IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)
e-ISSN: 2321–0990, p-ISSN: 2321–0982.Volume 8, Issue 1 Ser. III (Jan – Feb 2020), PP 34-40
www.iosrjournals.org

Deterministic Hydrocarbon Volume Estimation in the OnshoreFuba Field Niger Delta, Nigeria

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Abstract: *Deterministic hydrocarbon volume estimation is applied to predict hydrocarbon volume initially in place in Fuba Field Onshore Niger Delta, Nigeria using Well-log and seismic data. Well-to-seismic-ties, faults and horizon mapping, time surface generation, velocity modelling and depth conversion were carried out using Petrel software while uncertainty analysis was carried out using Crystal Ball Monte Carlo simulation software. The reserves estimated using the deterministic approach were 18.52MMSTB,13.59MMSTB, 9.40MMSTB, for the high, base and low cases of reservoir A while that of reservoir I was 25.56MMSTB, 14.59MMSTB and 7.63MMSTB for the high, base and low cases showing that there is a significant difference between the high, low and base case volumes of both A and I reservoirs. The large difference in the low case, base case and high case hydrocarbon volumes calculated is attributed to the reservoir's bulk volume. The bulk volume accounts for 85.9% and 86.1% of the total uncertainty surrounding the estimated hydrocarbon volumes in reservoir A and reservoir I respectively. The low case is recommended asit has a lower uncertainty of finding hydrocarbon. The advantages of deterministic approach over other methods include the following using mathematical formulas for estimating oil volumes in a reservoir, each parameter is presented with a single value. Moreoverdeterministic calculation makes use ofparameters used in the calculation.Models perform same way for a given set of parameters and initial conditions and their solution is unique. The results of this work can be used to estimate HC volume in the study area.*

Keywords: *Hydrocarbon,Deterministic, Volumetric Estimation, Reservoir, Niger Delta, Nigeria.*

Date of Submission: 24-02-2020 Date of Acceptance: 07-03-2020

I. Introduction

Estimation of hydrocarbon initially in place (HIIP) is a critical issue for both economic and technological aspects of Petroleum industry. In reservoir management, making decisions requires a method for quantifying uncertainty. It is possible to run sophisticated calculations that were previously impossible to perform by development of computational instruments. In the case of deterministic method, mathematical formulas are used to estimate oil volumes or reserves [7]. Deterministic methods use single-point parameters to obtain reserves [12]. The deterministic method will commonly be used to give a 'best estimate' or 'most likely' case, but it can also be used to generate 'high-side' and 'low-side' hydrocarbon volumes [2]. An improved Deterministic value is scenario approach, where we can produce three values for each parameter, low, best and high value [6]. Each of these categories can be related to specific areas or volumes in the reservoir and a specific development plan. The resulting volumetric uncertainty estimates can be used as input for material balance calculation [11] or for dynamic reservoir simulations which will provide a production forecast estimate with uncertainty. The production forecast in turn is used in economics or not proved volumecalculations and further transformed into riskinvolved in decisions [3].

The deterministic definitions, which have been used for years by both the SPE and SEC2, have limited the proved area to "the area defined by fluid contacts". In the case of reservoirs where only a lowest-known hydrocarbon level exists, this restricts the proved volume to the absolute minimum insofar as the downdip limit is concerned [8].

In order to delineate areas containing geologically similar discoveries and prospects, play analysis is used. The yet-to-find (YTF) recoverable resource for a conventional play can be predicted using deterministic scenarios utilizing the fact that discoveries within a part play (or common risk segment) can be fitted to a lognormal distribution [5].

Assuming the part play works, a YTF scenario can be made with estimates of (i) the number of drillable prospects, (ii) the average prospect risk, (iii) the resource size of an upside discovery (based on the evaluation of a favoured prospect), and (iv) a downside resource from an implied P99 volume (based on historical data or calculation)[8]. Using low, median and high case scenarios, a range of YTF is then developed.

This case study is taken from Fuba field, Depobelt, Niger Delta, Nigeria. The ultimate deliverable of this study was hydrocarbon volume estimation using deterministic method in the area. The major components of our study are: (a) Well Correlation performed in order to determine the continuity of the reservoir sand across the field. (b) Seismic Interpretation which involves Seismic well tie, fault mapping, horizon mapping, time surface generation, velocity modelling, depth conversion and uncertainty analysis. This aids in giving more insight into deterministic hydrocarbon volume estimation.

