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Review of the Methods for Estimating Hydrocarbon in Place

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Abstract:
Reserve Estimation is an important and essential aspect of petroleum engineering. This is because as we all know the aim of all oil operators is to make profit and accurate reserve estimation so as to help the operator to determine its profit. Without his information, the operator cannot successfully embark on any project. This research works seeks to help find a lasting solution to errors and discrepancy that always arise in the obtained values of reserve in place. This will help the operators to always make decisions under situation of certainty thereby reducing risk. The Oziengbe reservoir, D4 Sand Guico reservoir, wedge shaped reservoir, A2 reservoir and a case study reservoir characteristic were reviewed. Also, all the methods of estimation used to estimate each reservoir were reviewed and objective assessment of each reservoir result was made. Each reservoir showed peculiar property and drive mechanism. Errors and discrepancy in estimation results are best minimized if the data used in obtaining the result are accurate.

Keywords*: Reserve, Reservoir, Hydrocarbon in place, Drive mechanism*

1. Introduction

CRUDE oil (petroleum) will remain one of the world's major if not the only major source of energy. Therefore, as old reserves get depleted rapidly, necessity is laid on the professionals in the oil and gas industries saddled with the responsibility of discovering new reserves. As it is known, the sole aim of the operator is to make maximum profit; this is why estimation of reserves is of great importance to determine the volume of hydrocarbon in a reservoir if it meets economic quantity.

Reserve estimation is the process of determining how much of these reserves exist. (Ramalial T. K. and Prosper A. 2013). Petroleum reserves are volumetric estimates of hydrocarbon that can be economically produced from a reservoir to the surface.

A number of methods are being employed to date for estimating reserves but estimation is not an exact science. The reason is that the process of estimation is based on limited data which must be extrapolated over large area and long period of time. Therefore, uncertainties do arise in making such estimates.

Estimating oil or gas reserves is one of the most important phases of work a petroleum engineer, since the solutions of problems which are dealt with usually depends on the comparison of the estimated cost. Specific engineering problems which require such knowledge of recoverable oil or gas reserves and a projection of future rates are the exploitation and development of oil or gas reservoir.

In general perspective, petroleum reserves refer to the quantities of petroleum available for production plus the quantities which are anticipated to become available within a practical timeframe through additional field development technological advances, or exploration. In 1962, J. J. Arps published one of the most complete reserve classification systems, a tentative classification of petroleum reserves by energy source (primary and secondary), by degree of proof (proved, probable, and possible) by development status (producing and non-producing). The process of estimating oil and gas reserves for producing field continues throughout the life of the field. There is always uncertainty in making such estimates. The magnitude of uncertainty however decreases with time until the economic limit is reached and ultimate recovery is realized.

Therefore, it is of paramount importance to seek ways of obtaining accurate values of reserve in place and minimizing the effect of the factors that cause errors in the obtained values of reserve in place.

The conventional methods, which are volumetric method, the material balance, and decline curve analysis are the three most prevalent procedures for estimating hydrocarbon in place, but there is no guarantee that the estimate generated using either procedure will even be close to the correct value. A more reliable method is required for determining the volume of hydrocarbon existing in real reservoirs.

This study seeks to investigate the problem of inaccurate values and proffer a solution to it.

This study will be to review methods of estimating hydrocarbon in place and to make objective assessment of them.

The three conventional methods of estimating stock tank oil initially in place (STOIIP); which are volumetric method, material balance method, and decline curve analysis. The results from this work will be useful for comparison, and further study in developing a more accurate method for estimating stock tank oil initially in place. It will also help to make objective decision of the method to be used in determining the stock tank oil in place.

2. Methodology

Oziengbe 2-S, OZ-1S, and OZ-1L Reservoir

The Oziengbe field located in OML65/II has three hydrocarbon bearing levels as OZ-1, OZ-2, and OZ-L. But considering all the levels, the production commences from Oziengbe field in 2002 with four (4) string from two wells OZ-1L, OZ-1S and OZ-2L. The OZ-2L was opened to production in November, 2003 in which the strings currently producing at Oziengbe source are OZ-2S, OZ-1S and OZ-1L. The OZ-2S was commissioned to production in June, 2002 with an average oil rate of 1130bopd on 26/64" choke size in which the initial water cut was zero and gas-oil ratio of about 1200scf/stb, hence the string produced. From the saturated oil with initial formation pressure of 4572psig and bubble point pressure of 3839psig, the drive mechanism was due to solution gas expansion, hence no down hole intervention since the beginning of production. The OZ-2S, OZ-1S, and OZ-1L from September, 2003 to July, 2004, in which it shows a decreasing production from the data obtained, indicating a gradual pressure decline, and certainly signifying a partial aquifer support.

