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Hydrocarbon Reserve Estimates and Risks Assessment in 'X' Ray Field, Niger Delta, Nigeria

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Abstract

Hydrocarbon exploration and production is a high-risk venture. The uncertainties surrounding return on investment is taking a new dimension under the current industry condition. The dwindling nature of crude oil price requires robust assessment of the likelihood of occurrence, the range of possible outcomes, and the threat of loss throughout the life of a hydrocarbon field. Hydrocarbon prospecting in 'X' ray field, Niger Delta, Nigeria, revealed two gas prospects inter-bedded in thick shale sequences. Petroleum system elements were evaluated for the two prospects using a set of 3D seismic cube and well logs. Risks associating with each petroleum element were assessed. Result of study shows that the reservoir, trap, and seal are in-place and effective for hydrocarbon accumulation and production. However, organic rich rock that generated the gas accumulation was not found within the field. The absence of source rock within the field indicates high risk for the source and migration path. Average hydrocarbon saturations obtained from the prospects are 0.69, and 0.57 respectively. The estimated gas volumes of 38,620,000,000 BTU(37,892,707 scf)and 1,437,000,000 BTU (1,397,652 scf)for reservoirs 1 and 2 respectively were found to be substantial, to yield positive returns, but continuous charging of the reservoir through the life of the field is a cause for concern. It is presumed that the gas accumulation is generated by a regional source or a source located outside the field under study. To allow well-informed business decision, acquisition and analysis of more data from the neighboring field are recommended.

Keywords: Reserves; risk; uncertainties; prospect; probability of success; petroleum system.

Introduction

Despite the advancement in technology and knowledge, decisions related to petroleum exploration and production is still very complex because of the high number of issues involved in the process. These issues include reserve estimates, risks and uncertainties. Estimation of reserves is done to quantify the volume of hydrocarbon that can be produced. Uncertainty and risk analysis are useful in clarifying the range of possibilities, estimating the probability of discovery prior to drilling of a mapped prospect and for determining financial return on investment (Suslick and Furtado, 2001).Geological and economic uncertainties are related to costs of exploration and development. Risk is a threat: The threat of losing investment. The risk and uncertainties relating to the hydrocarbon charge system, the reservoir, the trap, and the seal must be evaluated one after the other and weighted together to determine whether to go into a venture or not.

Therefore, hydrocarbon mapping should not be limited to identifying prospects and determining the producible hydrocarbons. The geological and economic risks that are involved should be evaluated. A Prospect is an area characterized by a geological or geophysical anomaly (Sheriff, 1991). In most cases, the anomaly is either a geologic structure or a seismic amplitude anomaly that can be recommended for drilling (Schlumberger, 2014). Exploratory wells are abandoned if no hydrocarbons are found, and if hydrocarbons are found in sufficient quantities, and risk factors do not pose a threat, well completions are carried out to convert the exploratory wells to development wells.

Justification for drilling a particular prospect is made by assembling evidence for an active petroleum system (Magoon and Dow, 1994).A petroleum system is used to describe all the geologic elements and processes that are essential if an oil and gas accumulation is to exist (Schlumberger, 2014). The essential elements of a petroleum system include the Source rock, reservoir rock, seal rock, trap formation and migration of accumulated hydrocarbons. Source rock identification is concerned with oil and gas generation. The source rock is a subsurface sedimentary rock unit which is made of shale or limestone. It contains the precursors of hydrocarbon formation: organic matters, which must have been subjected to high temperature over a long period of time. Therefore within a study area or in adjacent fields, it is important to map out the source because it is the basis of the oil/gas recharge into the reservoir. The components of the oil/gas recharge system also include migration and entrapment. Migration is the process of moving oil and gas from the source rock to the reservoir pores where it is trapped after its generation.

After a viable petroleum system has been identified, the geologic risks that are associated with each of the petroleum system elements must also be identified. Risk weighs the level of investment against net financial assets. It represents the chance of success or failure of a project(Rose, 2004). Risk is related to the probability of success(POS) in the sense that probability of success (or probability of occurrence) is risk, subtracted from one (Cozzolino, 1977). In other words, probability and risks can be scaled between 0.0 and 1.0 respectively. For instance, probability of 1.0 for a trap means that there is 100 percent certainty that the trap is present and effective, which invariably implies that there is no risk involved. Geological risk analysis, is therefore performed using the analysis of probability of success (POS) and is usually analyzed by taking the product of probability of occurrence of the petroleum system elements that have been identified (Kjemperud, 2008).

Apart from geologic risks, another risk factor that must be dealt with is the economic risk. This can only be done if the capital and operating expenditures of the company are available. By definition, economic risk refers to the justification of the investment in terms of profitability. The net present value (NPV) is the assessment of the economic risk. Net present value, is a numerical calculation that shows the present value of an investment based on expected income from that investment, when such income is removed from the overall cost of the entire project (Frank et al, 1998). If a certain project has a Net Present Value (NPV) of zero, then the company neither gains nor loses money by pursuing the project. When net present value is negative, the project is expected to lose money. A project with a negative net present value is usually avoided. On the other hand the expected monetary value (EMV) calculations represent the integration of both economic and geological risk (Fiona, 2000).

Geology of the Study Area

'X' Ray field is an offshore field located in the Niger Delta of Nigeria. The location and specific details of the ‘X’ Field are withheld for proprietary reason. The Niger Delta Geology consists of three broad formations. These are the pro delta facies Akata Formation, the paralic delta front facies Agbada Formation and the continental top facies Benin Formation (Short and Stauble 1965). The Akata formation lithofacies is composed of shales, clays and silts at the base of the sequence. They contain a few streaks of sand, possibly of turbiditic origin, and were deposited in the delta-front to deeper marine environments. The thickness of this sequence is not known for certain but may reach about 7000 m in the central part of the delta. The Agbada Formation which overlies the Akata Formation consists primarily of sand and shale and it is of fluviomarine origin. The Agbada Formation has a maximum thickness of about 4500 m (Weber and Dakoru, 1975). Most Exploration Wells in the Niger-Delta have bottomed in this lithofacies. The Benin formation is the shallowest part of the sequence. It is composed almost entirely of non-marine sand (Ajakaiye and Bailly, 2002). In the Niger Delta, Reservoir development is typically restricted to the sandy regressive offlap sequences of the Agabada formation where reservoirs are favourably juxtaposed with intra-formational seals whereas shales provide seals along fault zones where clay smears are observed.