II. Location and Geology of the Study Area

The study area Fuba field is located in the onshore Niger Delta region (Fig.1). Well logs and 3D seismic data were acquired from oilfields within the study area shown on the base map. The Niger Delta lies between latitudes 4° N and 6° N and longitudes 3° E and 9° E [13]. The Delta ranks as one of the major oil and gas provinces globally, with an estimated ultimate recovery of 40 billion barrels of oil and 40 trillion cubic feet of gas [1].The coastal sedimentary basin of Nigeria has been the scene of three depositional cycles [9]. The first began with a marine incursion in the middle Cretaceous and was terminated by a mild folding phase in Santonian time. The second included the growth of a proto-Niger delta during the Late Cretaceous and ended in a major Paleocene marine transgression. The third cycle, from Eocene to Recent, marked the continuous growth of the main Niger delta. A new threefold lithostratigraphic subdivision is introduced for the Niger delta subsurface, comprising an upper sandy Benin Formation, an intervening unit of alternating sandstone and shale named the Agbada Formation, and a lower shalyAkata Formation. These three units extend across the whole delta and each ranges in age from early Tertiary to Recent. They are related to the present outcrops and environments of deposition. A separate member of the Benin Formation is recognized in the Port Harcourt area. It is Miocene-Recent in age with a minimum thickness of more than 6,000ft (1829m) and made up of continental sands and sandstones (>90%) with few shale intercalations [4]. Subsurface structures are described as resulting from movement under the influence of gravity and their distribution is related to growth stages of the delta. Rollover anticlines in front of growth faults form the main objectives of oil exploration, the hydrocarbons being found in sandstone reservoirs of the Agbada Formation.

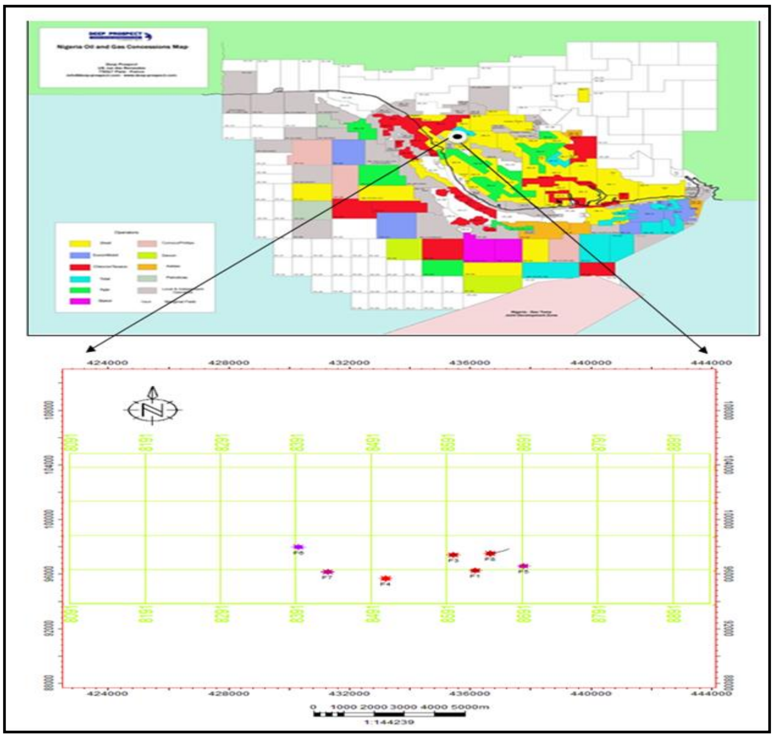

Figure 1: Map of Niger Delta Oilfields showing the location of Fuba Field

III. Materials and Methods

3.1 Well-to-Seismic Ties

Well correlation is the first stage of the pre-interpretation process.The process of well correlation involves lithologic description, picking top and base of sand-bodies, fluid discrimination and then linking these properties from one well to another based on similarity in trends. In between these two lithologies in the subsurface, the gamma ray log is often used. Correlation of reservoir sands was achieved using the top and base of reservoir sands picked. The correlation process was possible based on similarity in the behavior of the gamma ray log the Niger Delta; the predominant lithologies are sands and shales. In order to discriminate shapes. Also, the thickness of the shale bodies overlying and underlying the sand body is considered during Correlation. After defining the lithologies, the resistivity log was used for discriminating the type of fluid occurring within the pores in the rocks.

