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Original Research Article

The Use of Volumetric and Material Balance Methods as Protocol for the Estimation of Reserve

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Abstract: Reserves estimation is one of the most crucial tasks in the petroleum industry. It is the process by which the economically recoverable hydrocarbons in a field, area, or region are evaluated quantitatively. A major goal in this initiative is preparation of training modules that depict industry's recommended practices. The scope of this investigation was limited to comparing two of the various methods of estimating reserve. These methods encompass: Volumetric and Material Balance. The volumetric estimation procedure was based on a detailed geological analysis. The Area vs. Depth graph was plotted using planimetry readings, and this was used to estimate the reservoir bulk volume. Arithmetic averages of petrophysical data from five wells were used. The Net-to-Gross ratio of the average sand thickness was estimated from log responses; and thus, the reserve was estimated with this method. The Material balance method was carried out using Pressure, Volume and Temperature (PVT) data, pressure and production history of the reservoir. The reservoir used as a case study has a combination drive mechanism; thus, the water influx was calculated using Hurst and Van Everdingen model. The Havlena and Odeh linear form of material balance equation was employed. The reserve estimate obtained from the Volumetric and material balance methods are in close agreement.

Keywords: Volumetric, Reservoir, Reserve, Material Balance, Net-To-Gross Ratio.

I.0 INTRODUCTION

Estimation of the oil and gas in place and the recoverable reserves happens to be a crucial phase in the various activities leading to the development of oil and gas fields. The ultimate target of all oil companies is to increase their income by producing oil and gas. The essential element to produce oil/or gas is the investments such as purchasing licenses, drilling wells, and constructing production facilities. Companies allocate their investments to a particular field by analyzing the ultimate recovery from that field (Rejas & Avinash, 2020). Calculating the oil and gas or hydrocarbon reserves in the oil and gas basin is necessary to estimate the potential amount of oil and gas reserves. Besides, calculating the volume of petroleum reserves is also needed to re-evaluate oil fields that are currently or have been operating. This aims to increase production and maximize the volume of subsurface oil and gas extraction (Ardiyansyah *et al*., 2021).

The general performance characteristics of hydrocarbon producing reservoirs are largely dependent on the types of energy available for moving the hydrocarbon fluids to the wellbore. Drive mechanisms are determined by the analysis of historical production data, primarily reservoir pressure data and fluid production ratios. The total resource base of oil and gas is the entire volume formed and trapped in place within the earth before any production. The largest portion of this total resource base is non-recoverable by current or foreseeable technology. Most of the nonrecoverable volume occurs at very low concentrations throughout the earth's crust and cannot be extracted short of mining the rock or the application of some other approach that would consume more energy than it produced. Depending on the kinds and amounts of data available, and a judgment on the reliability of those data, the estimator will select one of several methods of making a proved reserve estimate. Methods based on production performance data are generally more accurate than those based strictly on inference from geological and engineering data. Data collection is a process of inspection, transforming and modeling data with the goal of discovering useful information, informing and support decision-making (San, 2019).

Volumetric Method; as the name implies, requires the volume of the reservoir to be calculated through maps and petrophysical data of the drilled wells. This method is carried out in the early phases of exploration to find the amount of Oil and Gas in place and the likely corresponding reserves (Rejas & Avinash, 2020). This method is used when the available data is incomplete. The method can be used to determine the initial hydrocarbon in place (Ardiyansyah *et al.*, 2021). Volumetric methods of estimating Hydrocarbon Initially in Place (HIIP) can be engaged immediately after first discovery, before production begins. For this reason, they are the primary tool used for the techno/economic assessment of oil properties and for the design of field-development projects. The accuracy of HIIP estimates calculated using volumetric method depends significantly on one's understanding of regional geology and on the quality of the seismic analysis, both of which will improve as more wells are drilled and more accurate descriptions, geologic and petrophysical maps of reservoirs become available (Urayet, 2004). Three different volumetric methods—Isopach, Pore-volume, and Hydrocarbon pore volume are used to estimate Oil Initially in Place (OIIP), and they all use the same basic data: petrophysical properties described by well logs, geological maps, and the physical properties of the oil at the initial reservoir conditions (Ahmed, 2010; Saleh *et al.*, 2010)