3. PVT Data

The PVT data was obtained with API gravity of 50.3 and has initial bubble point pressure f 4715psia at 3757.679ft datum and a temperature of 243Oft. The initial pressure, Pi was obtained as 4572 psi, initial formation volume factor as 23.13rb/stb and solution gas-oil ratio of 2469 (scf/bbl). The net-gross rate is 0.86 and porosity 0.286, 2.216md, reservoir area bulk volume as 25556acre-ft and connate water saturation was 25% for OZ-2S reservoir.

Likewise for OZ-1S reservoir, net-gross ratio was 0.95, reservoir area bulk volume is 25356acre-ft, porosity is 0.8185 and connate water saturation as 0.232 and initial oil formation volume factor is 1.325rb/stb. Also, for OZ-1L reservoir, the net- gross ratio was 0.571, reservoir bulk volume is 4266.64 acre-ft, porosity 0.170, connate water saturation is 0.506 and formation volume factor is 2.218rb/stb.

4. Methods of Estimation used

Volumetric Method

The volumetric method involves direct substitution of the required geologic, geophysical, reservoir data and PVT data into the expression below to obtain the stock tank oil initially in place (STOIIP).

$$STOIIP = \frac{7758 V_b \phi F (1 - S_{wc})}{B_{oi}} \quad (1)$$

$$7758 = \frac{barrel}{acre-ft} \quad (2)$$

4.1. Decline Curve Analysis Method

In the application of this method, it was first observed that the reservoirs (OZ-2S, OZ-1S, OZ-1L) has a constant percentage or exponential decline and therefore the expression for the exponential decline curve was used to obtain the decline constant D, qi and Qt are initial and maximum amount of producible oil respectively. Qt will then be added to the cumulative production up to the last year recorded to obtain the stock tank oil initially in place.

D = Slope of the straight line of the graph of productive rate vs. cumulative production

$$Q_t = Np_{max} = \frac{q_i}{D} \quad (3)$$

Wells	Decline Curve (Mmstb)	Volumetric Rate (Mmstb)
2S	13.6	8824
1S	12.7	20.2
1L	14.3	764

Table 1: Result

Actual STOIIP obtained by the operating company during production was 83.4MMstb

4.2. D4 Sand Guico Field Reservoir Characteristics

The D4 sand which was discovered in 1943 is presently in a depleted state. Since its discovery, it has produced underwater drive, gas-cap-gas, and solution gas drive. In November, 1947, water injection was initiated to arrest further pressure decline. When discovered, the D4 sand was a saturated reservoir with a gas cap/oil zone volume ratio estimated volumetrically at 0.0731, an average permeability of 500md, a porosity value of 25% and an oil viscosity at reservoir condition of 0.3cp. The volumetrically determined stock-tank oil initially in place was 23.1 million bbl. Using a dimensionless radius value of 15 and a dimensionless time tD of 0.078t, a straight line plot and an oil-in-place value of 27 million stock-tank barrels was obtained.

5. Methods of Estimation used

5.1. Material Balance Method

This method is an equation derived as a volume balance which equates the cumulative observed production, expressed as an underground withdrawal, to the expression of the fluid in the reservoir resulting from a finite pressure drop. The equation is reduced according to reservoir in question drive mechanism

$F = \left(E_O + mE_g + E_{f,w}\right) + W_e B_w$ (4)BW was assumed to be unity. Therefore, a convenient material balance equation was derived by introducing the concept of total (two-phase) formation volume factor, B_t.