There are six basic steps involved in seismic interpretation relevant to this study and they include; Seismic well tie, Fault Mapping, Horizon mapping, Time surface generation, velocity Modelling, Depth Conversion and Uncertainty Analysis. Seismic well tie is a process that enables the visualization of well information on seismic data. For this process to be achieved, the following are basic requirements;checkshot, sonic log, density log and a wavelet. The sonic log, which is the reciprocal of velocity, was calibrated using the checkshot data. The calibration process is necessary in order to improve the quality of the sonic log because the sonic log is prone to washouts and other wellbore related issues. The results of calibrating the sonic log with the checkshot gives a new log called the calibrated sonic log.

The calibrated sonic log is used along with the density log to generate an acoustic impedance (AI) log. The acoustic impedance log is calculated for each layer of rock. The next step involves generating the reflectivity coefficient (RC) log. The RC is calculated and generated using the AI log. The RC log generated is then convolved with a wavelet to generate a synthetic seismogram which is comparable with the seismic data. The statistical wavelet utilized for convolution is extracted from the seismic data. The synthetic seismogram was generated for every well that had checkshot, density and sonic log. The reflections on the synthetic seismogram were matched with the reflections on seismic data. The mathematical expressions that govern the entire well-to-seismic tie workflow are presented below;

$$AI = \rho v AI = \rho v \tag{1}$$

$$RC = \frac{\rho_2 v_2 - \rho_1 v_1}{\rho_2 v_2 + \rho_1 v_1} RC = \frac{\rho_2 v_2 - \rho_1 v_1}{\rho_2 v_2 + \rho_1 v_1} \tag{2}$$

Synthetic Seismogram = $\frac{\rho_2 v_2 - \rho_1 v_1}{\rho_2 v_2 + \rho_1 v_1} * wavelet \frac{\rho_2 v_2 - \rho_1 v_1}{\rho_2 v_2 + \rho_1 v_1} * wavelet$ (3)

where ρ = density; v = velocity, AI = acoustic impedance, RC = reflection coefficient.

Faults were identified as discontinuities or breaks in the seismic reflections. Faults were mapped on both inline and cross-line directions. Horizons are continuous lateral reflection events that are truncated by fault lines. The horizon interpretation process was conducted along both inline and crossline direction. At the end of the horizon mapping, a seed grid is generated which serves as an input for time surface generation. Time surfaces were generated using the seed grids gotten from the horizon mapping process.

3.2 Velocity Modelling

Three velocity models were generated in this study and utilized for depth conversion. The velocity models generated includes Linear velocity function (average velocity), second order polynomial and third order polynomial velocity models. The linear velocity function, second order polynomial and third order polynomial velocity models generated were used separately to depth convert the time surfaces of the reservoirs of interest. Uncertainty known as residuals were estimated at well points for the various velocity models. The model with the least residual was preferred as most suitable for converting surfaces from time to depth. The depth residuals were added to the base case structural map to generate a high case structural map are subtracted from the base case structural map to generate the low case depth structural map.

Reservoir parameters usedto determine the volume of hydrocarbons in a reservoirinclude effective porosity (Ø), net to gross (NTG), water saturation (S_w) and gross rock volume (GRV). The GRV is gotten from the depth converted reservoir surfaces while porosity, NTG and Sw are petrophysical properties determined from well logs. Hydrocarbon volumes were calculated based on Udegbunam, (1988) [10] empirical model presented as follows:

$$STOIIP = \frac{7758 \times A \times h \times \varnothing \times NTG \times (1 - Sw)}{Boi} \tag{4}$$

where A = Area of the reservoir prospect (in squared feet); h = thickness of the reservoir (in feet); Ø = Effective porosity (in frac.); NTG = Net to Gross ratio (in frac.); S_W = Water saturation (in frac.); Boi = Formation Volume Factor

Hydrocarbon volumes were estimated using a scenario-based deterministic approach. In this approach, three scenarios were utilized; Low case corresponding to worse case (P90), Base case corresponding to the most likely scenario (P50) and High case scenario corresponding to best case (P10).

IV. Results and Discussion

4.1 Reservoir Identification and Correlation

The results for lithology and reservoir identification are presented in (Figure 2). A total of nine sand bodies (A, B, C, D, E, F, G, H, I) were identified and correlated across all seven wells in the field. Two reservoir sands were selected for the purpose of this study (A and I). The resistivity logs which reveals the presence of hydrocarbons were used to identify the hydrocarbon bearing sands. On (Figure 2), the sands are coloured yellow while shales are grey in colour.

