RESERVOIR PERFORMANCE PREDICTION USING

MBAL SOFTWARE: A CASE STUDY


By:

Mohammed Natee

Ameer Saad

Ali Saadoon

Haider Aqeed

Supervisor:

A.L. Dhiaa Salman

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Dedication

We would like to dedicate this work to our parents who without their prayers we did not get to which we are today, to our masters who have made every effort to elevate our scientific level and to the holy crowd who if not their sacrifices, we were not here today to discuss our graduation project.
ACKNOWLEDGMENT

Thanks God, for everything and for His continual grace love, who gave us the strength to complete this work.

We would like to express the great respect and appreciation to our project supervisor A.L. Dhiaa Salman, Who helped us to overcome the difficulties that we have been faced during the period of completing this project.

Also, we thank A.L. Ali Nooruldeen Abdul Kareem for his advices and guidance.
ABSTRACT

Predicting the performance of reservoirs helps engineers to estimate reserve, development planning which requires detailed understanding of the reservoir characteristics and production operations optimization and importantly, to develop a mathematical model that will adequately depict the physical processes more occurring in the reservoir such that the outcome of any action can be predicted within reasonable tolerance of Errors. In this work, software called MBAL was used to compute the oil originally in place by performing a nonlinear regression of average pressure against cumulative oil production and to perform different scenarios of reservoir performance predictions. The data that used in this study is from L.P Dake (example 9.2). The value of OIIP that determined by MBAL software in this study was 306.6 MMSTB and this value is very close to the measured value in L.P Dake example 9.2 (312 MM STB). The future performance show that pressure decrease from 1440 psia at 2004 to 1048 psia at 2010 and the cumulative oil produced 121MMSTB. When starting injection water from year 2004 to 2010 with flow rate 20000 STB/D the pressure decrees from 1440 psia to 1413.46 psia and the cumulative oil produced 94.7305 MM STB. When make injection with flow rate 40000 STB/D the pressure increase from 1440 psia at 2004 to 2030.65 psia at 2010 and the cumulative oil produced 94.7305 STB/D.
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C_w………………………………………………… Water compressibility, psi$^{-1}$
C_f………………………………..Formation (rock) compressibility, psi$^{-1}$
API…………………………………… American Petroleum Institute
T……………………………………………………….. Temperature
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1.1 Background of Study:

One of the roles of a reservoir engineer is to continuously monitor the reservoir, collect relevant data and interpret these data to be able to determine the present conditions of the reservoir, estimate future conditions and control the flow of fluids through the reservoir with an aim to increase recovery factor and accelerate oil recovery. It therefore implies that the ability of a Reservoir Engineer to predict the behavior of petroleum reservoirs depends solely on his ability to predict the flow characteristics of the fluids in the reservoir. Thus, the main concern of the engineer to carry out a study on the reservoir is to adequately simulate the reservoir with the minimum effort. In the real life scenario, the knowledge of a reservoir is not accurately known since the reservoirs are large complex systems with irregular geometries that are found in subsurface formations with several uncertainties, limited information about the reservoir structure and behavior (Holstein 2007).

Reservoir fluid properties are very important in petroleum engineering computations, such as material balance calculations, well test analysis, reserve estimates, inflow performance calculations and numerical reservoir simulations. Ideally, these properties are determined from laboratory studies on samples collected from the bottom of the wellbore or at the surface. Such experimental solution is to use the empirically derived correlations to predict PVT properties. There are many empirical correlations for predicting PVT properties, most of them were developed using linear or non-linear multiple regression or graphical techniques.
Each correlation was developed for a certain range of reservoir fluid characteristics and geographical area with similar fluid compositions and API gravity. Thus, the accuracy of such correlations is critical and it is not often known in advance. Among those PVT properties is the bubble point Oil Formation Volume Factor ($B_{ob}$), which is defined as the volume of reservoir oil that would be occupied by one stock tank barrel oil plus any dissolved gas at the bubble point pressure and reservoir temperature. Precise prediction of $B_{ob}$ is very important in reservoir and production computations.

This Study used (MBAL) software to predict the future performance of the reservoir.

### 1.2 Statement of The Problem:

One of the problems faced today in the industry in making predictions of the reservoir behavior is to adequately take into account the knowledge about geological trends and some set of constraints whether quantified or not that are essential in making a good simulation study. The engineer should bear in mind a list of designated limits of all variables. It can be argued very effectively that there is really no unique set of descriptive parameters which fit a reservoir. Material balance equation makes use of pressure in the prediction. Tamer and Muscat method which are widely used do not consider time in their prediction performance, also neither water influx nor gravity segregation was considered. Thus, this study incorporate aquifer and time scale to the equation in making predictions. The time history will be inferred from the reserves and well production rates, though it does not consider reservoir geometry, Heterogeneity, fluid distribution, the drainage area, the position and orientation of the wells.
1.3 Objectives of the Study:

1. Determine hydrocarbon volume in place.
2. Determine the type of the energy in the system.
3. Determine the most likely aquifer model and evaluate the strength of aquifer.
4. Determine the probable limits of the reservoir.
5. Perform different scenarios of reservoir performance predictions.
2.1 General Review:

Tarek (2010) stated that material balance equation, (MBE) plays a major role in most reservoir engineering calculations. It helps reservoir engineers to constantly seek for ways to optimize hydrocarbon recovery by predicting the future performance of the reservoir. We should note that the (MBE) simply provides performance as a function of average reservoir pressure without the fluid flow concepts. Combining the (MBE) and fluid flow concepts would enable the engineer to predict the reservoir future production performance as a function of time. Odeh & Havlena (1963) rearrange (MBE) into different linear forms. This method requires the plotting of a variable group against another variable group selected depending on the reservoir drive mechanism and if linear relationship does not exist, then this deviation suggests that reservoir is not performing as anticipated and other mechanisms are involved which were not accounted for but once linearity has been achieved, based on matching pressure and production data then a mathematical model has been achieved. This technique is referred to as history matching. Therefore, the application of the model enables predictions of the future reservoir performance. There are several methods which have appeared in literatures for predicting the performance solution gas behavior relating pressure decline to gas-oil ratio and oil recovery. Tamer (1944) and Muskat (1945) proposed an iterative technique to predict the performance of depletion (solution-gas) - drive reservoirs under internal gas drive mechanism, using rock and fluid properties. The assumptions of both
methods include negligible gravity segregation forces. These authors considered only thin, horizontal reservoirs. Both methods use the material balance principle (static) and a producing gas-oil ratio equation (dynamic) to predict reservoir performance at pressures. A more detailed description of both methods appears in Craft and Hawkins Tracy (1955) in the model developed for reservoir performance prediction, did not consider oil reservoirs above the bubble-point pressure (under saturated reservoir). It is normally started at the bubble-point pressure or at pressures below. To use this method for predicting future performance, it is necessary to choose the future pressures at which performance is desired. This means that we need to select the pressure step to be used. Furthermore, among these methods of reservoir performance prediction, none considered aquifer in the (MBE) hence, the software developed for this study incorporated aquifer into Tamer's method of reservoir performance prediction for solution gas drive. Three aquifer models such as Hurst Van Everdingen (1947), Carter-Tracy (1960) and Fetkovich (1971) were programmed to allow for flexibility. Classic analytical models of aquifers are relatively easy to program in computer spreadsheets, provided that equation discretization is correctly done. With the exception of the van Everdingen & Hurst, the models do not demand much computer power. In the van Everdingen & Hurst, calculations of the previous steps are redone at each time step added to the behavior, which represents a bigger computational effort. The equation that rules the van Everdingen & Hurst model is based on the superposition principle. Any numerical calculation method for this model requires more computing power than other models. Despite this drawback, it is the ideal model for comparisons, because it faithfully represents the hydraulic diffusivity equation. Other proposed models, such as Carter & Tracy, Fetkovich and Leung, sought to eliminate the disadvantage of the required
computing power and thus became more popular in commercial flow simulators. The error of this model in computing the accumulated influx is insignificant when compared to the base model (van Everdingen & Hurst).

