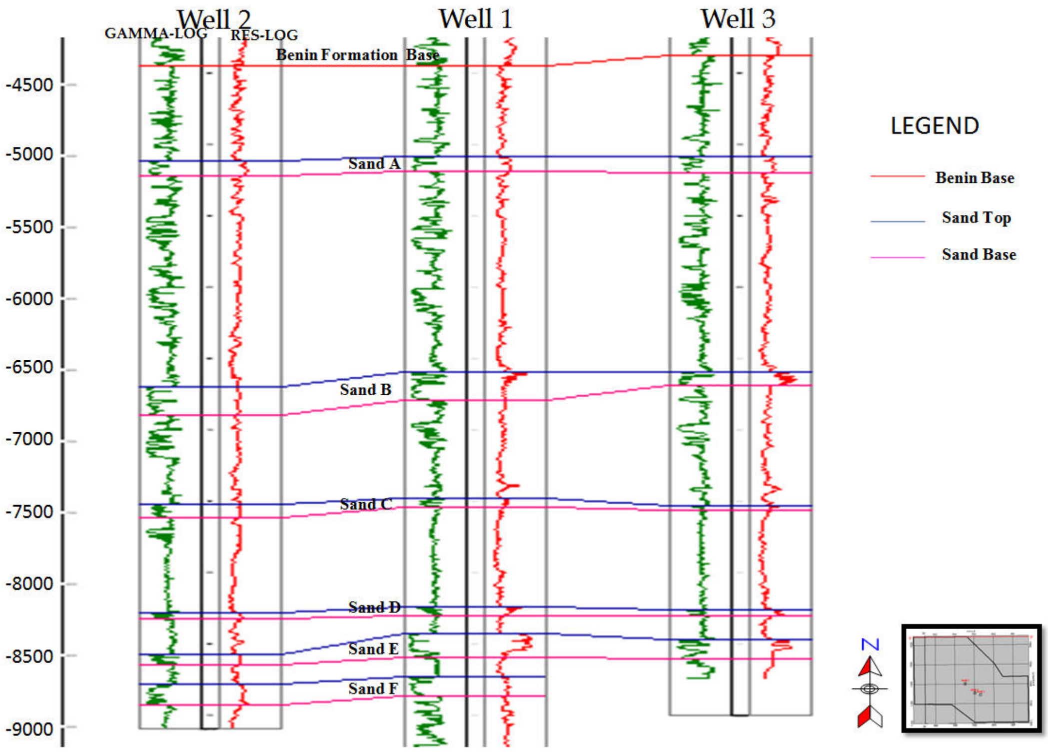

Figure 4.1: Structural Wells Correlation

Sand-A

In well 1, sand-A was oil bearing with an Oil-Down-To (ODT) to about -5124.00ft with a subsea true vertical depth (TVDSS) of about -5004.50ft & -5124.29ft at the top and base respectively. The reservoir gross interval thickness was 119.79ft, net-pay thickness 96.50ft and the net to gross (N:G) ratio was 0.806. The porosity, water saturation and volume of shale values in well 1 were 0.275%, 0.529% and 0.107% respectively. In well 2, the top and base values were -5028.00ft & -5140.51ft respectively with an Oil-Down-To (ODT) contact at -5140.00ft. The gross interval was 112.51ft with a net-pay thickness of 61.00ft given a net to gross (N:G) ratio of 0.546. The porosity, water saturation and volume of shale values were 0.305%, 0.568% and 0.078% respectively. Furthermore, in well 3, the reservoir top and base values were at -4997.00ft & 5115.75ft with an Oil-Down-To (ODT) contact at -5115.75ft. The gross interval thickness was 118.75 with a net-pay thickness of 88.50ft. The net-gross ratio of the reservoir was 0.745 with porosity, water saturation and volume of shale values as 0.375%, 0.533% and 0.104% respectively. The 3D seismic subsurface mapping and interpretation has shown that sand-A has an area estimate of about 8,557.44 acres of oil.

