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Comparison of Decline Curve Analysis and Material Balance Method as Procedure for Estimating Reserve

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Abstract-* Reserve estimation is by far an essential aspect with regards to Petroleum Engineering jobs. Several methods have been developed for estimating and evaluating reserve. The present work therefore focused on comparing two of the various methods of estimating reserve. These methods are: Decline Curve Analysis and Material Balance. The decline curve analysis was based on observed production history. The reservoir used in this paper shows an exponential decline trend with a constant; 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 with Decline Curve Analysis and material balance methods are in close agreement.

Keywords: Decline Curve, Exponential decline, Material Balance, Reserve, Reservoir

I. INTRODUCTION

Estimation of reserves is one of the most important works of a Petroleum Engineer; and also, one of the most essential tasks in the petroleum industry. It is the process by which the economically recoverable hydrocarbons in a field, area, or region are evaluated quantitatively. Long before the issue caught the public's attention, however, reserves estimation was a challenge for the industry. The challenge stems from many factors: tangible and intangible, that enter the estimation process, and judgment is an integral part of the process (Rejas and Avinash, 2020).

Specifically, a knowledge of reserves is necessary for decisions on the exploitation and development of a reservoir, evaluation of the result of an exploitation program, financing of the development among others. These estimates will help the operating companies to economically evaluate returns expected from the venture. The sustainability of an oil and gas company depends upon its ability to replace reserves at a faster pace than its production rate. The primary determinants of the value of an oil and gas company are its cash flows and earnings, which are dependent upon the quantity and quality of the hydrocarbons it produces, along with commodity sales, prices, production potential, which is described by its reserves, reserves replacement rate, and its inventory of capital assets, equipment, infrastructure, and acreage (Mark, 2019).

Unfortunately, reliable reserve figures are mostly needed during the early stages of a project, when only a minimum amount of information is available. Because the information base is cumulative during the life of a property; the Reservoir Engineer has an increasing amount of data to work with as a project matures, and this data increase not only changes the procedures for estimating reserve but also correspondingly improve the confidence of the estimate. Reserves are frequently estimated (i) before drilling or any subsurface development is done, (ii) during the development drilling of the field, (iii) after some performance data are available, and (iv) after performance trends are well established Reserves estimation can be categorized relating to pre and postproduction stages i.e. (static and dynamic). The static methods indicate analogy and volumetric calculation which are used before the start of production in the reservoir and generally used geologic and engineering data while dynamic methods involved performance techniques applied after production started in the field and typically need production data and pressure of wells (Abdelrazek, 2023).

Material balance is the process of using the application of conservation of mass to the analysis of a reservoir (tank) system. They are routinely used to estimate oil and gas reserves and predict future reservoir performance, Schilthuis, in 1936 was among the first to formulate and apply material balances. An MBAL tool software was used to achieve this process by identifying reservoir characteristics and properties using the material balance concept. MBAL (Material Balance) is used to estimate the oil or gas originally in place and understanding drive mechanisms, and to estimate the current fluid contacts in the reservoirs. The main purpose of a material balance study is to calculate the remaining hydrocarbon reserves and future reservoir performance. MBAL is used for either a single tank or multiple tanks (Ayorinde *et al.,* 2019).

The material balance is simply a volumetric balance, which states that since the volume of a reservoir is a constant, the sum of the volume changes of the oil, the free gas and the water volume must be zero. When an oil and gas reservoir is tapped with wells, oil and gas, and frequently some water, are produced, thereby reducing the reservoir pressure and causing the oil and gas to expand to fill the space vacated by the fluids removed. Where the oil and gas bearing strata are connected with water bearing strata, or aquifers, water encroaches into the reservoir as the pressure drops owing to production, decreasing the extent to which the remaining oil and gas must expand and accordingly retarding the decline in reservoir pressure. Method 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 (San,2019).

Engineers have been using the material balance equation (MBE) for almost the last five decades to estimate cumulative production. However, it still is an effective tool to estimate the original hydrocarbon (oil and gas) available in the reservoir. The conventional material balance method has been successfully applied for the regular structure of a typical reservoir. In this method, all formation properties are assumed constant. However, it is very important to take care of the alteration of rock and fluid properties concerning space and time during the production history of the reservoir. Therefore, there is an immense need to understand how rocks and fluid properties change with space and time (Rashid & Hossain, 2020).

