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Monte Carlo (MC) Assessment of Structurally-Controlled Shallow Offshore "Teldomi" Reservoirs, Niger Delta, Nigeria - Inferences from 3D Seismic and Wireline Log Data

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Abstract
Monte Carlo Simulation (MCS) was used to assess the properties of three structurally controlled reservoirs namely, Reservoir A, Reservoir B, and Reservoir C in the study area. Geologically plausible ranges specified by the mean and standard deviation values of the initial petrophysical parameters of gross pay volume (GPV), net-to-gross (NTG), porosity (POR), and hydrocarbon saturation (S_h) were estimated from six wells and 3D seismic data. The MC simulation consisted of the generation of independent random values, representing the uncertainties constrained by a random probability distribution. For each randomly simulated combination of these parameters, original-oil-in-place (OOIP) was simulated. This process was repeated ten thousand (10000) times for each parameter after which the cumulative distribution functions (CDFs) for the simulated parameters were constructed from which summary statistics, risks and uncertainties were determined at P10 (downside), P25, P50, P75 and P90 (upside). Between the downside and upside probabilities, the GPV would be more than 13000 acre feet but less than 141000 acre-feet; the NTG would be more than 0.43 but less than 0.84; the porosity could be as low as 6% but not more than 29%; the hydrocarbon saturation would be more than 36% but less than 100%. At any given percentile, Reservoir C contains more hydrocarbon than the other two reservoirs but has the highest uncertainty. The three reservoirs would have more than 16 million barrels at P10, but not more than 111.5 million barrels combined in-place oil volume at P90. The results obtained can guide optimal future development decision on the reservoirs in the study area and thus confirmed MC simulation as veritable uncertainty modelling tool.
Keywords: Monte Carlo, Structural, 3D Seismic, Wireline Log, Reservoir

1. Introduction

Integration of subsurface data in assessing prospectivity of oil fields and improving decision making towards implementing viable development strategies is paramount to understanding possible economic returns on a company's assets. It is vital for optimum exploitation of reserves and utilization of company financial resources. These decisions regarding optimal hydrocarbon extraction and future production revenue are usually based on the models developed from sparse seismic and well log data. Such models have significant geological uncertainty related to the reservoir geometry and the distribution of petrophysical properties. These have the most direct effect on the production forecasts and so constitute greater basis for reservoir management decision-making. There are always many realizations of the reservoir - geological models and its fluid contents that are consistent with the observed and derived data from wells and seismic data processing, and each one of these valid interpretations could lead to significantly different assessments of future oil and gas production. Since the inherent uncertainties in deciding how much oil is present in a reservoir, and how much of this oil is ultimately recoverable, cannot be eliminated, it is incumbent to quantify these uncertainties as rigorously as possible and then manage them to arrive at an optimum development plan. The need to account for uncertainty in decision-making was identified very early, in the 1930s (Hayward, 1934). Probability theory, decision trees, Monte Carlo simulation and economic models were introduced for decision analysis in exploration (Grayson, 1960; Newendorp, 1975) and in development (Smith, 1970; McCray 1975) for cases where the uncertainty was characterized by probability distributions of the parameters involved, such as oil in place or production curve. For independent variables, if their probability distributions can be modelled as simple distributions, such as the uniform or triangular distribution, a final probability distribution of linear combinations of these variables can be evaluated analytically (Lerche, 1997). Monte Carlo is a powerful statistical method that may be applied to combine different types of uncertainty (Behrenbruch, Azinger, and Foley, 1989) and has been used extensively in the petroleum industry for decades in developing qualitative and quantitative insights and answers into a wide variety of the decisions involved in field development. It has been used for pressure transient analysis (Baldwin, 1969); reserves estimation (Huffman and Thompson, 1994); material balance analysis (Murtha, 1987); workover risk assessment (Wiggins and Zhang, 1993; Peterson, Murtha, and Schneider, 1995; Komlosi, 2001); project evaluation (Gilman, Brickey and Redd, 1998; Galli, Armstrong and Jehl, 1999; Kokolis, Litvak, Rapp and Wang, 1999) and even fracture-characteristic investigation (Han, Kang and Choe, 2001). It is a tool that yields probability versus value relationships for key parameters, including oil and gas reserves, capital exposure and economic yardsticks after considering many possible iterations (Murtha, 1997). The results of the simulation are various descriptive statistics, charts and graphs and percentiles which ultimately help with the decision making process.

This study seeks to evaluate the probable original-oil in place estimates of suspected structurally controlled hydrocarbon reservoirs using Monte Carlo simulation techniques on parameters derived from well log and 3D seismic data. This is with the view to proposing scientifically informed decisions as to the future development of the hydrocarbon reservoirs. The result is expected to improve our understanding of the subsurface characteristics of the reservoirs, the trapping relationships that favour the accumulation of hydrocarbon in the field and their associated uncertainties.