The main and most global method of calculating oil reserves is the volumetric method, which can be performed at any stage of reservoir development with varying degrees of accuracy. The importance of the volumetric method of reserve estimation is also explained by the fact that the study of geological features of the field structure in order to determine its shape, size, nature of reservoirs, their oil content, etc., which is the basis of the volumetric method, is the logical conclusion of geological exploration, while calculation of almost all the parameters of the volumetric method is also necessary for the development project (Deryaev, 2024). In calculating reserves using the volumetric method, bulk volume value (V_b), rock porosity (φ), fluid saturation (S_w), and formation fluid volume factor are required (Bischke *et al*., 2021; Gherabat,2020). To calculate the bulk volume of the reservoir layer, the area from the depth structure map is calculated first using the grid method (Amyx *et al*., 1988). Then, bulk volume calculations can be done using the pyramidal and trapezoidal equations, which are determined based on the ratio between the area with the greatest thickness with the area above it (Ardiyansyah *et al*., 2021).

The Material Balance Method is a dynamic method that estimates HIIP by analyzing historical data on production and pressure (Saleh, 2019). Calculations using the material balance method are carried out based on changes in reservoir conditions during production. The material balance method requires fluid properties, reservoir and production data. The method can be used to estimate the initial volume of hydrocarbons in place, predict future reservoir behavior, and the recovery of hydrocarbons in various primary drive mechanisms (Ratnaningsih, 2022). Material Balance employs the Single Tank Model, treating reservoir systems as homogeneous units or ―blocks. One of the earliest, simplest, and yet most reliable tank models is the Schilthius Tank Model, which is expressed as a Volumetric Material Balance Equation (Ahmed, 2010; Saleh *et al.,* 2019).

The material balance method can be used to estimate the number of reservoirs' reserves in gas and oil fields that have been developed, where the production data obtained is quite a lot. The principle of the derivation of the equation is formulated upon the Schiltuis equation (1936), which is predicated on the law of conservation of mass, where the amount of mass in the system is constant or there is a volume balance between cumulative production and reservoir fluid expansion or the net withdrawal of the fluid (produced – inputted) is the sum of the change in the original reservoir fluid volume and the expansion due to pressure drop (Widiyaningsih *et al*., 2021)

The material balance equation or MBE is a standard approach for analysing reservoir recovery performance given natural drainage conditions. Indeed, the general structure of material balance offers a robust tool that can ascertain important reservoir functions and assist in decisions about their applications. In particular, it is used to undertake history matching of the historical performance of a reservoir, to estimate OHIP and the recovery rate as well as to make predictions or at least forecasts about future performance. Additional crucial variables that the MBE can assess are aquifer support and reservoir pressure. The important economic and technical decisions made in field development all rely on this kind of analysis (Mashallo, 2020)

Material balance models are simplified numerical approximations to estimate the evolution of oil and gas reservoirs when undergoing depletion and injection. The model typically assumes that there is one container which, if an oil reservoir, the producing layer, gas-cap and aquifer or, if a gas reservoir, the producing layer and aquifer. The input to the model is usually production and injection profiles, initial surface gas or oil in place, gas-cap and aquifer size, fluid and rock properties and relative permeability curves. The output is profiled in time of reservoir pressure, saturation of oil, gas and water, and incremental produced surface volumes of the associated phase, i.e. gas and water if an oil reservoir or condensate and water if a gas reservoir (Stanko, 2020).

2.0 METHODOLOGY

In this study, a practical example is provided and an oil reservoir is considered. The oil reservoir employed is located in the Niger Delta area of Nigeria, an oil-bearing reservoir, which was tested for production in March 1985 and placed on product1on in 1986.