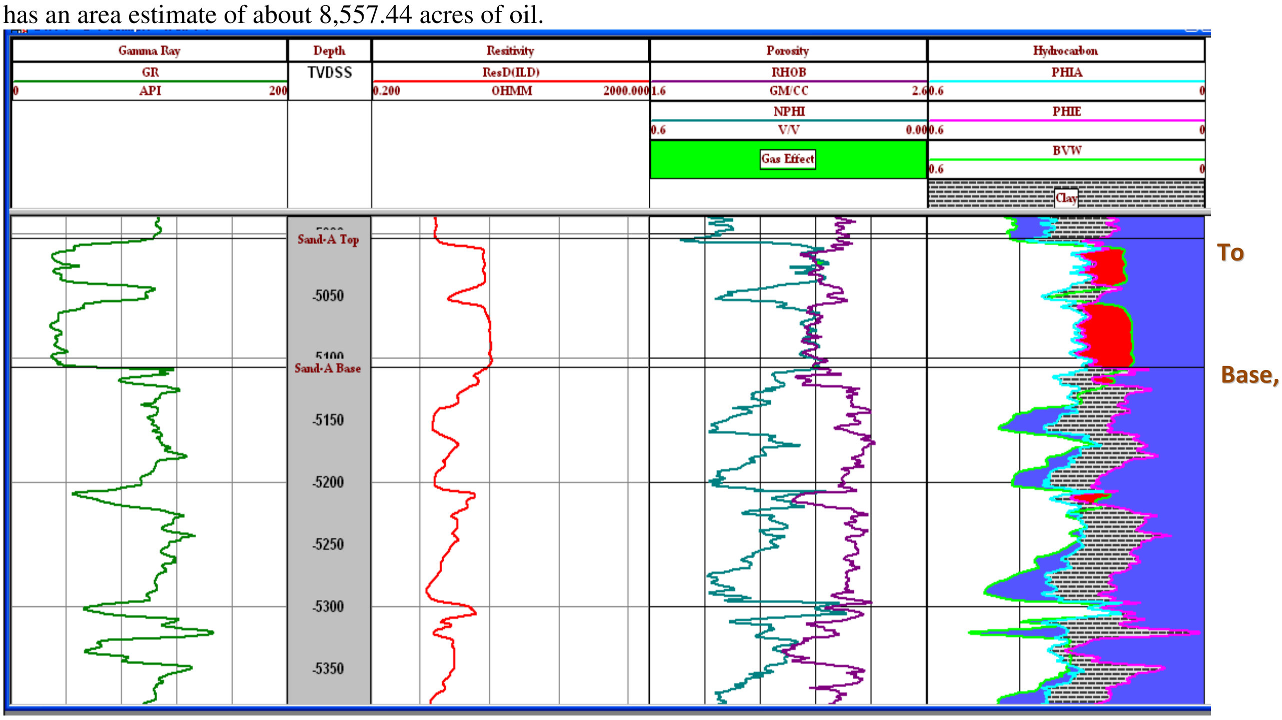

Fig 4.2: Petrophysical Summary of Sand-A in well 1

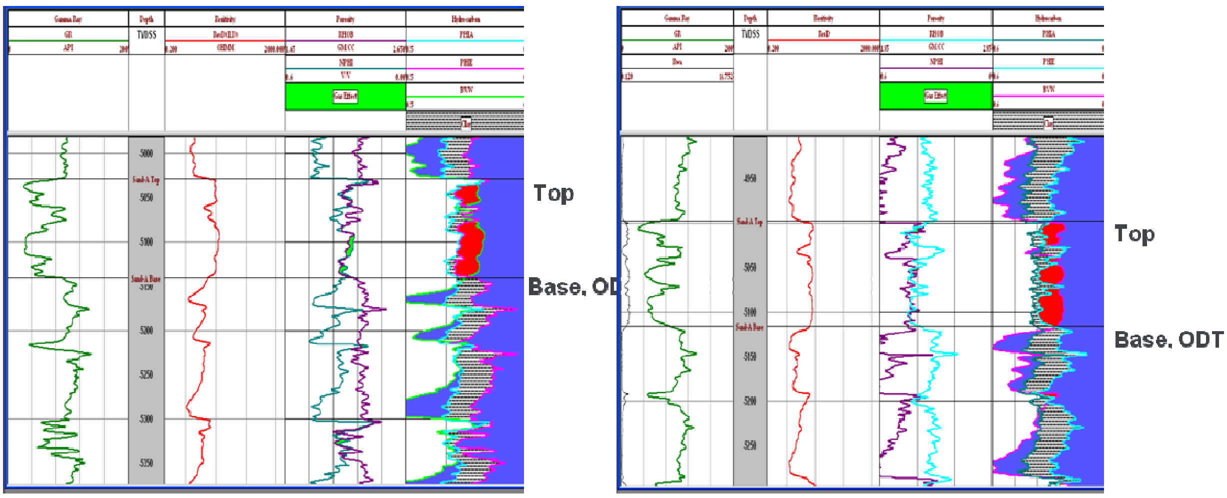

Fig 4.3: Petrophysical Summary of Sand-A in Well 2 & 3 Respectively.

