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Volumetric and Material Balance Methods of Reserve Estimation: A Comparative Study using Niger Delta Reservoirs

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ABSTRACT

This paper investigated the estimations of reserve in place in four Niger Delta Reservoirs using both the Volumetric and Material Balance (MB) methods comparatively. The Volumetric estimations started from the planimeter readings while the MB method used plots from the Havelena and Odeh formats in its estimations. Reservoir "A" is a saturated oil reservoir, no water drive, and negligible rock and fluid compressibilities; Reservoir "B" is a saturated oil reservoir underwater drive at encroachment angle of 70o; Reservoir "C" is an undersaturated oil reservoir under solution gas drive, while Reservoir "D" is a gas reservoir without water influx. There were good to the very good correlation between the results obtained by both methods except in the case of "D" where an extension of the reservoir to another occurred and so the Volumetric method gave a value of 4.48MMMSCF as the value of gas in place while the MB method gave a value of 9.15MMMSCF. The MB method was recommended to give better accuracy though very cumbersome to evaluate.

Keywords: *Petrophysical parameters, Akata formation, Agbada formation, Benin formation, Material Balance.*

1. INTRODUCTION

Reserves are estimated volumes of crude oil, condensate, natural gas, natural gas liquids, and marketable substances anticipated to be commercially recoverable and marketable from a given date forward, under existing economic conditions, by establishing operating practices, and under current government regulations [1]. In order to make reasonable recovery predictions, estimates of initial hydrocarbon in place in each reservoir must be made. The Volumetric method is a useful tool for calculating the hydrocarbon in place at any time, particularly applicable when a field is comparatively new (that is before sufficient hydrocarbons have been produced to cause appreciable drop in pressure). Here, the pore space volume in the reservoir containing oil/gas is converted to oil/gas volume at standard conditions. After the exploratory wells are drilled, much more information on the reservoir is available and so the initial oil/gas in place can be computed using; the reservoir pore volume, initial volume factors (B_{oi} or B_{gi}) which converts reservoir volumes to volumes at standard conditions, and Petrophysical parameters like water saturation (S_w) and Porosity ($\emptyset$).

When sufficient pressure production data are recorded and Pressure, Volume and Temperature (PVT) data describing the reservoir fluid behavior are available, the amount of oil or gas in- place in a reservoir sometimes may be computed by the Material Balance Method. This method is based on the premise that the pore volume (PV) of a reservoir remains constant or changes in a predictable manner with the reservoir pressure drop as oil, gas, and/or water are produced. If the reservoir PV remains near constant, then as it is produced and reservoir pressure falls, the fluid remaining in the reservoir must expand to occupy the PV. The Material Balance calculates the volume of reservoir fluids that would be required to exhibit an expansion for the observed

pressure drop, which would equal the withdrawals. This method requires accurate history of the average pressure of the reservoir, reliable oil, gas, and water production data and of course PVT data of the reservoir fluids.

2. BRIEF GEOLOGY OF STUDY AREA

The Niger Delta Basin occupies the Gulf of Guinea continental margin in equatorial West Africa, between latitudes 3° and 6°N and longs, 5° and 8°E. It ranks among the world's most prolific petroleum-producing Tertiary deltas, and has been rated sixth largest oil producer and twelfth hydrocarbon province occupying about 100,000 sq.mile [2]. As a sedimentary basin, the Niger Delta encompasses a region that is much larger than the geographical extent of the modern delta constructed by the Niger-Benue drainage systems. It embraces other deltas "which are not members of the Niger system" [3], notably the Cross River Delta [4], and extends into the continental margins of neighbouring Cameroon and Equatorial Guinea, which therefore "have portions of the Niger Delta that contain hydrocarbons" [5].The base of the Delta consists of massive and monotonous marine shales (Akata formation) which grade upwards into interbeded shallow-marine and fluvial sands, silts and clays (Agbada formation) that form the typical paralic facies portion of the delta. The uppermost part of the Delta sequence is a massive nonmarine sand section known as Benin formation [6].

The Niger Delta Basin holds enormous petroleum reserves, estimated at about 30 billion barrels of oil and 260 trillion cubic feet of natural gas, ranking the delta seventh in world production, with a current average production of about 1.8 million bbl of oil/day. A few giant oil and condensate fields, with reserves exceeding 500 million bbl occur in the Niger Delta [7].The basement map of Niger Delta is shown in figure 1, bearing the study reservoirs “A”, “B”, “C”, and “D”.