2.2 Material Balance Theory:
Schillthuis (1936) first presented a method of reservoir estimation using the material balance. Material balance is a volumetric balance which states that since the volume of a reservoir (as defined by its initial limits) is constant, the cumulative observed production, expressed as an underground withdrawal, must equal the expansion of fluids in the reservoir resulting from finite pressure drop.

2.2.1 Derivative of Material Balance Equation:
The equation is structured to simply keep inventory of all materials entering, leaving and accumulating in the reservoir. The concept of the material balance equation was presented by Schillthuis in (1941). In its simplest form, the equation can be written on volumetric basis as:

Initial volume = volume remaining + volume removed ............(2-1)

Since oil, gas and water are present in petroleum reservoirs, the material balance equation can be expressed for the total fluids or for any one of the fluids present. Before deriving the material balance, it is convenient to denote certain terms by symbols for brevity. The symbols used conform where possible to the standard nomenclature adopted by the Society of Petroleum Engineers.

Several of the material balance calculations require the total pore volume (P.V) as expressed in terms of the initial oil volume N and the volume of the gas cap. The expression for the total pore volume can be Oil Recovery
Mechanisms and the Material Balance Equation derived by conveniently introducing the parameter \( m \) into the relationship as follows:

Defining the ratio \( m \) as:

\[
m = \frac{\text{initial volume of gas cap}}{\text{volume of initially oil in place}} = \frac{G_{Bi}}{N_{Boi}} \tag{2-2}
\]

Solving for the volume of the gas cap gives:

Initial volume of the gas cap = \( G_{Bi} = m \cdot N_{Boi} \) \( \tag{2-3} \)

The total volume of the hydrocarbon system is then given by:

Initial oil volume + initial gas cap volume = (P.V) \( (1 - S_{wi}) \) \( \tag{2-4} \)

\[
N_{Boi} + m \cdot N_{Boi} = (P.V) (1 - S_{wi}) \tag{2-5}
\]

Or

\[
P.V = \frac{N_{Boi}(1+m)}{1-S_{wi}} \tag{2-6}
\]

Where:

\( (S_{wi}) = \) initial water saturation

\( N = \) initial oil in place, STB

\( P.V = \) total pore volume, bbl

\( m = \) ratio of initial gas-cap-gas reservoir volume to initial reservoir oil volume, bbl/bbl

The MBE can be written in a generalized form as follows:

Pore volume occupied by the oil initially in place at \( p_i \) 
+ 
Pore volume occupied by the gas in the gas cap at \( p_i \) 
= 
Pore volume occupied by the remaining oil at \( p \)  
+  
Pore volume occupied by the gas in the gas cap at \( p \)  
+  
Pore volume occupied by the evolved solution gas at \( p \)  
+  
Pore volume occupied by the net water influx at \( p \)  
+  
Change in pore volume due to connate water expansion and pore  
Volume reduction due to rock expansion  
+  
Pore volume occupied by the injected gas at \( p \)  
+  
Pore volume occupied by the injected water at \( p \)  

\[ \ldots \ldots \ldots \ldots (2-7) \]

**Figure (2-1)** Tank – Model Concept

The above nine terms composing the MBE can be separately determined from the hydrocarbon PVT and rock properties, as follows:
Pore Volume Occupied by the Oil Initially in Place:

Volume occupied by initial oil in place = \( N B_{oi} \) ...................(2-8)

Where:

\( N = \) oil initially in place, STB
\( B_{oi} = \) oil formation volume factor at initial reservoir pressure (\( p_i \)), bbl/STB

Pore Volume Occupied by the Gas in the Gas Cap:

Volume of gas cap = \( m N B_{oi} \) ............................(2-9)

Where:

\( m = \) is a dimensionless parameter and defined as the ratio of gas-cap volume to the oil zone volume.

Pore Volume Occupied by the Remaining Oil:

Volume of the remaining oil = \( (N - N_p) \) ...........................(2-10)

Where:

\( N_p = \) cumulative oil production, STB
\( B_o = \) oil formation volume factor at reservoir pressure \( p \), bbl/STB

Pore Volume Occupied by the Gas Cap at Reservoir Pressure \( p \):

As the reservoir pressure drops to a new level \( p \), the gas in the gas cap expands and occupies a larger volume. Assuming no gas is produced from the gas cap during the pressure decline, the new volume of the gas cap can be determined as:

Volume of the gas cap at \( p = \left[ \frac{m NB_{oi}}{B_{Gi}} \right] B_g \) ...........................(2-11)

Where:

\( B_{Gi} = \) oil formation volume factor at initial reservoir pressure (\( p_i \)), bbl/STB
B_{gi} = \text{gas formation volume factor at initial reservoir pressure, bbl/scf}

B_{g} = \text{current gas formation volume factor, bbl/scf}

**Pore Volume Occupied by the Evolved Solution Gas:**

This volumetric term can be determined by applying the following material balance on the solution gas:

\[
\text{Volume of the evolved solution gas} = \text{[volume of gas initially in solution]} - \text{[volume of gas Produced]} - \text{[volume of gas remaining in solution]}
\]

\[
\text{Volume of the evolved solution gas} = \left[ N R_{si} - Np R_p - (N - Np) R_s \right] B_g \tag{2-12}
\]

Where:

- Np = cumulative oil produced, STB
- Rp = net cumulative produced gas-oil ratio, scf/STB
- R_s = current gas solubility factor, scf/STB
- B_g = current gas formation volume factor, bbl/scf
- R_{si} = gas solubility at initial reservoir pressure, scf/STB

**Pore Volume Occupied by the Net Water Influx:**

\[
\text{Net water influx} = \text{We} - \text{Wp} B_w \tag{2-13}
\]

Where:

- We = cumulative water influx, bbl
- Wp = cumulative water produced, STB
- B_w = water formation volume factor, bbl/STB
Change in Pore Volume Due to Initial Water and Rock Expansion:

The component describing the reduction in the hydrocarbon pore volume due to the expansion of initial (connate) water and the reservoir rock cannot be neglected for an under saturated oil reservoir. The water compressibility (C_w) and rock compressibility (C_r) are generally of the same order of magnitude as the compressibility of the oil. The effect of these two components, however, can be generally neglected for gas-cap-drive reservoir or when the reservoir pressure drops below the bubble-point pressure. The compressibility coefficient (C) which describes the changes in the volume (expansion) of the fluid or material with changing pressure is given by:

\[ C = \frac{1}{\frac{\Delta p}{V \Delta V}} \]  

...(2-14)

Or

\[ \Delta V = V C \Delta p \]  

...(2-15)

Where (\Delta V) represent the net changes or expansion of the material as a result of changes in the pressure. Therefore, the reduction in the pore volume due to the expansion of the connate water in the oil zone and the gas cap is given by:

Connate water expansion = [(pore volume) S_wi] C_w \Delta p ...........(2-16)

Substituting for the pore volume (P.V) with Equation (2-16) gives:

\[ \text{Expansion of connate water} = \frac{N B_{oi}(1+m)}{1-S_{wi}} S_w C_w \Delta p \]  

...(2-17)

Where:

\[ \Delta p = \text{change in reservoir pressure, } p_i - p \]

\[ C_w = \text{water compressibility coefficient, } \text{psi}^{-1} \]
m = ratio of the volume of the gas-cap gas to the reservoir oil volume, bbl/bbl

Similarly, the reduction in the pore volume due to the expansion of the Reservoir rock is given by:

\[
\text{Change in pore volume} = \frac{NB_{oi}(1+m)}{1-S_{wi}} \text{cf} \Delta p \quad \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (2-18)
\]

Combining the expansions of the connate water and formation as represented by Equations (2-17) and (2-18) gives:

\[
\text{Total change in pore volume} = N B_{oi} (1 + m) \left( \frac{S_{wi} C_{w} + cf}{1-S_{wi}} \right) \Delta p \quad \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (2-19)
\]

**Pore Volume Occupied by the Injection Gas and Water:**

Assuming that \((G_{\text{inj}})\) volumes of gas and \((W_{\text{inj}})\) volumes of water have been injected for pressure maintenance, the total pore volume occupied by the two injected fluids is given by:

\[
\text{Total volume} = G_{\text{inj}} B_{ginj} + W_{\text{inj}} B_{w} \quad \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (2-20)
\]