4.2 Results of Petrophysical Evaluation

The results of petrophysical evaluation are presented in Figure 3. The petrophysical properties includes shale volume, total porosity, effective porosity, net to gross and water saturation. The average net thickness of reservoir A and I are 50ft and 170ft respectively. Shale volumes ranges from 8 to 14% with an average of 11% in reservoir A and from 10 to 25% with an average of 16% in reservoir I. The net to gross ratio ranges from 86 to 92% with an average of 89% in reservoir A, while in reservoir I, it ranged from 75 to 94% with an average of 84%. These results show that the reservoir rocks are predominantly composed of clean sands. On average, total and effective porosity in reservoir A are 31% and 28%, while 25% and 24% in Reservoir I respectively. Based on Riders (1986) porosity classification scheme, effective porosity in A and I reservoirs are classed as very good. Water saturation ranged from 10 to 41% in reservoir A and 11 to 54% in reservoir I. On average, water saturation is 33% and 23% in reservoir A and reservoir I respectively. In both reservoir A and I, hydrocarbons were encountered by all seven wells drilled in the field.

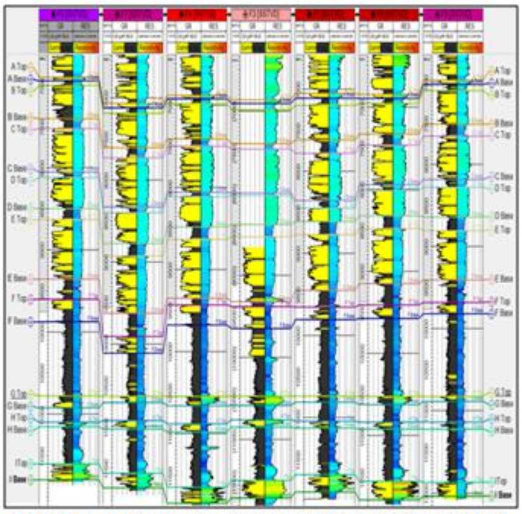

Fig 2: Well section showing reservoir identified and correlated across Fuba Field

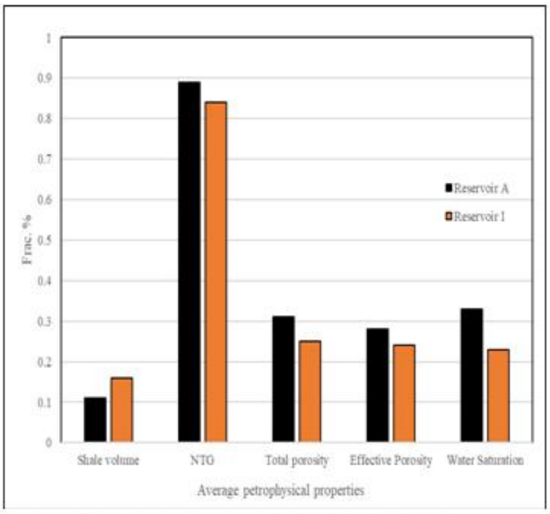

Figure 3: Histogram showing average petrophysical properties in A and I reservoirs

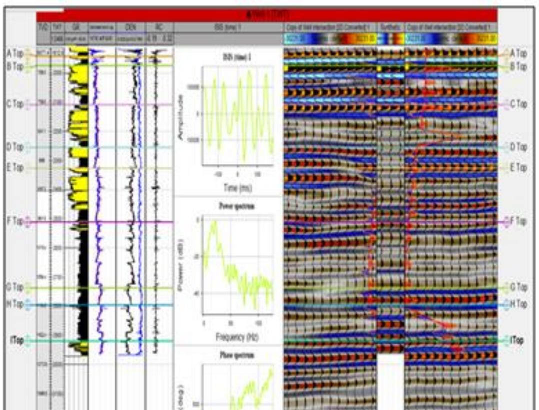

Figure 4: Synthetic seismogram generation and seismic well tie conducted for Fuba Field using Well-1

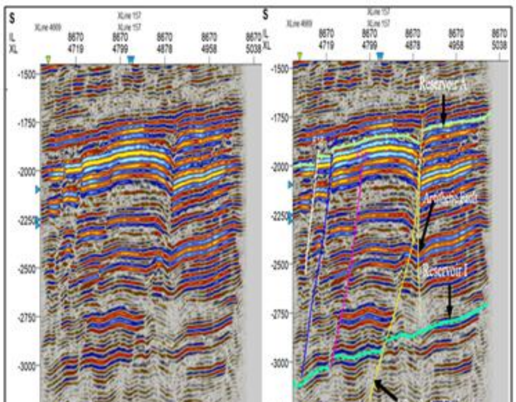

Figure 5: Faults and horizon interpreted along seismic inline section (a) Original seismic, (b) faults and horizons interpreted

4.3 Well-to-seismic Tie

The results for well-to-seismic tie conducted on Fuba field using density log, sonic log and checkshot of Well-1 is presented in Figure 4. A statistical wavelet (ISIS time) was used to give a near perfect match between the seismic and synthetic seismogram.