2.1 Volumetric Estimation of A2 Reservoir

Volumetric method for estimating stock tank oil initially in place (STOIIP) is based upon log response, core analysis and/or geological parameter to determine the bulk volume, porosity, fluid saturation and fluid analysis (PVT data) to determine the oil formation volume factor.

2.2 Steps in Volumetric Estimation

The steps used in volumetric estimation are based on the available data. The following are required for any volumetric estimation to be done; Geological data, Petrophysical data and PVT data.

A. Geological Data

The structural map is the basic Geological data required. It is a map showing the level and depths of the reservoir increase in a field. This structural map is planimetered to get the area of each contour line. This is done either with a digital or mechanical planimeter. Planimetering is done normally up to the GOC and OWC. Before planimctering, the planimeter is set up to a scale factor of the structural map. The general scale in most Niger Delta structural maps including the one used in this work is $I: 25000cm$.For a mechanical planimeter therefore, the following conversions are made.

$$scale\ 1:25000\ cm$$
$$1:250\ m$$

This means that 1cm on paper is equivalent to 250m in the reservoir

$$= 250m\ x\ 3.281ft\ x\ 1m^{-1}$$
$$= 820.25ft$$
$$1\ unit\ from\ planimetering = 1sqft$$
$$Or\ 1sqcm\ on\ map = (820.25)^2 ft^2$$
$$1ft^2 = \frac{1}{(820.25)^2} cm^2$$

Converting this to acres;

$$1\ acre = 43560ft^2$$
$$1ft^2 = \frac{1}{43560} acre$$

Therefore,

$$\frac{1}{(820.25)^2} cm^2 = \frac{1}{43560} acre$$
$$1cm^2 = \frac{(820.25)^2}{43560} acre$$

Therefore, I planimeter unit

$$= \frac{820.25^2 ft^2}{43560\ ft^2/acre} = 15.445acres$$

The cumulative bulk volume of the reservoir can be estimated from the structural map by the help of a Depth Vs. Area graph of the structural map (see Figure l). At this stage, only the top sand curve is plotted. Then to obtain the base sand curve, the average thickness of the reservoir is added to each of the depth and corresponding areas earlier plotted. The contact levels are marked out and the bulk volume is calculated from the graph up to the oil water contact.

B. Petrophysical Data

Petrophysical Data required for volumetric estimation include Porosity,φ, Connate water saturation (S_{wc}), Oil saturation (S_o), Shale factor (F), also known as net gross factor, sand thickness, sand top ($ft - ss$), sand base ($ft - ss$), GOC, and WOC. Because of reservoir heterogeneity, weighted average of these data is usually used during evaluations. Petrophysical data are obtained from self-potential (Spontaneous potential) logs and gamma-ray logs run on the wells drilled into the reservoir A2; from which petrophysical properties of interest are determined.

C. PVT Data

The initial volume factor is the main PVT parameter required for volumetric calculation. It enables the calculation of Stock Tank Oil Initially in Place (STOIIP) and other PVT parameters needed for material balance calculations like reservoir viscosity, μ_o, oil specific gravity, γ_O, gas viscosity, μ_g, solution gas-oil ratio, and pressure. A2 reservoir was producing through petrophysical parameters as obtained from the logging of five wells, depicted in Table 1.

2.3 Reservoir Volume

The volume of the oil-bearing rock in A2 reservoir under consideration is a very important parameter in the estimation of STOIIP. The Depth Vs. Area graph is the method used in this work and for all cases where the geometry of the reservoir is represented by contour map, structure map or some form of thickness map. The area enclosed by each contour depth obtained were deployed against corresponding measured depth (see Figure I). From the structural map or log response, the Gas-oil contact and Oil-water-contact were inferred. Each is represented within the reservoir zone by a straight horizontal line. The space enclosed by the GOC and OWC gives the gross oil-bearing volume of the reservoir. The planimetry constant used was 15.45 acres as was got from the scaled structural map. The planimetry readings for A2 reservoir are shown in Table 2.