Where:

- \(G_{\text{inj}}\) = cumulative gas injected, scf
- \(B_{ginj}\) = injected gas formation volume factor, bbl/scf
- \(W_{\text{inj}}\) = cumulative water injected, STB
- \(B_{w}\) = water formation volume factor, bbl/STB

Combining Equations (2-8) through (2-20) with Equation (2-7) and rearranging gives:

\[
N = \frac{NpB_{o} + (Gp-NpR_{s})B_{g} - (We-WpB_{w}) - G_{inj} B_{ginj} - W_{inj} B_{w}}{(B_{o}-B_{oi}) + (R_{sl}-R_{s})B_{g} + mB_{oi}\left[\frac{B_{g}}{B_{gl}}-1\right] + B_{oi}(1+m)\left[\frac{S_{wi} C_{w} + cf}{1-S_{wi}}\right]} \Delta p \quad \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (2-21)
\]

Where:
N = initial oil in place, STB
Gp = cumulative gas produced, scf
Np = cumulative oil produced, STB
Rsi = gas solubility at initial pressure, scf/STB
m = ratio of gas-cap gas volume to oil volume, bbl/bbl
Bgi = gas formation volume factor at pi, bbl/scf
Bginj = gas formation volume factor of the injected gas, bbl/scf

The cumulative gas produced Gp can be expressed in terms of the cumulative gas-oil ratio Rp and cumulative oil produced Np by:

\[ Gp = Rp \times Np \]  \hspace{1cm} (2-22)

Combining Equation 2-22 with Equation 2-21 gives:

\[
N = \frac{Np[Bo+(Rp-Rs)Bg]-(We-WpBw)-Ginj Bginj-W inj Bijn}{(Bo-Boi)+(Rsi-Rs)Bg+mBoi \left( \frac{Bg}{Bgi} - 1 \right) + Boi(1+m)\left[ \frac{Swi \times Cw+ Cf}{1-Swi} \right] \Delta p}
\]  \hspace{1cm} (2-23)

The above relationship is referred to as the (material balance equation) (MBE). A more convenient form of the MBE can be determined by introducing the concept of the total (two-phase) formation volume factor Bt into the equation. This oil PVT property is defined as:

\[ B_t = B_o + (Rsi - Rs) B_g \]  \hspace{1cm} (2-24)

Introducing Bt into Equation (2-23) and assuming, for sake of simplicity, no water or gas injection gives:

\[
N = \frac{Np[B_t+(Rp-Rst)B_g]-(we-WpBw)}{(B_t-Bti)+mBti \left( \frac{Bg}{Bgi} - 1 \right) + Bti(1+m)\left[ \frac{Swi \times Cw+ Cf}{1-Swi} \right] \Delta p}
\]  \hspace{1cm} (2-25)

Where:
Swi = initial water saturation
Rp = cumulative produced gas-oil ratio, scf/STB
Δp = change in the volumetric average reservoir pressure, psi

In a combination drive reservoir where all the driving mechanisms are simultaneously present, it is of practical interest to determine the relative magnitude of each of the driving mechanisms and its contribution to the production rearranging Equation (2-23) gives:

\[
\frac{N(B_{t} - B_{i})}{A} + \frac{Nm(B_{g} - B_{gi})/B_{gi}}{A} + \frac{Wc - WpB_{w}}{A} + \frac{NB_{oi}(1+m)(C_{wi} + C_{f})(p_t - p)}{1 - Sw_{wi}} = 1 \ldots (2-26)
\]

with the parameter A as defined by:

\[
A = Np [B_{t} + (Rp - R_{si}) B_{g}] \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (2-27)
\]

Equation (2-26) can be abbreviated and expressed as:

\[
DDI + SDI + WDI + EDI = 1.0 \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (2-28)
\]

Where:

\[
DDI = \text{depletion-drive index}
\]

\[
SDI = \text{segregation (gas-cap)-drive index}
\]

\[
WDI = \text{water-drive index}
\]

\[
EDI = \text{expansion (rock and liquid)-depletion index}
\]

The four terms of the left-hand side of Equation (2-28) represent the major primary driving mechanisms by which oil may be recovered from oil reservoirs. As presented earlier in this chapter, these driving forces are:

a. **Depletion Drive:** Depletion drive is the oil recovery mechanism wherein the production of the oil from its reservoir rock is achieved by
the expansion of the original oil volume with all its original dissolved gas. This driving mechanism is represented mathematically by the first term of Equation (2-26) or:

$$DDI = \frac{N (B_t - B_{ti})}{A}$$

Where: (DDI) is termed the **depletion-drive index**.

**b. Segregation Drive.** Segregation drive (gas-cap drive) is the mechanism wherein the displacement of oil from the formation is accomplished by the expansion of the original free gas cap. This driving force is described by the second term of Equation (2-26) or:

$$SDI = \frac{\left[N m B_{ti} (B_g - B_{gi})/B_{gi}\right]}{A}$$

Where: (SDI) is termed the **segregation-drive index**.

**c. Water Drive.** Water drive is the mechanism wherein the displacement of the oil is accomplished by the net encroachment of water into the oil zone. This mechanism is represented by the third term of Equation (2-26) or:

$$WDI = \frac{(We - Wp B_w)}{A}$$

Where: (WDI) is termed the **water-drive index**.

**d. Expansion Drive.** For under saturated oil reservoirs with no water influx, the principle source of energy is a result of the rock and fluid expansion. Where all the other three driving mechanisms are contributing to the production of oil and gas from the reservoir, the contribution of the rock and fluid expansion to the oil recovery is too small and essentially negligible and can be ignored.

$$EDI = \frac{NB_{oi}(1+m)[C_{ws}S_{wi}+C_f]}{1-S_{wi}}(p_i-p)\frac{1}{A}$$
Where

**EDI: Expansion Drive index**

### 2.3 Material balance equation as straight line:

The general MBE, Equation (2-23), may be gained by considering the physical significance of the following groups of terms of which it is comprised:

**Oil expansion and dissolved gas:**

\[ E_o = (B_o - B_{oi}) + (R_{si} - R_s) B_g \ \text{(RB/STB)} \]  
\[ \text{(2-29)} \]

**Gas expansion:**

\[ E_g = B_{oi} \left( \frac{B_g}{B_{gi}} - 1 \right) \ \text{(RB/STB)} \]  
\[ \text{(2-30)} \]

**Expansion of connate water and reduction in the pore volume**

\[ E_{fw} = (1+m) B_{oi} \left( \frac{C_w S_{wc} + C_f}{1-S_{wc}} \right) \ \text{(RB/STB)} \]  
\[ \text{(2-31)} \]

**Underground withdrawal:**

\[ F = Np \left[ B_o + (R_p - R_s) B_g \right] + WP B_w \ \text{(RB)} \]  
\[ \text{(2-32)} \]

This is reduced to the form:

\[ F = N \left[ E_o + mE_g + E_{fw} \right] + We B_w \]  
\[ \text{(2-33)} \]
2.4 The Straight-Line Solution Method To The MBE:

The straight-line solution method requires the plotting of a variable group versus another variable group, with the variable group selection depending on the mechanism of production under which the reservoir is producing. The most important aspect of this method of solution is that it attaches significance the sequence of the plotted points, the direction in which they plot, and to the shape of the resulting plot. The significance of the straight-line approach is that the sequence of plotting is important and if the plotted data deviates from this straight line there is some reason for it. This significant observation will provide the engineer with valuable information that can be used in determining the following unknowns:

- Initial oil in place $N$
- Size of the gas cap $m$
- Water influx $W_e$
- Driving mechanism

The remainder of this chapter is devoted to illustrations of the use of the straight-line solution method in determining $N$, $m$, and $W_e$ for different reservoir mechanisms.

Case1. Volumetric Under saturated-Oil Reservoirs

Assuming no water or gas injection, the linear form of the MBE as expressed by Equation (2-23) can be written as:

$$ F = N [E_o + m E_g + E_{f,w}] + W_e \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots}catches the assumed reservoir driving mechanism. For
a volumetric and under saturated reservoir, the conditions associated with driving mechanism are:

- \( W_e = 0 \), since the reservoir is volumetric.
- \( m = 0 \), since the reservoir is under saturated.
- \( R_s = R_{si} = R_p \), since all produced gas is dissolved in the oil.