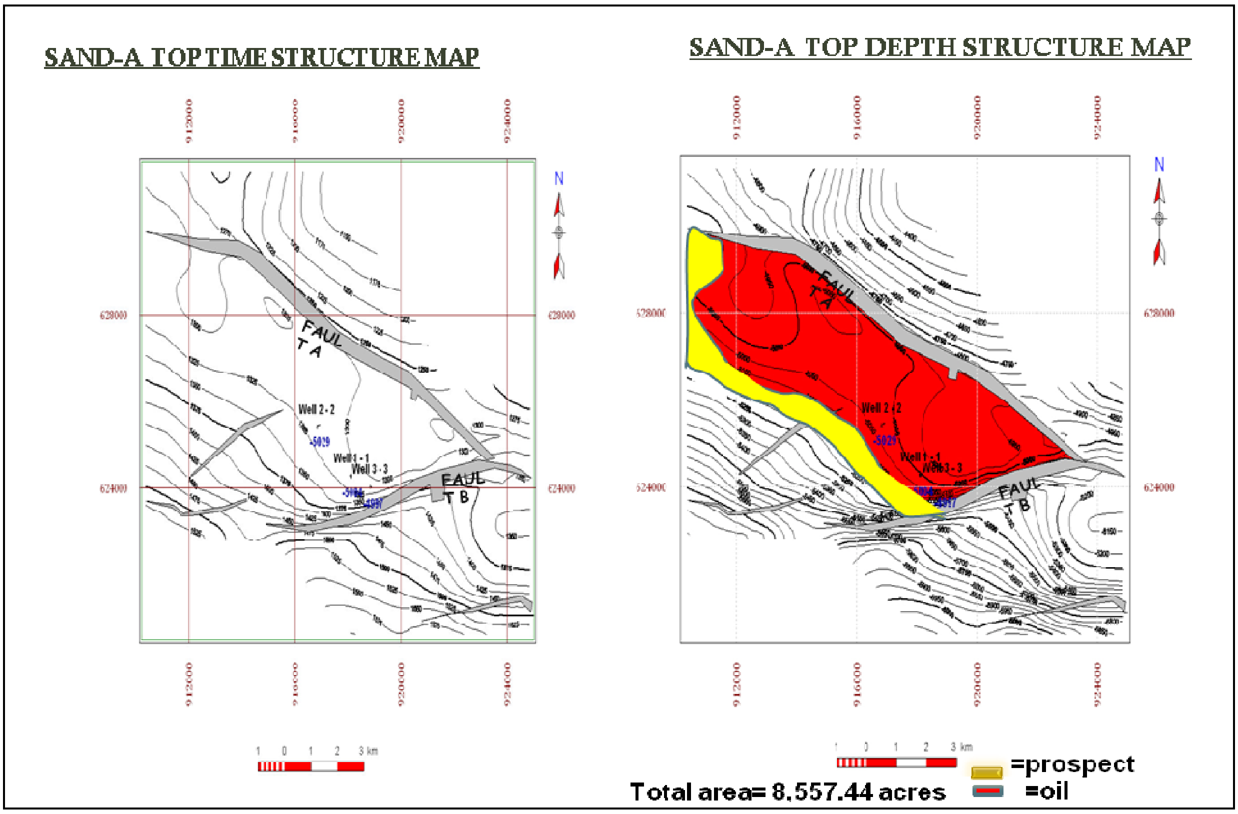

Fig 4.4: Sand-A Top Time & Depth Structure Maps

Sand-B

In sand-B, the reservoirs were characterized by large gas caps with underlying thin oil-rims in both wells1 and 3. However, the gas cap formed was larger in well 3 than in well 1, and the fluid-contacts identified were Gas-Oil Contacts (GOC) at -6564.00ft, -6580.00ft and Oil-Water Contacts (OWC) at -6581.00ft, -6603.00ft in wells 1&3 respectively. In well 1, the reservoir has its top value at -6514.00ft and base at -6715.75ft with a gross thickness of 201.75ft, while the net-pay thickness was about 45.00ft with a net to gross (N:G) ratio of 0.223. The porosity, water saturation and volume of shale values were 0.219%, 0.402%, and 0.110% respectively. Moreover, in well 3, sand-B yielded more hydrocarbon reserve than in well1 as its gross and net-pay thicknesses were 97.91ft and 77.00ft respectively with a net to gross ratio of 0.786. Furthermore, volume of shale and water saturation values were 0.076% and 0.323% respectively which were lesser than that of the well 1, while the porosity value 0.247% was also greater than that of well 1.

