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 70°; 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 ($B_o$ or $B_g$) which converts reservoir volumes to volumes at standard conditions, and Petrophysical parameters like water saturation ($S_w$) and Porosity ($\phi$).

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 interbedded 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”.

![Basement map of Niger Delta](image_url)

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
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 of 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);

$$N \text{ (STB)} = \frac{7.758 Ah \phi (1 - S_w)}{B_{oi}} \quad (1)$$

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, “\( \phi \)” 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.

$$G \text{ (scf)} = \frac{7.758 Ah \phi (1 - S_w)}{B_{gi}} \quad (2)$$

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 “\( \phi \)” 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 \( \Delta V \)’s would then yield the volume element (Ah). Defining (3);

$$\Delta V = \frac{h}{3} (A_j + A_{j+1} + \sqrt{A_j A_{j+1}}) \quad \ldots \ldots \ldots \ldots (3)$$

\( h \) 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 
\( = \) EXPANSION OF OIL & FREE GAS + WATER INFUX \( \ldots \ldots \) \( \ldots \ldots \) \( \ldots \ldots \) (5)

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

$$N_p [B_o + B_g (R_p - R_s)] - (W_e - W_p B_w) =$$

$$N \left( B_o - B_{oi} + m B_{oi} \left( \frac{B_o}{B_{gi}} - 1 \right) + B_g (R_{gi} - R_s) + B_{oi} (1 + m) \left( \frac{c_w S_w + c_f}{1 - S_w} \right) \Delta p \right) \quad \ldots \ldots \ldots \ldots (5)$$

“\( N \)” is the initial oil in place in stock tank barrels, “\( m \)” is the ratio of volume of gas cap to volume of oil zone. “\( N_p \)” 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. “\( W_e \)” is the cumulative water influx from the aquifer into the reservoir in stb, “\( W_p \)” is the cumulative amount of aquifer water produced in stb, “\( B_{wi} \)” 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), \( \Delta p \) 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:

\[ F = N_p (B_o + (R_p - R_s) B_g) + W_p B_w \]  

(6)

which represents the underground withdrawal;

\[ E_o = (B_o - B_{oi}) + (R_{si} - R_s) B_g \]  

(7)

which represents the expansion of the oil and liberated gas;

\[ E_g = B_{oi} \left\{ \frac{B_g}{B_{gi}} - 1 \right\} \]  

(8)

Which concerns the expansion of the gas cap, and

\[ E_{fw} = N (E_o + m(E_o) + E_{f,w}) + W_e \]  

(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 \( N \).

\[ F = NE_o \]  

(11)

\[ \frac{F}{E_o} = N + \frac{W_e}{E_o} \]  

(12)

Water influx “\( W_e \)” 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 “\( W_e \)”. 

![Figure 2: Water influx model plot](image)
\[ W_e = C \Delta p \quad \text{(13)} \]

\[ C = 1.119f \varphi c_t r_e^2 h \quad \text{(14)} \]

\[ f = \text{encroachment angle/360°} \quad \text{(15)} \]

\[ t_D = 6.38 \times 10^{-3} \frac{kt}{\varphi \mu_w c_t r_e^2} \quad \text{(16)} \]

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 chart in fig.3. which converts \( t_D \) to \( W_{eD} \). “We” is finally determined at various pressure differential using (13).

Restricting the parameters: \( t = \text{time in days}, k = \text{permeability of the aquifer in md}, \varphi = \text{porosity of the aquifer}, \mu_w = \text{viscosity of water in the aquifer in cp}, r_e = \text{radius of the reservoir in ft}, c_t = \text{total compressibility coefficient in psi}^{-1}, h = \text{thickness of the aquifer in ft}, \) while \( \Delta p = \text{pressure drop at the boundary in psi}. \)

For an undersaturated reservoir without water influx, equation (10) is considered with ascertions; \( W_e = 0, m = 0 \) since the reservoir is undersaturated. \( R_e = R_w = R_p \) since all produced gas is dissolved in the oil. A parameter “\( S_{oc} \)” 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 \( N_p B_o \) against \( \frac{S_{og} + S_w c_w + c_f}{1 - S_w} \) \( \Delta \text{phases} \) “\( N B_{oil} \)” as the slope, thus \( N \) could be determined; this is a typical study reservoir C case.

\[ N_p B_o = N B_{oil} \left( \frac{S_{og} + S_w c_w + c_f}{1 - S_w} \right) \Delta \text{p} \quad \text{.................} \quad \text{(17)} \]

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). Noting that “\( F \)” is “\( G_p B_g \)”, (18) finally assumes the form of (20).

\[ F = G (B_g - B_{pg}) + W_e B_w \quad \text{.........................} \quad \text{(18)} \]

\[ F = G (B_g - B_{pg}) \quad \text{.................................} \quad \text{(19)} \]

\[ G_p B_g = G (B_g - B_{pg}) \quad \text{.................................} \quad \text{(20)} \]

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: $\phi = 24\%, S_w = 22\%, B_o = 1.298 \text{ resbbl/STB}$.