Trapping mechanism of the Niger Delta include Structural and stratigraphic traps. Structural traps are generally formed by the deformation of sedimentary rocks into geologic features such as anticlines. Doust and Omatsola (1990) describe a variety of structural trapping elements, which include: Simple roll-over anticline, structure with multiple growth faults, antithetic or synthetic closure and collapsed crestal structures. The stratigraphic trap in the Niger Delta includes porosity pinch-out Structures. A study by Jibrin and Raji (2014) on deep steered multi-trace techniques shows that there are abundant macro structures that are essential for hydrocarbon trapping in Akata formation. Stacher (1995) presume that hydrocarbon migration in the Niger Delta overlaps in time with the burial and structural development of the overlying reservoir sequences and that migration occurs primarily across faults. Migrations were short as evidenced from the wax content, API gravity and chemistry of the oils (Short and Stable, 1965).

The source rock in the Niger Delta has been a controversial topic. Weber and Daukoru, among others have proposed possibilities of source rock to include variable contributions from the marine inter-bedded shale in the Agbada Formation and the marine Akata shale, and a Cretaceous shale (Weber and Daukoru, 1975).Based on organic-matter content and type, Evamy *et al.,* (1978) supported Weber and Dakoru's theory and proposed that both the marine shale of the Akata Formation and the shale inter-bedded with paralic sandstones in the lower Agbada formation were the source rocks for the Niger Delta oils. Lambert-Aikhionb are and Ibe (1984) argued that the migration efficiency from the over-pressured Akata shale would be less than 12%, indicating that little fluid would have been released from the formation. They propose a different thermal maturity profile, showing that the shale within the Agbada Formation is mature enough to generate hydrocarbons. Ejedawe (1984) used maturation models to conclude that in the central part of the delta, the Agbada shale sources the oil while the Akata shale sources the gas.

Materials and Methods

Prospect mapping

The data used for this study include digital suites of well logs, 3D seismic data and check shot data. Petrel software was used to evaluate, analyze, and interpret the data. Reservoir thickness for each prospect can be obtained from well log panels (Adeoye *et al*, 2016).Prospect reserve was estimated based on optimistic (P10%), median (P50%) and pessimistic (P90%) cases, using volumetric parameters like porosity, hydrocarbon saturation, and reservoir thickness. Each of these volumetric parameters has a range of uncertainty in their estimation because they vary laterally and vertically within the reservoir. Therefore, the problem of how to express uncertainties in a form that can be utilized in economic situations is in the formulation of such range of anticipated values for a given parameter (e.g. porosity) with probabilities of 90%, 50%, and 10% assigned to the values that constitute the range(Rose, 2004).The reserve estimate equation is shown below:

$$G_f = 43560 * GRV * \phi * S_h * B_{gi} * \text{RF}. \qquad (1)$$

Where: G_f is the volumetric recoverable gas in reserves in standard cubic feet (SCF); GRV is the gross rock volume (i.e. area in acres* Height in feet); $\phi$is thePorosity calculated from the Density porosity (DPHI) Log. S_h is the hydrocarbon Saturation obtained from Archie's water saturation Equation. B_{gi} is the gas formation volume factor (0.3 was assumed because there is no information on temperature and pressure), and RF is the recovery factor. RF depends on the drive mechanisms. Gravity drive and water drive mechanism are appropriate in this case. 60% recovery factor is assumed.

Synthetic seismograms were generated using the velocity and density logs. Well-to-seismic tie was performed by matching the synthetic seismogram and resistivity log to the appropriate seismic line. Consequently, reflections that represent the top of the hydrocarbon prospects were identified. Following this, horizon interpretation was carried out on seismic timelines. The Seismic lines were carefully mapped for fault indications. Time-structure maps were generated from horizon and fault interpretation using Kriging method (Krige, 1951).The method is a linear regression technique of interpolation to predict horizon values away from picked horizon control. The closures on the map were examined for adequate area. Time to depth conversion of the time structure maps was carried out using interval velocity obtained from the check shot data.

Reservoir area was obtained on the structure maps using the square grid computational method. Note that input for reservoir area was not varied in uncertainty estimate because the defined area from fluid contact definition does not vary. Reserves initially obtained in standard cubic feet (SCF) was converted to British thermal units (BTU) using an online conversion calculator (http://www.convert-me.com/en/convert/energy/scfgas.html).

The British thermal unit (Btu or BTU) is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. BTU is used nowadays as a standard unit of measurement for natural gas and provides a convenient basis for comparing the energy content of various grades of natural gas and other fuels. A single Btu is insignificant in terms of the amount of energy a single household or an entire country uses.

Results obtained in any study may also present in million metric British thermal units (MMBTU) when large volumes of natural gas are estimated.

Hydrocarbon typing was done by mapping fluid contacts using neutron-density log overlay. The fluid contacts were located on depth structure maps. This was used to define the reservoir area (prospect). Capping rocks (seals) were obtained by analyzing the litho-facie panel obtained from the gamma ray log interpretation. The delineated impermeable intervals (shales) were presumed to act as seals. The thickness of sealing unit was established from the log (Raji and Adeoye, 2014). To interpret the source rock, the delta log R technique was adopted using sonic and resistivity logs (Passey, 1990). In hydrocarbon reservoir rocks or organic rich non-reservoir rocks, a separation between the two curves will occur. Since the shale unit usually has high clay volume, shale unit can be discriminated from clastic reservoir rock using gamma ray log.