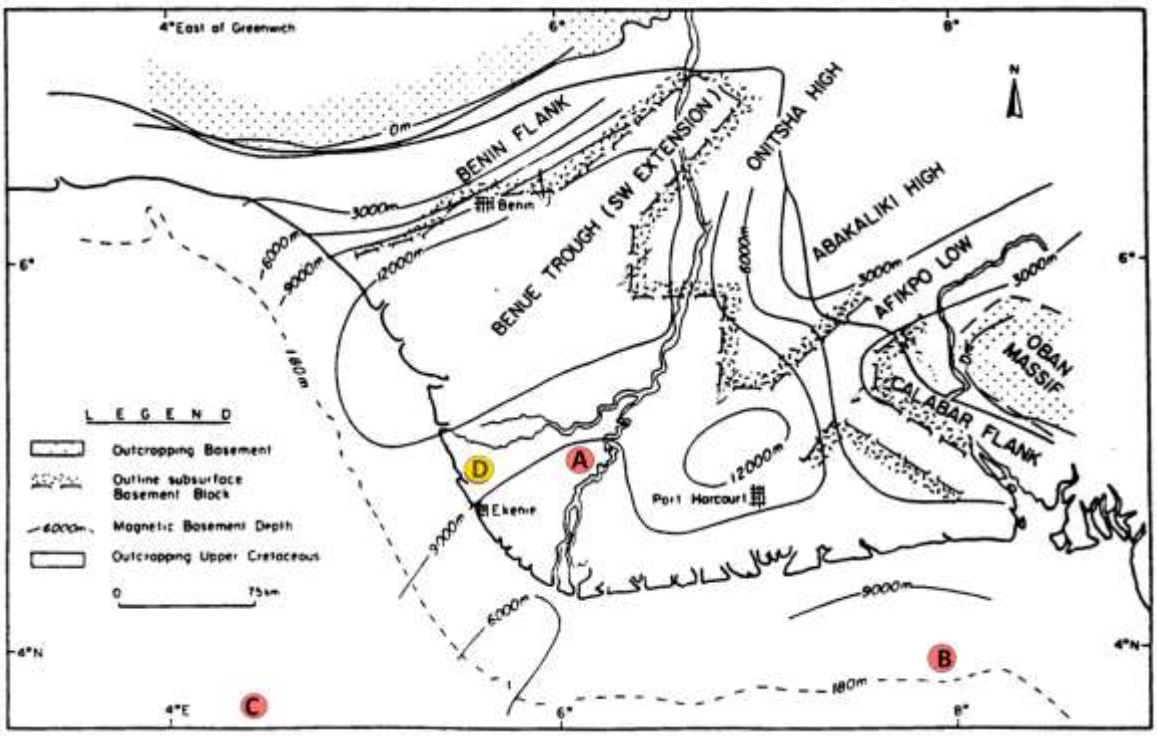

Figure 1: Basement map of Niger Delta [4], modified with Reservoir locations (coloured circles)

3. THEORETICAL BACKGROUND AND METHODOLOGY

Volumetric methods to estimate reserves generally are used early in the life of a reservoir before there are sufficient production and/or pressure data to use the performance-based methods. Although it is the most widely used method to estimate reserves, the volumetric method may be subject to considerable uncertainty, depending on the geologic setting and the amount and quality of geologic and engineering data. Thus, good practice mandates checking reserves estimated using volumetric methods against well

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and reservoir performance at the earliest practical stage of production. Regarding estimates of reserves made early in field or reservoir life, [8] observed that reserves for "very prolific fields have been generally underestimated, while (reserves for) the poorer ones are usually overestimated".

The volumetric method involves calculating: (a) the amount o f oil and gas initially in place by a combination of geologic mapping, petrophysical analysis, and reservoir engineering and (b) the fractions of oil, gas, and associated products initially in place that are expected to be recovered commercially-i.e., the recovery efficiencies-using analytical methods and/or analogy [9]. For oil reservoirs, the initial oil in place (N) is computed using (1);

$$\text{N (STB)} = \frac{7{,}758Ah\emptyset(1-S_w)}{B_{oi}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(1)$$

while for gas reservoirs, we compute the initial gas in place (G) using (2). "A" is the reservoir area in acres, "h" is the net thickness in feet, "$\emptyset$" is the porosity, "S_w" is the water saturation "B_{oi}" is the oil formation volume factor in res.barrels/STB and "B_{gi}" is the gas formation volume factor in res. barrels/scf.

$$\text{G (scf)} = \frac{7{,}758Ah\emptyset(1-S_w)}{B_{gi}} \ldots\ldots\ldots\ldots\ldots\ldots \quad (2)$$

The volumetric estimation of oil/gas in place is an on-going project. Each time that new information becomes available, usually from additional wells, then all the maps should be updated and a new volumetric calculation made. In this manner, as the field is drilled, the reserves estimate becomes more accurate [10].