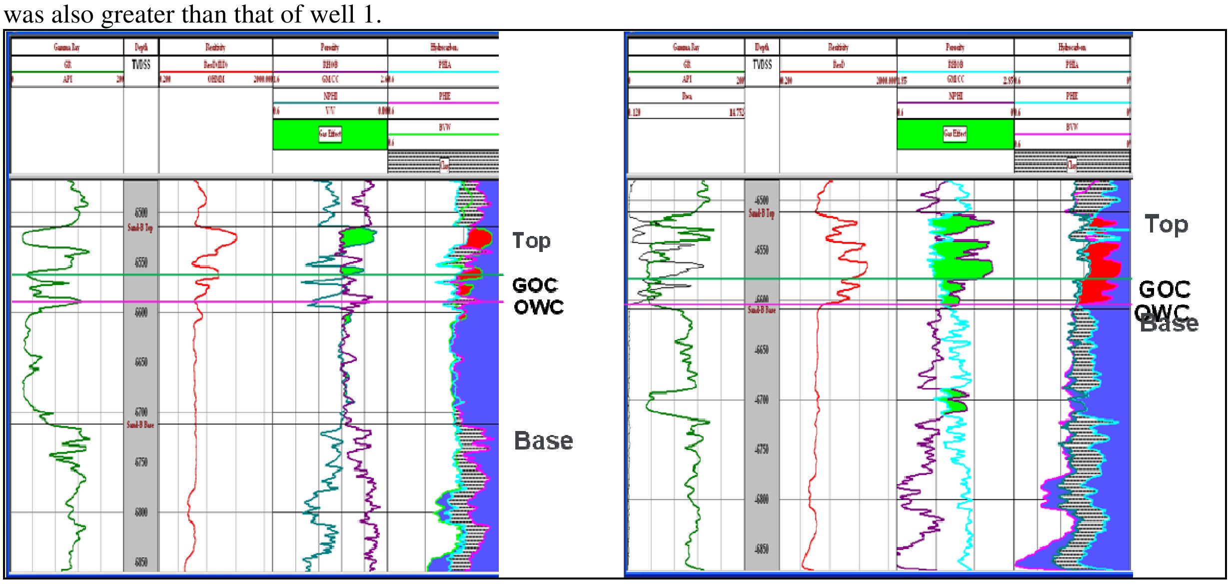

Fig 4.5: Petrophysical Summary for Sand-B in Well 1&3 Respectively.

The 3-D seismic subsurface mapping and interpretation of sand-B top has generated a depth structure map from which an area extent of 1,830.78 acres were estimated as hydrocarbon bearing, however, about 1,603.31 acres were for gas cap and 227.47 acres as thin oil rim.