Risk Assessment

A probability scheme to rate each identified petroleum system element was adopted, using the guidelines provided by Coordinating Committee for Coastal and Offshore Geosciences Programmes (CCOP, 2002). Numerical values of probability of occurrence were assigned to each petroleum system element. The probability that an event will occur can be related to the risk that the event will not occur by the following formula (CCOP, 2002).

$P_{prob.} = 1 - P_{risk}$ (Fekete, 2008). (2)

Where

$P_{prob.}$ is probability that a given event will occur.

P_{risk} is probability that the event will not occur.

Therefore Probability (that each of the petroleum system elements is present in the field of study) ranges from 0.0 to 1.0 which means 0% certainty and 100% certainty respectively.

Probability of success (POS) on the other hand is the probability of finding sufficient quantities of oil and gas to produce sustainable flow over a long period of time. This probability law states that the probability of the simultaneous occurrence of several independent events (in this case probability of occurrence of trap, seal, migration, reservoir and source rock) is equal to the product of their individual probabilities.

$POS = P_a P_b P_c P_d P_e$ (Fekete, 2008). (3)

Where

POS= Probability of success

P_a= Probability of occurrence of a trap

P_b= Probability of occurrence of a seal

P_c= Probability of occurrence of a migration pathway

P_d= Probability of occurrence of a reservoir

P_e= Probability of occurrence of a source rock

If there is a geologic chance of success from the analysis of probability of success, the second probability node must take into account the probability of finding an accumulation size exceeding the minimum economic field size (Frank *et al.*, 1998). In other words, finding enough hydrocarbon to obtain a positive Net Present Value (NPV) and a positive Expected Monetary Value (EMV). This is only done where the capital and operating expenditures of a company is available. Therefore risk assessment in this study is limited to the analysis of the geologic risk (Probability of Success-POS).

Results and Discussion

In all, two prospects have been identified on structure maps. The analysis of the well logs established the fact that these prospects contain hydrocarbon. Well to seismic tie was performed to ascertain the reliability of our interpretation and a good tie was observed. Petroleum system analysis was done and the results are discussed prospect by prospect in the following sub-sections.

Prospect 1

Analysis of well logs for lithologic description revealed a sequence of intercalating sandstones and shales as expected of the Niger Delta area. Figure 1, contains information on lithologic description, depth to reservoir top and bottom, reservoir thickness, porosity ranges and seal analysis. The hydrocarbon reservoir is of variable porosity, ranging from 0.22 to 0.38.The variations in depth to top of reservoirs across the field were documented from well A and B. The top of the reservoir varies between 2135m and 2457m. Reservoir gross thickness ranges between 85m and 242m. Net thickness was obtained from gross thickness because the reservoir contains thin shale beds. The detail thickness estimates based on P10%, P50% and P90% confidence levels are provided in Table 1. The table also shows the hydrocarbon saturation obtained from Archie's water saturation equation. The water saturation ranges between 0.21 and 0.38. This indicates that hydrocarbon saturation is high i.e. 0.79 and 0.62 respectively. Prospect reserves are estimated based on optimistic (P10%), median (P50%)and pessimistic (P90%) cases because of the variations in the input values of net thickness, net to Gross, porosity and hydrocarbon saturation (Table 1). At the end of the analysis, a value of 77,267,773SCF of gas was estimated for the reservoir of prospect 1 at the P10 confidence level. Taking an average of P10, P50 and P90 volumetric estimates of 38,620,000,000 British thermal units (BTU) (37,892,707 scf) of gas can be produced with an assumed recovery factor of 30%. This value is adjudged to be very high, promising good financial reward.

Table 1: Reserve Estimate for Prospect 1

	PROSPECT	TOP(m) (ft)	BOTTOM (m)(ft)	GROSS THICKNESS(m)(ft)	NET THICKNESS(m)(ft)	N/G	Area(Acres)	POROSITY	HYDROCARBON SATURATION	GAS RESERVES (SCF)	GAS RESERVES (MMBTU)
ONE	P10	2215	2457	242 (793)	214(702)	0.88	1387.97	0.34	0.79	77,267,773	79,430,000,000
	P50	2200	2300	100 (328)	86 (282)	0.86	1387.97	0.28	0.68	22,654,787	22,280,000,000
	P90	2135	2220	85 (278)	72 (236)	0.85	1387.97	0.22	0.62	13,755,563	14,150,000,000