4.4 Fault and Horizon Interpretation

The results for the interpreted faults in Fuba field are presented in Figure 5b shows both synthetic and antithetic faults interpreted along seismic inlines. Faults are more visible along the inline direction because this direction reveals the true dip position of geologic structures. The variance time slice was used to validate the interpreted faults. All interpreted faults are normal synthetic and antithetic faults. A total of twenty-nine faults were interpreted across the entire seismic data. Of the 29 interpreted faults, only F1 (synthetic fault) and F16 (antithetic fault) faults are regional, running from the top to bottom across the field. Hence, these faults play significant roles in trap formation at the upper, middle and lower sections of the field.

The results for the interpreted seismic horizons (Horizon A and Horizon I) are also presented in Figure 5b. On these horizons, the fault polygons were generated and eliminated. The horizons were used as inputs for the generation of reservoir time surfaces.

4.5 Depth Residual Surfaces

The result of depth conversion residual analysis is presented in Table 1. The depth residual is the difference between the depth values of the well top from each well and the depth value from the depth converted reservoir surfaces. The depth residual analysis revealed that surfaces converted using the linear velocity function had the largest residuals ranging from -31.60 to +61.67 and from -50.58 to +40.84 ft in reservoir A and reservoir I respectively. This is closely followed by the residual values obtained with the 2nd order polynomial function. The third order polynomial function shows the least residuals, ranging from -6.69 to +6.61 ft in reservoir A, and -9.48 to +8.42 ft respectively. A negative depth residual indicates that the depth conversion process displaces the reservoir to a greater depth than where it occurs in the subsurface, while a positive depth residual signifies that the depth converted result has placed the reservoir at a shallower depth. The resultant depth residual values generated using the various velocity models (linear, 2nd and 3rd order polynomials) were compared in order select the most suitable velocity model for depth conversion of the reservoir surfaces. Figure 6 shows the 3rd order polynomial velocity model which was selected and used as most suitable velocity model for converting A and I reservoirs from time to depth because it has the least residuals. The depth residuals recorded from the various well locations were used to generate depth residual maps.

Table 1: Depth Residual Between Well Tops and Resultant Depth Surfaces

Reservoir	Well	WellTop(ft)	Depth Surface (ft)	Difference (ft)	Depth Surface (ft)	Difference (ft)	Depth Surface (ft)	Difference (ft)
			Linear VelocityFunction		2nd Order Polynomial		3rd Order Polynomial	
Reservoir A	Well-1	-7054.07	-7079.08	25.01	-7032.58	-21.49	-7053.13	-0.95
	Well-2	Missing	Missing	Missing	Missing	Missing	Missing	Missing
	Well-3	-6877.06	-6849.08	-27.98	-6886.40	9.34	-6880.86	3.80
	Well-4	-6977.93	-7039.60	61.67	-7004.73	26.80	-6971.24	-6.69
	Well-5	-6905.39	-6873.79	-31.60	-6859.58	-45.81	-6900.65	-4.74
	Well-6	-7065.18	-7105.10	39.92	-7028.91	-36.27	-7070.87	5.69
	Well-7	-6846.24	-6877.44	31.20	-6854.65	8.41	-6852.85	6.61
Reservoir I	Well-1	-11690.91	-11720.12	29.21	-11674.22	-16.69	-11690.91	0.00
	Well-2	-11823.41	-11780.54	-42.87	-11807.54	-15.87	-11823.41	0.00
	Well-3	-11650.06	-11684.44	34.38	-11666.36	16.30	-11656.67	6.61
	Well-4	-11887.08	-11845.26	-41.82	-11912.42	25.34	-11877.60	-9.48
	Well-5	-11599.86	-11549.01	-50.85	-11581.29	-18.57	-11595.11	-4.75
	Well-6	-11569.00	-11534.94	-34.06	-11586.60	17.60	-11564.27	-4.73
	Well-7	-11551.91	-11592.75	40.84	-11534.64	-17.27	-11560.33	8.42