2. Regional Geology of the Study Area

The "Teldomi" area is a hypothetical name for a real location in Niger Delta basin. The real name has been concealed for proprietary reasons. The Niger Delta basin has been described by several authors. It is situated on the Gulf of Guinea on the west coast of central Africa (Figure 1) and forms one of the world's major hydrocarbon provinces (Doust and Omatsola, 1990). It is situated at the intersection of the Benue Trough and the South Atlantic Ocean where a triple junction developed during the separation of South America from Africa (Burke, 1972; Whiteman, 1982). It covers an area of about 75000km^2 and is composed of an overall regressive clastic sequence, which reaches a maximum thickness of 30000 - 40000 ft (9000 - 12000 m). The Niger Delta extends from about longitudes 3^o – 9^o E and latitudes 4^{o}30' – 5^{o}20' N. It is a large, arcuate delta of the destructive, wave-dominated type (Petroleum Inspectorate, 1985).

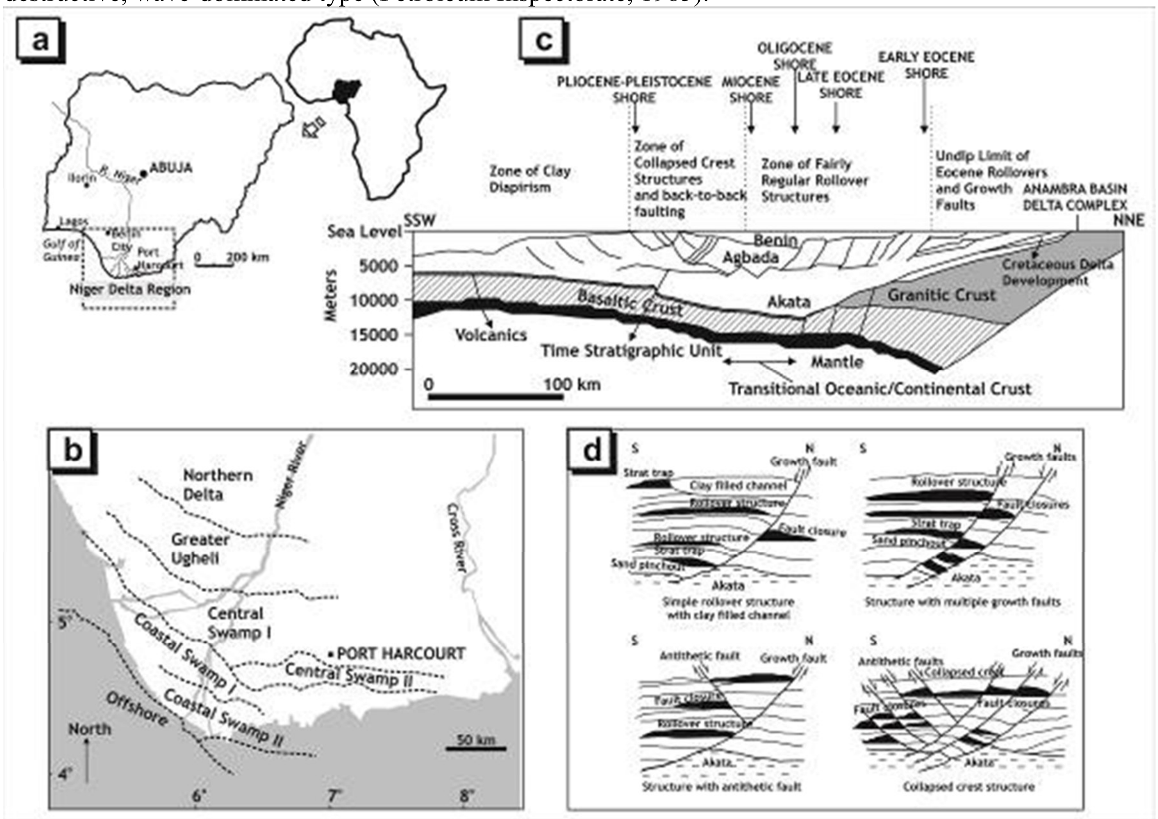

Figure 1. Showing (a) the location of the Niger Delta Region in Nigeria, (b) escalator-like geometry forming six depobelts (after Knox and Omatsola 1989; Doust and Omatsola, 1990) (c) schematic dip section of the Niger Delta after Kamerling in Weber and Daukoru 1975 and (d) principal types of oilfield structures in the Niger Delta with schematic indications of common trapping configurations after Weber and Daukoru, 1975.