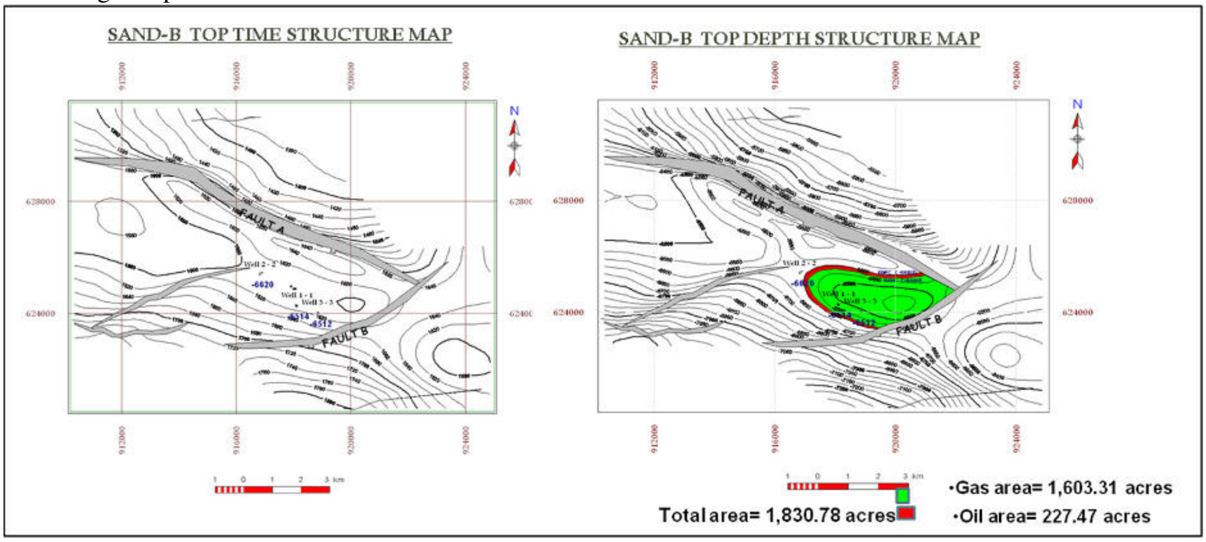

Fig 4.6: Sand-B Top Time & Depth Structure Maps

Sand-D

The petrophysical analysis of sand-D showed that it has a thin oil-rim with large volume of shale of about 0.245% and 0.268% as well as Oil-Water Contacts (OWC) at -8192.50ft and -8214.50ft in wells 1 and 3 respectively. In well 1, sand-D has a top reservoir depth value of -8159.00ft and -8219.42ft at the base with a gross thickness of 60.42ft, net-pay thickness of 33.00ft, and a net to gross ratio of 0.546. It has a low porosity value of 0.199% to a moderately high water saturation value of 0.496%. Conversely, in well 3, the reservoir has both higher porosity and water saturation values of 0.257 and 0.498% respectively. The gross thickness was 39.59ft while the net-pay thickness was 20.50 with a net to gross (N:G) ratio of 0.518. However, the hydrocarbon bearing area estimated at sand-D from the 3-D seismic interpretation was 1,680.31 acres.