$B_t = B_O + (R_{si} + R_{si})B_g \text{ and } B_{oi} = B_{ti}$ (5)

For a water drive reservoir mechanism with a known gas cap, water influx expression is given as

$W = \sum \Delta PQ(\Delta tD)$ (6)

$$F = N\left[E + \frac{mB_{ti}}{B_{gi}}E_g\right] + C\sum \Delta PQ(\Delta tD) \quad (7)$$

$E_O = B_t - B_{ti}, C = \text{consistency test which is a function of real time}$

$\frac{F}{E + \frac{mB_{ti}}{B_{gi}}E_g} = N + \frac{C\sum \Delta PQ(\Delta tD)}{E_O + \frac{mB_{ti}}{B_{gi}}E_g}$ (8))Hence, a plot of $\frac{F}{E_t}$ vs $\frac{\sum \Delta PQ(\Delta tD)}{E_t}$ will give the stock-tank oil initially in place N as intercept and the slope is the aquifer reservoir constant.

5.2. Decline Curve Analysis

In the application of this method, it was first observed that the reservoir has a constant percentage or exponential decline and therefore the expression for the exponential decline curve was used to obtain the decline constant D, qi, and Qt are initial rate and maximum amount of producible oil respectively. Qt are initial rate and maximum amount of producible oil respectively. Qt was then added to the cumulative production up to the last year recorded to obtain the stock tank oil initially in place.

D = Slope of the straight line of the graph of productive rate vs. cumulative production

$Q_t = Np_{mzx} = \frac{q_i}{D}$

6. Wedge-Shaped Reservoir Characteristics

The wedge-shaped reservoir is suspected of having a fairly strong natural water drive. The reservoir has a constant production decline from the first year to the tenth year of production. Though the reservoir was initially at the bubble point pressure with apparently no initial gas cap (m = 0) but for the purpose of this work, an initial gas cap of m = 0.4 was assumed.

It can be inferred therefore from the foregoing that the reservoir is made up of a fairly strong natural water drive, solution gas drive, and gas-cap drive. This makes it a combination rate.

7. Reservoir and Aquifer Properties

Height = 100ft, Permeability = 200mD, Water Compressibility = 3.0 x 10-6ps-1, Viscosity (μw) = 0.55cp, Porosity (ϕ) = 0.25, Formation Pore Compressibility = 4.0 x 10-6 ps-1, Water Formation Volume Factor = 1.0rb/stb

The reservoir was observed to be producing under combination drive mechanism. For this combination drive mechanism, the following assumptions were made:

Change in the hydrocarbon pore volume due to connate water expansion is negligible.

The water formation volume factor, Bw is unity.

Therefore, the material balance reduces to:

$F = N(E_O + mE_g) + W_e$ (9) The equation above can be re-written as:

$\frac{F}{E_O + mE_g} = N + \frac{W_e}{E_O + mE_g}$ (10) The Hurst and Van-Everdingen method for water influx radial flow was applied:

$W_e = U\sum_{i=1}^{n=1} \Delta P_i W_d(t_d - T_{di})$ (11)

The dimensionless time was calculated using the expression below:

$t_D = \frac{2.309kt}{\phi U c_1 r_0^2}$ (12)

$\Delta P_i = \frac{P_{i-1} - P_{i+1}}{2}$ (13) The pressure drop was determined with the expression above and the aquifer/oil leg radius was obtained at 5.

7.1. Decline Curve Analysis

The same procedure for exponential decline was done on the production history of the wedge-shaped reservoir and stock tank oil in place was obtained.

Reservoirs	Decline Curve (Mmstb)	Volumetric Rate (Mmstb)
Wedge-Shaped	197.23	200.5
Guico D4 Sand Field	28.674	29

Table 2: Result

7.2. A2 Reservoir Characteristics

Eleke field located in OML 344 has two hydrocarbon bearing levels, A and B. For the purpose of this study, level A will be considered, which has five pools (A1, A2, A3, A4, and A5). Of these, only A2 reservoir was considered for the purpose of the study. A2 reservoir is an oil-bearing reservoir, which was tested for production in March, 1985 and place on production 1986.

Five out of seven wells drilled were completed and they included 2T, 3T, 4T, 5T, and 6T. From the structural map, A2 reservoir has a relatively thin oil layer overlain by gas and completely underlain by water. In the reservoir pressure history, it indicates a gradual pressure decline, which is an indication of a strong aquifer support. It also shows a pressure decrease after the initial pressures of 4228 psia was attained the previous year which was attributed to the late aquifer response, which naturally pressurized the reservoir. The production was started at bubble point pressure. Also, from log response, gas-oil contact is at 10348ft-ss and oil-water contact at 10202ft-ss.