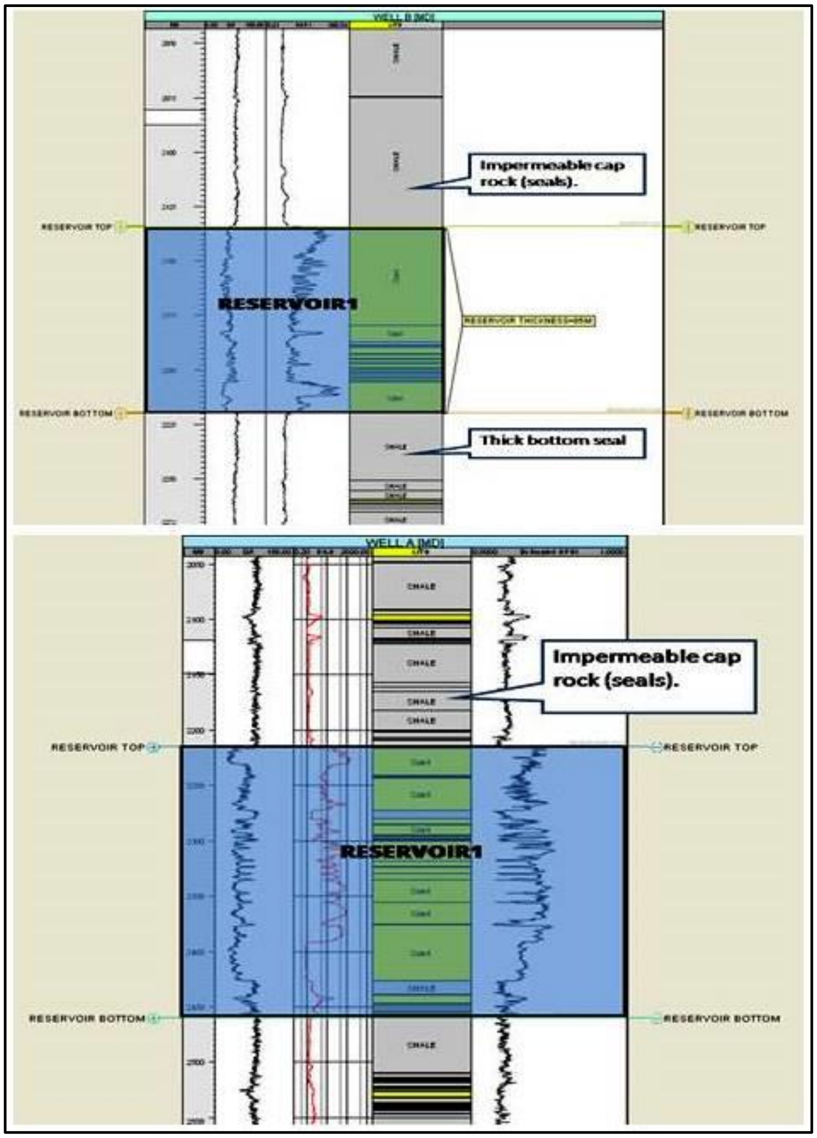

Figure 1: Reservoir and seal identification for Prospect 1.

Well to seismic tie is shown in Figure 2.The top of reservoir 1 coincides with a low impedance reflection (blue reflection).This reflection was picked on the seismic section (horizon interpretation). Time structure map generated from seismic horizon interpretation reveals a prospect area at the time interval of 2250ms and 2280ms (Figure 3). No fault was observed to be cutting through this prospect. Figure 4 is a Depth structure map obtained from the time structure map. The diagram shows the prospect area (prospect 1) defined by hydrocarbon fluid contact (red fill). The figure also reveals a square grid used for obtaining reservoir area. The prospect is interpreted as an anticline that covers an estimated area of about 5.62km^2(or1387.97Acres).

Organic rich rocks (source rocks), intended to be established from sonic –resistivity overlay were not found(Figure 5).This is because the sonic log does not increase with crossing over of the resistivity log and sonic log. It is possible that the accumulations are derived from a regional source. The absence of source rock is assumed to constitute a major geologic risk in this study. This is discussed under the risk analysis section. Hydrocarbon sealing is provided by the capping shales of the sequence. The seals are thick (up to 98m) and are laterally continuous.

According to guidelines provided Coordinating committee for coastal and offshore Geosciences programmes, a corresponding value of risk can be assigned when the capping rocks are combined (CCOP, 2002).

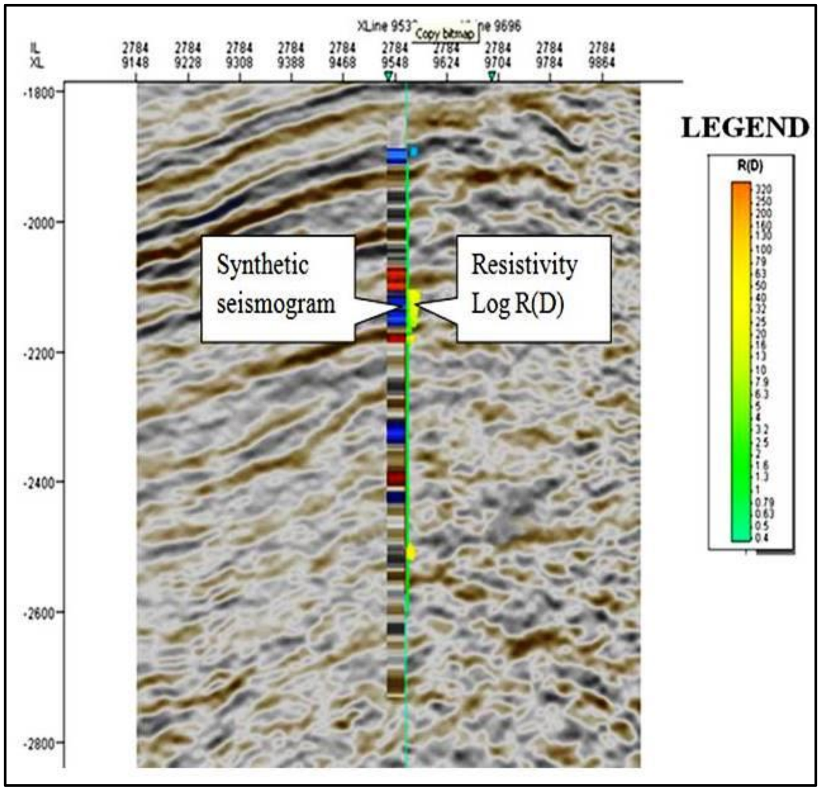

Figure 2: Well to Seismic tie-overlying synthetic seismogram and resistivity log on a seismic section