In using (1) and (2), the parameters "$\emptyset$" and "S_w" were adopted from petrophysical analysis; B_{oi} and B_{gi} came from PVT analysis while the volume element (Ah) was obtained through the use of (3) which relates the volume between two contours in an isopach map to the frustum of a pyramid. A summation of all ΔVs would then yield the volume element (Ah). Defining (3);

$$\Delta V = \frac{h_i}{3}\left(\mathrm{A_j} + \mathrm{A_{j+1}} + \sqrt{\mathrm{A_j A_{j+1}}}\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (3)$$

h_i is the interval between isopach contours in feet, while A_j and A_{j+1} are the areas (in acres) enclosed by the lower and upper contours respectively.

The general Material Balance Equation (MBE) was developed on the premise that [11]:

PRODUCTION OF (OIL + GAS + WATER) = EXPANSION OF OIL & FREE GAS (INITIALLY IN PLACE) + WATER INFLUX …… (4)

This gave birth to the general MBE expressed in (5);

$$N_p\left[B_o + B_g\left(R_p - R_s\right)\right] - \left(\mathrm{W_e} - \mathrm{W_p}B_w\right) =$$

$$N\left\{B_o - B_{Oi} + mB_{Oi}\left[\left(\frac{B_g}{B_{gi}}\right) - 1\right] + B_g(R_{si} - R_s) + B_{Oi}(1+m)\left[\frac{c_w S_w + c_f}{1 - S_w}\right]\Delta p\right\} \ldots\ldots\ldots\ldots\ldots\ldots(5)$$

"N" is the initial oil in place in stock tank barrels, "m" is the ratio of volume of gas cap to volume of oil zone. "Np" is the cumulative oil production in stock tank barrels, "R_p" is the cumulative produced gas oil ratio, while "R_s" is the solution gas oil ratio. "We" is the cumulative water influx from the aquifer into the reservoir in stb, "Wp" is the cumulative amount of aquifer water produced in stb, "B_w" means water formation volume factor rb/stb, "c_w" is the connate water isothermal compressibility in (1/psi), "c_f" is the pore volume isothermal compressibility in (1/psi), Δp represents change in pressure (in psi), while subscript "i" indicates initial conditions.

It is very much possible to transform (5) reminiscent of [12] and [13] to a linear equation by making the following assumptions:

$$F = N_p (B_o + (R_p - R_s) B_g) + W_p B_w \quad \text{.....} \quad (6)$$

which represents the underground withdrawal;

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s) B_g \quad \text{.....} \quad (7)$$

which represents the expansion of the oil and liberated gas;

$$E_g = B_{oi}\{ (B_g/B_{gi}) -1\} \quad \text{.....} \quad (8)$$

Which concerns the expansion of the gas cap, and

$$E_{f,w} = B_{Oi}(1+m) \left[\frac{c_w S_w + c_f}{1-S_w}\right] \Delta p \quad \text{... ... ...} \quad (9)$$

That takes care of the rock and connate water expansion.

Finally, fitting (6),(7),(8) and (9) into (5) yields the form ;

$$F = N(E_o + mE_g + E_{f,w}) + W_e \quad \text{.....} \quad (10)$$

A saturated oil reservoir with negligible water influx, and negligible compressibilities of connate water and rock (as in study reservoir A) will have equation (10) reduced to the form of (11); a plot of F against E_o will give N (the oil in place) as slope. For the case of water drive saturated oil reservoir with negligible connate water and rock compressibilities (as in reservoir B), equation (10) assumes the form of (12); plotting F/E_o against W_e/E_o will give a straight line whose intercept on the vertical axis reveals N.

$$F = NE_o \quad \text{.....} \quad (11)$$

$$\frac{F}{E_o} = N + \frac{W_e}{E_o} \quad \text{.....} \quad (12)$$

Water influx "We" is usually difficult to estimate owing to the unavoidability of data involved in the computation and so trial and error approach is usually adopted [14] and the correct water influx will always plot in a straight line as shown in figure 2. However, where the data exist, we use the [15] formula (i. e. (13)) to estimate "We".