The decline curve analysis (DCA) technique is the simplest, fastest, least computationally demanding, and least data-required reservoir forecasting method. Assuming that the decline rate of the initial production data will continue in the future, the estimated ultimate recovery (EUR) can be determined at the end of the well/reservoir lifetime based on the declining mode (Taha *et al.,* 2023). Decline-curve analysis (DCA) is a widely utilized method for production forecasting and estimating remaining reserves in oil and gas reservoir. Based on the assumptions that past production trend can be mathematically characterized and used to predict future performance. It relies on historical production data and assumes that production methods remain unchanged throughout the analysis. This method is particularly valuable due to its accuracy in forecasting and its broad acceptance within the industry (Rahaman *et al*., 2025).

When bidding for a license area for hydrocarbon exploration, operating companies need to evaluate an expected margin as accurately as possible. A significant portion of overall investment into an oilfield is spent to get as much a-priori information about a reservoir as possible. Estimation of expected oil recovery is essential for the asset evaluation and further field development planning. Oil recovery factor is critically affected by characteristics of the reservoir (geological structure, internal architecture, properties of reservoir rock and fluids) and the specifics of the oilfield development scheme (Ivan *et al*.,2022; Lu *et al.*,2017)

The analysis presented in this paper compares two methods of estimating reserve. These methods are: Decline curve and Material Balance. The accuracy of such estimation of reserve and other parameters depends on the quality and the kind of performance data available. The procedure can be used to estimate both oil and gas reserves but this work will focus on oil reserve estimation only. In reserves estimation, uncertainty, along with risk, is an endemic problem that must be addressed. Consequently, the industry's record of properly predicting reserves has been mixed. Despite appeals from some quarters, there is currently

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no standardized reserves-estimation procedure (Rejas and Avinash, 2020).

Mathematically, there are basically three types of production decline:

i. Exponential constant percentage decline.
ii. Hyperbolic decline.
iii. Harmonic decline.

Decline curve has been developed empirically by principles of lost ratio. The Exponential, Hyperbolic and Harmonic declines were also developed. Of these three declines, only hyperbolic decline does not have a direct linear form from Production rate and time equation. Exponential and Harmonic form of the rate trend with time could easily be transformed to straight line forms based on simple Algebraic operations (Nwankwo, 2024).

The material balance equation (MBE) is a versatile analytical tool in petroleum reservoir engineering. Solution to the MBE is put to a predictive use for predicting reservoir performance, i.e., cumulative oil production, N_p as a function of the declining average reservoir pressure (Olatunde *et al.,* 2015).

II. METHODOLOGY

Decline curve analysis method of reserve estimation is a graphical representation of production curve that decreases with time. The curves are known as "decline curves".

A. *ESTIMATION OF A2 RESERVOIR USING DECLINE CURVE ANALYSIS*

For the purpose of this work, a field example is used and an oil reservoir is considered. The oil reservoir employed is in the Niger Delta area of Nigeria, an oil-bearing reservoir which was tested for production in March 1985 and placed on production in 1986. From the production history depicted in Figure 1, it shows that production rate was fairly constant between 1986 and 1990 but decline afterwards. A semi log plot of rate versus time shown in Figure 2 indicates that A2 reservoir has a constant or exponential decline from 1990 to 1996. The maximum amount of produceable oil from the reservoir was calculated to be 193.10 MMSTB. Considering up to 1996 when the estimation was done, a cumulative production of 16.570 MMSTB has been obtained from A2 reservoir. Therefore, the estimate of Stock tank oil initially in place (STOIIP) of the reservoir is gotten by adding cumulative production up to 1996 to maximum oil produceable (N_{pmax}) from the reservoir.

Therefore, $\text{STOIIP} = 16.570 + 193.10$

$= 209.67 \text{ MMSTB}$

B. *ESTIMATION OF A2 RESERVOIR 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 1 is corresponding to the pressure/production history. Also, the gas formation volume factor (B_g) in table l was calculated using the gas compressibility factors.

Calculation of ($\boldsymbol{B_g}$)

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

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

Where

$$E = gas\ expansion\ factor$$

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$$E = \frac{V_{sc}}{V_{res}} = \frac{Vol. of\ n\ mole\ of\ gas\ at\ standard\ cond.}{Vol. of\ n\ mole\ of\ gas\ at\ reservoir\ cond.}$$

$$PV = ZnRT$$

Where,

$P = Pressure$

$V = Volume$

$Z = Gas\ compressibily\ factor$

$R = Universal\ gas\ constant$

$n = Number\ of\ moles$

$T = Absolute\ temperature$

Therefore,

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

Assuming ideal behaviour at standard condition of

Thus,

$P_{sc} = 14.7\ psia, T = 520$ K and $Z = 1.0$

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

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

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

It implies that

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

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

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

Therefore, using eqn. (3), for $P = 4487\ psia$ and the corresponding

$$Z = 0.842$$

From table 1

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

Similarly, all other values for B_g were calculated using their corresponding pressure P and compressibility factors Z (see table 1).