The Tertiary sediments of the Niger Delta Basin were deposited in three major sequences. The sequence consists of uniformly developed dark grey shale, the Akata shale that ranges in age from Eocene to Recent. This is overlain by a dominant marine sand-shale sequence, the Agbada Formation which is the main objective in the exploration for oil in southern Nigeria. Hydrocarbons have been found in the Agbada Formation from Eocene to probably Pliocene-Pleistocene age (Petroleum Inspectorate, 1985). The youngest sequence, the Benin Formation is predominantly massive continental sand whose age ranges from Eocene to Recent (Petroleum Inspectorate, 1985). The southward progradation of the Niger Delta was accomplished by a stepwise build-out of fluvio-marine offlap sequences controlled by subsidence along synsedimentary faults, and punctuated by rapid shifts from depobelts to the next. These sudden shifts, recognized by the rapid seaward advance of alluvial sands over the thick paralic sequence, form the escalator regressive style (Knox and Omatsola, 1989). The main characteristic of this regression – the rapid advance of alluvial sands – is due to the cessation of subsidence in a depobelt and the continuation of sediment supply (Doust and Omatsola, 1990). The Niger Delta holds enormous petroleum reserves. Oil and gas reserves in the Niger Delta basin mainly occur in the sandstone reservoirs throughout the Agbada Formation. The Agbada Formation is defined by synsedimentary faulting formed as a result of variable rate of subsidence and supply and correspond to break in regional dip of the delta, bounded landward by growth faults and seaward by large counter-regional faults (Weber and Daukoru, 1975; Evamy et al. 1978; Doust and Omatsola, 1990). These synsedimentary structures include simple non-faulted anticline roll over structures, faulted roll over anticline with multiple growth faults, complicated collapse crest structures, sub-parallel growth fault and structural closures along back of major faults (Weber and Daukoru, 1975; Evamy et al, 1978; Nton and Adesina, 2009). In addition to growth fault-related structural traps, stratigraphic traps related to palaeo-channel fills, regional sand pinch outs and truncations occur. The gross reservoir properties are a function of depth, sand/shale ratio and sealing potential of faults, whilst the transgressive marine shales form important regional top seals with faults often providing lateral seals. Because of stacked sand/shale alternations, most oil fields in the Niger Delta have multiple reservoir levels with oil column height averaging between 15 to 50 m. Exceptionally, longer columns do exist under favourable (fault) sealing conditions and/or in Stratigraphic traps (Reijers, 1996). Mature Eocene to Miocene shales of the Akata and Agbada Formations constitute the major source rocks.

The southward progradation of the Niger Delta was accomplished by a stepwise build-out of fluvio-marine offlap sequences controlled by subsidence along synsedimentary faults, and punctuated by rapid shifts from depobelts to the next. These sudden shifts, recognized by the rapid seaward advance of alluvial sands over the thick paralic sequence, form the escalator regressive style (Knox and Omatsola, 1989). The main characteristic of this regression – the rapid advance of alluvial sands – is due to the cessation of subsidence in a depobelt and the continuation of sediment supply. Regressive “pulses” are so rapid in many depobelt that it is impossible to recognize any significant age difference at the base of the alluvial sand section between the northern and southern parts of each depobelt. The base of alluvial sands in adjacent depobelts becomes younger as one moves southward across the delta, however, and thus an escalator-like geometry for the base of this horizon becomes apparent (Doust and Omatsola, 1990). The Niger Delta holds enormous petroleum reserves which mainly occur in the sandstone reservoirs throughout the Agbada Formation, usually trapped in faulted (rollover) anticlines associated with growth faults. In addition to growth fault-related structural traps, Stratigraphic traps related to palaeo-channel fills, regional sand pinch outs and truncations occur. The gross reservoir properties are a function of depth, sand/shale ratio and sealing potential of faults, whilst the transgressive marine shales form important regional top seals with faults often providing lateral seals. Because of stacked sand/shale alternations, most oil fields in the Niger Delta have multiple reservoir levels with oil column height averaging between 15 to 50 m (Reijers, 1996). Mature Eocene to Miocene shales of the Akata and Agbada Formations constitute the major source rocks (Evamy et al., 1978). Niger Delta crudes originate mostly from land plant materials; hence, they are high in resins and waxes with significant contributions of organic matter from marine sources. The low sulphur content of the Nigerian Crudes (below 0.4%) also confirms land plant source material.

3. Methodology

3.1 The Nature of the Data

Seismic and wireline log data were used for this research. The seismic data are a three-dimensional (3D) multiple fold, stacked and migrated seismic data. The well data consist of six wells. The wells are named Teldomi-01, Teldomi-02, Teldomi-03, Teldomi-04, Teldomi-05 and Teldomi-06. Teldomi-01 was drilled to a total depth (TD) of 13020 ft (3968.5 m) with a Kelly Bushing (KB) of 46.5 ft (14.2 m); Teldomi-02 was drilled to total depth (TD) of 11669.1 ft (3556.7 m) using KB of 45.93 ft (14.0 m); Teldomi-03 is a sidetracked hole drilled to a (TD) of 12090 ft (3685.0 m) with KB of 45 ft (13.7 m); Teldomi-04 was to a (TD) of 11440 ft (3486.9 m) with KB of 42 ft (12.8 m); Teldomi-05 was drilled to a (TD) of 11700 ft (3566.2 m) with KB of 45 ft (13.7 m); and Teldomi-06, a deviated hole was drilled to a total depth of 13310 ft (4056.9 m) with a 34.4 ft (10.5 m) of KB. Gamma ray (GR), Resistivity (RES), Effective Porosity (PHIE) and Water Saturation (S_W) logs were provided or calculated at the selected hydrocarbon intervals.

3.2 Identification and Correlation of Hydrocarbon Bearing Zones

The GR log was used to delineate the sand-shale intervals in the wells using 60 API as the cutoff. GR values above 60 API correspond to shale while GR values below 60 API correspond to sand. The resistivity log (RES) was used to narrow down to the pay intervals, which formed the basis of delineating three hydrocarbon bearing reservoirs, namely Reservoir A (R_A), Reservoir B (R_B) and Reservoir C (R_C). R_A is the shallowest at an average depth of -9518.90 ft subsea (SS), R_B is at average depth of -10604.89 ft SS; while R_C is the deepest at average depth of -11146.99 ft SS. These sands were correlated in a West - East direction. The average gross pay (GPay), net-to-gross (NTG), porosity (POR) and hydrocarbon saturation (S_h) were estimated for the three reservoirs from the well logs directly in most cases. Wherever any of these logs was not provided, the basic parameters were estimated using a variety of equations (Archie, 1942; Dresser Atlas, 1979; Asquith and Gibson, 1982; Asquith, 1990).