Applying the above conditions on Equation (2-34) gives:

\[
F = N \left( E_o + E_{f,w} \right) \tag{2-35}
\]

Where:

\( N = \) initial oil in place, STB
\( F = N_p B_o + W_p B_w \).
\( E_o = B_o - B_{oi} \)

When drawing \( F \) (Underground withdrawal) versus \( (E_o+E_{f,w}) \) result straight line pass through the origin with slop equal \( N \).

![Graph](image)

**Figure (2-2)** Underground withdrawal versus \( (E_o+E_{f,w}) \).
Case 2. Volumetric Saturated-Oil Reservoirs

An oil reservoir that originally exists at its bubble-point pressure is referred to as a saturated oil reservoir. The main driving mechanism in this type of reservoir results from the liberation and expansion of the solution gas as the pressure drops below the bubble-point pressure. The only unknown is the initial oil in place $N$. Assuming that the water and rock expansion term $E_{f,w}$ is negligible in comparison with the expansion of solution gas, Equation (2-33) can be simplified as:

$$F = Ne_o$$

$$
\text{Where } F \text{ is the underground withdrawal and } E_o \text{ the oil expansion:}
F = Np \left[B_t + (R_p - R_{si}) B_g \right] + W_p B_w
$$

$$E_o = B_t - B_{ti}$$

When drawing $F$ (Underground withdrawal) versus $(E_o)$ result straight line pass through the origin with slop equal $N$.

![Graph](image.png)

**Figure (2-3) Under**ground withdrawal (F) versus (Eo).
Case 3: Gas-Cap-Drive Reservoirs

For a reservoir in which the expansion of the gas-cap gas is the predominant driving mechanism and assuming that the natural water influx is negligible ($W_e = 0$), the effect of water and pore compressibility can be considered negligible. Under these conditions, the Havlena-Odeh material balance can be expressed as:

$$F = N \left[ E_o + m E_g \right] \quad \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \li
CHAPTER THREE

METHODOLOGY

3.1 Theory of MBAL:

The equation of the material balance developed by Schilthius which equates the cumulative observed production (expressed as underground withdrawal) to the expansion of the fluid in the reservoir resulting from finite pressure drop which is the governing principle for the MBAL software i.e.

\[ F = N (E_0 + mE_g + E_{fw}) + W_e \]

3.2 The Software (The M-BALTM 10.5) Used For the Study:

*M-BALTM* 10.5 software package developed by Petroleum Experts was used as a material balance tool for this evaluation. *M-BALTM* is a software application made up of various tools designed to help the reservoir engineer gain a better understanding of the reservoir behavior.

![Figure (3-1) Interface of Petroleum Experiment Package](image-url)
3.3 Theory of Correlations:

3.3.1 Gas Solubility:

The gas solubility $R_s$ is defined as the number of standard cubic feet of gas which will dissolve in one stock-tank barrel of crude oil at certain pressure and temperature. The solubility of a natural gas in a crude oil is a strong function of the pressure, temperature, API gravity, and gas gravity. For a particular gas and crude oil to exist at a constant temperature, the solubility increases with pressure until the saturation pressure is reached. At the saturation pressure all the available gases are dissolved in the oil and the gas solubility reaches its maximum value. A typical gas solubility curve, as a function of pressure for an under saturated crude oil, is shown in Figure (3-3). As the pressure is reduced from the initial reservoir pressure $p_i$, to the bubble-point pressure $p_b$, no gas evolves from the oil and consequently the gas solubility remains constant at its maximum value of $R_{sb}$. Below the bubble-point pressure, the solution gas is
liberated and the value of Rs decreases with pressure. The following five empirical correlations for estimating the gas solubility are given below:

- Standing’s correlation.
- The Vasquez-Beggs correlation.
- Glaso’s correlation.
- Marhoun’s correlation.
- The Petrosky-Farshad correlation.

**Standing correlation:**

The correlation was developed from a total of 105 experimentally determined data points on 22 hydrocarbon mixtures from California crude oils and natural gases. The proposed correlation has an average error of
4.8%. Standing (1981) expressed his proposed graphical correlation in the following more convenient mathematical form:

\[ Rs = \gamma_g \left[ \left( \frac{P}{18.2} + 1.4 \right) 10^x \right]^{1.2045} \] ..........................(3-1)

Where:

\[ X = 0.0125 \text{API} - 0.00091 \left( T - 450 \right) \]

\[ T = \text{temperature, R} \]

\[ P = \text{system pressure, psia} \]

\[ \gamma_g = \text{solution gas specific gravity} \]

**The Vasquez-Beggs Correlation:**

Vasquez and Beggs (1980) presented an improved empirical correlation for estimating Rs. The correlation was obtained by regression analysis using 5,008 measured gas solubility data points. Based on oil gravity, the measured data were divided into two groups. This division was made at a value of oil gravity of 30°API. The proposed equation has the following form:

\[ Rs = C_1 \gamma_{gs} P^{C_2} \exp \left[ C_3 \left( \frac{API}{T} \right) \right] \] ..........................(3-2)

\[ \gamma_{gs} = \gamma_g \left[ 1 + 5.912(10-5) \left( \frac{API}{114.7} \right) \log \left( \frac{P_{sep}}{460} \right) \right] \] ........................(3-3)

Where:

\[ \gamma_{gs} = \text{gas gravity at the reference separator pressure} \]

\[ \gamma_g = \text{gas gravity at the actual separator conditions of } P_{sep} \text{ and } T_{sep} \]

\[ P_{sep} = \text{actual separator pressure, psia} \]

\[ T_{sep} = \text{actual separator temperature, } °\text{R} \]
Glaso’s Correlation

Glaso (1980) proposed a correlation for estimating the gas solubility as a function of the API gravity, pressure, temperature, and gas specific gravity. The correlation was developed from studying 45 North Sea crude oil samples. Glaso reported an average error of 1.28% with a standard deviation of 6.98%. The proposed relationship has the following form:

\[ R_s = \gamma_g \left( \frac{API^{0.989}}{(T-460)^{0.172}} \right) (Pb^*)^{1.2255} \] \hspace{1cm} (3-4)

\[ Pb^* = 10^X \] \hspace{1cm} (3-5)

Where:

\[ X = 2.8869 - [14.1811 - 3.3093 \log (p)]^{0.5} \] \hspace{1cm} (3-6)

Marhoun’s Correlation

Marhoun (1988) developed an expression for estimating the saturation pressure of the Middle Eastern crude oil systems. The correlation originates from 160 experimental saturation pressure data. The proposed correlation can be rearranged and solved for the gas solubility to give:

\[ R_s = [a \gamma_g^b \gamma_o^c T^d p]^e \] \hspace{1cm} (3-7)
Where:

\( \gamma_g \) = gas specific gravity
\( \gamma_o \) = stock-tank oil gravity
T = temperature, °R
a = 185.843208
b = 1.87784
c = -3.1437
d = -1.32657
e = 1.398441

**The Petrosky-Farshad Correlation**

Petrosky and Farshad (1993) used a nonlinear multiple regression software to develop a gas solubility correlation. The authors constructed a PVT data base from 81 laboratory analyses from the Gulf of Mexico crude oil system. Petrosky and Farshad proposed the following expression:

\[
S_g = \left[ \frac{P}{112.727} + 12.34 \right] \gamma_g^{0.8439} 10^{x} \right]^{1.73184} \] ..........................(3-8)

\[
x = 7.916 \left( 10^{-4} \right) \left( \text{API} \right)^{1.541} - 4.561\left( 10^{-5} \right) \left( T - 460 \right)^{1.3911} \] ..........................(3-9)

Where:

p= pressure, psi
T= temperature, °R
3.3.2 Bubble-Point Pressure

The bubble-point pressure $P_b$ of a hydrocarbon system is defined as the highest pressure at which a bubble of gas is first liberated from the oil. This important property can be measured experimentally for a crude oil system by conducting a constant-composition expansion test. In the absence of the experimentally measured bubble-point pressure, it is necessary for the engineer to make an estimate of this crude oil property from the readily available measured producing parameters. Several graphical and mathematical correlations for determining $P_b$ have been proposed during the last four decades. These correlations are essentially based on the assumption that the bubble-point pressure is a strong function of gas solubility $R_s$, gas gravity $g_g$, oil gravity API, and temperature $T$.