<table>
<thead>
<tr>
<th>Area (Acres)</th>
<th>Interval height (ft)</th>
<th>$\Delta V$ (ac-ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$A_0 = 0$</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>$A_1 = 115$</td>
<td>40</td>
<td>1,533.3</td>
</tr>
<tr>
<td>$A_2 = 132$</td>
<td>40</td>
<td>4,936.1</td>
</tr>
<tr>
<td>$A_3 = 206$</td>
<td>40</td>
<td>6,705.3</td>
</tr>
<tr>
<td>$A_4 = 295$</td>
<td>30</td>
<td>7,475.2</td>
</tr>
<tr>
<td>$A_5 = 373$</td>
<td>30</td>
<td>9,997.2</td>
</tr>
</tbody>
</table>

$\sum \Delta V = 30,647.1$

Oil in place (N) $\frac{(7750)(30,647.1)(0.24)(1-0.22)}{1.298} = 34.3\text{MMSTB}$

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>
<thead>
<tr>
<th>Time (days)</th>
<th>Press. (Psia)</th>
<th>$N_p \times 10^6$ (STB)</th>
<th>$E_0 \times 10^{-1}$ (rb/STB)</th>
<th>$B_o$ (rb/STB)</th>
<th>$F = N_p B_o \times 10^6$</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>3640</td>
<td>0</td>
<td>0</td>
<td>1.298</td>
<td>0</td>
</tr>
<tr>
<td>50</td>
<td>3610</td>
<td>1.975</td>
<td>0.67</td>
<td>1.233</td>
<td>2.44</td>
</tr>
<tr>
<td>150</td>
<td>3530</td>
<td>2.981</td>
<td>1.04</td>
<td>1.220</td>
<td>3.64</td>
</tr>
<tr>
<td>200</td>
<td>3385</td>
<td>6.188</td>
<td>2.01</td>
<td>1.115</td>
<td>6.90</td>
</tr>
<tr>
<td>250</td>
<td>3200</td>
<td>9.246</td>
<td>2.52</td>
<td>0.964</td>
<td>8.91</td>
</tr>
</tbody>
</table>
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;

\[ \phi = 21\%, S_w = 26\%, B_{oi} = 1.118 \text{ resbbl/STB} \]

\[
\begin{array}{|c|c|c|}
\hline
\text{Area (Acres)} & \text{Interval height (ft)} & \Delta V (ac-ft) \\
\hline
A_0 = 0 & - & - \\
A_1 = 80 & 40 & 1,067 \\
A_2 = 139 & 40 & 4,327 \\
A_3 = 209 & 40 & 6,913 \\
A_4 = 243 & 40 & 9,031 \\
A_5 = 319 & 40 & 11,205 \\
\hline
\sum \Delta V = 32,543 \\
\hline
\end{array}
\]

Oil in place (N) \( = \frac{(7750)(32543)(0.21)(1–0.26)}{1.118} \) = 35.1MMSTB

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: \( h = 222\text{ft}, c_i = 4 \times 10^{-6}\text{psi}, r_e = 6667\text{ft}, k = 12.3\text{md}, \mu = 0.64\text{cp} \). Equations (13), (14), (15) and (16) together with fig. 3 were also employed.

\[
\begin{array}{|c|c|c|c|c|c|}
\hline
\text{Time (Days)} & \text{Press. (Psia)} & \text{Np} \times 10^5 \text{(STB)} & \text{Wp} \times 10^5 \text{(STB)} & \text{E}_2 \times 10^2 \text{(rb/STB)} & \frac{F = (NpB_0 + Wp)}{10^6 \text{(rb/STB)}} & B_0 \text{(rb/STB)} \\
\hline
0 & 4312 & 0 & 0 & - & 1.118 & - \\
50 & 3943 & 0.343 & 0 & 0.512 & 0.384 & 1.1205 \\
150 & 3481 & 1.069 & 0.264 & 1.096 & 1.227 & 1.1234 \\
300 & 3284 & 1.915 & 1.73 & 1.443 & 2.327 & 1.1252 \\
600 & 3822 & 2.114 & 2.04 & 0.842 & 2.576 & 1.1222 \\
\hline
\end{array}
\]
The oil in place was finally estimated using fig. 5 yielding a value of 34.2MMSTB.

![Graph showing the plot of \( F/E_o \times 10^6 \) vs \( W_e/E_o \times 10^6 \) for Reservoir B]

**Fig. 5 Plot of \( F/E_o \) Vs \( W_e/E_o \) 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: \( \phi = 14\% \), \( S_w = 24\% \), \( B_{oi} = 1.3102 \text{ resbbl/STB} \).