3.3 Integration Seismic

Major faults were mapped on the seismic sections and correlated across the study area. Two horizons corresponding to near the tops of R_A and R_C were mapped as Teldomi_H_1 and Teldomi_H_2 on the seismic sections and were used along with the fault framework to produce both time and depth structural maps. The structural maps provide relationship that exists between the faults and folds beneath the study area (Tearpock and Bischke, 1991). For the purpose of this study, the content of each prospect was assumed to be oil and the petrophysical properties estimated from the analysis of the well logs from the drilled structures T_1 and T_2 were assumed to be constant for the prospects delineated on Horizons Teldomi_H_1 and Teldomi_H_2 respectively. The prospects were planimetered to obtain the area extent of the gross pays and a rough oil-originally-in-place (OOIP) was estimated for each prospect (Singh et al. 2009). To further delimit the hydrocarbon extents, the root-mean-square amplitude attribute was extracted from the seismic sections at 20 ms time-window covering Teldomi_H_2 (Reservoir C). This was done in order to analyze the attribute changes and relate them possibly to changing reservoir properties away from well control on Teldomi_H_2 across the field. The extraction of seismic attributes is a means of analyzing seismic data from different points of view which often results in new insight and the discovery of relationships not otherwise evident (Sheriff, 1978; Brown, 1996). Seismic attributes generally correlate to certain physical properties of interest and they enhance the visualization of features, relationships and pattern that may not be clearly seen on conventional seismic interpretation. Moreover, in using a sampling window, it was recognized that the seismic signals, by its physical nature, tend to disperse information generated by a localized reflector throughout a larger volume of recorded amplitude data feature (Hotteling, 1933; Hagen, 1982; Grubb and Warden, 1997; Scheevel & Payrazyan, 1999 and Liu et al., 2004). Therefore, to recover all reflection information about a localized, finely-layered feature in the subsurface, and for the purpose of predicting reservoir properties away from well control, the analysis covered the sub-volume 20 ms that may reasonably contain the spread-out reflection information.

3.4 Monte Carlo Simulation (MCS)

Monte Carlo simulation (MCS) builds models of possible results by substituting a range of values—a probability distribution—for any factor that has inherent uncertainty. It calculates results over and over, each time using a different set of random values from the probability functions and the result is a probability distribution of possible outcomes (Zhang, 2003). The Monte Carlo method was applied in this study with the understanding that OOIP, a dependent variable is a function of some independent variables (gross pay volume, net-to-gross, porosity, and hydrocarbon saturation). The oil-originally-in-place (OOIP) for each reservoir was obtained from Singh et al., 2009 given as.

$$OOIP = 7758 * GPV * N/G * \phi * (1 - Sw)/FVF \tag{1}$$

Where GPV = gross pay volume, N/G = net to gross thickness, ϕ = porosity, Sw = water saturation, FVF = formation volume factor. The FVF of 2.0425 for oil being the average value for light crude with API > 35 was assumed (Azubuike and Ikiensikimama, 2013).

The GPV was determined by multiplying the average gross thickness obtained from the logs with the areas of the structural traps obtained from the structural maps of the two horizons. The gross pay areas of the R_A and R_C were obtained by planimetry from their structural maps while that of R_B was calculated from the average areas of R_A and R_C. Areas for R_A, R_B and R_C are 883.803 acres, 903.272 acres and 922.740 acres respectively. The OOIP is the dependent variable; while gross pay volume (GPV), net-to-gross (NTG), porosity (POR), and hydrocarbon saturation (S_h) are the independent variables. The oil formation volume factor (FVF) of 2.0425 bbl/stb was used being the average value of FVF for light crude that ranges from 1.082 to 3.003 bbl/stb (Azubuike and Ikiensikimama, 2013). Based on the assumptions that the intervals are oil bearing and the assessed petrophysical parameters are randomly distributed, a random number generator RAND() embedded in NORM.INV function in Matlab software version 7.12.0.635 was used to generate random numbers for all the independent variables from the estimated probability density parameters (means and standard deviations) for each reservoir. Given a value of probability, the NORM.INV function, seeks that random value X such that NORM.DIST (X, mean, standard_dev, TRUE) = probability. Where X is a random number specified by RAND(). For each randomly simulated combination of these parameters, oil-in-place was simulated. This process was repeated ten thousand (10000) times for each parameter after which the cumulative distribution functions (CDFs) for the simulated parameters were constructed from which summary statistics, risks and uncertainties were determined at P10 (downside), P25, P50, P75 and P90 (upside). These are probabilities of obtaining more than the simulated parameters.