2.4 Gross Volume Computation

A2 reservoir shows a uniform sand development trend so that the Area vs. Depth graph approach is considered sufficiently accurate for estimation of gross volume from the cumulative bulk volume area- depth graph (Figure l), the gross oil-bearing volume of the reservoir is that bounded by the GOC and OWC. The entire volume of A2 reservoir is underlain by bottom water, so the curve for the base reservoir is replaced by a straight line at the OWC depth.

Area of trapezium ABCD (i.e., area enclosed by GOC and OWC)

$$= 1/2\,(sum\ of\ parallel\ sides)x(perpendicular\ height)$$
$$\text{ABCD} = 1/2\,(8450 + 5150)x(10348 - 102262)$$
$$= 584800 \text{ acreft}$$

This gives a gross oil-bearing volume of $584800\ acreft$. From the interpretation of the structural map, the gross thickness is $(10348 - 10262).fi\ - ss$, which gives 86ft as the gross thickness. From the summary of the log response, the average net oil sand is $63\ ft$. Therefore, Net/gross ratio,

$$\text{F} = 63/86 = 0.73$$

2.5 Volumetric Calculation

After the above analysis, the complete data as determined are as follows:

$$\text{V}_b = 584800\ acreft$$
$$F = 0.73$$
$$\emptyset = 15\%$$
$$S_{wc} = 23\%$$
$$\text{B}_{oi} = 1.308\ \text{rb}/stb$$

Therefore,

$$STOIIP = \frac{7758xV_bx\emptyset xF(1 - S_{wc})}{B_{oi}}$$
$$= \frac{7758x584800x0.15x0.73x(1 - 0.23)}{1.308}$$
$$= 292.452x10^{-1}stb$$
$$= 292MMstb$$

2.6 Estimation of A2 Reservior Using MBE

For the estimation of STOIIP using material balance equation, the following data are required.

1. Reservoir fluid Pressure, volume, and temperature (PVT) properties.
2. Pressure/Production history of the reservoir.
3. Pressure/water influx history (for a reservoir with strong aquifer support).

The pressure history of reservoir A2 indicates that the pressure is at the bubble point at the initial pressure of 4487 psia in 1986, which explains the presence of a gas cap. The pressure declined from the initial value of 4487 psia to 4228 psia in 1993; then started increasing from 4230 psia in 1996. This is due to late aquifer response, which naturally repressurized the reservoir. Thus, it can be inferred from the foregoing, that A2 reservoir is producing under a gas cap, solution gas and water drive mechanisms. The reservoir PVT data shown in table 4 is corresponding to the pressure/production history. Also, the gas formation volume factor (B_g) in table 4 was calculated using the gas compressibility factors.

Calculation of (B_g)

The gas formation volume factor B_g is calculated using the equation.

$$B_g = \frac{1}{5.615\ E}(rb/scf) \qquad (1)$$

Where,

$$E = gas\ expansion\ factor$$

$$E = \frac{V_{sc}}{V_{res}} = \frac{Volume\ of\ n\ mole\ of\ gas\ at\ standard\ condition}{Volume\ of\ n\ mole\ of\ gas\ at\ reservoir\ condition}$$

$PV = ZnRT$

Where,

$$P = Pressure$$
$$V = Volume$$
$$Z = Gas\ compressibily\ factor$$
$$R = Universal\ gas\ constant$$
$$n = Number\ of\ moles$$
$$T = Absolute\ temperature$$

Therefore,

$$E = \frac{V_{sc}}{V_{res}} = \frac{P_{res}}{P_{sc}} x \frac{T_{sc}}{T_{res}} x \frac{Z_{sc}}{Z_{res}} \ (2)$$

Assuming ideal behaviour at standard condition of $P_{sc} = 14.7\ psia$, $T = 520$ K and $Z = 1.0$