Several ways of combining the above parameters in a graphical form or a mathematical expression are proposed by numerous authors, including:

- Standing
- Vasquez and Beggs
- Glaso
- Marhoun
- Petrosky and Farshad

**Standing’s Correlation**

Based on 105 experimentally measured bubble-point pressures on 22 hydrocarbon systems from California oil fields, standing (1947) proposed a graphical correlation for determining the bubble-point pressure of crude oil systems. The correlating parameters in the proposed correlation are
the gas solubility $R_s$, gas gravity $g_g$, oil API gravity, and the system temperature. The reported average error is 4.8%. In a mathematical form, standing (1981) expressed the graphical correlation by the following expression:

$$P_b = 18.2 \left( \frac{R_s}{g_g} \right)^{0.83} (10)^a - 1.4$$ .............................................. (3-10)

$$a = 0.00091 (T - 460) - 0.0125 (API)$$ .............................................. (3-11)

Where:

$P_b = \text{bubble-point pressure, psia}$

$T = \text{system temperature, } ^\circ R$

**Glaso’s Correlation**

Glaso (1980) used 45 oil samples, mostly from the North Sea hydrocarbon system, to develop an accurate correlation for bubble-point pressure prediction. Glaso proposed the following expression:

$$\log (P_b) = 1.7669 + 1.7447 \log (p^*_b) - 0.30218 [\log (p^*_b)]^2$$ ............ (3-12)

Where $P_b^*$ is a correlating number and defined by the following equation:

$$P_b^* = \left( \frac{R_s}{g_g} \right)^a (t)^b (API)^c$$ .............................................. (3-13)

Where:

$R_s = \text{gas solubility, scf/STB}$

$t = \text{system temperature, } ^\circ F$

$g_g = \text{average specific gravity of the total surface gases}$

$a, b, c = \text{coefficients of the above equation having the following values:}$

$a = 0.816$

$b = 0.172$
Marhoun’s Correlation:

Marhoun (1988) used 160 experimentally determined bubble-point pressures from the PVT analysis of 69 Middle Eastern hydrocarbon mixtures to develop a correlation for estimating $P_b$. The author correlated the bubble-point pressure with the gas solubility $R_s$, temperature $T$, and specific gravity of the oil and the gas. Marhoun proposed the following expression:

$$P_b = a \cdot R_s^b \cdot \gamma_g^c \cdot \gamma_o^d \cdot T^e$$

Where:

- $T = \text{temperature, } ^\circ\text{R}$
- $\gamma_o = \text{stock-tank oil specific gravity}$
- $\gamma_g = \text{gas specific gravity}$
- $a = 5.38088 \times 10^{-3}$
- $b = 0.715082$
- $c = -1.87784$
- $d = 3.1437$
- $e = 1.32657$

The reported average absolute relative error for the correlation is 3.66% when compared with the experimental data used to develop the correlation.

The Petrosky-Farshad Correlation

The Petrosky and Farshad gas solubility equation, Equation (3-8), can be solved for the bubble-point pressure to give:
\[ P_b = \left[ \frac{112727 R_s^{0.577421}}{\gamma_g^{8.43910^x}} \right] - 1391.051 \] \hspace{1cm} (3-15)

Where the correlating parameter \( x \) is previously defined by Equation (3-9). The authors concluded that the correlation predicts measured bubble point pressures with an average absolute error of 3.28%.

**The Vasquez-Beggs Correlation**

Vasquez and Beggs’ gas solubility correlation as presented by Equation (3-2) can be solved for the bubble-point pressure \( p_b \) to give:

\[ P_b = \left[ \left( \frac{c_1 R_s}{\gamma_g} \right) 10^a \right] c^2 \] \hspace{1cm} (3-16)

Where:

\[ a = - C3 \frac{API}{T} \] \hspace{1cm} (3-17)

The gas specific gravity \( \gamma_g \) at the reference separator pressure is defined by Equation (3-3). The coefficients \( C1, C2 \) and \( C3 \) have the following values:

<table>
<thead>
<tr>
<th>Coefficient</th>
<th>API &quot; 30</th>
<th>API &gt; 30</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>27.624</td>
<td>56.18</td>
</tr>
<tr>
<td>C2</td>
<td>0.914328</td>
<td>0.84246</td>
</tr>
<tr>
<td>C3</td>
<td>11.172</td>
<td>10.393</td>
</tr>
</tbody>
</table>
3.3.3 Oil Formation Volume Factor:

The oil formation volume factor, Bo, is defined as the ratio of the volume of oil (plus the gas in solution) at the prevailing reservoir temperature and pressure to the volume of oil at standard conditions. Bo is always greater than or equal to unity. The oil formation volume factor can be expressed mathematically as:

\[ Bo = \frac{(Vo)_{p,T}}{(Vo)_{sc}} \] \hspace{1cm} (3-18)

Where:

- Bo = oil formation volume factor, bbl/STB
- (Vo)_{p,T} = volume of oil under reservoir pressure P and temperature T, bbl
- (Vo)_{sc} = volume of oil is measured under standard conditions, STB

A typical oil formation factor curve, as a function of pressure for an under saturated crude oil (pi > pb), is shown in Figure (3-4). As the pressure is reduced below the initial reservoir pressure pi, the oil volume increases due to the oil expansion. This behavior results in an increase in the oil formation volume factor and will continue until the bubble-point pressure is reached. At pb, the oil reaches its maximum expansion and consequently attains a maximum value of Bob for the oil formation volume factor. As the pressure is reduced below pb, volume of the oil and Bo are decreased as the solution gas is liberated. When the pressure is reduced to atmospheric pressure and the temperature to 60°F, the value of Bo is equal to one. Most of the published empirical Bo correlations utilize the following generalized relationship:

\[ B_o = f(R_s, \gamma_g, \gamma_o, T) \]
Five different methods of predicting the oil formation volume factor are presented below:

- Standing’s correlation
- The Vasquez-Beggs correlation
- Glaso’s correlation
- Marhoun’s correlation
- The Petrosky-Farshad correlation

It should be noted that all the correlations could be used for any pressure equal to or below the bubble-point pressure.
Standing’s Correlation

Standing (1947) presented a graphical correlation for estimating the oil formation volume factor with the gas solubility, gas gravity, oil gravity, and reservoir temperature as the correlating parameters. This graphical correlation originated from examining a total of 105 experimental data points on 22 different California hydrocarbon systems. An average error of 1.2% was reported for the correlation. Standing (1981) showed that the oil formation volume factor can be expressed more conveniently in a mathematical form by the following equation:

$$B_o = 0.9759 + 0.000120[R_s(y_g/y_o)^{0.5} + 1.25(T-460)]^{1.2} \ldots \ldots (3-18)$$

Where:

- $T = \text{temperature, } ^\circ\text{R}$
- $y_o = \text{specific gravity of the stock-tank oil}$
- $y_g = \text{specific gravity of the solution gas}$

**Vasquez and Beggs:**

Vasquez and Beggs (1980) developed a relationship for determining $B_o$ as a function of $R_s$, $y_o$, $y_g$, and $T$. The proposed correlation was based on 6,000 measurements of $B_o$ at various pressures. Using the regression analysis technique, Vasquez and Beggs found the following equation to be the best form to reproduce the measured data:

$$B_o = 1.0 + C_1R_s + (T-520)(API/y_{gs})[C_2+C_3R_s] \ldots \ldots (3-19)$$
Table (3-3) Coefficient of equation (3-19)

<table>
<thead>
<tr>
<th>Coefficient</th>
<th>API=30</th>
<th>API &gt; 30</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>4.677*10^{-4}</td>
<td>4.677*10^{-4}</td>
</tr>
<tr>
<td>C2</td>
<td>1.751*10^{-3}</td>
<td>1.100*10^{-3}</td>
</tr>
<tr>
<td>C3</td>
<td>-1.811*10^{-8}</td>
<td>1.337*10^{-9}</td>
</tr>
</tbody>
</table>

Vasquez and Beggs reported an average error of 4.7% for the proposed correlation.