4. Discussion of Results

4.1 Hydrocarbon Bearing Reservoirs

Figure 2 shows the correlation of the delineated hydrocarbon reservoirs while Table 1 indicates the deterministic distributions of the properties of the three reservoirs from the available wells. Reservoir A occurs at an approximate depth of -9518.90 SS ft. It is the shallowest of the three hydrocarbon reservoirs. It has an average gross pay (hydrocarbon thickness) of about 38.45 ft and an average net-to-gross pay ratio of about 63%. The average porosity (POR) is 18% while the average hydrocarbon saturation (S_h) is about 68%. Reservoir B occurs at an approximate depth of -10604.89 SS ft. It is about 1100 ft deeper than Sand A. It has an average gross pay of about 48.45 ft and a net-to-gross of about 64%. The POR is about 22% while the hydrocarbon saturation (S_h) is 73%. Reservoir C is the deepest and occurs at an approximate average depth of -11146.99 SS ft. It is just about 540 ft deeper than Reservoir B. It has an average gross pay of about 90.77 ft and NTG of about 64% with porosity of about 20% and hydrocarbon saturation (S_h) of about 80%. The three hydrocarbon reservoirs seem to possess desirable hydrocarbon properties but the standard deviations of the various parameters indicate certain level of variability that may affect future development of the reservoirs. This is because Reservoir A has a GPay with a standard deviation of 17.65 ft constituting about ±46% variation; the NTG varies by ±21%; the porosity varies by ±50% while the hydrocarbon saturation varies by ±37%. In Reservoir B, the GPay varies by ±37%; the NTG by ±25%; the Por by ±18% while the hydrocarbon saturation varies by ±21%. Reservoir C, however, has a GPay that varies by more than ±50%; NTG by about ±20%; the Por by about ±16% while the hydrocarbon saturation varies by about ±19%. The inherent variations in the properties of the reservoirs make it illogical to depend on the deterministic results only (Goovaerts, 1997; (Caers *et al*., 2003).

4.2 Structures and Prospects

The top of Reservoir A is approximated by Horizon_Teldomi_H1 (upper horizon) (Figure 3a) and varies from 7790 ft in the far northeastern part to over 10500 ft in the southwestern part of the area (Figure 3b). While the top of Reservoir C is approximated by Horizon_Teldomi_H2 (deeper horizon) (Figure 3a) and varies from 8600 ft in the far northeastern part to over 12000 ft in the southwestern part of the area (Figure 3c). There are three major structure building faults labeled as FF1, FF2 and FF3; and some antithetic faults such as faults FF5 and FF6 mapped alongside anticlinal structures in the study area (Figures 3b and 3c). Faults FF1, FF2 and FF3 are extensive; they trend Northwest-Southeast and dip in the southwest direction. Faults FF5, and FF6 are two antithetic faults acting against faults FF2 and FF3 respectively. Each of FF5 and FF6 trends approximately Southwest-Northeast direction and dipping towards Northwest direction. These faults act alongside the anticlines to form traps.

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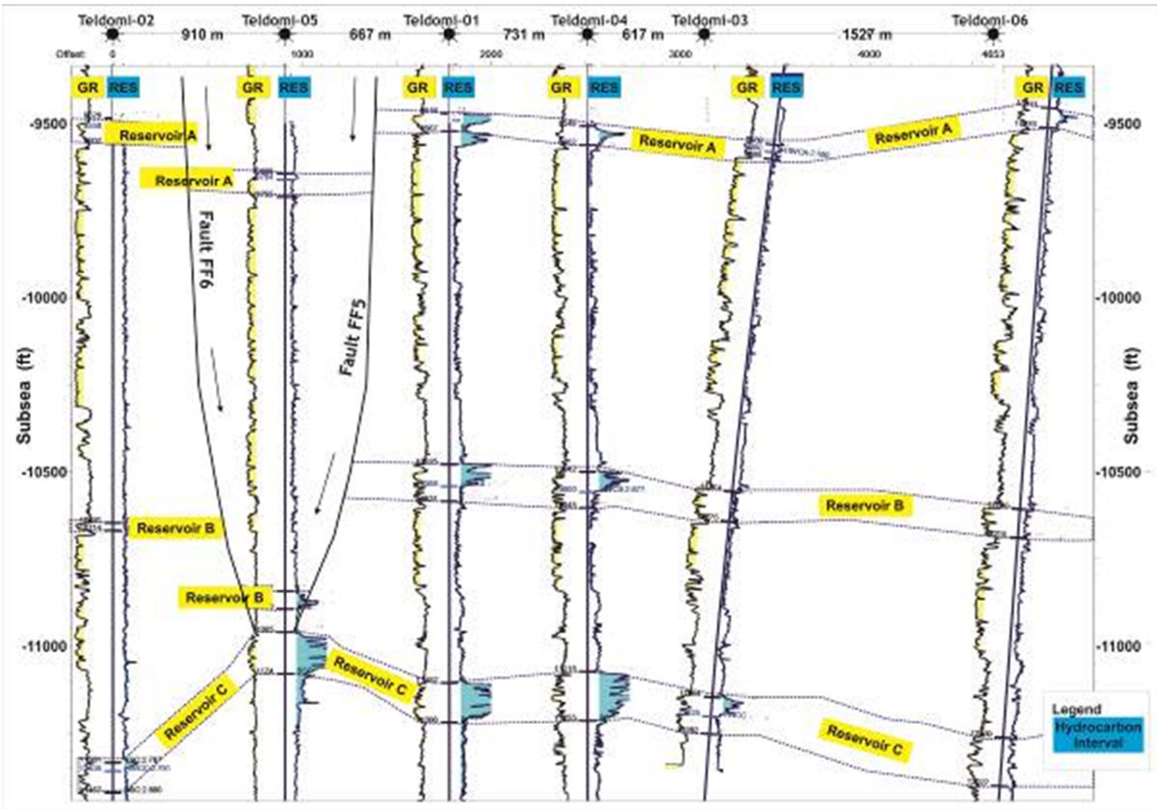