Thus,

$$E = \frac{520\ x\ 1.0\ x\ P_{res}}{14.7\ x\ T_{res}\ x\ Z_{res}} = \frac{35.37\ P}{ZT}$$

It implies that

$$B_g = \frac{1}{5.615\ x\ 35.35\ x\ (P/ZT)}$$

$$B_g = \frac{ZT}{198.6\ P}\ (rb/scf)\ (3)$$

A2 reservoir has a constant isothermal temperature of 755 K. So absolute temperature

$$T = 755 + 460 = 1{,}215$$

$1{,}215\ x\ 5/9 = 675$ K.

Therefore, using eqn. (3), for $P = 4487\ psia$ and the corresponding $Z = 0.842$ from table 4,

$$B_g = \frac{0.842\ x\ 675}{198.6\ x\ 4487} = 0.639\ x\ 10^{-3}\ (rb/scf)$$

Similarly, all other values for B_g were calculated using their corresponding pressure P and compressibility factors Z (see table 4).

2.7 MBE Application on A2 Reservoir

The linear form of general material balance equation (Dake, 1978) is given by:

$$F = N\left[E_O + mE_g + E_{f,W}\right] + W_e B_W\ (4)$$

In applying the equation to A2 reservoir, the following are assumed:

1. The reservoir is producing under combination drive.
2. Change in the HCPV due to connate water expansion is negligible.
3. The water formation volume factor B_W is I.

With these, the linear MBE equation is reduced to:

$$F = N\left[E_O + mE_g\right] + W_e$$

Dividing through the coefficient of N, we have,

$$\frac{F}{E_O + mE_g} = N + \frac{W_e}{E_O + mE_g}\ (5)$$

A plot of $(F/(E_O + mE_g)$ against $W_e/(E_O + mE_g)$ on a Cartesian graph will give a straight line with an intercept of N, which is the desired STOIIP. The estimation of "m" is as follows. Rock volume of gas cap (between top of sand and gas oil contact),

$$= 1/2\ (5150 + 2400)(10260 - 10160) = 377500\ acreft$$

. Rock volume of the oil leg (between GOC and OWC)

$$= 1/2\ (8450 + 5150)(10340 - 10262)$$
$$= 544000\ acreft.$$

Therefore, the ratio $m = \frac{377500}{544000} = 0.694 \cong 0.7$

2.8 Calculation of $F, Eo\ and\ Eg$ for the corresponding pressure

From the of general material balance equation

$F = N_P\left[B_O + (R_P - R_S)B_g\right] + W_P$ (rb)

as the underground withdrawal

$E_O = (B_O - B_{Oi}) + (R_{Si} - R_S)B_g$ (rb/stb)

Which is the oil and dissolved gas expansion terms.

$E_g = B_{oi}(\frac{B_g}{B_{gi}} - 1)$ (rb/stb)

The gas cap expansion

The above equations are then used for the different pressures.

For $P1 = 4444\ psia$

$$F1 = 2010\ x\ 10^{-3}[1.301 + (746 - 799)\ 0.644\ x\ 10^{-3}] + 0$$
$$= 2.546\ x\ 10^{6}\ \text{rb}$$
$$E_O1 = (1.301 - 1.308) + (811 - 799)0.644\ x\ 10^{-3}$$
$$= 0.000073\ \text{rb/stb}$$
$$E_g1 = 1.308\left(\frac{0.644}{0.639} - 1\right)$$
$$E_g1 = 0.0102\ rb/stb$$

Jn the same way, calculations were made for other pressures and the results are displayed in table 5.