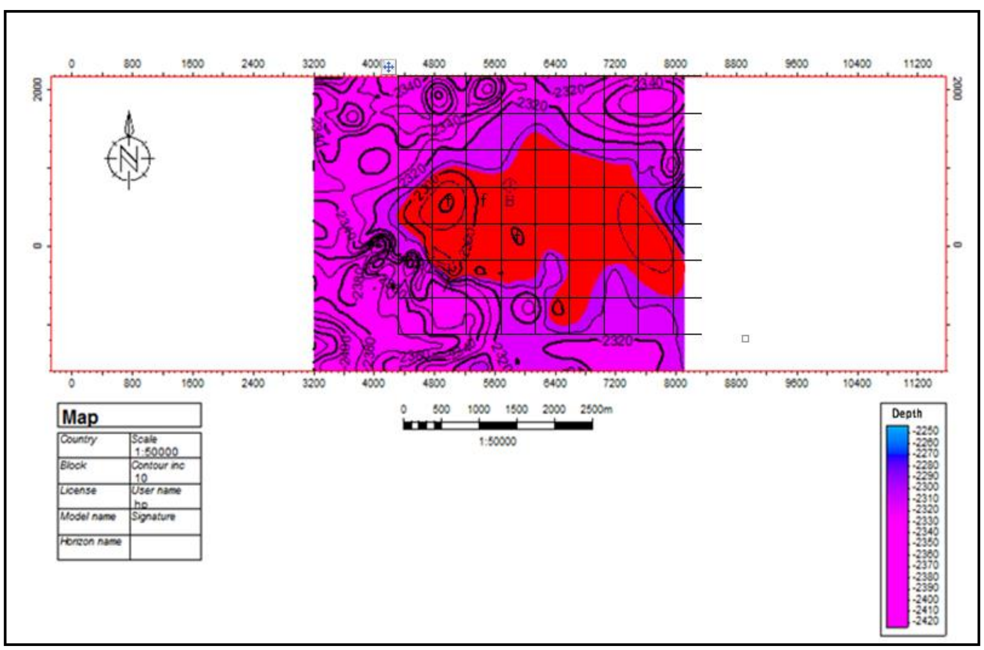

Figure 3: Time structure map showing prospect 1.

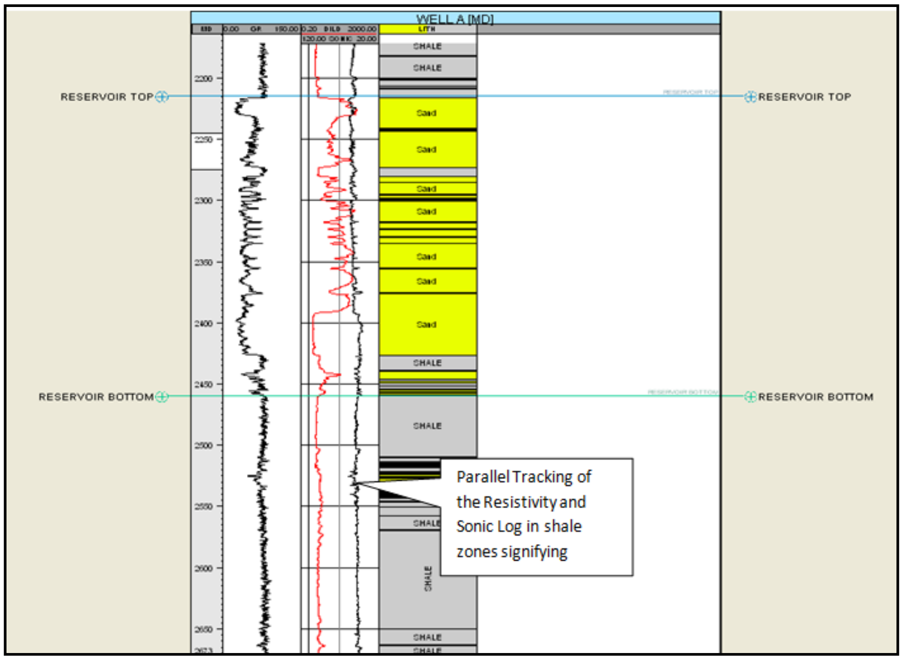

Figure 4: Depth structure map showing prospect area (prospect 1)

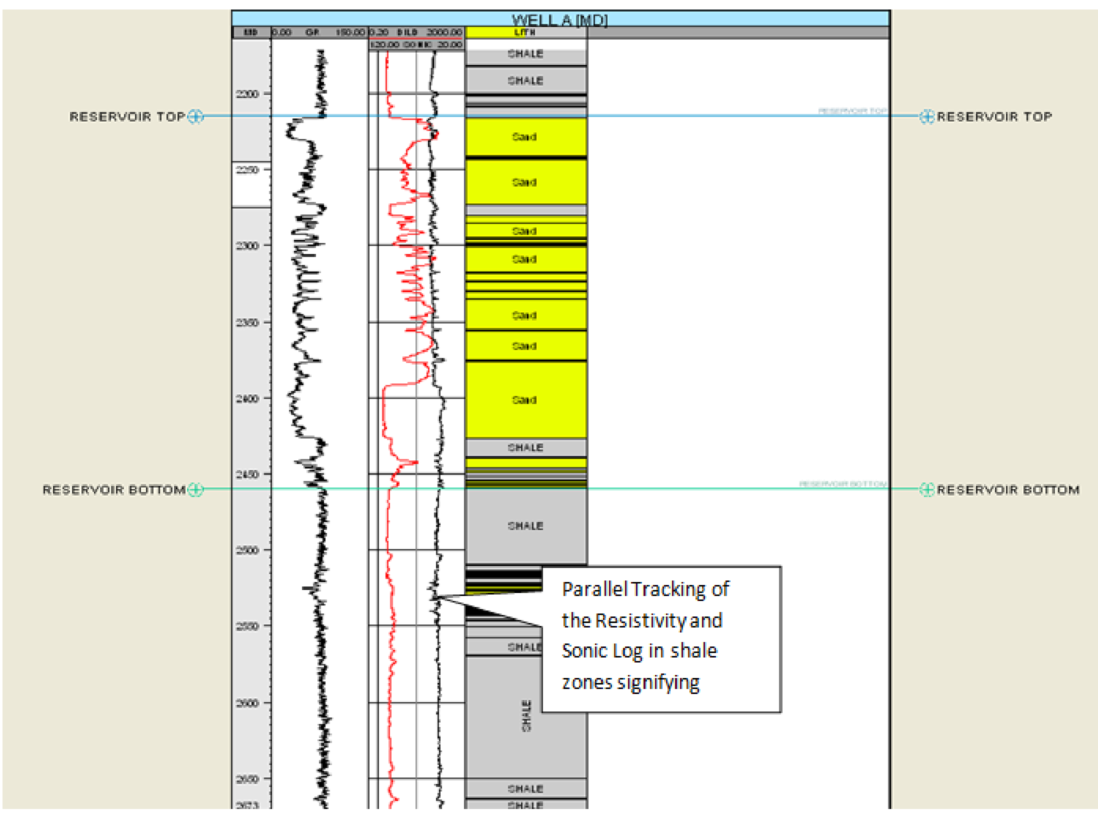

Figure 5: Source rock Identification from delta R log (Reservoir 1)