**Glaso's Correlation:**

Glaso (1980) proposed the following expressions for calculating the oil formation volume factor:

\[ B_o = 1.0 + 10A \] \hspace{1cm} (3-20)

Where:

\[ A = -6.58511 + 2.91329 \log B_{ob^*} - 0.27683 \left( \log B_{ob^*} \right)^2 \] \hspace{1cm} (3-21)

\( B_{ob^*} \) is a correlating number and is defined by the following equation:

\[ B_{ob^*} = R_s \left( \gamma_g / \gamma_o \right)^{0.526} + 0.968(T-460) \] \hspace{1cm} (3-17)

Where:

- \( T \) = temperature, °R
- \( \gamma_o \) = specific gravity of the stock-tank oil.

The above correlations were originated from studying PVT data on 45 oil samples. The average error of the correlation was reported at -0.43% with a standard deviation of 2.18%. Sutton and Farshad (1984) concluded that
Glaso’s correlation offers the best accuracy when compared with the Standing and Vasquez-Beggs correlations. In general, Glaso’s correlation under predicts formation volume factor. Standing’s expression tends to over predict oil formation volume factors greater than 1.2 bbl / STB. The Vasquez-Beggs correlation typically over predicts the oil formation volume factor.

**Marhoun’s Correlation**

Marhoun (1988) developed a correlation for determining the oil formation volume factor as a function of the gas solubility, stock-tank oil gravity, gas gravity, and temperature. The empirical equation was developed by use of the nonlinear multiple regression analysis on 160 experimental data points. The experimental data were obtained from 69 Middle Eastern oil reserves. The author proposed the following expression:

\[
B_o = 0.497069 + 0.86296 \times 10^{-3} T + 0.182594 \times 10^{-2} F + 0.318099 \times 10^{-5} F^2
\]

\[\text{……………………………………………………………………………………………………(3-22)}\]

with the correlating parameter \(F\) as defined by the following equation:

\[
F = R_s^a \gamma_g^b \gamma_o^c
\]

\[\text{……………………………………………………………………………………………………(3-23)}\]

The coefficients \(a\), \(b\) and, \(c\) have the following values:

\[
\begin{align*}
a &= 0.742390 \\
b &= 0.323294 \\
c &= -1.202040
\end{align*}
\]

Where \(T\) is the system temperature in °R
The Petrosky-Farshad Correlation

Petrosky and Farshad (1993) proposed a new expression for estimating $B_o$. The proposed relationship is similar to the equation developed by Standing; however, the equation introduces three additional fitting parameters in order to increase the accuracy of the correlation. The authors used a nonlinear regression model to match experimental crude oil from the Gulf of Mexico hydrocarbon system. Their correlation has the following form:

$$B_o = 1.0113 + 7.2046 \times 10^{-5} \left[ \text{Rs}^{0.3738} \left( \frac{\gamma_g^{0.2914}}{\gamma_o^{0.6265}} \right) + 0.24626 \left( T - 460 \right) \right]^{3.0936} \tag{3-24}$$

Where:

- $T$ = temperature, °R
- $\gamma_o$ = specific gravity of the stock-tank oil

3.6 Data Requirements and Input:

The following data are required for Material Balance Analysis using MBAL software:

- PVT Data
- Initial Reservoir Pressure
- Reservoir Average Pressure History
- Production History
- All available Reservoir and Aquifer Parameters
3.7 Describing PVT:

To appropriately estimate the reservoir pressure and saturation changes as fluid is produced throughout the reservoir requires a precise description of the reservoir fluid properties. To accurately describe these properties, the ideal process is to sample the reservoir fluid and perform a laboratory studies on the fluid samples. This is not always possible to continuously take fluid sample for analysis as the reservoir pressure declines; hence, engineers have resorted to correlations to generate the fluid properties. MBAL program uses traditional black oil correlations, such as Petrosky and Fashad (1993), Standing a(1994) and Glaso (1980) etc. The PVT data in this research obtained from L.P Dake (Chapter 9. Example 9.2) , this study depend on Glaso's correlation.

3.8 History Matching:

History matching involves a trial and error approach to provide a best fit comparison between the observed data and the calculated data on a zero dimensional level. It comprises the functions of the graphical method, the analytical method, simulation tests and pseudo-relative permeability matching techniques. History matching is used to determine and identify sources of reservoir energy and their magnitude, the value of $OOIP$, $Gi$, aquifer type and strength etc. History matching in MBE is the most effective way to determine the aquifer model that best fits the observed data.
3.9 Water influx

Nearly all hydrocarbon reservoirs are surrounded by water-bearing rocks called aquifers. These aquifers may be substantially larger than the oil or gas reservoirs they adjoin as to appear infinite in size, or they may be so small in size as to be negligible in their effect on reservoir performance. As reservoir fluids are produced and reservoir pressure declines, a pressure differential develops from the surrounding aquifer into the reservoir. Following the basic law of fluid flow in porous media, the aquifer reacts by encroaching across the original hydrocarbon-water contact. In some cases, water encroachment occurs due to hydrodynamic conditions and recharge of the formation by surface waters at an outcrop. In many cases, the pore volume of the aquifer is not significantly larger than the pore volume of the reservoir itself. Thus, the expansion of the water in the aquifer is negligible relative to the overall energy system, and the reservoir behaves volumetrically. In this case, the effects of water influx can be ignored. In other cases, the aquifer permeability may be sufficiently low such that a very large pressure differential is required before an appreciable amount of water can encroach into the reservoir. In this instance, the effects of water influx can be ignored as well. Several models have been developed for estimating water influx that is based on assumptions that describe the characteristics of the aquifer. Due to the inherent uncertainties in the aquifer characteristics, all of the proposed models require historical reservoir performance data to evaluate constants representing aquifer property parameters since these are rarely known from exploration-development drilling with sufficient accuracy for direct application. The material balance equation can be used to determine historical water influx provided original oil-in-place is known from pore
volume estimates. This permits evaluation of the constants in the influx equations so that future water influx rate can be forecasted. The mathematical water influx models that are commonly used in the petroleum industry include:

- Pot aquifer
- Schilthuis’s steady-state
- Hurst’s modified steady-state
- The Van Everdingen-Hurst unsteady-state
- The Carter-Tracy unsteady-state
- Fetkovich’s method

3.10 Graphical method

The first step taken was to plot \((\frac{F}{We}) / E_t \) versus \(F\) (i.e. the withdrawal) known as Campbell’s plot with no aquifer defined initially. If there is no other source of reservoir energy other than the total fluid expansion \(E_t\), then this Campbell’s plot will be a horizontal straight line with a Y axis intercept equal to the original oil in place (OOIP). Any “turn-up” in the plot (i.e. deviation from the theoretical horizontal straight line) indicates another source of energy present (due to a source (injector) or an aquifer influx).

3.11 Analytical method

The analytical method allows for regression on all reservoir model parameters. Regression is used to adjust the reservoir model to minimize the difference between the observed/measured and the model production. It is used to assess the effects of varying parameters such as formation
compressibility that cannot easily be assessed using graphical methods. The quality of the regression match is expressed as the standard deviation between model and measured values. The analytical plot was regressed to compute the oil in place, the encroachment angle, and the aquifer permeability, inner and outer radius

### 3.12 Energy Plot

The plot describes the prevalent energy system present in the reservoir; water influx, pore volume compressibility, fluid expansion, ingestions etc. It describes the fractional contributions of these energy systems present in the reservoir and the most prominent at various date.
4.1 PVT Data:

The data used in this study were obtained from Dake’s book. The correlation that gives best matching with original PVT data that used is Glaso's correlation. Figure (4-1) illustrates that.

The correlation that gives least standard deviation is the correlation that has best match.