2.9 Water Influx Calculations

Reservoir A2 has an oil column underlain by an aquifer, which became strong after sometime during the production history, helping to repressurize the reservoir. In the estimation of water influx, Hurst and Van Evendingen method was applied. In doing this, the dimensionless time t_D for one day is calculated using.

$$t_D = \frac{4.56\ x\ 10^{-7} x\ Kt}{\varphi \mu C_t A}$$

For this computation, the relevant data are obtained from the petrophysical data in the table 5.

$$\text{Thus, } t_D = \frac{4.56\ x\ 10^{-7} x\ 585t}{0.15\ x\ 0.53\ x\ 0.7\ x 10^{-6}\ x\ 8500}$$

The water influx is calculated using water influx equation.

$$W_e = U \sum_{i=0}^{n-1} \Delta P_i W_D(t_D - t_{Di})\ \ (6)$$

Where U= water influx constant

$W_D(t_D)$= dimensionless water influx read from the Van Everdingen and Hurst water influx chart. This is for $r_e\ (r_w\ =\ 40)$.

The pressure drop $\Delta P(P_{si})$ is calculated using the equation,

$$\Delta P_i = \frac{P_{i-1} - P_{i+1}}{2}$$

Which is calculated at the occurring times 0 to 3285.

The water influx for different ΔP is calculated using the water influx equation of W_e by using the given field data in which,

$W_e\ =\ Total\ water\ influx\ (rb)$

ΔP= Pressure drop

For the field data, U has been taken to be the slope of $F/(E_O + mE_g)$ Vs $W_e/(E_O + mE_g)$ plot, which is theoretically equal to 1. A summary of MBE table of values calculated is shown in table 5. The water influx calculations are also shown in table 5.

We = Total water influx (r_b(rb)

ΔP_i = Pressure drop

$W_D(t_D - t_{Di})$= dimensionless water influx corresponding to ΔP_i.

A plot of $(F/(E_O + mE_g)$Vs $W_e/(E_O + mE_g)$ was obtained which is shown in fig. 3. The intercept N is the stock tank oil initially in place $(STOIIP), N = 213\ MMSTB$.

Table 1: Electrical Log Data

Well	Top sand (ft-ss)	Bottom sand (ft-ss)	Net oil sand Top sand (ft)	Porosity (%)	Water saturation (%)
2T	10123	10408	73	13.0	28.0
3T	10110	10364	66	18.0	22.0
4T	10190	10466	62	16.0	24.0
5T	10191	10443	61	15.0	21.0
6T	10178	10450	51	14.0	20.0
	AVERAGE		63	15.2	23.0

Table 2: Planimetry Readings

Depth (ft-ss)	1st reading	2nd reading	Average reading	Area (acre) Average x 15.45
10150	142.40	142.40	142.40	2200
10200	227.0	226.00	226.50	3500
10250	310.70	310.70	310.70	4800
10300	333.30	333.30	333.30	5150
10350	411.50	411.50	411.50	6350
10400	547.00	546.80	546.90	8450

Table 3: Petrophysical Data of A2 Reservoir

Porosity	$\mathbf{15}$ %
Connate water saturation S_{wc}	23 %
Net to gross ratio (F)	0.73 %
Gas- oil-contact (GOC)	$10262\ (ft-ss)$
Oil-water-contact (OWC)	$10348\ (ft-ss)$
Average sand thickness	$63\ (ft)$
Area of oil leg (A)	$85000\ (acres)$
Permeability (K)	$585\ md$
Water plus rock compressibility	$0.7\ x\ 10^{-6}\ psi^{-1}$
Aquifer configuration	40
Water viscosity	$0.53\ cp$

Table 4: PVT Data of A2 Reservoir

Pressure $(psia)$	B_o $(rb/_{stb})$	R_s $(scf/_{stb})$	Z	$B_g\ 10E^{-3}$ $(rb/_{scf})$
4487	1.308 (B_{oi})	811(R_{si})	0.842	0..639(B_{gi})
4444	1.301	799	0.843	0.644
4416	1.298	793	0.840	0.647
4370	1.297	788	0.836	0.650
4332	1.293	785	0.834	0.654
4298	1.290	779	0.833	0.659
4260	1.287	774	0.831	0.653
4228	1.285	769	0.829	0.666
4230	1.286	772	0.829	0.667
4257	1.289	778	0.830	0.665
4282	1.299	780	0.833	0.665