The gross oil bearing volume is 584500 acre-ft, gross oil thickness is 86ft of gross thickness as per the interpretation of the structural map. The average net oil sand is 63ft, net/gross ratio F is 0.73.

The oil is bounded by gas cap on top and aquifer water on bottom. Also, the pressure history indicates that the pressure is at bubble point at the initial pressure of 4487psia and increased from 4230psia to 4282psia. The reservoir is producing under combination drive.

8. Methods of Estimation Used

8.1. Volumetric Method

Volumetric method for estimating STOIIP is based on log response, core analysis and/or geological and geophysical parameters to determine the bulk volume, porosity, fluid saturation, and fluid analysis i.e. PVT data to determine the oil formation volume factor to determine STOIIP.

$$STOIIP = \frac{7758Ah\phi(1-S_{wc})}{B_{oi}} \qquad (14)$$

8.2. Material Balance Method

General Form:

$$F = N(E_O + mE_g + E_{f,w}) + W_e B_w \qquad (15)$$

1. Change in the hydrocarbon pore volume due to connate water expansion is negligible.
2. The water formation volume factor, Bw is unity.
3. Then the equation reduces to:

$$F = N(E_O + mE_g) + W_e \qquad (16)$$

The equation above can be re-written as:

$$\frac{F}{E_O + mE_g} = N + \frac{W_e}{E_O + mE_g} \qquad (17)$$

Since water influx was experienced, the Van-Everdingen and Hurst method were applied and the dimensionless water influx was read from Van-Everdingen and Hurst water influx chart of $r_e/r_w = 40.$

A plot of $\frac{F}{E_O + mE_g}$ vs $\frac{W_e}{E_O + mE_g}$ was obtained which shows that slope is the water influx constant and intercept N is the STOIIP.

8.3. Decline Curve Analysis

The reservoir was noticed to have a constant percentage decline from a semi-log plot of rate versus time. Therefore, the usual process and procedure for exponential decline was carried out and STOIIP was obtained.

Method	Result (Mmstb)
Volumetric	292
Material Balance	213
Decline Curve	210

Table 3: Result

Actual Result Obtained By the Operating Company Is 302.8mmstb

8.4. The Ramaiah T. K. and Prosper A.: Case Study Reservoir

The data used for this case study was obtained from a field whose identity was not revealed due to owner's policies. Volumetric method, material balance method and decline curve analysis were used to obtain the hydrocarbon in place.

8.5. Volumetric Method

The exploration data used include average rock porosity, ϕ = 26%, average productive area of field A=404.85 acres, average thickness of productive zone, H=49.0ft, average initial water saturation, Swi = 45%, average oil formation volume factor, Boi = 1.68rb/stb, estimated recovery factor, RF = 0.2, oil reserve originally in place, N is given by:

$$N = \frac{7758Ah\phi(1-S_{wc})}{B_{oi}} \quad (18)$$

Estimated Ultimate Recovery (EUR) is given by

$$EUR = N \times RF \quad (19)$$

8.6. Material Balance Method

Data used include, NP = 2665600stb, Bt = 1.4954bbls/stb, Wp = 1.05x106stb, Rp = 700scf/stb, Rsoi = 562scf/stb, Bw = 1.028bbl/stb, Bti = 1.34bbls/stb, M = 0.175stb, Bgi = 0.01116bbl/scf, Bg = 0.001510

Recovery factor is given by:

$$\frac{N_p}{N} = \frac{(B_t - B_{ti}) + m\frac{B_{ti}}{B_{gi}}(B_g - B_{gi})}{(B_t + (R_p - R_{soi}) - (W_e - W_p B_w)} \quad (20)$$

Recovery factor $RF = \frac{N_p}{N}$ (21)

(21)

Decline Curve Analysis

Data used are:

Initial well decline rate, qi = 1000BOPD

Well decline rate at the end of a month, q = 990BOPD

Period of decline, t = 1 month

Using nominal exponential decline

$$D = \frac{ln\frac{q_i}{q}}{t} \quad (22)$$

Extending the decline for a year period

$$q = qie^{-Dt} \quad (23)$$

Maximum producible amount

$$N_p = \frac{q_i - q}{D} \quad (24)$$

Therefore,

$$N = \frac{N_p}{R.F.} \quad (25)$$

Reserve Estimation Method	Recoverable Reserves (STB)
Volumetric Method	2620000
Material Balance Method	2665600
Decline Curve Analysis	2776650

Table 4: Result True Value of Recoverable Reserve was Obtained as 2777574 STB.