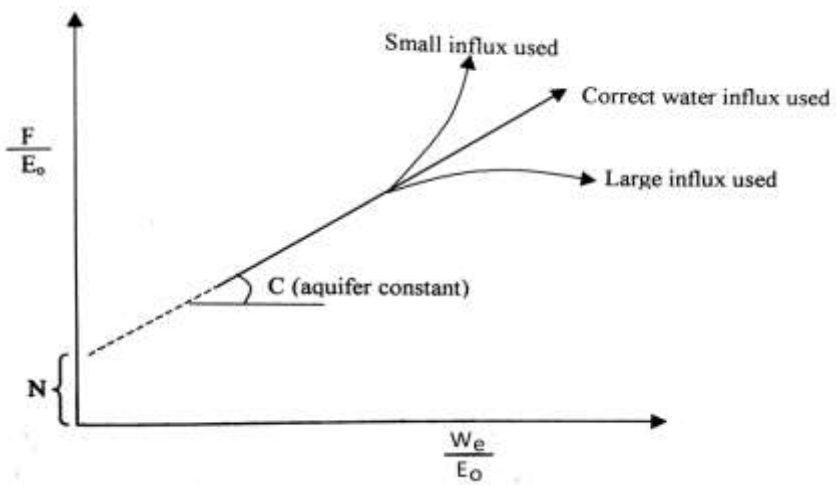

Figure 2: Water influx model plot

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$W_e = C\,\Delta p\,W_{eD}$ ……..(13)

$C = 1.119 f\varphi c_t r_e^2 h$ ……...(14)

f = encroachment angle/360° ……(15)

$$t_D = 6.38 \times 10^{-3} \frac{kt}{\varphi \mu_w c_t r_e^2} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (16)$$

The aquifer constant "C" is first computed using (14) and (15),then the dimensionless water influx (W_{eD}) is estimated at dimensionless times (t_D) using (16) and the chat in fig.3. which coverts t_D to W_{eD}."We" is finally determined at various pressure differential using (13).

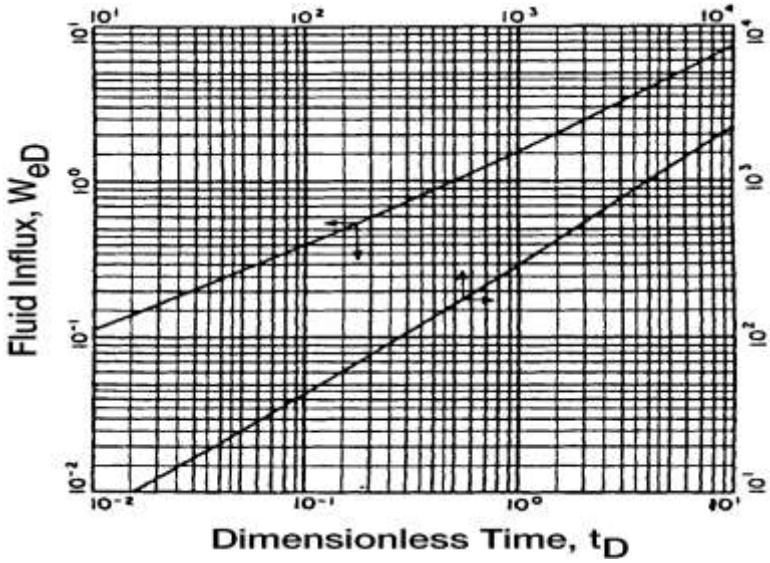

Figure 3: W_{eD} determination chat [15]

Defining the parameters; t = time in days, k = permeability of the aquifer in md, φ = porosity of the aquifer, μ_w = viscosity of water in the aquifer in cp, r_e = radius of the reservoir in ft, c_t = total compressibility coefficient in psi^{-1},h = thickness of the aquifer in ft, while Δp = pressure drop at the boundary in psi.