Table 5: MBE Table of Values

Pressure $(psia)$	F $(MMrb)$	E_o $(rb/_{stb})$	E_g $(rb/_{stb})$	mE_g $(rb/_{stb})$	$E_o + mE_g$	W_e Mrb	$F/(E_o + mE_g)$	$W_e/(E_o + mE_g)$
4487								
4444	2.5464	0.00073	0.0102	0.00714	0.00787	1.63	323.507	207.116
4416	5.337	0.00165	0.0164	0.01148	0.01313	5.67	406.474	431.835
4370	8.410	0.00395	0.0225	0.01575	0.01917	11.82	426.904	600.000
4332	12.369	0.00200	0.0310	0.0217	0.02370	20.22	521.899	853.165
4298	16.194	0.00309	0.0409	0.0286	0.03169	30.13	511.013	950.773

$\boldsymbol{Pressure}$ $(\boldsymbol{psia})$	$\boldsymbol{F}$ $(\boldsymbol{MMrb})$	$\boldsymbol{E_o}$ $(\boldsymbol{rb/_{stb}})$	$\boldsymbol{E_g}$ $(\boldsymbol{rb/_{stb}})$	$\boldsymbol{mE_g}$ $(\boldsymbol{rb/_{stb}})$	$\boldsymbol{E_o + mE_g}$	$\boldsymbol{W_e}$ $\boldsymbol{Mrb}$	$\boldsymbol{F/(E_o + mE_g)}$	$\boldsymbol{W_e/(E_o + mE_g)}$
4260	20.751	0.00316	0.0287	0.02009	0.02325	41.58	892.516	1788.387
4228	26.194	0.00497	0.0553	0.03871	0.04368	54.53	599.679	1248.397
4230	28.2560	0.00401	0.0573	0.04011	0.04412	67.14	640.435	1521.759
4257	29.360	0.00295	0.0532	0.03724	0.04019	77.29	731.276	1923.115
4282	30.6540	0.01160	0.0532	0.03724	0.04884	84.81	627.641	1736.486