Figure (4-1) oil black matching
The plot of Bo versus pressure show that the type of reservoir is saturated reservoir because \( P_i = P_b \), Figure (4-2) show that.

**Figure (4-2) Plot of FVF versus Pressure**

Plot of Gas Oil Ratio versus pressure also show that the type of reservoir is saturated reservoir, Figure (4-3).

**Figure (4-3) Plot of Gas Oil Ratio versus pressure**
4.2 History Matching

4.2.1 Graphical Method:

Figure (4-4) Campell – No Aquifer

Figure (4-4) shows that an additional energy mechanism was suspected due to the turn-up seen in the Campbell’s plot, so aquifer fitting followed in order to compensate for the turn-up observed so as to obtain a history match, figure (4-5).

Figure (4-5) Graphical Plot (Campbell-aquifer)
4.2.2 Analytical Method

Figures (4-6) shows the analytical history matched model after regression analysis has been carried out. Regression analysis was carried out to improve the quality of the match. The red line shows the simulated model without aquifer strength while the blue line shows the simulated model with aquifer strength after regression, figure (4-6). The black zigzag line represents the history (measured data points); the history trend depicts a uniform pressure decline. As can be seen, the blue line matches with the measured data points and this mean that the reservoir is supported by aquifer.

Original oil in place is (306.6 MM STB) and this value is very close to the value of the Dake example (312 MMSTB).
4.2.3 Energy Plot

From Figure (4-7), it can be seen that there are three drives affecting the recovery of oil which are Pore Volume Compressibility (represented in green). Fluid Expansion (in blue sections of figure(4-7) and aquifer (in red sections of figure(4-7) with Fluid Expansion being the dominant drive.

![Figure (4-7) Energy plot](image-url)
4.4 Future Prediction

First Case: Constant Rate Of Oil Producing 20000 STB/Day From 2004/08/01 To 2010/08/01 And, Without Any Injection.

Figure (4-8) show that the cumulative oil will be 121.25 MM STB, and the pressure will be 1048.3 psia at 2010/08/01.

![Figure (4-8) Production prediction without injection](image)

Second Case: Water Injection Rate Of 20000 STB/Day.

Figure (4-9) show that the cumulative oil produced will be 94.7305 MM STB, and pressure will be 1413.46 psia - at 2010/08/01. This case shows that drop pressure of reservoir is reduced by water injection, comparing with the first case where there is no injection, the cumulative oil produced is reduced and this mean reducing in drop pressure lead to reducing in cumulative oil produced.
Third Case: Water Injection Rate 40000 STB/Day

Figure (4-10) show that cumulative oil produced will be 94.7305 MM STB and pressure will be 2030.65 psia at 2010/08/01.
This case show that the reservoir pressure increased from 1440 psig at 2004/08/01 to 2030 psig at 2010/08/01. This mean increasing in reservoir life, while cumulative oil produced is same as second case.
CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions:

1. This study depended on MBAL software to calculate OOIP and to predict the future performance of the reservoir in three cases.
2. The value of OOIP that obtained in this study was very close to measured value this means that using mbal software to determine OOIP is provided.
3. The drive mechanism in studied reservoir was water-drive and this concluded from the diagnostic plot of Campbell’s plot as shown in Fig (4-4).
4. History matching was achieved with high percentage in compared with measured pressure, and this is an important indicator that the modeling with Mbal is precise and simulates reality.
5. Aquifer model was selected and we got quite good match in the historical production data.
6. Different production scenarios has been investigated to predict the reservoir performance for six years and it shows that injection 40000 STB/day of water would lead to 2030 psig average reservoir pressure compared to 1413 psig (20,000 STB/day water injection) and 1048 psig (for depletion case).
7. Water injection can be used to reduce drop pressure of reservoir (second case) also it can be used to increase life of reservoir (third case).
5.2 Recommendations:

1. MBAL software is good and reliable software in calculating OOIP and predicting the performance of the reservoir in the future.
2. Softwares such as: Petrel and Eclipse can be used to make sure that the results obtained from MBAL are valid results.
3. PVT data can be calculated by another software like PVTP software to take in consideration of multi well PVT.
4. A Monte Carlo analysis is also recommended to enhance credibility of estimate and minimize the inherent risk associated with underestimation or overestimation.
References:

**APPENDIX (A)**

**DATA USED IN THE STUDY**

Table (A 1) PVT data for L.P Dake example 9.2

<table>
<thead>
<tr>
<th>Time (Day)</th>
<th>Pressure (psig)</th>
<th>GOR (scf/STB)</th>
<th>Oil FVF (rb/STB)</th>
<th>Gas FVF (rb/SCF)</th>
<th>Oil viscosity (cp)</th>
<th>Gas viscosity (cp)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>2740</td>
<td>650</td>
<td>1.404</td>
<td>0.0004</td>
<td>0.54</td>
<td>0.0148</td>
</tr>
<tr>
<td>365</td>
<td>2500</td>
<td>592</td>
<td>1.374</td>
<td>0.001</td>
<td>0.589</td>
<td>0.0148</td>
</tr>
<tr>
<td>730</td>
<td>2290</td>
<td>545</td>
<td>1.349</td>
<td>0.001</td>
<td>0.518</td>
<td>0.0148</td>
</tr>
<tr>
<td>1096</td>
<td>2109</td>
<td>507</td>
<td>1.329</td>
<td>0.001</td>
<td>0.497</td>
<td>0.0148</td>
</tr>
<tr>
<td>1461</td>
<td>1949</td>
<td>471</td>
<td>1.316</td>
<td>0.001</td>
<td>0.497</td>
<td>0.0148</td>
</tr>
<tr>
<td>1826</td>
<td>1818</td>
<td>442</td>
<td>1.303</td>
<td>0.001</td>
<td>0.497</td>
<td>0.0148</td>
</tr>
<tr>
<td>2191</td>
<td>1702</td>
<td>418</td>
<td>1.294</td>
<td>0.002</td>
<td>0.497</td>
<td>0.0148</td>
</tr>
<tr>
<td>2557</td>
<td>1608</td>
<td>398</td>
<td>1.287</td>
<td>0.002</td>
<td>0.497</td>
<td>0.0148</td>
</tr>
<tr>
<td>2922</td>
<td>1535</td>
<td>383</td>
<td>1.28</td>
<td>0.002</td>
<td>0.497</td>
<td>0.0148</td>
</tr>
<tr>
<td>3287</td>
<td>1480</td>
<td>381</td>
<td>1.276</td>
<td>0.002</td>
<td>0.497</td>
<td>0.0148</td>
</tr>
<tr>
<td>3652</td>
<td>1440</td>
<td>364</td>
<td>1.273</td>
<td>0.002</td>
<td>0.497</td>
<td>0.00182</td>
</tr>
</tbody>
</table>

PVT data

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>GOR (Rs)</td>
<td>650 (scf/STB)</td>
</tr>
<tr>
<td>Oil Gravity</td>
<td>40 (API)</td>
</tr>
<tr>
<td>(γg)</td>
<td>0.7</td>
</tr>
<tr>
<td>Salinity</td>
<td>140000 (ppm)</td>
</tr>
</tbody>
</table>
### Table (A 2) Reservoir and aquifer data

<table>
<thead>
<tr>
<th>Parameter</th>
<th>L.P Example 9.2</th>
<th>Parameter</th>
<th>L.P Example 9.2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir thickness</td>
<td>100 ft</td>
<td>Temperature</td>
<td>115 F</td>
</tr>
<tr>
<td>Reservoir radius</td>
<td>9200 ft</td>
<td>Initial pressure</td>
<td>2740 psia</td>
</tr>
<tr>
<td>Aquifer radius</td>
<td>46000 ft</td>
<td>Porosity</td>
<td>0.25</td>
</tr>
<tr>
<td>Encroachment angle</td>
<td>140</td>
<td>Swc</td>
<td>0.05</td>
</tr>
<tr>
<td>Aquifer * permeability</td>
<td>200 md</td>
<td>Cw</td>
<td>3.00E-06 psi⁻¹</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Cf</td>
<td>4.00E-06 psi⁻¹</td>
</tr>
</tbody>
</table>