For an undersaturated reservoir wthout water influx, equation (10) is considered with ascertions; $W_e = 0$, m = 0 since the reservoir is undersaturated. $R_s = R_{si} = R_p$ since all produced gas is disolved in the oil. A pararmeter "S_oc_o" is included to take care of oil compressibility and finally equation (10) transforms to equation (17). It is easy to deduce from equation (17) that a plot of N_pB_o against $\left(\frac{S_oc_o+S_wc_w+c_f}{1-S_w}\right)\Delta p$has "$NB_{oi}$" as the slope, thus N could be determined; this is a typical study reservoir C case.

$$N_pB_o = NB_{oi}\left(\frac{S_oc_o + S_wc_w + c_f}{1 - S_w}\right)\Delta p \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (17)$$

.Using the same Havelena and Odeh fashion, the equation for gas reservoir with negligible rock and water expansion term ($E_{f,w}$) is given by (18); when there is no water influx (18) reduces to (19). Noteing that "F" is "G_pB_g", (18) finally assumes the form of (20).

$F = G(B_g - B_{gi}) + W_eB_w$ ……. (18)

$F = G(B_g - B_{gi})$ …… (19)

$G_pB_g = G(B_g - B_{gi})$ …… (20)

The value of G is easily deducible by plotting appropriate variables in (20). This was applied in study reservoir D.

4. RESULTS AND DISCUSSION

In my computations especially in Volumetric method, I used the conventional elaborate approach to aid in appreciation and presentation of fundamental concepts instead of the modern computer techniques which would have given results (by use of software) without highlighting intricacies involved. The Volumetric method used the isopach maps and planimeters to aid in the computations of reserves in place while the MB methods used the Havelena and Odeh's approach to generate plots from which reserves in place were estimated.

4.1. Reservoir A

Table 1 shows the computations from planimeter readings using equation (3), from which we estimated the oil in place using equation (1) and the following data; $\emptyset = 24\%, S_w = 22\%, B_{oi} = 1.298\, resbbl/STB$.

Table 1: Pore volume computation table for Reservoir A

Area (Acres)	Interval height (ft)	ΔV (ac-ft)
$A_0 = 0$	-	
$A_1 = 115$	40	1,533.3
$A_2 = 132$	40	4,936.1
$A_3 = 206$	40	6,705.3
$A_4 = 295$	30	7,475.2
$A_5 = 373$	30	9,997.2
		$\sum \Delta V = 30{,}647.1$

$$\text{Oil in place (N)} = \frac{(7758)(30{,}647.1)(0.24)(1-0.22)}{1.298} = 34.3\text{MMSTB}$$

Next I used the data in table 2 to evaluate the same oil in place using the material Balance method; the result was derived from the slope of the plot in fig. 4 as 34.9MMSTB.

Table 2: PVT data for Reservoir A

Time (days)	Press. (Psia)	Np x10^6 (STB)	E_0 x 10^{-1} (rb/STB)	B_0 (rb/STB)	F =NpB_0 x 10^6
0	3640	0	0	1.298	0
50	3610	1.975	0.67	1.233	2.44
150	3530	2.981	1.04	1.220	3.64
200	3385	6.188	2.01	1.11 5	6.90
250	3200	9.246	2.52	0.964	8.91

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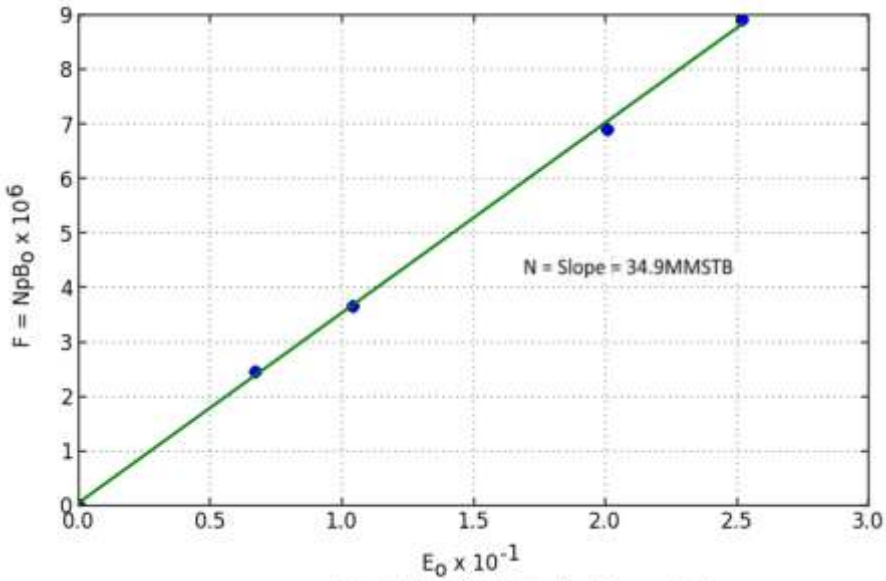