Figure 2. Geologic cross section of the six wells showing three main reservoirs with respect to depth from the signatures of Gamma Ray (GR) and Resistivity (RES) logs

Table 1: Deterministic Characteristics of the Hydrocarbon Reservoirs

Depth Range	***Reservoir A*** **(9453.42 – 9659.47) ft**		***Reservoir B*** **(10478.82 – 10892.71) ft**		***Reservoir C*** **(10959.67 - 11402.46) ft**	
Input Parameters	***Mean***	***Std***	***Mean***	***Std***	***Mean***	***Std***
GROSS Pay (GPay)	38.45	17.65	48.28	18.03	90.77	48.71
Net-to-Gross (NTG)	0.63	0.13	0.64	0.16	0.64	0.13
Porosity (POR)	0.18	0.09	0.22	0.04	0.20	0.04
Hydrocarbon Saturation (S_h)	0.68	0.25	0.73	0.15	0.80	0.15

Std – Standard deviation

There are four likely prospects on the upper horizon, namely, A, B, C and D with T_1 representing a drilled structure with discoveries at about 9500 ft (Figure 3b). Prospect A is the deepest of the prospects occurring at about 10200 ft and located downdip of FF1. It has gross pay area (GPA) of about 556 acres (Table 2); Prospect B is about 9600 ft deep and it is a four way dip closure sandwiched between FF1 and FF2. Its gross pay area about 57 acres. Its hydrocarbon could be spilling to feed the drilled structure T_1. Prospect C is also a four-way dip closure sandwiched between the upthrown side of Fault FF2 and downthrown side of Fault FF3. It is at depth of 8500 ft with gross pay area of about 1419 acres. Prospect D is the shallowest of the prospects at depth 7800 ft located in the far northeastern part of the study area and sandwiched between upthrown part of FF3 and upthrown part of FF4. It looks like a collapsed crestal structure with probable gross pay area of about 125 acres. The structures and faults on this horizon generally trend in the northwest-southeast direction.

There are three likely prospects on the deeper horizon, namely, E, F, and G and one drilled structure T_2 occurring at average depth of 11140 ft with GPA of 923 acres (Figure 3c). Prospect E, F, and G have similar characteristics (shape and trend) to prospect B, C and D respectively in the upper horizon (Figure 3b).

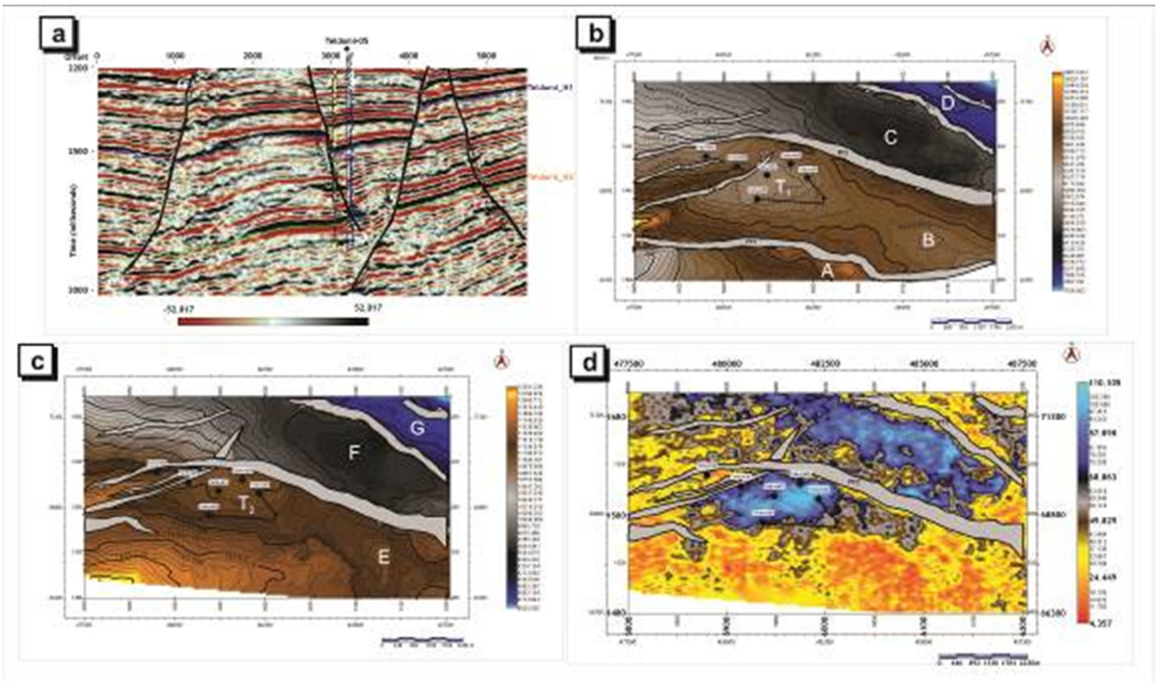

Figure 3: Showing (a) seismic section showing one of the wells and two picked horizons (b) depth structural maps of horizon (Teldomi_H1) (c) depth structural map of Teldomi_H2 and (d) windowed root-mean-square amplitude map through Teldomi_H2