Prospect 2

The top of reservoir 2 mapped from lithology (Gr) and resistivity (Dild) logs varies from2534m to 2719m in well A and well B respectively while the bottom of the reservoir varies between 2552 m and 2755m (Figure 6). Gross reservoir thickness is found to be the same as net reservoir thickness because the reservoir is clean sand with no shale intercalations. The thickness of the reservoir varies between 18m and 35m. Reservoir evaluation reveals porosity in the range of 0.25 and 0.34. Estimated water saturation (S_w) and overall summary of the petrophysical analysis at the various uncertainty levels (P10, P50 and P90 confidence levels) are provided in Table 2.With an assumed recovery factor of 30%,an average value of 1,437,000, 000British thermal units (BTU)can be produced from this reservoir. Sealing is provided by the capping shales of the sequence (Figure 6). The shale is observed across the two wells. It is laterally continuous, thick and impermeable. Seal effectiveness is rated high in the absence of differential permeability.

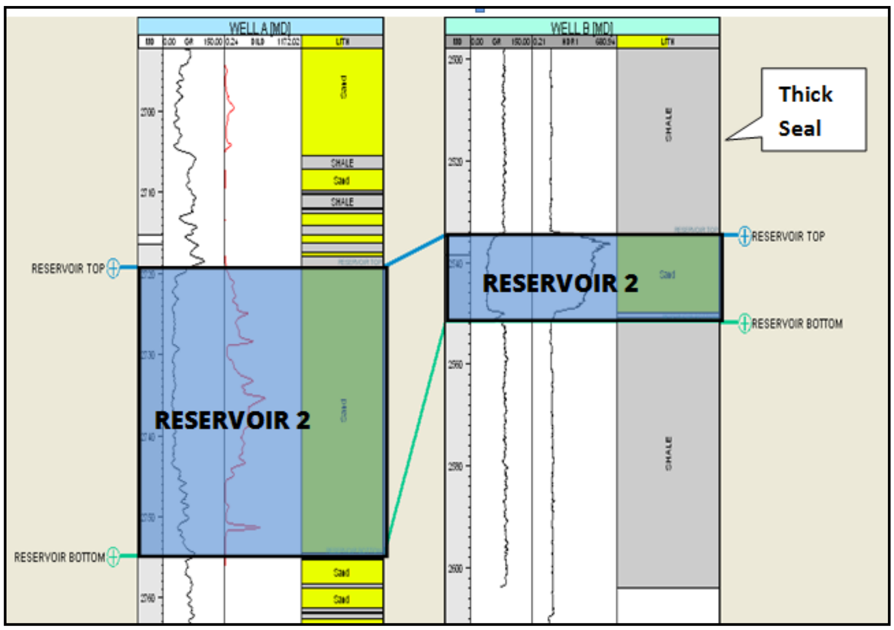

Figure 6: Reservoir 2 identification and seal analysis

Table 2: Reserve Estimate for Prospect 2

	PROSPECT	TOP (m) (ft)	BOTTOM (m)(ft)	GROSS THICKNESS (m)(ft)	NET THICKNESS (m)(ft)	N/G	Area (Acres)	POROSITY	HYDROCARBON SATURATION	GAS RESERVES (SCF)	GAS RESERVES (MMBTU)
TWO	P10	2719	2755	36 (118)	36 (118)	1.0	388.63	0.35	0.65	2,726,709	2,803,000,000
	P50	2600	2625	25 (82)	25 (82)	1.0	388.63	0.22	0.55	1,007,800	1,036,000,000
	P90	2534	2552	18 (59)	18 (59)	1.0	388.63	0.15	0.51	458,447	471,200,000

Figure 7 and 8 presents' prospect area 2, in terms of the trapping mechanism and reservoir area. There is evidence of minor faults on the seismic vertical sections. Structural closure reveals the prospect area on the time structure map in the central part of the field. The closure covers an area of about 388.63acres defined from the fluid contact map. Sonic and resistivity log were overlaid to test for the availability of organic rich rocks that could serve as source rock(Figure 9).The observed result is only diagnostic of water saturated organic lean rocks. Since the source presence is not established, it was included in the risk analysis section.