4.6 Deterministic Reserve Estimation

Table 2: Deterministic Hydrocarbon Reserve Estimation for Reservoir A and Reservoir I

Reservoir	Cases	Input Parameters: Porosity	NTG	Sw	OWC (ft)	Boi	Bulk Volume [$*10^6$ ft^3]	Deterministic STOIIP (MMSTB)
Reservoir A	High Case (P10)	0.30	0.92	0.10	-7170.00	1.20	147446.00	18.52
	Base Case (P50)	0.28	0.89	0.33	-7036.00	1.20	89583.00	13.59
	Low Case (P90)	0.25	0.86	0.41	-6926.00	1.20	43185.00	9.40
Reservoir I	High Case (P10)	0.35	0.90	0.11	-12240.00	1.20	251970.00	25.56
	Base Case (P50)	0.24	0.84	0.23	-11915.86	1.20	84566.00	14.59
	Low Case (P90)	0.21	0.75	0.54	-11735.00	1.20	25027.00	7.63

Hydrocarbon reserves estimated are 18.52 MMSTB (high case), 13.59 MMSTB (base case) and 9.40 MMSTB (low case) for reservoir A. In reservoir I, 25.56 MMSTB, 14.59 MMSTB and 7.63 MMSTB Were estimated for low case (P10), base case (P50) and high case (P10) respectively. Table 1shows a comparative analysis of hydrocarbon volumes obtained using the various case scenarios. The results show that there are significant differences in hydrocarbon volumes estimated for the low case, base case and high case scenarios in both A and I reservoirs.

V. Conclusion

A total of nine sand bodies (A, B, C, D, E, F, G, H, I) were identified and correlated across all seven wells in the field. Hydrocarbon reserves estimated are 18.52 MMSTB (high case), 13.59 MMSTB (base case) and 9.40 MMSTB (low case) for reservoir A. In reservoir I, 25.56 MMSTB, 14.59 MMSTB and 7.63 MMSTB were estimated for high case, base case and low case respectively. The results show that there are significant differences in hydrocarbon volumes estimated for the low case, base case and high case scenarios in both A and I reservoirs. This study has shown that the major reservoir property influencing the estimated hydrocarbon volume for studied Fuba field is the reservoirs bulk volume. The bulk volume accounts for 85.9% and 86.1% of the total uncertainty surrounding the estimated hydrocarbon volumes in reservoir A and reservoir I respectively.Oil saturation accounts for only 12% and 7.8% of the total uncertainty in hydrocarbon volumes in reservoir A and reservoir I. Porosity and net to gross do not have any significant impact on the quantified reserves. Hence, any slight increase or decrease in the reservoir' s bulk volume will lead to a significant impact on the quantified hydrocarbon volume.Meanwhile, variations in the reservoir' s net to gross and porosity will not have any significant impact on the quantified volumes. The study also showed that the relevance of scenario-based (low case, base case and high case) deterministic approach in hydrocarbon volume estimation cannot be underestimated if one must get a realistic volume. Low case is recommended for use because it is the lower base and it has a lower uncertainty of finding hydrocarbon. The advantages of determining the volume using Deterministic approach over other methods include the following:

1. Probabilistic methods use stochastic parameters such as a Monte Carlo simulation. On the other hand, deterministic calculations are made with discrete values. Deterministic methods use single-point parameters to obtain reserves. The result is a single value such as 800 Million barrels.
2. Proved reserves derived from probabilistic methods are intangible and impossible to "point to on a map." They also may be difficult to reconcile with legal definitions of a proved area. In a probabilistic calculation one cannot back calculate the input parameters associated with the proved reserves. One knows only the end result but not the exact value of any input parameter. On the other hand, deterministic methods derive proved reserves that are more tangible and explainable.
3. In a deterministic calculation one knows exactly the parameters used in the calculation. Probabilistic methods allow the incorporation of more variance in the data.
4. A deterministic model is one in which state variables are uniquely determined by in the model and by sets of previous states of variables. Therefore, deterministic models perform same way for a given set of parameters and initial conditions and their solution is unique.

Acknowledgements

The authors are grateful to Shell Petroleum Development Company of Nigeria (SPDC), Port Harcourt Nigeria for the release of the academic data for the purpose of this study.

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O. I. Horsfall, etal. "Deterministic Hydrocarbon Volume Estimation in the OnshoreFuba Field Niger Delta, Nigeria."*IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)*, 8(1), (2020): pp. 34-40.