Table 6: Summary of Results

Method	**Results**
Volumetric	292 $MMSTB$
Material balance	213 $MMSTB$

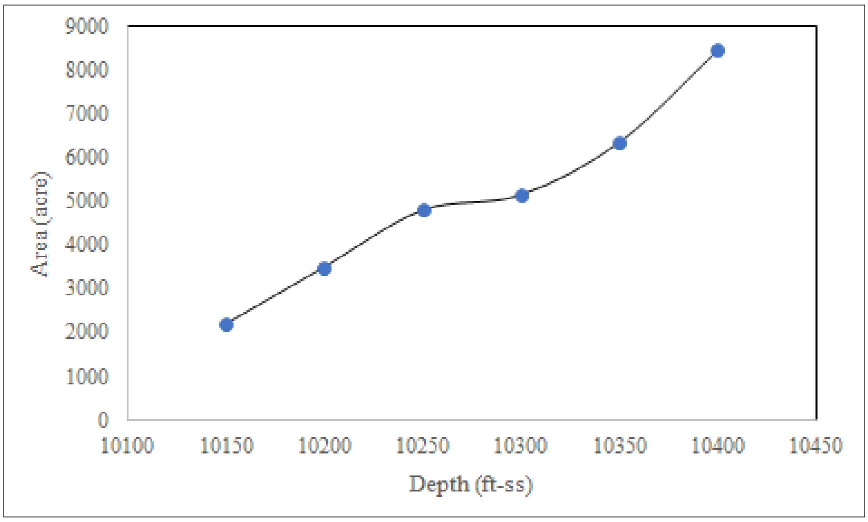

Figure 1: Plot of Depth vs. Area for gross

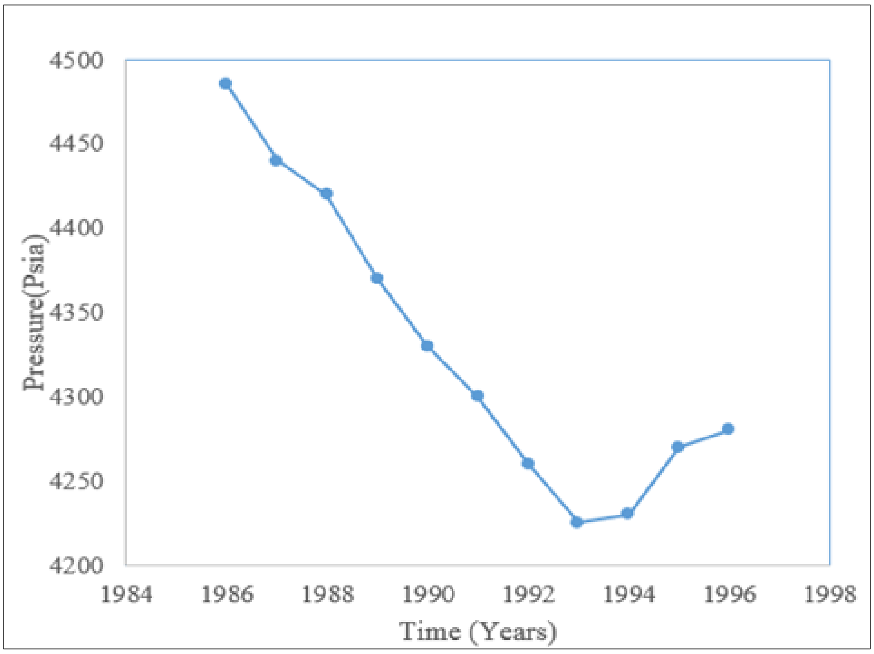

Figure 2: Plot of Pressure history of the reservoir

3.0 DISCUSSION

This study has investigated the use of volumetric and material balance methods of reserve estimation for evaluating the stock tank oil initially in place (STOIIP) of A2 reservoir. In comparing the results obtained from the two methods, there was a close match in their results. The results obtained from the two methods differ because of the different assumption made, level of accuracy, and the different method of approach. The result from the volumetric calculation is higher than that of the material balance by 79MMSTB. The results obtained from the different methods differ because of the different assumptions made, level of accuracy and the method of approach of each. The volumetric result is an over-estimation and it is referred to as a rough estimation of the work. This is because the parameters used are based on the initial geologic data of the reservoir. The material balance takes account of the reservoir as well as the fluid PVT data. Besides, it is a dynamic method based on current reservoir fluid expansion due to production and therefore, the physical law of conservation of mass.

4.0 CONCLUSION

The STOIIP obtained from the Volumetric method was $292 MMstb$.The production history of A2 reservoir indicated a fairly constant rate between 1986 and 1990 after which the rate started declining. The material balance data when plotted gives a straight line with an intercept on the vertical axis, which estimated the reserve as 213MMSTB.Aquifer water was responsible for the gradual repressurization experienced by the reservoir from 1994 upward. A2 reservoir still has a large quantity of oil to be discovered and hence may require additional wells to increase its daily production.

5.0 RECOMMENDATIONS

Following a quantitative analysis of A2 reservoir, the following recommendations are made:

1. Volumetric method should be used in the quantitative evaluation of newly discovered reservoirs.
2. Over the life of the field/reservoir, the volumetric value should be updated using the material balance method.
3. A2 reservoir experiencing repressurization may require re-evaluation of its material balance result using a modified material balance method for repressurized reservoir if repressurization continues in the future.
4. The production companies should make certain that the production data are accurately taken for accurate reserve estimation.
5. For more study for A2 reservoir, it is recommended or advised that a simulation study be done.

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