Fig. 4 Plot of F Vs E_O for Reservoir A

4.2. Reservoir B

Table 3 shows the computations from planimeter readings using equation (3), from which I estimated the oil in place using equation (1) and the following data; $\emptyset = 21\%, S_w = 26\%, B_{oi} = 1.118\, resbbl/STB$

Table 3: Pore volume computation table for Reservoir B

Area (Acres)	Interval height (ft)	ΔV (ac-ft)
A_0 = 0	-	
A_1 = 80	40	1,067
A_2 = 139	40	4,327
A_3 = 209	40	6,913
A_4 = 243	40	9,031
A_5 =319	40	11,205
		$\sum \Delta V = 32{,}543$

$$\text{Oil in place (N)} = \frac{(7758)(32543)(0.21)(1-0.26)}{1.118} = 35.1\text{MMSTB}$$

The PVT data for the Material Balance computations are shown in tables 4 and 5; the reservoir had water influx with encroachment angle of 70°.Other parameters used in the MB calculations are: h = 222ft, c_t = 4 x 10^{-6}/psi, r_e = 6667ft, k = 12.3md, μ = 0.64cp.Equations (13), (14),(15) and (16) together with fig. 3 were also employed.

Table 4: PVT data for Reservoir B

Time (Days)	Press. (Psia)	Np x10^6 (STB)	Wp x 10^5 (STB)	E_0 x10^{-2} (rb/STB)	F =(NpB_0 +Wp) 10^6 (rb/STB)	B_0 (rb/STB)
0	4312	0	0	0	-	1.118
50	3943	0.343	0	0.512	0.384	1.1205
150	3481	1.069	0.264	1.096	1.227	1.1234
300	3284	1.915	1.73	1.443	2.327	1.1252
600	3822	2.114	2.04	0.842	2.576	1.1222

Table 5: Water influx calculation for Reservoir B

Time (days)	W_e x 10^6 (rb)	W_e/ E_ox 10^6(STB)	F/E_o x 10^6 (STB)
0	0	0	0
50	0.226	44.1	75.0
150	0.834	76.1	111.9
300	1.810	125.5	161.3
600	2.307	274.0	305.9

The oil in place was finally estimated using fig. 5 yielding a value of 34.2MMSTB.