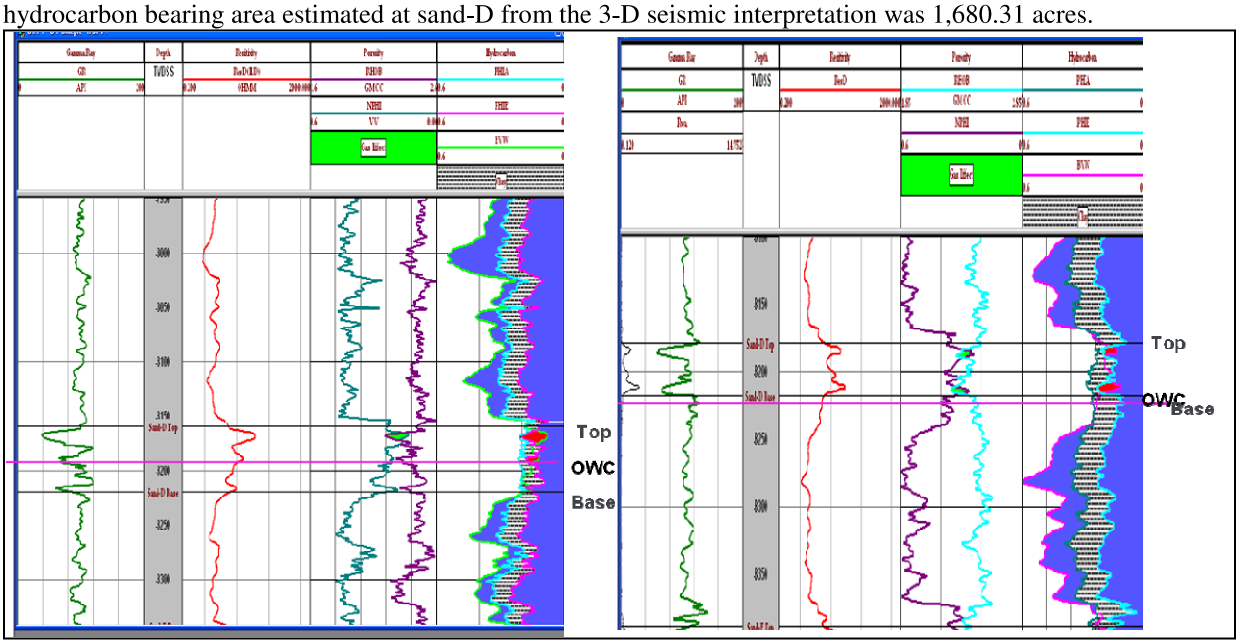

Fig4.7: Petrophysical Summary of Sand-E in Wells 1 & 3

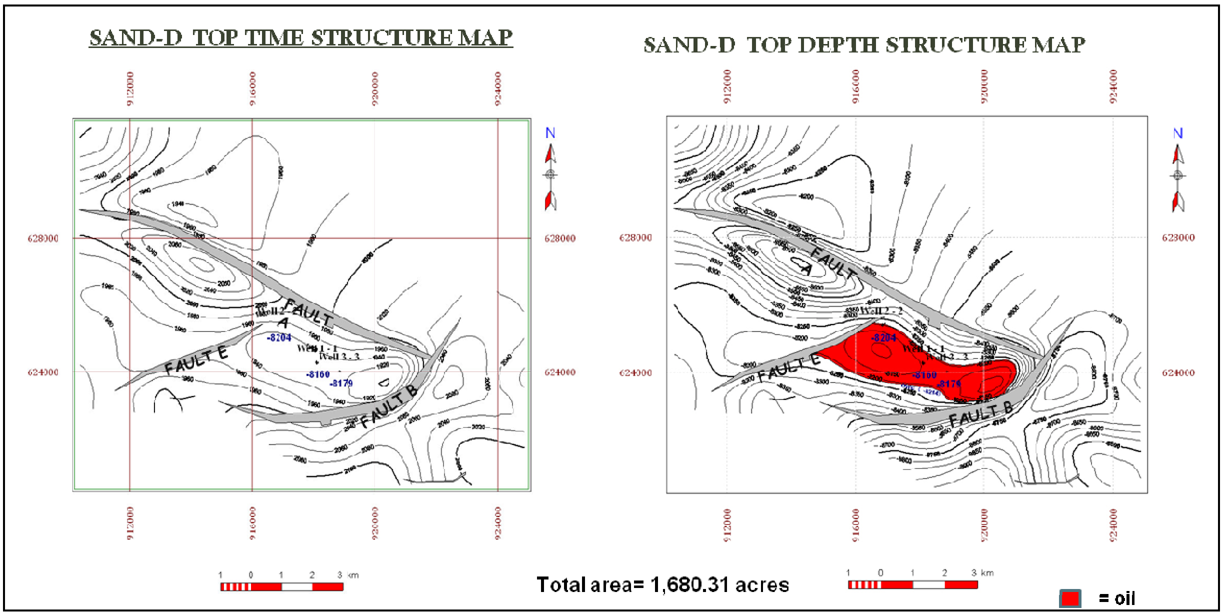

Fig 4.8: Sand-D Top Time & Depth Structure Maps

Sand-E

Sand-E is the most prolific reservoir in the Q-field because of its very low shale contents of about 0.018% and 0.064% coupled with very low water saturation values of about 0.252% and 0.379% in wells1 and 3 respectively. It has an extensive net gas cap of 107.00ft with very thin net oil-rim of 7.50ft; hence, the formed fluid-contacts were Gas-Oil Contacts (GOC) at -8440.50ft & -8454.50ft and Oil-Water Contacts (OWC) at -8462.00 & -8461.00ft in wells 1 and 3 respectively. In well1, the reservoir top is at -8342.50ft and base at -8515.42ft. The gross thickness was 172.92ft while the net-pay thickness was 114.50ft with a net to gross (N:G) ratio of 0.662 and a porosity of 0.175%. However, in well 3, sand-E yielded a less reserve when compared to well 1 with a gross thickness of 133.34ft, net-pay thickness of 53.50ft and a net to gross ratio of 0.401. Its porosity value was 0.210%. The reservoir top and base values were -8388.50ft and -8521.84ft respectively. The reservoir has a total hydrocarbon estimate of 2,035.17 acres with about 1,892.68 acres being occupied by gas cap and 142.49 acres oil.