Date	Time/Date	Average Pressure	Cumm. Oil Np (MMstb)	Gas, Gp (MMscf)	Water (Mbbl)	Production GOR, Rp (scf/stb)
01/01/86	0	4487	0	0	0	0
01/01/87	365	4444	2010	1.5	0	746
01/01/88	730	4416	4245	3.1	0	730
01/01/89	1095	4370	6393	5.2	10	813
01/01/90	1460	4332	8733	8.5	24	973
01/01/91	1825	4298	10792	11.8	39	1093
01/01/92	2190	4260	12526	16.7	58	1333
01/01/93	2555	4228	13986	23.0	72	1644
01/01/94	2920	4230	15047	24.7	184	1641
01/01/95	3285	4259	15900	25.4	203	1600
01/01/96	3650	4282	16700	25.9	265	1563

Table 5: Pressure/Production History of A2 Reservoir

Pressure, psi	F, MMrb	-EO, Rb/stb	Eg, Rb/stb	mEg	EO+ mEg	We, Mrb	$\frac{F}{E_o+mE_g}$ MMstb	$\frac{W_e}{E_o+mE_g}$ MMstb
4487	-	-	-	-	-	-	-	-
4444	2.5464	0.000073	0.0102	0.006834	0.006907	1.590	368.670143	230.20124
4416	5.3369	0.001650	0.0164	0.010988	0.012638	5.64	422.296214	446.273144
4370	8.4056	0.003950	0.0225	0.015075	0.019025	11.79	441.819041	619.710900
4332	12.3895	0.002004	0.0300	0.0201	0.022104	20.19	560.509809	913.40933
4298	16.1938	0.003088	0.0490	0.03283	0.035918	30.11	450.855432	838.293462
4260	20.8213	0.003531	0.0491	0.032897	0.036428	41.56	571.574353	1140.8064
4228	26.1943	0.004972	0.0553	0.037051	0.042023	54.51	623.333686	1297.14680
4230	28.2560	0.004010	0.0573	0.038391	0.042401	67.12	666.400068	1582.98153
4259	29.3895	0.002945	0.0532	0.035644	0.038589	77.27	761.603488	2002.38409
4282	30.6539	0.002600	0.0532	0.035644	0.038244	84.72	801.535051	2215.24945

Table 6: Material Balance Table of Values

A plot of $\frac{F}{E_O+mE_g}$ vs $\frac{W_e}{E_O+mE_g}$ was obtained

The slope is the water influx constant, U

$$U = \frac{650 - 500}{1275 - 950} = 461.5385 rb/stb$$

The intercept, N is the stock tank oil initially in place (STOIIP)

N = 200MMstb

9. Estimation Using Decline Analysis

Date	Production Rate (Stb/D)	Cummulative Production
01/01/86	0	0
01/01/87	5507	2010
01/01/88	6123	4245
01/01/89	6123	6393
01/01/90	6411	8733
01/01/91	5641	10793
01/01/92	4751	12536
01/01/93	4131	13986
01/01/94	2907	15047
01/01/95	2337	15900
01/01/96	1836	16570

Table 7: Table of Values

From the plot of rate (q) vs cumulative production (Np) starting from 1990 when the decline started.The decline constant, D obtained by calculating the slope of the straight line.

$$U = \frac{7300 - 1800}{1657 \times 10^6} = 0.000032 day^{-1}$$

Therefore, the maximum amount of producible oil from the reservoir with initial decline rate will be,

$$Q_1 = N_{p,max} = \frac{q_1}{D} = \frac{6411}{0.000032} = 193.10 MMstb$$

Considering that up to 1996 when the estimation was done, a cumulative production of 16.570MMstb has been obtained from A2 reservoir. Therefore, the estimation of STOIIP of the reservoir is got be adding cumulative production up to 1996 to maximum oil producible (Npmax) from the reservoir.
STOIIP = 16.570 x 106 + 193.10 x 106
= 209.67MMstb

10. Discussion of Results

In this study review, volumetric method, material balance calculations and decline curve analysis methods are the three predominant methods considered. Various discussions, comments, and recommendations were reviewed to set the records straight on the accuracy of the methods of estimating hydrocarbon in place.