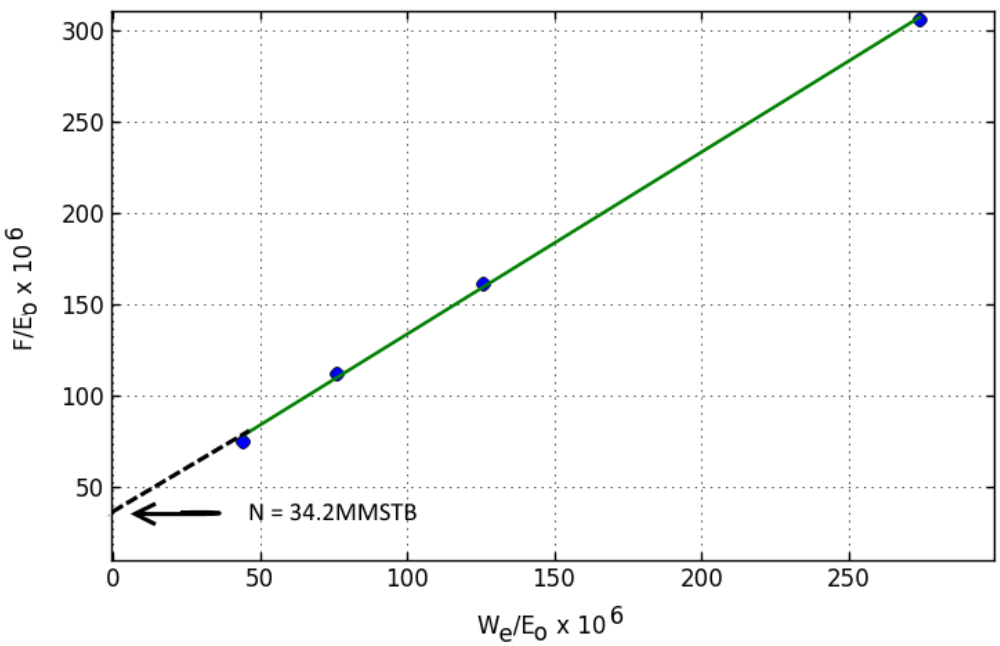

Fig. 5 Plot of F/E_oVs W_e/E_o for Reservoir B

4.3 Reservoir C

The computation of oil in place (using Volumetric method) for this reservoir was achieved using (3) and (1) and the data in table 6 while also considering the following;$\emptyset = 14\%, S_w = 24\%, B_{oi} = 1.3102\ resbbl/STB$.

Table 6: Pore volume computation table for Reservoir C

Area (Acres)	Interval height (ft)	ΔV (ac-ft)
A_0 = 0	-	
A_1 = 230	50	3,833
A_2 = 525	50	18,374.9
A_3 = 891	50	34,999
A_4 = 1241	50	53,059
A_5 = 2214	50	85,210
A_6 = 3661	50	145,367
		$\sum \Delta V = 340{,}842$

$$\text{Oil in place (N)} = \frac{(7758)(340{,}842)(0.14)(1-0.24)}{1.3102} = 214.7\text{MMSTB}$$

The PVT data for the MB method is highlighted in table 7 from which we deduced the oil in place (for this case) from the resulted slope of the plot in fig. 6 as 218.2MMSTB. Other data used are c_f = 4.95 x 10^{-6} psi^{-1} and c_w = 3.6 x 10^{-6} psi^{-1}.

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Table 7: PVT data for Reservoir C

Time (Days)	Pressure (psia)	N_p x 10^3 (STB)	B_o (rb/STB)	N_pB_o x 10^4	C_o x 10^{-6}	ΔP	$\frac{(S_oC_o+S_wC_w+C_f)}{1-S_w}$ ΔP x 10^{-4}
0	3685	0	1.3102	0	11.01	-	-
60	3685	0.342	1.3102	0.0448	11.01	0	0
120	3680	20.481	1.3104	2.6838	11.02	5	0.93
180	3676	34.750	1.3104	4.5536	11.03	9	1.68
240	3667	74.872	1.3105	9.812	11.04	18	3.39
300	3664	84.723	1.3105	11.103	11.05	21	3.93

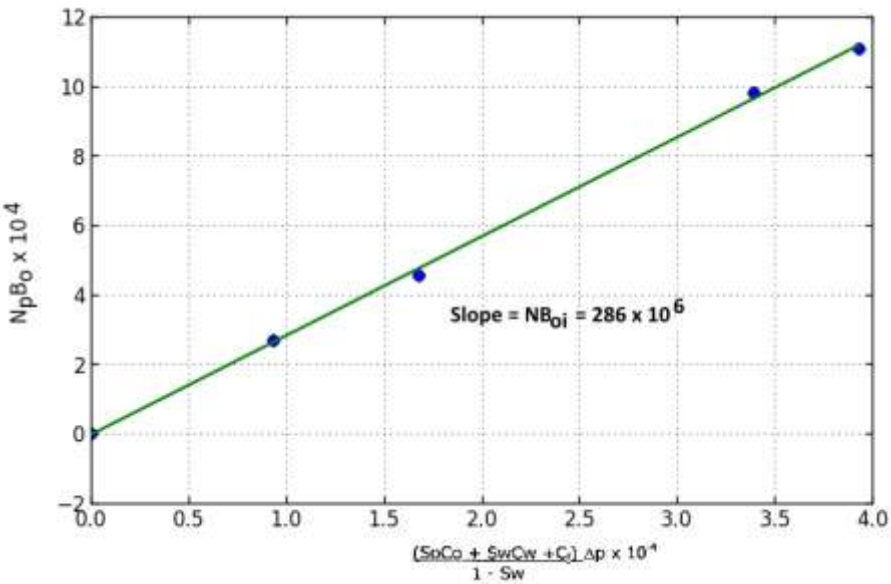

Fig.6: Plot of N_pB_o Vs $\frac{(S_oC_o + S_wC_w + C_f)\,\Delta p \times 10^4}{1 - S_w}$ for Reservoir C

4.3. Reservoir D

In this case, a gas reservoir was considered with the volumetric method and the computations involved equations (3) and (2) in conjunction with table 8 data and the following; $\emptyset = 18.5\%, S_w = 31\%, B_{gi} = 0.00178\ resbbl/SCF$.