#### Table 6: Pore volume computation table for Reservoir C

<table>
<thead>
<tr>
<th>Area (Acres)</th>
<th>Interval height (ft)</th>
<th>( \Delta V ) (ac-ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A_0 = 0</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>A_1 = 230</td>
<td>50</td>
<td>3,833</td>
</tr>
<tr>
<td>A_2 = 525</td>
<td>50</td>
<td>18,374.9</td>
</tr>
<tr>
<td>A_3 = 891</td>
<td>50</td>
<td>34,999</td>
</tr>
<tr>
<td>A_4 = 1241</td>
<td>50</td>
<td>53,059</td>
</tr>
<tr>
<td>A_5 = 2214</td>
<td>50</td>
<td>85,210</td>
</tr>
<tr>
<td>A_6 = 3661</td>
<td>50</td>
<td>145,367</td>
</tr>
<tr>
<td></td>
<td></td>
<td>( \sum \Delta V = 340,842 )</td>
</tr>
</tbody>
</table>

Oil in place (N) \( = \frac{\sum \Delta V}{1.3102} \times \frac{(7.758 \times 340,842 \times (0.14)/1 - 0.24)}{1.3102} = 214.7\text{MMSTB} \)

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 \( c_i = 4.95 \times 10^{-6} \text{ psi}^{-1} \) and \( c_w = 3.6 \times 10^{-6} \text{ psi}^{-1} \).
### Table 7: PVT data for Reservoir C

<table>
<thead>
<tr>
<th>Time (Days)</th>
<th>Pressure (psia)</th>
<th>N_p x 10^3 (STB)</th>
<th>B_o (rb/STB)</th>
<th>N_pB_o x 10^4</th>
<th>C_o x 10^6</th>
<th>ΔP</th>
<th>ΔP x 10^4</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>3685</td>
<td>0</td>
<td>1.3102</td>
<td>0</td>
<td>11.01</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>60</td>
<td>3685</td>
<td>0.342</td>
<td>1.3102</td>
<td>0.0448</td>
<td>11.01</td>
<td>0</td>
<td>0.93</td>
</tr>
<tr>
<td>120</td>
<td>3680</td>
<td>20.481</td>
<td>1.3104</td>
<td>2.6838</td>
<td>11.02</td>
<td>5</td>
<td>1.68</td>
</tr>
<tr>
<td>180</td>
<td>3676</td>
<td>34.750</td>
<td>1.3104</td>
<td>4.5536</td>
<td>11.03</td>
<td>9</td>
<td>3.39</td>
</tr>
<tr>
<td>240</td>
<td>3667</td>
<td>74.872</td>
<td>1.3105</td>
<td>9.812</td>
<td>11.04</td>
<td>18</td>
<td>3.93</td>
</tr>
<tr>
<td>300</td>
<td>3664</td>
<td>84.723</td>
<td>1.3105</td>
<td>11.103</td>
<td>11.05</td>
<td>21</td>
<td></td>
</tr>
</tbody>
</table>

**Fig.6:** Plot of N_pB_o Vs (\(\frac{(S_o-C_o)+(S_w-C_w)}{1-S_w}\))ΔP x 10^4 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: \(\phi = 18.5\%, S_w = 31\%, B_{gi} = 0.00178\)reshbl/SCF.

### Table 8: Pore volume computation table for Reservoir D

<table>
<thead>
<tr>
<th>Area (Acres)</th>
<th>Interval height (ft)</th>
<th>ΔV (ac-ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A_0 = 0</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>A_1 = 22</td>
<td>50</td>
<td>367</td>
</tr>
<tr>
<td>A_2 = 36</td>
<td>50</td>
<td>1,435.7</td>
</tr>
<tr>
<td>A_3 = 74</td>
<td>50</td>
<td>2,694</td>
</tr>
<tr>
<td>A_4 = 110</td>
<td>40</td>
<td>3,656</td>
</tr>
<tr>
<td>   (\Sigma ΔV = 8,152.7)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Oil in place (N) = \(\frac{(7750)(0.1527)(0.185)(1-0.31)}{0.00178} = 4.48\)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

<table>
<thead>
<tr>
<th>Time (Years)</th>
<th>Pressure (psia)</th>
<th>$G_p$ (MMMSCf)</th>
<th>$B_g$ (Res.bbl/Scf)</th>
<th>$G_pB_g \times 10^6$ (res bbl)</th>
<th>$(B_g - B_{gi}) \times 10^{-4}$ (Res.bbl/Scf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>3432</td>
<td>0</td>
<td>0.00178</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>0.5</td>
<td>3215</td>
<td>0.97</td>
<td>0.00196</td>
<td>1.90</td>
<td>1.82</td>
</tr>
<tr>
<td>1.0</td>
<td>3004</td>
<td>1.63</td>
<td>0.00214</td>
<td>3.48</td>
<td>3.62</td>
</tr>
<tr>
<td>1.5</td>
<td>2818</td>
<td>2.22</td>
<td>0.00229</td>
<td>5.08</td>
<td>5.10</td>
</tr>
<tr>
<td>2.0</td>
<td>2615</td>
<td>2.51</td>
<td>0.00247</td>
<td>6.21</td>
<td>6.88</td>
</tr>
</tbody>
</table>

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

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.
REFERENCES