Prospect E is the deepest occurring at about 11200 ft with gross pay area (GPA) of about 253 acres (Table 2). Prospect F occurs at about 9600 ft with GPA of 1859 acres. The shallowest prospect on this horizon is prospect G which occurs at about 8700 ft and 266 acres GPA. The trends and dips of the structures are the same as in the first horizon. These delineated structural patterns are common hydrocarbon traps in the Niger Delta (Weber and Daukoru, 1975; Evamy et al., 1978; Knox and Omatsola, 1989; Doust and Omatsola, 1990). Based on the Gross Pay Area alone (Table 2) and with all other parameters for each horizon remaining constant, it is expected that Prospect C would contribute the highest volume (47%) to the upper horizon while prospect B would contribute the lowest (2%). On the other hand, Prospect F would contribute highest volume (56%) to the deeper horizon while prospect E would contribute the lowest (8%). It is expected that the contributions of Prospect B and Prospect E would further deplete if production is initiated on the drilled structures T_1 and T_2 on the upper and deeper horizons respectively. Prospects C, F and the drilled structure T_2 would contribute about 76% of the hydrocarbon volume that might be encountered between the two horizons (Table 2).

Table 2: The Areal Characteristics of the Prospects and Drilled Structures

Prospect	***Drilled Structure with Discoveries***	***AREA***	***% Contribution***
	Upper Horizon – Teldomi_H1		
C		1418.86	0.47
	T_1	883.8	0.29
A		555.69	0.18
D		125.67	0.04
B		57.24	0.02
	Deeper Horizon – Teldomi_H2		
F		1859.44	0.56
	T_2	922.74	0.28
G		265.86	0.08
E		253.26	0.08

The root-mean-square amplitude attribute results over the deeper horizon reveal characteristic patterns of high and low amplitude areas (Figure 3d). The low amplitude portion is considered as the background amplitude, while the high amplitude portion is the anomalous amplitude. The high amplitude zone on the downthrown side of FF2 falls within the top of the drilled structure where the occurrence of hydrocarbon has been confirmed whereas the high amplitude on the upthrown side of FF2 falls on the undrilled structure (Prospect F). Similarly, the high amplitude on the upthrown side of FF4 falls on Prospect G. This was interpreted as having similar characteristics in terms of the lithologic and fluid content since hydrocarbon has been confirmed on T_2. This is an example of how attributes may be used to delineate prospects (Chen and Sydney, 1997; Sheriff, 1978; Fournier and Derain, 1995; Chambers and Yarus 2002).

4.3 Uncertainties and Risks

The probabilities of exceeding certain reservoir parameters thresholds are presented in Table 3 and Figure 4). P90 is the allowable upside while P10 is the allowable downside. There is a 90% chance of having more than (P10) 13.9, 22.8 and 26.1 thousand acre-feet for Reservoir A, Reservoir B and Reservoir C respectively. Conversely, there is 90% chance of having less than (P90) 53.6 thousand, 64.1 thousand and 141.4 thousand acre-feet of GPV from the three reservoirs. There is a 10% chance of having Net-to-gross more than 0.45, 0.43 and 047; and 90% chance of having less than 0.79, 0.84 and 0.81 respectively for Reservoirs A, B and C respectively. Porosity would vary at 10% probability for the three reservoirs at 6%, 16% and 15%; and not more than 29%, 28% and 25% at 90% probability respectively.

Table 3: Probabilistic Reservoir Parameters and Volumes at Certain Risk Levels

Probability	***Reservoir A***	***Reservoir B***	***Reservoir C***
		Gross Pay Volume (Acre-feet)	
P10	13,995.88	22,871.32	26,095.28
P25	23,702.99	32,649.79	53,219.69
P50	34,115.46	43,724.88	83,428.62
P75	44,227.21	54,675.02	113,857.42
P90	53,567.71	64,063.70	141,354.13
		Net-to-Gross (NTG) in fractions	
P10	0.45	0.43	0.47
P25	0.53	0.53	0.55
P50	0.63	0.64	0.64
P75	0.63	0.64	0.64
P90	0.79	0.84	0.81
		Porosity (POR) in fractions	
P10	0.06	0.16	0.15
P25	0.11	0.19	0.17
P50	0.18	0.22	0.20
P75	0.24	0.25	0.23
P90	0.29	0.28	0.25
		Hydrocarbon Saturations (Sh) in fractions	
P10	0.36	0.53	0.61
P25	0.51	0.63	0.70
P50	0.68	0.73	0.80
P75	0.85	0.84	0.90
P90	1.01	0.93	0.99
		Oil-Originally-in-Place OOIP in barrels	
P10	1,201,574.12	6,564,090.21	8,342,369.78
P25	3,616,491.72	10,234,972.51	17,641,764.58
P50	7,695,379.72	15,406,695.33	29,466,608.95
P75	13,532,187.71	22,164,059.88	44,320,303.72
P90	20,747,862.16	29,866,708.16	60,851,096.26

Hydrocarbon saturation would not be less than 36%, 53% and 61% for the three reservoirs at 10% probability to maximum saturation at P90. The random combination of these parameters suggests that there is a 90% probability of having original-oil-initially in place more than 1.2, 6.6 and 8.3 million barrels respectively for the three reservoir but less than 20.7, 29.9 and 60.6 million barrels respectively. In other words, between the downside and upside probabilities, the gross pay volume GRP would be 90% more than 13000 acre feet but less than 141000 acre-feet; the NTG would be 90% more than 0.43 but less than 0.84; the porosity could be as low as 6% but not more than 29%; the hydrocarbon saturation would be more than 36% but less than 100%. At any given percentile, Reservoir C contains more hydrocarbon than the other two reservoirs but has the highest uncertainty. The three reservoirs would have more than 16 million barrels, but not more than 111.5 million barrels combined in-place hydrocarbon volume.