In all of the discussion, it was made clear that reserve estimation is not an exact science, they are based on limited data that must be extrapolated over a large area and long period of time, therefore errors as minimal they could be are bound to surface at one point or the other.

Also, it was deduced that each method has its own time of application, that is volumetric method can only be used when a reservoir is just newly discovered, which helps to give an idea of the upper limit of hydrocarbon in place. Material balance is used when more production data are available with the PVT parameters during production. Decline curve analysis is used when the production is nearly completed and there is enough information about the reservoir. Again, it can be deduced that each method has its own merits and demerits. All the methods are important in their own way and works symbiotically for a common purpose. Depending on the experience and ingenuity of the estimator to reduce the errors that may want to arise during the estimation. The approach used by each method is also to be noted. Volumetric method uses initial geologic and geophysical information of the reservoir. Material balance uses pressure history and PVT data and the application of the law of conservation of mass.

Decline curve analysis uses the decline rate and initial production rate with the time, production rate and cumulative production that has been obtained.

It is noteworthy that the result obtained from each method is as good as the data that produced them. The accuracy of the results depends on the accuracy of the data used.

Decline curve analysis was observed to give the most accurate results. Therefore, theoretically, decline curve gives the most accurate result with the assumption that production trends remains constant. But the result is less useful often times because estimates are made nearly when the production is completed.

So, no method can be rated the best or worst because each method has its own strength and weakness, which must be properly understood to achieve the best result.

Also, in the mode of approach used by each method, assumptions from general to particular and from particular to general are made along the way. Hence, care must be taken when using the assumptions.

Decline curve analysis is best suited for oil wells, but for gas wells, well-head back pressure usually fluctuates. Material balance calculations are best suited for both gas wells and oil wells if the drive mechanisms are properly identified. Ramaiah T. K. and Prosper A. (2013) made a very convincing study. According to them, calculations using three methods may be deterministic or probabilistic. In their study, they observed that the volumetric method which entails determining the areal extent of the reservoir, the rock pore volume and the fluid content within the pore volume had the highest relative error but expressed that given quality data, the volumetric method can be accurately used to estimate reserves.

However, they noted that decline analysis and material balance method greatly reduce uncertainty in reserve estimates but they pointed out that during early depletion, caution should be exercised in using them. They also noted that decline analysis is best suited to oil wells, which are usually produced against fixed bottom-hole pressure. In gas wells, wellhead back-pressure usually fluctuate, causing varying production trends and therefore not reliable but material balance is an excellent tool for estimating gas reserves.

They consider the decline curve as the most accurate of all the three methods because it incorporates time in its calculations and there are enough data to accurately evaluate the field.

11. Conclusion

This study has objectively reviewed the modus operandi of each methods of reserve estimation. The methods are volumetric method, material balance method and decline curve analysis. The methods do not show the same results at any point or time.

The volumetric method treats a reservoir as a single homogenous system and thereby obtains its volume from initial geologic data with the assumption that the properties of the reservoir do not change.

The common material balance equation uses the principle of conservation of mass for a reservoir system. The assumption made depends on the drive mechanism observed in the reservoir. In the case of water influx, the Van-Everdingen and Hurst water influx

model are always employed.
The production history of a reservoir is always used to the reserve estimate through decline analysis. Decline curve analysis assumes that initial production trends continue over a long time.
Therefore, it is good to note that reserve estimation is not an exact science, hence each method can never give an absolute accurate result but the errors can greatly be minimised.

12. Recommendation
Data to be used for each of the methods should be obtained carefully and accurately.
Since each method has its own strength and weakness, all the methods should be used and their result compared.
Decline curve analysis should not be applied on gas reservoirs.
Each method should be applied appropriately and at the right time.
Data to be used for decline curve analysis should be obtained when the pressure has been observed to be stable.
Since the result of decline curve analysis is usually obtained after production, it should be run for confirmation of reserve estimates.
Equipment should not be designed based on the result of just one method of estimated. Allowance should be given for contingency purpose.

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- **List of Terms**
- A = areal coverage in acres
- EUR- Estimated ultimate Recovery
- H= thickness in feet
- Swc = connate water saturation
- Boi = formation volume factor in rb/stb
- Φ = porosity
- Vb = gross oil bearing volume in acre-ft
- F = net-gross ratio
- RF –Recovery Factor
- N- original oil in place
- STOIIP- Stock Tank Oil Initially In Place.