Relative permeability data

<table>
<thead>
<tr>
<th>Residual saturation</th>
<th>End point</th>
<th>Exponent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Krw</td>
<td>0.25</td>
<td>0.039336</td>
</tr>
<tr>
<td>Kro</td>
<td>0.15</td>
<td>0.8</td>
</tr>
<tr>
<td>Krg</td>
<td>0.05</td>
<td>0.9</td>
</tr>
</tbody>
</table>

### Table (A 3) Production data of L.P Dake Example 9.2

<table>
<thead>
<tr>
<th>Time (dd/mm/yyyy)</th>
<th>Pressure (psig)</th>
<th>Cumulative oil produced (MMSTB)</th>
<th>Cumulative gas produced (MMSCF)</th>
<th>Cumulative water produced (MMSTB)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/8/1994</td>
<td>2740</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1/8/1995</td>
<td>2500</td>
<td>7.88</td>
<td>5988.8</td>
<td>0</td>
</tr>
<tr>
<td>1/8/1996</td>
<td>2290</td>
<td>18.42</td>
<td>15564.9</td>
<td>0</td>
</tr>
<tr>
<td>1/8/1997</td>
<td>2109</td>
<td>29.15</td>
<td>26818</td>
<td>0</td>
</tr>
<tr>
<td>1/8/1998</td>
<td>1949</td>
<td>40.69</td>
<td>39672.8</td>
<td>0</td>
</tr>
<tr>
<td>1/8/1999</td>
<td>1818</td>
<td>50.14</td>
<td>51393.5</td>
<td>0</td>
</tr>
<tr>
<td>1/8/2000</td>
<td>1702</td>
<td>58.42</td>
<td>62217.3</td>
<td>0</td>
</tr>
<tr>
<td>1/8/2001</td>
<td>1608</td>
<td>65.39</td>
<td>71602.8</td>
<td>0</td>
</tr>
<tr>
<td>1/8/2002</td>
<td>1535</td>
<td>70.74</td>
<td>79228.8</td>
<td>0</td>
</tr>
<tr>
<td>1/8/2003</td>
<td>1480</td>
<td>74.54</td>
<td>85348.3</td>
<td>0</td>
</tr>
<tr>
<td>1/8/2004</td>
<td>1440</td>
<td>77.43</td>
<td>89818.8</td>
<td>0</td>
</tr>
</tbody>
</table>
APPENDIX (B)

PROCEDURE

B.1 Setting Up The Problem:

Begin the session by clearing all previous calculations Click – File - New. Save changes to your previous work if required. Select - Tool - Material Balance, and then click options from the main menu the following selections can be made:

Click done to return to main menu

B.2 PVT Menu

Click- PVT- Fluid properties and enter the Following PVT data:
The PVT correlation will now be matched to lab PVT data:

**Figure (B 2) PVT enters screen**

**Figure (B 3) match data enter screen**
As soon as the data is entered, the "Match Button" is selected again and this will prompt the regression screen:

**Figure (B 4) matching the data to correlation**

As soon as the calculations are finished, the "Match Parameters" screen will allow selection of the correlation that best matches the data:

**Figure (B 5) selecting the match parameters screen**
Figure (B 6) choosing the best correlation

From this, Glaso is chosen and selected in the main PVT screen:

Figure (B 7) Setting the chosen correlation

As the PVT is now done, the next section will describe how the reservoir data are entered.
B.3 Reservoir Input

![Reservoir screen data](image)

**Figure (B 8)** reservoir screen data

B.4 Rock Properties

Next, click on the **Rock Properties** tab. Select the User Specified button and enter the following:

Rock Compressibility = $4 \times 10^{-6}$

B.5 Relative Permeability

The next step is to select the **Relative Permeability** tab:
Figure (B 9) relative permeability screen

**B.6 Production History**

The next task is to set up the production history. Click on the Production History tab. Enter the following production data:

<table>
<thead>
<tr>
<th>Time (d/m/y)</th>
<th>Reservoir Pressure (Psig)</th>
<th>Cumulative Oil Produced (MMSTB)</th>
<th>Cumulative Gas Produced (MMscf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>01/06/1994</td>
<td>2740</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>01/08/1995</td>
<td>2500</td>
<td>7.88</td>
<td>5988.8</td>
</tr>
<tr>
<td>01/08/1996</td>
<td>2290</td>
<td>13.42</td>
<td>15564.9</td>
</tr>
<tr>
<td>01/08/1997</td>
<td>2109</td>
<td>29.15</td>
<td>26818</td>
</tr>
<tr>
<td>01/08/1998</td>
<td>1949</td>
<td>40.69</td>
<td>39672.8</td>
</tr>
<tr>
<td>01/08/1999</td>
<td>1818</td>
<td>50.14</td>
<td>51393.5</td>
</tr>
<tr>
<td>01/08/2000</td>
<td>1702</td>
<td>58.42</td>
<td>62217.3</td>
</tr>
<tr>
<td>01/08/2001</td>
<td>1608</td>
<td>65.39</td>
<td>71602.1</td>
</tr>
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<td>01/08/2002</td>
<td>1535</td>
<td>70.74</td>
<td>79228.8</td>
</tr>
<tr>
<td>01/08/2003</td>
<td>1480</td>
<td>74.54</td>
<td>85348.3</td>
</tr>
<tr>
<td>01/08/2004</td>
<td>1440</td>
<td>77.43</td>
<td>89818.8</td>
</tr>
</tbody>
</table>
B.7 History Matching

The purpose of this section is to illustrate a methodology for carrying out the matching process and compare the results obtained using a number of different methods. Bear in mind that the set of reservoir data entered in the **Input** section is used only as the starting point for the history matching.

The aquifer was initially disallowed. This will enable us to assess if an aquifer is present or not. Click **History Matching - All** and 3 tiled windows showing the available methods will be displayed.

![Figure (B 10) Accessing the history plots screen](image)

**Figure (B 10) Accessing the history plots screen**
Figure (B 11) History matching plot

Display the graphical plot full size by double clicking on its window title bar.

Figure (B 12) Graphical Methods plot
The graphical plots are based on the basic material balance formula:

\[ F = \frac{N}{Et} - W_e \]

Where:

- \( F \) = Total Production
- \( W_e \) = Water Influx
- \( Et \) = Total Expansion
- \( N \) = Original Oil in Place

The Campbell method is displayed by default. This plot displays:

\[ (F - \frac{W_e}{Et}) \text{ vs } F \]

Theoretically the data would be expected to fit to a horizontal line whose intersection with the Y axis gives the OOIP. The increasing trend in the data on the Campbell plot suggests that an aquifer may be the source of the increasing energy. In this case, an aquifer needs to be added to the model.

Going back to the tank input data screen, an aquifer is selected based on Dake's recommendation:
Figure (B 13) selecting an aquifer model.

Going back to "history matching – All"

Figure (B 14) History matching including aquifer
On the analytical methods, we select the "Regression" options:

**Figure (B 15)** selecting the Regression options.

On the regression screen, select the variable for regression.

**Figure (B 16)** select the variable for regression
**Figure (B 17)** Regression on selecting parameters

The best-fit button above will transfer all the calculated data on to the model and the necessary updates will be performed automatically when "Done" is clicked.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Start</th>
<th>Best Fit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil in Place</td>
<td>300</td>
<td>312.737 NMSTB</td>
</tr>
<tr>
<td>Initial Gas Cap</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Outer/Inner Radius</td>
<td>5</td>
<td>5.13861 feet</td>
</tr>
<tr>
<td>Reservoir Radius</td>
<td>9.200</td>
<td></td>
</tr>
<tr>
<td>Encroachment Angle</td>
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<td></td>
</tr>
<tr>
<td>Reservoir Thickness</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Porosity</td>
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<td></td>
</tr>
<tr>
<td>Aquifer Permeability</td>
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<td></td>
</tr>
<tr>
<td>Formation Compressibility</td>
<td>4.0-5</td>
<td></td>
</tr>
</tbody>
</table>

**Figure (B 18)** Campbell plot and analytical method after the mach
And from the simulation Screen It can be seen that the match is ok.

Figure (B 19) Simulation result