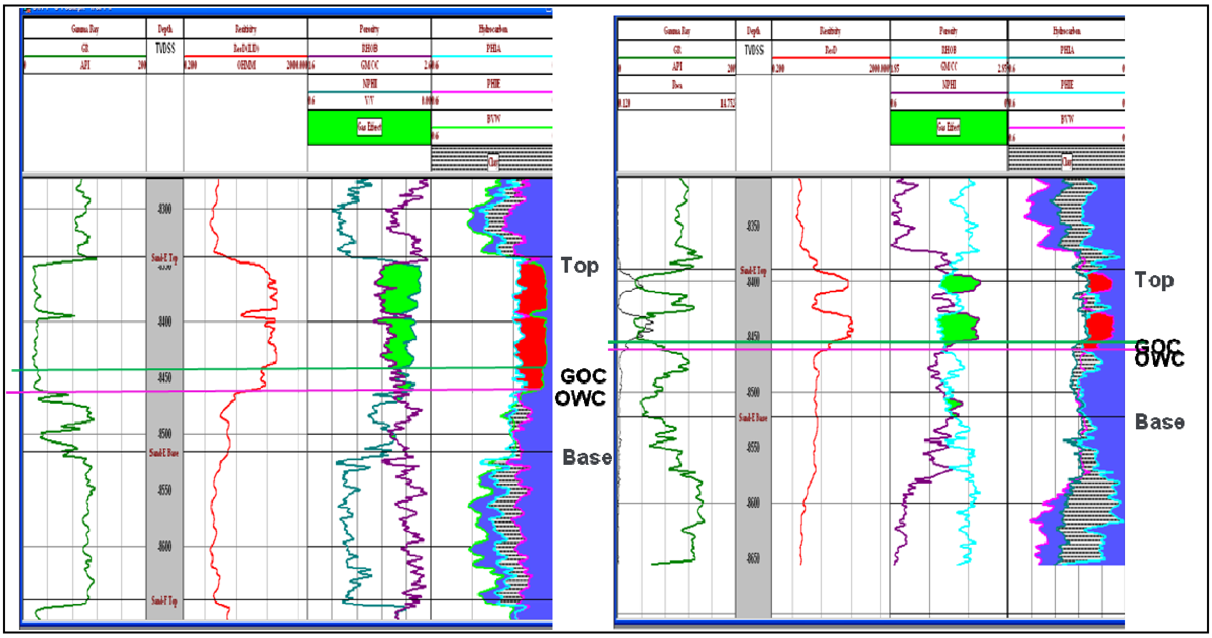

Fig 4.9: Petrophysical Summary of Sand-E in Well 1&3

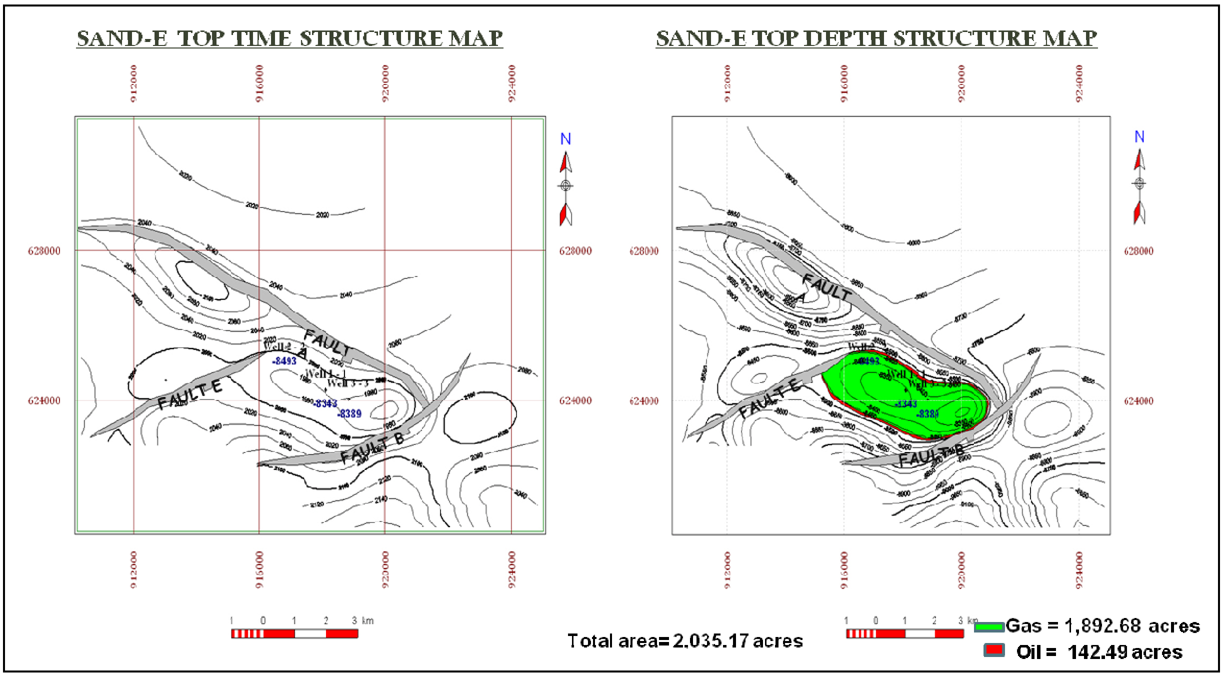

Fig 4.10: Sand-E Top Time and Depth Structure Maps

4.2 Discussions

By integrating the results of petrophysical analysis and 3D seismic interpretation, the field has been evaluated to yield a considerable amount of original gas in-place (OGIP) and original oil in-place (OOIP) which were calculated as follows:

Original Gas In-Place (OGIP) = 43560 x A x h x $\emptyset$ x (1-S_w)

In Sand-B, $OGIP = 43560 \times 1603.310 \times 54.000 \times 0.233 \times (1 \quad 0.363) = 559.75\ MCF$

In SandE, $OGIP = 43560 \times 1892.680 \times 107.000 \times 0.193 \times (1 - 0.314) = 1167.97\ MCF$

Total Original Gas In-Place (OGIP) = 727.72 MCF = *1.728 TCF*

MCF and BCF: Million and Billion Cubic Feet

Original Oil In-Place (OOIP) = 7758 x A x h x $\emptyset$ x (1-S_w)

In Sand-A, $OOIP = 7758 \times 8557.440 \times 96.500 \times 0.318 \times (1 - 0.543) = 931.030\ MMB$

In Sand-B, $OOIP = 7758 \times 227.470 \times 23.000 \times 0.233 \times (1 - 0.363) = 6.024\ MMB$

In Sand-D, $OOIP = 7758 \times 1680.310 \times 33.000 \times 0.228 \times (1 - 0.497) = 49.340\ MMB$

In Sand-E, $OOIP - 7758 \times 142.490 \times 7.500 \times 0.193 \times (1 - 0.314) - 1.097\ MMB$

Total Original Oil In-Place (OOIP) = 987.488 MMB

MMB: Million Barrels.

STOGIP = Total OGIP x Gas Formation Volume Factor (FVF)

Where, Gas FVF = Not available

Hence, STOGIP = Not estimated as gas FVF is not available

STOOIP = Total OOIP / Oil Formation Volume Factor (FVF)

Where, Oil FVF = 1.56 (as given by Addax Petroleum Development (Nigeria) Limited)