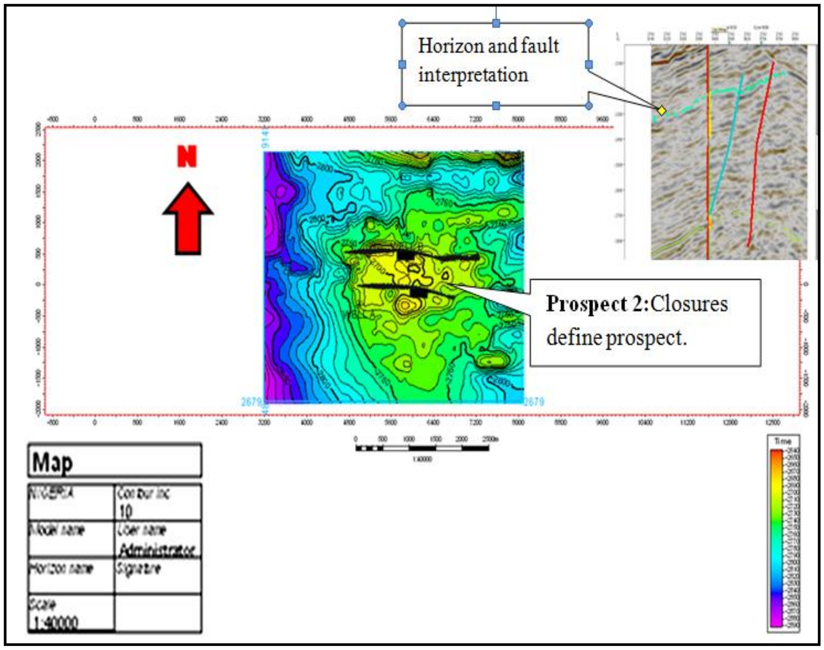

Figure 7: Prospects area 2 shown on the time structure map

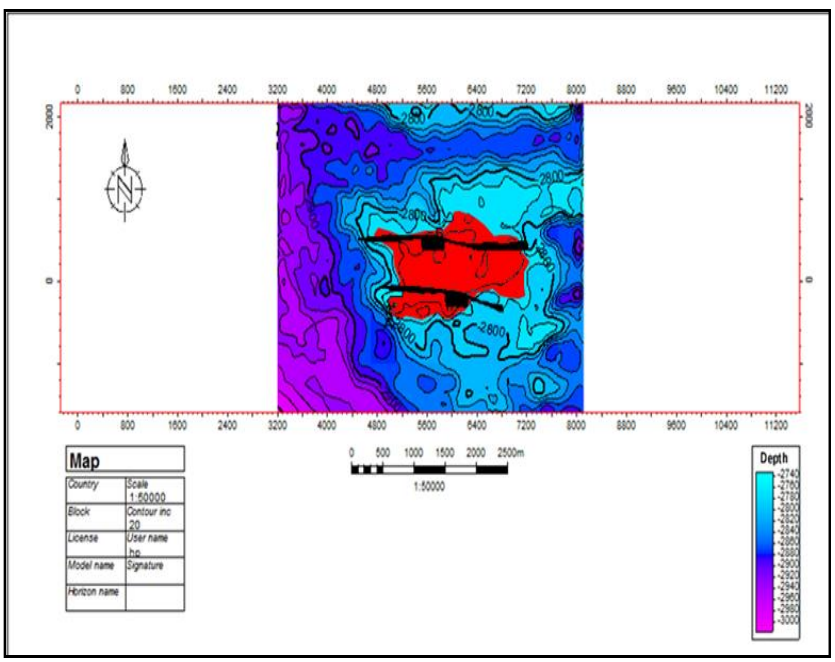

Figure 8: Depth structure map showing fluid contact

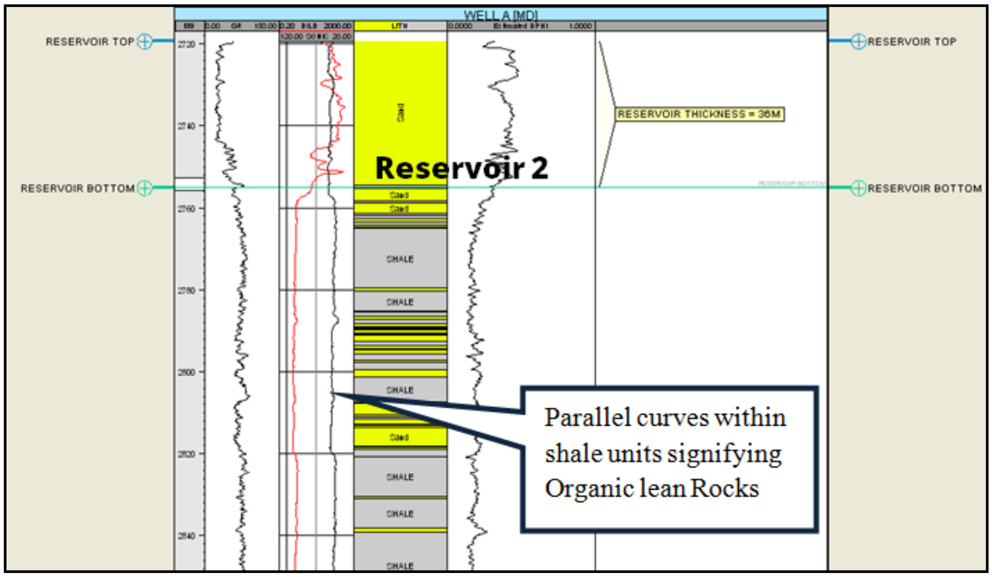

Figure 9: Source rock analysis for Reservoir 2

Risk analysis

The CCOP (Coordinating Committee for Coastal and Offshore Geoscience Programmes) guidelines for risk assessment of petroleum prospects have been introduced in this project to guide petroleum risking and reduce subjectivity. Table 3 is an example of a probability scheme from the CCOP guideline. It shows how the well log data, structural complexities available in an area and the quality of the seismic data, can be taken into consideration in risk assessment. It is clear from the discussions above that efficient structural closures have been mapped in the area. This is coupled with low structural complexities. Therefore, the probability of occurrence of a trap in the study area has been assigned a value range of 0.9-1.0. Invariably, this will mean that the risk associated with the effectiveness of the trapping system is low.

Table 3: CCOP table showing the probability Scheme of an effective trapping system

Seismic correlation and mapping \ Data reliability		3D-seismic	2D-seismic		
			Dense grid size	Open grid size	Very open grid
Good corr., nearby wells	Low structural complexity	0.9 - 1.0	0.9 - 1.0	0.8 - 1.0	0.7 - 0.9
	High structural complexity	0.7 - 1.0	0.6 - 0.9	0.5 - 0.8	0.4 - 0.7
	Low relief, uncertain depth conversion	0.6 - 0.9	0.5 - 0.8	0.4 - 0.7	0.3 - 0.6
Uncertain corr, distant wells	Low structural complexity	0.9 - 1.0	0.8 - 1.0	0.7 - 0.9	0.5 - 0.8
	High structural complexity	0.7 - 0.9	0.6 - 0.9	0.4 - 0.8	0.3 - 0.7
	Low relief, uncertain depth conversion	0.5 - 0.8	0.4 - 0.7	0.3 - 0.6	0.2 - 0.5
Unreliable corr. analogue model	Low structural complexity	0.9 - 1.0	0.7 - 1.0	0.6 - 0.8	0.4 - 0.7
	High structural complexity	0.4 - 0.7	0.3 - 0.6	0.2 - 0.5	0.1 - 0.4
	Low relief, uncertain depth conversion	0.3 - 0.7	0.2 - 0.6	0.1 - 0.5	0.1 - 0.4