C. MBE APPLICATION ON A2 RESERVOIR

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

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

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:

$$F = N[E_O + mE_g] + W_e$$

Dividing through the coefficient of N, we have,

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

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

$$m = \frac{377500}{544000} = 0.694 \cong 0.7$$

D. CALCULATION OF F, Eo and Eg FOR THE CORRESPONDING PRESSURE

From the general material balance equation

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

as the underground withdrawal

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

Which is the oil and dissolved gas expansion terms

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

The gas cap expansion

The above equations are then used for the different pressures

$$= 2.546 \times 10^6\ \text{rb}$$

$$E_O1 = (1.301 - 1.308) + (811 - 799)0.644 \times 10^{-3}$$
$$= 0.000073\ \text{rb/stb}$$

$$E_g1 = 1.308\left(\frac{0.644}{0.639} - 1\right)$$
$$E_g1 = 0.0102\ rb/stb$$

Jn the same way, calculations were made for other pressures and the results are displayed in table 2.

E. WATER INFLUX CALCULATIONS

Reservoir A2 has an oil column u underlain by an aquifer, which became strong after some time 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 t0 for one day is calculated using.

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

For this computation, the relevant data are obtained from the petrophysical data in the table 3.

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

The water influx is calculated using water influx equation.

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

Where U= water influx constant

Wo(to) = 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 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 3. The water influx calculations are also shown in table 3.

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 ($STOIIP$), $N = 213\ MMSTB$.

III. DISCUSSION

In this study, decline curve and material balance methods of reserve estimation have been used to estimate 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 material balance calculation is higher than that of the decline curve analysis by 3MMSTB. This can be said to be near the actual reserve estimate since 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.

IV. CONCLUSION

The Decline curve analysis result obtained was 210MMSTB. 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.

V. RECOMMENDATIONS/ FURTHER WORKS

Having quantitatively analyzed A2 reservoir, the following recommendations are made:

i. 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.
ii. The production companies should ensure that the production data are accurately taken for accurate reserve estimation.
iii. For more study for A2 reservoir, it is recommended or advised that a simulation study be done.

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Table 1: 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 2: 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
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

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Table 3: PETROPHYSICAL DATA OF A2 RESERVOIR

Porosity	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: SUMMARY OF RESULTS

Method	Results
Decline curve analysis	210 $MMSTB$
Material balance	213 $MMSTB$

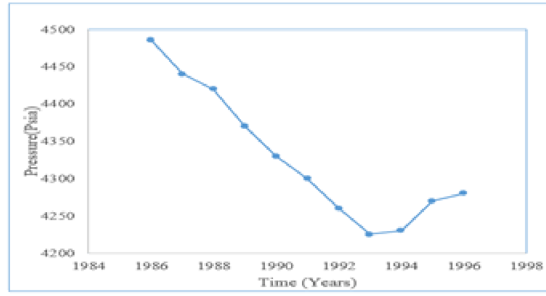

Fig 1: Plot of Pressure history of the reservoir

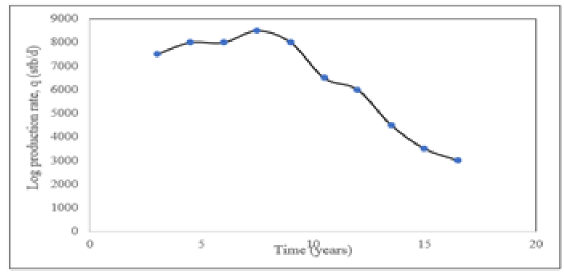

Fig 2: Plot of Log of production rate vs. Time

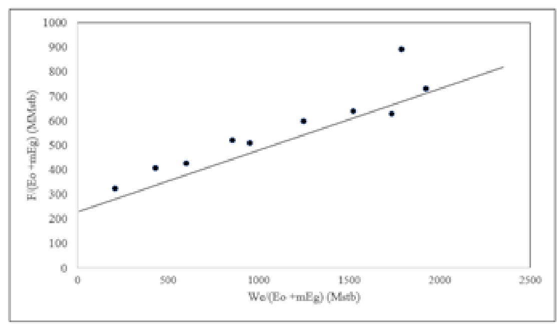

Fig 3: Plot of $F/(E_O + mE_g)$ Vs. $W_e/E_O + mE_g)$