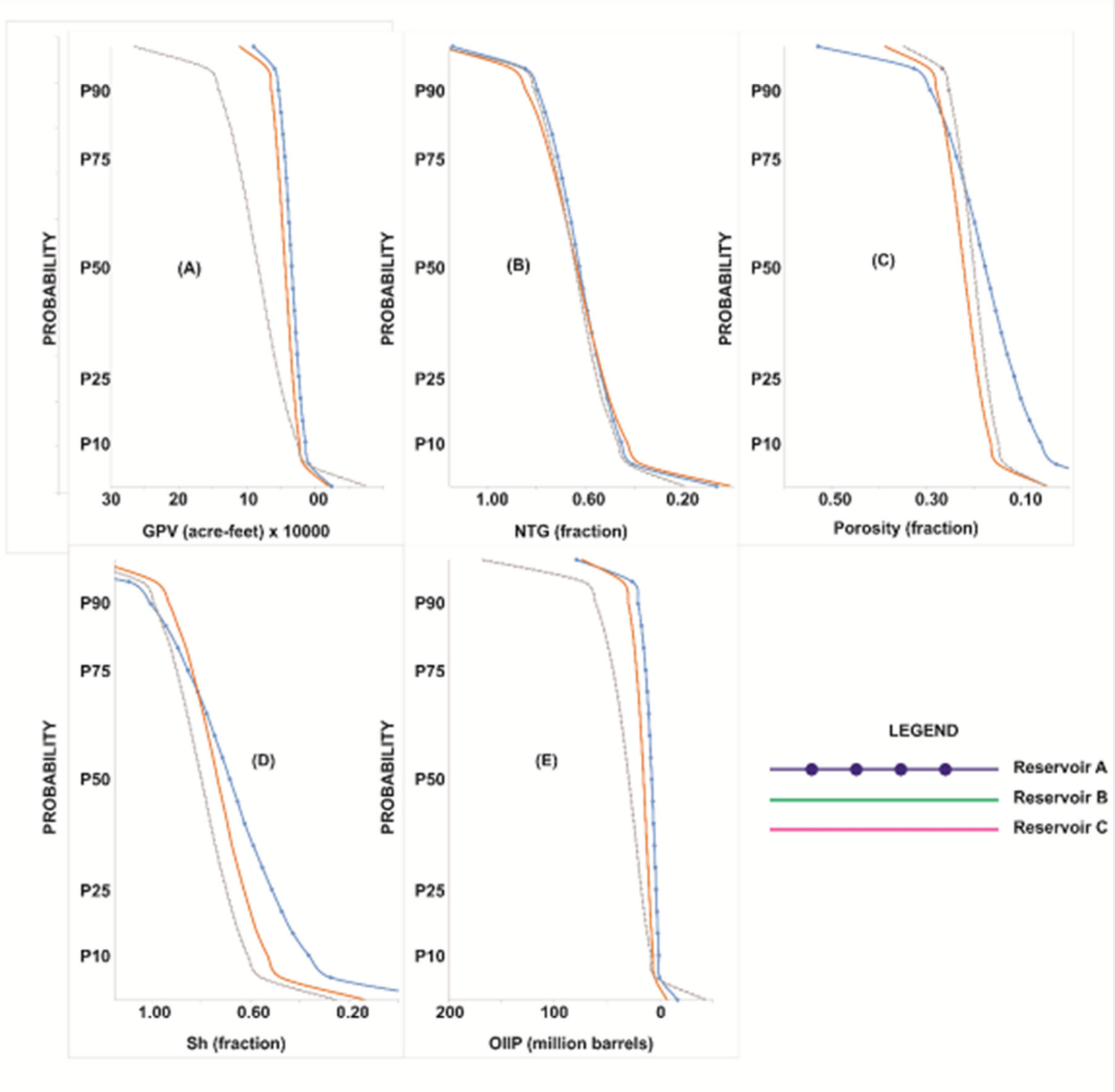

Figure 4: Risk distribution of the simulated parameters (gross pay volume GPV, Net-to-gross NTG, porosity POR, hydrocarbon saturation Sh and original oil-in-place OOIP) for Reservoirs A, B, and C.

5. Conclusion

This study has evaluated five main parameters (GPV, NTG, POR, Sh and OOIP) of three structurally controlled hydrocarbon reservoirs from available well log and 3D seismic data using the Monte Carlo Simulation technique. The subsurface characteristics of the reservoirs, the trapping relationships that favour the accumulation of hydrocarbon in the field were delineated and associated uncertainties were quantified. The information derived from this study can be managed for optimal hydrocarbon extraction in the study area.

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