Table 8: Pore volume computation table for Reservoir D

Area (Acres)	Interval height (ft)	ΔV (ac-ft)
A_0 = 0	-	
A_1 = 22	50	367
A_2 = 36	50	1,435.7
A_3 = 74	50	2,694
A_4 = 110	40	3,656
		$\sum \Delta V = 8{,}152.7$

$$\text{Oil in place (N)} = \frac{(7758)(8152.7)(0.185)(1-0.31)}{0.00178} = 4.48\text{MMMSCF}$$

The PVT data for the MB method is shown in table 9 which led to the plot for estimation of initial gas in place as revealed in fig. 7; the initial gas in place was estimated to be 9.15MMMSCF.

Table 9: PVT data for Reservoir D

Time (Years)	Pressure (psia)	G_p (MMMScf)	B_g (Res.bbl/Scf)	G_pB_g x 10^6 (res bbl)	(Bg – Bgi) x 10^{-4} (Res.bbl/Scf)
0	3432	0	0.00178	0	0
0.5	3215	0.97	0.00196	1.90	1.82
1.0	3004	1.63	0.00214	3.48	3.62
1.5	2818	2.22	0.00229	5.08	5.10
2.0	2615	2.51	0.00247	6.21	6.88

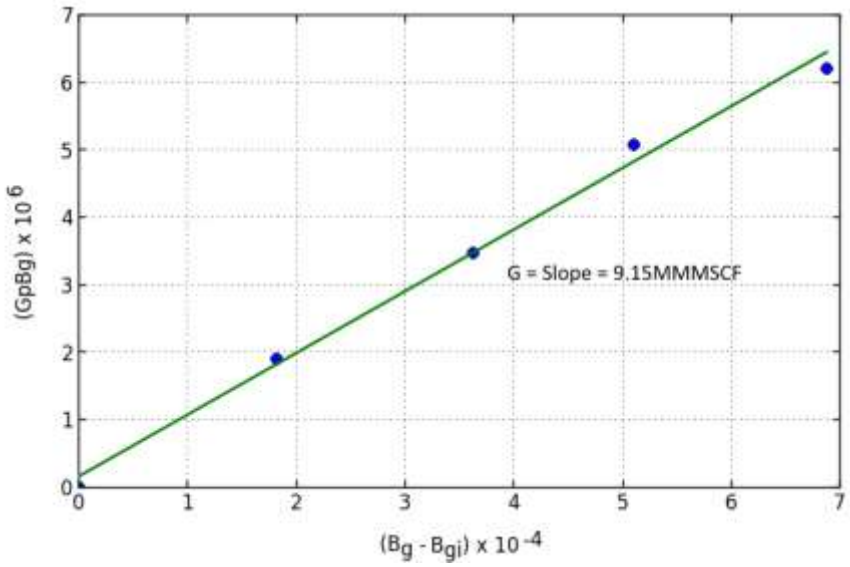

Fig. 7: Plot of (G_pB_g) x 10^6 vs (B_g – B_{gi}) x 10^{-4}

5. CONCLUSION

The results obtained in this research clearly indicate that both the Volumetric and Material Balance methods are suitable in the computation of reserve in place. Both methods gave results that are relatively the same for each reservoir considered except in Reservoir C (where the reserve was partially underestimated by the volumetric method owing to incomplete area extent coverage by the geologic mapping since enough exploratory wells weren't drilled by then) and in Reservoir D (where the reserve was grossly underestimated by the volumetric method which didn't sense the extension of the reservoir through a fault to a lower reservoir thereby leading to the former being constantly recharged by migration through the fault. The MB method for Reservoir B was very cumbersome due to the fitting of data involved in the water influx calculations (despite the rock and fluid parameters available).

The volumetrically determined results are based on geological and Petrophysical data of somewhat unknown accuracy and so it evaluates total oil/gas in place part of which may not contribute to production, while the reserve in place obtained by the MB method is that oil/gas which contributes to the pressure production history. Because of this, a disagreement between the two answers might be of paramount importance and the concordance between them should not be overemphasized. I posit therefore that the MB method which requires pressure history data and several data points (when the Havelena and Odeh method is used) gives more accurate estimation.

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