Hence, STOOIP = 987.488 / 1.56 = 633.005 Million Barrels.

GAS RESERVE = STOGIP x Gas Recovery Factor (R.F)

Where, Gas RF = Not available

Hence, RESERVE = Not estimated

OIL RESERVE = STOOIP x Oil Recovery Factor (R.F)

Where, Oil RF = 45% (as given by Addax Petroleum Development (Nigeria) Limited)

Hence, RESERVE = 633.005 x 0.45 = 284.852 Million Barrels

Table 4.1: Reserve Estimation 0f Gas and Oil in the Q-Field

HYDROCARB	OGIP	OOIP	FVF GAS	FVF OIL	STOGIP	STOOIP	RF GAS	RF OIL	GAS RESERVE	OIL RESERVE
GAS Total	1.728 TCF		NA		Not Estimated		NA		Not Estimated	
OIL Total		987.488 MMB		1.56		633.005 MMB		0.45		284.852 MMB

5.0 CONCLUSION

The study has been able to highlight the importance of exploration seismology in effective reservoir characterization and hydrocarbon exploration. The presence of the two-way faulted boundary closure constitutes the main hydrocarbon prospect in the area. The synergistic interpretation of seismic and well data presented as; maps, sections, models, well ties, and correlation panel has made the study both very qualitative and quantitative, as information missed by any of the methods in complemented for by the other and thereby necessitating a justifiable conclusion.

Finally, the study has shown that Q-field bears considerable amount of about 1.728 Trillion Cubic Feet (TCF) of gas in-place and about 284.852 Million Barrels (MMB) of oil reserve which could be exploited for commercial uses at profitable rate.

6.0 RECOMMENDATION

Fault Seal Analysis should be carried out on hydrocarbon fields after their reserve estimation in order to increase level of confidence in production.

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