Table 4 is a modified version of the CCOP tablet at summarizes assigned numerical values of probability of occurrence of the other petroleum system elements. This is arising from the occurrence/nonoccurrence of these system elements. From the analysis of data and the results shown in the table, the major geologic risk associated with the prospects is the dearth of a source rock (within the field) to recharge hydrocarbon volumes in reservoir 1 and 2. The source rock, based on Passey *et al.*, 1990 model, could not be established for these prospects within the field of study. Therefore, the risk associated with the source rock availability is high. The worst case scenario is to prefer a low probability of occurrence value that ranges between 0.1-0.3 on the CCOP guideline.

In terms of sealing capabilities in the area, for reservoir 1, the seal above the reservoir is interpreted to be effective because of the presence and dominance of thick impermeable units on top of the reservoir. They are expressed as simple seals. The probability that an effective seal is present has been valued to range from0.6-0.8 because limited data from well logs have been used to suggest the lateral continuity of the seals. However for the second reservoir, probability of occurrence of a seal in the area is rated between 0.3 and 0.4 because of combining nature of the seals (Table 4).

Table 4: Petroleum system probability scheme Adapted from CCOP, 2000

Probability of effective reservoir facies		**Direct data/proximal deposits**	**Direct data/more distal deposits**	**Limited data, discontinuous deposits**	**Indirect data, seismic sequence analysis**
Depositional Environment (Marine Environment)	Shallow marine, “blanket	0.9 - 1.0	0.7 - 0.8	0.6 - 0.7	0.4 - 0.6
	Coastal, deltaic, tidal	0.8-0.1	0.7 - 0.8	0.6 - 0.7	0.4 - 0.6
	Submarine fan	0.7-0.8	0.5 - 0.6	0.3 - 0.5	0.1 - 0.3
	Carbonates	0.8-1.0	0.6 - 0.8	0.5 - 0.7	0.3 - 0.5
Probability of an Effective seal mechanism		**Very Good**	**Good**	**Acceptable**	**Poor**
Simple Seal		0.9-1.0	0.8-1.0	0.6-0.8	0.4-0.6
Combined Seal		0.5-0.7	0.4-0.5	0.3-0.4	0.1-0.3
Probability of an effective source rock		Sufficient/marginal volume& Environment	Restricted marine environment	Mixed marine or lacustrine environment	Deltaic environment
Proven source rock		Marginal volume	0.5-0.8	0.4-0.7	0.4-0.7
Speculative source rock		Marginal mature	0.1-0.4	0.1-0.3	0.1-0.3

Reservoir facies on the other hand have been interpreted as deltaic facies, and direct data have been used from wells; thus, a corresponding probability of occurrence value that ranges between0.7-0.8 has been assigned for both reservoirs. Currently in the study, the migration pathway could not be analyzed and outlined due to the unavailability of source rock in the study area. However, generally the migration system in the Niger Delta for generated hydrocarbon probably occurred in phases with migration and remigration of earlier generated products (Ajakaiye, 2002).Therefore the lowest probability of occurrence can be chosen for the migration pathon the scale of probability of occurrence. If this is done, for reservoir 1, the average probability of success (POS) which represents the probability of discovery of a petroleum system in the area, obtained by taking the product of individual probabilities (of the trap, reservoir, source rock, migration and seal) is estimated to be0.01008. This value is judged to be very low on the scale of 0 to 1. The implication of this is that the risk associated with an effective petroleum system is high. This means that, even though hydrocarbon is present in large quantity, the recharge into the reservoir is not guaranteed.

On the other hand, the probability of success (POS) for reservoir 2 obtained by taking the product of individual probabilities of the presence of the trap, reservoir, source rock, migration and seal is estimated to be 0.00864.This value also reduces the geologic confidence of discovering hydrocarbon in place in the future.

Prospect Ranking

Prospect 1 is ranked well than prospect 2 because it has higher gross reservoir volume. Its reservoir thickness and area are sufficiently greater than that of prospect 2. Even though prospect 2 has a higher net/gross (1.0) signifying that reservoir uncertainties as a result of intercalated shale units are minimal, gas reserves obtained from prospect 1 is higher than that of prospect 2.In addition, in terms of risk analysis, the risks associated with each of the petroleum system elements are lower for prospect 1. The probability of success for prospect 1 is 0.01008 whereas that of prospect 2 is lower (0.00864) which depicts higher risks.

Conclusion

Two hydrocarbon prospect areas have been identified in ‘X ray’ field. The two hydrocarbon prospects are interpreted as closures on the structure maps. The three petroleum system elements: the source, the trap, and the seal were found to be present and effective. The presence of a source rock (a petroleum system element) in the field of study could not be established. This increases the risk that is associated with the petroleum system and creates a petroleum charge risk because the migration route cannot be known if the source rock is not identified. The probability of success (POS) is very low on a scale of 0-1, with the following values: 0.01008 and 0.00864 for reservoir 1 and 2 respectively. This geologic risk was estimated to be very high and reduces the geologic confidence that the field can produce hydrocarbon over a long period of time. The source rock charging the identified reservoirs in X ray field may be located in adjacent fields. Using probabilistic volumetric approach, reserve estimates for the two prospects reveal that an estimated average value of 38,620,000,000 BTU (37,892,707 scf) and 1,437,000,000 BTU (1,397,652 scf) of gas can be obtained from prospect 1 and 2 respectively. Despite the challenges that are related to the petroleum charge system, X ray field is believed to have a high hydrocarbon potential, given the high gross reservoir volume and reserves estimate. If more data are provided from fields, the presence of source rock may be established. Analysis of geochemical and biostratigraphic data within and outside the field is necessary for a reliable business decision.

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